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Cyclic Water Injection

A Simulation Study

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Abstract

Cyclic waterflooding is a recovery method that increases the cumulative oil production in stratified, heterogeneous reservoirs. The process is based on alternated injection rates and alternating waterflood patterns within the reservoir. Improved oil recovery is achieved by improved sweep of low permeable layers and previously poor swept areas.

The thesis presents the results obtained from analytical evaluations and numerical simulations of a 2D and 3D synthetic model. The effect of cyclic injection is controlled by multiple parameters. A sensitivity study related to reservoir pressure, cycle period, injection rate, well spacing, reservoir thickness, wettability, permeability distribution, transmissibility, startup time and waterflood pattern was conducted.

From the simulation results, cyclic injection shows promising results related to increased oil production and reduced water production. All the simulated cases produced additional oil in the range of 2-20% compared to a conventional waterflood. The best case was found to be the more intensive injection schemes with a relative short base period, and startup time at high water cut. Improved oil recovery is accompanied by significant decrease in water production.

Cyclic water injection can improve a waterflood in terms of improved oil recovery and reduced water production at virtually zero additional cost, and is easy to implement.

Sammendrag

Syklisk vanninjeksjon er en utvinningsteknikk som øker den totale oljeproduksjon i lagdelte, heterogene reservoar. Metoden baserer seg på alternerende injeksjons rate og endring i vannstrømmings mønster i et reservoar. Økt oljeutvinning er oppnådd ved økt fortrengningseffektivitet av de lav permeable lagene og tidligere lite fortrengte områder.

Denne avhandlingen presenterer resultatene som er oppnådd gjennom analytiske evalueringer og numeriske simuleringsmodeller av en syntetisk 2D og 3D modell. Effekten av syklisk vanninjeksjon er styrt av ulike parametere. Sensitivitetsstudie relatert til reservoar trykk, syklisk periode, injeksjons rate, avstand mellom brønner, reservoar tykkelse, fuktighet, permeabilitetsfordeling, vertikal overførbarhet, oppstartstid og strømningsmønster er utført.

Resultatene fra simuleringsmodellene viser lovende resultater ved syklisk vanninjeksjon i form av økt utvinning og redusert vannproduksjon. Alle simuleringsmodellene produserte ytterligere olje i forhold til tradisjonell vanninjeksjon i en størrelsesorden på 2-20%. Det mest optimale tilfelle var funnet å være de mer intense injeksjonsordninger med relativt korte basisperioder, med oppstart ved høye vannkutt. I tillegg til økt utvinning, resulterer syklisk vanninjeksjon til mindre vann produksjon.

Syklisk vanninjeksjon kan øke utvinning i form av økt oljeproduksjon og redusert vannproduksjon ved nesten null ekstra utgifter, og kan enkelt bli iverksatt.

Acknowledgement

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Table of Contents

Table of Figures

List of Tables

1. Introduction

1.1 Motivation

This section is partly taken from and modified from the specialization project written by the author fall 2013 (Langdalen, 2013).

Secondary recovery methods are used to improve oil recovery beyond the natural drive mechanisms which appear during a primary production stage, and waterflooding is the oldest and by far the most common used secondary recovery technique. One limitation in secondary recovery projects is the excessive water production. An alternative to the conventional waterflood is cyclic waterflooding. Especially in mature waterflood projects where the water cuts are reaching uneconomic levels and resulting in low ultimate recovery (Arenas and Dolle, 2003), the waterflood can be optimized by cyclic injection or production.

In the Russian fields Jablonev Ovrag and Kalinovskoye in the Ural-Volga area at the beginning of the 1960's cyclic injection was applied for the first time as a method to improve recovery (Surguchev et al., 2008). Large scale cyclic injection was implemented in the Samara region, the Tatar republic in the Ural-Volga basin, and in the West Siberia, Russia (Surguchev et al., 2008). The cyclic waterflooding resulted in additional 23.2 million tons in 1984 compared to a continuous waterflood, Table 1.1, and the positive results led to further interest in the procedure.

In the US (Brownscombe and Dyes, 1952), China (Pu et al., 2009) and as mentioned the former Soviet Union (Gorbunov et al., 1977), cyclic injection has improved the sweep efficiency in both carbonate and sandstone reservoirs.

Table 1.1: Results from cyclic water injection application in Russia (Surguchev et al., 2008)

	Samara region Volga-Ural	Tatar republic Volga-Ural	West Siberia
Application period	1968-1984	1974-1984	1975-1984
Number of fields with cyclic waterflooding process	15	22	17
Additional oil production, million tons	6.8	8.4	8.0
Reduced water production, million m^3	N/A	25.2	2.8
Reduced water injection, million m^3	N/A	N/A	4.6

In addition to increasing oil recovery, cyclic water injection also reduces water production. Handling excessive water production is a common challenge in mature fields both in Norway and worldwide. The cumulative oil production on the Norwegian shelf in 2011 was 97.5 million cubic meters, in comparison with 161 million standard cubic meters of water (The Norwegian Petroleum Department, 2012). As a result of cyclic injection less water is injected into the reservoir – consequently, less water will be produced. Produced water contains natural and added chemicals, which need to be removed before it is released into the sea; a decreased water production requires less water treatment which may reduce operation costs. Limited water production is even more important for onshore wells, where the surface facilities are limited in storage tanks and most of the produced water must be re-injected into the reservoir (NPC, 2011).

On the Norwegian shelf, cyclic injection is a seldom used improved oil recovery (IOR) method. Simulation studies of a heterogeneous sandstone in the North Sea (Shchipanov et al., 2008) and at the Lower Tilje/Åre formation in Heidrun (Surguchev et al., 2002) are two examples of cyclic injection studies of oil reservoirs on the Norwegian shelf. ConocoPhillips Norway is currently doing a study on cyclic injection and its impact on Ekofisk (ConocoPhillips, 2013). Around year 2000 an investigation of potential of different IOR methods on Ekofisk was conducted – and cyclic injection was deemed inefficient back then, with 0% additional oil recovery. In 2000, focus was on maximizing oil rate and recovery. Maximizing oil rate was accomplished by maximizing injection to re-pressurize the reservoir; hence conventional waterflooding was the most effective IOR method. Over ten years later the focus is still maximizing oil rate and recovery, but now that the flood is maturing, this is being attempted using a different injection strategy; specifically, cyclic injection. In essence, the “new” interest in cyclic water injection has originated from a maturing waterflood. Interest has continued to grow with (1) the recognition that potential recovery improvements are possible through multiple mechanisms and (2) the work that has been done so far show that temporary injection reductions do not significantly increase the well failure rate (ConocoPhillips, 2013). The strategy of optimizing a mature waterflood project as being done at Ekofisk, could also be applied to improve the recovery in other fields on the Norwegian shelf.

At Ekofisk, two additional benefits related to cyclic waterflooding could potentially be realized. Firstly, compaction can push oil from rock that was previously at residual oil saturation after waterflooding (SORw) into rock that can be displaced by water. Secondly, a lab experiment conducted by IRIS in 2006 resulted in potential recovery benefits associated with a cyclic injection core flood. Challenges associated with cyclic injection are compaction and its unfortunate impact on infrastructure (e.g. surface facilities and wellbores) (ConocoPhillips, 2013). In addition to enhance the oil production and limit the water production, cyclic water injection is applied at zero additional cost and applied with simple procedures.

1.2 Objectives

Simulation and laboratory studies have yielded positive results of cyclic injection (Surguchev et al., 2008, Surguchev et al., 2002, Shchipanov et al., 2008). In the specialization project "*Cyclic Water Injection: A Literature Study" (Langdalen, 2013)* the concept of cyclic injection was recognized to be well established in the industry. And the key reservoir parameters affecting the outcome of a successful cyclic waterflood were listed as (Langdalen, 2013):

- Reservoir heterogeneity and layering
- Fractures and fracture frequency
- Rock and fluid compressibility
- Saturation distribution in the reservoir
- Initiation time of the cyclic injection
- Duration of the cyclic period
- Maturity of the waterflood
- Pressure differences in the reservoir

However, there is little information about the optimum condition of a cyclic injection. The objective in this thesis is to investigate the optimum condition related to:

- Reservoir pressure related to bubblepoint pressure
- Duration of the cyclic period
    - Shifted or equal cycle length
    - Cycle lengths related to injection rates
- Wettability: water-, mixed- and oil-wet rock
- Magnitude of the permeability difference between the layers and transmissibility
- Distance between the injector and producer
- Initiation time of the cyclic injection
- Alternation of the waterflood pattern.

The uncertainties of cyclic injection are related to the physical IOR-mechanisms, ability to model and predict the efficiency of the process, and to design a field application for specific reservoir conditions (Shchipanov et al., 2008). In addition to investigate the unknown parameters listed above, a sensitivity study of the critical reservoir parameters influence on cyclic injection will be conducted for each case. Hopefully, this thesis will create a platform for additional work and give a greater understanding of the topic.

1.3 Approach and Organization

This thesis is based on simulations by Eclipse100 and FrontSim, and is a continuation of the specialization project written by the author (Langdalen, 2013). Some of the theoretical information is transferred from the specialization project and modified with respect to the thesis objectives. The thesis has the following configuration:

- Chapter 2 provides an overview of the cyclic water injection concept and previous work done related to the topic.
- Chapter 3 describes the important reservoir and fluid properties, and explains how they affect or are affected by cyclic water injection.
- Chapter 4 introduces the simulation models, cyclic schemes and rates applied in the study of cyclic injection.
- Chapter 5 presents the simulation results with a respective numerical evaluation, analyze and discussion.
- Chapter 6 includes an overall evaluation of the study and proposals for improvement
- Chapter 7 summarizes the work by making inferences from the results obtained.

2. Cyclic Injection

Before looking into the different physical mechanisms of cyclic water injection in detail and the reservoir properties affecting the process, a short introduction to the topic will be given in this section. *Most of this section has been modified from the specialization project written by the author (Langdalen, 2013).*

2.1 Cyclic Injection – The Concept

Cyclic water injection (CWI) is based on two mechanisms in stratified or fractured reservoirs; (1) alternating the injection rates and (2) changing the waterflood patterns. During the cyclic injection, water injection rate is systematically alternated between high/normal injection rate and low/halted injection rate. The injection rate is directly proportional to the injection pressure, therefore also to the external pressure support a reservoir is seeing during a waterflood. By alternating the pressure within the reservoir, transient pressure pulses will occur between layers with contrasting reservoir properties (Surguchev et al., 2002). Imbibition of water will flow from the high permeability layers into the low permeability layers during the time an injector is online. In a naturally fractured chalk, such as Ekofisk (Agarwal et al., 1999), water will imbibe from the fractures into the matrix. This period of injection will be referred to as the pressurizing half cycle. After a certain period of injection the injector is ceased or reduced for a determined time period, which is referred to as the de-pressurizing half cycle. During the de-pressurizing period, a countercurrent flow of oil from the low permeable layers into the high permeable layers (in chalk: from matrix to fracture) will occur. This newly mobilized oil will be swept towards a producer during the next pressurizing half cycle. This dual process consists of two “cycles”; hence the term cyclic injection, Figure 2.1

(Shchipanov et al., 2008). In this context cyclic water injection is sometimes referred to as pressure pulsing.

Another similar recovery method is the pressure pulse technology (PPT). The main difference between the CWI and PPT is the duration of the intervals between the pressure pulses. Where CWI applies cycles in the range of days to months, PPT provides dynamic pressure pulses in a frequency of 5-6 pulses per minute (Groenenboom et al., 2003). Instead of modify the injector another procedure could be to alternate the production rate or a combination of the two to alternate the reservoir pressure and/or changing the waterflood pattern. The improved recovery is obtained because of different physical mechanisms. Changes in reservoir pressure cause capillary- and viscous forces, gravity and compressibility to behave different than under a conventional, steady-state waterflooding. Later in the thesis these terms will be discussed further. Summarizing this subsection, cyclic water injection is a means of improving oil production and provides potential additional sweep of previously poor swept areas from three different mechanisms; (1) streamline changes, (2) compaction and associated sweep of newly mobilized oil, and (3) microscopic recovery benefits.

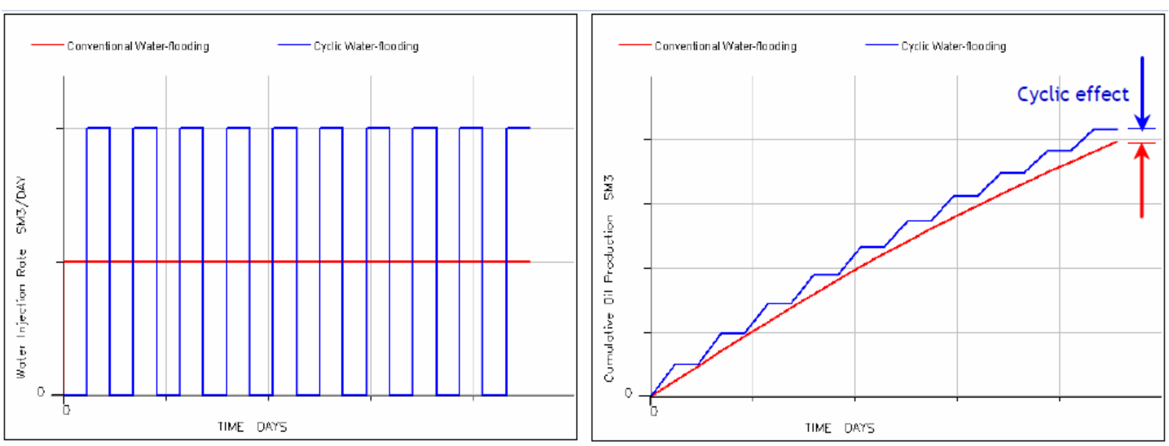

Figure 2.1: *Conceptual illustration of cyclic injection (blue) and conventional injection (red) (Shchipanov et al., 2008). Right: Injection rates. Left: Cumulative production to the corresponding pressure in the right side figure.*

2.2 Literature Review

This subsection is modified from the specialization project written by the author (Langdalen, 2013). In the project thesis the focus was on both experimental and simulation studies reported in the literature, while this thesis focuses more on the numerical simulation. For further information about the experimental work conducted on the topic see “Cyclic Water Injection: A Literature Review” (Langdalen, 2013).

Surguchev et al. (2002) did a simulation study of cyclic injection potential at the Lower Tilje/Åre formations of the Heidrun Field in the Norwegian Sea (Surguchev, et al., 2002). This study showed lower water cut (WC), increased sweep efficiency and faster oil production with cyclic water injection compared to continuous waterflood. Over a 10 years period of cyclic injection the reserves increased with 5 to 6% over a conventional waterflood. The most optimum injection scheme was the shorter but more intensive pulsing periods (injection/no injection ratios of 1:2 and 1:3). Surguchev et al. identified six reservoir characteristics that control the outcome of a cyclic water injection (Surguchev, et al., 2002):

- Heterogeneity and layering
- Degree of communication between the high and low permeable layers
- Presence of compressible reservoir rocks and fluids
- Pressure differences within the reservoir
- Frequency of fractures
- Pressure-dependent permeability in the fracture.

Shchipanov et al. (2008) outlined an effective work procedure to investigate cyclic water injection. The numerical errors can be limited by conducting a thoroughly analysis of the historical data and pre-screening of the key parameters. A synthetic 2D cross section should be modelled to get a better understanding of the potential following a cyclic waterflood for the reservoir being analyzed and pre-screen the key parameters. In the synthetic case, key parameters, such as rock-fluid parameters, fluid saturation distribution, heterogeneities, cycle-period and pressure depletions are evaluated. The study showed that the duration of the cycle length is controlling the influence of compressibility, gravity and capillary forces on cross flows and the process efficiency

(Shchipanov et al., 2008); Compressibility induced cross flow is dominating if the cycle lengths are short, and during a long-time cycle period the capillary and gravity are the controlling forces. After a synthetic model has been run, the results obtained should be implemented in a sector model of the actual field that is being investigated. Numerical simulations showed that a combination of cyclic injection and production resulted in maximum utilization of the IOR effects.

Surguchev et al. (2008) applied the concept of cyclic water injection in core flood experiments and numerical simulation of a carbonate rock with an artificial fissure in the middle. Cycling above and below bubble point were conducted after SORw was reached, and compared to conventional waterflooding. Oil recovery above bubble point resulted in an additional 2.9% oil recovery of original oil in place (OOIP). Cyclic injection with a pressure drop below the saturation point whilst keeping the free gas saturation below the critical gas saturation yielded an additional oil recovery of 5.9% of OOIP. The first cycle resulted in the largest incremental recovery. Surguchev et al. (2008) also stated that the cyclic injection initiation time has great influence of the additional oil recovered by the procedure. This result had been previously confirmed by Yaozhang et al. (2006) when a study of the cyclic injection initiated at different water cut levels was conducted. The cyclic process provided the greatest additional production when initiated at a water cut of 95% related to 70, 84.7 and 90% water cut. In the project thesis written by the author (Langdalen, 2013) it was explained that at lower water cuts pressure alternation could not improve oil by water exchange, but instead only increased the difference of oil distribution between the high and low permeable layers. At very high water cuts, water is almost the only mobile phase within the high permeable zone, and compressibility, gravity and capillary forces has greater influence on the exchange of oil in the low permeable layers by water from the high conductive zones.

The Spraberry Trend Area in west Texas is an area of great interest regarding cyclic water injection. Several studies related to the area have been conducted (Brownscombe and Dyes, 1952, Putra and Schechter, 1999, Elkins and Skov, 1963, Owens and Archer, 1966) to explain the benefits of cyclic water injection and the procedure of the process. Putra and Schechter (1999) proved with numerical simulations that over-injection was the reason for the poor recovery. From the numerical models, continuous waterflooding resulted in early water breakthrough and excessive water production. Different injection arrangements, with both equal and shifted cycle periods, were simulated and an 1:2-cyclic scheme yielded the highest cumulative recovery, Figure 2.2 (Putra and Schechter, 1999).

Al-Mutairi et al. (2008) focused on reducing excessive water production in mature oil fields by applying a cyclic production scheme (CPS). Instead of controlling the injection rates, alternation of the production rate can also improve recovery and reduce water cut. The procedure is the same as alternating the injection well; the producer is alternated between flowing and shutting condition over a predetermined period of time. Significant reduction in water cut was observed in simulation models, with a decrease up to 50% in cumulative water production. Optimization of the CPS was managed by determining the ideal cyclic startup time and cyclic period. Al-Mutairi et al. (2008) could not obtain any additional oil production in any of their simulation studies.

Arenas and Dolle (2003) introduced the term pressure cycling. Cyclic water injection, or pressure pulsing, uses the entire injector to perform the cycling. Pressure cycling applies a smart water injector to control the injection into isolated sections of the reservoir (Arenas and Dolle, 2003). This procedure helps to control the injection into zones which results in early breakthrough at the producer, simultaneously as the more homogeneous layers are being swept. Five development scenarios were compared in the study of a tight fractured reservoir; (1) conventional waterflooding, (2) no injection, (3) fracture shut-off at injector, (4) pressure cycling and (5) pressure pulsing. The cycling pressure and fracture shut-off option resulted in the highest ultimate recovery, typically in the range of 200-300% compared to conventional waterflood. In most cases cycling pressure was the preferred option with an improvement of ultimate recovery in the range of 10-60% over fracture shut-off.

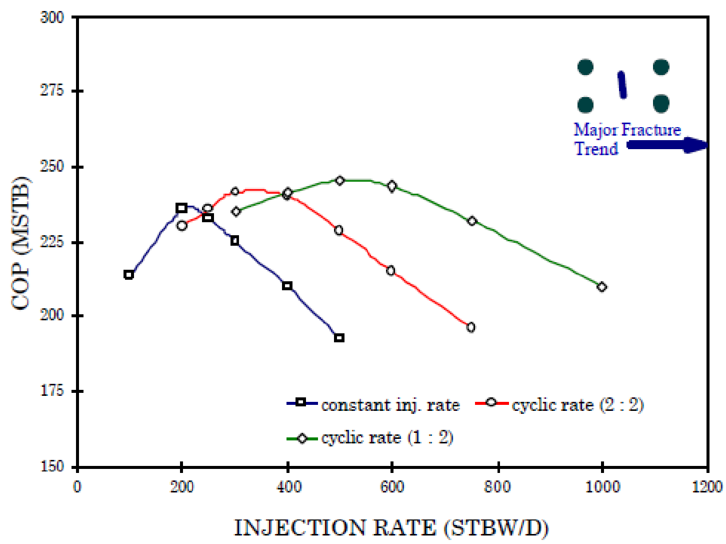

Figure 2.2: *Cumulative water injection for continuous (blue), homogeneous cyclic (red) and shifted cyclic injection (green) at different injection rates (Putra and Schechter, 1999).*

The previous work has increased the general knowledge of the recovery method. And in common between all the papers, both the ones based on numerical and experimental studies, is how the cyclic injection concept is defined, and which factors are important for the outcome of the method (Langdalen, 2013):

- Layer heterogeneity and fractures
- Rock and fluid compressibility
- Saturation distribution and maturity of the waterflood
- Initiation time of the cyclic injection and the cyclic rate with respect to duration
- Pressure differences in the reservoir

3. Fundamentals of Reservoir Properties

How successful a cyclic water injection becomes depends on several reservoir parameters. These parameters play an equal important role in a conventional waterflood, and there are lots of similarities in how they affect the recovery process. Although, the cyclic injection method can alternate the dominating displacement forces participating during the fluid flow. The literature predicts that cyclic waterflooding can result in additional oil production and reduced water cut compared to a conventional waterflood (Brownscombe and Dyes, 1952, Gorbunov et al., 1977, Surguchev et al., 2008, Pu et al., 2009, Shchipanov et al., 2008). This section will describe the important parameters associated with cyclic injection and explain their function related to cyclic water injection to better give an understanding of various effects used later in this thesis.

3.1 Hydrocarbon Reservoirs

Hydrocarbon reservoirs are complex systems with large variety of physical-chemical properties (density, PVT properties, viscosity, etc.) and formations types (fractured chalk stones, clastic sandstones, etc.) (Zitha et al., 2011). To accurately determine the fluid flow and recovery process at a full field scale, the process needs to be investigated at a micro scale. On a small scale the basis of the oil displacement can be observed and then be up-scaled to the reservoir scale, Figure 3.1 (Zitha et al., 2011). Different scales provide insight in how a recovery process could be implemented and the following benefits and limitations.

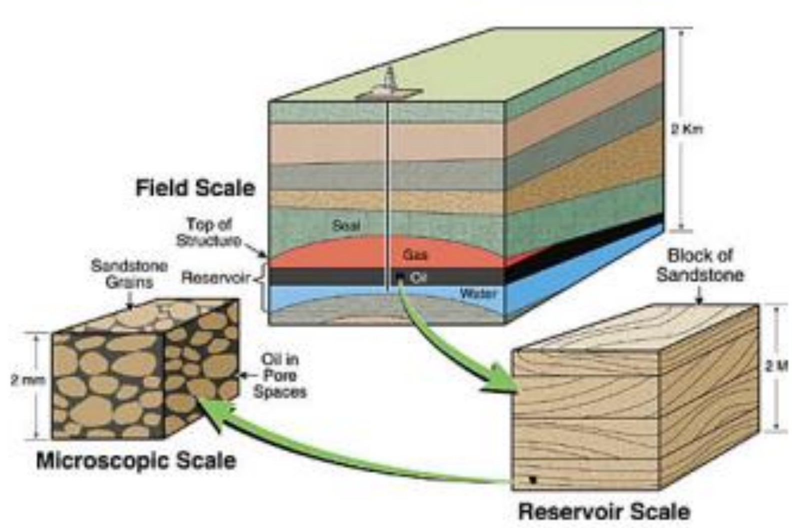

Figure 3.1: *Different scales of reservoir representation (Zitha et al., 2011).*

3.2 Porosity

The porosity (*φ*) of a rock is a measure of its storage capacity of fluids. Porosity is defined as the pore volume of the rock (V_p) divided by the bulk volume (V_b). Expressed in terms of symbols porosity is defined by Eq. (3.1) (Ezekwe, 2011).

$$\varphi = \frac{V_P}{V_b} \tag{3.1}$$

Two terms of porosities can be present in a formation; (1) primary porosity and (2) secondary porosity. The primary porosity is formed during the deposition of the rock. The secondary porosity is developed after deposition, and is caused by geological processes, ground stresses or water movement (Torsæter and Abtahi, 2003). Grain structure, size, sorting and packing affects the porosity in a rock. Further, porosity can be defined in total and effective porosity; total porosity includes all open pore space in a rock, while the effective porosity only considers the interconnected spaces in the rock (Ezekwe, 2011).

3.3 Permeability

One of the most important reservoir parameters is the permeability. Permeability is a measure of the ability of a material, such as a reservoir rock, to transmit fluids (Ezekwe, 2011). Absolute permeability is the measurement of the permeability with only one fluid present in the reservoir rock (Schlumberger, 2014). If more than one fluid is present in the system, the effective permeability measures the ability to flow a particular fluid through the reservoir rock (Ezekwe, 2011). The ratio of effective permeability to absolute permeability is defined as the relative permeability (Ezekwe, 2011):

$$k_{ri} = \frac{k_i}{k_a} \tag{3.2}$$

In Eq. (3.2) :

- k_{ri} = Relative permeability of the porous medium to fluid i
- k_i = Effective permeability of the porous medium for fluid i
- k_a = Absolute permeability of the porous medium.

Relative permeability is a crucial parameter to determine the ability of fluids to flow in a multiphase flow system like a waterflood. The relative permeability is a semi-empirical parameter strongly related to the saturation distribution (see chapter 3.4), describing how the physical effects are correlated with the saturation of a phase in a given volume. The most widely used correlations for determining the water, oil and gas relative permeability are different modifications of the Corey equations (Ezekwe, 2011):

$$k_{rw} = k_{rw@S_{orw}} \left(\frac{S_w - S_{wi}}{1 - S_{wi} - S_{orw}}\right)^n \tag{3.3}$$

$$k_{ro} = k_{ro@S_{wi}} \left(\frac{1 - S_w - S_{orw}}{1 - S_{wi} - S_{orw}}\right)^n \tag{3.4}$$

$$k_{ro} = k_{ro@S_{gi}} \left(\frac{1 - S_g - S_{wi} - S_{org}}{1 - S_{wi} - S_{org}}\right)^n \tag{3.5}$$

$$k_{rg} = k_{rg@S_{org}} \left(\frac{S_g - S_{gc}}{1 - S_{wi} - S_{org} - S_{gc}}\right)^n \qquad \textbf{(3.6)}$$

In Eq. (3.3) to (3.6):

- k_{rw} = Relative permeability of water
- k_{ro} = Relative permeability of oil
- k_{rg} = Relative permeability of gas
- $k_{rw@Sorw}$ = Water curve endpoint
- $k_{ro@Swi}$ = Oil curve endpoint
- $k_{ro@Sgi}$ = Oil curve endpoint
- $k_{rg@Sorg}$ = Gas curve endpoint
- S_w = Water saturation
- S_{wi} = Residual water saturation
- S_{orw} = Residual oil saturation
- S_{org} = Residual oil saturation to gas
- S_{gc} = Critical gas saturation
- n = Corey curve exponent.

The relative permeability dependence on phase saturation can also be illustrated as a function of water saturation (in an oil-water system) typically shown in Figure 3.2 (Torsæter and Abtahi, 2003).

The relative permeability curves are build up on three elements (Torsæter and Abtahi, 2003); (1) the endpoint fluid saturations, (2) the endpoint permeability, and (3) the shape of the relative permeability curves. The drainage curve describes a process with decreasing saturation of the wetting phase. And the imbibition curve describes the opposite function.

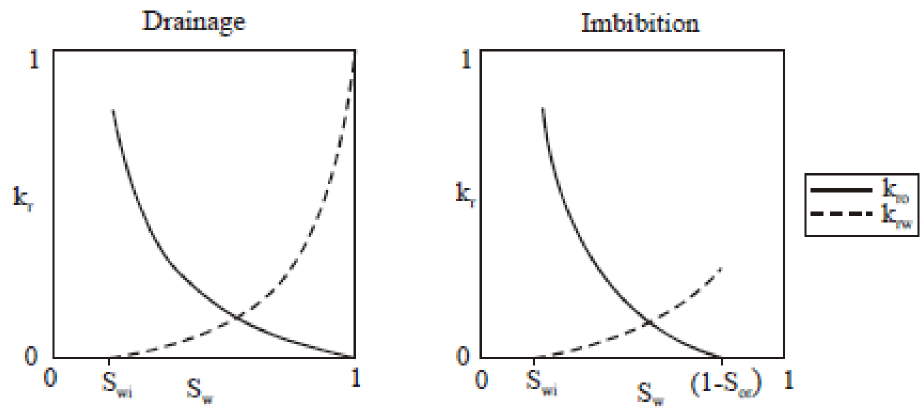

Figure 3.2: *Relative permeability curves for a water-wet system (Torsæter and Abtahi, 2003).*

The permeability is dependent on reservoir porosity and pressure. Darcy's law describes one phase, steady-state flow of a fluid through a porous medium, Eq. (3.7).

$$\vec{\upsilon_i} = -\frac{k}{\mu_i}\nabla\Phi_i \quad \textbf{(3.7)}$$

In Eq. (3.7):

- $\vec{\upsilon_i}$ = The velocity vector of fluid *i*
- k = Permeability
- μ_i = Viscosity of fluid *i*
- Φ_i = The potential of fluid *i* which is defined as the sum of pressure and hydrostatic head ($p_i + \rho_i g \nabla z$; *p* is the pressure; ρ_i is the density of fluid *i; g* is the gravitational acceleration constant; and *z* is the depth).

The success of a cyclic waterflooding is greatly dependent on the permeability distribution within the reservoir. Common to all literature regarding cyclic water injection is the presence of heterogeneity in the reservoir. The difference between a homogeneous and heterogeneous reservoir was explained by the author (2013); if all reservoir rock has the same permeability, the preferred water flow path is more or less equal all over the reservoirs. Hence, in a homogeneous reservoir the amount of bypassed oil is not segregated within the reservoir due to a uniform waterflood, and the benefit of extra imbibition is negligible. In a reservoir with anisotropy, high permeable layers would be swept more efficient compared to less permeable layers. Heterogeneous reservoirs will create a natural pressure difference between high and low permeable layers by means of water injection. The piezo-conductivity is different in high and low permeable layers. And the pressure transmitting capacity in the high permeable layers is greater compared to the low permeable zones; hence, the high permeable intervals become low pressure zones first under the de-pressuring cycle (Yaozhong et al., 2006).

During the pressurizing half cycle water is injected and the reservoir pressure increases. Water is expected to imbibe into the low permeable layers from the high permeable zones. The water saturation difference between layers of different permeability is increasing with the maturity of the waterflood. In a mature flood, the oil saturation in the low permeable layers is greater compared to in the high permeable layers, where water has displaced more of the oil. Yaozhang et al. (2006) explained that under a relative low water cut the exchange rate of oil by water will be low and production will see little improvement. In a mature waterflood, with water cut equal or higher than 95%, the high permeable zones are almost full filled with water; hence, gravitational and capillary forces can improve the production (Yaozhong et al., 2006). The magnitude of the imbibed water is depending on wettability, injection rates and pressure gradient between the layers. With a longer injection period, more of the low permeability rock surface area will be affected by the injected water. When the injection is reduced or shut-in the reservoir pressure will drop and countercurrent flow of both oil and water, from the low permeability rock into the high permeable zones, will take place. In a water-wet rock, the relative permeability of water and oil will increase and decrease respectively, with increased water saturation. Therefore, due to the relative permeability of water at low water saturations and the capillary pressure in a water-wet rock, water has a low flow capacity in the low permeable layers (Surguchev et al., 2002). In the low permeable layers capillary-retained water has displaced some of the oil and pushed previously un-swept oil towards the high permeability zones. As the injection is back online and a new cycle is initiated, the newly mobilized oil in the high permeable layers can easily be swept towards a producer.

When high permeability layers become low pressure zones, the natural energy of the system tends to transport fluids from the high pressure zones, with lower permeability and greater oil saturation, into the high permeable layers (Yaozhong et al., 2006). Water will be soaked up in the low permeable areas, and release mobilized oil for production. Differences in permeability and heterogeneity are necessary to create a favorable pressure drop in the vertical direction within the reservoir and greater interlayer cross flow (Shchipanov et al., 2008) when cyclic injection is being applied.

3.4 Saturation

Fluid saturation is defined as the ratio of the volume for a specific phase over the pore volume (Torsæter and Abtahi, 2003):

$$S_i = \frac{V_i}{V_p} \tag{3.8}$$

In Eq. (3.8):

- S_i = Saturation of phase i
- V_i = Volume of phase i
- V_p = Pore volume.

The relative permeability of a phase is greatly affected by the saturation, as shown in section 3.3; hence, the fluid flow and the areal sweep in a reservoir are essentially governed by the fluid distribution. Higher water saturation reflects rapid movement of water through high conductive areas (Agarwal et al., 1999).

Vertical cross flow can also be induced by saturation differences. Qingfeng et al. (1995) derived an expression of capillary pressure as a function of water saturation, pore radius and contact angle, Eq. (3.9).

$$\frac{\partial P_c}{\partial z} = \frac{\partial P_c}{\partial S_w}\frac{\partial S_w}{\partial z} - \frac{2\sqrt{2}\sigma\cos\theta \bullet J(\mathrm{S}_w)}{r_c^2}\frac{\partial r_c}{\partial z} + \frac{2\sqrt{2}\sigma\cos\theta \bullet J(S_w)}{r_c}\frac{\partial\cos\theta}{\partial z} \tag{3.9}$$

In Eq. (3.9):

- P_c = Capillary pressure
- S_w = Water saturation
- σ = Interfacial tension
- Θ = Contact angle
- $J(S_w)$ = Leverett's J-function
- r_c = Pore radius
- z = Vertical direction.

Water saturation induced cross flow will result in water flow from zones with high water saturation towards zones with lower water saturation (Qingfeng et al., 1995). Cyclic water injection will equalize the saturation differences between layers by pushing water into the low permeable, low water saturated layers and oil towards the high permeable, high water saturated layers – and make a more uniform fluid distribution. The initiation time of the cyclic process is also affected by the saturation distribution in a reservoir; in a more mature waterflood, the difference in water saturation distribution is greater than in an immature waterfood.

3.5 Wettability

Wettability plays a major role in conventional waterflooding by controlling the fluids flow and distribution in the reservoir, and has the same effect on a cyclic waterflooding. With multiple phases flowing in the reservoir the importance of understanding wettability becomes crucial. Wettability is defined as the preference of a solid to contact a specific fluid phase rather than another fluid. Wettability will strongly influence the waterflood behavior and relative permeability, because of its ability to control the distribution, flow and location of the different fluids in a porous medium (Anderson, 1987). Reservoir wettability varies between strongly water-wet and strongly oil-wet (Rao et al., 1992). The wettability of a fluid can be expressed by the contact angle, Θ, of the liquid-solid surface. As shown in Figure 3.3, the wetting characteristics of the fluid increases with decreasing contact angle.

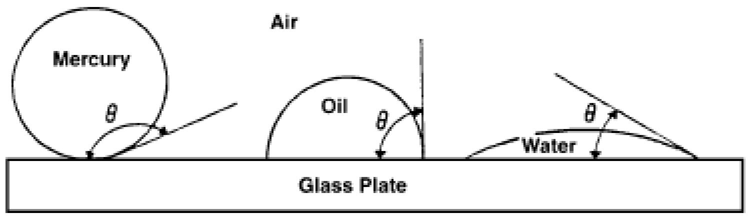

Figure 3.3: *Wettability and the respective contact angle (Ahmed, 2006).*

Literature often states that during a waterflood, the recovery in a water-wet reservoir is high when water breaks through, and little additional recovery is seen after the water breakthrough (Anderson, 1987). Oil-wet reservoirs usually have earlier water breakthrough, with oil production over a longer time period simultaneously with water production. Hence, the amount of water injected in an oil-wet reservoir is greater compared to a water-wet reservoir to reach the same amount of cumulative oil production, if possible.

The wetting phase will occupy the small pores and spread as a thin layer over the solid surface. The non-wetting phase will be distributed in the centers of the larger pores, resulting in lower energy of the system (Anderson, 1987). During a waterflood in a water-wet system the injected water imbibes into the smaller and medium sized pores and make oil more easily displaced in the larger pores (Anderson, 1987). Behind the water front in a water-wet system, oil could be trapped in discontinuous globules. Hence, in a mature waterflood most of the oil in place is immobile or not in contact with the displacement front and the water-oil ratio (WOR) rapidly increases after the water breakthrough. In an oil-wet system the fluid location is reversed. Waterflood in an oil-wet reservoir will create continuous channels of water through the center of the pore network, and the amount of bypassed oil is greater compared to a water-wet system.

Cyclic injection will utilize the spontaneous imbibition as a conventional waterflood. But the difference of wetness within the reservoir can provide an additional imbibition under the right circumstances during a cyclic injection. Qingfeng et al. (1995) expressed the vertical cross flow in terms of wettability, Eq.(3.10):

$$v_{zw} = \frac{1}{\frac{\mu_o}{k_z k_{ro}} + \frac{\mu_w}{k_z k_{rw}}} \left(\frac{\partial P_c}{\partial S_w} \frac{\partial S_w}{\partial z} - \frac{2\sqrt{2}\sigma \cos\theta \bullet J(S_w)}{r_c^2} \frac{\partial r_c}{\partial z} + \frac{2\sqrt{2}\sigma \cos\theta \bullet J(S_w)}{r_c} \frac{\partial \cos\theta}{\partial z} + \Delta\rho g \right) - \frac{k_z k_{rw}}{\mu_w} \frac{\partial p_{wa}}{\partial z} \quad \textbf{(3.10)}$$

Eq. (3.10) describes how greater wettability contrasts between layers can yield larger vertical cross flow of water from high to low permeability zones, and improve sweep efficiency.

3.5.1 Wettability Alteration

Understanding the wettability of a reservoir is essential to obtain a successful waterflood, as described in the previous section. Literature indicates that the most favorable wetting condition for improved recovery by waterflooding ranges from neutral to water-wet (Fathi et al., 2012, Jadhunandan and Morrow, 1995, Kulathu et al., 2013). Ionic composition of the injected brine, the chemistry of the crude oil, temperature, the mineralogy of the rock surface and initial wetting condition all affects the wetting alteration (Fathi et al., 2012). And the chemical adsorption on the rock surface creates wettability alteration (Araujo and Araujo, 2005).

Fathi et al. (2012) studied the impact of ionic composition and salinity of the injected brine in a carbonate rock. Injected brine of lower salinity increased both imbibition rate and the ultimate recovery relative to sea water (SW). Results of imbibition of modified sea water: i.e. sea water drained of potassium chloride, NaCl, (SW0NaCl); and sea water with 4 times the normal NaCl content (SW4NaCl) can be observed in Figure 3.4. Diluted sea water (dSW) yielded a low recovery, because of the reduction in concentrations of the active ions (Ca^{2+}, Mg^{2+} and SO_4^{2-}) which can alternate the wetting phase. Lower concentration of NaCl increases the recovery in a carbonate rock.

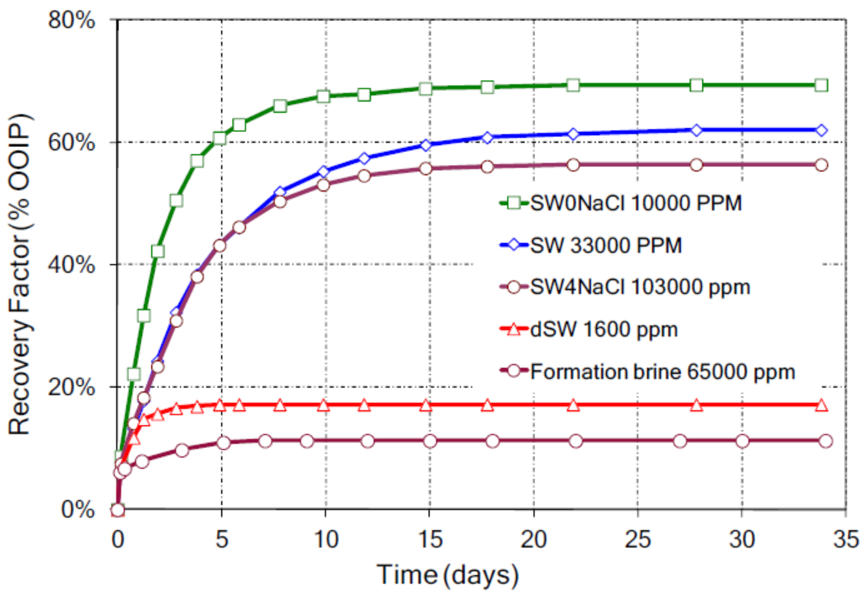

Figure 3.4: *Spontaneous imbibition into oil saturated chalk cores at 120 ^oC using different imbibing fluids with different salinities and ionic composition (Fathi et al., 2012).*

Active ions can interact with the positively charged chalk surface and result in wettability alteration (Fathi et al., 2012). Concentration of sulfate ion, SO_4^{2-}, had largest effect on oil recovery of the active ions in seawater. Higher temperature provides better environment for chemical reactions. Hence, increased temperature on the injected brine/modified brine strongly affected the wettability alteration and the oil recovery (Fathi et al., 2012). Combination of salinity and cyclic injection has yielded good results (Kulathu et al., 2013). Low salinity and cyclic injection of very short periods resulted in faster recovery and lower residual oil saturation relative to conventional waterflood. Reduction of salinity provided additional oil production for the same volume of injected brine. Also, Kulathu et al. (2013) stated that cyclic injection had greater oil recovery than continuous waterflooding, and the decrease in residual oil saturation was associated with an increase in water wetness.

3.6 Capillary Pressure

The capillary forces acting in a reservoir are the result of surface and interfacial tensions of the rock and fluids, pore size and structure, and the wetting phase of the fluids present (Ahmed, 2006). Whenever two immiscible fluids are in contact, a pressure difference occurs between the fluids; this pressure discontinuity is defined as the capillary pressure, Eq. (3.11).

$$p_c = p_{nw} - p_w \qquad \textbf{(3.11)}$$

In Eq. (3.11):

- p_c = Capillary pressure
- p_{nw} = Pressure of the non-wetting phase
- p_w = Pressure of the wetting phase.

The pressure excess in the non-wetting fluid is the capillary pressure and is a function of capillary pressure (Ahmed, 2006). The capillary force is reciprocal function of the pore radii, when assuming that the pores are circular. And the pressure needed for forcing the non-wetting phase out of the pore is given by Eq. (3.12):

$$p_c = \frac{2\sigma\cos\theta}{r} \qquad \textbf{(3.12)}$$

In Eq. (3.12):

- σ = Interfacial tension
- Θ = Contact angle
- r = Radius of pore element.

The capillary hysteresis and relative permeability curves at the micro level yields that fluids in the reservoir will switch between imbibition and drainage with alternating pressure – resulting in higher recovery. Saturation, pore radius and wettability differences between layers are controlling the intensity of the capillary cross flow (Qingfeng et al., 1995). Capillary forces will encourage inflow of water and oil leakage in low permeable zones, and enhance production and reduce water cut (Fedorov, 2012). A cyclic waterflood will equalize the saturation differences between layers by pushing water into low permeable, low water saturated layers and oil towards the high permeable, high water saturated layers – and make a more uniform fluid distribution. Hence, cyclic waterflood will reduce the effect of additional capillary cross flow in a water-wet reservoir. During the first cycle, both capillary cross flow and cyclic injection induced cross flow should be the greatest. This could be a contributing reason why incremental production seems to be largest following the first cycle, as observed in the study of cyclic injection in carbonate rock conducted by Surguchev et al. (2008). Halted water injection permits capillary pressure to become the dominated force. Rock and fluids will expand because of lower pressure, and improve expulsion of oil from matrix into fractures through compressibility (Elkins and Skov, 1963). This contradicts with continuous waterflooding and constant pressure injection, which primarily depends on capillary imbibition of water into the matrix to expel countercurrent flow (Elkins and Skov, 1963).

3.6.1 The Combined Effect of Viscous and Capillary Forces

Putra et al. (1999) described the critical and optimum water injection rate in a naturally fractured reservoir based on experiments and simulation studies. The critical water injection rate is defined as the maximum injection rate where the benefit of the capillary imbibition is absent (Putra et al., 1999). And the optimum injection rate is achieved at the injection rate where the capillary imbibition and capillary forces are balanced (Putra et al., 1999). In a naturally fractured system fluids are displaced between the matrix and fracture due to the difference in conductivity. This exchange of fluids are obtained by the viscous forces and the capillary forces – which respectively causes pressure gradient imposed water flow and spontaneous water imbibition from fracture into matrix. As the injection rate is increased the contact time between injected fluid and matrix is reduced, and thereby limiting the capillary imbibition efficiency (Putra et al., 1999). Babadagli (1994) stated that after a certain value an increase of injection rate will worsen the effect of capillary imbibition. This critical value was considered to be the maximum injection rate at which the capillary imbibition is ineffective (Babadagli, 1994). Based on the study of Putra et al. (1999) and Babadagli (1994) an optimum cyclic injection could also be obtained by balancing the capillary and viscous forces. A critical water injection rate is easiest evaluated experimentally, whilst an optimum injection rate must be obtained by simulation studies (Putra et al., 1999). The main difficulty by obtaining the optimum injection rate experimentally is related to the countless possible well configurations available in a field.

The effect of combined capillary and viscous forces is well described by McDougall and Sorbie (1993) in their study of the combined forces effect on waterflood efficiency. Even though there are some differences in a continuous and cyclic waterflood, the physical mechanisms described are applicable in both injection methods. The balance between viscous and capillary forces depends upon lamina orientation and matrix wettability (McDougall and Sorbie, 1993). When the geological aspects are included in the evaluation of a reservoir, the importance of applying the right scale to catch the physical mechanisms are crucial. The effect of layered systems is widely studied (Stiles, 1949, Goddin et al., 1966, Haq and Reis, 1993), and McDougall and Sorbie (1993) described the affection of various stratigraphic orientations on a waterflood by different scales, in both oil- and water-wet systems.

As the additional pressure from the injected water increases, it is able to overcome the capillary entry pressure and therefore fill up smaller and smaller pores. The interfacial tension is working against the injected water, and requires that an external pressure must be applied to the injected water (McDougall and Sorbie, 1993). If the waterflood is applied with low rate, the viscous forces within the system is negligible compared to the pressure difference between the oil- and water interface. As the injection rate increases, the viscous forces will increase and contribute to pushing water into the smaller pores. The threshold pressure is reciprocal to the pore radii and the largest pores will be filled first when the capillary imbibition is the dominating force. However, if the injection rate is increased and the viscous forces are no longer negligible the filling events can be altered (McDougall and Sorbie, 1993). According to Eq. (3.13) the viscous pressure drop over a pore, ΔP_i, can help or restrict invasion. If the injection rate is very high this pressure drop may be so large that the entry pressure for the corresponding pore becomes negative (McDougall and Sorbie, 1993). Water may be sucked into the pore if the threshold pressure becomes negative, and simultaneously invasion of different pores can be achieved (assuming the injection is constant).

$$P_{entry} = \frac{2\sigma \cos\theta}{r_i} + \Delta P_i \qquad \textbf{(3.13)}$$

In Eq. (3.13):

- P_{entry} = Total entry pressure for a pore
- σ = Interfacial tension
- Θ = Contact angle
- r_i = Radius of pore element *i*
- ΔP_i = Viscous pressure drop across element *i*.

McDougall and Sorbie (1993) concluded that under capillary dominated flow, conditions are favorable when flooding parallel with laminas compared to flow through vertical laminas, in both oil- and water-wet systems. And that layered water-wet systems achieve greater displacement efficiency as the viscous forces increase. In a cyclic waterflood the objective is to produce more oil from the low permeable layers; hence, McDougall and Sorbie’s (1993) work has a significant value. The case of a horizontal low permeable layer showed how a balance between the capillary and viscous force could be beneficial when flooding along the lamina; viscous forces displace the water through the high permeable layers, whilst capillary imbibition simultaneously makes water go into the low permeable layer, Figure 3.5 b; White indicates the pores that were filled first, followed by the darker color.

Figure 3.5c demonstrates how the viscous forces ignore the low permeable zone and trap oil within the low permeable zone. The overall production will be higher by obtaining a viscous dominated flow if the saturation distribution is equal in the low and high permeable zones. If the cyclic injection is initiated at late time in a mature waterflood, uniform saturation distribution is not the case; hence, a balance of capillary and viscous dominated flow could be the best injection scheme.

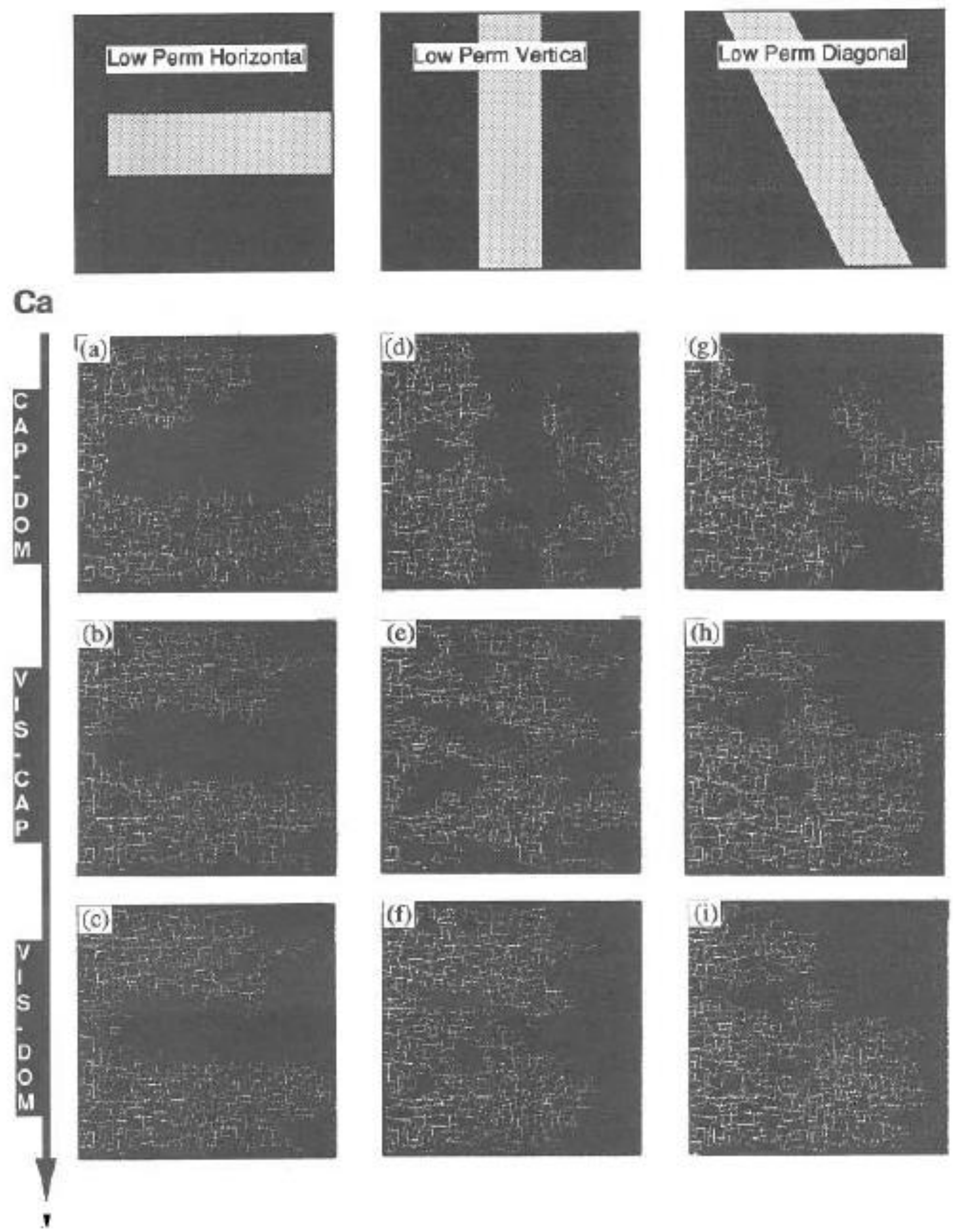

Figure 3.5: *Waterflood in heterogeneous water-wet system, for the respective geometry with a low permeability layer. Viscous forces increase downwards(McDougall and Sorbie, 1993) .*

3.7 Gravitational Forces

The force of gravity will affect the fluid distribution in a reservoir. Based on density, oil has a normal position above the water (and gas above the oil if present). Vertical transmissibility plays an important role in gravitational segregation of the fluids. An increase in vertical transmissibility should lead to greater effect of gravitational force and benefit the vertical sweep.

3.7.1 Tilted Reservoir

In a tilted reservoir cyclic injection could enhance better sweep by exploiting the gravitational forces during shut-in of an injector. IRIS (2013) explained the concept as "gravitational siesta", Figure 3.6. The density of water is greater than of oil, and has a natural position below the oil column in the reservoir. With no injection, water will be drawn down in the reservoir and oil is pushed upwards to fill the space that initially was filled by the water. When injection is re-initiated more oil is being displaced towards the producer. If the shut-in period is long enough, the pressure could drop below the saturation pressure and create a gas cap that displaces some of the oil further down in the reservoir. The importance of well placement is vital for a case like this to optimize the production strategy.

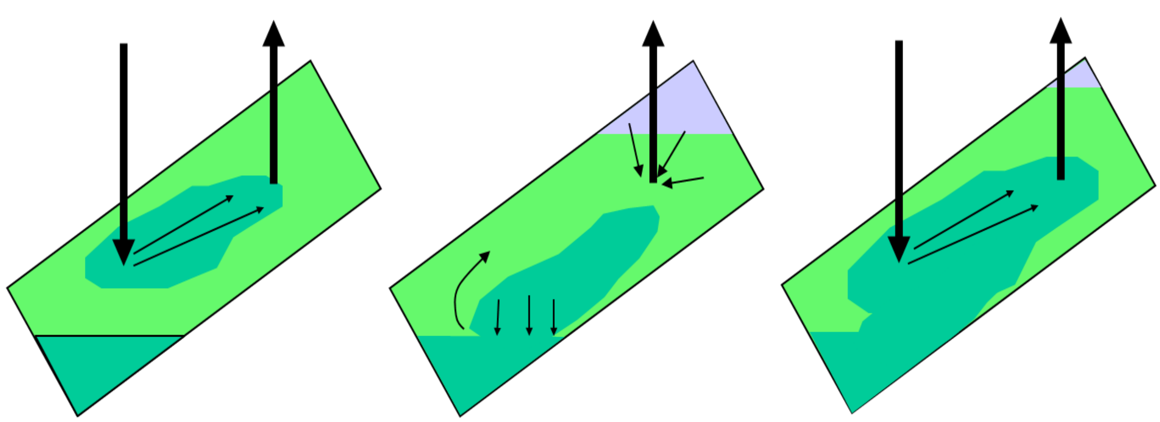

Figure 3.6: *Gravitational effects during cyclic injection: Gravity pulls water down in the reservoir during shut-in and improves sweep when injection is back online (Surguchev et al., 2013).*

3.8 Rock and Fluid Compressibility

The expansion and compaction of a rock or fluid in any reservoir depends on the isothermal compaction, Eq. (3.14).

$$c = -\frac{1}{V}\frac{\partial V}{\partial p}\bigg|_{T} \tag{3.14}$$

In Eq. (3.14):

- c = Compressibility
- V = Volume
- p = Pressure
- T = Temperature.

In any reservoir capillary and gravity forces impact the cross flow intensity. A more uniform fluid distribution because of cyclic injection occurs, but the process is slow – and capillary and gravity forces plays a secondary role in the cross flow between layers (Shchipanov et al., 2008). Pressure differences between layers will control the compressibility, and be the main provider of cross flow. Compressibility is a function of pressure; hence the pressure will change faster in water saturated layer than in an oil saturated layer (Shchipanov et al., 2008). Therefore, in the high permeable layers mostly saturated with water, pressure drops faster compared to the low permeable layer with more oil – and the vertical pressure difference between low and high permeable layers is increased.

Compressibility of the system provides energy for production and faster displacement. Reducing pressure support, by cessation of water injection, the compaction will force oil to expel into the high permeability zones. Surguchev et al. (2008) conducted cycling above and below saturation pressure and resulted in an incremental production of 2.9% and 5.8% of OOIP, respectively. Pressure was lowered too much during the fifth cycle in the below saturation pressure flood and free gas started to flow. Critical gas saturation is defined as the value at which free gas flow initiates (Li and Yortsos, 1993). And very little oil was observed at the outlet after the free gas saturation exceeded the critical gas saturation. Surguchev et al. (2008) concluded that lowering the pressure below bubblepoint pressure is beneficial, as long as critical gas saturation is not exceeded (Surguchev et al., 2008). This is related to the resolution of gas into the oil, and an increase in fluid compressibility

3.8.1 Stress-Sensitive Reservoirs

In a naturally fractured chalk reservoir the fractures are the main transporter of fluids, and the fracture permeability is a pressure dependent key property. Effective stress can change as a result of pressure depletion and affect the fracture permeability. Fracture permeability can increase or decrease with depletion depending on the in-situ stress condition (Tao et al., 2010). The strength of the rock strongly controls the magnitude of the permeability change, and the fractures are more deformable than the matrix in a natural fractured chalk. Depletion could therefore lead to fracture closure and limit the production. This was the case in the massive Spraberry Trend, Texas, in the 1960's (Elkins and Skov, 1963). As the fractures close, the contact area between injected water and matrix is reduced. The importance of understanding the relationship between permeability and stress changes is obviously great. In a cyclic injection perspective open fractures are increasing the amount of imbibition before shut-in, similar to a conventional injection. Pressure depletion during the de-pressurizing cycle should not be below closure pressure so that the oil from the matrix can flow into the fracture. Obviously, the injection pressure should not exceed the fracture gradient to create adverse fractures and severe non-matrix flow.

Fractures will close when pressure is reloaded, and perfect re-establishment of initial in-situ conditions is unlikely to occur during de-pressurizing and pressurizing half cycle. Development of micro fractures could take place and increase the contact area, and alternate the flow pattern to displace new areas (Fjær et al., 2004).

3.8.2 Compaction can Mobilize Oil

During shut-in of injectors the reservoir pressure will be reduced – and stress changes can be utilized to mobilize new oil. Based on poroelastic theory, porosity-changes ($\Delta\varphi$) associated with stress changes can be expressed as (Fjær et al., 2004):

$$\frac{\Delta\varphi}{\varphi} = \frac{1}{K_{fr}}\left(\frac{\alpha}{\varphi} - 1\right)(1 - \bar{\gamma})\Delta p_f \tag{3.15}$$

In Eq. (3.15):

- K_{fr} = Frame bulk modulus
- α = Biot coefficient
- $\bar{\gamma}$ = Average arching coefficient
- p_f = Pore pressure.

Reduction in reservoir pressure will compress the rock and reduce porosity. To illustrate the concept of newly mobilized oil by compression, the constant bulk volume-porosity curves from Ekofisk (ConocoPhillips, 2013) can be used for a simple calculation, Figure 3.7.

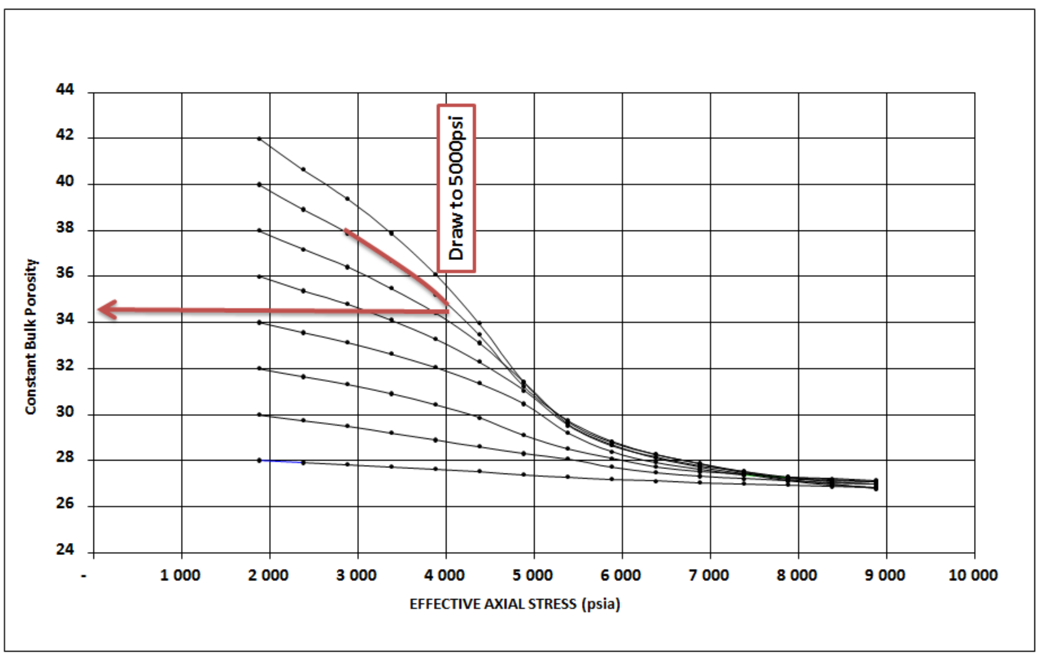

Figure 3.7: *Constant bulk porosity as a function of axial stress on Ekofisk (ConocoPhillips, 2013).*

Assuming that fluid properties are constant during depletion and oil saturation at SORw (~30%), calculated drawdown of 1000psi (from 6000 to 5000psi) results incremental production of 2.8% OOIP. Calculations are described in Figure 3.7 and 3.8.

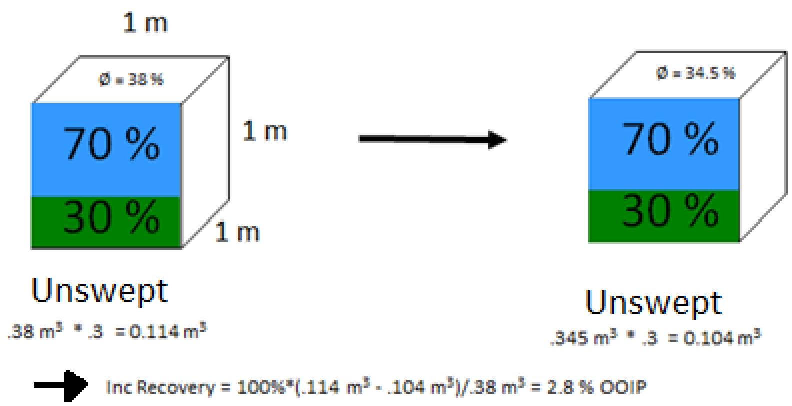

Figure 3.8: *Pressure depletion of 1000psi, changes the porosity and improves recovery.*

If a compaction results in a porosity reduction of 3.5%, the volume of residual oil in the rock will be less compared to the initial condition without compaction. An incremental recovery of 2.8% of a reservoir rock at SORw implies that new oil has been mobilized through compaction. Therefore, cessation of the injection rate should be expected to mobilize new oil (if a significant pressure drop is observed). These calculations don't consider the pressure independent fluid properties which could cause errors in the simplified calculations. But the concept is clear and promising.

3.8.3 Water Induced Compaction

Compaction of the reservoir rock can be an important driving force for oil recovery. For example, in the Valhall Cretaceous Age chalk formation rock-compaction is estimated to have contributed with 50% of the recovery during primary depletion (Cook and Jewell, 1996). Pressure depletion has always been considered to be the main contributor for compaction. But the compaction cannot be exclusively related to the drainage of reservoir fluids, especially in chalk formations. Injected water interferes with the chalk formation, and induces compaction (Piau and Maury, 1994). When the injected water can result in further compaction, waterflooding can no longer only be considered as a mean of preventing compaction even though it increases the reservoir pressure. This was exactly what happened in the Ekofisk field while water injection was initiated in 1988 (Maury et al., 1996); The oil recovery was improved, while the subsidence was continuing despite a constant and somewhat increased reservoir pressure. Water induced compaction can take place in cyclic injection as well as conventional waterflooding, and the affection is similar and will be discussed briefly in this section.

A physical picture of the process of the deformation in a chalk rock can be viewed as a two-step compaction mechanism, Figure 3.9 (Cook et al., 2001). During the natural depletion, plastic deformation is taking place due to the reduction in reservoir pressure. This plastic deformation can be related to pore-collapse, and the volume of the rock is reduced simultaneously as the natural fractures are tightening. As water injection is initiated, the temperature is lowered and the pressure is increased. The average effective stress will decrease, and can lead to further compaction of the rock (Perkins and Gonzalez, 1984). Following the water injection new fractures may be induced, and slightly increase the permeability.

3.8.4 Compaction and Subsidence Risks

The primary risk associated with using cyclic injection, except loss of production, is damage to the formation and infrastructure (wellbore integrity and surface facilities). Casing deformation is the biggest concern with a compacting reservoir (Fjær et al., 2004). A vertical well will have casing strain equal to the formation strain, and a deviated well will have casing strain equal to the formation strain parallel to the well (Fjær et al., 2004). Consequently, a deviated well will receive less compressive force if compaction is uniform. Great insight of stress and strain evolution is necessary to restrict casing failure. Geomechanical models must be applied to analyze the impact of pressure depletion, and select well locations and well angles that limit the risk of running cyclic injection (Fjær et al., 2004). In a waterflood or cyclic injection 4D seismic can be of great help to observe compaction propagation.

In a depleted reservoir, fracture pressure (horizontal stress) could decrease significantly in high permeable layers, simultaneously with no change in collapse pressure (pore pressure) in very tight and low permeable shale layers present in the reservoir (Fjær et al., 2004). This in-situ state could possibly lead to difficulties of achieving stable infill drilling. Hence, changes in reservoir pressure by alternating injection pressure must be equalized by increased injection in an offset injector.

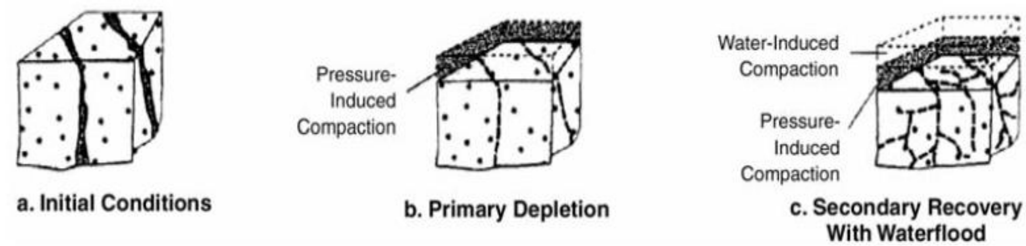

Figure 3.9: *A physical picture of a chalk rock compaction (Cook et al., 2001).*

3.9 Reservoir Recovery and Displacement Fronts

Several different recovery methods can be applied when a field is being developed. And a carefully evaluation of recovery methods is essential for a successful production. A recovery method will determine the reservoir performance and recovery factor, and is strongly dependent on the reservoir characteristics; hence a good understanding of the mechanisms applied for a specific reservoir is vital (Dake, 1985). It is common to distinguish between three types of recovery: (1) primary, (2), secondary and (3) tertiary recovery.

1. Primary recovery is the amount of hydrocarbons which can be produced by utilizing the natural energy drive provided by the reservoir. The basic of primary recovery is related to the fluid and rock compressibility, Eq. (3.14), and the ability to expel fluids from the rock by pressure depletion. During the primary recovery a limited amount of the original oil in place is produced (Schlumberger, 2014).
2. Secondary recovery methods are applied to increase hydrocarbon production beyond the primary recovery. An external pressure support helps to raise or

maintain the reservoir pressure. Waterflooding and gas injection are the two most common secondary recovery methods. In addition to improve the pressure condition in the field, the injected fluids also sweeps the hydrocarbons in place towards a producer.

3. Tertiary recovery, or enhanced oil recovery (EOR), is defined by Ezekwe (2011) as every process that will increase oil recovery beyond primary and secondary recovery.

Fedorov (2012) identified cyclic water injection to belong to the group of EOR-methods, while Shchipanov et al. (2008) defined the method to be an advanced waterflood and IOR-method.

3.9.1 Recovery Efficiency

Microscopic displacement, also called fluid displacement efficiency, E_D, is defined as the ratio of volume of oil displaced from the invaded region over the initial volume of oil in place in the invaded region. Rock wettability, capillary forces, relative permeability and mobility ratios of the fluids present are affecting the micro displacement (Ezekwe, 2011). A general expression of the displacement efficiency is given in Eq. (3.16).

$$E_D = 1 - \frac{S_{or}}{S_{oi}} \tag{3.16}$$

In Eq. (3.16):

- S_{or} = Residual oil saturation in the invaded area
- S_{oi} = Initial oil saturation in the invaded area.

The macroscopic displacement efficiency, sometimes called volumetric displacement efficiency, E_V, is the total volume swept by the displacing fluid in a reservoir. It is the product of areal and vertical sweep efficiency; respectively, E_A and E_I. Areal sweep efficiency is representing the reservoir area in contact with the displacing fluid, and the vertical sweep efficiency is the fraction of a vertical cross-section of the reservoir affected by the displacing fluid (Ezekwe, 2011). The macroscopic sweep efficiency can be expressed as:

$$E_V = E_A \times E_I \quad \textbf{(3.17)}$$

The total recovery efficiency, E_R, is defined as the fraction of swept/produced oil over the initial volume of oil in place (Ezekwe, 2011):

$$E_R = E_D \times E_V \quad \textbf{(3.18)}$$

The different displacement efficiencies are displayed in Figure 3.10. With a cyclic injection or production scheme the total recovery efficiency can be improved by an increase in fluid and volumetric displacement efficiency. The microscopic sweep efficiency is improved by mobilization of new oil from low permeable layers through compaction during the de-pressurizing cycle. And by changing the waterflood patterns and increasing cross-flow within the reservoir, the areal and vertical sweep efficiency can be increased, respectively.

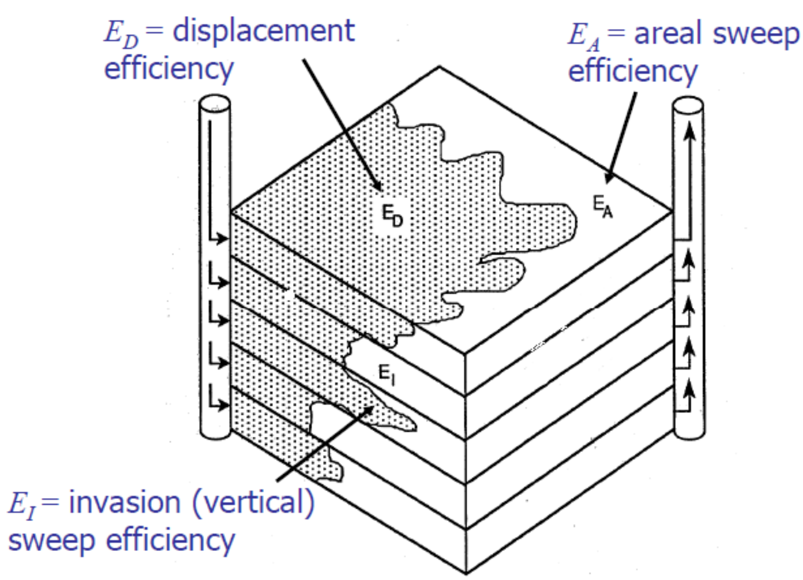

Figure 3.10: *Recovery efficiency of a reservoir section (Devegowda, 2013).*

3.9.2 Displacement Fronts – Conventional vs. Cyclic Water Injection

In a displacement of oil by water, the water invades the area of high oil saturation and pushes the oil towards a producer. The displacing water is removing the oil and increasing the water saturation in the invaded zone with time. The displacing fluid does not act as a piston pushing all the oil in front of the injected water; water and oil flow together and simultaneously in the pores (Buckley and Leverett, 1941). Fluid flow rate is strongly dependent on its saturation at any point in the reservoir; hence, the relative permeability controls the fluid flow rate. Applying Darcy's law (Eq. (3.7)), the fluid flow rate can be represented as:

$$q_i = -\frac{k_x k_{ri} A}{\mu_i}\left(\frac{\partial p_i}{\partial x} + \rho_i g \sin\alpha\right) \quad \textbf{(3.19)}$$

In Eq. (3.19):

- q_i = Flow rate of phase i
- A = Area cross-section for fluid flow
- α = Dip angle of the reservoir (positive counter clockwise from horizontal flow direction)

Re-arranging and modifying Eq. (3.19), the fractional flow, $f_i = q_i / q_t$, can be expressed as a function of all parameters that affect the fluid flow (viscosity, density, effective permeability, saturation, capillary pressure total flow rate and structural orientation):

$$f_w = \frac{1}{\left(1 + \frac{\mu_w}{\mu_o} \times \frac{k_o}{k_w}\right)} + \frac{\frac{k_o A}{\mu_o q_t}\left[\frac{\partial p_c}{\partial l} + \Delta\rho g \sin\alpha\right]}{\left(1 + \frac{\mu_w}{\mu_o}\frac{k_o}{k_w}\right)} \quad \textbf{(3.20)}$$

Similarly to the derivation of the fractional flow equation, Qingfeng et al. (1995) derived an expression of fractional water cross flow in vertical direction under influence of cyclic injection from Darcy's law, Eq. (3.21). Besides the vertical cross flow induced by gravity and capillary forces, an additional pressure gradient is created by the cyclic water injection, $\partial p_{wa} / \partial z$.

$$v_{zw} = \frac{1}{\dfrac{\mu_o}{k_z k_{ro}} + \dfrac{\mu_w}{k_z k_{rw}}} \left(\frac{\partial p_c}{\partial z} + \Delta \rho g \right) - \frac{k_z k_{rw}}{\mu_w} \frac{\partial p_{wa}}{\partial z} \tag{3.21}$$

For comparison of the two waterflood methods Eq. (3.20) can be re-arranged to represent a vertical water flow (with a dip angle of 90^o), Eq. (3.22). The only difference in the two equations is the additional pressure gradient. Qingfeng et al. (1995) concluded that the additional cross flow induced by cyclic injection is changing with the alternating injection; during the de-pressurizing half cycle both oil and water flow from low permeable to high permeable zones, and countercurrent during the pressurizing half cycle. The cross flow magnitude of each phase is controlled by the phase's relative permeability at a specified point in the reservoir. More oil will flow from the low permeable layers compared to water, and improve the production and minimizing the saturation differences in the reservoir (Qingfeng et al., 1995).

$$v_{zw} = \frac{1}{\dfrac{\mu_o}{k_z k_{ro}} + \dfrac{\mu_w}{k_z k_{rw}}} \left(\frac{\partial p_c}{\partial z} + \Delta \rho g \right) \tag{3.22}$$

The mobility of a fluid is strongly controlling the success of a waterflood, hence also a cyclic waterflood. Phase mobility is defined by the ratio of relative permeability to the viscosity of the fluid, Eq. (3.23).

$$\lambda_i = \frac{k_i}{\mu_i} \tag{3.23}$$

The mobility ratio *M*, is defined as the ratio of mobility for the displacing fluid (water in cyclic injection) and displaced fluid (oil). And can be expressed as Eq. (3.24) for simple calculations based on the endpoint relative permeability for water and oil.

$$M = \frac{k_{rwe}}{k_{roe}} \frac{\mu_o}{\mu_w} \tag{3.24}$$

In Eq. (3.24):

- k_{rwe} = Relative permeability to water at S_{orw}
- k_{row} = Relative permeability to oil at S_{wi}.

4. Simulation Models

In this section the simulation models are elaborated, and the reservoir properties applied to the simulations described. Most of the simulations are carried out in a 2D model, for execution time and better control of the physical mechanisms. Some interesting properties are also investigated in 3D. For a better understanding of the physical benefits at micro-level a black oil model is applied with Eclipse100, and to gain insight in the alternation of fluid flow patterns a FrontSim model is run for cases where it is of interest. The purpose of the study is to analyze critical variables and physical mechanisms – therefore, an idealized model was build and simulated.

4.1 Numerical Models

The two dimensional model consists of 100 active grid cells distributed in a 10x1x10 grid system along the x, y and z-direction for a corner point grid. Sensitivity in the number of layers present in the model where carried out by refining the base case by adding 10 and 20 layers in z-direction – which resulted in a small numerical dispersion compared to the 10 layer case and no further studies were conducted related to or with grid refinement. An asymmetric and a symmetric permeability and layer thickness base case were made to investigate the effect of permeability distribution within the reservoir, Figure 4.1 and Table 4.1.

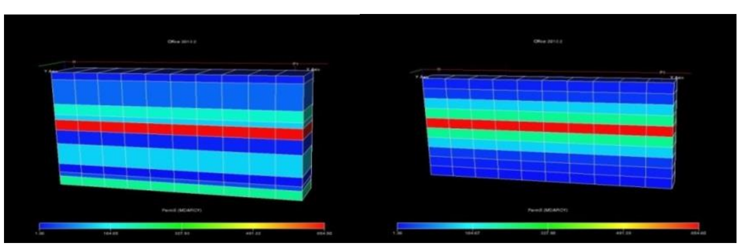

Figure 4.1: *Asymmetric (left) and symmetric (right) base case models.*

Table 4.1: Layer thickness and permeability for the asymmetric and symmetric base case.

	Asymmetric		Symmetric	
	PermX (md)	DZ (ft)	PermX (md)	DZ (ft)
Layer 1	13.64	20	13.64	32.8
Layer 2	60.64	70	27.27	32.8
Layer 3	190.91	30	136.36	32.8
Layer 4	136.36	15	231.82	32.8
Layer 5	654.55	30	654.55	32.8
Layer 6	13.64	40	231.82	32.8
Layer 7	136.40	60	136.36	32.8
Layer 8	1.36	25	27.27	32.8
Layer 9	40.91	12	13.64	32.8
Layer 10	231.82	26	1.36	32.8

The simulation model consists of one open hole perforated producer and injector located in grid block (1,1) and (1,10), respectively. The length of a grid block in x- and y-direction is 328ft, and the total length between the injector and producer is 3280ft (approximately 1000m) in the base case. Both the injection and production well is completed throughout the reservoir (from z=1 to z=10). Rock data, fluid data and initial conditions are given in Table 4.2 and PVT data can be viewed in appendix A. Most of the data in Table 4.2 are taken from the second SPE comparative solution project (Weinstein et al., 1986) to build up a functional model. The effect of vertical communication will be investigated by estimating the vertical permeability, k_v, by multipliers of vertical to horizontal permeability ratios, k_v/k_h, of 0.1 and 0.5. In the base case the k_v/k_h of 0.1 was used.

Table 4.2: Rock and fluid data and initial conditions.

Rock and Fluid Data		
Rock Compressibility	4,0E-06	psi^{-1}
Water Compressibility	3,0E-06	psi^{-1}
Stock tank Oil Density	45,00	lbm/ft^3
Stock tank Water Density	63,02	lbm/ft^3
Standard Condition Gas Density	0,0702	lbm/ft^3
Saturation Pressure	5600	psi
Porosity	0,3	
Initial Conditions		
Oil Pressure at GOC	6600	psi
Depth of GOC	8990	ft
Depth of OWC	9500	ft
Payzone Thickness	328	ft

4.2 Pre-Screening

Before investigation related to cyclic injection can be started, some parameters have to be determined to make sure that the model is consistent and the numerical dispersion is limited to an acceptable error. The injection and production rates had to be obtained for each model to maintain a constant reservoir pressure. Maintaining a constant reservoir pressure is not optimum with respect to oil production, but is necessary to evaluate the effect of cyclic injection. The relative permeability curves had to be estimated for different rock wettability. The optimum base case should be able to maintain the reservoir pressure, reduce amount of water produced and increase the amount of oil produced by the cyclic injection approach. The pre-screening helps to identify the effect of important parameters and the variables that play a major role in success of cyclic waterflooding. The total oil- and water production, field water cut and total water injected for the base case with different wettability is given in Table 4.3.

Table 4.3: Total oil (FOPT) and water (FWPT) production, water injected (FWIT) and water cut (FWCT) for the water-, mixed- and oil-wet conventional waterflood case.

Wettability	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
WF Water	7,05E+06	1,90E+06	9,84E+06	69,02 %
WF Mixed	5,27E+06	3,68E+06	9,84E+06	85,34 %
WF Oil	4,30E+06	4,66E+06	9,84E+06	91,98 %

4.2.1 Control of Reservoir Pressure

The first step of the simulation was to obtain a continuous waterflood scenario with a constraint that average reservoir pressure has a small deviation and remain above the saturation pressure. The producer is controlled by a liquid production rate target. By applying the liquid rate as a boundary condition, the effect in enhanced oil production and reduced water production can be observed. By maintaining the injection and production rate for each scenario, potential benefits or limitations are purely related to the parameters investigated and can be compared with confidence.

For the base case, also referred to as the long spacing case with a 328ft thick water wet pay zone an injection rate of 1000STB/day and liquid production rate of 910STB/day resulted in an approximately maximum deviation of 10% below the initial pressure,

Figure 4.2. These rates provided a simulation period of approximate 27 years. This step is important with respect to the bubble point pressure which is considered as an important parameter for the cyclic injection.

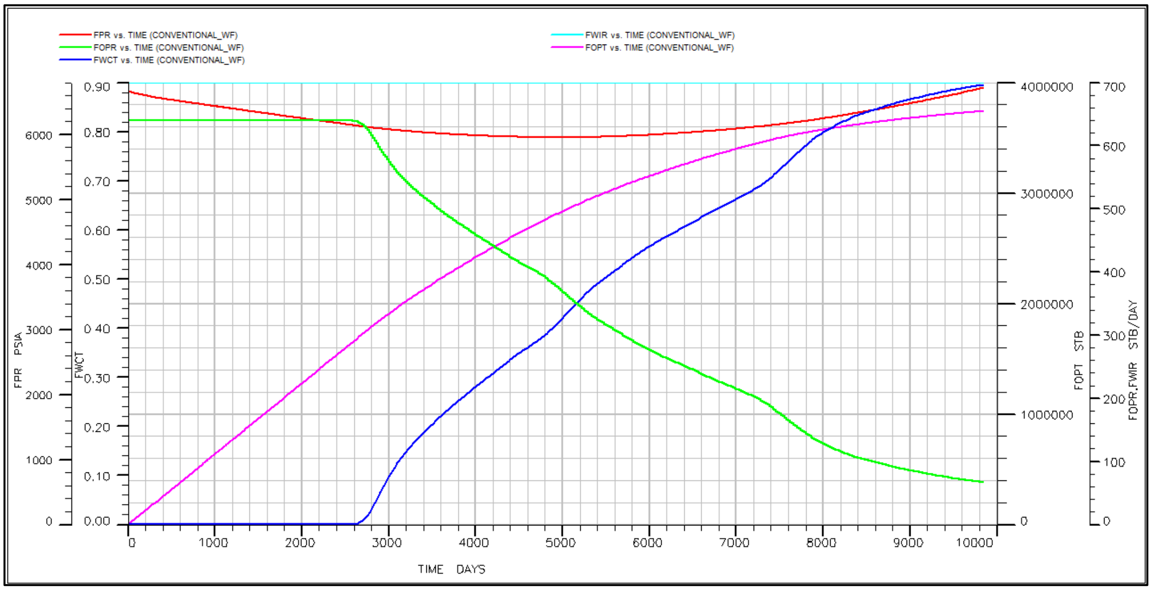

Figure 4.2: *Field pressure, water cut, oil production rate, total oil production and injection rate for the conventional waterflooding scenario with a 328ft thick water wet reservoir.*

Figure 4.2 illustrates how the base case was created. Average reservoir pressure needed to be above the saturation pressure, to limit gas resolution which will enhance the compressibility. A significant water cut needed to be established so that the effect of cyclic injection could be proven in terms of reduced water production. Similar figures were established for all the conventional waterflooding cases, and the injection and production constraints used are given in Table 4.4. Reducing the reservoir thickness to 164ft to investigate the effect of reservoir thickness, an injection rate of 500STB/day and a production rate of 440STB/day was applied. Every simulation model is run over a time period of approximately 27 years.

To analyze the effect of distance between wells a short spacing model with a total distance of 1640ft between the two wells was created with the same properties as the base case. The reservoir with a thickness of 328ft observed an approximately constant reservoir pressure with an injection rate of 700STB/day and a production rate of

640STB/day. The thinner model had an injection rate of 300STB/day and liquid production rate of 270STB/day to maintain a constant reservoir pressure, Table 4.4 is based on a water wet system, and these injection and production rates also made the basis for the oil- and mixed-wet reservoir cases. Rates given in Table 4.4 resulted in a very early water breakthrough and high water production due to the poor mobility ratio between water and oil for the given relative permeability curves for the oil-wet scenario, Figure 4.3. The reduced injection and production rates for the oil-wet case are given in Table 4.5.

Table 4.4: Long and short spacing conventional injection and production rates related to reservoir thickness.

Scenario	Distance I1 to P1 (ft)	Res. Thickness (ft)	Inj. Rate (B/D)	Prod. Liq. Rate (STB/day)
Long Spacing	3280	328	1000	910
Long Spacing	3280	164	500	440
Short Spacing	1640	328	700	640
Short Spacing	1640	164	300	270

Table 4.5: Long and short spacing injection and production rates for the oil-wet scenario.

Scenario	Distance I1 to P1 (ft)	Res. Thickness (ft)	Inj. Rate (B/D)	Prod. Liq. Rate (STB/day)
Long Spacing	3280	328	1000	910
Long Spacing	3280	164	290	250
Short Spacing	1640	328	700	640
Short Spacing	1640	164	300	270

4.2.1 Relative Permeability and Wettability Profiles

In section 3.5 the effect of different wettability was discussed, and will be taken into consideration when the effect of having a water-, oil-, or mixed-wet reservoir will be investigated. The different wettability profiles were generated by applying Corey equations, Eq. (3.3) to (3.6). By use of Corey equations three different relative permeability and saturation profiles were created based on endpoint fluid saturations and Corey coefficients for water, oil and gas (n_w, n_o and n_g respectively) given in Table 4.6. Corey coefficients are within the range recommended by Behrenbruch and Goda (2006).

Table 4.6: Endpoint fluid saturations and Corey coefficients.

	Water Wet	Mixed Wet	Oil Wet
S_{wi}	0,20	0,20	0,20
Sorw	0,20	0,25	0,30
Sorg	0,20	0,20	0,20
S_{gc}	0,05	0,05	0,05
$K_{ro@Swi}$	0,90	0,80	0,50
$K_{ro@Sgi}$	0,90	0,80	0,50
$K_{rw@Sorw}$	0,40	0,63	0,80
$K_{rg@Sorg}$	1,00	1,00	1,00
n_w	3,50	2,00	3,00
n_o	2,00	3,00	4,00
n_g	1,50	2,00	2,00

The different wettability profiles were mainly created by different residual oil saturations in the reservoir which is a major controlling factor for a waterflood. The three-phase relative permeability as a function of saturation levels is presented in Figure 4.3 and 4.4. The slightly oil-wet model has high residual oil saturation and low relative oil permeability, and is predicted to see the lowest cumulative recovery among the three wetting conditions. A water-wet reservoir has often a lower residual oil saturation and higher relative oil permeability, and is expected to have a higher ultimate recovery than the mixed- and oil-wet case. In the simulation study of the three wettability environments, no other parameters (grid, PVT, injection/production rates, etc.) are changed as to better understand the relationship between cyclic injection and wettability. When the three wetting conditions are compared, the oil and water will behave differently for the given injection and production rates in Table 4.4 and Table 4.5. The total oil production was expected to be much greater for the water wet case; hence, for comparison the additional increments must be investigated to gain insight and confidence of the cyclic injection process under different wettability.

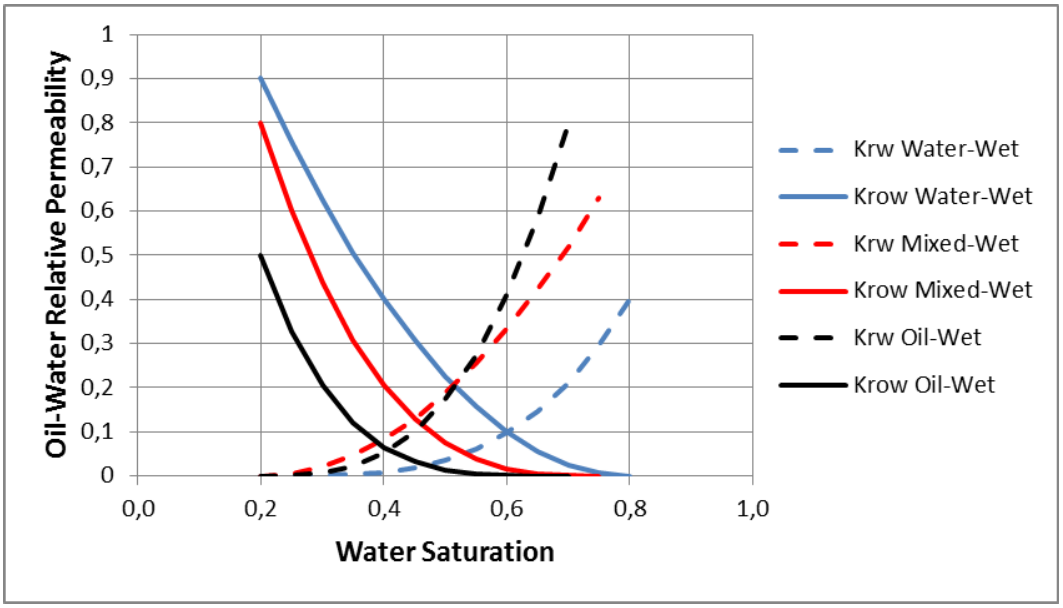

Figure 4.3: *Oil-water relative permeability for water-, mixed- and oil-wet reservoir.*

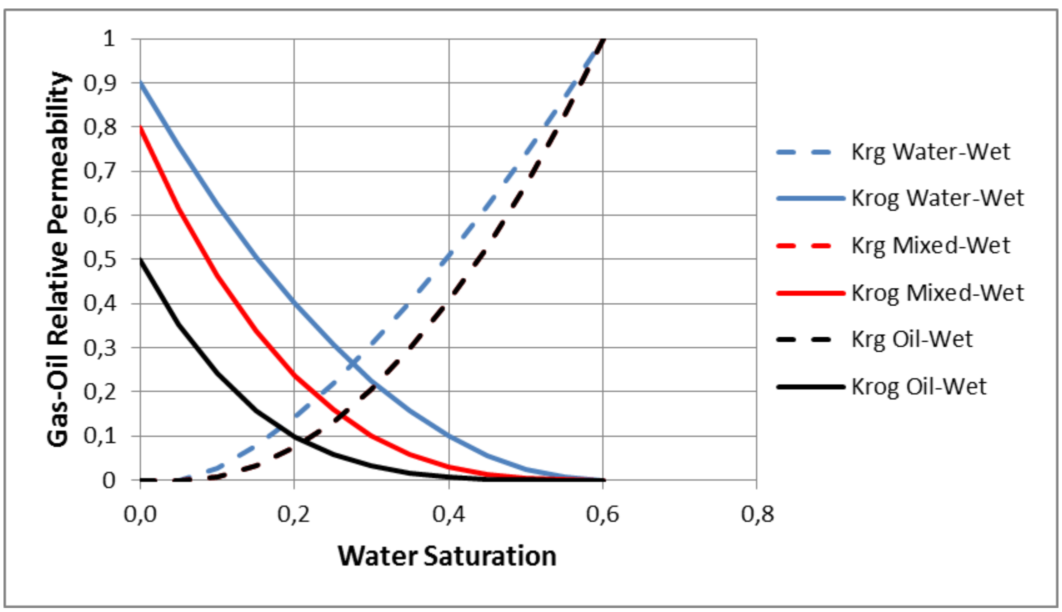

Figure 4.4: *Gas-oil relative permeability for water-, mixed- and oil-wet reservoir.*

The capillary pressure as a function of fluid saturation is maintained the same for all three wetting conditions for easier comparison of the effect of wettability and due to lack of good data. This would not be the case in a real reservoir, and some numerical error in the results could occur and should be tuned when being applied for a real oil field. It should also be noted that the given relative permeability curves may give a conservative result, because the saturation endpoint are changed with the wettability. The total volume of oil is being reduced from the water-wet towards the oil-wet case, and should be taken into consideration when analyzing the results.

4.2.3 Cyclic Injection Schemes

For each cycling program the injection rates are calculated such that the cumulative injection volume is equal to the volume injected during conventional waterflooding. In these simulations the production is restricted by a liquid production rate in order to maintain the voidage replacement ratio for easier comparison of the different injection schemes. Another important aspect by controlling the production well by a liquid production rate is to limit the effect of increased oil volume production due to increased water volume injection. The daily injection rates for the different injection schemes defined by the ratio of injection to no injection are given in Table 4.7. No consideration of formation damage was done and the injection rates were not limited. To be able to compare the results between long and short spacing, thin and thick reservoir the ratio of injection to production was calculated to be approximately the same, Table 10.9.

Table 4.7: Cyclic injection scenarios for the water wet case with the respective injection rates in STB/day.

Scenario	Long Spacing	Long Spacing	Short Spacing	Short Spacing
Res. Thickness (ft)	**328**	**164**	**328**	**164**
WF Inj. Rate (STB/day)	**1000**	**500**	**700**	**300**
1:1 (STB/day)	2000	1000	1400	600
1:2 (STB/day)	3000	1500	2100	900
1:3 (STB/day)	4000	2000	2800	1200
2:1 (STB/day)	1500	750	1050	450

Four types of cycles based on the ratio of injection to no injection (injection:no-injection) were analyzed:

- One symmetrical cycle (1:1)
- Three asymmetrical cycles (1:2, 1:3 and 2:1).

Conventional waterflooding has a continuous and constant injection rate throughout the simulation period, whereas the cyclic injection schemes are alternating between an open or closed injector. Four different base periods were analyzed:

- 15 days
- 1 month (assumed to be 30 days)
- 3 months
- 6 months.

Accuracy of the numerical results depends strongly on the time step length in the simulation model. Even though Eclipse100 applies a fully implicit approach to maintain stability during long time steps, the simulation time step limit when a cyclic injection is simulated should be maximum half the cycle period – meaning, for a base period of 15 days the time step is set to 7.5 days. Obviously, the simulation error is limited with shorter time steps, but another aspect is to be able to model the pressure within each cycle to accurately simulate the cyclic process.

4.3 Outputs

The results are organized in two main groups for the 2D section – with reservoir pressure above and below the saturation pressure at 5600psi. Further the cyclic water injection will be analyzed with respect to the following parameters:

- Period of the cycles: Symmetric and shifted cycles with different cycle length.
- Wettability: water-, mixed, and oil-wet condition.
- Thickness of the reservoir: 328ft versus 164ft thick reservoir.

- Distance between the producer and injector, referred to as the long- and short-spacing scenario.
- Vertical transmissibility and layering.
- Permeability distribution and differences.
- Initiation of the cyclic process: at different water cut levels.

4.4 3D-Synthetic Model Characteristics

The benefits of cyclic waterflood at a physical and microscopic level will be investigated in the 2D synthetic model. In addition to the expected enhancement in vertical cross flow and compaction at pore level, the cyclic waterflood can alternate the waterflood patterns and increase the sweep efficiency. Taking the best scenarios from the 2D-model, a three dimensional case was created. Overall, the 1:3-scheme with a base period of 30 days provided the greatest increase and decrease in oil and water production, respectively – and will be compared to the conventional waterflood in this 3D model (further discussion in Chapter 5). The symmetric cycle of 1:1 is also simulated. Similar to the 2D-model a solid base case, that makes it possible to observe the effects of cyclic injection – with respect to incremental change in water and oil production, had to be created.

The model size is 3000x3000x328ft, and distributed with 30x30x10 grid cells in the x-, y- and z-direction, respectively. Fluid and rock properties are taken from the 2D-model, Table 4.1, Table 4.2 and appendix A. The permeability distribution remains unchanged compared to the 2D base case, and relative permeability and capillary curves are taken from the water-wet condition in Figure 4.3 and Figure 4.4.

Two pairs of wells were included in the model to gain insight in the effect of offset producers and injectors. The two injectors are located at center of each x-axis as illustrated in Figure 4.5. The production wells are located at the center of the y-axis. This well placement is not optimum, but will leave a significant amount of oil left in the middle and in the corners of the reservoir which waterflood pattern alteration may extract during the cyclic injection. Daily injection rate was set to be 5000STB/day for both wells. Production was controlled by the bottomhole pressure at 5500psi. In this model with two pairs of wells, restriction in bottomhole pressure at the producer will maintain the voidage replacement condition for all cases, and no effect of improved recovery due to increased water injection during cyclic injection will transpire.

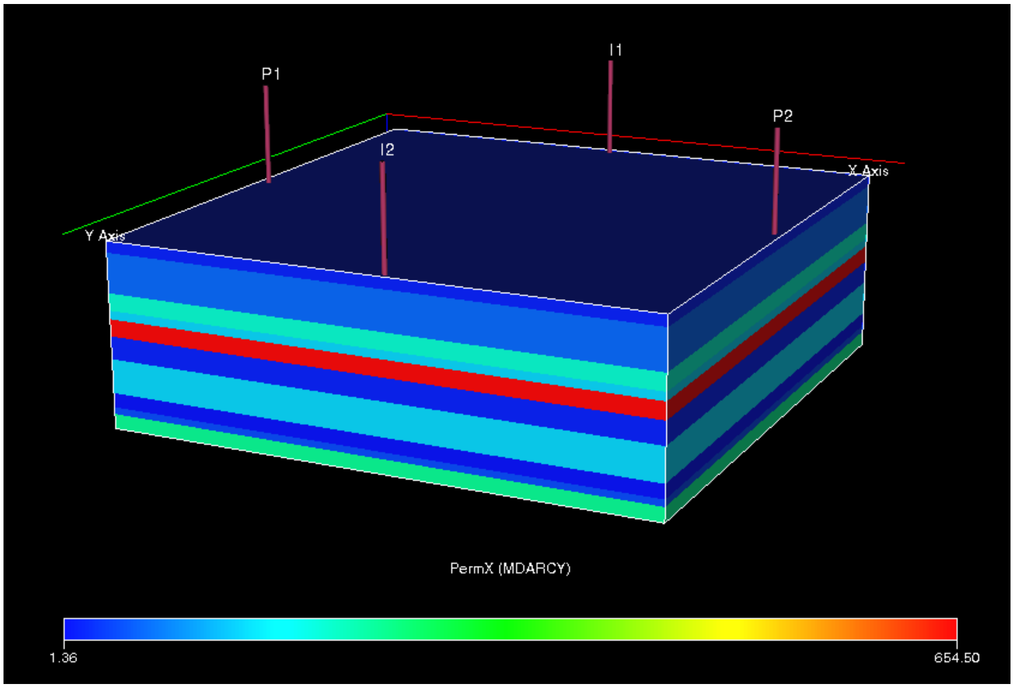

Figure 4.5: *3D-model and the horizontal permeability distribution.*

Four different cycle schemes are investigated; the 1:1 and 1:3-scheme with simultaneously cycling, and the same schemes with shifted cycles. Shifted cycles represent a condition where one injector is shut-in while the other is injecting. Overview of the chosen injection rates and conditions investigated is given in Table 4.8.

Table 4.8: Injection rates for different scenarios (rates related to one injector).

Injection/No Injection (Time Ratio)	Injection Rate (STB/day)	Simulataneously Injection In I1 and I2
Conventional	5000	-
1:1	10000	Yes
1:3	20000	Yes
1:1 Shifted	5000	No
1:3 Shifted	20000	No

4.5 Eclipse100 and FrontSim

Black oil simulation and streamline models are effective tools working with cyclic water injection. The 2D-model is only simulated by Eclipse100. And the 3D-model is investigated with both Eclipse100 and FrontSim. Eclipse100 will provide a more exact result of the displacement process compared to FrontSim.

Eclipse100 is a fully implicit, three phase and three dimensional black oil simulator. The results obtained with Eclipse100 are expected to provide a low numerical error due to Newton's method to solve the non-linear equations. FrontSim provides a three dimensional, three phase black oil simulator. The simulator is defaulted on the IMPES (Implicit Pressure Explicit Saturation) formulation, which requires care with respect to choice of time step. Major purpose of applying FrontSim in the 3D-model is to investigate fluid flow pattern. Each streamline illustrates a certain fluid velocity at the given point. A denser streamline accumulation represents an area of high fluid flow. However, the streamline model neglects fluid flow across the stream lines and needs to be treated with care in numerical evaluation of the results.

5. Simulation Results and Discussion

5.1 Reservoir Pressure above the Saturation Pressure (2D)

The first simulation results presented are related to the case described in chapter 4 with an average reservoir pressure above the saturation pressure – no gas present in the reservoir and a constant gas-oil ratio.

5.1.1 Different Cyclic Injection Schemes for the Water-Wet Case

One of the most important factors related to a cyclic waterflood is the ratio of injection to no-injection. Four different injection schemes were simulated: 1:1, 1:2, 1:3 and 2:1. The different injection schemes were simulated with different cycle periods of 15 days, 30 days (equals 1 month), 90 days and 180days. All the cumulative water and oil production, total volume water injected and field water cut at the end of the simulation period is given in Table 10.1 and Table 10.2. All cycles are initiated at the beginning of the production period, at day 1.

For the water-wet case it was clear that the more intensive injection scheme resulted in the greatest increase in cumulative oil production, Figure 5.1. An incremental cumulative oil production of 3.16% was seen for the injection scheme with one month of injection and three months of injector shut-in and natural depletion (1:3-scheme). Figure 5.1 shows how all the injection schemes resulted in a greatest incremental oil production with a base period of 30 days and lowest for the longest base period of 180 days compared to the conventional waterflooding case. A large amount of the additional oil produced during the 1:3-scheme with a base period of three months can be directly related to the greater pressure amplitude observed during the pressurizing and de-pressurizing period, Figure 5.2. With a longer shut-in period the water injection rates where modified to yield approximately the same volume of injected water, resulting in a higher injection rate and greater pressure amplitude. As the intensity of the injection is reduced, the injection rates were reduced, and less additional oil production was observed. Clearly a more intensive injection scheme should be applied for a water-wet reservoir. For a real field the injection pressure is limited with respect to capacity and formation damage, and could not be increased above any unreasonable value. As the base period is increased from 30 days to 90 and 180 days, the additional oil recovery is slowly decreasing – but still improves the oil production compared to the conventional waterflood.

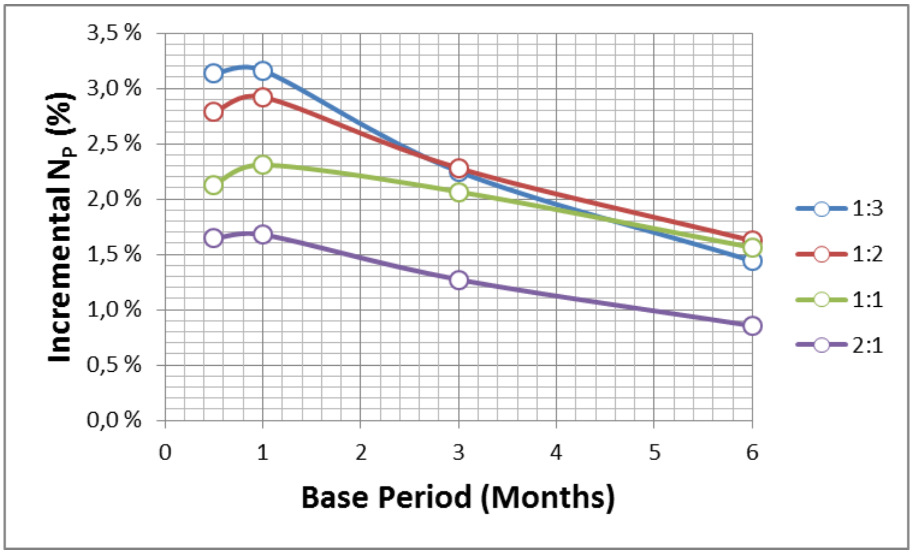

Figure 5.1: *Comparison of additional cumulative oil production (N_P) over conventional waterflood for the different injection schemes and base periods given in months (water-wet reservoir).*

The major factor for increased production, by increasing the oil saturation in the high permeable layers by gravitational and capillary forces, is that during the pressurizing cycle pressure can replenish energy in the system, and low pressure zones can be created during production. The pressure transferring capacity in the high permeable layers are greater than in the low permeable layers – high permeable zones will become low pressure zones before the low permeable zones, and the oil will flow from the low to the high permeable layers. This effect is clearly seen from Figure 5.3, were the oil production rate is decreasing during the injection (here: 1:3-cycle) and increasing during the shut-in period. Water injected will imbibe into the low permeable zones during pressurizing half cycles, and expel countercurrent flow of oil into the high permeable layers.

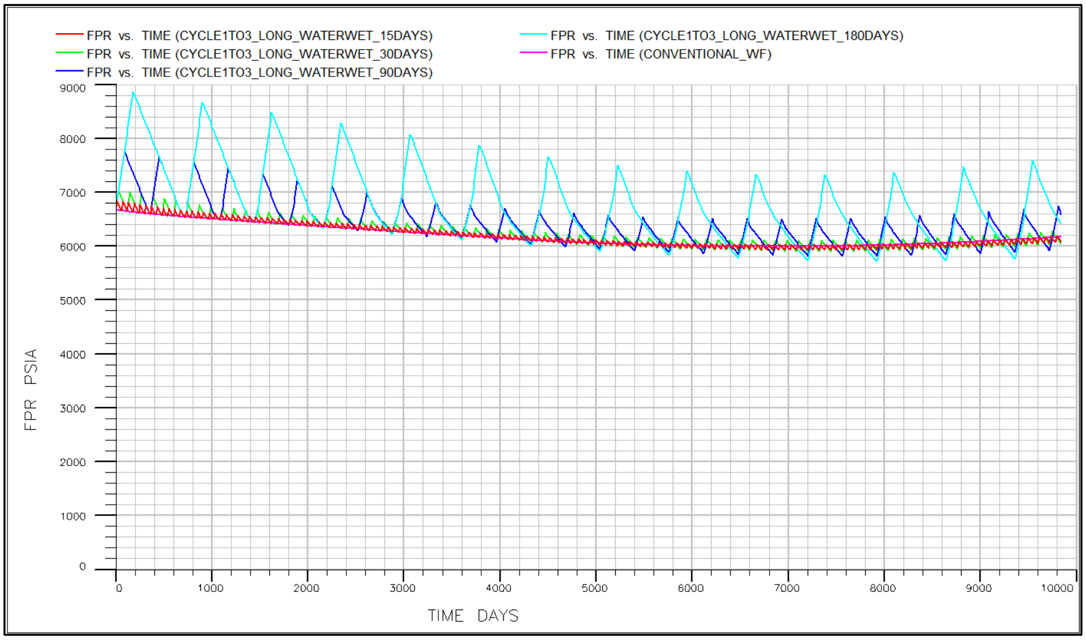

Figure 5.2: *Reservoir pressure (FPR) over time for the 1:3 cyclic scheme, water wet case.*

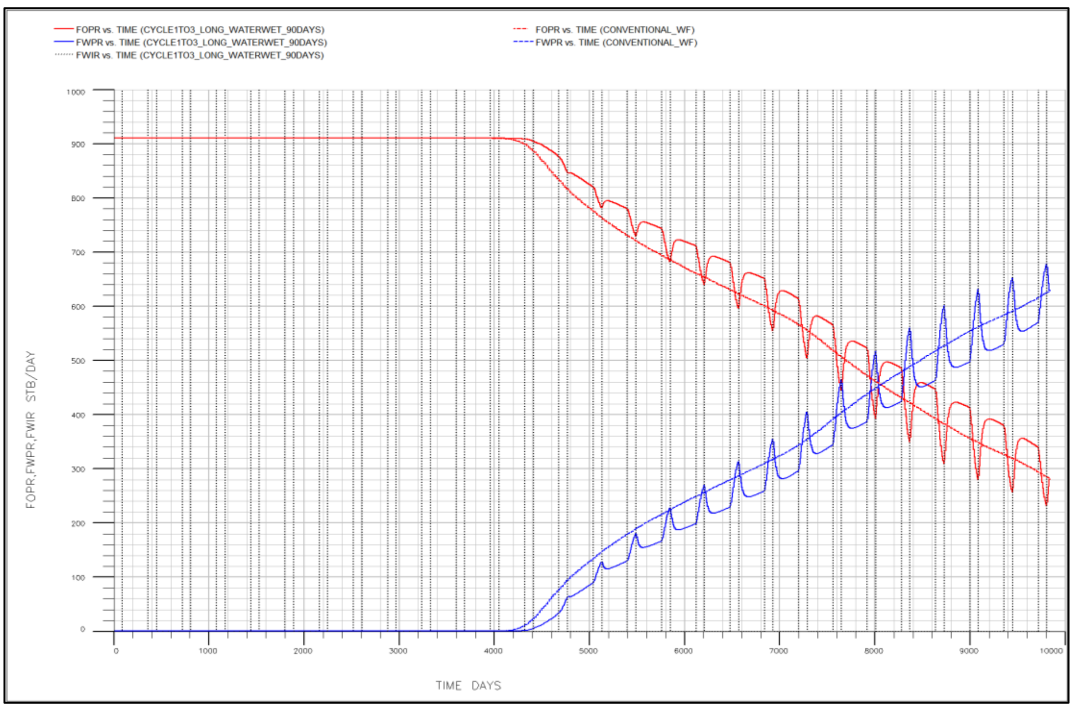

Figure 5.3: *Oil (red) and water (blue) production rate for conventional and cyclic 1:3 injection.*

Figure 5.1 also shows how the injection scheme is affected by the base period. The less intensive injection scheme, 1:1, is resulting in greater oil production when the base period is larger than 90 days. With a very high injection rate as for the 1:3-scheme, the water will easily result in a massive water breakthrough and mainly produce water during the pressurizing cycle with long base periods. The contact time between the injected water and formation, especially with the low permeable zones, under very short base periods of 15 days are reduced and no improved water imbibition will occur. Lower injection rates and less intensive schemes improve the contact time between water and formation, and sweep the reservoir better than the 1:3 scenario for longer base periods.

Another aspect with the cyclic injection is the reduction in water production. Figure 5.4 shows the percentage decrease in total water production for the different injection schemes and base periods. Similar to the improved oil production case, a more intensive injection scheme results in less water production – and a greater amount of water is retained in the formation. The 1:3 injection scheme, with a base period of one month resulted in a reduction of 11.74% in total water produced compared with the conventional waterflood.

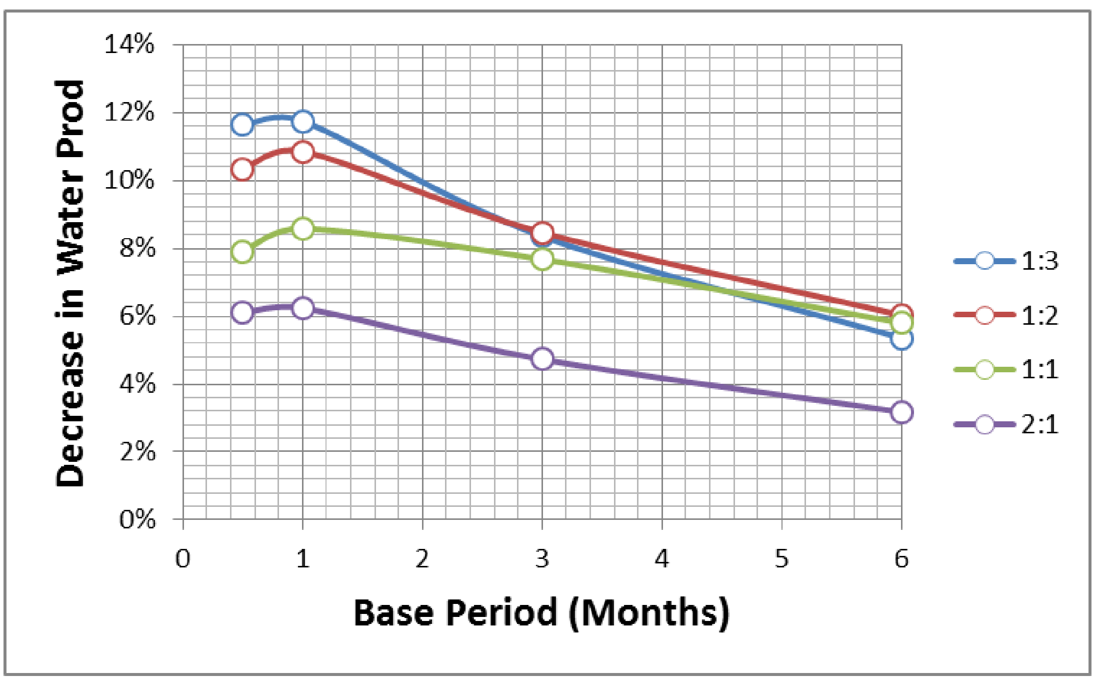

Figure 5.4: *Decreased water production related to the different injection schemes and base periods given in months (water-wet reservoir).*

A greater increase in cumulative oil production following a cyclic injection seems to result in a greater reduction in water production, Figure 5.5. A greater increase in total oil production resulted in a greater decrease in water production. Meaning, more water is retained in the formation and expels a larger amount of oil from the low permeable areas and increase the volume of oil which can be produced.

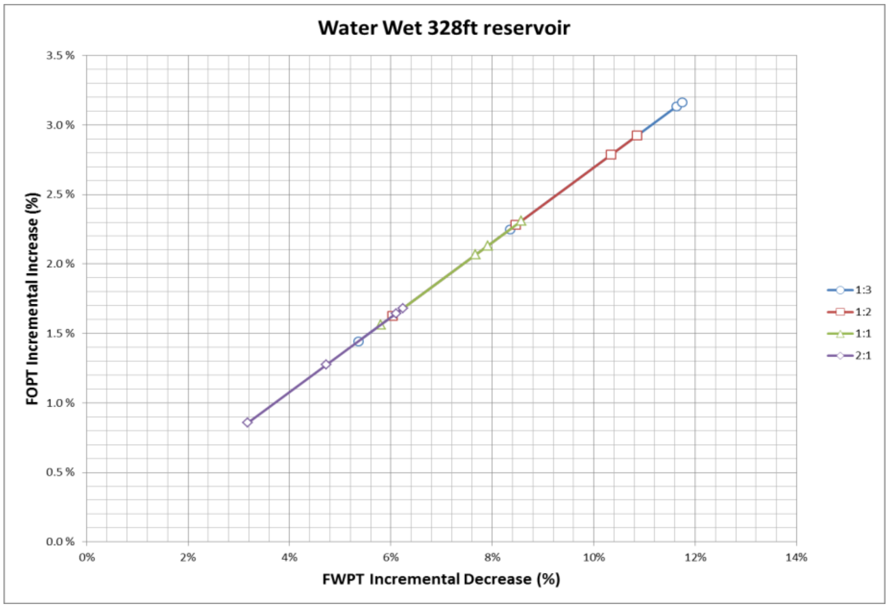

Figure 5.5: *Relationship between cumulative oil (FOPT) and water (FWPT) produced for a water-wet 328ft thick reservoir.*

The oil and water production profiles over time for the 1:3 injection scheme is given in Figure 5.6. As explained in Figure 5.1 and Figure 5.4, the 1 to 3 injection scheme resulted in improved oil recovery for every base period, with a respectively decrease in water production, compared to the conventional waterflood.

Water cut is fluctuating between a high and low value, respectively to the pressurizing and de-pressurizing cycles. As the injector is online a rapid increase in water cut is observed, with a equally rapid decline when the injector is shut in. The chosen liquid production and injection rates for this simulation are most likely not optimum, and could have been tuned to result in a different water cut profile with less water breakthrough during the pressurizing half cycle. Total water injection for the base periods of 90 and 180 days deviated with 1.5 and 2.4% respectively, over the conventional waterflood

(Table 10.2) because of the choice in cycle period, but the effect is not considered to be affecting the outcome significantly.

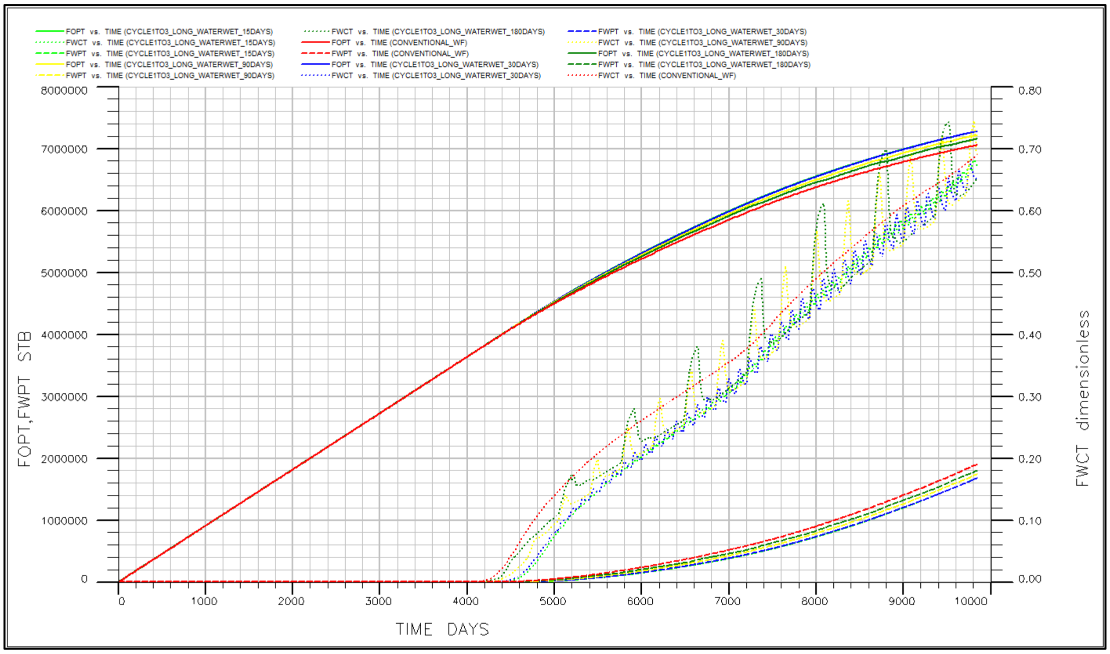

Figure 5.6: *Oil and water production, and water cut versus time for the 1 to 3 injection scheme for the 328ft water-wet reservoir.*

The benefit of applying cyclic injection for the water wet case is clearly observed in Figure 5.7. The pink circles around layer 1, 6 and 8 which are the low permeability zones, are better swept with the cyclic injection compared to the continouse waterflood. Different piezoconductivity in water and oil and in water saturation results in water invading the low permeable zones during the pressurizing half cycle, and countercurrent flow of oil from the low permeable layers into the more permeable layers during the depressurizing cycle – and more oil is mobilized and produced.

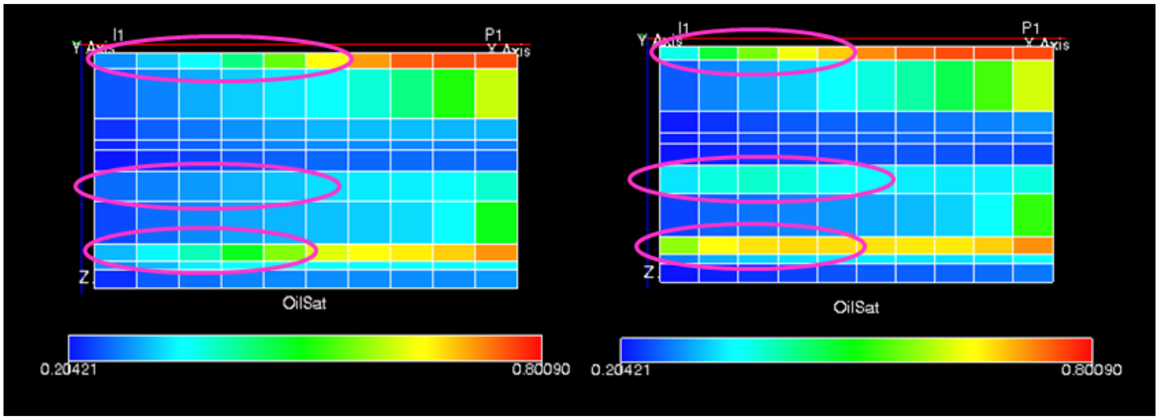

Figure 5.7: *Cyclic injection 1:3 (left) compared to conventional waterflooding (right) at the end of simulation.*

5.1.2 Oil Saturation Difference

It is indispensable to include the oil saturation distribution in this analysis, because the variation in oil corresponding to the pressure gradient between the zones will determine the saturation of oil over time. Migration of oil during the halt of an injector can help to identify the flow patterns with increase in oil saturation at the displacement front. Figure 5.8 shows a period of halted injection; at time 9090 days the injection is halted over 270 days before injection is initiated again (at 9360 days), and the water cut is clearly dropping while the oil production rate is rising.

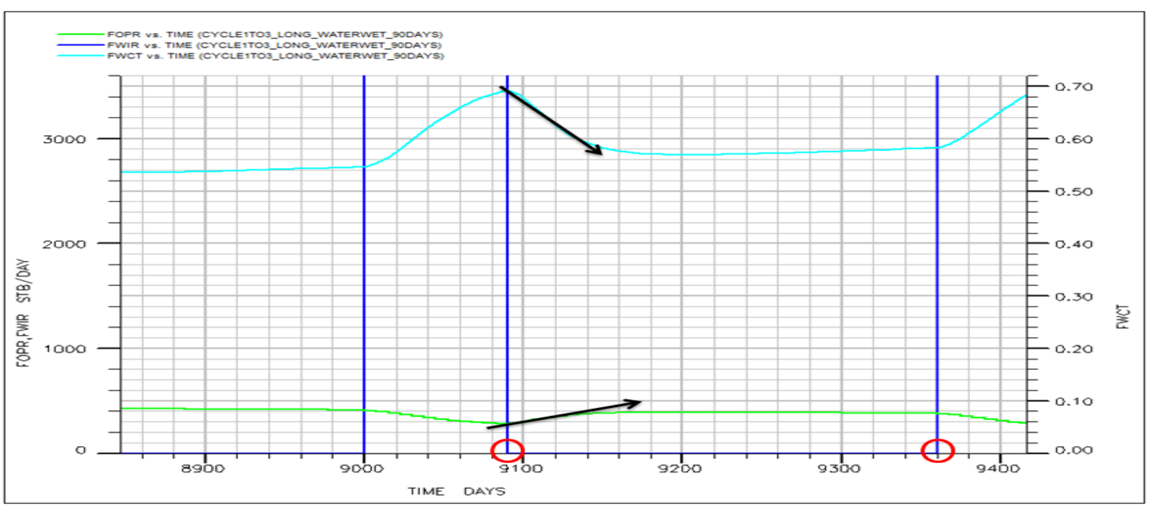

Figure 5.8: *Water cut (turquoise), injection profile (blue) and oil production rate (green) over a shut-in period (1:3-cycle with 90 days base period).*

During the injection halt, oil migrates from the low permeability zones into the better quality facies. Substracting the oil saturation before injection shut-in (at 9090 days) to the oil saturation at the end of the halted injection period (at 9360 days) the effect of cyclic injection is clearly visible. Table 5.1 shows the variation in oil saturation over the shut-in period illustrated in Figure 5.8, in each grid cell. A positive difference expresses that oil has migrated out of the grid cell. Negative numbers are maninly seen in the swept, high permeability areas. Reason for small changes in the high permeability zones is gain in oil saturation from the surrounding layers simultaneously as drainage due to production. Naturally the grid cells close to the producer experience a greater loss in oil saturation over time. To summarize, the oil in place in the high quality zones is increasing, while oil is migrating from the lower permeability zones. Oil saturation used in the calculations at 9090 and 9360 days are given in Table 10.7 and Table 10.8.

Table 5.1: Oil saturation difference after a period of halted injection.

J	K	I= 1	2	3	4	5	6	7	8	9	10	PermX (md)
1	1	0,07 %	0,63 %	1,54 %	2,68 %	2,98 %	2,89 %	2,73 %	2,04 %	1,57 %	1,44 %	*13,64*
1	2	-0,17 %	-0,07 %	0,06 %	0,32 %	0,61 %	0,85 %	1,43 %	2,59 %	3,06 %	2,72 %	*60,64*
1	3	-0,23 %	-0,27 %	-0,30 %	-0,25 %	0,00 %	0,00 %	-0,11 %	-0,34 %	0,10 %	0,54 %	*190,91*
1	4	-0,18 %	-0,13 %	-0,09 %	-0,05 %	0,02 %	-0,01 %	-0,13 %	-0,09 %	0,15 %	0,39 %	*136,36*
1	5	-0,43 %	-0,41 %	-0,30 %	-0,18 %	-0,02 %	0,04 %	0,06 %	0,08 %	0,07 %	0,18 %	*654,55*
1	6	0,00 %	0,16 %	0,29 %	0,43 %	0,64 %	0,58 %	0,52 %	0,46 %	0,58 %	1,79 %	*13,64*
1	7	-0,39 %	-0,36 %	-0,21 %	0,03 %	0,37 %	0,42 %	0,51 %	0,77 %	2,77 %	7,27 %	*136,4*
1	8	0,58 %	1,33 %	1,78 %	2,05 %	2,26 %	2,17 %	1,88 %	1,67 %	1,59 %	1,75 %	*1,36*
1	9	-0,64 %	-0,66 %	-0,56 %	-0,46 %	-0,28 %	-0,26 %	-0,37 %	-0,33 %	0,27 %	1,30 %	*40,91*
1	10	-0,35 %	-0,38 %	-0,32 %	-0,18 %	0,04 %	0,15 %	0,13 %	0,14 %	0,28 %	0,66 %	*231,82*

5.1.3 Different Injection Rates

Section 5.1.1 explained how the more intensive injection scheme resulted in the greatest increase and decrease in oil and water production, respectively. Further investigation was conducted related to different injection rates for the given liquid production rates give in Table 4.4. Injection rates of 500, 1000, 2000, 4000, 6000 and 10000STB/day were simulated for all the schemes with a base period of 30days. The intensity of the injection schemes is strongly controlled by the injection rate. With a low injection rate the less intensive schemes with an injection to no-injection ratio of 1:1 and 2:1 yields a significant larger incremental oil production compared to having high injection rates (over 2000STB/day). When the shut-in period of the injector is equal or shorter than the injection period, less water must be injected to prevent water breakthrough and no further oil production – hence, the low production of oil observed with high injection rates for the less intensive schemes in Figure 5.9.

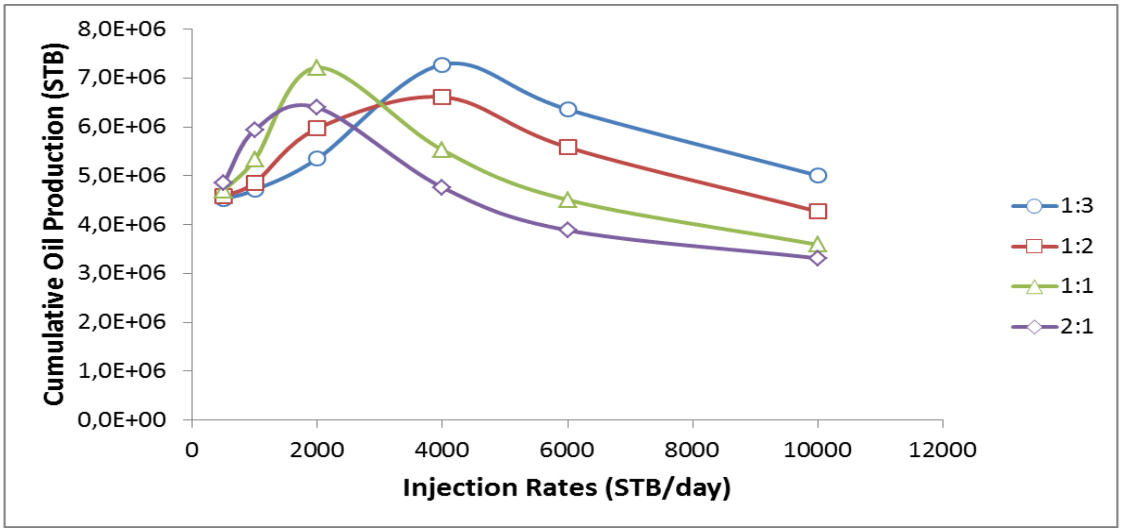

Figure 5.9: *Cumulative oil production versus injection rates for the water wet case with a base period of 30 days.*

The 1:2 and 1:3 injection schemes yielded greater cumulative oil production as the injection rate is increased up to a certain level. As the time period with no external pressure support is increased, the injection rate needs to be significant during the relative short injection period to maintain the pressure over a full cycle. Therefore, with a low injection rate these two high intensive schemes produce less oil compared to the less intensive schemes. Oil production is increasing up to an optimum rate where the benefit of cyclic injection is exceeding the conventional waterflood, Figure 5.10. If the chosen injection rate is not pre-screened and optimum for the reservoir no benefit of applying cyclic injection will be seen. Over-injection by applying a too high injection rate will not improve the effect of cyclic water injection, but only result in more water production. Water production is continuously increasing as the water injection rates are increased as a result of over-injection. The water production is rapidly increasing with increasing injection rate as water breakthrough takes place, and slowly increasing as the injection rate is raised further, Figure 5.11. Equivalent to the trend in Figure 5.5, less additional oil production resulted in a larger amount of water being produced.

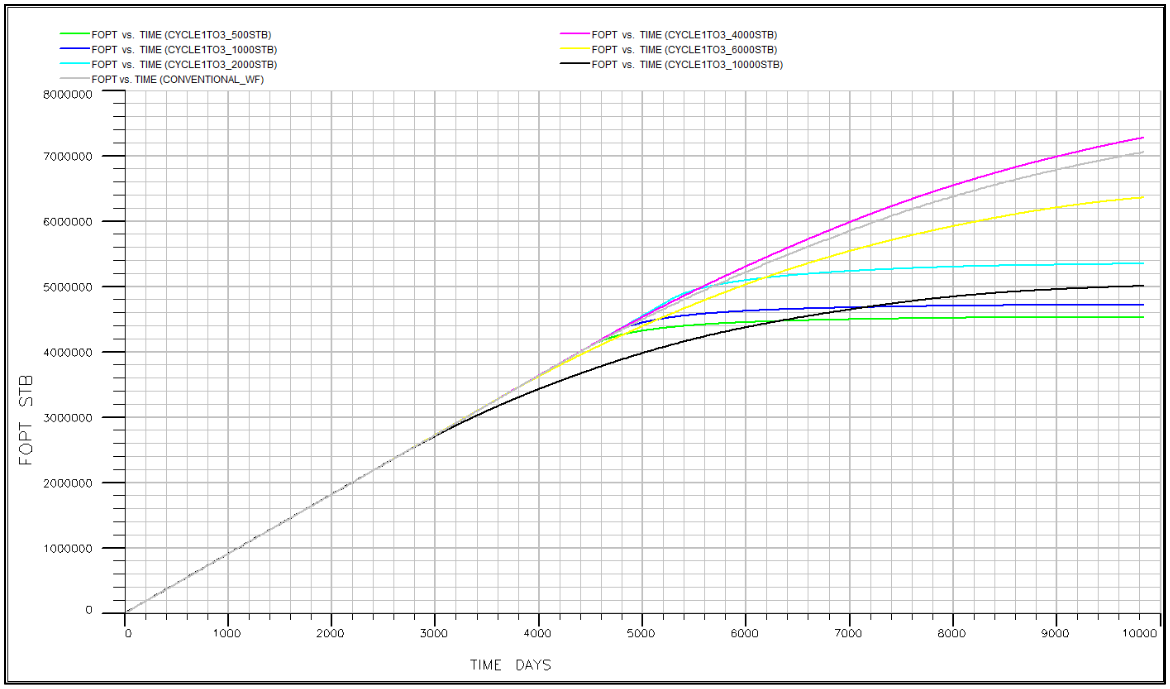

Figure 5.10: *Comparison of cumulative oil production for the 1:3 injection scheme with different injection rates and a base period of 30 days.*

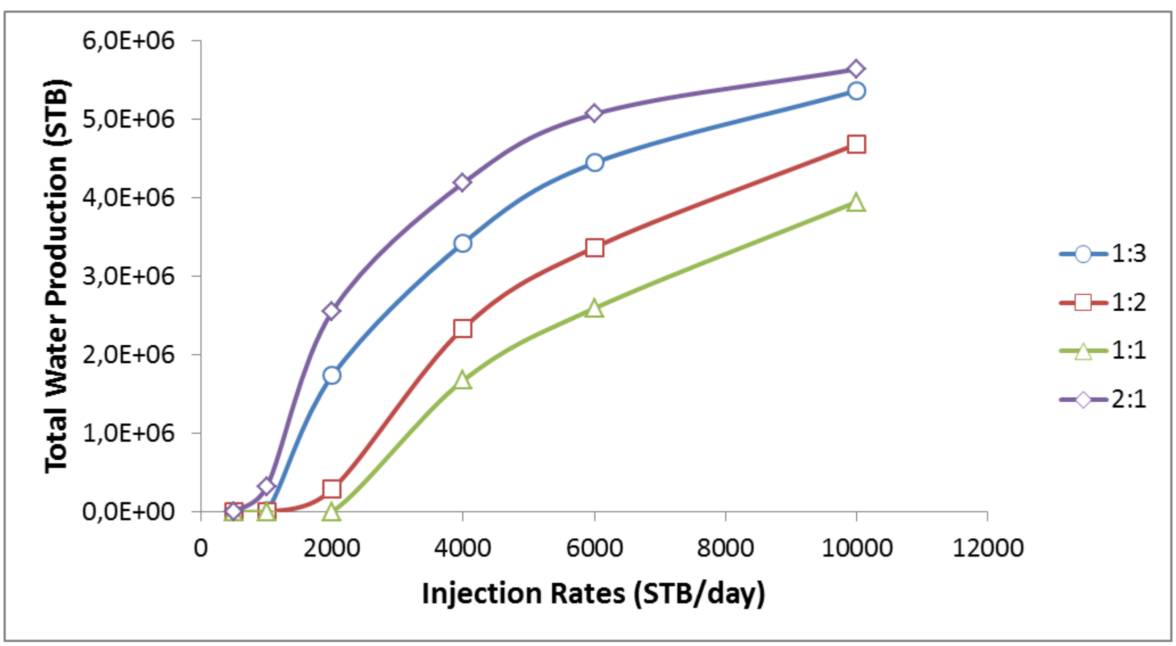

Figure 5.11: *Total water production versus injection rates for the water wet rock with a base period of 30 days.*

For the less intesive injection schemes an injection rate of 2000STB/day resulted in the largest cumulative oil production. Wheras for the more intesive schemes a higher rate of 4000STB/day yielded the greatest recovery. Higher injection rates obviously requires higher injection cycle rate ratio in order to balance the viscous and capillary forces – to obtain an improved recovery. The contact time between water and formation is reduced because of the high injection rates and no effect of capillary imbibition is obtained. The oil production-peaks obserevd in Figure 5.9 is approximatly at the critical value for water injection for *this* syntethic reservoir – and needs to be specified for each single reservoir.

5.1.4 Oil-Wet Reservoir

The effect of applying cyclic injection to mixed- and oil-wet reservoirs is widly discussed (Owens and Archer, 1966, Shchipanov et al., 2008), and is often resulting in improved recovery and reduced water production as for a water-wet case. The same injection schemes and rates applied for the water-wet case were applied for the mixed-wet case, Table 4.7. However, for the oil-wet case some modifications were done regarding the injection rates for the thinner reservoir section which will be discussed later in the text. For the oil-wet case the relative permeability profiles presented in Figure 4.3 and Figure 4.4 were applied in the model. The conventional waterflooding case for the oil-wet reservoir resulted in 39% less cumulative oil production, as expected, and 145% more water production compared to the water-wet case. The continous waterflood case for the mixed-wet reservoir produced 25% less oil, and 94% more water compared with the water-wet case (Table 4.3). Oil and water production and field water cut is presented in Figure 5.12. Due to poor recovery, more oil is left behind and the effect of cyclic injection could be beneficial.

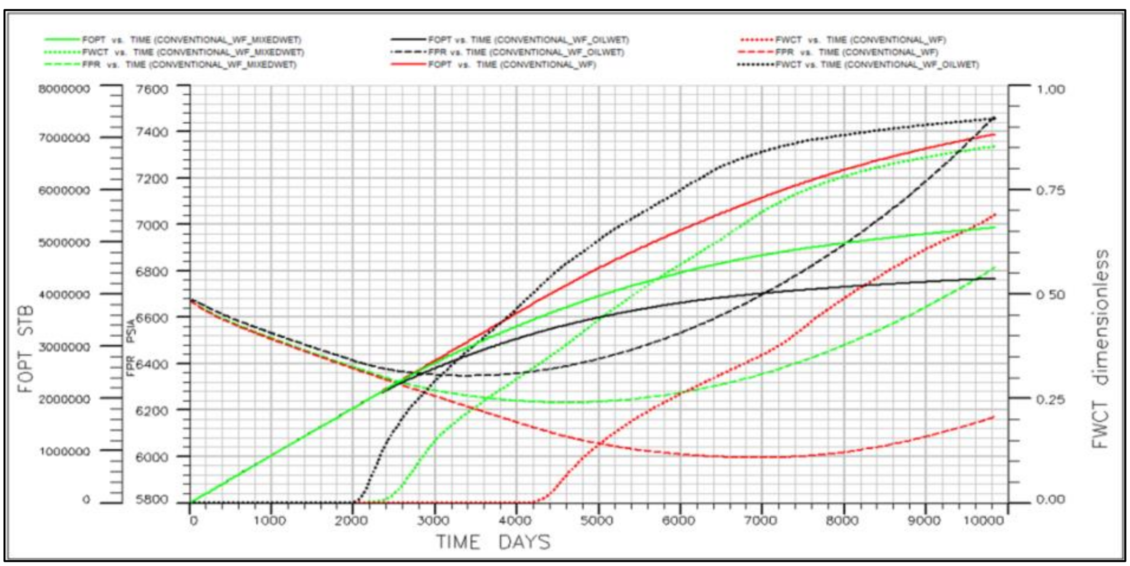

Figure 5.12: *Oil production, reservoir pressure, and field water cut for the water-wet (red), mixed-wet (green) and oil-wet (black) conventional waterflooding over time.*

Reservoir pressure for the three wetting conditions are not equal, and most likely affecting the results. Nevertheless, the incremental changes in oil- and water production could be compared between the wettabilities because the reservoir pressure is always greater than the saturation pressure at 5600psi. Mobility of water and oil are strongly controlled by the relative permeability of the fluid which is changing with the wettability; the relative permeability of water is increasing with increased oil-wetness and the relative permeability of oil is decreasing. The mobility ratios for the water- and mixed-wet conventional waterflooding case were favorable (M<1), whereas unfavorable for the oil-wet case. Eq. (3.24) was applied to calculate the mobility ratios given in Table 5.2. Oil and water viscosity used in these calculations were choosen to be the value at bubblepoint because the reservoir pressure was maintained above the saturation pressure.

Table 5.2: Mobility ratio for the oil-, mixed, and water-wet case.

Oil Wet	1,483
Mixed Wet	0,730
Water Wet	0,412

Oil saturation distribution at the end of simulation period for the three wettability conditions after conventional waterflooding is given in Figure 5.13.

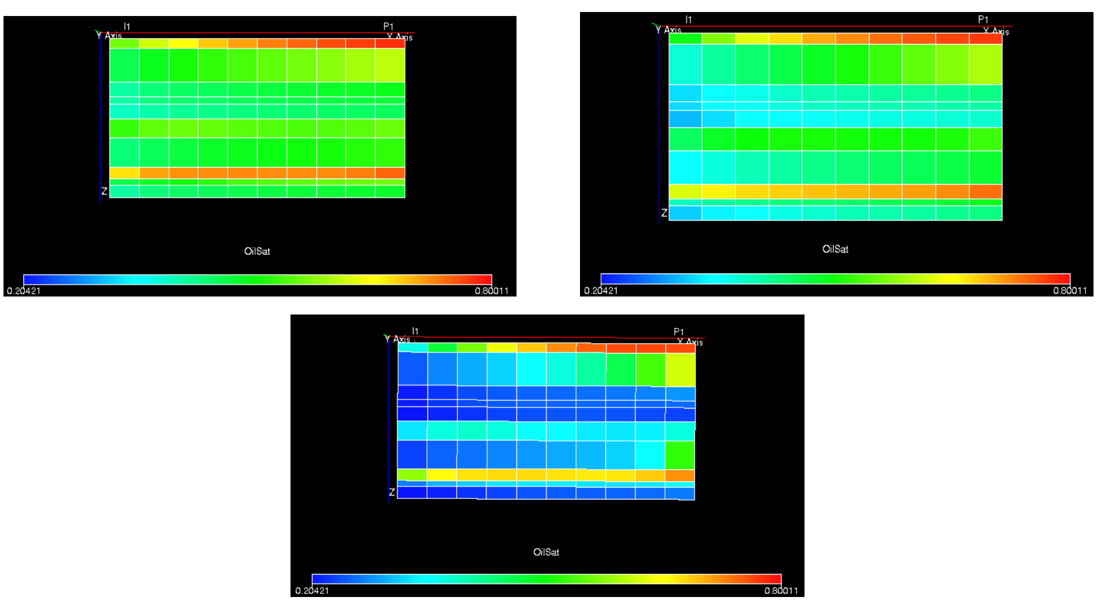

Figure 5.13: *Oil-wet (up left), mixed-wet (up right) and water-wet (low) oil saturation distribution at the end of simulation for the conventional waterflood.*

Figure 5.13 illustrates an important factor for the success of cyclic water injection – the oil distribution in the reservoir. The phase saturation in the reservoir is controlling the respectively fluid's relative permeability. For the oil-wet case, the remaining volume of oil in the reservoir is significantly greater than for the water-wet case. And the effect of applying cyclic injection to this case is expected to yield greater incremental recovery due to the difference in mobility between the water and oil phase at different water saturations.

In the oil-wet reservoir water breakthrough occurred approximately 2000 days earlier than for the water-wet case, Figure 5.12. Channels of water will form and flow through the reservoir, bypassing significant volumes of oil – resulting in the low recovery. With cyclic injection and oil-wet conditions these channels are limited by allowing the fluids to redistribute during the de-pressurizing half cycle and restrict channeling of water flow. And the cyclic scheme of 1:3 resulted in a total additional oil production of 5.52% compared to the conventional waterflood (oil-wet reservoir). Figure 5.14 shows the incremental oil production for the different cycle schemes over different base periods. The trend is approximately the same as for the water-wet case, except for the 1:1-scheme which observed an increased oil production by increasing the base period from 30 days to 90 days.

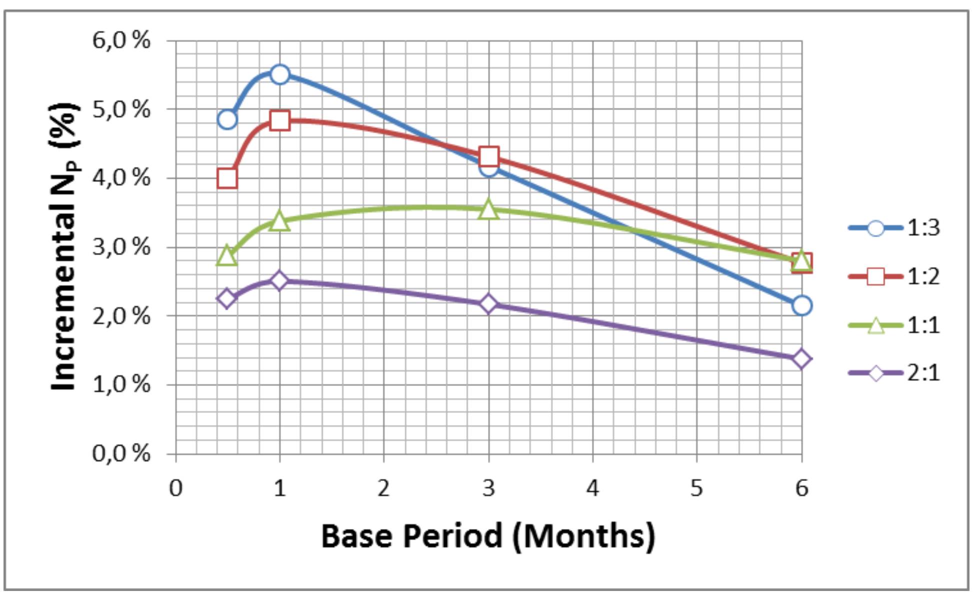

Figure 5.14: *Additional cumulative oil production (N_P) over conventional waterflood for the different injection schemes and base periods given in months (oil-wet reservoir).*

Same injection rates were applied for the oil- and water-wet case with a 328ft thick reservoir, and for all the schemes and base periods additional oil production were observed (relative to the respective wetting condition's base case), Figure 5.15. And the effect of cyclic injection is approximately twice the magnitude of incremental increase over the water-wet case. The saturation differences within the reservoir are greater between the cyclic and conventional injection for the oil-wet compared to the water-wet case, Table 10.3 and Table 10.4. High oil saturations present in the reservoir provides greater effect of cyclic injection in terms of the fluid magnitude exchanged by capillary imbibition during the pressurizing half cycle and compaction during the de-pressurizing half cycle. Most important is the effect of phase relative permeability; relative permeability of water is greater in the low permeable layers for the water-wet compared to the oil-wet case at a certain saturation level. Increasing water saturation reduces the oils relative permeability for the water-wet case faster than for the oil-wet case (see decline rate for k_{row} in Figure 4.3). The relative permeability of water in the oil-wet rock is greater than in the water-wet rock at high water saturation, which is present in the high permeable layers after water breakthrough. High relative permeability of water in the oil-wet case is the major factor for bypassing of oil. And by reducing the injection, with cyclic injection, the contact time between water and formation is enhanced – and more imbibition of water into the low permeable layers occurs. Hence, the oil-wet rock is more suitable for cyclic injection.

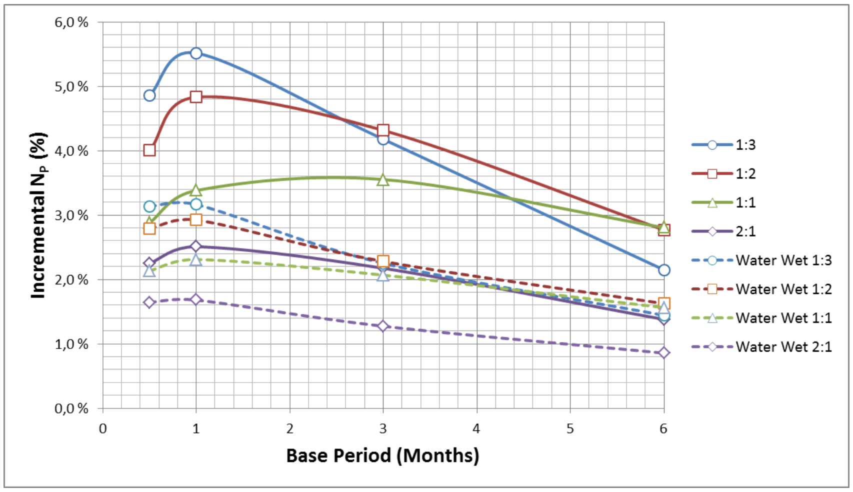

Figure 5.15: *Additional oil production for the oil-wet (solid line) and the water-wet (dashed line) cyclic injection.*

The high permeable layers (especially layer 3, 4 and 5) are producing 13-14% more oil during the 1:3-scheme (30 days cycle) compared to the conventional waterflood for the oil-wet case at the end of simulation, Table 5.3. This means that some of the oil in the low permeable layers have been expelled into the high permeable zones and towards the producer due to fluid exchange. Table 5.3 is calculated from the total fluid prodution from each grid block at the producer, and expresses the incremental variance bweteen cyclic injection (1:3) and conventional waterflood (WF):

$$\frac{Total\ Prod(1:3\ scheme) - Total\ Prod(WF)}{Prod(WF)}$$

The high permeable layers also see the greatest reduction in water production by 10-13%. For the water-wet case, the high permeable layers are producing an additional 7-9%. In addition more oil is being produced from the less permeable layers for the oil-wet rock over the water-wet rock.

Table 5.3: Incremental oil- and water production for oil-wet and water-wet rock at 9840days.

			PermX	Oil Wet Incr.:		Water Wet Incr.:	
Block (I, J, K)			(md)	Oil Prod	Water Prod	Oil Prod	Water Prod
10	**1**	**1**	13,6	6 %	0 %	1 %	0 %
10	**1**	**2**	60,6	2 %	86 %	1 %	0 %
10	**1**	**3**	190,9	14 %	-13 %	7 %	-10 %
10	**1**	**4**	136,4	13 %	-10 %	8 %	-10 %
10	**1**	**5**	654,5	14 %	-11 %	9 %	-14 %
10	**1**	**6**	13,6	11 %	7 %	4 %	-10 %
10	**1**	**7**	136,4	1 %	33 %	0 %	88 %
10	**1**	**8**	1,4	2 %	0 %	2 %	0 %
10	**1**	**9**	40,9	3 %	13 %	0 %	10 %
10	**1**	**10**	231,8	-1 %	8 %	-1 %	1 %
			Total	6 %	-5 %	3 %	-12 %

On the other side, the total water production was significantly lower for the oil-wet case compared to the water-wet rock, Figure 5.16. The high permeable layers, are producing approximately the same amount of water; this is due to the unfavorable mobility ratio in the oil-wet rock and that less water is imbibed into the water-wet rock and retained than expected. Water has a natural position below the oil colum, and will tend to segregate at the bottom of the reservoir. This is most likely the casue of the increased water production observed in the lower layers in the model. The incremental reduction in water production for the oil-wet and water-wet rock is illustrated in Figure 5.16.

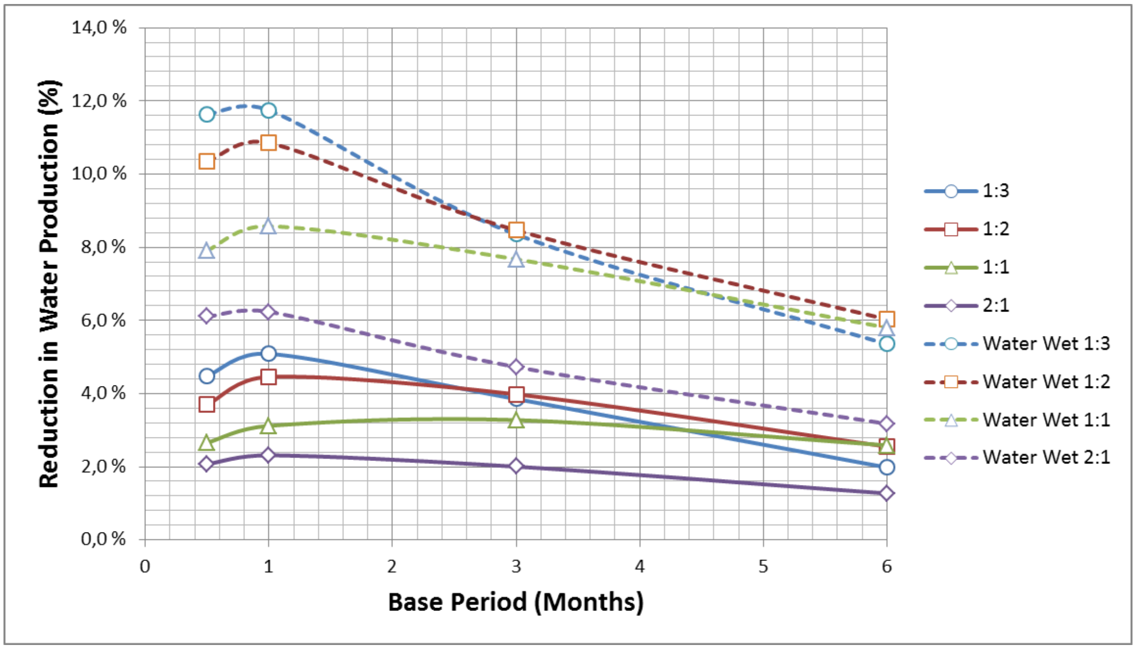

Figure 5.16: *Reduced water production for the oil-wet (solid line) and the water-wet (dashed line) cyclic injection.*

Figure 5.17 shows the oil saturation for the cyclic 1:3 injection (30 days cycle) to the left and the conventional waterflood to the right, at the end of simulation. As described above, the lower permeability layers (pink circle) are better swept, due to the effect of cyclic injection. High permeable layers in the center of the reservoir (yellow circle) appears to be less swept with the cyclic injection due to two reasons; first, the less permeable areas surrounding the high permeable layers are contributing with oil. Second is that more water has entered the low permeable zones from the high permeable layers due to capillary imbibition.

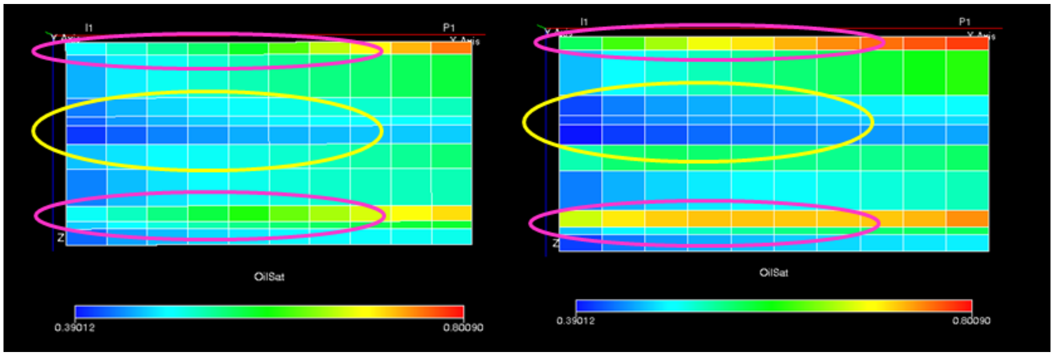

Figure 5.17: *Cyclic injection 1 to 3 (left) compared to conventional waterflooding (right) at the end of simulation for the oil-wet case.*

To summarize the effect of cyclic injection, a higher incremental increase in oil production and less reduction in water production compared to the water-wet case were seen. And the best injection scheme, similar to the water-wet case, was obsereved to be the 1:3 cyclic scheme with a base period of 30 days, Figure 5.18.

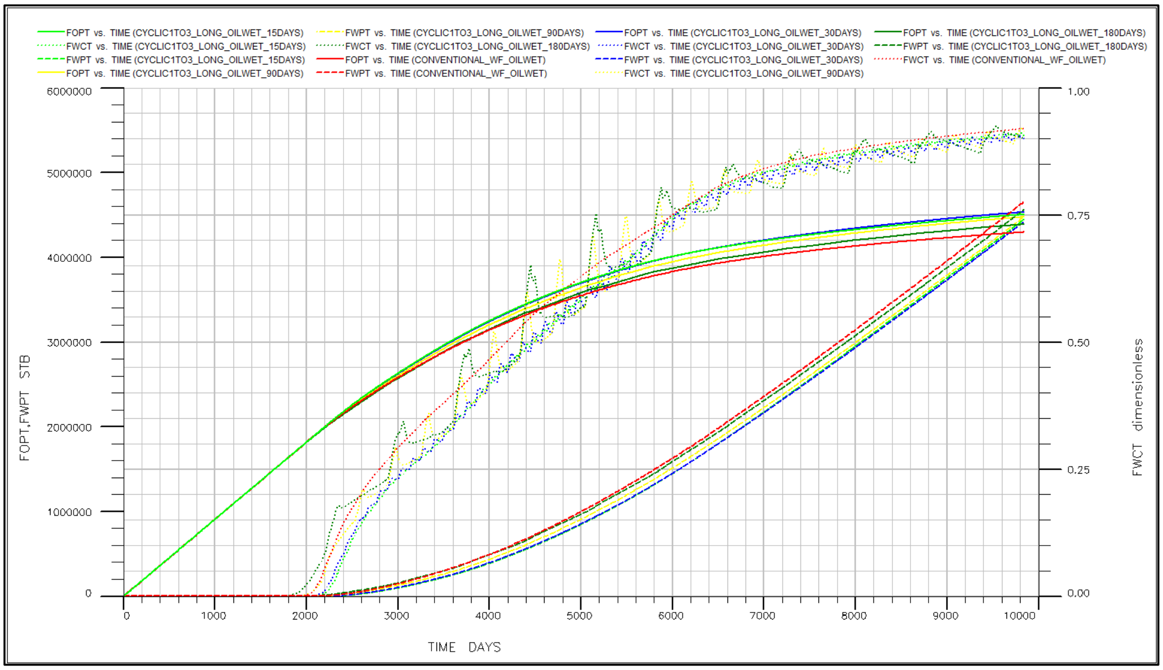

Figure 5.18: *Oil and water production, and water cut versus time for the 1 to 3 injection scheme with a base period of 30days for the 328ft oil-wet reservoir.*

5.1.5 Mixed-Wet Reservoir

Continuing from the previous section, a short analyze of cyclic injection in a mixed-wet reservoir will be carried out. The cumulative water and oil production for the conventional waterflood were, as expected, between the respective values for the water- and oil-wet case. And the same trend was observed for the cyclic injection, Figure 5.19. The best case is the 1: 3 cyclic scheme with a base period of 30 days. Compared with the water-wet case, the more intensive injection schemes increased the additional oil production, whereas the less intensive schemes produced more oil for the longer base periods of 90 and 180 days. The oil-wet case produced significantly more oil for all the four schemes compared with the mixed-wet case, because of the reasons described in the previous section. A significant greater decrease in water production than for the oil-wet case was observed for the mixed-wet case, Figure 5.20.

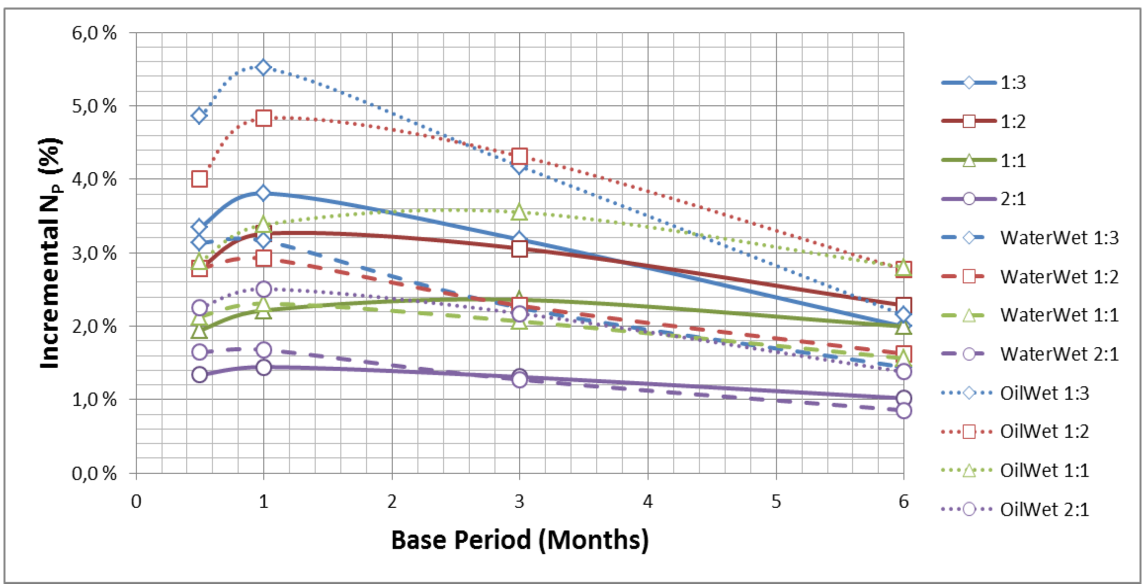

Figure 5.19: *Additional oil production related to the cyclic injection schemes for the water-wet (dashed line), oil-wet (dotted line) and mixed-wet (solid line).*

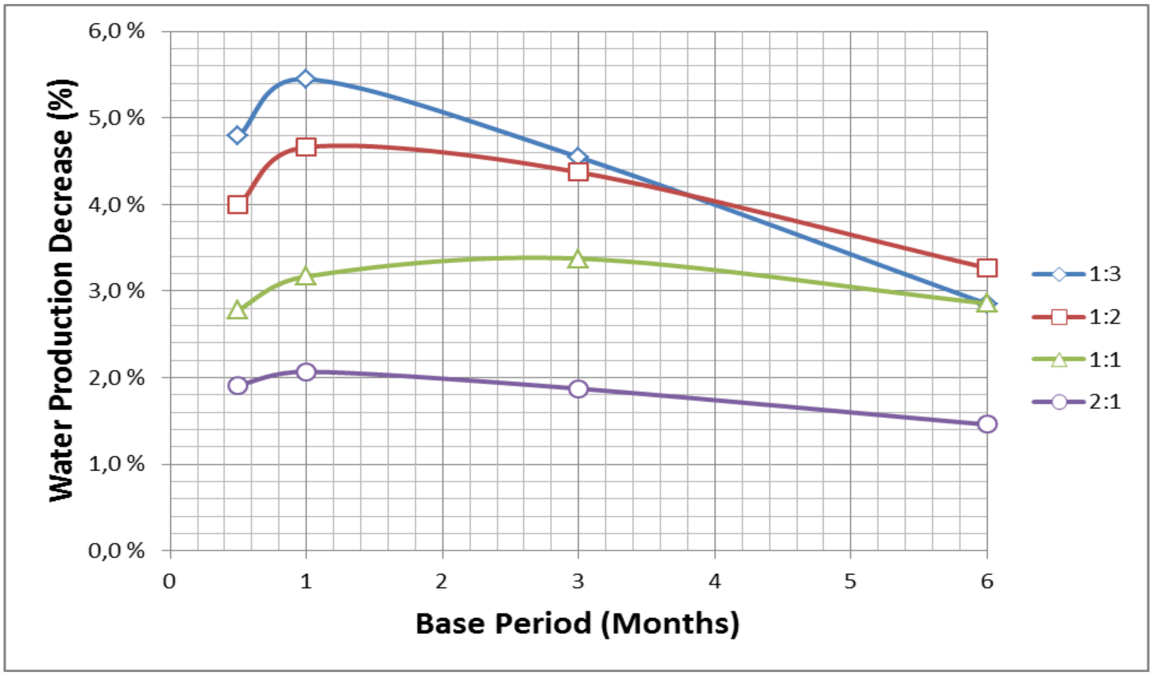

Figure 5.20: *Decrease in water production for the mixed-wet case for different injection schemes and base periods.*

5.1.6 Well Spacing – Long vs. Short

Distance between the injector, I1, and producer, P1, in the model is considered to be a critical parameter for the outcome of cyclic injection. The base case, which was discussed in section 5.1.1-5, was modelled with an injector-producer distance of 3280ft (referred to as the long spacing case). By creating an equivalent model with a shorter well-to-well distance of 1640ft (short spacing) the cyclic water injection process will be analyzed. For the case with shorter distance, the water injection and liquid production rates were adjusted to the new reservoir volume; 700STB/day of injection and 640STB/day of liquid production for the conventional model. Injection rates respective to the cyclic schemes are given in Table 4.7. Because the capillary pressure curve applied for all three wetting-cases is fitted for a water-wet rock, this case was tested under water-wet conditions to increase the confidence of the result. All other variables are maintained unchanged. Injection cycles of 1:3, 1:2, 1:1 and 2:1 were simulated with the same range of base periods (15, 30, 90 and 180 days).

Table 10.5 and Table 10.6 show a summary of the simulation results. Conventional waterflood produced 3.74MMSTB of oil equivalents and 2.55MMSTB of water after a total injection of 6.88MMSTB water. Field water cut at the end of simulation period was 89.5%. Figure 5.21 shows a summary of the additional oil production for the short spacing case.

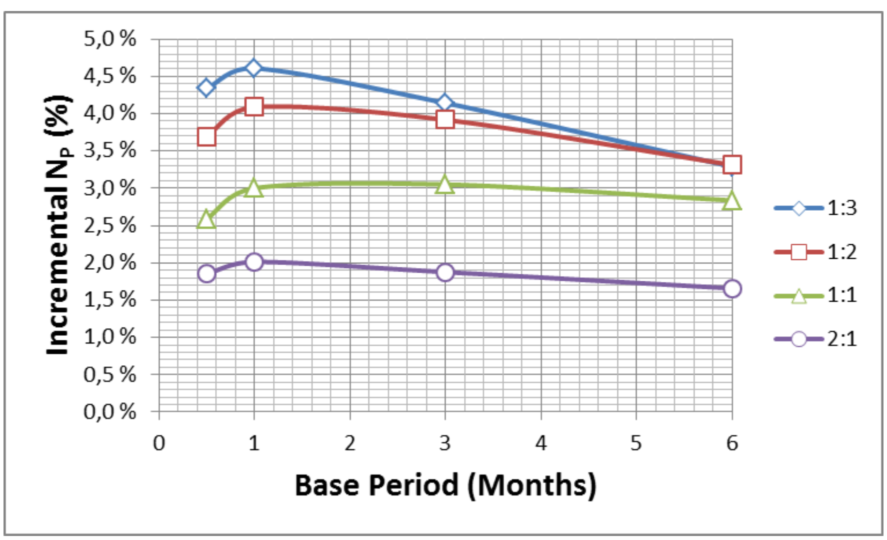

Figure 5.21: *Additional cumulative oil production (N_P) for the short spacing case for the different injection schemes and base periods given in months (water-wet reservoir).*

Intensive cycle schemes result in the greatest additional oil recovery, similar to the long spacing case. It was found that the 1:3 yielded the best result with an incremental increase of 4.61% with a base period of 30 days. Meaning, the short spacing resulted in over one percentage more incremental increase in production compared to the long spacing. Overall the short spacing provided greater increase in oil production independent of the cyclic setup and base period, Figure 5.22.

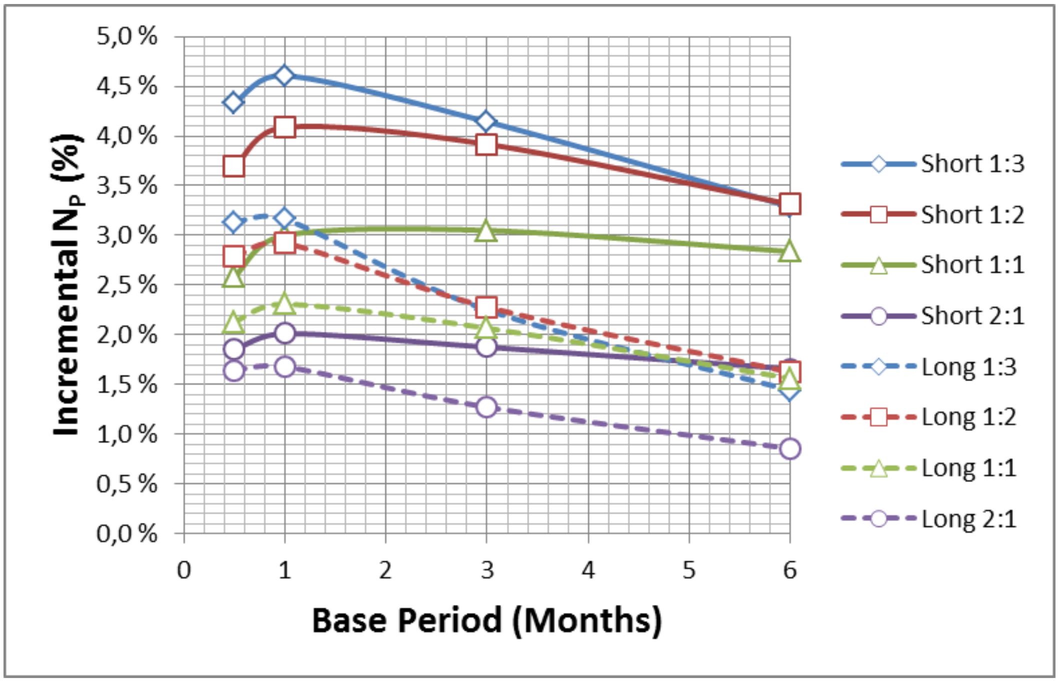

Figure 5.22: *Additional oil production for the short and long spacing, water-wet system.*

As the distance between the wells is decreasing, the relative amount of formation directly affected by the cyclic injection is increasing when the reservoir is being produced over the same time period. Water breakthrough is obtained after day 2800 and 4400 days for the short and long spacing, 1:3 cycle, respectively. Considering the water flow in the reservoir as a line drive displacement, the distance an oil and water particle must travel is increasing proportionally to the well spacing. In a line drive with 1640ft between the injector and producer the average oil particle needs to travel 820ft (1640ft for an oil particle close to the injector and 0ft near the producer). With an injector-producer distance twice as large, the travel distance doubles. Hence, injected water in a reservoir with short well spacing will faster reach the producer. In other words, the effective contact time between formation and water for a short spacing system will be longer compared to a long spaced system over the same time period (here: 9840 days). Figure 5.23 illustrates the realtive area affected by the injected water for the short spacing case. Therefore, more area is affected by the cyclic injection and a greater amount of oil is produced with a short well spacing.

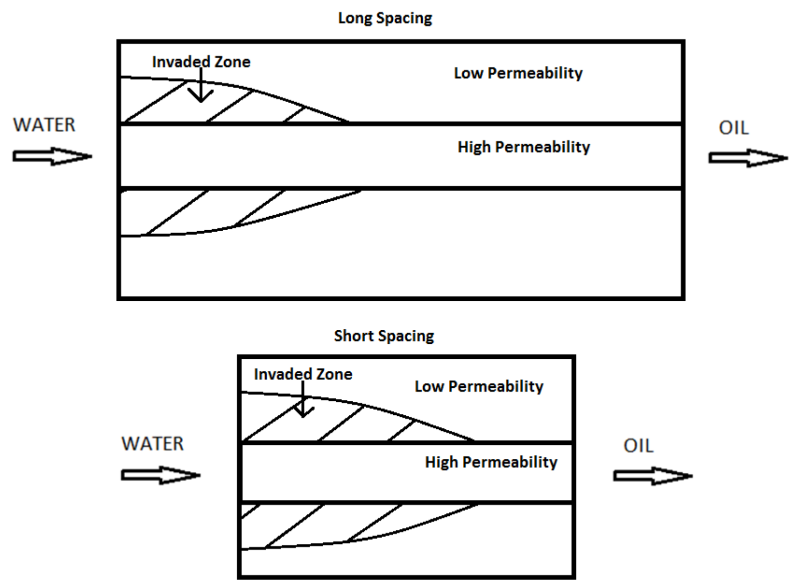

Figure 5.23: *Water invasion near injector and producer for the long and short spacing.*

On the other hand, the incremental water production is significantley lower for the short spacing, Figure 5.24. Obviously, with a shorter well spacing the relative amount of water produced over time will be greater than for the long spacing, due to shorter travel distance for the water particles. Both the short and long spacing case are favored by cyclic water injection, and the short spacing sees a greater relative increase in oil production compared to the long spacing.

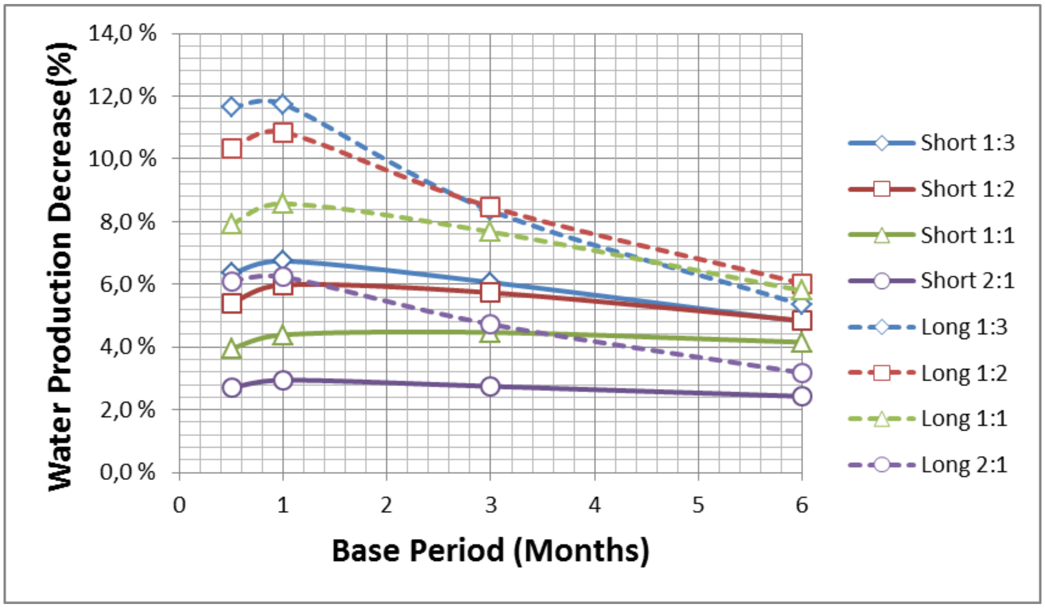

Figure 5.24: *Water production for the long and short spacing case, water-wet.*

5.1.7 Reservoir Thickness – 328ft vs. 164ft

An equivalent model for the long and short spacing case was modelled by reducing the reservoir thickness – from 328ft to 164 ft. Because the injection to production rate ratio for the thick and thin reservoir section differed with 3-4% in favor of the thin reservoir section (Table 9.7), analyzes should be done with care. The thinner model resulted in a greater recovery factor for both the conventional waterflood and the best cycle scheme, which was the 1:3-scheme with a base period of 30days. Figure 5.25 and Table 5.4 present the results from the thinner reservoir compared with the thicker section.

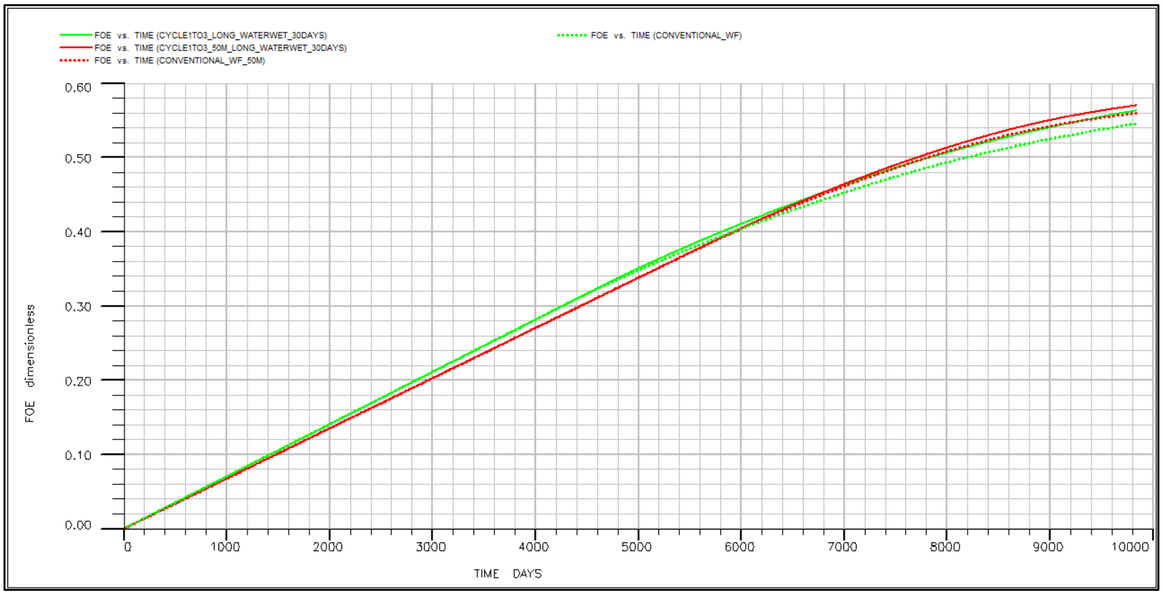

Figure 5.25: *Oil recovery (FOE) for the conventional (dotted line) and cyclic 1:3 (solid line), for the thin (red) and thick (green) reservoir.*

Yaozhong et al. (2006) explained that thinner reservoir sections are favorable to cyclic injection. An unexpected result of a lower incremental increase in the recovery was observed with cyclic injection; 3.16% and 1.83% increase in oil recovery for the thick and thin section, respectively.

Table 5.4: Oil recovery at for the 328ft and 164ft reservoir and incremental increase with cyclic injection after 9840days.

Thikness	328ft	164ft
Conv WF	54,57 %	55,98 %
Cycle 1 :3	56,30 %	57,00 %
Increase	3,16 %	1,83 %

After water breakthrough the fluid productivity index will decrease for a continuous waterflood. Productivity index (J) is defined as the ratio of total liquid flow rate (Q) to pressure drawdown (Δp):

$$J = \frac{Q}{\overline{p_r} - p_{wf}} = \frac{Q}{\Delta p} \quad (5.1)$$

Through cyclic injection, the fluid productivity index will increase by reduction in the water cut – resulting in greater liquid/oil extraction rate. In Figure 5.26 there is a large difference in time when water cut is starting to rise – between the cyclic 1:3-scheme and conventional waterflood and the thick and thin reservoir. But more important is the greater drop in water cut observed for the 1:3-scheme for the thick section. This drop in water cut is mainly caused by greater alternation in injection rate for the thick payzone over the thin section – from 4,000-0 STB/day and 2,000-0 STB/day, respectively. Following the greater drop in water cut for each cycle during injection shut-in, a larger increase in oil production rate was observed in the de-pressurizing cycle, Figure 5.27. Hence, the reason why the thin reservoir produced less additional oil by cyclic injection is most likely related to the chosen injection and production constraints in the model.

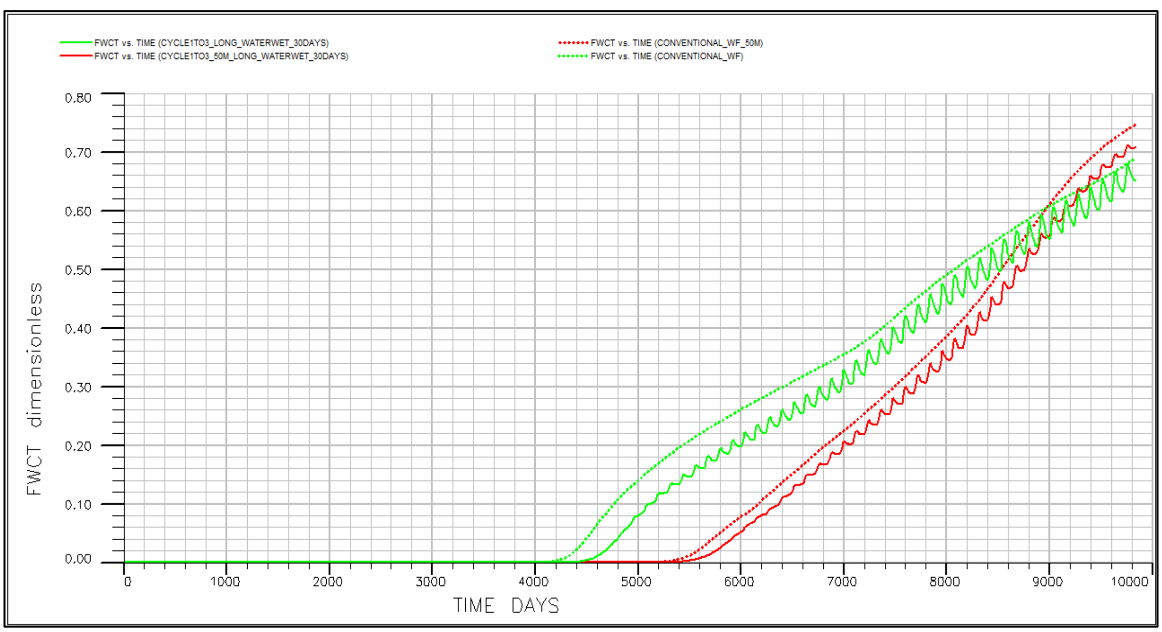

Figure 5.26: *Field water cut for the conventional (dotted line) and cyclic 1:3 (solid line), for the thin (red) and thick (green) reservoir.*

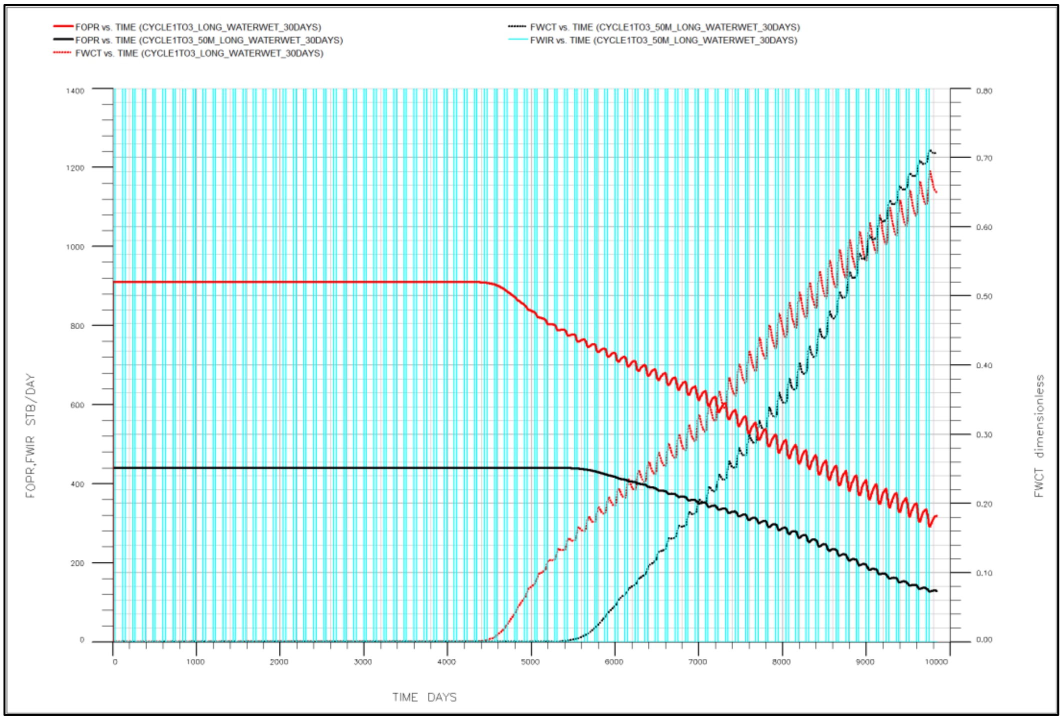

Figure 5.27: *Oil production rate (FOPR, solid line), water cut (FWCT, dotted line), and 1:3 cyclic injection rate (light blue) for cyclic injection of 1:3 and 30days base period. Thick (red) and thin (black) reservoir.*

5.1.8 Effect of Transmissibility

Communication between the high and low permeable zones is considered as a crucial parameter for the amount of increase in oil production by the cyclic waterflood approach. Ratio of vertical to horizontal permeability was increased from 0.1 to 0.5 to investigate the effect of increased vertical transmissibility. Obviously, an increase in the vertical permeability was positive for both the conventional and cyclic waterflood with respect to oil recovery, Figure 5.28. Improved vertical permeability helps gravitational segregation of the fluids and allows a better sweep. When compared, the increase in vertical transmissibility is discouraging for the cyclic injection effect. Figure 5.28 shows a small increase in cumulative oil production by 1.17% for the high transmissibility model when the water injection is cycled. A greater incremental oil production of 3.16% is observed with a lower transmissibility. Total water production also diminishes with increased vertical permeability, Figure 5.29. And the higher vertical permeability reduces the water production less than the low permeability compared to the non-cyclic model – by 11.7% and 5.3%, respectively.

An increase in vertical transmissibility improves the communication between the layers, and affects the amount of retained water in the low permeable zones. Hence, more water is being produced from the high permeable layers due to gravitational segregation of water from the low permeable layers, and the effect of cycling is reduced.

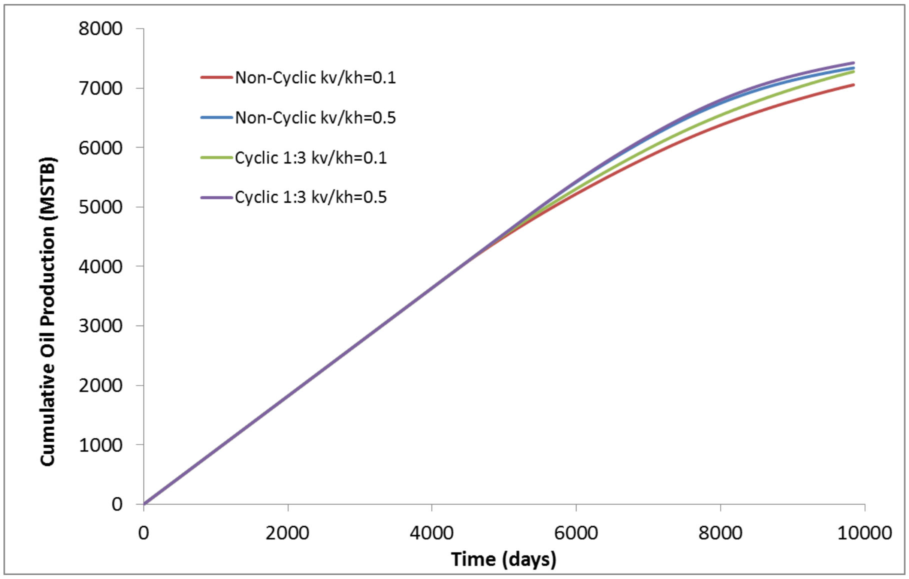

Figure 5.28: *Cumulative oil production for different k_v/k_h-ratios.*

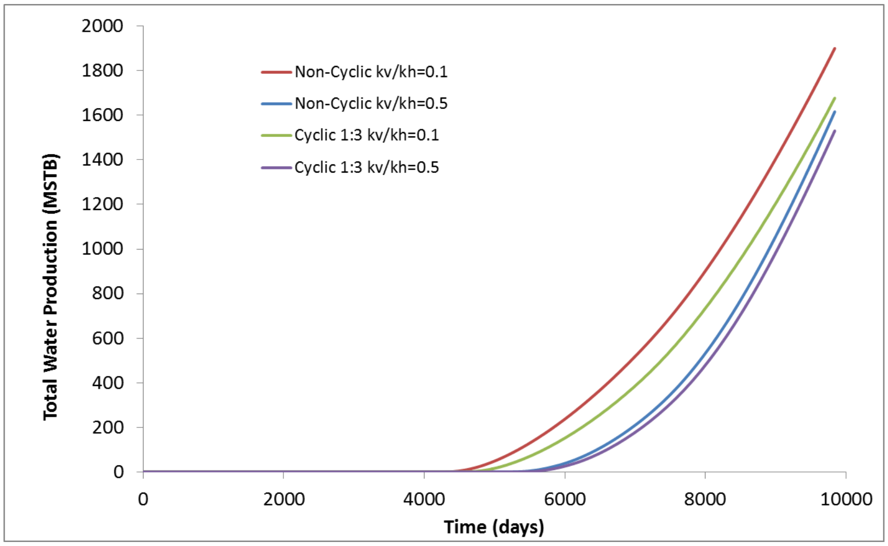

Figure 5.29: *Cumulative water production for different k_v/k_h-ratios.*

5.1.9 Symmetric Permeability

Reservoirs with the presence of layered heterogeneity and permeability differences are the base of obtaining an increase in oil production by cyclic injection. In this section the water-wet base case is changed with respect of the permeability distribution and layer thickness – one model with symmetric permeability (explained in Figure 4.1), and one homogeneous model was created. No other parameters are changed from the original base case, and the injection/production rates are maintained the same.

The symmetric case is illustrated in Figure 5.30, and consists of homogenous layers with a high permeable central section surrounded by decreasing permeability layers towards the top and bottom of the reservoir. The thickness of each layer is 32.8ft. Introducing a layer with significantly greater permeability than the surrounding zones, will increase the total permeability differences within the system. And it is expected to sweep more of the surrounding layers with cyclic injection than the previous heterogeneous case.

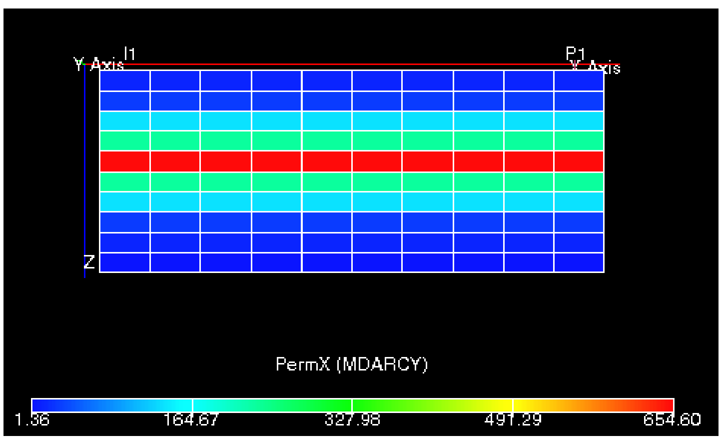

Figure 5.30: *Permeability distribution for the symmetric case.*

The 1:3-cycle has been the best scheme for all cases investigated, therefore it was applied to this model. Figure 5.31 shows the relative amount of oil production for the 1:3-scheme at different base periods for the base case and symmetrical case (Figure 5.30). From the 1:3-scheme, 3.8% increase in cumulative oil production was given for the symmetrical case, which is 0.6% more than the original base case increased by applying cyclic injection. Again the best case was achieved with 30days of injection and 90 days of shut-in.

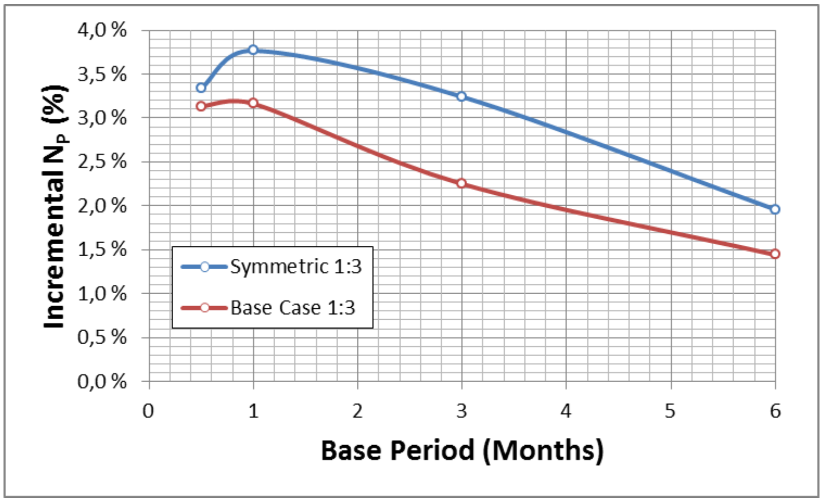

Figure 5.31: *Incremental oil production for the base case (red) and symmetrical (blue) model.*

Figure 5.32, shows the advantage of applying cyclic injection to a more symmetric, heterogeneous reservoir. Greater sweep of the low permeable layers (pink circles) and flow of oil towards the high permeable layers (red circle) take place, and improves the recovery. It is clear from Figure 5.32 that the low permeable layers are better swept, and that the oil saturation in the middle of the reservoir is slightly lower than for the continuous waterflood. The single layer with significantly larger permeability than the others will be the major contributor of oil production in a conventional waterflood. Applying cyclic injection will reduce the amount of bypassed oil by de-pressurizing cycles, where oil is flowing from the low permeable layers towards the high permeable layers.

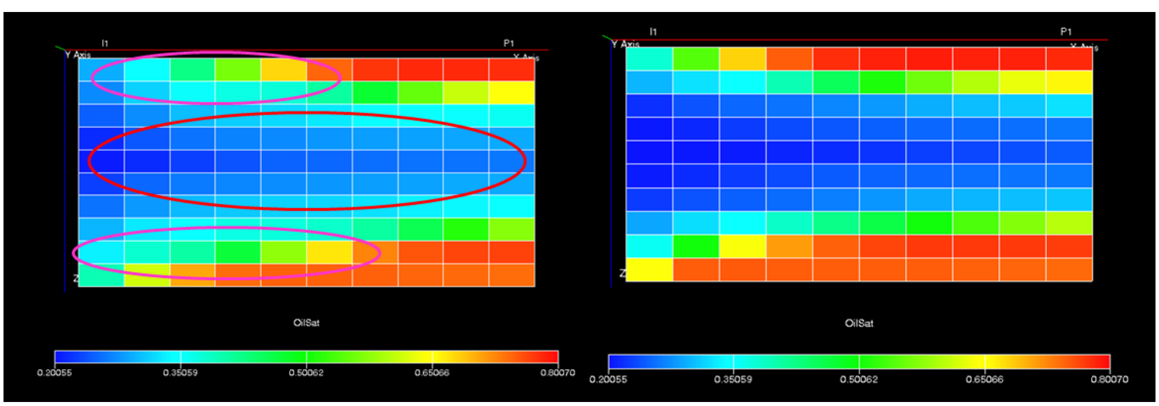

Figure 5.32: *Oil saturation for the 1:3-cycle (left) and conventional waterflood (right) for the symmetric permeability case after 9840 days.*

Reduction in water production is lower than for the base case; nevertheless 7.4% reduction was obtained with the 1:3-scheme with 30 days of base period, Figure 5.33.

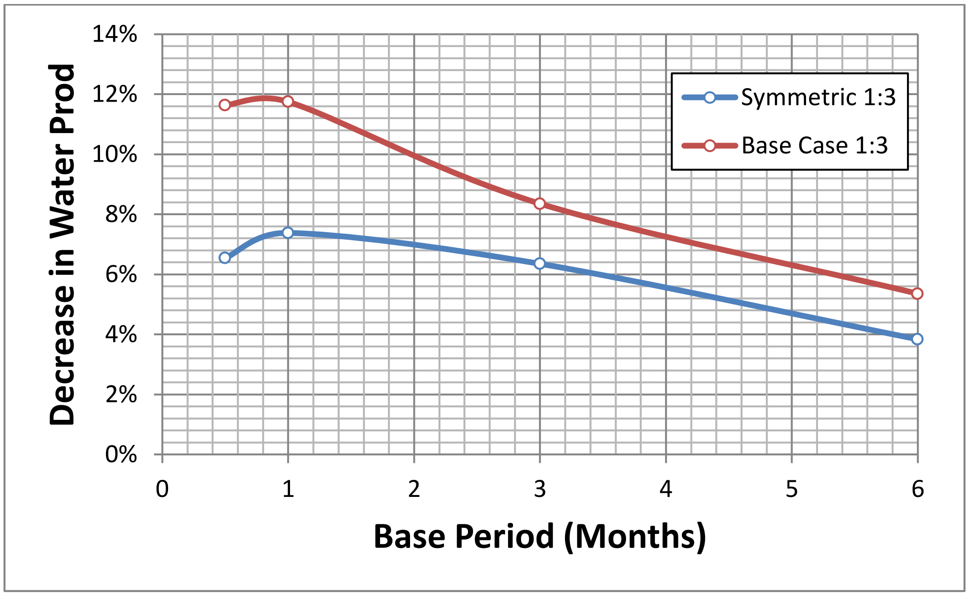

Figure 5.33: *Reduction in water production for the base case (red) and symmetrical (blue) model.*

5.1.10 Homogeneous Model

Stratified reservoirs are said to be favorable to cyclic injection, therefore a homogeneous model equal to the base case was modelled to test the theory. The average permeability value for the base case is 142md, and was applied to all ten layers for this homogeneous model. All the ten layers have the same properties, and will act like a single layer. The injected water will displace the oil in front, and the waterflood will act as a piston-like displacement. Displaced oil is located in front of the water, and no bypassing of oil is taking place. Hence, a late water breakthrough is observed, Figure 5.34.

Figure 5.34 presents the cumulative oil production and water cut for continuous and 1:3 cyclic injection. Minor additional oil is produced by cyclic injection compared to conventional waterflood – 0.1-0.2% incremental production over the conventional waterflood. After water breakthrough there is a small change in production rate, but the change is considered as insignificant. Because all oil is in front of the water, no additional recovery from non-existing poor swept areas is possible – hence, the effect of cycling is absent. The small difference in oil production by cycling is related to an increased plateau period of approximately 300 days, followed by a steeper decline in production rate by cyclic injection.

Reduction in water production is substantial – the 15 and 30 days base period reduced the water production with 4-5% compared to conventional waterflood. Natural drive energy in the system is able to produce all layers independent of external pressure support – hence, the cumulative oil production is equal. But by shutting the injector, the amount of water reaching the producer is lower and less water production occur. This section has proved the importance of having significant permeability differences to obtain a successful cyclic waterflood.

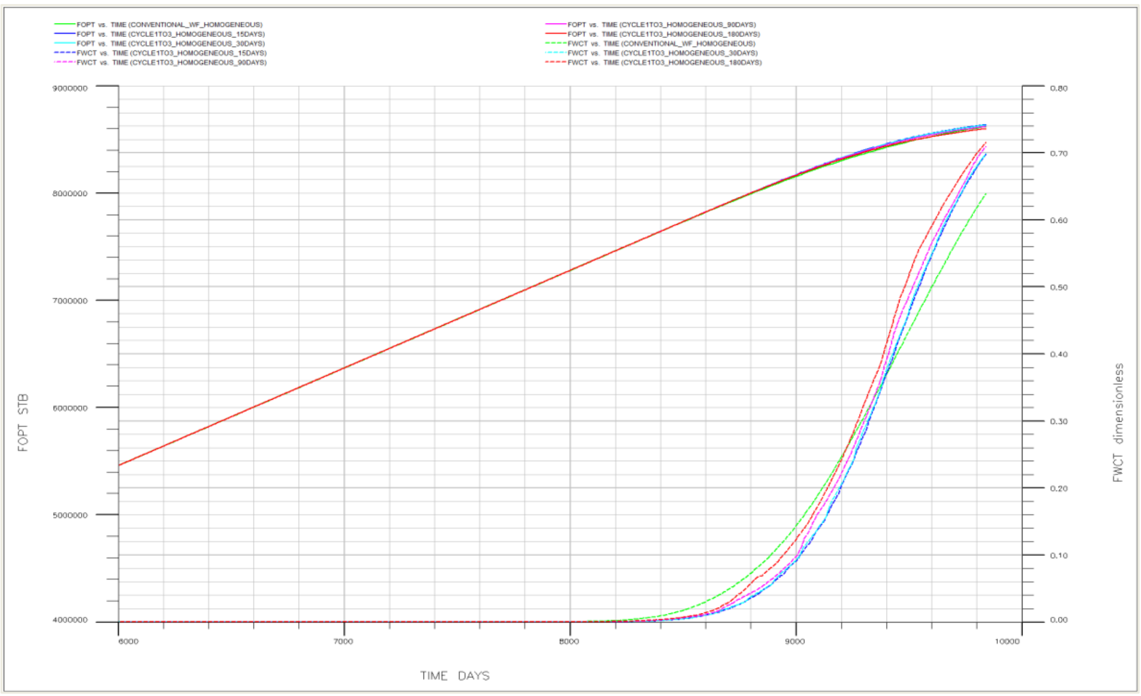

Figure 5.34: *Comparison of cumulative oil production and water cut for the conventional and cyclic 1:3 injection.*

5.1.11 Cyclic Initiation Time

Cyclic startup time is defined as the time the cyclic injection commences – and is considered as one of the most important factors for success. Because of the low water cut level in the synthetic water-wet model, the oil-wet model was used to investigate the startup time. Cycle of 1:3 has proven to be the optimum setup for this model, and will be used in this analyze. From Figure 5.18, a noticeable increase in oil production from cyclic injection occurs approximately at a water cut of 25% under conventional waterflood, and will be the lowest water cut level investigated for late time initiation of the cyclic process. 50, 65, 75 and 85% are considered as good water cut levels for this case to initiate cycling and will be further analyzed. The time when these water cuts are reached is presented in Table 5.5.

Table 5.5: Simulation time before certain water cuts are achieved.

Water Cut Level	Time(days)
25 %	2801
50 %	4181
65 %	5141
75 %	6001
85 %	7181

Comparing the results for cyclic initiation at the times and water cut levels given in Table 5.5, the increase and decrease in fluid production are only related to the time period when cyclic injection is occurring. The increment in total production, ΔN_p, is calculated as follows:

$$\Delta N_p = \frac{N_{p(end)}^{Cyclic} - N_{p(end)}^{Conv}}{N_{p(end)}^{Conv} - N_{p(Cyclic\ startup)}^{Conv}} \qquad \textbf{(5.2)}$$

The superscript *cyclic* and *conv* represent the cyclic and conventional waterflood, and the subscript *end* and *cyclic startup* stand for cumulative production at the end of simulation and at the time when cyclic injection is initiated. Production numbers are given in appendix D. Quantity of increment in oil and water production indicates the impact cyclic injection has on the oil and water production.

Simulations show that the effect of cyclic injection is positive for all water cut levels. And a significant increase in incremental oil production is observed when being applied under medium-high water cuts. Cyclic injection (with 30 days base period) applied at a water cut of 75% after continuous waterflood, produced 14.1% additional oil over the conventional waterflood, Figure 5.35. Also, the incremental reduction in water production was decreasing with higher water cuts. At relatively low water cut, the oil displacement by water in the low permeable zones will be low. This exchange rate of oil by water will increase with the water cut; under high water cut stages, the high permeable zones are basically full filled with water. And the difference in fluid mobility and phase pressure between the high and low permeable layers is increased and will create excellent conditions for water to expel oil from the low permeable zones due to increased gravity and capillary pressure. The oil and water production and water cut profiles are given in appendix D.

An unexpected decrease in incremental oil production befell when cyclic injection was started at 85% water cut. A clear trend from 0 to 75% water cut should have resulted in further increase in oil production at 85% water cut.

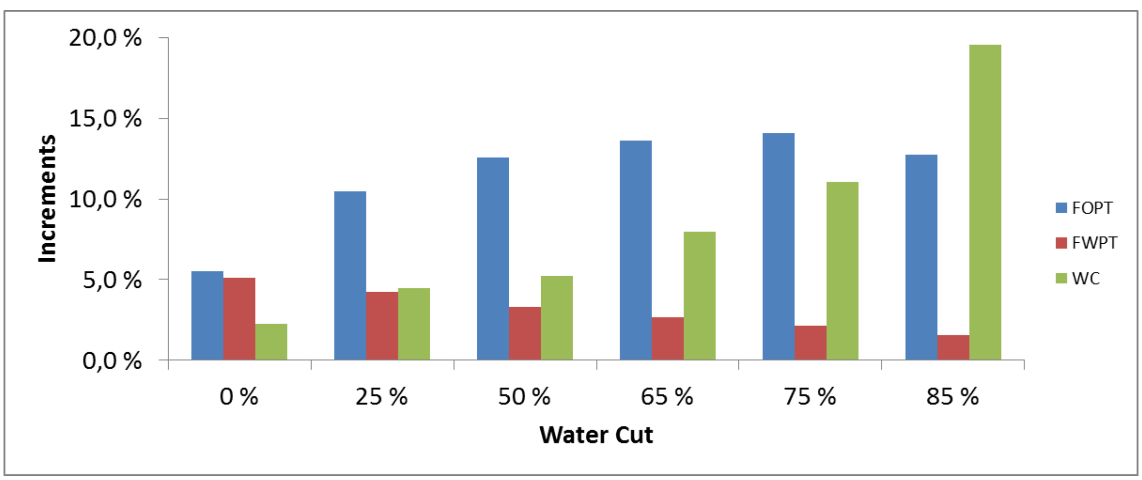

Figure 5.35: *Comparison of oil (blue) and water (red) production and water cut (green) increments for different initiation times (expressed in water cut) for the cyclic scheme of 1:3 and 30 days base period.*

Longer base periods of 90 days resulted in the same trend as the shorter, 30 days base period did. Figure 5.36 displays the increase of increments by initiation of cyclic injection at higher water cut levels, until the water cut has reached 85%. Late startup of cycling shows positive results of longer cycle periods. With a 90 days base period, the 1:3-scheme produced 22.6% additional oil compared to the conventional waterflood when initiated at 75% water cut. The reduction in water production also favored the longer base period rather than the shorter. As explained above, the saturation difference between layers of different quality is increased in mature waterfloods. By allowing the fluid exchange to elapse over a longer time period more oil is expected to seep out of the low permeable zones into the better quality layers. The difference in cumulative oil production from a cyclic injection after a period of continuous waterflood and cyclic waterflood from day one indicates that cyclic injection effects are increased when being applied at higher water cuts. Observations made in Figure 5.35 and Figure 5.36 are of great value in fields that produces under high water cuts, and have a mature waterflood pattern.

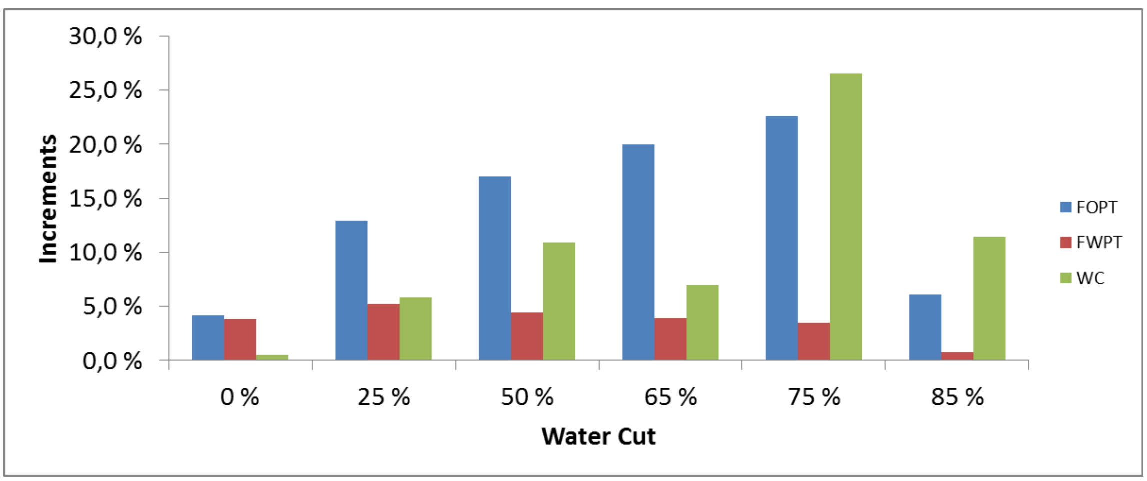

Figure 5.36: *Comparison of oil (blue), water (red) production and water cut (green) increments for different initiation times (expressed in water cut) for the cyclic scheme of 1:3 and 90 days base period.*

5.2 Reservoir Pressure below the Saturation Pressure (2D)

To investigate the effect of cyclic injection at reservoir pressure below the bubblepoint (at 5600psi), three cases with reservoir pressure of 5300psi (close to the bubblepoint pressure), 4300psi and 3500psi were selected. Injection and production rates are maintained the same as before. Released gas is expected to provide greater energy in the system, and increase the production.

Letting the reservoir pressure be 300psi below the bubble point at 5600psi, the cumulative oil production improved compared to the cyclic injection above the saturation pressure, Figure 5.37, for all the cyclic injection schemes. The greatest difference was observed with the symmetric cycle and base period of 15 days, which yielded 0.9% additional oil. Same trend was observed with a reservoir pressure at 4300psi and 3500psi, see Appendix E.

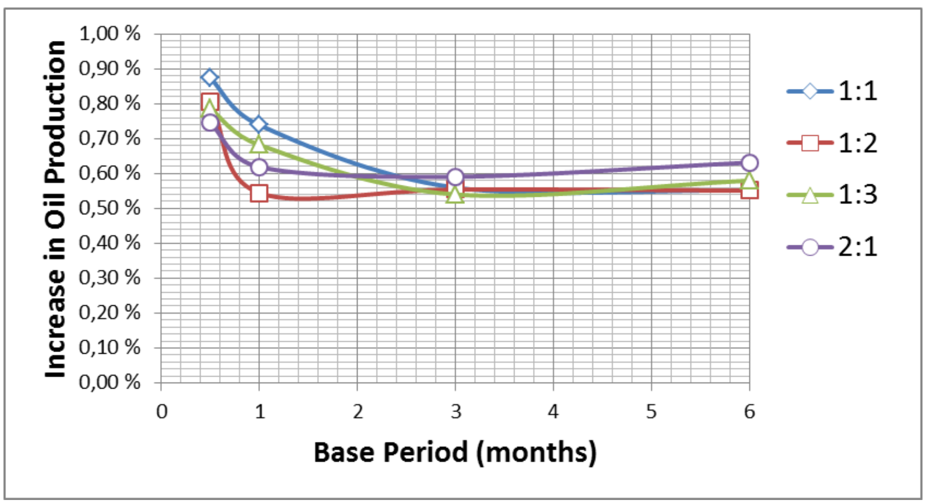

Figure 5.37: *Increase in oil production for cycling at 5300psi compared to cycling above saturation pressure.*

The additional oil produced by letting pressure drop below bubble point pressure, is related to the extra compression due to re-solution of gas and oil swelling. By increased gas saturation in the reservoir, the overall system compressibility increases, and the effect of the de-pressurizing cycle is enhanced. Gas-oil ratio (GOR) is fluctuating with the cycles, and indicates the re-solution of gas, Figure 5.38 – which is positive for the cyclic injection. Pressure reduction is followed by a period of GOR reduction.

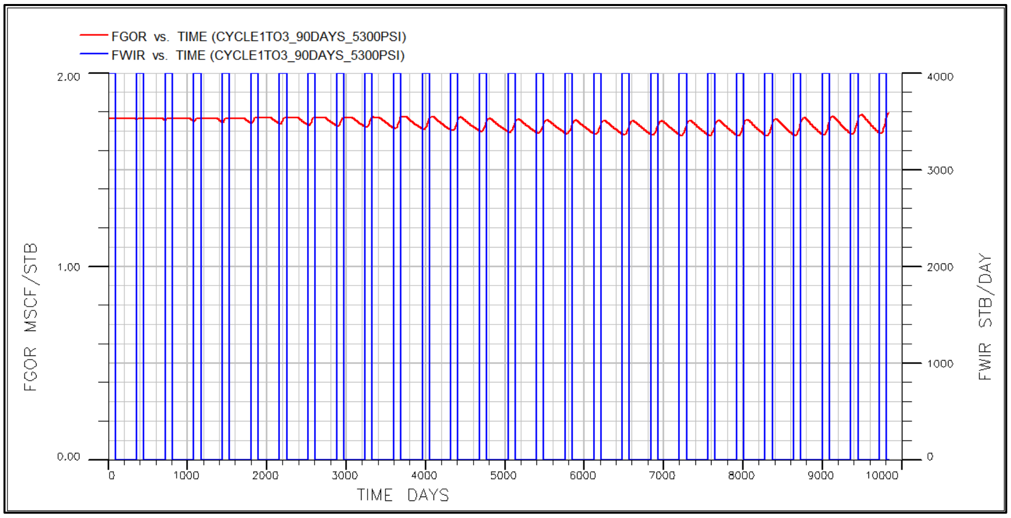

Figure 5.38: *Relationship between injection cycles and GOR, for the 1:3-scheme and 90 days base period.*

An interesting observation is the lower increase in additional oil production by cyclic injection under the saturation pressure versus the increments of cyclic injection over the saturation pressure, compared to the conventional waterflood at the respective pressures. In other words, the incremental gain from cyclic injection was lower when applied at a reservoir pressure below compared to above the saturation pressure.

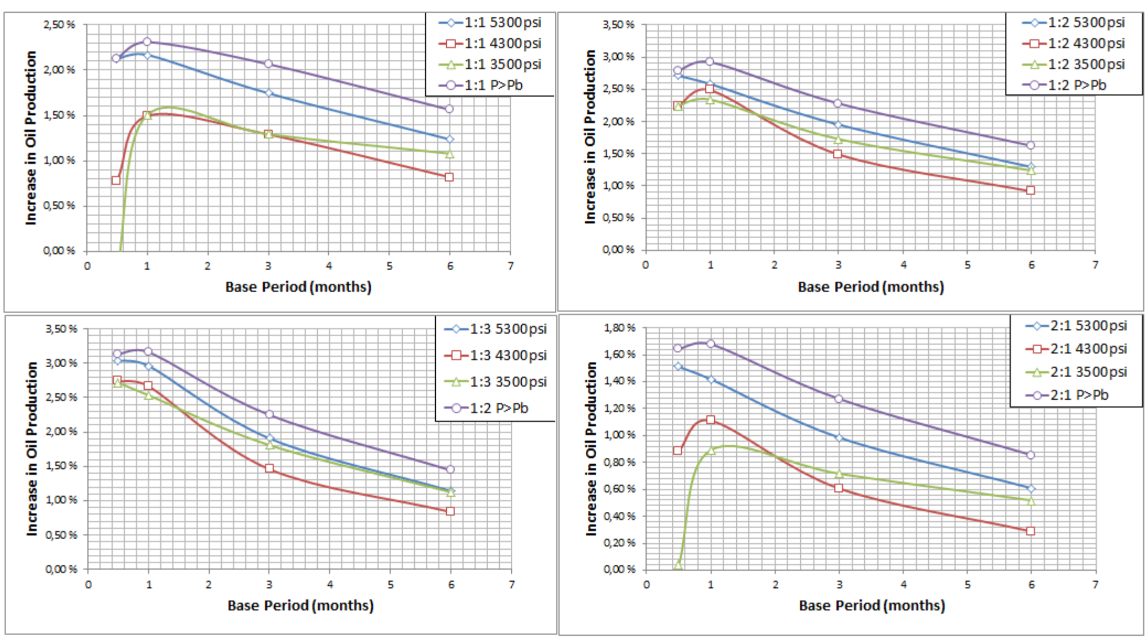

Figure 5.39: *Comparison of increase in oil production for different schemes and reservoir pressures; 1:1 (up left), 1:2 (up right), 1:3 (bottom left), 2:1 (bottom right).*

The total water production was also reduced by cyclic below the saturation pressure, for all three reservoir pressures, Figure 5.40. Correlation between improved oil recovery and decrease in water production is interesting, but no further analyzes were carried out. All simulation results for the 5300psi, 4300psi and 3500psi are given in Appendix E.

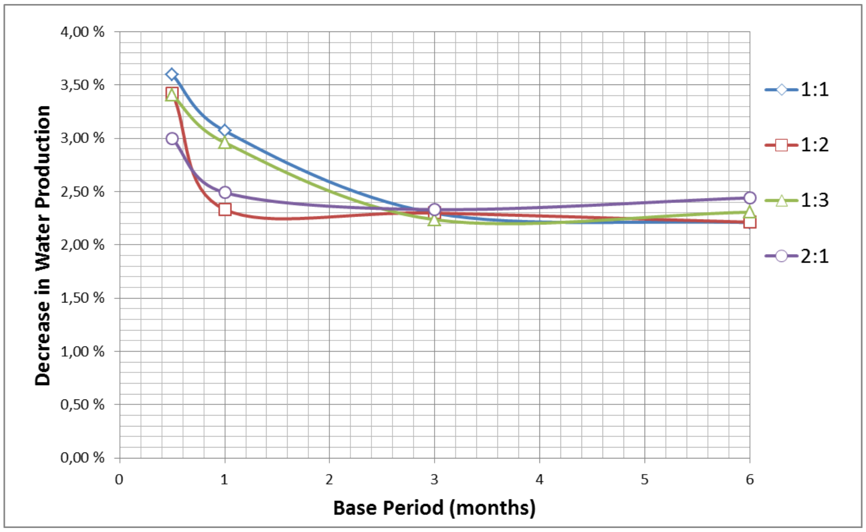

Figure 5.40: *Reduction in water production for cycling at 5300psi compared to cycling above saturation pressure.*

5.3 3D-Model – Black Oil Simulator

To investigate the impact of offset producers and to see how the cyclic injection alternates the flow patterns in the reservoir a 3D-model was created as explained in section 4.4. The best scenarios from the 2D-model were applied in this full "field" case. Cyclic startup was initiated when water production started in the conventional waterflood case, after approximately 3200 days. The continuous waterflood resulted in 61MMSTB and 28MMSTB of oil and water, respectively, after roughly 27years of production, Figure 5.41. These rates are compared with the 1:3- and 1:1-cyclic setup.

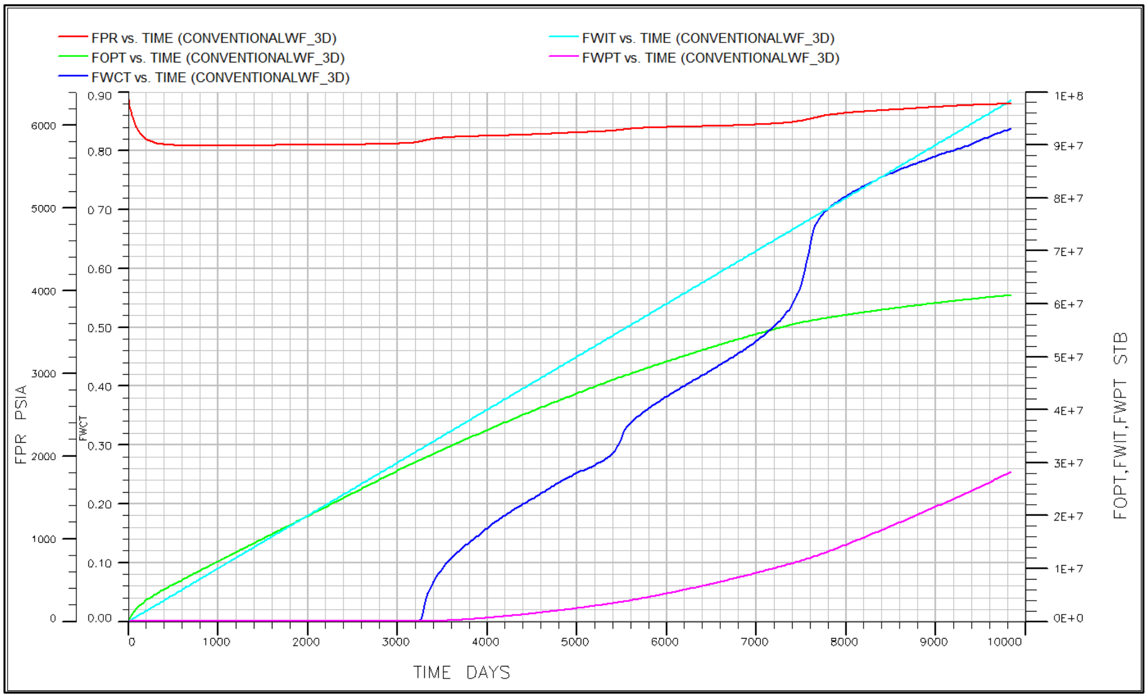

Figure 5.41: *Field pressure (red), water cut (blue), total oil production (green), water production (pink) and total injection (turquois) for the conventional waterflood.*

5.3.1 Simultaneously Cyclic Injection

Base periods of 30 and 90 days were applied to the cyclic schemes with simultaneously and equal cycling in both wells, and the results were positive, although, the increase in oil production was a bit disappointing. The 1:3-scheme with 30 days base period resulted in 2.4% additional oil compared to the conventional waterflood, Figure 5.42. Least increase was observed with the less intensive 1:1-scheme and 30 days base period. Interesting observation from the reduction in water production for the different scenarios was how the reduction seemed to favor longer period of injection and a more intensive setup, Figure 5.42. The output results are given in Table 10.15.

Total water injected was within an acceptable deviation of 0-2% compared to the conventional injection, and considered as insignificant. And the pressure was fluctuating over and under the pressure observed under conventional waterflood, Figure 10.9. Reasonable deviation in these parameters assures that the results are credible.

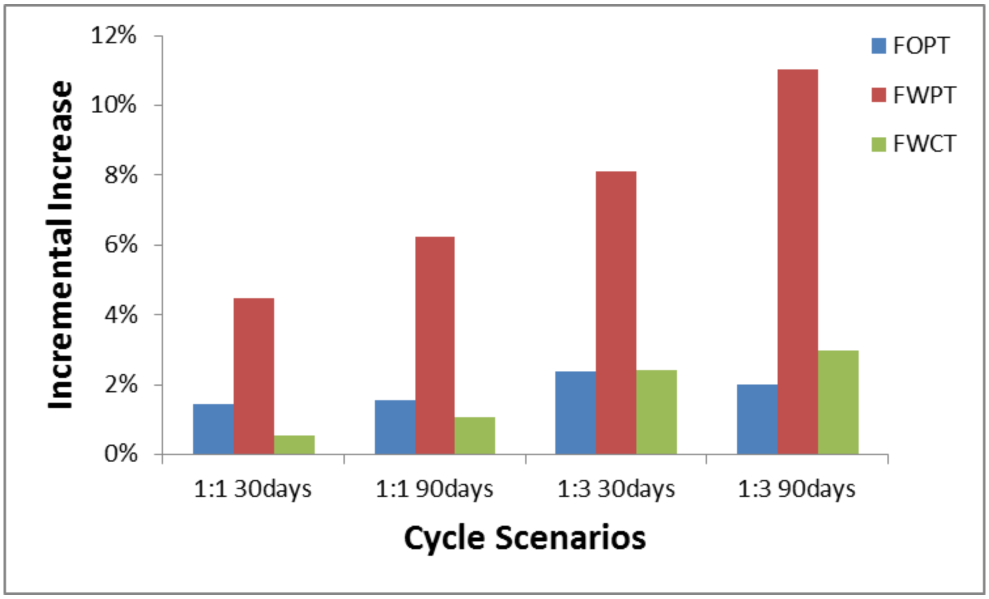

Figure 5.42: *Positive increase and decrease in oil and water production and cut (absolute value), respectively.*

Both the oil and water production rate is greatly affected by the cycling, in much greater deal than what was observed in the 2D-model – see comparison of oil and water production rate in Figure 5.43. High injection rates in the 3D-model of 20,000STB/day in each injector will affect the production behavior greater than the lower rates of 4,000STB/day in the 2D-model. In the 3D-model the production rate amplitudes are larger than in the 2D-model during cyclic injection, and are fluctuating over and under the production rate observed under conventional waterflood. Same characteristics are observed from the 2D-model. Nevertheless, the production rates are behaving different over time for the two models; the 3D-model seems to fluctuate less with time, while the production rates in the 2D-model fluctuates more over time. These differences are mostly related to the lower recovery obtained in the 2D-model, resulting in a greater saturation difference in the 2D-model compared to in the 3D-model.

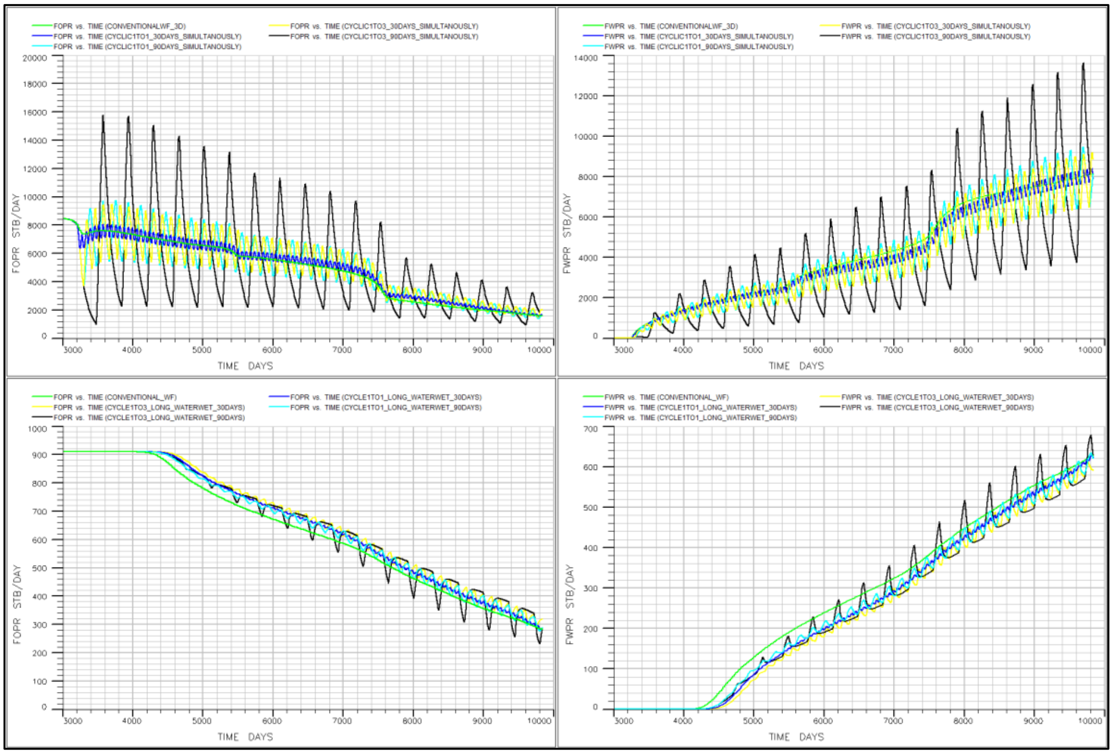

Figure 5.43: *Oil (right) and water (left) production rates for different waterfloods in the 3D-model (upper figures) and 2D-model (lower figures).*

The additional oil produced is mainly coming from increased sweep in the low permeable layers (layer 1, 6 and 8). Cyclic injection is producing more oil from the low permeable layers, as explained regarding the increased production in the 2D-model. Figure 5.44 shows how the conventional and cyclic 1:3-injection has swept the reservoir in terms of remaining oil saturation. High permeable layers have experienced approximately the same sweep, and early water breakthrough. Major difference in oil saturation was observed in the three low permeable layers, Figure 5.45.

In front of the water, the oil bank is pushed further towards the center and production wells under cyclic injection than by conventional waterflood. The difference is impressive, knowing that the total water injected in the reservoir is equal for the two waterfloods. And the effect of cyclic injection is clearly present.

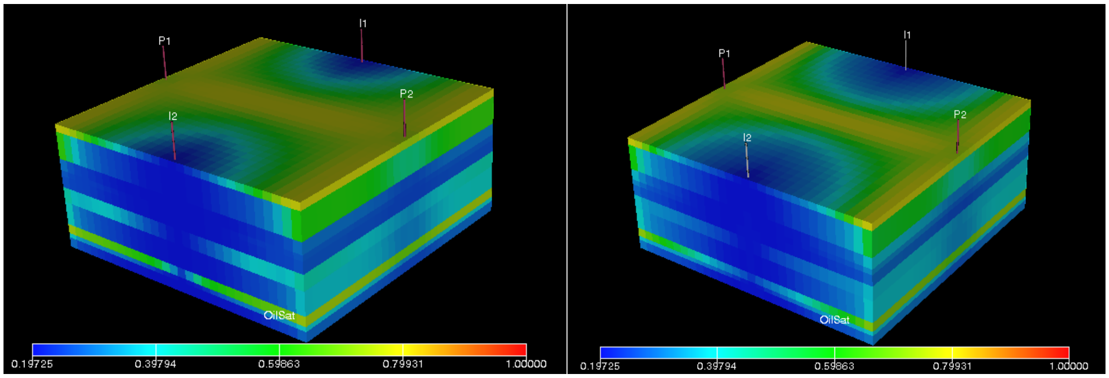

Figure 5.44: *Oil saturation at 9840 days for conventional (left) and cyclic 1:3 (right) injection.*

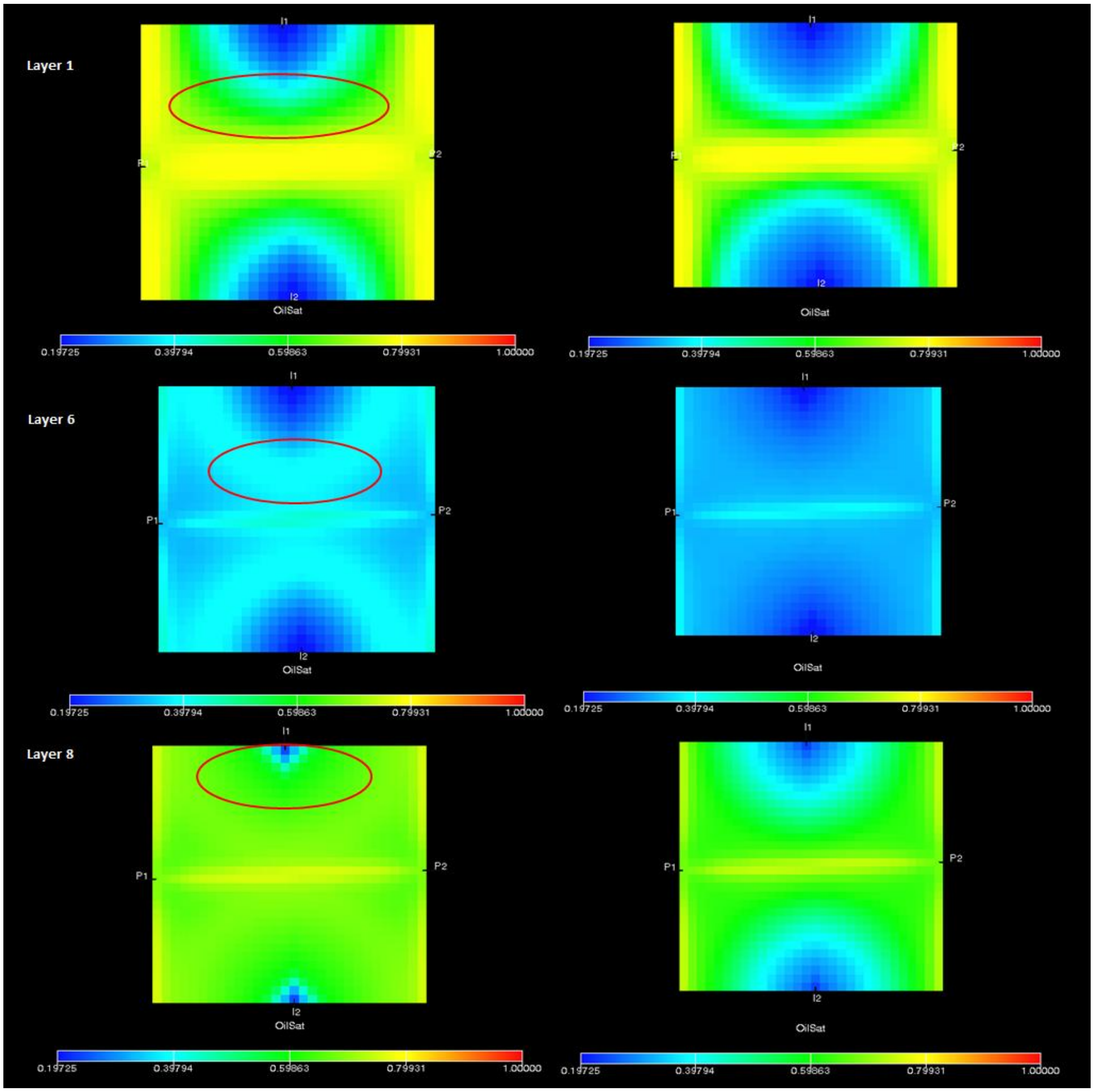

Figure 5.45: *Oil saturation in layer 1, 6 and 8 after 9840 days for the conventional (right) and cyclic (left) injection.*

5.3.1 Shifted Cyclic Injection

Instead of alternating the injection wells simultaneously, a shifted well management is possible. Here the injectors are not injecting during the same time period. Two cycle ratios of 1:1 and 1:3 were shifted in time with a goal of alternate the flood patterns in a greater deal than observed in the previous section. The symmetric cycle (1:1-scheme) was managed by injection in well I1 during a base period at the same time as I2 is shut-in, and vice versa. The results were negative in respect of increase in oil production and reduction in water production compared to the simultaneous cycling procedure (Table 10.16). Cyclic injection scenarios with a short base period and intensive pulsing allowed oil production to rise with 2.03%, which is less than the observed increase under simultaneous cycling. Figure 5.46 shows the increase in oil production and absolute reduction in water production and water-cut for the different injection scenarios.

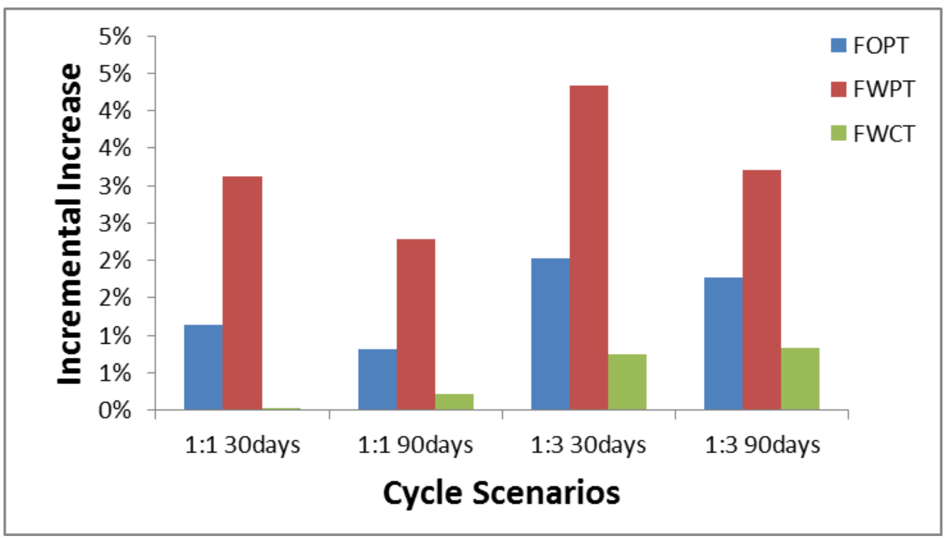

Figure 5.46: *Positive increase and decrease in oil and water production and cut (absolute value), respectively, under shifted cycle scenarios.*

Shifting the injection periods will result in no significant de-pressurizing period where oil can be cumulated in the high permeability zones. Nevertheless, the results are dissapointing. A greater sweep by waterflood pattern alteration should have been expected due to the shifting. Less fluctation in pressure was observed when shifting was applied, and the lower recovery is most likely related to this as the oil production rates are not experiencing any significant peaks, Figure 5.47.

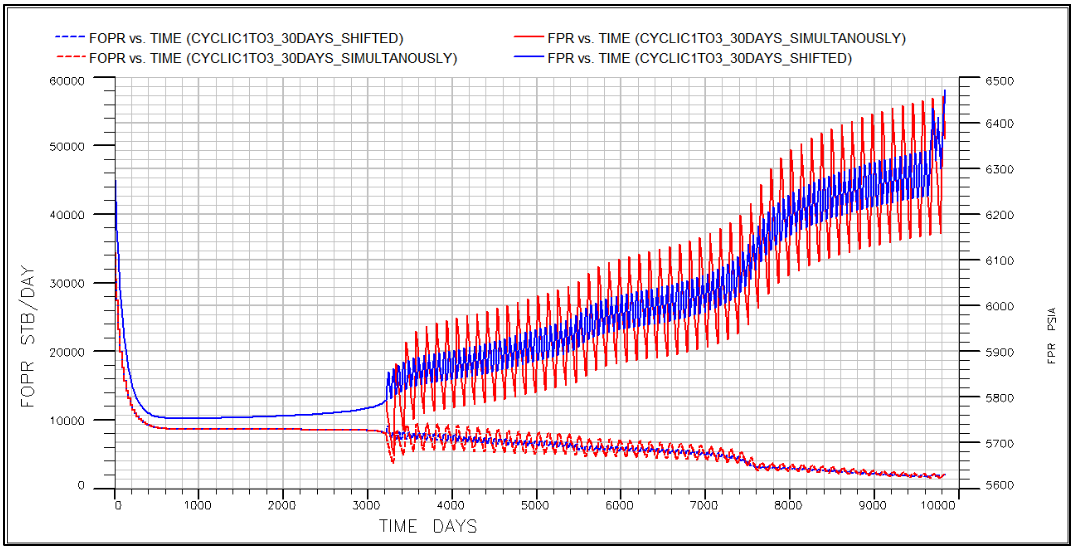

Figure 5.47: *Reservoir pressure and oil production rate for the 1:3-scheme under simultaneously and shifted cyclic waterflood.*

Overall the cyclic approach seems to favor both the water production and recovery factor under simultaneously and shifted cycling. In Figure 5.48 it is clear that the conventional waterflood, represented by the blue line, is producing the least and most oil and water respectively.

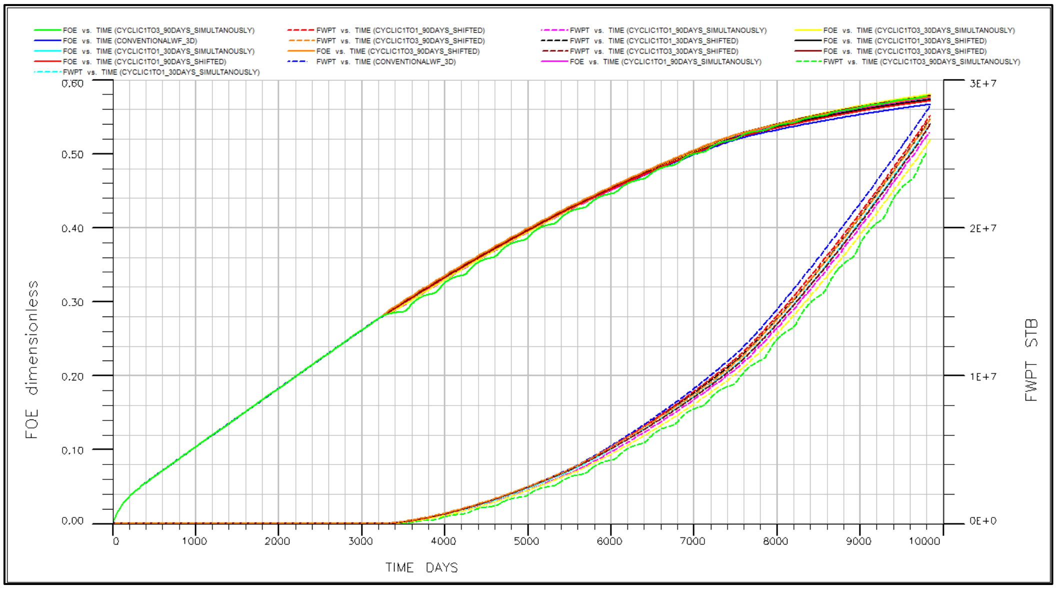

Figure 5.48: *Oil recovery and water production for different scenarios.*

5.3 Streamline Simulation – Alternate Waterflood Pattern

After a period of waterflooding, the flow lines tend to gather over the already swept areas. At a given time, stopping the injection allows water to reach out to previously poor swept areas and deviate from the original flow pattern. To examplify the change in waterflood pattern by cyclic injecten, a FrontSim version of the 3D-model was created. Figure 5.50 illustrates the flow patterns before, under and after a random shut-in period under the simultaneously 1:1-scheme with a base period of 90 days.

During the pressurizing half-cycle, the streamlines accumulate in the high permeable layers and create a steady waterflood pattern. After halted injection an accumulation of streamlines was observed in the low quality layers, Figure 5.50 (the same figure is presented from another point of view in Figure 10.10). And the the flow patterns are changed from the previous condition under constant injection. Under injection the oil is being transported through its original layer, and a fairly straight fluid displacement occurs. With time during halted injection, fluids from the low permeable layers are transported in vertical direction into the high permeable layers and towards the producers. Cyclic injection sweeps previous poor swept areas, and leave less oil behind. Figure 5.49 proves the increase in sweep of low permeable layers (visible in the top layer) after a period of shut-in. A clear reduction in oil saturation in the low permeable layers are observed – oil is migrated out of the low permeable layers to the high permeable zones availalbe for production.

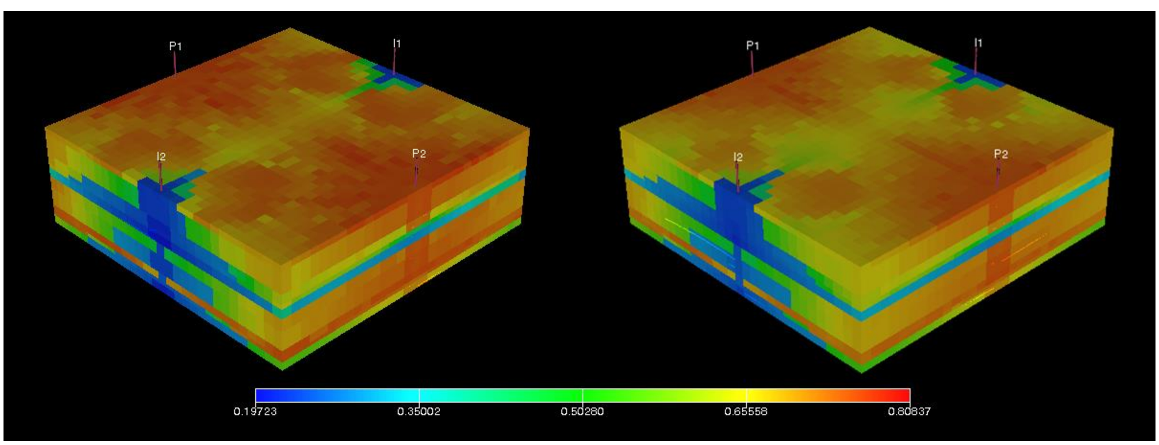

Figure 5.49: *Oil Saturation before and after shut-in of 90 days.*

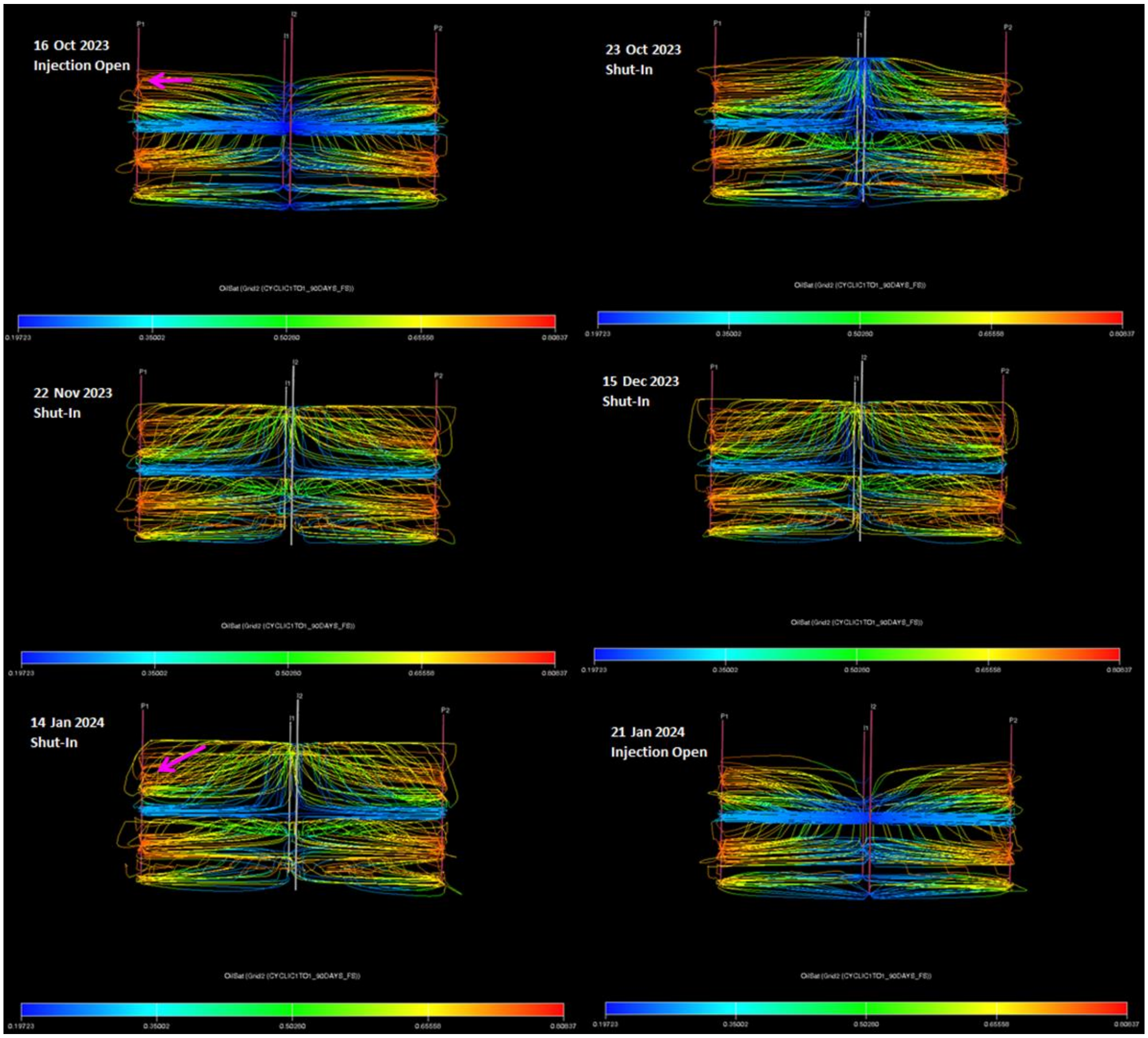

Figure 5.50: *Waterflood patterns before, during and after shut-in of injectors.*

6. Evaluation

6.1 Discussion and Evaluation of the model

Cyclic water injection allows oil production to increase compared to traditional waterflooding simultaneously as water production is reduced. Degree of success by the cyclic injection approach is dependent on reservoir characteristics, and has been proven throughout this thesis. In this sub-section we summarize the numerous simulations studied and evaluate the quality of the models.

Increase in cumulative oil production can amount 0-20% additional oil. A simple 2D-model investigated the physical mechanisms improving the waterflood by injection alternation. The grid cells were 328ft in x- and y-direction. Grid refinement of the 10x1x10, water-wet system by adding 10 and 20 cells in x- and z-direction resulted in approximately no deviation (0.1-0.2%). These numerical dispersions were considered insignificant initially. After running all the simulations, a numerical error of 0.1-0.2% is of the same magnitude as a small incremental increase or decrease. Hence, the simulation study should have been run with the refined grid system. Nevertheless, the effect observed is clear and can be considered as true. Numerical dispersion can also occur from too long time steps, especially when the injectors are alternated between open and shut condition. And the importance of having time steps which capture the injection switch is considered necessary.

The most important parameter to control under simulation of cyclic injection is the reservoir pressure. Increase or decrease in pressure has great impact on the imbibition of water, hence, the amount of countercurrent oil flow from low permeable to high permeable layers is controlled by the pressure. This was not managed in the degree that it should have been. A trial and error method resulted in the well constraints applied in the 2D and 3D-model. Further investigation of the well boundary condition would be favorable. In the 2D-model both wells were controlled by rates; the injector by daily injection rate and the producer by daily liquid production rate. Purpose was to maintain the voidage displacement condition equal for all the cases for comparison. And the selected rates provided a stable reservoir pressure under conventional waterflood. Obviously, fluctuating pressure occurred under cyclic injection. But the amplitudes should have been further evaluated to prevent potential of increased oil production exclusively by pressure increase and decrease. Most of the scenarios were investigated under reasonable pressure conditions, and are considered applicable for evaluation of the process. The effect of starting the cyclic process with injection or shut-in also seems to affect the results, and should be analyzed further.

Relative permeability curves are calculated from the Corey equations and are considered to be reasonable. Then again, the Corey coefficients are set to be within the range of what was proposed by Behrenbruch and Goda (2006), and could have been tuned to make a better relative permeability profile for the different fluid phases. In the model a drop in reservoir pressure is observed until the water production initiates. After water production, and reduction in oil production rate is observed, a constant increase in reservoir pressure is taking place (with some curvature from water breakthrough in different layers) – the relationship between oil and water relative permeability is most likely not optimum for the chosen reservoir characteristics and fluid properties.

Relative permeability is set equal for the imbibition and drainage process, to interfere with the affection of cyclic injection. This could lead to an unrealistic view of the process, but was considered necessary to look into the effect of pulsing injection. Oil-water and oil-gas capillary pressures are set equal for all three wettability cases due to lack of data, and should have been estimated to better illustrate the difference in wettability. Identification of the capillary pressure’s impact on the cyclic injection efficiency is recommended. One proposal for further analyze on capillary pressure is as follow: Multiply the capillary curve with a factor, and simulate them with different injection schemes and base periods. Additional information about the flow type will also be obtained from this approach. A very low capillary number illustrates a flow where capillary forces are dominating, and high numbers represent the viscous dominated flow.

This knowledge provides great insight in the physical mechanisms occurring under cyclic injection.

There are other interesting parameters left for further investigation. Tilted reservoirs are said to provide additional oil production because of gravitational segregation and was excluded in this thesis. The impact of layer thickness and permeability differences could benefit from running more cases with different ratios. Plugging of zones producing large amount of water could also show interesting results under cyclic injection and increase the knowledge of the topic. Geomechanical aspects under cyclic injection, which are excluded in this thesis due to lack of data, would be to study the long term effects related to pressure dependent properties, compaction, subsidence and well failure – this is considered essential when applied to a real field. The last feature recommended to study would be the effect of critical gas saturation during the de-pressurizing cycles at pressures below bubblepoint pressure.

To increase the effect of cyclic injection, enhanced oil recovery techniques could be implemented in the procedure similar to in a conventional waterflood: polymers, surfactants, low salinity, etc.

6.2 Evaluation and Summary of the Results

Capturing all physical mechanisms in the cyclic process is a key when investigating the effect. Numerous simulations related to the effect of cyclic injection compared to the traditional waterflood has been studied. Positive effect of cyclic injection resulted in improved oil production and reduced water production. Different scenarios and cases have been tested, and in this sub-section the numerical results obtained under all the cases are summarized and evaluated.

Cyclic injection below the saturation pressure produced more cumulative oil compared to the same schemes above the saturation pressure. But the incremental increase in oil production by cyclic injection below the bubblepoint pressure was lower than what was observed above the saturation pressure. Obviously, gas re-solution increases the compressibility of the system and allows more oil to be produced. The lower increments of cyclic injection below the saturation pressure could be related to the critical gas saturation. Ideally the pressure should be lowered until the gas is mobilized at saturations greater than the critical value. No analyzes were conducted related to this problem, and is recommended for future work.

An infinite amount of different cycle schemes can potentially be used. In this thesis four schemes (1:1, 1:2, 1:3 and 2:1) were tested with cycle period of 15, 30, 90 and 180 days. Longer base periods in terms of years could have been interesting to study. Cycling controlled by shut or open production could as well result in positive effects. Different ratios of production time to injection time would also alternate the reservoir pressure, but no study was conducted in this thesis. The more intensive scheme of 1:3 and base period of 30 days resulted in the greatest increments – for water-, oil- and mixed-wet reservoir. The oil-wet 2D-model increased oil production by 5.5% which was the greatest increments obtained in the 2D base case. Incremental oil production was in general larger for the oil- and mixed-wet case. Largest reduction in water production was observed in the water-wet rock; 11.7% less water production was achieved with the 1:3-scheme and 30 days of injection before shut-in.

Shorter distance between the wells produced more oil with cyclic waterflood than the longer well spacing. Only two distances between the injector and producer was simulated. The effect of cyclic injection in a reservoir with shorter well spacing seems to increase the success, in terms of oil and water increments. 4.6% increase in oil production was gained from the shorter spacing, and 3.2% with the longer spacing. Well spacing was just simulated with the water-wet rock, and was considered to represent a general trend independent of the wettability. Hence, the oil- and mixed-wet should have been studied as well to gain insight in the effect.

Unexpected results from the investigation of reservoir thickness effect on cyclic injection needs to be studied further. Firstly, the injection to production rate ratio chosen in the two models must be matched better than in this thesis to compare the results. Limitation in time and softwares, made the trial and error process time consuming and resulted in the specified rates.

Homogeneous reservoir showed small increase in oil production and confirmed the need of permability difference in the reservoir to see a significant effect of cyclic injection. However, the water production dropped with 4-5% under cyclic injection – hence, the cyclic aproach could be beneficial in homogenous reservoirs where excessive water production is a problem.

Initiation of cyclic injection is important for the degree of success. Startup after conventional waterflood favored the cyclic process. Greater fluid saturation differences between the layers is beneficial for cyclic injection – hence, at a higher water cut the cumulative production of oil is increasing. Mature waterflood projects with excessive water production is recommended to alternate the injection rates instead of conventional waterflood.

6.3 Workflow Recommendations

High complexity and simultaneous events in a field makes the effect of cyclic injection difficult to analyze. Severe risk analysis is necessary before a cyclic waterflood is applied in any field. Down time of injectors can result in production loss and in worst case damage to facilities and wellbores. Variation in reservoir characteristics makes it difficult to create a best-practice workflow.

One very useful tool is the decline analysis plot of log(WOR) versus cumulative oil production. Under cyclic injection, water production is expected to decrease simultaneously as the oil production improves – hence, the water-oil ratio represents the expected changes in production. Baker et al. (2003) stated the following criteria for waterflood decline analysis:

- The water cut should be mature
- A constant voidage replacement ratio
- Constant number of wells
- Constant well rates
- Constant reservoir pressure
- Constant GOR

- An injection volume equal or higher than 25% of the pore volume.

More information about the procedure can be found in the specialization project written by the author. Here, an example of the diagnostic plot is presented in Figure 6.1.

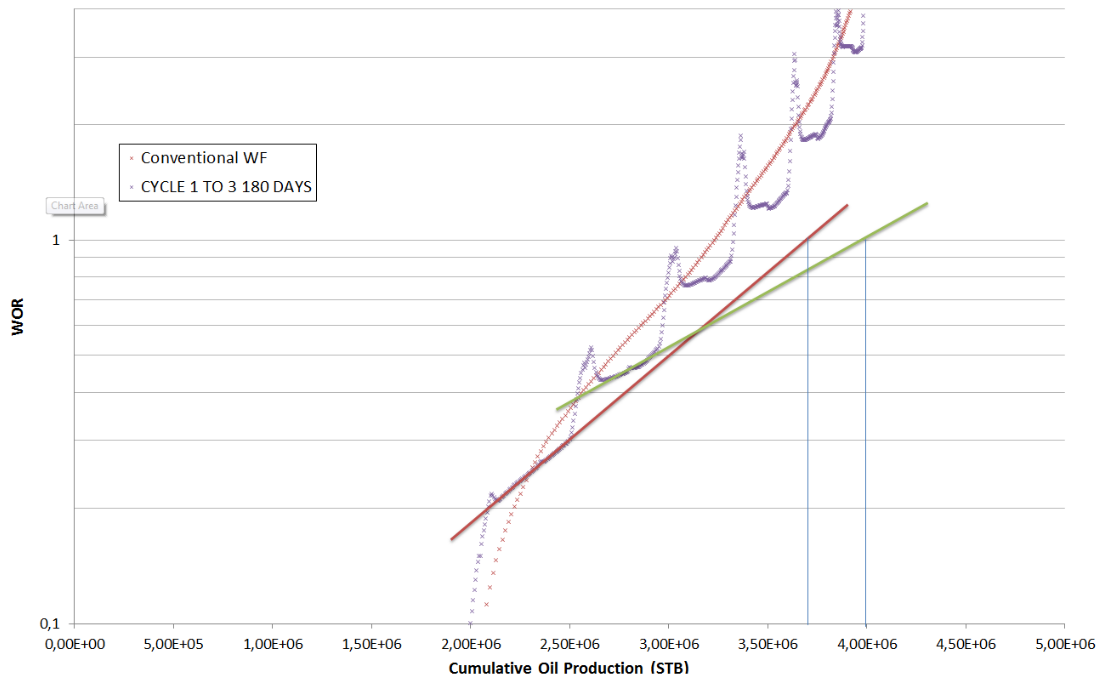

Figure 6.1: *WOR versus cumulative oil production indicates a positive trend after shut-in.*

Illustrated in Figure 6.1 the estimated ultimate recovery after a period of shut-in is improved. The WOR-trend is declining, and the expected cumulative oil production for a certain WOR is improved. This method is useful when the possibility of cyclic injection is evaluated for a field. Annotated WOR-plots, such as Figure 6.1, could be used as a pattern health indicator for the cyclic injection process. Benefits and potential outputs from the diagnostic plots are optimum cycle period, injector location and maturity of injection pattern. It can also help to identify non-matrix bypass, where rapid increase in WOR simultaneously as liquid rate drops is observed. The WOR versus cumulative oil production is recommended for further analysis of cyclic injection.

7. Conclusions

This thesis shows interesting and promising results regarding increased oil production and decreased water production by cyclic water injection. To sum up the findings of this simulation study the following conclusions can be made:

- In all simulation cases, cyclic water injection into a stratified reservoir allowed additional oil to be produced compared to conventional waterflood.
- An even greater benefit is observed in terms of total water production decrease. All cases produced less water than the conventional waterflood.
- The greatest increase in cumulative oil production is observed with the intensive schemes (1:2 and 1:3) and medium base periods of 30 and 90 days.
- Cyclic schemes behave different associated with base periods of injection and shut-in. The more intensive 1:3-scheme with a base period of 30 days provides the best scenario for the 2D and 3D model. In a water-wet rock the cumulative oil production increased by 3.2% with a reduction of 11.7% in total water production.
- The effect of a specific cyclic injection ratio (of injection to no-injection) is strongly controlled by the injection rate. Less intensive schemes produces the greatest amount of additional oil under lower rates than the more intensive schemes, which favors higher injection rates.
- Cyclic injection is positive for water-, mixed, and oil-wet reservoirs. In this thesis, the oil-wet rock had the greatest increase in oil production of 5.5% over the conventional waterflood.
- Cyclic water injection has a greater effect when applied at high water cuts, after a period of conventional waterflood.

- Shorter well spacing improves the effect of cyclic injection. 4.6% additional oil was produced with a distance of 1640ft between the injector and producer, which is 1.2% more than the long spacing (3280ft) case produced.
- Higher transmissibility resulted in greater cumulative oil production, but the increased communication between layers of different permeability deters the effect of cyclic injection compared to the respective conventional waterflood.
- The presence of heterogeneity favors the cyclic process in terms of incremental oil production increase.
- For the reservoir pressures investigated, cyclic water injection was favorable for all pressures – both above and below the saturation pressure.
- The improvements from cyclic waterflood can be realized at virtually zero additional cost and is easy to implement.

8. Nomenclature

ΔP_i	Viscous pressure drop
μ_i	Viscosity of fluid *i*
A	Area cross-section for fluid flow
c	Compressibility
CPS	Cyclic production scheme
CWI	Cyclic water injection
E_A	Areal sweep efficiency
E_D	Fluid displacement efficiency
E_I	Vertical sweep efficiency
E_R	Total recovery efficiency
E_V	Volumetric displacement efficiency
FOE	Field oil recovery
$FOPR$	Field oil production rate
$FOPT$	Field oil production total
FPR	Field pressure
$FWCT$	Field water cut total
$FWIT$	Field water injection total
$FWPT$	Field water production total
g	Gravitational acceleration constant
GOR	Gas-oil ratio
IOR	Improved oil recovery
J	Productivity index
$J(S_w)$	Leverett's J-function
k_a	Absoulute permeability of the porous medium
K_{fr}	Frame bulk modulus
k_i	Effective permeability of the porous medium for fluid *i*
k_{rg}	Relative permeability of gas
$kr_{g@Sorg}$	Gas curve endpoint permeability
k_{ri}	Relative permeability of the porous medium to fluid *i*
k_{ro}	Relative permeability of oil
$k_{ro@Sgi}$	Oil curve endpoint permeability (gas-oil system)
$k_{ro@Swi}$	Oil curve endpoint permeability
k_{rw}	Relative permeability of water
$k_{rw@Sorw}$	Water curve endpoint permeability
M	Mobility ratio
n	Corey curve exponent
N_p	Cumulative oil production
$OOIP$	Original oil in place

P_c	Capillary pressure
P_{entry}	Total entry pressure for a pore
p_f	Pore pressure
p_i	Pressure of fluid *i*
p_{nw}	Pressure of the non-wetting phase
PPT	Pressure pulse technology
p_w	Pressure of the wetting phase
q_i	Flow rate of phase *i*
r_c	Pore radius
S_{gc}	Critical gas saturation
S_i	Saturation of phase *i*
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
S_{org}	Residual oil saturation to gas
SORw	Residual oil saturation after waterflood
S_{orw}	Residual oil saturation
S_w	Water saturation
S_{wi}	Residual water saturation
T	Temperature
V_b	Bulk volume
V_i	Volume of phase *i*
V_p	Pore volume
WC	Water cut
WF	Conventional waterflood
WOR	Water-oil ratio
z	Depth
α	Biot coefficient
α	Dip angle of the reservoir
γ	Arching coefficient
θ	Contact angle
λ_i	Phase mobility
ρ_i	Density of fluid *i*
σ	Interfacial tension
υ_i	Velocity of fluid *i*
φ	Porosity
Φ_i	Potential of fluid *i*

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10. Appendix

A. PVT Data for the Synthetic Model

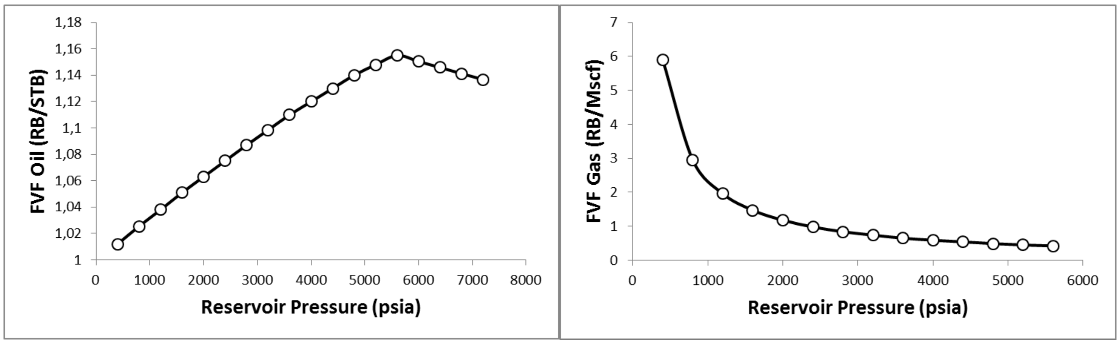

Figure 10.1: *Oil (right) and gas (left) formation volume factors versus pressure.*

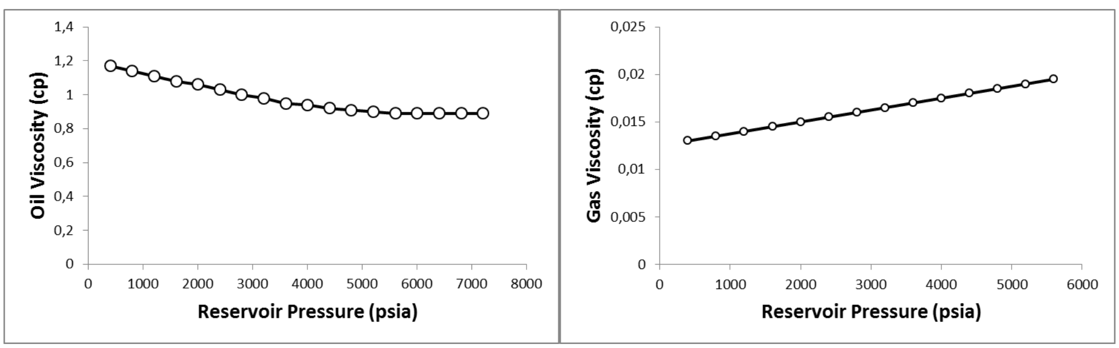

Figure 10.2: *Oil (right) and gas (left) viscosities versus pressure.*

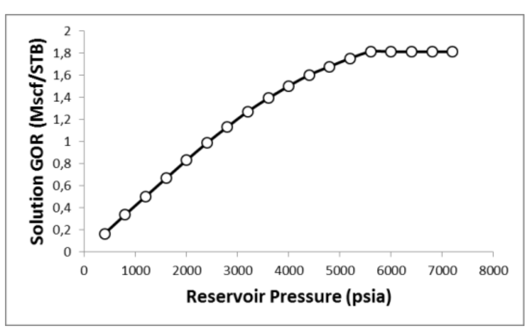

Figure 10.3: *Solution gas-oil ratio versus pressure.*

B. Results for Pressure above Saturation Pressure

Table 10.1: Simulation results for the long spacing case with reservoir pressure above saturation pressure.

Long Spacing P>Psat									
328ft	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT	164ft	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
WF Water	7054320	1900079,9	9840000	69,02 %	WF Water	3644668,5	684931,44	4920000	74,69 %
WF Mixed	5269529,5	3684870,3	9840000	85,34 %	WF Mixed	2758336,5	1571263,5	4920000	84,65 %
WF Oil	4296626	4657774	9840000	91,98 %	WF Oil	1949377,9	510622,19	2853600	75,04 %
	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT		FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
Water Wet 328ft					Water Wet 164ft				
1 to 1 15days	7204702,5	1749697,5	9840000	69,76 %	1 to 1 15days	3688903,7	640696,19	4920000	73,33 %
1 to 1 30days	7217255	1737145	9840000	68,48 %	1 to 1 30days	3689906,8	639693,19	4920000	72,86 %
1 to 1 90 days	7200119,5	1754280,3	9900000	68,24 %	1 to 1 90 days	3678734	650865,94	4950000	72,86 %
1 to 1 180days	7164590,5	1789809,5	9960000	70,76 %	1 to 1 180days	3665194	664405,94	4980000	73,72 %
1 to 2 15days	7250795,5	1703604,5	9855000	69,09 %	1 to 2 15days	3704869,3	624730,81	4927500	72,52 %
1 to 2 30days	7260507,5	1693892,8	9900000	68,50 %	1 to 2 30days	3703020,5	623279,44	4938750	71,99 %
1 to 2 90 days	7215166,5	1739233,4	9990000	68,58 %	1 to 2 90 days	3683332,8	646267,31	4995000	72,21 %
1 to 2 180days	7168906,5	1785493,6	10080000	73,12 %	1 to 2 180days	3663453,5	666146,5	5040000	73,60 %
1 to 3 15days	7275347	1679052,9	9840000	67,25 %	1 to 3 15days	3710150,7	619449,13	4920000	71,60 %
1 to 3 30days	7277475	1676924,9	9840000	65,02 %	1 to 3 30days	3711112	618488	4920000	70,75 %
1 to 3 90 days	7213011	1741389	10080000	69,17 %	1 to 3 90 days	3682883,3	646716,75	5040000	72,04 %
1 to 3 180days	7156072,5	1798327,8	10080000	65,06 %	1 to 3 180days	3658368	671231,94	5040000	71,92 %
2 to 1 15days	7170281	1784119	9855000	69,97 %	2 to 1 15days	3672098	657502	4927500	74,02 %
2 to 1 30days	7172778	1781622	9855000	68,85 %	2 to 1 30days	3670731,8	658868,25	4927500	73,72 %
2 to 1 90 days	7144134	1810265,9	9900000	69,66 %	2 to 1 90 days	3660866,3	668733,69	4950000	74,06 %
2 to 1 180days	7114680,5	1839719,6	9900000	69,71 %	2 to 1 180days	3651319,5	678280,5	4950000	73,99 %
Mixed Wet 328ft					Mixed Wet 164ft				
1 to 1 15days	5372053	3582347,3	9840000	84,56 %	1 to 1 15days	2792343	1537257	4920000	84,43 %
1 to 1 30days	5386342	3568058	9840000	83,88 %	1 to 1 30days	2793059,8	1536540,3	4920000	84,35 %
1 to 1 90 days	5393902	3560498	9900000	83,31 %	1 to 1 90 days	2787078,8	1542521,4	4950000	84,73 %
1 to 1 180days	5374804	3579595,8	9960000	84,57 %	1 to 1 180days	2773629	1555971	4980000	85,07 %
1 to 2 15days	5416624	3537776	9855000	84,17 %	1 to 2 15days	2806981	1522618,9	4927500	84,19 %
1 to 2 30days	5441369,5	3513030,5	9900000	84,09 %	1 to 2 30days	2806099,8	1523500,3	4950000	84,36 %
1 to 2 90 days	5430685,5	3523714,5	9990000	83,00 %	1 to 2 90 days	2790548,5	1539051,5	4995000	84,84 %
1 to 2 180days	5389892,5	3564507,8	10080000	84,70 %	1 to 2 180days	2769983,5	1559616,5	5040000	84,93 %
1 to 3 15days	5446051,5	3508348,5	9840000	83,13 %	1 to 3 15days	2813393,3	1516206,9	4920000	83,72 %
1 to 3 30days	5470321	3484079	9840000	82,08 %	1 to 3 30days	2818597,8	1511002,3	4920000	83,54 %
1 to 3 90 days	5437076	3517323,8	10080000	83,61 %	1 to 3 90 days	2789469,5	1540130,5	5040000	84,91 %
1 to 3 180days	5374609	3579791,3	10080000	82,94 %	1 to 3 180days	2760178,8	1569421,1	5040000	83,94 %
2 to 1 15days	5339935,5	3614464,5	9855000	85,01 %	2 to 1 15days	2779185,5	1550414,5	4927500	84,63 %
2 to 1 30days	5345740	3608659,8	9855000	84,63 %	2 to 1 30days	2778977,8	1550622,4	4927500	84,61 %
2 to 1 90 days	5338548	3615852	9900000	84,75 %	2 to 1 90 days	2771355	1558244,9	4950000	85,04 %
2 to 1 180days	5323267,5	3631132,5	9900000	84,88 %	2 to 1 180days	2761189,8	1568410,4	4950000	84,87 %
Oil Wet 328ft					Oil Wet 164ft				
1 to 1 15days	4420359,5	4534040,5	9840000	92,00 %	1 to 1 15days	1938563	521436,97	2853600	75,47 %
1 to 1 30days	4441908	4512492	9840000	91,29 %	1 to 1 30days	1966621,5	493378,47	2853600	74,24 %
1 to 1 90 days	4449261,5	4505138,5	9900000	91,01 %	1 to 1 90 days	1968224,9	491775,16	2871000	74,43 %
1 to 1 180days	4417193	4537207	9960000	91,49 %	1 to 1 180days	1958882,1	501117,81	2888400	75,02 %
1 to 2 15days	4468715	4485685	9855000	91,51 %	1 to 2 15days	1980487,1	479512,91	2857950	74,00 %
1 to 2 30days	4504216	4450184	9900000	91,19 %	1 to 2 30days	1985649,5	474350,5	2871000	73,64 %
1 to 2 90 days	4482044	4472356	9990000	91,20 %	1 to 2 90 days	1969451,3	490548,69	2897100	74,57 %
1 to 2 180days	4415574,5	4538825,5	10080000	91,60 %	1 to 2 180days	1955881,3	504118,78	2923200	75,01 %
1 to 3 15days	4505375,5	4449024,5	9840000	90,64 %	1 to 3 15days	1991573,5	468426,44	2853600	72,94 %
1 to 3 30days	4533636	4420764	9840000	89,92 %	1 to 3 30days	1989357,6	470642,44	2853600	72,46 %
1 to 3 90 days	4476076	4478324	10080000	91,48 %	1 to 3 90 days	1968331,8	491668,19	2923200	74,74 %
1 to 3 180days	4388926,5	4565473,5	10080000	90,03 %	1 to 3 180days	1946105,4	513894,59	2923200	73,82 %
2 to 1 15days	4393176,5	4561223,5	9855000	92,10 %	2 to 1 15days	1953770,6	506229,41	2857950	74,76 %
2 to 1 30days	4404359,5	4550040,5	9855000	91,59 %	2 to 1 30days	1959298,6	500701,41	2857950	74,51 %
2 to 1 90 days	4390004,5	4564395,5	9900000	91,58 %	2 to 1 90 days	1958004,8	501995,25	2871000	74,99 %
2 to 1 180days	4355880,5	4598519,5	9900000	91,36 %	2 to 1 180days	1951136,8	508863,19	2871000	74,88 %

Table 10.2: Incremental increase/decrease in oil production, water production, total water injected and field water cut.

Long Spacing P>Psat									
328ft	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT	**164ft**	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
WF Water	7054320	1900079,9	9840000	69,02 %	**WF Water**	3644668,5	684931,44	4920000	74,69 %
WF Mixed	5269529,5	3684870,3	9840000	85,34 %	**WF Mixed**	2758336,5	1571263,5	4920000	84,65 %
WF Oil	4296626	4657774	9840000	91,98 %	**WF Oil**	1949377,9	510622,19	2853600	75,04 %
	FOPT (STB)	**FWPT (STB)**	**FWIT (STB)**	**FWCT**		**FOPT (STB)**	**FWPT (STB)**	**FWIT (STB)**	**FWCT**
Water Wet 328ft					**Water Wet 164ft**				
1 to 1 15days	2,13 %	-7,91 %	0,00 %	1,07 %	1 to 1 15days	1,21 %	-6,46 %	0,00 %	-1,83 %
1 to 1 30days	2,31 %	-8,58 %	0,00 %	-0,78 %	1 to 1 30days	1,24 %	-6,60 %	0,00 %	-2,46 %
1 to 1 90 days	2,07 %	-7,67 %	0,61 %	-1,12 %	1 to 1 90 days	0,93 %	-4,97 %	0,61 %	-2,45 %
1 to 1 180days	1,56 %	-5,80 %	1,22 %	2,52 %	1 to 1 180days	0,56 %	-3,00 %	1,22 %	-1,30 %
1 to 2 15days	2,79 %	-10,34 %	0,15 %	0,11 %	1 to 2 15days	1,65 %	-8,79 %	0,15 %	-2,91 %
1 to 2 30days	2,92 %	-10,85 %	0,61 %	-0,75 %	1 to 2 30days	1,60 %	-9,00 %	0,38 %	-3,61 %
1 to 2 90 days	2,28 %	-8,47 %	1,52 %	-0,63 %	1 to 2 90 days	1,06 %	-5,64 %	1,52 %	-3,33 %
1 to 2 180days	1,62 %	-6,03 %	2,44 %	5,94 %	1 to 2 180days	0,52 %	-2,74 %	2,44 %	-1,46 %
1 to 3 15days	3,13 %	-11,63 %	0,00 %	-2,56 %	1 to 3 15days	1,80 %	-9,56 %	0,00 %	-4,14 %
1 to 3 30days	3,16 %	-11,74 %	0,00 %	-5,80 %	1 to 3 30days	1,82 %	-9,70 %	0,00 %	-5,27 %
1 to 3 90 days	2,25 %	-8,35 %	2,44 %	0,21 %	1 to 3 90 days	1,05 %	-5,58 %	2,44 %	-3,55 %
1 to 3 180days	1,44 %	-5,36 %	2,44 %	-5,74 %	1 to 3 180days	0,38 %	-2,00 %	2,44 %	-3,71 %
2 to 1 15days	1,64 %	-6,10 %	0,15 %	1,39 %	2 to 1 15days	0,75 %	-4,00 %	0,15 %	-0,90 %
2 to 1 30days	1,68 %	-6,23 %	0,15 %	-0,25 %	2 to 1 30days	0,72 %	-3,81 %	0,15 %	-1,30 %
2 to 1 90 days	1,27 %	-4,73 %	0,61 %	0,93 %	2 to 1 90 days	0,44 %	-2,36 %	0,61 %	-0,85 %
2 to 1 180days	0,86 %	-3,18 %	0,61 %	1,01 %	2 to 1 180days	0,18 %	-0,97 %	0,61 %	-0,95 %
Mixed Wet 328ft					**Mixed Wet 164ft**				
1 to 1 15days	1,95 %	-2,78 %	0,00 %	-0,92 %	1 to 1 15days	1,23 %	-2,16 %	0,00 %	-0,26 %
1 to 1 30days	2,22 %	-3,17 %	0,00 %	-1,72 %	1 to 1 30days	1,26 %	-2,21 %	0,00 %	-0,35 %
1 to 1 90 days	2,36 %	-3,38 %	0,61 %	-2,38 %	1 to 1 90 days	1,04 %	-1,83 %	0,61 %	0,10 %
1 to 1 180days	2,00 %	-2,86 %	1,22 %	-0,90 %	1 to 1 180days	0,55 %	-0,97 %	1,22 %	0,49 %
1 to 2 15days	2,79 %	-3,99 %	0,15 %	-1,38 %	1 to 2 15days	1,76 %	-3,10 %	0,15 %	-0,55 %
1 to 2 30days	3,26 %	-4,66 %	0,61 %	-1,46 %	1 to 2 30days	1,73 %	-3,04 %	0,61 %	-0,34 %
1 to 2 90 days	3,06 %	-4,37 %	1,52 %	-2,75 %	1 to 2 90 days	1,17 %	-2,05 %	1,52 %	0,23 %
1 to 2 180days	2,28 %	-3,27 %	2,44 %	-0,75 %	1 to 2 180days	0,42 %	-0,74 %	2,44 %	0,33 %
1 to 3 15days	3,35 %	-4,79 %	0,00 %	-2,59 %	1 to 3 15days	2,00 %	-3,50 %	0,00 %	-1,10 %
1 to 3 30days	3,81 %	-5,45 %	0,00 %	-3,83 %	1 to 3 30days	2,18 %	-3,84 %	0,00 %	-1,32 %
1 to 3 90 days	3,18 %	-4,55 %	2,44 %	-2,04 %	1 to 3 90 days	1,13 %	-1,98 %	2,44 %	0,31 %
1 to 3 180days	1,99 %	-2,85 %	2,44 %	-2,81 %	1 to 3 180days	0,07 %	-0,12 %	2,44 %	-0,84 %
2 to 1 15days	1,34 %	-1,91 %	0,15 %	-0,39 %	2 to 1 15days	0,76 %	-1,33 %	0,15 %	-0,02 %
2 to 1 30days	1,45 %	-2,07 %	0,15 %	-0,84 %	2 to 1 30days	0,75 %	-1,31 %	0,15 %	-0,04 %
2 to 1 90 days	1,31 %	-1,87 %	0,61 %	-0,70 %	2 to 1 90 days	0,47 %	-0,83 %	0,61 %	0,46 %
2 to 1 180days	1,02 %	-1,46 %	0,61 %	-0,54 %	2 to 1 180days	0,10 %	-0,18 %	0,61 %	0,26 %
Oil Wet 328ft					**Oil Wet 164ft**				
1 to 1 15days	2,88 %	-2,66 %	0,00 %	0,02 %	1 to 1 15days	-0,55 %	2,12 %	0,00 %	0,57 %
1 to 1 30days	3,38 %	-3,12 %	0,00 %	-0,74 %	1 to 1 30days	0,88 %	-3,38 %	0,00 %	-1,08 %
1 to 1 90 days	3,55 %	-3,28 %	0,61 %	-1,06 %	1 to 1 90 days	0,97 %	-3,69 %	0,61 %	-0,82 %
1 to 1 180days	2,81 %	-2,59 %	1,22 %	-0,54 %	1 to 1 180days	0,49 %	-1,86 %	1,22 %	-0,03 %
1 to 2 15days	4,01 %	-3,69 %	0,15 %	-0,51 %	1 to 2 15days	1,60 %	-6,09 %	0,15 %	-1,39 %
1 to 2 30days	4,83 %	-4,46 %	0,61 %	-0,86 %	1 to 2 30days	1,86 %	-7,10 %	0,61 %	-1,88 %
1 to 2 90 days	4,32 %	-3,98 %	1,52 %	-0,84 %	1 to 2 90 days	1,03 %	-3,93 %	1,52 %	-0,63 %
1 to 2 180days	2,77 %	-2,55 %	2,44 %	-0,42 %	1 to 2 180days	0,33 %	-1,27 %	2,44 %	-0,05 %
1 to 3 15days	4,86 %	-4,48 %	0,00 %	-1,45 %	1 to 3 15days	2,16 %	-8,26 %	0,00 %	-2,81 %
1 to 3 30days	5,52 %	-5,09 %	0,00 %	-2,24 %	1 to 3 30days	2,05 %	-7,83 %	0,00 %	-3,44 %
1 to 3 90 days	4,18 %	-3,85 %	2,44 %	-0,55 %	1 to 3 90 days	0,97 %	-3,71 %	2,44 %	-0,40 %
1 to 3 180days	2,15 %	-1,98 %	2,44 %	-2,11 %	1 to 3 180days	-0,17 %	0,64 %	2,44 %	-1,64 %
2 to 1 15days	2,25 %	-2,07 %	0,15 %	0,13 %	2 to 1 15days	0,23 %	-0,86 %	0,15 %	-0,38 %
2 to 1 30days	2,51 %	-2,31 %	0,15 %	-0,43 %	2 to 1 30days	0,51 %	-1,94 %	0,15 %	-0,71 %
2 to 1 90 days	2,17 %	-2,00 %	0,61 %	-0,43 %	2 to 1 90 days	0,44 %	-1,69 %	0,61 %	-0,07 %
2 to 1 180days	1,38 %	-1,27 %	0,61 %	-0,67 %	2 to 1 180days	0,09 %	-0,34 %	0,61 %	-0,22 %

Table 10.3: Difference in water saturation between the conventional and cyclic (1:3, 30 days) injection for each cell at the last time step, water-wet case.

J	K	I=	1	2	3	4	5	6	7	8	9	10
1	1		12,6 %	24,0 %	33,3 %	36,7 %	30,4 %	20,9 %	11,5 %	3,5 %	0,4 %	-0,1 %
1	2		0,0 %	0,6 %	0,5 %	0,1 %	1,7 %	3,5 %	4,9 %	5,4 %	4,6 %	0,9 %
1	3		-2,2 %	-3,6 %	-3,4 %	-4,5 %	-6,1 %	-7,2 %	-7,4 %	-6,7 %	-5,0 %	-3,1 %
1	4		-1,3 %	-2,2 %	-2,0 %	-2,1 %	-3,0 %	-3,6 %	-3,5 %	-3,0 %	-2,5 %	-2,2 %
1	5		-0,7 %	-1,0 %	-1,3 %	-1,7 %	-1,8 %	-1,6 %	-1,6 %	-2,0 %	-2,8 %	-3,3 %
1	6		9,6 %	13,8 %	14,1 %	10,8 %	6,5 %	2,7 %	0,2 %	-1,0 %	-1,5 %	-2,2 %
1	7		-0,7 %	-1,0 %	-1,6 %	-2,8 %	-3,0 %	-2,4 %	-2,0 %	-1,4 %	0,3 %	6,4 %
1	8		39,4 %	48,1 %	45,8 %	37,0 %	24,0 %	12,0 %	3,7 %	0,0 %	-0,7 %	0,2 %
1	9		-1,7 %	-1,4 %	-3,0 %	-4,7 %	-4,8 %	-4,6 %	-4,2 %	-3,4 %	-2,3 %	-0,9 %
1	10		-2,7 %	-4,8 %	-4,9 %	-4,8 %	-4,9 %	-4,6 %	-4,3 %	-3,9 %	-3,3 %	-2,5 %

Table 10.4: Difference in water saturation between the conventional and cyclic (1:3, 30 days) injection for each cell at the last time step, oil-wet case.

J	K	I=	1	2	3	4	5	6	7	8	9	10
1	1		14,5 %	21,5 %	26,7 %	30,0 %	31,0 %	29,3 %	24,6 %	19,3 %	15,1 %	10,3 %
1	2		0,9 %	1,5 %	1,7 %	2,3 %	2,7 %	3,1 %	4,1 %	5,7 %	6,9 %	7,2 %
1	3		-3,7 %	-4,2 %	-4,5 %	-5,7 %	-6,7 %	-6,9 %	-6,7 %	-6,5 %	-6,9 %	-7,4 %
1	4		-2,3 %	-2,9 %	-3,1 %	-3,8 %	-4,7 %	-4,9 %	-4,8 %	-4,7 %	-4,9 %	-5,2 %
1	5		-2,6 %	-2,5 %	-3,2 %	-3,7 %	-3,8 %	-3,5 %	-3,3 %	-3,2 %	-3,5 %	-3,7 %
1	6		12,0 %	14,3 %	13,7 %	11,2 %	8,3 %	5,8 %	3,9 %	2,5 %	1,8 %	1,5 %
1	7		-0,4 %	-0,8 %	-1,4 %	-2,3 %	-2,7 %	-2,7 %	-2,7 %	-2,3 %	-1,8 %	-1,1 %
1	8		34,9 %	39,6 %	38,7 %	35,8 %	30,9 %	24,9 %	18,8 %	14,4 %	12,3 %	11,2 %
1	9		-1,1 %	-1,1 %	-1,3 %	-1,7 %	-1,8 %	-1,7 %	-2,2 %	-2,9 %	-3,7 %	-4,2 %
1	10		-2,6 %	-3,0 %	-2,7 %	-3,3 %	-3,7 %	-3,9 %	-4,0 %	-4,1 %	-4,2 %	-4,2 %

Table 10.5: Simulation results for the short spacing case with reservoir pressure above saturation pressure, water-wet rock.

Short Spacing P>Psat									
328ft	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT	164ft	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
WF Water	3741497	2556103	6888000	89,47 %	WF Water	1897109,9	759690,06	2952000	85,07 %
	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT		FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
Water Wet 328ft					Water Wet 164ft				
1 to 1 15days	3838363,5	2455008,3	6888000	88,09 %	1 to 1 15days	1927244,9	729555,13	2952000	83,89 %
1 to 1 30days	3853778	2443822	6888000	87,09 %	1 to 1 30days	1928346,1	728453,88	2952000	83,36 %
1 to 1 90 days	3855634,3	2441965,8	6930000	86,60 %	1 to 1 90 days	1924220,3	732579,69	2970000	83,17 %
1 to 1 180days	3847690,5	2449909,5	6972000	88,51 %	1 to 1 180days	1920318,5	736481,44	2988000	83,95 %
1 to 2 15days	3879730,5	2417869,5	6898500	87,45 %	1 to 2 15days	1941117,8	715682,25	2956500	83,17 %
1 to 2 30days	3894446,5	2403153,5	6930000	89,37 %	1 to 2 30days	1940657,3	716142,75	2970000	83,85 %
1 to 2 90 days	3888074	2409526	6993000	85,71 %	1 to 2 90 days	1933689,1	723110,81	2997000	82,27 %
1 to 2 180days	3865435,8	2432164,3	7056000	88,86 %	1 to 2 180days	1926076,8	730723,19	3024000	83,60 %
1 to 3 15days	3903761,5	2393838,5	6888000	86,24 %	1 to 3 15days	1947495,9	709304,13	2952000	82,33 %
1 to 3 30days	3913911,5	2383688,5	6888000	85,54 %	1 to 3 30days	1945528,5	711271,44	2952000	81,89 %
1 to 3 90 days	3896497,5	2401102,5	7056000	85,89 %	1 to 3 90 days	1936337,9	720462,13	3024000	82,11 %
1 to 3 180days	3864606,5	2432993,5	7056000	85,54 %	1 to 3 180days	1924477,9	732322,13	3024000	82,02 %
2 to 1 15days	3810717,3	2486882,8	6898500	89,42 %	2 to 1 15days	1914847,5	741952,5	2956500	84,75 %
2 to 1 30days	3816806	2480794	6898500	89,05 %	2 to 1 30days	1913838,6	742961,38	2956500	84,59 %
2 to 1 90 days	3811706	2485894	6930000	88,87 %	2 to 1 90 days	1910467,8	746332,19	2970000	84,60 %
2 to 1 180days	3803554	2494046	6930000	88,82 %	2 to 1 180days	1907512,1	749287,81	2970000	84,40 %

Table 10.6: Short spacing incremental increase/decrease in oil production, water production, total water injected and field water cut, water-wet rock

Short Spacing P>Psat									
328ft	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT	164ft	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
WF Water	3741497	2556103	6888000	89,47 %	WF Water	1897109,9	759690,06	2952000	85,07 %
	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT		FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
Water Wet 328ft					Water Wet 164ft				
1 to 1 15days	2,59 %	-3,96 %	0,00 %	-1,54 %	1 to 1 15days	1,59 %	-3,97 %	0,00 %	-1,39 %
1 to 1 30days	3,00 %	-4,39 %	0,00 %	-2,66 %	1 to 1 30days	1,65 %	-4,11 %	0,00 %	-2,02 %
1 to 1 90 days	3,05 %	-4,47 %	0,61 %	-3,21 %	1 to 1 90 days	1,43 %	-3,57 %	0,61 %	-2,24 %
1 to 1 180days	2,84 %	-4,15 %	1,22 %	-1,07 %	1 to 1 180days	1,22 %	-3,06 %	1,22 %	-1,32 %
1 to 2 15days	3,69 %	-5,41 %	0,15 %	-2,26 %	1 to 2 15days	2,32 %	-5,79 %	0,15 %	-2,24 %
1 to 2 30days	4,09 %	-5,98 %	0,61 %	-0,11 %	1 to 2 30days	2,30 %	-5,73 %	0,61 %	-1,43 %
1 to 2 90 days	3,92 %	-5,73 %	1,52 %	-4,20 %	1 to 2 90 days	1,93 %	-4,82 %	1,52 %	-3,29 %
1 to 2 180days	3,31 %	-4,85 %	2,44 %	-0,69 %	1 to 2 180days	1,53 %	-3,81 %	2,44 %	-1,73 %
1 to 3 15days	4,34 %	-6,35 %	0,00 %	-3,61 %	1 to 3 15days	2,66 %	-6,63 %	0,00 %	-3,22 %
1 to 3 30days	4,61 %	-6,75 %	0,00 %	-4,39 %	1 to 3 30days	2,55 %	-6,37 %	0,00 %	-3,74 %
1 to 3 90 days	4,14 %	-6,06 %	2,44 %	-4,00 %	1 to 3 90 days	2,07 %	-5,16 %	2,44 %	-3,48 %
1 to 3 180days	3,29 %	-4,82 %	2,44 %	-4,39 %	1 to 3 180days	1,44 %	-3,60 %	2,44 %	-3,59 %
2 to 1 15days	1,85 %	-2,71 %	0,15 %	-0,06 %	2 to 1 15days	0,93 %	-2,33 %	0,15 %	-0,38 %
2 to 1 30days	2,01 %	-2,95 %	0,15 %	-0,47 %	2 to 1 30days	0,88 %	-2,20 %	0,15 %	-0,56 %
2 to 1 90 days	1,88 %	-2,75 %	0,61 %	-0,67 %	2 to 1 90 days	0,70 %	-1,76 %	0,61 %	-0,56 %
2 to 1 180days	1,66 %	-2,43 %	0,61 %	-0,73 %	2 to 1 180days	0,55 %	-1,37 %	0,61 %	-0,79 %

Table 10.7: Oil saturation at 9090 days.

J	K	I= 1	2	3	4	5	6	7	8	9	10
1	1	0,304	0,357	0,420	0,512	0,613	0,692	0,749	0,773	0,773	0,770
1	2	0,250	0,280	0,307	0,329	0,347	0,367	0,407	0,486	0,590	0,676
1	3	0,220	0,247	0,262	0,279	0,297	0,308	0,316	0,315	0,311	0,319
1	4	0,216	0,238	0,251	0,261	0,274	0,283	0,285	0,280	0,278	0,285
1	5	0,207	0,221	0,235	0,247	0,253	0,257	0,260	0,262	0,262	0,261
1	6	0,274	0,293	0,305	0,313	0,321	0,327	0,332	0,337	0,350	0,416
1	7	0,243	0,265	0,285	0,301	0,312	0,318	0,327	0,344	0,403	0,673
1	8	0,370	0,440	0,498	0,548	0,588	0,624	0,648	0,667	0,696	0,739
1	9	0,299	0,330	0,349	0,358	0,362	0,360	0,351	0,342	0,344	0,379
1	10	0,221	0,245	0,256	0,265	0,273	0,277	0,278	0,277	0,279	0,290

Table 10.8: Oil saturation at 9360 days.

J	K	I= 1	2	3	4	5	6	7	8	9	10
1	1	0,303	0,350	0,405	0,485	0,583	0,663	0,722	0,752	0,758	0,756
1	2	0,252	0,281	0,307	0,326	0,341	0,359	0,393	0,460	0,559	0,648
1	3	0,223	0,250	0,265	0,281	0,297	0,308	0,317	0,319	0,310	0,313
1	4	0,218	0,240	0,252	0,262	0,274	0,283	0,286	0,281	0,276	0,281
1	5	0,212	0,225	0,238	0,249	0,253	0,257	0,260	0,261	0,261	0,259
1	6	0,274	0,292	0,302	0,309	0,315	0,322	0,327	0,332	0,344	0,398
1	7	0,247	0,269	0,287	0,300	0,308	0,314	0,322	0,336	0,375	0,601
1	8	0,365	0,427	0,480	0,527	0,565	0,603	0,629	0,651	0,680	0,722
1	9	0,305	0,337	0,354	0,362	0,365	0,362	0,355	0,345	0,341	0,366
1	10	0,224	0,249	0,259	0,267	0,273	0,276	0,276	0,275	0,276	0,283

C. Injection-Production ratios

Table 10.9: Ratio of daily injection to production rate for different cases.

Scenario	Long Spacing	Long Spacing	Short Spacing	Short Spacing
Res. Thickness (ft)	328	164	328	164
WF Inj. Rate (STB/day)	1000	500	700	300
WF	1,1	1,1	1,1	1,1
1 to1	2,2	2,3	2,2	2,2
1 to 2	3,3	3,4	3,3	3,3
1 to 3	4,4	4,5	4,4	4,4
2 to 1	1,6	1,7	1,6	1,7

D. Results from Initiation of Cyclic at Different Water Cut

Table 10.10: Results of different initiation times: Total Production (right) and increments after initiation of cyclic injection (right).

Long Spacing P>Psat					Long Spacing P>Psat				
328ft	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT	328ft	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
WF Oil-Wet	4,30E+06	4,66E+06	9,84E+06	91,98 %	WF Oil-Wet	4,30E+06	4,66E+06	9,84E+06	91,98 %
Cyclic Initiation	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT	Cyclic Initiation	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
At 0% WC					At 0% WC				
1 to 3 30days	4,53E+06	4,42E+06	9,84E+06	89,92 %	1 to 3 30days	5,52 %	-5,09 %	0,00 %	-2,24 %
1 to 3 90 days	4,48E+06	4,48E+06	1,01E+07	91,48 %	1 to 3 90 days	4,18 %	-3,85 %	2,44 %	-0,55 %
At 25% WC					At 25% WC				
1 to 3 30days	4,49E+06	4,46E+06	9,76E+06	88,98 %	1 to 3 30days	10,48 %	-4,27 %	-0,84 %	-4,47 %
1 to 3 90 days	4,54E+06	4,42E+06	9,64E+06	88,08 %	1 to 3 90 days	12,88 %	-5,25 %	-2,06 %	-5,83 %
At 50% WC					At 50% WC				
1 to 3 30days	4,43E+06	4,52E+06	9,82E+06	89,77 %	1 to 3 30days	12,58 %	-3,29 %	-0,23 %	-5,25 %
1 to 3 90 days	4,48E+06	4,48E+06	9,58E+06	87,39 %	1 to 3 90 days	16,99 %	-4,44 %	-2,67 %	-10,92 %
At 65% WC					At 65% WC				
1 to 3 30days	4,39E+06	4,56E+06	9,82E+06	89,83 %	1 to 3 30days	13,64 %	-2,67 %	-0,23 %	-7,96 %
1 to 3 90 days	4,44E+06	4,52E+06	9,82E+06	90,11 %	1 to 3 90 days	19,96 %	-3,91 %	-0,23 %	-6,94 %
At 75% WC					At 75% WC				
1 to 3 30days	4,36E+06	4,59E+06	9,84E+06	90,10 %	1 to 3 30days	14,09 %	-2,17 %	0,00 %	-11,07 %
1 to 3 90 days	4,40E+06	4,55E+06	9,60E+06	87,47 %	1 to 3 90 days	22,61 %	-3,48 %	-2,44 %	-26,56 %
At 85% WC					At 85% WC				
1 to 3 30days	4,33E+06	4,62E+06	9,82E+06	90,62 %	1 to 3 30days	12,73 %	-1,56 %	-0,23 %	-19,52 %
1 to 3 90 days	4,31E+06	4,64E+06	1,01E+07	91,18 %	1 to 3 90 days	6,06 %	-0,74 %	2,21 %	-11,46 %

Table 10.11: Cumulative oil and water production at given water cut stage for the conventional waterflood.

At WC	Np (STB)	Wp (STB)	WC
0 %	0	0	0 %
25 %	2,44E+06	9,35E+04	25 %
50 %	3,23E+06	5,75E+05	50 %
65 %	3,60E+06	1,08E+06	65 %
75 %	3,83E+06	1,63E+06	75 %
85 %	4,03E+06	2,50E+06	85 %

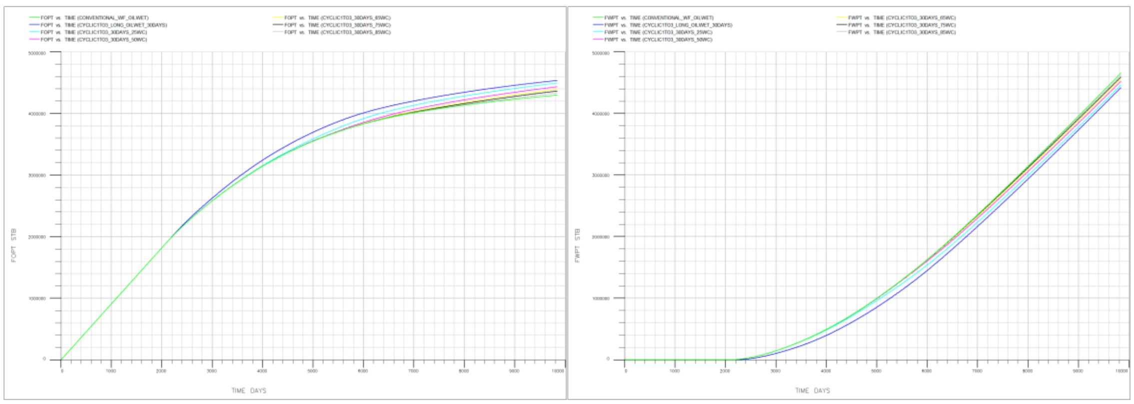

Figure 10.4: *Oil (left) and water (right) production over time for different initiation times, 30 days base period.*

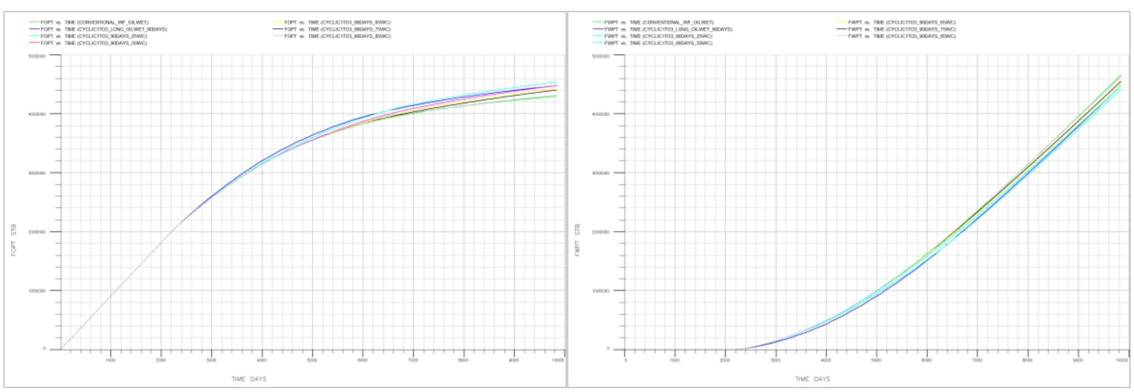

Figure 10.5: *Oil (left) and water (right) production over time for different initiation times, 90 days base period.*

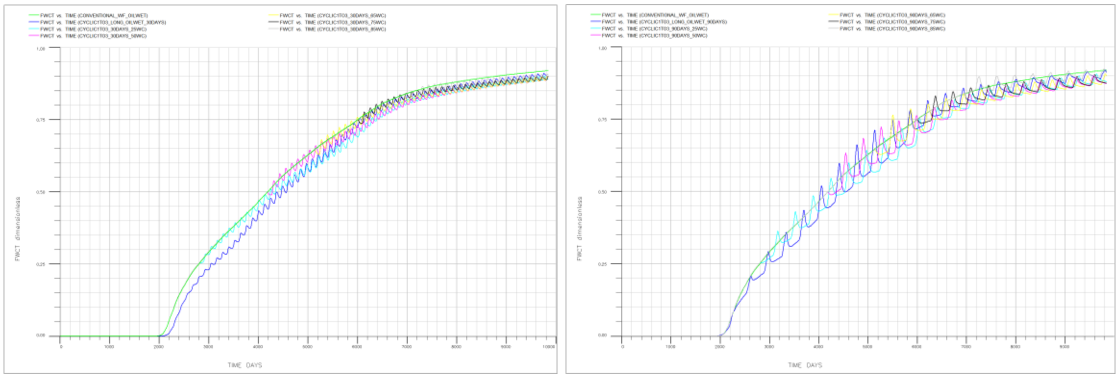

Figure 10.6: *Water cut profiles for the 1:3-cycles with base period of 30 (left) and 90 (right) days.*

E. Results for Pressure below Saturation Pressure

Table 10.12: Results of conventional and cyclic injection for different initial reservoir pressures below saturation pressure.

WF Water	**7,12E+06**	**1,84E+06**	**9,84E+06**	**67,71 %**	**WF Water**	**7,16E+06**	**1,79E+06**	**9,84E+06**	**66,96 %**	**WF Water**	**7,14E+06**	**1,82E+06**	**9,84E+06**	**66,22 %**
	FOPT (STB)	**FWPT (STB)**	**FWIT (STB)**	**FWCT**		**FOPT (STB)**	**FWPT (STB)**	**FWIT (STB)**	**FWCT**		**FOPT (STB)**	**FWPT (STB)**	**FWIT (STB)**	**FWCT**
Water Wet 328ft					**Water Wet 328ft**					**Water Wet 328ft**				
1 to 1 15days	7267669	1686730,8	9840000	68,02 %	1 to 1 15days	7215544,5	1738855,5	9840000	67,53 %	1 to 1 15days	7120050	1834350	9840000	63,97 %
1 to 1 30days	7270581	1683819,3	9840000	67,02 %	1 to 1 30days	7266955,5	1687444,5	9840000	65,64 %	1 to 1 30days	7243251,5	1711148,8	9840000	63,68 %
1 to 1 90 days	7240418	1713982	9900000	67,02 %	1 to 1 90 days	7252334	1702065,8	9900000	65,63 %	1 to 1 90 days	7228029,5	1726370,5	9900000	63,68 %
1 to 1 180days	7204123	1750276,9	9960000	70,67 %	1 to 1 180days	7218545,5	1735854,4	9960000	70,43 %	1 to 1 180days	7212729,5	1741670,6	9960000	67,02 %
1 to 2 15days	7309138,5	1645261,4	9855000	67,65 %	1 to 2 15days	7319724	1634676	9855000	66,96 %	1 to 2 15days	7296044,5	1658355,3	9855000	65,09 %
1 to 2 30days	7300023,5	1654376,5	9900000	67,78 %	1 to 2 30days	7338046,5	1616353,4	9900000	68,44 %	1 to 2 30days	7302800	1651600,3	9900000	66,55 %
1 to 2 90 days	7255154,5	1699245,6	9990000	67,72 %	1 to 2 90 days	7266510	1687890	9990000	66,25 %	1 to 2 90 days	7259032	1695368	9990000	64,13 %
1 to 2 180days	7208417,5	1745982,5	10080000	74,59 %	1 to 2 180days	7225497,5	1728902,8	10080000	69,65 %	1 to 2 180days	7224177,5	1730222,5	10080000	68,78 %
1 to 3 15days	7332536	1621864,1	9840000	65,67 %	1 to 3 15days	7356150,5	1598249,6	9840000	63,39 %	1 to 3 15days	7329728,5	1624671,6	9840000	62,22 %
1 to 3 30days	7327107	1627293,1	9840000	63,11 %	1 to 3 30days	7350897,5	1603502,3	9840000	60,48 %	1 to 3 30days	7316691	1637708,9	9840000	61,18 %
1 to 3 90 days	7251966	1702434,1	10080000	68,42 %	1 to 3 90 days	7264429	1689970,8	10080000	66,47 %	1 to 3 90 days	7264869,5	1689530,5	10080000	64,86 %
1 to 3 180days	7197568,5	1756831,3	10080000	63,62 %	1 to 3 180days	7219836	1734564,1	10080000	63,75 %	1 to 3 180days	7216043	1738356,8	10080000	62,41 %
2 to 1 15days	7223750,5	1730649,6	9855000	68,46 %	2 to 1 15days	7223281	1731119	9855000	67,78 %	2 to 1 15days	7138416	1815984,1	9855000	66,05 %
2 to 1 30days	7217163	1737236,9	9855000	67,51 %	2 to 1 30days	7239486	1714913,9	9855000	66,72 %	2 to 1 30days	7199379	1755021	9855000	65,54 %
2 to 1 90 days	7186342	1768057,8	9900000	69,14 %	2 to 1 90 days	7203398	1751001,9	9900000	69,32 %	2 to 1 90 days	7186919,5	1767480,3	9900000	66,30 %
2 to 1 180days	7159597	1794803,3	9900000	69,00 %	2 to 1 180days	7180518	1773881,9	9900000	69,54 %	2 to 1 180days	7172734,5	1781665,5	9900000	66,22 %

Table 10.13: Incremental increase/decrease by cyclic injection for different initial reservoir pressures compared to conventional waterflood at the same reservoir pressure.

Pi=5300psi					**Pi=4300psi**					**Pi=3500**				
328ft	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT	**328ft**	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT	**328ft**	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
WF Water	7116208,5	1838191,4	9840000	0,677068	**WF Water**	7159911,5	1794488,5	9840000	0,6696317	**WF Water**	7135700	1818700	9840000	0,6622429
	FOPT (STB)	**FWPT (STB)**	**FWIT (STB)**	**FWCT**		**FOPT (STB)**	**FWPT (STB)**	**FWIT (STB)**	**FWCT**		**FOPT (STB)**	**FWPT (STB)**	**FWIT (STB)**	**FWCT**
Water Wet 328ft					**Water Wet 328ft**					**Water Wet 328ft**				
1 to 1 15days	2,13 %	-8,24 %	0,00 %	0,46 %	1 to 1 15days	0,78 %	-3,10 %	0,00 %	0,84 %	1 to 1 15days	-0,22 %	0,86 %	0,00 %	-3,41 %
1 to 1 30days	2,17 %	-8,40 %	0,00 %	-1,01 %	1 to 1 30days	1,50 %	-5,97 %	0,00 %	-1,98 %	1 to 1 30days	1,51 %	-5,91 %	0,00 %	-3,84 %
1 to 1 90 days	1,75 %	-6,76 %	0,61 %	-1,02 %	1 to 1 90 days	1,29 %	-5,15 %	0,61 %	-1,99 %	1 to 1 90 days	1,29 %	-5,08 %	0,61 %	-3,84 %
1 to 1 180days	1,24 %	-4,78 %	1,22 %	4,38 %	1 to 1 180days	0,82 %	-3,27 %	1,22 %	5,18 %	1 to 1 180days	1,08 %	-4,24 %	1,22 %	1,20 %
1 to 2 15days	2,71 %	-10,50 %	0,15 %	-0,09 %	1 to 2 15days	2,23 %	-8,91 %	0,15 %	-0,01 %	1 to 2 15days	2,25 %	-8,82 %	0,15 %	-1,72 %
1 to 2 30days	2,58 %	-10,00 %	0,61 %	0,10 %	1 to 2 30days	2,49 %	-9,93 %	0,61 %	2,20 %	1 to 2 30days	2,34 %	-9,19 %	0,61 %	0,49 %
1 to 2 90 days	1,95 %	-7,56 %	1,52 %	0,02 %	1 to 2 90 days	1,49 %	-5,94 %	1,52 %	-1,07 %	1 to 2 90 days	1,73 %	-6,78 %	1,52 %	-3,16 %
1 to 2 180days	1,30 %	-5,02 %	2,44 %	10,17 %	1 to 2 180days	0,92 %	-3,65 %	2,44 %	4,01 %	1 to 2 180days	1,24 %	-4,86 %	2,44 %	3,86 %
1 to 3 15days	3,04 %	-11,77 %	0,00 %	-3,01 %	1 to 3 15days	2,74 %	-10,94 %	0,00 %	-5,34 %	1 to 3 15days	2,72 %	-10,67 %	0,00 %	-6,04 %
1 to 3 30days	2,96 %	-11,47 %	0,00 %	-6,79 %	1 to 3 30days	2,67 %	-10,64 %	0,00 %	-9,68 %	1 to 3 30days	2,54 %	-9,95 %	0,00 %	-7,62 %
1 to 3 90 days	1,91 %	-7,39 %	2,44 %	1,05 %	1 to 3 90 days	1,46 %	-5,82 %	2,44 %	-0,74 %	1 to 3 90 days	1,81 %	-7,10 %	2,44 %	-2,06 %
1 to 3 180days	1,14 %	-4,43 %	2,44 %	-6,03 %	1 to 3 180days	0,84 %	-3,34 %	2,44 %	-4,80 %	1 to 3 180days	1,13 %	-4,42 %	2,44 %	-5,77 %
2 to 1 15days	1,51 %	-5,85 %	0,15 %	1,11 %	2 to 1 15days	0,89 %	-3,53 %	0,15 %	1,22 %	2 to 1 15days	0,04 %	-0,15 %	0,15 %	-0,26 %
2 to 1 30days	1,42 %	-5,49 %	0,15 %	-0,30 %	2 to 1 30days	1,11 %	-4,43 %	0,15 %	-0,37 %	2 to 1 30days	0,89 %	-3,50 %	0,15 %	-1,03 %
2 to 1 90 days	0,99 %	-3,82 %	0,61 %	2,12 %	2 to 1 90 days	0,61 %	-2,42 %	0,61 %	3,51 %	2 to 1 90 days	0,72 %	-2,82 %	0,61 %	0,11 %
2 to 1 180days	0,61 %	-2,36 %	0,61 %	1,90 %	2 to 1 180days	0,29 %	-1,15 %	0,61 %	3,85 %	2 to 1 180days	0,52 %	-2,04 %	0,61 %	0,00 %

Table 10.14: Incremental increase/decrease by cyclic injection under bubblepoint compared to cyclic waterflood above bubblepoint.

Pi=5300psi					Pi=4300psi					Pi=3500				
	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT		FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT		FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
Water Wet 328ft					Water Wet 328ft					Water Wet 328ft				
1 to 1 15days	0,87 %	-3,60 %	0,00 %	-2,50 %	1 to 1 15days	0,15 %	-0,62 %	0,00 %	-3,20 %	1 to 1 15days	-1,17 %	4,84 %	0,00 %	-8,30 %
1 to 1 30days	0,74 %	-3,07 %	0,00 %	-2,13 %	1 to 1 30days	0,69 %	-2,86 %	0,00 %	-4,15 %	1 to 1 30days	0,36 %	-1,50 %	0,00 %	-7,00 %
1 to 1 90 days	0,56 %	-2,30 %	0,00 %	-1,79 %	1 to 1 90 days	0,73 %	-2,98 %	0,00 %	-3,82 %	1 to 1 90 days	0,39 %	-1,59 %	0,00 %	-6,68 %
1 to 1 180days	0,55 %	-2,21 %	0,00 %	-0,12 %	1 to 1 180days	0,75 %	-3,01 %	0,00 %	-0,46 %	1 to 1 180days	0,67 %	-2,69 %	0,00 %	-5,28 %
1 to 2 15days	0,80 %	-3,42 %	0,00 %	-2,09 %	1 to 2 15days	0,95 %	-4,05 %	0,00 %	-3,09 %	1 to 2 15days	0,62 %	-2,66 %	0,00 %	-5,80 %
1 to 2 30days	0,54 %	-2,33 %	0,00 %	-1,06 %	1 to 2 30days	1,07 %	-4,58 %	0,00 %	-0,09 %	1 to 2 30days	0,58 %	-2,50 %	0,00 %	-2,85 %
1 to 2 90 days	0,55 %	-2,30 %	0,00 %	-1,25 %	1 to 2 90 days	0,71 %	-2,95 %	0,00 %	-3,40 %	1 to 2 90 days	0,61 %	-2,52 %	0,00 %	-6,49 %
1 to 2 180days	0,55 %	-2,21 %	0,00 %	2,01 %	1 to 2 180days	0,79 %	-3,17 %	0,00 %	-4,74 %	1 to 2 180days	0,77 %	-3,10 %	0,00 %	-5,93 %
1 to 3 15days	0,79 %	-3,41 %	0,00 %	-2,36 %	1 to 3 15days	1,11 %	-4,81 %	0,00 %	-5,75 %	1 to 3 15days	0,75 %	-3,24 %	0,00 %	-7,47 %
1 to 3 30days	0,68 %	-2,96 %	0,00 %	-2,93 %	1 to 3 30days	1,01 %	-4,38 %	0,00 %	-6,98 %	1 to 3 30days	0,54 %	-2,34 %	0,00 %	-5,91 %
1 to 3 90 days	0,54 %	-2,24 %	0,00 %	-1,08 %	1 to 3 90 days	0,71 %	-2,95 %	0,00 %	-3,90 %	1 to 3 90 days	0,72 %	-2,98 %	0,00 %	-6,23 %
1 to 3 180days	0,58 %	-2,31 %	0,00 %	-2,21 %	1 to 3 180days	0,89 %	-3,55 %	0,00 %	-2,01 %	1 to 3 180days	0,84 %	-3,33 %	0,00 %	-4,08 %
2 to 1 15days	0,75 %	-3,00 %	0,00 %	-2,17 %	2 to 1 15days	0,74 %	-2,97 %	0,00 %	-3,14 %	2 to 1 15days	-0,44 %	1,79 %	0,00 %	-5,61 %
2 to 1 30days	0,62 %	-2,49 %	0,00 %	-1,95 %	2 to 1 30days	0,93 %	-3,74 %	0,00 %	-3,09 %	2 to 1 30days	0,37 %	-1,49 %	0,00 %	-4,80 %
2 to 1 90 days	0,59 %	-2,33 %	0,00 %	-0,75 %	2 to 1 90 days	0,83 %	-3,27 %	0,00 %	-0,49 %	2 to 1 90 days	0,60 %	-2,36 %	0,00 %	-4,83 %
2 to 1 180days	0,63 %	-2,44 %	0,00 %	-1,03 %	2 to 1 180days	0,93 %	-3,58 %	0,00 %	-0,24 %	2 to 1 180days	0,82 %	-3,16 %	0,00 %	-5,01 %

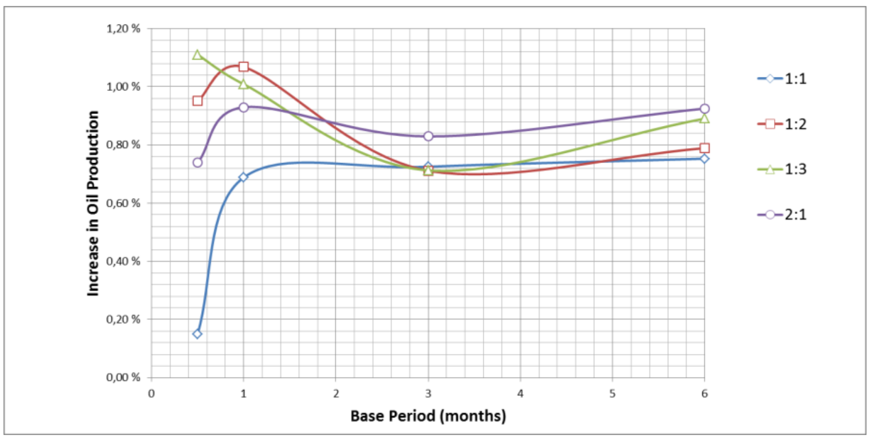

Figure 10.7: *Increase in oil production for cycling at 4300psi compared to cycling above saturation pressure.*

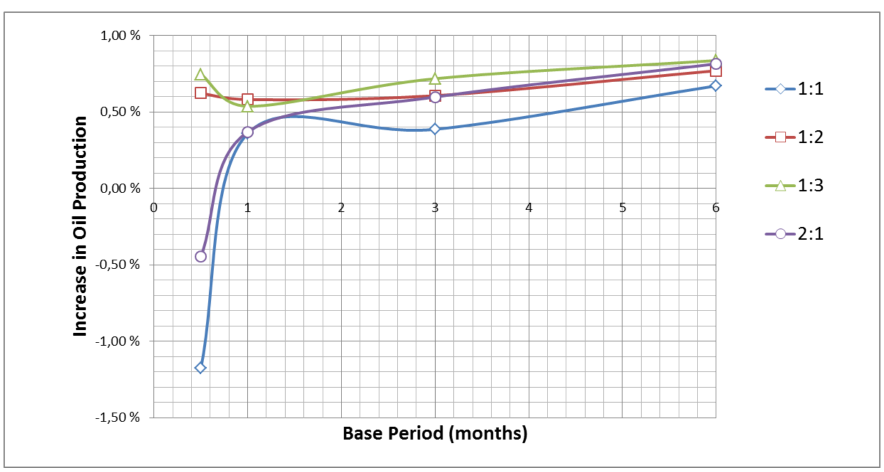

Figure 10.8: *Increase in oil production for cycling at 3500psi compared to cycling above saturation pressure.*

F. Results for the 3D-Model

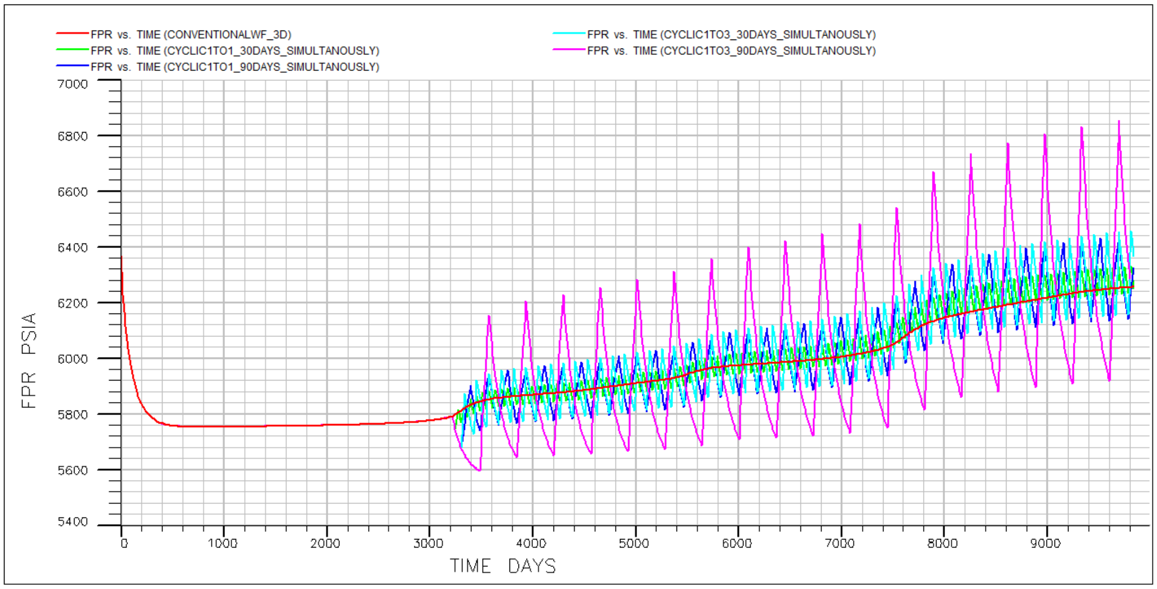

Figure 10.9: *Reservoir pressure (FPR) in the 3D-model.*

Table 10.15: Simultaneously cyclic injection results, 3D-model.

328ft Water Wet	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
WF Water	**6,16E+07**	**2,82E+07**	**9,84E+07**	**83,76 %**
1 to 1 30days	62496028	26956934	98150000	0,833143
1 to 1 90 days	62570972	26465972	98000000	0,828543
1 to 3 30days	63074712	25933296	98150000	0,817352
1 to 3 90 days	62837604	25112688	96950000	0,81262
Incremental Increase/Decrease compared with conventional WF				
328ft Water Wet	**FOPT (%)**	**FWPT (%)**	**FWIT (%)**	**FWCT (%)**
1 to 1 30days	1,45 %	-4,48 %	-0,25 %	-0,53 %
1 to 1 90 days	1,57 %	-6,22 %	-0,41 %	-1,08 %
1 to 3 30days	2,39 %	-8,11 %	-0,25 %	-2,42 %
1 to 3 90 days	2,00 %	-11,02 %	-1,47 %	-2,98 %

Table 10.16: Shifted cyclic injection results, 3D-model.

328ft Water Wet	FOPT (STB)	FWPT (STB)	FWIT (STB)	FWCT
WF Water	6,16E+07	2,82E+07	9,84E+07	83,76 %
1 to 1 30days	62308432	27340234	98400000	0,837407
1 to 1 90 days	62109928	27577732	98400000	0,839436
1 to 3 30days	62858300	26999818	99250000	0,83134
1 to 3 90 days	62691768	27317752	98750000	0,830608
Incremental Increase/Decrease compared with conventional WF				
328ft Water Wet	FOPT (%)	FWPT (%)	FWIT (%)	FWCT (%)
1 to 1 30days	1,14 %	-3,12 %	0,00 %	-0,02 %
1 to 1 90 days	0,82 %	-2,28 %	0,00 %	0,22 %
1 to 3 30days	2,03 %	-4,33 %	0,86 %	-0,75 %
1 to 3 90 days	1,76 %	-3,20 %	0,36 %	-0,83 %

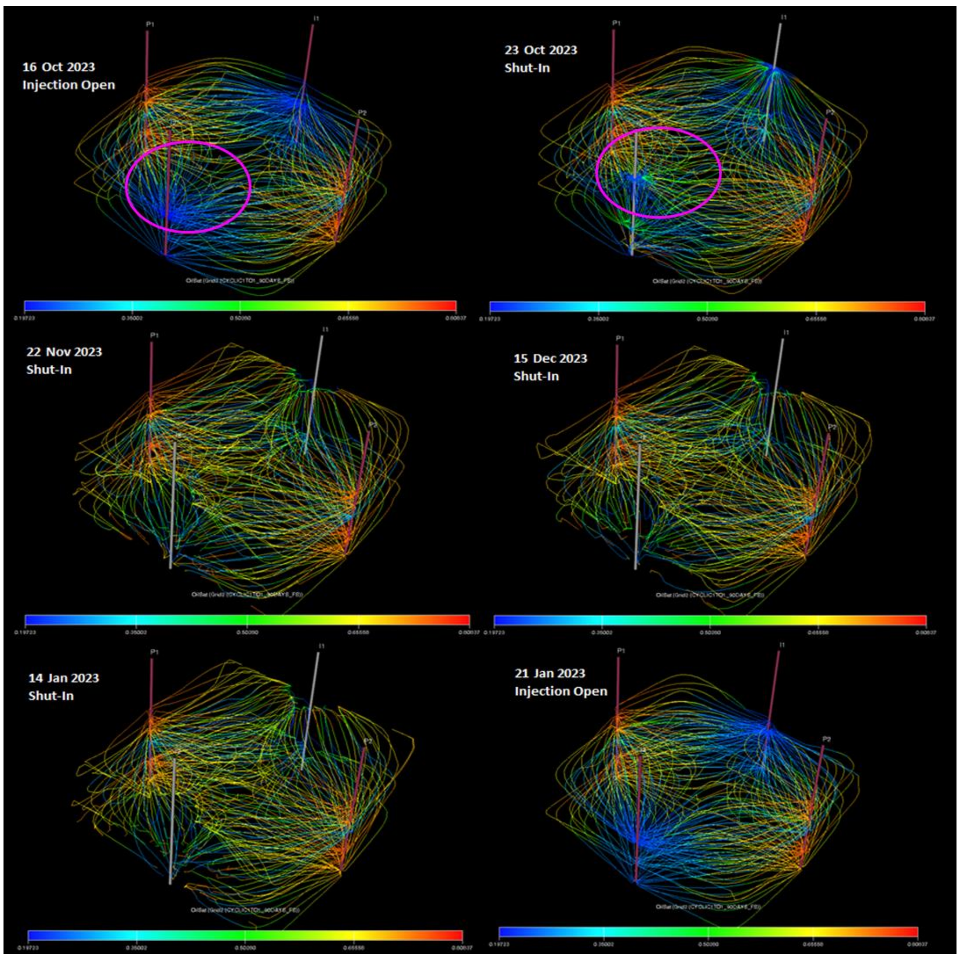

Figure 10.10: *Waterflood patterns before, during and after shut-in of injectors.*