NTNU
Norwegian University of
Science and Technology

# CO2 EOR Potential in the Brent Group at the Statfjord Field

**Petter Agersborg Bjørnå**

Petroleum Geoscience and Engineering
Submission date: June 2017
Supervisor: Jon Kleppe, IGP
Co-supervisor: Bamshad Nazarian, Statoil ASA

Norwegian University of Science and Technology
Department of Geoscience and Petroleum

# Preface

This is the final work of my master's thesis at the Department of Geoscience and Petroleum at the Norwegian University of Science and Technology (NTNU), spring 2017. The thesis has been written in cooperation with Statoil ASA.

I would like to thank the license partners at the Statfjord Field for allowing me to use their reservoir model and providing me valuable data for this thesis. The license partners are Statoil ASA, ExxonMobil AS and Centrica.

My supervisor in Statoil ASA, Bamshad Nazarian, has been very helpful and supporting through the whole project. I am really grateful for all the time he has spent with me, and always having a positive attitude when giving me guidance for the thesis.

I would also like to express my greatest thankfulness to my supervisor at NTNU, Jon Kleppe, Professor at the Department of Geoscience and Petroleum. He has guided me through the project and together with Bamshad Nazarian, he initiated this cooperation with Statoil ASA. I really have appreciated his helpfulness.

Trondheim, 10.06.2017

Petter Agersborg Bjørnå

# Abstract

$CO_2$ flooding is an enhanced oil recovery (EOR) technique that can be used to improve displacement efficiency and volumetric sweep efficiency. This is due to its favorable interactions with oil, which can be beneficial when trying to produce incremental oil. This method has been investigated in this thesis.

Statfjord is one of the largest oil discoveries in Europe, and has been producing oil since 1979. The main reserves are in the Brent group, and production from this reservoir is supposed to stop in 2025. A compositional model of the Brent group has been developed by Statoil, which is tuned to reflect the status in the reservoir in 2031. This model is used in this thesis to study the $CO_2$ EOR potential for the Brent group, and see how much extra oil that can be produced by using $CO_2$. Simulations on a field scale level have been performed, but also a pair of an injector and a producer has been studied for looking at injection strategies and compositional effects.

The best scenario in this study can increase the oil recovery by 5.4% of the original oil in place (OOIP), by injecting 22 million tons of $CO_2$ per year over a 25 year period. 3% of the OOIP can be produced by injecting 5 million tons of $CO_2$ per year, for the same time period. Unless the $CO_2$ can be brought to the oil field for 10 USD/bbl or less, the net present value (NVP) of the project is negative. For all the scenarios simulated, at least 72% of the $CO_2$ injected will be stored in the reservoir. A reinjection of the produced gas seems to have a positive effect on the oil production, and if it is reinjected the storage percentage of $CO_2$ can reach 100%. Continuous injection of $CO_2$ has given the best results of the injection strategies studied in this thesis.

# Sammendrag


$CO_2$ injeksjon er en metode for å øke utvinningen av olje, som kan forbedre både forskyvnings effektiviteten og hvor mye av reservoaret som blir kontaktet. Dette er på grunn av hvordan $CO_2$-en og oljen opptrer når de er ilag, noe som er veldig gunstig i forbindelse med å øke olje utvinningen. Denne metoden har blitt studert i denne masteroppgaven.

Statfjord er et av de største oljefunnene i Europa, og har produsert olje siden 1979. Hoved reservene er i Brent gruppen, and produksjonen fra dette reservoaret skal etter planen stoppe i 2025. En komposisjonell modell av Brent gruppen har blitt utviklet av Statoil, som er utviklet for å reflektere status for reservoaret i 2031. Denne modellen er blitt brukt i denne masteroppgaven til å studere potensialet $CO_2$ har for å øke utvinningen i Brent gruppen, og hvor mye ekstra olje som kan produseres. Simuleringer for hele reservoaret har blitt gjort, men for å studere injeksjons strategier og komposisjonelle effekter har et par av en injektor og en produsent også blitt studert.

Det beste scenariet i denne studien kan øke oljeutvinningen med 5,4% av den opprinnelige oljen i reservoaret (OOIP), ved å injisere 22 millioner tonn $CO_2$ per år over en 25 års periode. 3% av OOIP kan produseres ved å injisere 5 millioner tonn $CO_2$ per år, for samme tidsperiode. Med mindre $CO_2$ kan fraktes til oljefeltet for 10 USD / bbl eller mindre, er netto nåverdien (NVP) for prosjektet negativ. For alle de simulerte scenarioene lagres minst 72% av $CO_2$-en som er injisert i reservoaret. Reinjeksjon av den produserte gassen ser ut til å ha en positiv effekt på oljeproduksjonen, og hvis den blir reinjisert, kan lagringsprosenten av $CO_2$ nå 100%. Kontinuerlig injeksjon av $CO_2$ har gitt de beste resultatene av injeksjons strategiene som er studert i denne oppgaven.

# Contents

# List of Figures

# List of Tables

# Chapter 1

# Introduction

On the Norwegian continental shelf, oil fields are expected to have a total recovery of 46 % when they are shut down (NPD, 2011). A consequence of this is more than 50 % of the oil will be left behind in the reservoir. Worldwide it is even worse, where the average recovery is just 27 % (Søndenå et al., 2011). These numbers are showing a great potential for improving the recovery and new methods should be considered. Many techniques for enhanced oil recovery (EOR) exist, and these can be used to try to minimize the amounts of oil left behind in the reservoirs.

Global warming is a hot topic these days and many countries are trying to reduce their emissions of greenhouse gases (FN-Sambandet, 2017). A well-known greenhouse gas is $CO_2$ or carbon dioxide, and is often associated with global warming (Haraldsen and Pedersen, 2016). $CO_2$ can be very beneficial when taking about EOR, and have some qualities that can be taken advantage of in terms of improving recovery of oil fields. In this way, the $CO_2$ is injected into a reservoir in the underground, instead of contributing to the global warming. At the same time as it is being stored in the underground, it will also contribute to produce more of the oil remaining in the reservoir.

This thesis is going to study how $CO_2$ can be used as an EOR mechanism. The next chapter will explain what EOR means and give a brief introduction to different EOR methods. Further, some basic principles about injection processes will be presented, and different strategies regarding injection. A closer look at $CO_2$ and how this greenhouse gas behaves will be investigated.

The physical properties will be presented and how these are changing when $CO_2$ is applied to petroleum reservoir conditions.

The mechanisms happening during the interactions between the $CO_2$ and the oil will be studied, and how this is beneficial seen from an EOR point of view. Scenarios where $CO_2$ EOR is preferable will be reviewed through screen criteria, and also some challenges associated with $CO_2$ will be discussed.

Statfjord is a large oil field located in the North Sea and started production in 1979 (NPD, 2016). The production is from two main reservoirs, the Brent group and the Statfjord group. In 2025 the production is supposed to stop, and this thesis is going to investigate how $CO_2$ can be used to produce incremental oil from the Brent group. A compositional model of the Brent group has been developed by Statoil ASA, and is going to be used for studying the possibilities for enhancing the oil production by the use of $CO_2$. The $CO_2$ injection is supposed to start after the oil field is planned to be shut down, and different scenarios by the use of $CO_2$ have been simulated.

An introduction to the Statfjord field and especially the Brent group will be given, including the history of the field and status after production stop. Further, the different cases considered in this study will be presented, where the main scenarios are injection of pure $CO_2$, a combination of $CO_2$ and water, and pure water.

The potential for the whole Brent reservoir has been evaluated, in addition to a study of a pair of an injector and producer to study compositional effects and injection strategies. Results from these studies will be analyzed from a production point of view, but also storage and economic factors will be analyzed. For the study of a pair of an injector and a producer, compositional effects as change in viscosity, density and residual oil will be analyzed for several scenarios. At the end, practical aspects of the scenarios will be will be discussed, and the results will be analyzed further in this section. Also, factors not taken into account in this study will be discussed. Some conclusions summarizing the main points of the study will be given, where key numbers from the results are summarized. Recommendations for further work will be suggested, if someone is going to continue on this study in the future.

# Chapter 2

# Enhanced Oil Recovery

*This chapter has been modified from a specialization project written by the author (Bjørnå, 2016).*

## 2.1 Definition

Enhanced oil recovery (EOR) is oil recovery by injection of materials not normally present in the reservoir (Lake, 1989). By this definition, it means that all mechanisms which are not naturally in the reservoir, are characterized to be an EOR project. EOR is often called tertiary recovery, and will be briefly described in the following (Petrowiki.org, 2016a). It is normal to divide recovery of oil into three different phases; primary, secondary and tertiary recovery (Green and Willhite, 1998).

Primary recovery is when oil is produced using the natural drive mechanisms already existing in the oil reservoir. Examples of mechanisms like this are solution gas drive, water influx, gas cap drive and gravity drainage. Injection processes where the purpose is to maintain the reservoir pressure and sweep the reservoir are characterized as secondary recovery. Water and gas injection are examples of secondary recovery processes. Tertiary recovery is all techniques used as a recovery mechanism after secondary recovery, such as adding chemicals, thermal methods or the use of miscible gases. The mechanisms associated with tertiary recovery are often changing the rock or fluid properties from the present conditions. By the definition of EOR above, it means that EOR methods can be used in both the secondary and the tertiary phase, but EOR is normally used as a synonym for tertiary recovery in the petroleum industry (Green and Willhite, 1998).

Improved oil recovery (IOR) is another term that is frequently used in this context, but is a wider expression, which also includes EOR. IOR contains a wider range of activities regarding recovery of oil, and examples of IOR techniques can be reservoir characterization, improved reservoir management or infill drilling (Green and Willhite, 1998).

## 2.2 The need for EOR methods

When an oil field is shut down, a lot of oil still remains in the reservoir. According to the Norwegian Petroleum Directorate (NPD) expected recovery factor for oil fields on the Norwegian continental shelf is 46%. This means more than half of the oil may be left behind when the production stops and the oil fields are shut down (NPD, 2011). Worldwide the recovery factor is even lower, just 27 % (Søndenå et al., 2011). This is illustrating the potential for EOR methods, which can play an important role in the petroleum industry in the future to increase the total recovery of oil significantly. As a lot of oil fields on the Norwegian continental shelf are getting mature, the importance of EOR will be more and more important to maintain the production in the future. A lot of the remaining oil in the reservoir after using conventional recovery methods, is trapped in the pores, due to capillary forces and interfacial tension. This oil is said to be immobile and cannot be produced using seawater as injection fluid, but requires the use of chemicals or $CO_2$ in order to be produced (NPD, 2011). Figure 2.1 is illustrating how oil is trapped in the pores, after injected water has bypassed the area. Another issue is that water does not sweep all parts of the reservoir, for example the upper parts of the reservoir in the figure. The use of other injection fluids can sweep other parts of the reservoir where water cannot reach due to for example gravity differences.

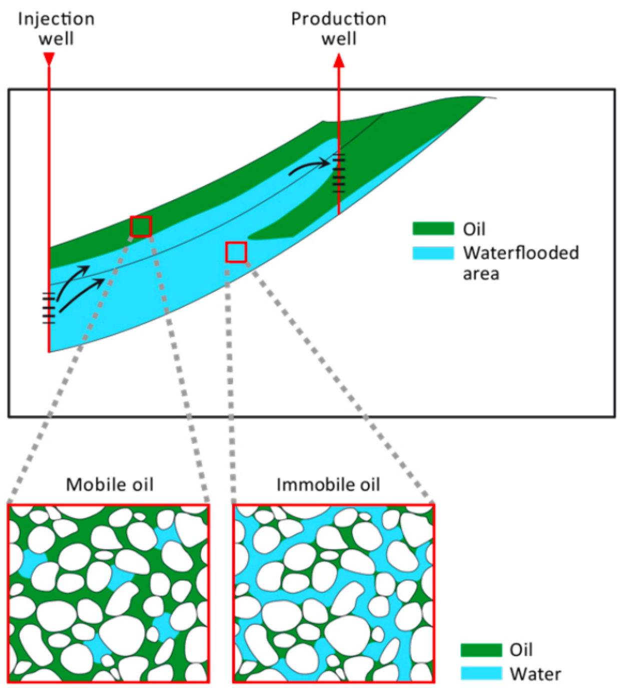


Figure 2.1: Water flooded oil reservoir (NPD, 2014).

## 2.3 Different EOR methods

EOR processes are classified into a different number of categories in the literature, but the three main categories are thermal, chemical and solvent/gas methods. Each of these categories can further be divided into more categories and some methods can fit into all of them. This thesis will in the following chapters have a deeper investigation into the solvent/gas methods, where $CO_2$ injection belongs.

**Thermal methods**

Thermal methods for EOR consist of several displacement mechanisms to recover oil, but the main point is to reduce the viscosity of the oil by adding heat (Lake, 1989). In this way the temperature of the crude oil will increase and a consequence of this is a reduction of the oil viscosity. A reduction of the oil viscosity will make the oil more mobile and it will flow easier in the porous media. Different processes within thermal methods are cyclic steam injection, steam flooding and steam-assisted gravity drainage (SAGD), a technique that has become more popular the recent years. Since thermal methods are mostly used for viscosity reduction, it is mostly used in heavy oil reservoirs where the oil is very viscous. This kind of oil reservoirs are often located in Canada, Former Soviet Union, US and Venezuela, and that is why thermal EOR is most frequently used here (Manrique et al., 2010).

#### Chemical methods

Chemical EOR methods are about injecting specific chemicals into the oil reservoir that will displace oil due to their phase behavior properties. A consequence of this is decreasing interfacial tension between the reservoir oil and the displacing liquid (Green and Willhite, 1998). Worldwide chemical methods have been negligible, except in China (Manrique et al., 2010). Examples of chemical methods are polymer flooding, surfactant flooding and alkali-surfactant-polymer. The chemicals are typically injected into the reservoir as a slug, followed by a drive fluid, normally water (Green and Willhite, 1998).

#### Solvent/gas methods

The main point of solvent methods is to inject gases that are miscible or partial miscible with the reservoir oil. A lot of the gases are not fully miscible with the reservoir fluid, so solvent is a more correct term to use, instead of miscible. Processes initiated by injecting the solvents can be extraction, dissolution, vaporization, condensation or other changes in phase behavior which involves the reservoir oil. The recovery mechanisms of solvent methods include viscosity reduction, oil swelling, solution gas drive, lowering capillary pressure and extraction. Examples of gases used in miscible or partially miscible flooding are solvents like $CH_4$, $N_2$, $CO_2$ and many additional potential candidates (Lake, 1989). The solvents can be injected continuously or in a water-alternating-gas (WAG) process, where slugs of solvent are injected, followed by slugs of water. This method is going to be described more detailed in later sections, by the use of $CO_2$. $CO_2$ used for EOR has not been implemented on the Norwegian continental shelf so far, but worldwide this has been implemented successfully for many years, especially in the US (Petrowiki.org, 2015b). The oil production from projects using $CO_2$ EOR in the US has increased a lot the last decades and is shown in Figure 2.2. If this trend continuous, the oil production from $CO_2$ EOR will continue to grow in the coming years (Kuuskraa et al., 2014).

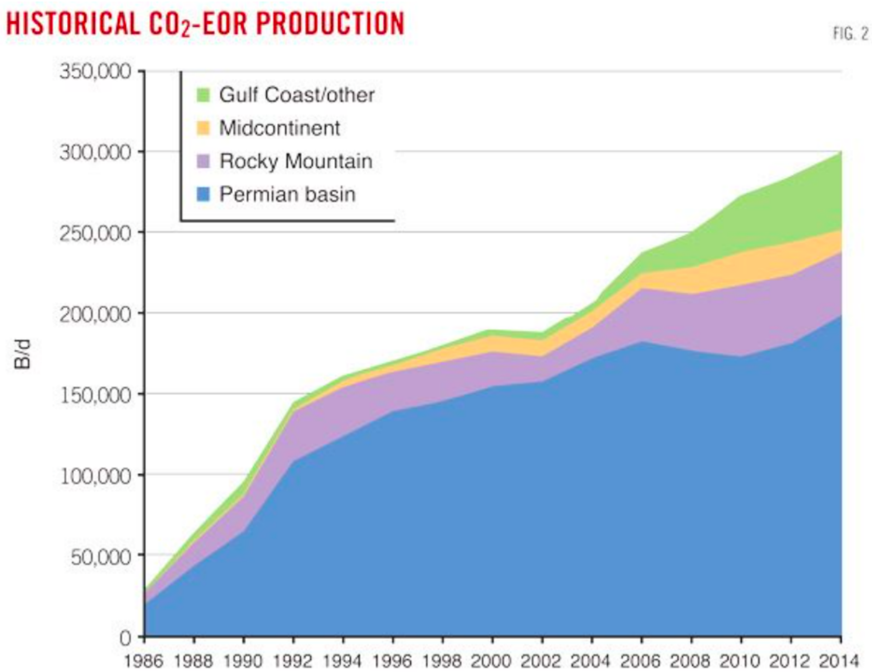


Figure 2.2: Oil production from $CO_2$ EOR projects in the US, in barrels per day (Kuuskraa et al., 2014).

# Chapter 3

# Concepts of injection

*This chapter has been modified from a specialization project written by the author (Bjørnå, 2016).*

## 3.1 General

The purpose of injecting a fluid into an oil reservoir to improve the recovery, is to displace as much of the reservoir oil as possible. To evaluate the performance of the injected fluid something called the recovery efficiency is used. This is a measure of how well the injection fluid performs, according to recover as much oil/gas as possible. The recovery efficiency ($E_R$) is a function of both the displacement efficiency ($E_D$) and the volumetric sweep efficiency ($E_V$) of the injected fluid or fluids. Both the displacement efficiency and the volumetric sweep efficiency are equally important for the magnitude of the total recovery efficiency. Eq. 3.1 shows how the recovery efficiency is the product of both. The displacement efficiency is often referred to as microscopic displacement and volumetric sweep efficiency as macroscopic displacement (Lake, 1989).

$$E_R = E_D E_V \tag{3.1}$$

## 3.2 Displacement Efficiency

The displacement efficiency is reflected in the magnitude of the residual oil left in the reservoir after it has been contacted by the displacing fluid (Green and Willhite, 1998). The displacement efficiency measures how well the injected fluid is removing the oil from the pores at a microscopic scale. Eq. 3.2 shows how the displacement efficiency is defined (Lake, 1989). There are a lot of factors influencing the displacement efficiency and many of the EOR methods are used to improve this. Capillary pressure, interfacial tension, rock wettability and relative permeabilities are important factors that can be changed to improve microscopic displacement, and later it will be discussed how $CO_2$ can play an important role in improving this efficiency. By mobilizing the oil, less oil will be left behind. After water flooding a lot of oil is left behind in the reservoir, but by implementing $CO_2$ flooding or other EOR methods, the displacement efficiency can be improved a lot (Green and Willhite, 1998). Figure 2.1 illustrated this very clearly, where water has bypassed a lot of oil.

$$E_D = \frac{\text{Amount of oil displaced}}{\text{Amount of oil contacted by displacing fluid}} \tag{3.2}$$

## 3.3 Volumetric Sweep Efficiency

The volumetric sweep efficiency ($E_V$) is defined in Eq. 3.3 (Lake, 1989). Based on this definition the volumetric sweep efficiency is a measure of how much of the reservoir oil that are being contacted by the injected fluid. Due to heterogeneities, viscous fingering or gravity effects, the injected fluid is not flowing as a constant shock front through the reservoir, and this will reduce the volumetric sweep efficiency, due to less of the reservoir is contacted.

$$E_V = \frac{\text{Volumes of oil contacted by displacing fluid}}{\text{Volumes of oil originally in place}} \tag{3.3}$$

It is normal to divide the macroscopic displacement further into areal ($E_A$) and vertical sweep efficiency ($E_I$) , and the total volumetric sweep efficiency is the product of these two, shown in

Eq. 3.4.

$$E_V = E_A E_I \tag{3.4}$$

The areal and vertical sweep efficiencies are given in Eq. 3.5 and Eq. 3.6.

$$E_A = \frac{\text{Area contacted by the displacing fluid}}{\text{Total area}} \tag{3.5}$$

$$E_I = \frac{\text{Cross-sectional area contacted by the displacing fluid}}{\text{Total cross-sectional area}} \tag{3.6}$$

Figure 3.1 shows the principles of the different efficiencies. Due to heterogeneities like variations in permeability in different reservoir layers, viscous fingering or gravity differences, the whole reservoir is not swept by the injected fluid.

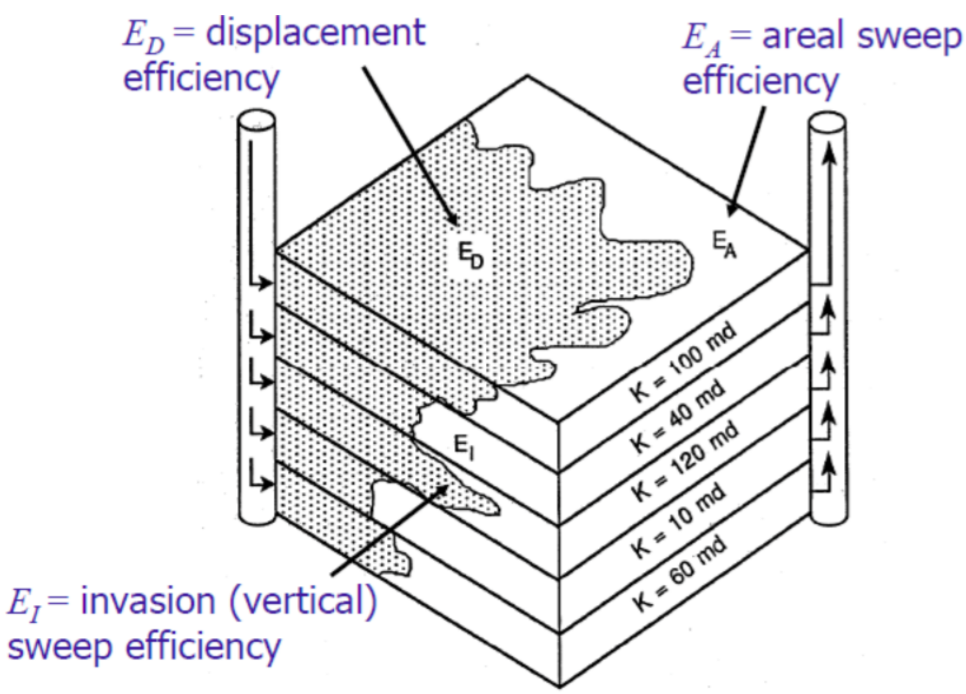


Figure 3.1: Concept of displacement efficiency and volumetric sweep efficiency (Devegowda, 2016).

## 3.4 Mobility ratio and viscous fingering

An important factor for the volumetric sweep efficiency is the mobility ratio between the injected fluid and the reservoir oil. The mobility ($\lambda$) of a fluid is defined in Eq. 3.7, as the ratio between the permeability ($k$) and the viscosity ($\mu$) (Green and Willhite, 1998).

$$\lambda = \frac{k}{\mu} \tag{3.7}$$

If the mobility of the injected fluid is much greater compared to the mobility of the reservoir oil, the injected fluid can bypass the oil and reduced the sweep efficiency. The mobility ratio (M) between of the displacing fluid and the displaced reservoir oil is given in Eq. 3.8. From a sweep efficiency point of view, a ratio lower than 1 is preferable.

$$M = \frac{\lambda_{\text{displacing fluid}}}{\lambda_{\text{displaced fluid}}} \tag{3.8}$$

If the mobility ratio is greater than 1, something called viscous fingering can take place. This is a phenomenon which is caused by the displacing fluid is flowing faster through the porous media compared to the displaced fluid. A consequence of this, is that the oil is bypassed. An illustration of viscous fingering is shown in Figure 3.2.

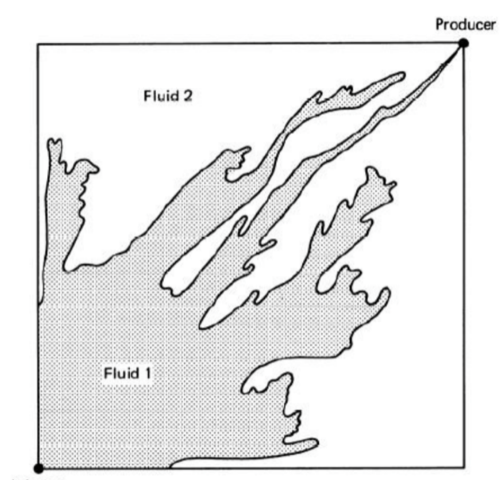


Figure 3.2: Viscous fingering, due to unfavorable mobility ratio (Habermann et al., 1960).

## 3.5 $CO_2$ injection strategies

There are several strategies for injecting $CO_2$ into the reservoir, and many factors need to be taken into consideration for which strategy to choose. The choice of design is to improve the recovery efficiency of the injection and depends on previous used recovery methods in the reservoir, in addition to which effect you want to have of the $CO_2$ flooding.

### 3.5.1 Continuous $CO_2$ Injection

With a continuous $CO_2$ injection strategy, $CO_2$ is injected continuously into the reservoir without any other fluids. Figure 3.3 shows this concept. The strategy is normally used in a gravity drainage reservoir or a reservoir which cannot be water flooded. Continuous $CO_2$ injection is often implemented directly after primary depletion. A lighter gas may also follow the $CO_2$ to maximize gravity segregation and minimize gravity tonguing or channeling, which is the same principle as viscous fingering (Jarrell et al., 2002).

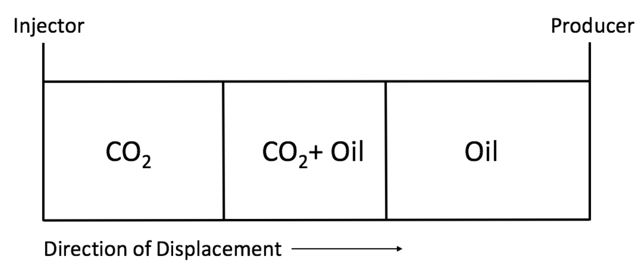


Figure 3.3: Continuous $CO_2$ injection.

### 3.5.2 Continuous $CO_2$ injection chased with water

Continuous $CO_2$ injection chased with water is a process where a continuous $CO_2$ slug is injected, follow by water as a chase fluid. In this method the water is displacing the miscible oil bank where $CO_2$ and the reservoir oil are mixed. This method is typically used in more homogenous reservoirs (Jarrell et al., 2002). The strategy is illustrated in Figure 3.4.

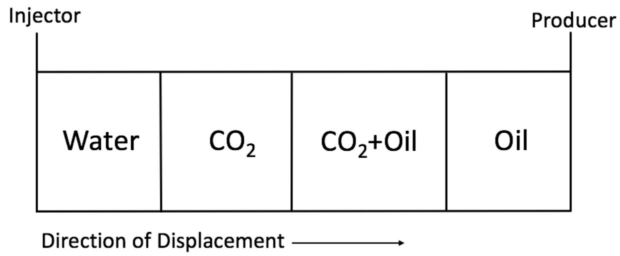


Figure 3.4: Continuous $CO_2$ injection chased with water.

### 3.5.3 Conventional alternating $CO_2$ and water, chased by water

In this method a $CO_2$ slug is injected first, followed by a water slug. This process goes on until the predetermined volumes of $CO_2$ are injected. A constant ratio between the volumes of $CO_2$ and water is used. This is known as a WAG (Water alternating gas) injection. After all the volumes of the $CO_2$ are injected, water is used as a chase fluid. This is typically used in heterogeneous reservoirs and can improve both the areal and vertical sweep efficiency (Jarrell et al., 2002). The strategy can improve the sweep efficiency by a more favorable mobility ratio, compared to continuous $CO_2$. The principle of a $CO_2$ WAG injection is illustrated in Figure 3.5.

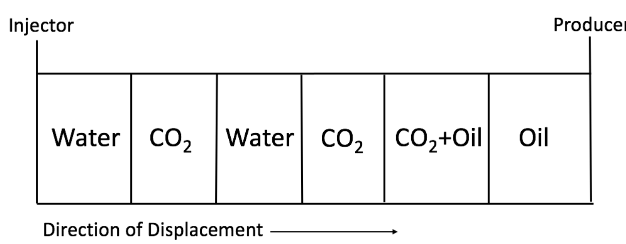


Figure 3.5: Water alternating gas injection (WAG).

### 3.5.4 Tapered alternating $CO_2$ and water

This method is the same as the conventional WAG method, except the WAG ratio is varied. The slugs of $CO_2$ can either be increased or decreased. By varying the slugs of $CO_2$ an utilization of the volumes of the reservoir oil that are contacted by the $CO_2$ can be improved, and a more efficient displacement can be achieved (Jarrell et al., 2002).

### 3.5.5 Alternating $CO_2$ and water chased with gas

Alternating $CO_2$ and water chased with gas, has the same principle as conventional alternating $CO_2$ and water, chased by water, except the chase fluid is a gas instead of water. The main point of using a gas as chase fluid is to maintain miscible displacement, but reducing the total $CO_2$ volumes required. Volumes of $CO_2$ required can often be a problem, and this can help solving that problem. The chase gas can also be injected alternating with water. In water sensitive lithologies, gas can be a good alternative as chase fluid (Jarrell et al., 2002).

### 3.5.6 Up-dip and down-dip injection

If the reservoir is tilted, you can inject either at the top, in the middle or at the bottom of the reservoir. Where to place the injector depends on what kind of fluid you are injecting, and which fluids that are present in the reservoir. If you have a gas cap at the top, it can be natural to inject up-dip if you are injecting gas. If water is going to be injected, it may be natural to inject down-dip under the oil-water-contact. The concepts of up-dip and down-dip are illustrated in Figure 3.6

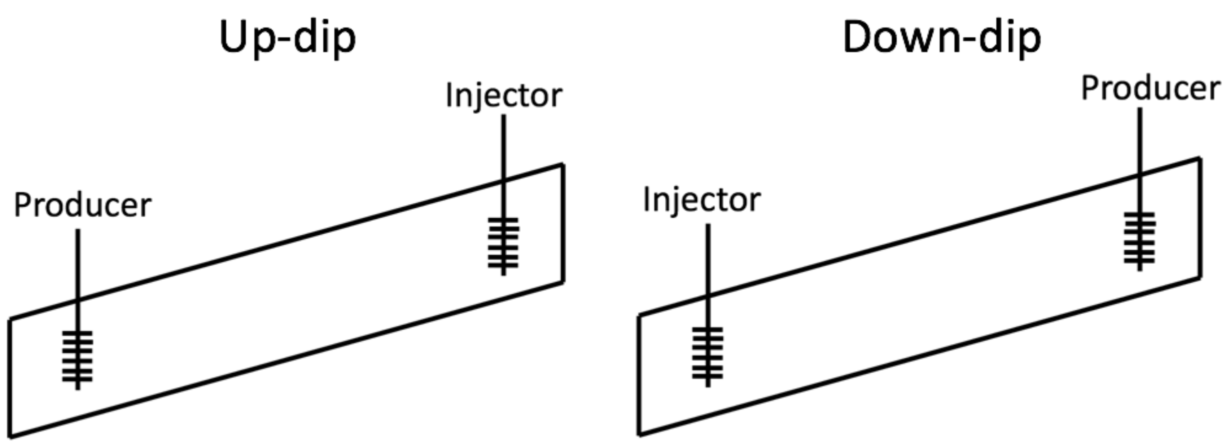


Figure 3.6: Up-dip and down-dip injection.

# Chapter 4

# Physical properties of $CO_2$

*This chapter has been modified from a specialization project written by the author (Bjørnå, 2016).*

Carbon dioxide or $CO_2$ is a well-known greenhouse gas. At standard conditions $CO_2$ is a stable, non-toxic and colorless gas (Whitson et al., 2000). At higher pressures and temperatures, like in petroleum applications, it can exist as a gas or a liquid-like supercritical fluid. It is about 1.5 times denser than air, with a molecular weight of 44,01 g/mol (Whitson et al., 2000). The critical temperature is 31 °C and the critical pressure is 75,3 atm (Haraldsen and Pedersen, 2016). How the physical properties of $CO_2$ varies with pressure and temperature, is the key to why it is suitable as an oil recovery mechanism, and will be described in the following sections.

## 4.1 Density

Figure 4.1 shows how the density of $CO_2$ is varying with temperature and pressure. The density is very sensitive for pressure changes at low pressures, compared to at high pressures. For a given pressure, the density decreases as the temperature gets higher. In general, it can be observed that the density increases when the pressure increases and the temperature decreases.

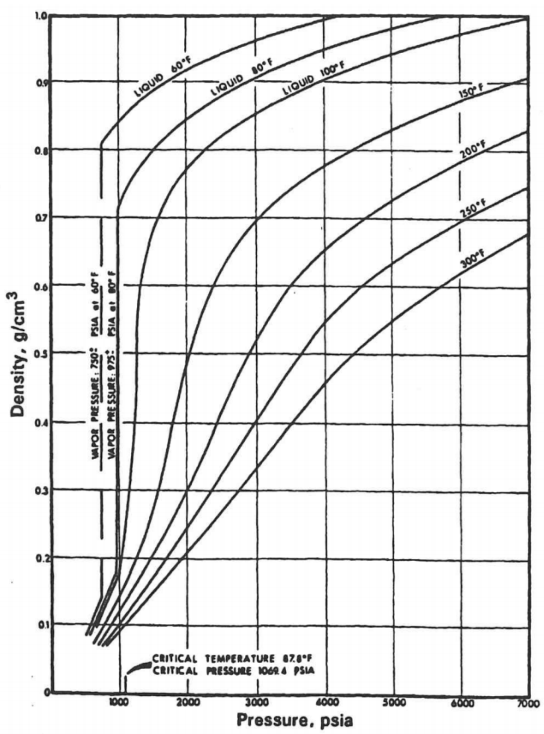


Figure 4.1: Density of $CO_2$ as a function of pressure and temperature (Whitson et al., 2000).

## 4.2 Viscosity

Figure 4.2 shows the relationship between the viscosity of $CO_2$, pressure and temperature. The higher the pressure gets, the more viscous the $CO_2$ gets. By lowering the temperature, the viscosity of $CO_2$ increases. It can be observed from Figure 4.2 that the viscosity of $CO_2$ is more sensitive to changes for low temperatures.

## 4.3 Formation volume factor

The formation volume factor (FVF) is the ratio between the volume of $CO_2$ at a given pressure and temperature, and the volume of $CO_2$ at standard conditions. The FVF compares the volume of $CO_2$ at surface, compared to how much volume it will occupy in an oil reservoir at a given pressure and temperature. In other words, it is reflecting the compressibility. Figure 4.3 shows how the FVF of $CO_2$ decreases with increasing pressure and decreasing temperature.

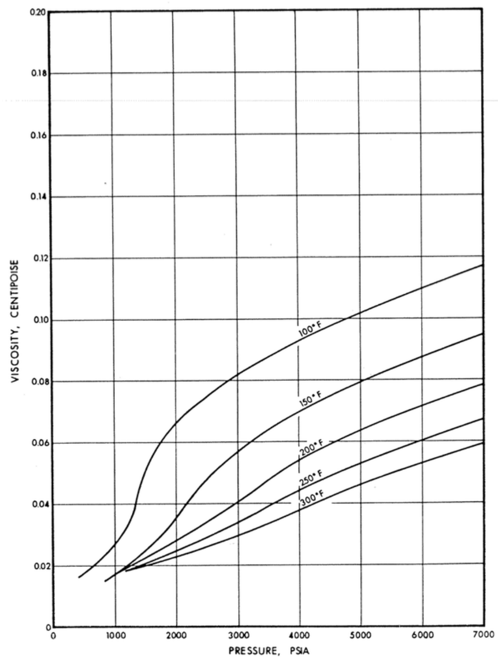


Figure 4.2: Viscosity of $CO_2$ as a function of pressure and temperature (Whitson et al., 2000).

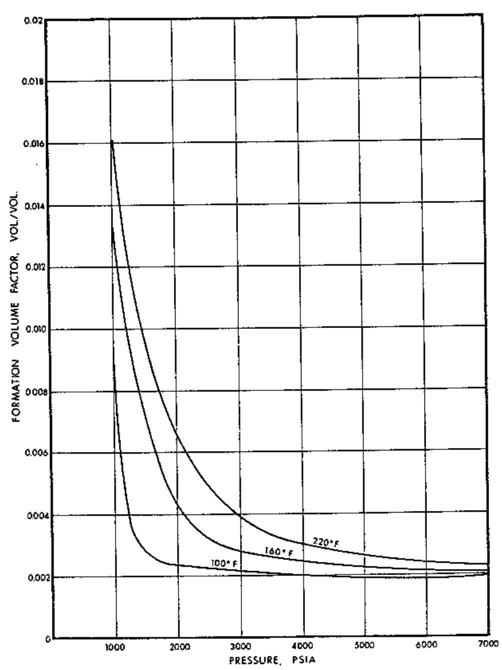


Figure 4.3: FVF of $CO_2$ as a function of pressure and temperature (Whitson et al., 2000).

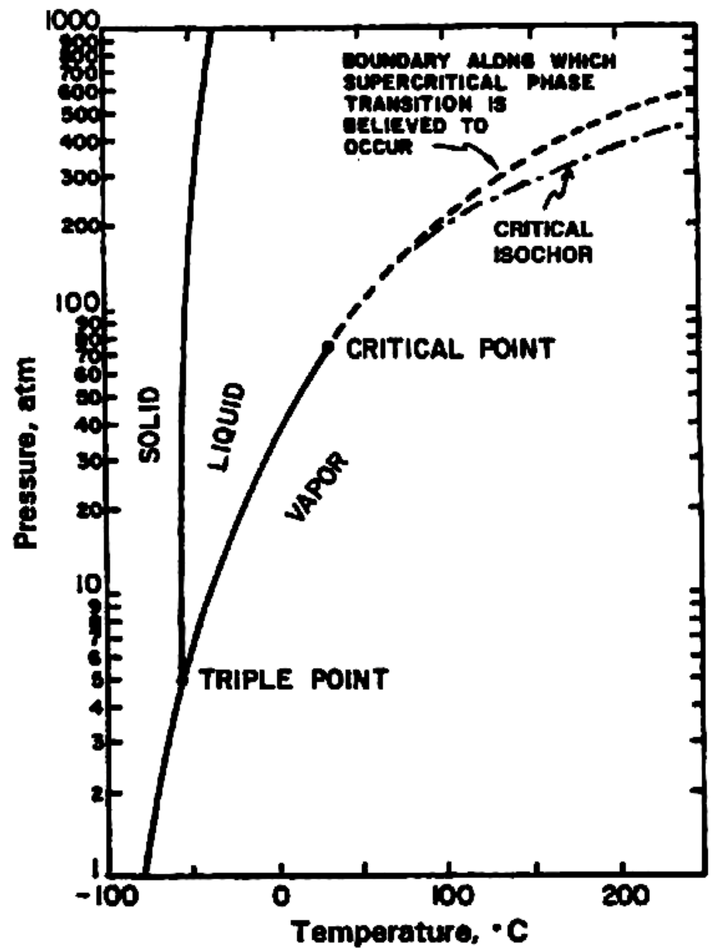


Figure 4.4: Phase diagram for $CO_2$ (Whitson et al., 2000).

## 4.4 Phase behavior

The phase behavior of $CO_2$ is an important aspect when it comes to $CO_2$ as an injection fluid into an oil reservoir, since this is deciding which fluid $CO_2$ will be at reservoir conditions. From Figure 4.4 it can be observed that $CO_2$ will be in solid form for low temperatures. At standard conditions where the pressure is 1 atm and the temperature is 15 $C^{\circ}$, $CO_2$ is a gas. Most oil reservoirs typically have a much higher pressure, and for very high pressures, $CO_2$ will be in liquid form, or supercritical phase. Supercritical state means you cannot measure if it is in liquid or gas phase, because no phase interface is visible (Petrowiki.org, 2015c). This phenomenon can be observed for very high pressures and high temperatures. The figure also shows that for low pressures, $CO_2$ will be a gas for all temperature over about -80 $C^{\circ}$.

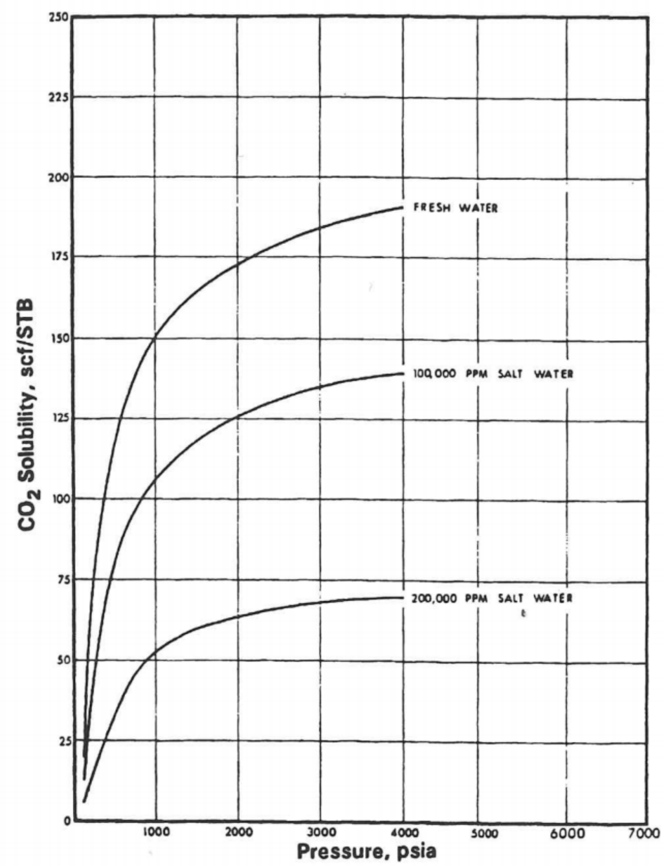


Figure 4.5: Solubility of $CO_2$ in water as a function of salinity and pressure (Whitson et al., 2000).

## 4.5 Solubility in water

When $CO_2$ is injected into a reservoir, it will sooner or later be in contact with water. Either with water already present in the reservoir or water injected after the $CO_2$ as a slug in a WAG process. Figure 4.5 shows how the solubility of $CO_2$ in water is dependent on the salinity and the pressure. Fresh water gives the best solubility and the solubility decreases as the salinity of the water increases. Down in a reservoir there can be one type of water, but the injected water can have another salinity. Dependent on what is available, the injection water can be both fresh and saline. If water is injected in a North Sea field, it will typically be sea water since it is easy available in the middle of the ocean. The solubility in water is important to account for, and not assume that all the injected $CO_2$ will mix with the oil.

# Chapter 5

# EOR using $CO_2$

*This chapter has been modified from a specialization project written by the author (Bjørnå, 2016).*

Using $CO_2$ as an injection fluid to enhance oil recovery can be done using two different types of flooding; immiscible or miscible flooding. Miscible flooding of $CO_2$ is the most effective of the two conditions, but immiscible flooding can be used when miscible flooding is not possible or water injection can be difficult due to high injection pressure or other reasons. The focus in the following will be on $CO_2$ miscible flooding, the ideal displacement mechanism for EOR, which has the biggest potential for enhancing oil production (Arshad et al., 2009).

## 5.1 Miscibility

Before understanding the interactions between $CO_2$ and oil, it is important to know what miscibility is, and how it is different from solubility. Solubility is the ability of a limited amount of one substance to mix with another substance to form a single homogeneous phase. Miscibility can be defined as the ability of two or more substances to form a single homogeneous phase when mixed in all proportions. In the case of petroleum reservoirs, miscibility can be defined as a physical condition between two or more fluids, that will allow them to mix in all portions and there does not exist an interface between the fluids (Holm et al., 1986). There are two ways of achieving miscibility, first-contact-miscibility (FCM) or multicontact miscibility (MCM).

## 5.2 First-contact miscibility

First contact miscibility (FCM) is when the injected fluid forms a single phase with the reservoir oil at first contact. Any amount of the injected fluid can be injected and it will exist as a single phase with the reservoir oil. This means that miscibility will be achieved from the first contact, independent of the amount injected. Typical fluids developing FCM with crude oil is low-molecular-weight hydrocarbons like propane or butane (Holm et al., 1986). On the other hand, these hydrocarbons can be sold, and a gas/solvent that is not so valuable should be considered, like $CO_2$. $CO_2$ and crude oil are not miscible at first contact (Jarrell et al., 2002).

## 5.3 Multicontact miscibility

Multicontact miscibility (MCM) is when the conditions of miscibility are generated in the reservoir through in-situ composition changes resulting from multiple-contacts and mass transfer between the reservoir oil and the injected fluid, as the injected fluid flows through the reservoir (Green and Willhite, 1998). The MCM consists of two mechanisms occurring, vaporization and condensing drive. First $CO_2$ condenses into the oil making it lighter and often driving methane out ahead of the "oil bank". After this, the lighter components of the oil vaporize into the $CO_2$ rich phase. This makes the $CO_2$ rich phase denser and more like the oil, and because of this more soluble in the oil. Mass transfer between the $CO_2$ and the oil continues until the two fluids are completely mixed and thereby miscible. When the $CO_2$ and the oil have achieved miscibility there is no interface between them and they are considered as indistinguishable in terms of fluid properties (Jarrell et al., 2002). The process of achieving miscible displacement through MCM is illustrated in Figure 5.1.

## 5.4 Development of miscibility

For development of miscibility between oil and $CO_2$ the right conditions for miscibility have to be fulfilled. The development of miscibility is a function of pressure, temperature and compo-

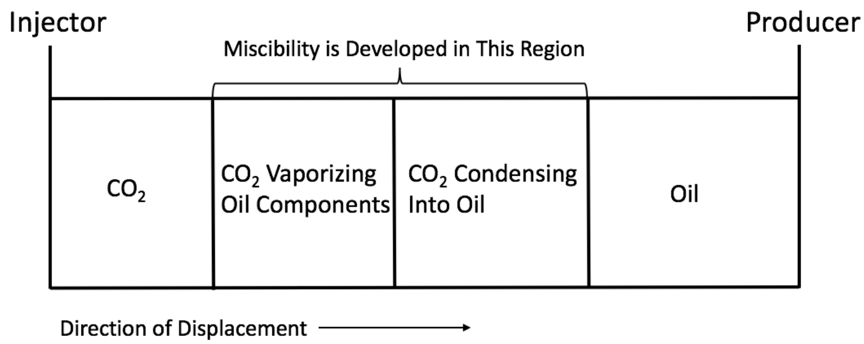


Figure 5.1: Development of multicontact miscibility (Jarrell et al., 2002).

sition of the oil (Yuan et al., 2005). For a given oil reservoir, the temperature and composition are slightly changing, so the miscibility is more or less a function of the pressure in that specific case, since this is what typically changes most during production. For a one component system like pure $CO_2$ in Figure 4.4 the phase behavior with the different phases is separated with straight lines. For a multi component system the phase behavior is different, where the different phases are separated with a phase envelop shown in Figure 5.2. Within the phase envelope there is a two phase region where you have both liquid and gas. Above the bubblepoint line only liquid exists, while below the dewpoint line only gas exists. To ensure miscibility, the temperature and pressure have to be at a point above the bubblepoint line. If the pressure is above the cricondenbar pressure, which is the highest pressure two phases can exist, miscibility will be achieved for all temperatures (Green and Willhite, 1998). Figure 5.2 illustrates the phase behavior of a general multicomponent system, and can be used to find at what conditions a mixture is miscible. The use of phase behavior diagrams is one way to measure the minimum miscibility pressure (MMP). MMP is the minimum pressure required for the $CO_2$ to develop miscibility with the reservoir oil for a given reservoir temperature and composition.

One other method to determine miscibility, is the use of ternary diagram. For a given pressure and temperature, a ternary diagram can be used to determine if a mixture of $CO_2$ and the reservoir oil will be miscible or not. The main point here is to see how the phase behavior changes when the composition of the mixture changes. If a mixture is on a straight line outside the two phase area, miscibility will be achieved for all mixtures of the reservoir oil and the injected $CO_2$. For the example shown in Figure 5.3 the line between the reservoir oil and the $CO_2$ lies outside

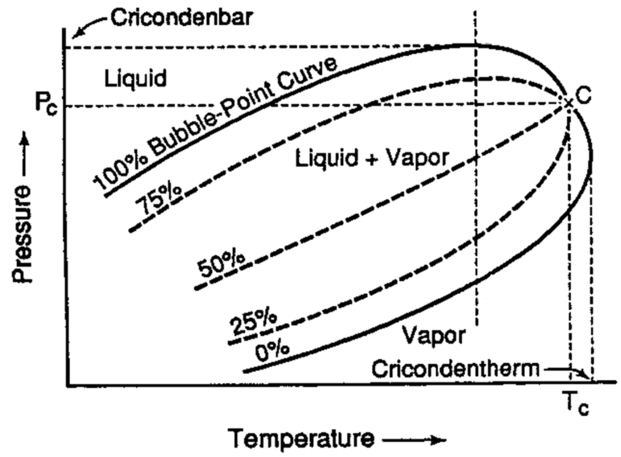


Figure 5.2: Phase envelope for a multi component system (Green and Willhite, 1998).

the two phase area, this means that $CO_2$ is miscible for the given pressure and temperature of this diagram. If methane had been used as the injection gas, miscibility would not have been achieved for all mixtures, since the line is crossing the two phase area for methane and the reservoir oil.

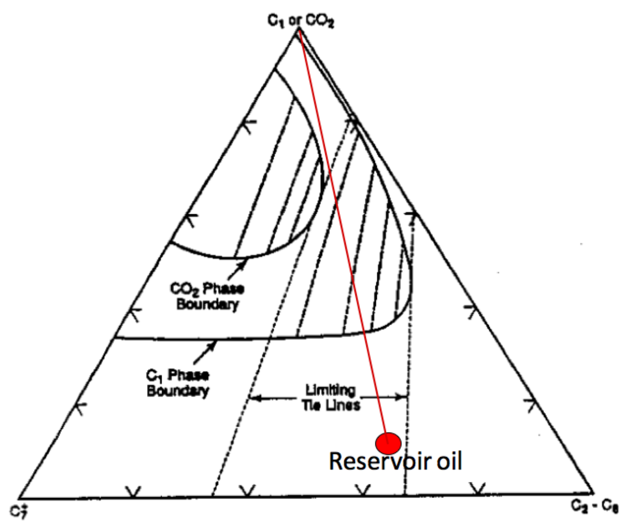


Figure 5.3: Ternary diagram which can be used to see if miscibility is achieved between $CO_2$ and oil (Green and Willhite, 1998).

## 5.5 How to determine MMP for $CO_2$

There are several ways to determine the MMP for a miscible process with $CO_2$ and they can be categorized within laboratory and correlations. Since laboratory tests in many cases can be expensive, correlations can provide a much cheaper option, but maybe not as certain. It exists a lot of correlations, but only some will be presented in the following sections.

### 5.5.1 Slim tube experiment

The slim tube method is a widely known and accepted method for determining the MMP in the petroleum industry (Arshad et al., 2009). The experiment consists of a small-diameter sand-packed tube and is initially fully saturated with oil. The oil in the tube is then displaced by $CO_2$ for several pressures. After injecting 1.2 HCPV (Hydrocarbon Pore Volume) of $CO_2$ the recovery of oil is measured/calculated. This procedure is repeated for several different pressures, and the recovery factor for the oil is plotted versus pressure as shown in Figure 5.4. The pressure where a break in the recovery curve can be observed, is the MMP (Petrowiki.org, 2015b).

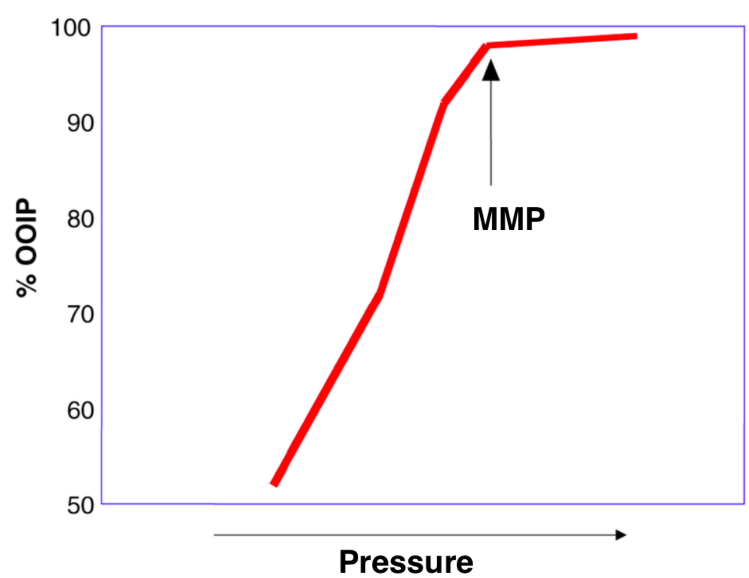


Figure 5.4: Oil Recovery vs. Pressure in a slim tube experiment (Petrowiki.org, 2015b).

### 5.5.2 Yellig-Metcalfe correlation

A correlation for finding MMP for pure $CO_2$ injection is the Yellig-Metcalfe correlation. This method does only take the reservoir temperature into account, not the composition of the reservoir fluid, and is not considered to be very accurate. The correlation for MMP is given in Eq. 5.1, where T is the reservoir temperature (Yuan et al., 2005).

$$MMP_{pure} = 1833.717 + 2.2518055T + 0.01800674T^2 - \frac{103949.93}{T} \tag{5.1}$$

### 5.5.3 Glaso correlation

Another correlation for the MMP is the Glaso correlation. In addition to the reservoir temperature, this correlation also takes the composition of the reservoir oil into account, by using the molar weights of the heaviest hydrocarbon components. The Glaso correlation is given in Eq. 5.2 and Eq.5.3 (Yuan et al., 2005).

$$MMP_{pure} = 810 - 3.404M_{C_{7+}} + 1.700 \cdot 10^{-9} M_{C_{7+}}^{3.730} e^{786.8M_{C_{7+}}^{-1.058}} T \tag{5.2}$$

for $C_{2-6}$> 18% and

$$MMP_{pure} = 2947.9 - 3.404M_{C_{7+}} + 1.700 \cdot 10^{-9} M_{C_{7+}}^{3.730} e^{786.8M_{C_{7+}}^{-1.058}} T - 121.2C_{2-6} \tag{5.3}$$

for $C_{2-6} < 18\%$.

where M is the molecular weight and T is the temperature.

### 5.5.4 Correlation by Huan et al for pure and impure $CO_2$

Yuan et al. (2005) found a new correlation for MMP based on analytical theory for MMP calculations using equation of state (EOS). This was done for both pure and impure $CO_2$ which can be an advantage if the produced $CO_2$ and associated gas are reinjected. The biggest advantage of this method is that it is valid for finding MMP for a wide range of temperatures and reservoir fluids (Yuan et al., 2005).

Correlations for MMP for pure $CO_2$ is given in Eq. 5.4.

$$MMP_{pure} = a_1 + a_2 M_{C_{7+}} + a_3 P_{C_{2-6}} + (a_4 + a_5 M_{C_{7+}} + a_6 \frac{P_{C_{2-6}}}{M_{C_{7+}}})T + (a_7 + a_8 M_{C_{7+}} + a_9 {M_{C_{7+}}}^2 + a_{10} P_{C_{2-6}})T^2 \quad (5.4)$$

and for impure $CO_2$ in and Eq. 5.5 .

$$\frac{MMP_{impure}}{MMP_{pure}} = 1 + m(P_{CO_2} - 100) \quad (5.5)$$

where

$$m = a_1 + a_2 M_{C_{7+}} + a_3 P_{C_{2-6}} + (a_4 + a_5 M_{C_{7+}} + a_6 \frac{P_{C_{2-6}}}{M_{C_{7+}}})T + (a_7 + a_8 M_{C_{7+}} + a_9 {M_{C_{7+}}}^2 + a_{10} P_{C_{2-6}})T^2 \quad (5.6)$$

.

M is molecular weight, P percentage and T the temperature. The coefficients $a_1 - a_{10}$ in Eq. 5.4 and Eq. 5.5 can be found in appendix.

## 5.6 Viscosity reduction

The $CO_2$ reduces the viscosity of the oil significantly in both miscible and immiscible flooding. By making the oil less viscous, it gets more mobile and thus oil recovery can be increased. The viscosity reduction is most effective for high-viscosity oils. The reduction in viscosity will also affect the mobility ratio between the fluids, like explain in the previous chapters. Figure 5.5 compares the viscosity of the mixture and the viscosity of the original oil (Whitson et al., 2000). A reduction in viscosity will improve the displacement efficiency.

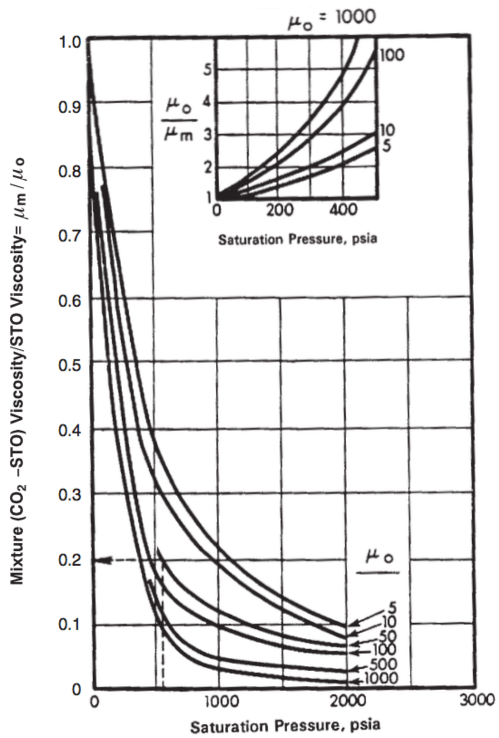


Figure 5.5: Viscosity reduction for oil mixed with $CO_2$ (Whitson et al., 2000)

## 5.7 Interfacial tension reduction

In miscible displacement of oil with $CO_2$ the two fluids form one single phase. One of the main arguments for using $CO_2$ flooding is to reduce the residual oil. If two fluids are completely miscible there will not be any interfacial tension between the fluids, by definition. Eq. 5.7 shows how the capillary pressure ($P_c$) is a function of the interfacial tension ($\sigma$) and the radius (r) of the pore. By reducing the interfacial tension, the capillary pressure will decrease and it is possible to recover more oil. For a completely miscible displacement of oil with $CO_2$, the capillary pressure will be zero due to no interfacial tension. According to this, all the oil can be recovered in theory. Immiscible flooding of $CO_2$ also reduces the interfacial tension since $CO_2$ is soluble in oil. The reduction in interfacial tension will improve the microscopic sweep efficiency.

$$P_c = \frac{2\sigma}{r} \tag{5.7}$$

## 5.8 Oil swelling

Oil swelling means an expansion in the oil volume when $CO_2$ is solved in the oil. The effect of swelling is dependent on temperature, pressure, composition and physical properties of the two fluids. By injecting $CO_2$, oil swelling can enhance the production by mobilizing residual oil trapped in inaccessible pore spaces (Schlumberger, 2016a). Oil swelling is a recovery mechanism that is important in both miscible and immiscible flooding of $CO_2$. The swelling increases with increasing solubility and decreasing oil molar volume (Whitson et al., 2000). An increase in relative permeability of oil will also be achieved by swelling (Arshad et al., 2009). The microscopic sweep efficiency will be improved by oil swelling and Figure 5.6 shows the oil swelling as a function of mole fraction of $CO_2$ in the mixture and oil molar volume.

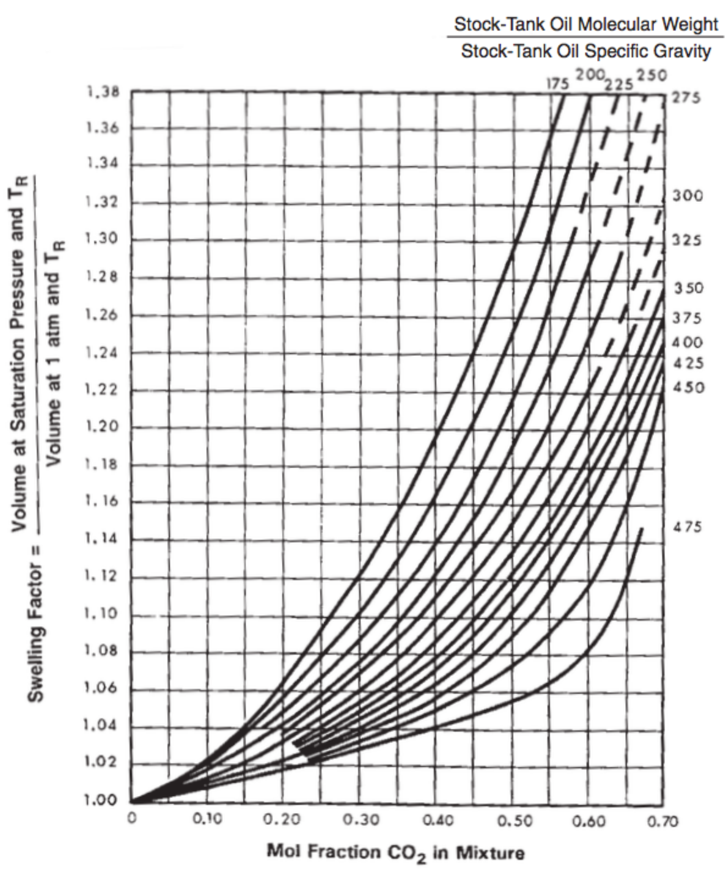


Figure 5.6: Correlation for swelling of dead stock tank oil when saturated with $CO_2$ (Whitson et al., 2000).

## 5.9 Gravity

Because of gravity differences between the injected fluid and reservoir oil, the vertical sweep efficiency can be poor if the injected fluid is much denser (like water) or much lighter (typical gas) compared to the reservoir oil. One advantage of $CO_2$ is that it in many cases has around the same density as oil at reservoir conditions. Figure 5.7 compares the density of some North Sea oil reservoirs and the density of the $CO_2$ at the reservoir conditions and Figure 5.8 shows the ideal case for $CO_2$ flooding. The density contrasts between the $CO_2$ and the reservoir oils, are in many cases smaller compared to the density contrasts between oil and water. The small contrasts in gravity, can improve the macroscopic sweep efficiency. Also, if $CO_2$ is lighter than the oil, it reaches areas in the reservoir where water cannot enter due to gravity differences, and can in this way sweep areas which are unswept.

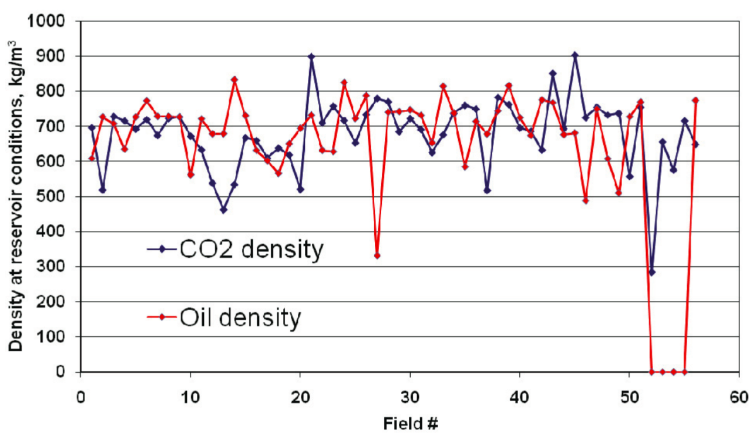


Figure 5.7: Density of $CO_2$ at reservoir conditions compared to 55 North Sea oil reservoirs (Akervoll et al., 2010).

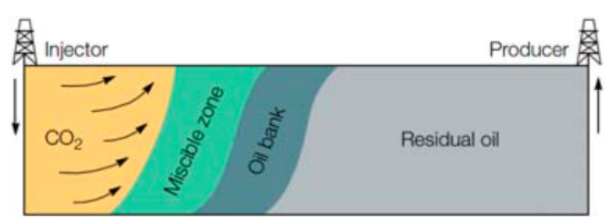


Figure 5.8: $CO_2$ flooding in an oil reservoirs where the density difference between the oil and $CO_2$ is small (Kossack, 2013).

## 5.10 Screening Criteria for $CO_2$ flooding

To screen which oil reservoirs that can be suitable for $CO_2$ flooding, some criteria for when $CO_2$ flooding can enhance the oil production need to be defined. Table 5.1 defines some criteria for when miscible $CO_2$ flooding can be a good option, given in Taber et al. (1997). Parameters ignored here, are considered as not critical for the success of the $CO_2$ flood.

Table 5.1: Screening criteria for miscible $CO_2$ flooding (Taber et al., 1997).

| | |
|---|---|
| Gravity | >22 API |
| Viscosity | <10 cp |
| Composition | High percent of $C_5$ to $C_{12}$ |
| Oil Saturation | > 20 %PV |
| Formation type | Sandstone or carbonate |
| Net Thickness | Wide range |
| Average permeability | Not critical if sufficient injection rates can be maintained |
| Pressure | >MMP |
| Temperature | Not critical |

### 5.10.1 Gravity

Oils with high API are normally more suitable for $CO_2$ miscible flooding, than oils with low gravity. To create a miscible bank in situ, where vaporization into a $CO_2$ rich phase or extraction of reservoir oil into a $CO_2$ rich liquid phase, requires a crude oil with high percentage of intermediate hydrocarbons from $C_5$ to $C_{12}$ (Arshad et al., 2009). The gravity of the reservoir oil also needs to be compared to the gravity of the $CO_2$ at reservoir conditions, since this can affect the macroscopic sweep efficiency. If the $CO_2$ is heavier than the oil, gravity will force the $CO_2$ to the bottom of the reservoir, and the upper layers will remain unswept. If the $CO_2$ is lighter than the oil the opposite will happen, due to the $CO_2$ will be forced to the top layers of the reservoir. These effects are very dependent on the vertical permeability of the reservoir (Jarrell et al., 2002).

### 5.10.2 Viscosity

The macroscopic sweep efficiency is directly related to the mobility ratio between the displacing fluid and the displaced fluid, like discussed in previous chapters. If the viscosity of the $CO_2$ is much lower than the reservoir oil, viscous fingering can occur, and the sweep efficiency will be reduced (Arshad et al., 2009). $CO_2$ has a relatively low viscosity, and a consequence of this is that heavy oils with high viscosity will experience viscous fingering and will not be very suitable for $CO_2$ flooding. A way to control the mobility ratio and increase the macroscopic sweep efficiency is to use the WAG injection strategy, where $CO_2$ and water are injected alternating.

### 5.10.3 Composition

One of the three factors affecting the miscibility between $CO_2$ and oil is the composition of the reservoir oil. For development of miscibility between the $CO_2$ and the oil the composition of the oil needs to be favorable, and is due to this one of the screening criteria.

### 5.10.4 Oil Saturation

If miscible $CO_2$ flooding is going to be initiated, sufficient amounts of oil should still remain in the reservoir after water injection or primary recovery. The volumes of oil left in the reservoir can directly be related to the financial parts of the project (Jarrell et al., 2002).

### 5.10.5 Permeability distribution and heterogeneity

An important parameter for the oil recovery in general is the permeability of the reservoir. Arshad et al. (2009) suggest that a minimum permeability of 5 md is necessary for a $CO_2$ miscible flooding project to succeed. The higher permeability, the better suited the reservoir is for miscible $CO_2$ flooding. A critical parameter when analyzing the possibility for success or not, is the heterogeneity of the reservoir. If the $CO_2$ is going to have a high sweep efficiency as much as possible of the reservoir oil should be contacted by the $CO_2$. Heterogeneities where the permeability is varying a lot some places will make the $CO_2$ flow in these channels, where a consequence is less of the reservoir will be contacted by the $CO_2$. Natural fingering can also occur due to heterogeneities. The more homogeneous the reservoir is, the greater the possibility for success is (Arshad et al., 2009). A high vertical permeability combined with the gravity contrasts between the reservoir oil and the $CO_2$ will also have a big impact on the performance of the $CO_2$.

### 5.10.6 Pressure

In order to achieve miscibility between the $CO_2$ and the reservoir oil, the reservoir pressure needs to be higher than the MMP. The MMP should always be considered as the lower limit for the reservoir pressure in a viable $CO_2$ flood (Jarrell et al., 2002). It is important to maintain the reservoir pressure above the MMP and this can be controlled by increasing the bottom hole injection pressure. A factor that can reduce the oil recovery due to loss of pressure maintenance is the loss of water injectivity in a $CO_2$ WAG process, due to hysteresis effects that will change the relative permeability of the water around the injection well. (Jarrell et al., 2002).

### 5.10.7 Wettability

The wettability of the reservoir should be known when planning $CO_2$ flooding. Strongly water-wet rocks can have a negative effect on the oil recovery during a $CO_2$ WAG process, and continuous $CO_2$ injection should be used instead of WAG. If the water moves ahead of the $CO_2$ the water can shield the oil in water-wet rocks and causing $CO_2$ to bypass the oil. Water blocking of $CO_2$ has not been reported to be a problem in mixed wet formations or oil-wet formations (Jarrell et al., 2002).

## 5.11 Challenges with $CO_2$ projects

Until now, only the beneficial parts of the $CO_2$ for enhancing oil production have been discussed. Even if oil recovery can be enhanced a lot, other challenges associated with $CO_2$ need to be taken into account. Some of the challenges with $CO_2$ will be briefly discussed in the following.

### 5.11.1 Corrosion

When designing a $CO_2$ flood, corrosion must be taken into account. When $CO_2$ and water are mixed, a carbonic acid is created, which is corrosive. The acid can cause corrosion on a lot of the production facilities topside and also in the well. This has to be evaluated when $CO_2$ is being considered for EOR. Corrosion on equipment downhole and on the surface, will increase the accident risk, and should therefore be avoided. One option to avoid corrosion is to use stainless steel, but it would only be necessary for short sections downstream and very little on the surface (Gao et al., 2010).

### 5.11.2 Scale

A consequence of $CO_2$ injection, is the high level of $CO_2$ present in the produced gas, oil and water. According to Schlumberger´s glossary, scale can be defined as; "A mineral salt deposit that may occur on wellbore tubulars. In severe conditions scale can create significant restrictions or even plugs in the production tubing", (Schlumberger, 2016b). The high $CO_2$ content can have a major impact on the calcite scaling situation in wells and pipes. The high solubility of $CO_2$ will make it dissolve in both the injected water and formation water, which can create hydrogen carbonate. The creation of this acid can dissolve calcium from limestone reservoirs, which increases the calcium concentration in the produced water. As the produced water flows to the wellhead, the pressure decreases, which will increase the calcite scaling tendency. Due to evaporation of the $CO_2$ at the surface, the pH increases in the produced water which again will increase the possibility for calcite scaling (Gao et al., 2010).

### 5.11.3 Asphaltene deposition

When $CO_2$ mix with the reservoir oil, the fluid behavior and equilibrium conditions will be changed which favor precipitation of organic solids like asphaltenes. The formation of asphaltenes can in some cases change the wettability of the reservoir rock, and can have consequences for the flood performance in the reservoir. The deposition of asphaltene can also cause formation damage, something that will reduce the flow capacity. Another consequence can be wellbore plugging. The problems associated with asphaltene deposition can cause expensive treatments and clean up procedures (Gao et al., 2010).

## 5.12 Field Example: SACROC Unit

The SACROC unit is located west in Texas and is a part of the Permian Basin where a lot of the $CO_2$ EOR projects in the United States are located (Kuuskraa et al., 2014). The US Department of Energy conducted a series of studies in 2004, and concluded that $CO_2$ EOR had the potential to become one of the most efficient methods for additional oil production in the United States (Brnak et al., 2006). A long time before this study was conducted, $CO_2$ EOR was attempted successfully in the SACROC unit, already in 1972. According to Brnak et al. (2006) it was the 7th largest oil field onshore in the US in 2006 and had 2.6 billion barrels of original oil in place (OOIP).

The field was discovered in 1948 and produced with primary depletion until 1954 when water flooding was initiated to improve the oil recovery (Brnak et al., 2006). After water flooding was completed, a $CO_2$ four-pattern flooding pilot project was initiated with the same wells and injection patterns. After starting the $CO_2$ injection, there was a peak in oil production rate which can be observed in Figure 5.9. The enhanced recovery due to the $CO_2$ injection was 9% of OOIP, which demonstrate that $CO_2$ EOR can improve the recovery of the reservoir oil after water flooding (Petrowiki.org, 2015b).

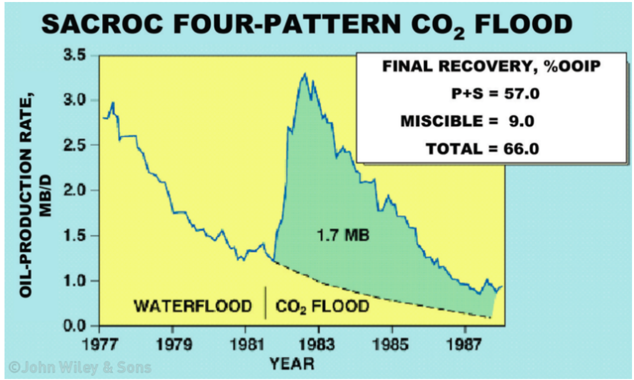


Figure 5.9: Oil production after implementing $CO_2$ flooding (Petrowiki.org, 2015b).

The project was simulated with a four-component compositional simulator, where Todd-Longstaff mixing model was used. The phase behavior was predicted with the use of pseudoternary diagram. Figure 5.10 shows the comparison of the simulated results and the actual oil production. There is an acceptable agreement between the simulated production and the actual production. The figure is also showing the well patterns, where the injectors and producers are placed in a four pattern system. This project shows the potential for $CO_2$ EOR, and that it is possible to predict the behavior of the miscible flooding with an acceptable precision using existing theory (Petrowiki.org, 2015b).

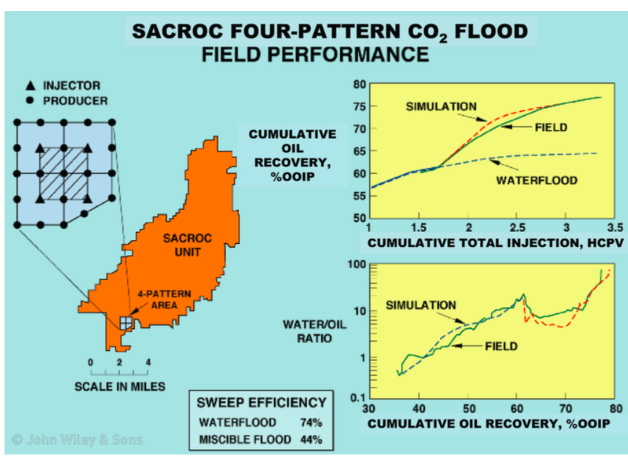


Figure 5.10: Comparison between simulated production and actual production for the SACROC pilot project (Petrowiki.org, 2015b).

## 5.13 Compositional Simulation

When trying to make realistic simulations with $CO_2$ in miscible flooding, the best way to predict the behavior is by the use of a compositional reservoir simulator (Petrowiki.org, 2015a). A compositional simulator describes the hydrocarbons in a different way compared to a traditional black oil simulator. In a black oil model, the hydrocarbons are only divided into two components, gas and oil. In a compositional simulator the hydrocarbons can be described as so many components as preferred (Kleppe, 2017). Because of more components in a compositional simulator, it is much more time consuming.

The compositional simulator computes the phase equilibrium of the reservoir oil and the injected solvent phases. When solvent and oil are mixed, the solvent and oil phase densities are calculated as well as new viscosities and interfacial tension. The compositions and densities at equilibrium are calculated using equation of state (EOS). If the EOS is tuned well, the phase behavior becomes very realistic. One big advantage compared to black oil simulators, is that it is no need for approximations when predicting the effects of pressure change and injection-solvent composition in the displacement process. In a black oil model you need to approximate the mixing behavior between solvent and the oil, by the use of for example the Todd-Longstaff mixing rule (Todd et al., 1972). The only approximation in a compositional model is the EOS itself. Even if the pressure is far below the MMP of the injected gas, close to the MMP or far above the MMP, the compositional simulator is computing realistic behavior (Petrowiki.org, 2015a).

In a compositional simulator, there is no need for a user-defined input for the residual oil saturation, since it will naturally calculate the amount of residual oil left after interactions between the phases. This will give a much more realistic picture of the situation, and the residual saturations will be distributed as a varying saturation, instead of as a constant given in the input. The effects of interfacial tension are also taken into account in a compositional simulator. This will affect the solvent/oil relative permeabilities and also give a change in capillary pressure (Petrowiki.org, 2015a). All these effects are interesting to take into account when trying to predict the behavior of $CO_2$ in a realistic way, which is why a compositional simulator should be used when simulating both miscible and immiscible $CO_2$ flooding.

# Chapter 6

# Description of the Statfjord field and Brent group

The Statfjord field is located in the North Sea on the border between the Norwegian and the UK sector, and was discovered back in 1973 (Crogh et al., 2002). Production start for the field was in 1979 (NPD, 2016). It is one of the largest oil discoveries in Europe to this date, with an original oil in place estimated to approximately 1 billion $Sm^3$. Expected oil recovery factor for the field is 68 % according to Boge et al. (2005), which is far above the expected recovery for oil fields on the Norwegian continental shelf (NPD, 2011). The field consists of three platforms; Statfjord A, B and C (Crogh et al., 2002). An overview of the field with platforms, installations and tie-ins is shown in Figure 6.1.

The oil field is 24 km long and averages 4 km in width, which means it covers a large area. The reservoirs are located in a large tilted fault block, which are dipping 7 degrees in the west direction, bounded on the east flank by a major fault system (Crogh et al., 2002). Figure 6.2 is illustrating how the reservoir is dipping, and shows the height differences within the reservoir. The main reservoirs where most of the recoverable reserves are the Brent group and the Statfjord group. About 80 % of the original oil in place was in the Brent group (Crogh et al., 2002). Both of the two reservoirs have extremely good reservoir characteristics (Haugen et al., 1988). The main focus in the following will be on the Brent reservoir, since the $CO_2$ EOR potential in this reservoir

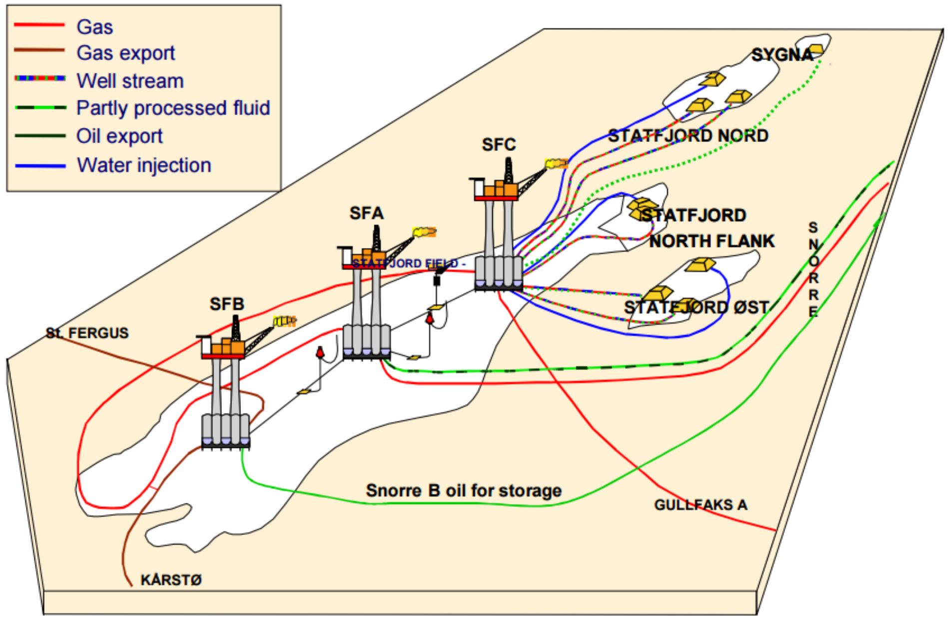


Figure 6.1: Overview of the Statfjord field installations (Crogh et al., 2002).

is going to be investigated in the rest of this thesis.

The Brent group consists of five formations, but can be divided into two main reservoirs for reservoir management purposes, Upper and Lower Brent. The thickness for the Brent group is 155 m, and consists of the following formations; Tarbert, Ness, Etive, Rannoch and Broom formation. The distribution of the formations and some reservoir properties are illustrated in Figure 6.3. The permeability within each of the formations is generally good, but there is a restricted communication between the formations. A shale layer in the Ness formation, works as a pressure barrier separating the Upper and Lower Brent reservoirs. In the north parts of the Brent group the shale layer is less defined. The east flank is very complex and highly faulted, but the pressure communication here is in general good. On the other hand, the reservoir properties are not so good in this area as the rest of the field. For example the permeability on the east flank is in general much lower, the same for the north part of the Brent reservoir, see Figure 6.5. Some reservoir and fluid properties for the Brent group are shown in Table 6.1.

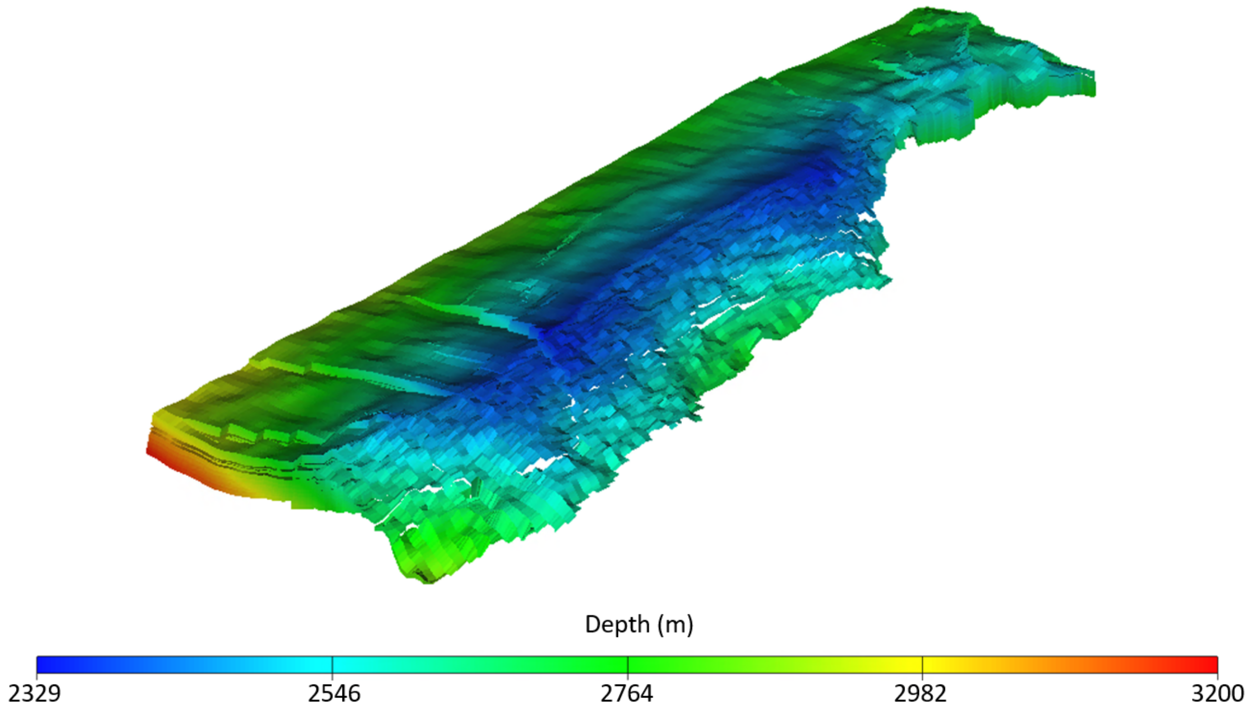


Figure 6.2: The reservoir geometry of the Brent reservoir showing depths to the different grid-blocks.

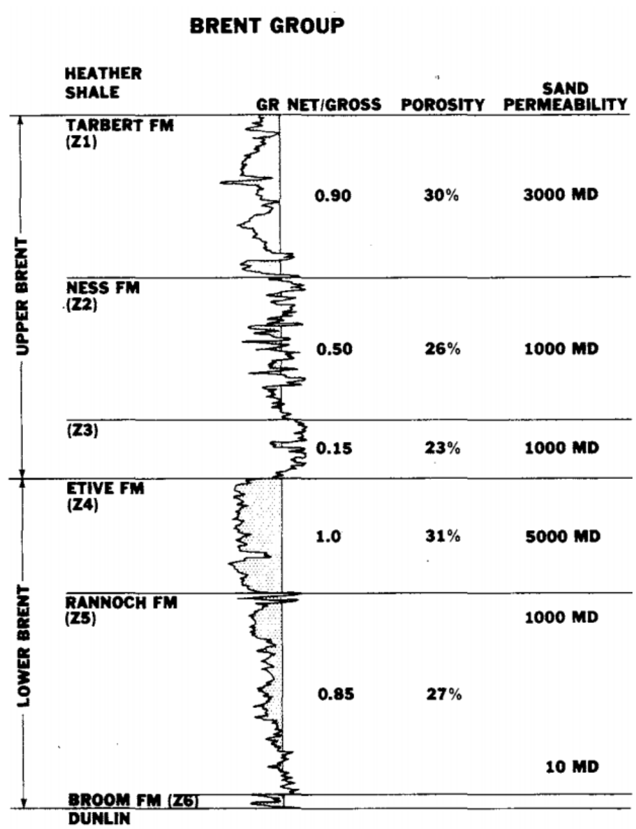


Figure 6.3: Overview formations in Brent group and rock properties (Haugen et al., 1988).

Table 6.1: Initial reservoir and fluid properties Brent group (Haugen et al., 1988).

| | |
|---|---|
| Depth of crest of structure | 2360 m |
| Initial reservoir pressure | 383 bar |
| Initial temperature | 89 °C |
| Initial oil FVF | 1.58 |
| Oil gravity | 41 °API |
| Initial reservoir oil viscosity | 0.34 cp |
| HCPV | $40 \times 10^9$ ft$^3$ |
| OOIP | $4500 \times 10^6$ STB |

## 6.1 Drainage strategies used in the Brent group

When the field opened in 1979 the drainage strategy for the Brent group, was to separate the production from the Upper and Lower Brent. Water was injected down-dip below the oil-water-contact, to maintain the reservoir pressure and sweep the reservoir oil. A steady rise of the oil-water-contact was observed, together with a good displacement efficiency. In 1996, down-dip WAG injection was implemented in order to supplement the water injection and displace remaining oil by improving the sweep efficiency (Crogh et al., 2002). From 2007 a new drainage strategy was implemented, where the objective was to go from pressure maintenance to depressurization. The reason for this was a limiting believe in increasing oil recovery, and that it will add revenue from gas export. By depressurizing the reservoir, gas was released from the remaining oil, and the North Sea oil giant was turned into a gas field (Boge et al., 2005).

## 6.2 $CO_2$ EOR model Brent group

To investigate the movement of $CO_2$ a compositional model of the Brent group has been developed by Statoil. The model has primarily been developed for the use of research on $CO_2$ storage in the reservoir, but can also be used for the study of $CO_2$ EOR. The model has been converted from the original black oil model used for the Brent group into a compositional model consisting of the following 5 pseudocomponents:

- $CO_2$
- $N_2 + C_1 + C_2$

- $C_3$-$C_6$
- $C_7$-$C_{19}$
- $C_{20+}$

The purpose of using this compositional model, is to get as realistic simulation results as possible, which was explained in previous sections (Petrowiki.org, 2015a). The model is tuned to reflect the status of the Brent group in 2031, after production stop in 2025 for the Statfjord license (NPD, 2017b). After the production stop, the field is being evaluated for a future $CO_2$ storage reservoir. With the expected recovery factor for the oil of 68 % for the whole Statfjord field, a lot of oil is still left behind after production stop. In the following, an investigation of how much extra oil you can produce by using $CO_2$ is going to be evaluated. Figure 6.4 is showing remaining oil in 2031 in the reservoir, after production stop in 2025.

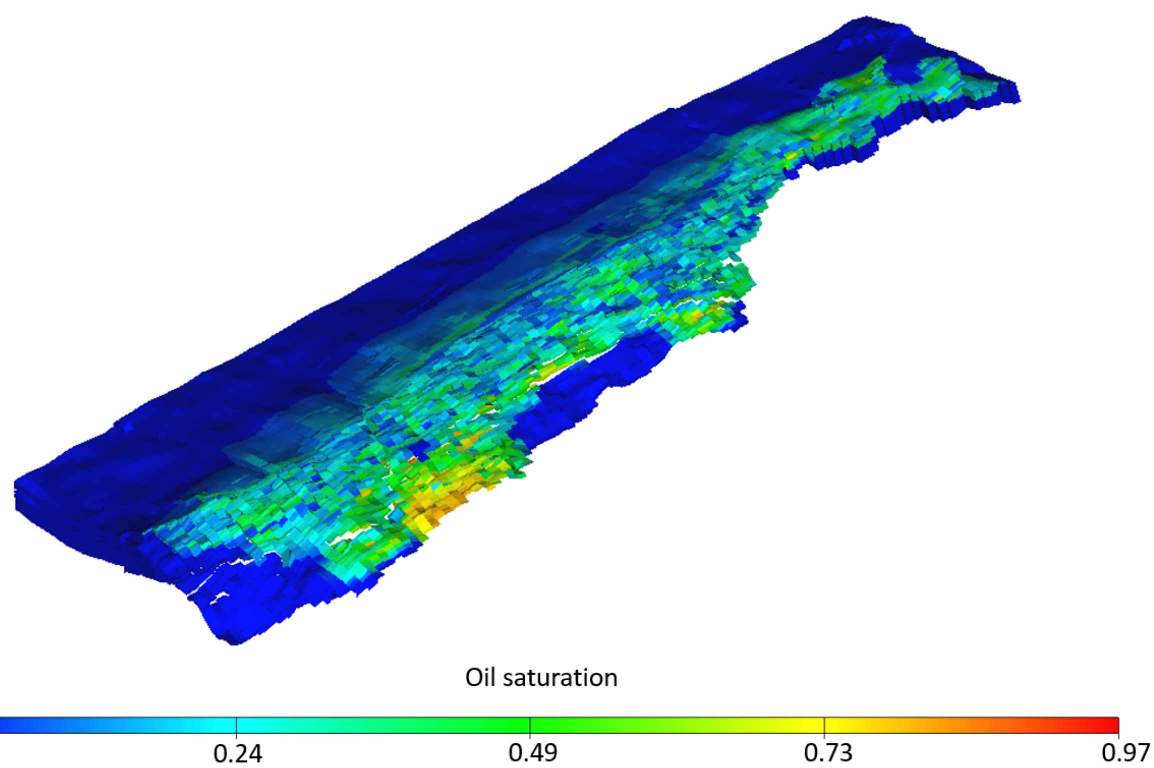


Figure 6.4: Oil saturation in the Brent reservoir in year 2031, after production stop in 2025.

The model consists of 34 layers, and a total of around 430000 gridblocks. Hundred thousands of gridblocks, in addition to compositional simulation, makes the model really time consuming to run. Compared to a black oil simulator with gas, oil, and water, the compositional model has more components, and therefore more time consuming.

## 6.3 Permeability distribution Brent group

The permeability in the Brent group is in general very good, with permeabilities in the Darcy scale. The permeability distribution for the whole reservoir is shown in Figure 6.5, seen from the top. There are a lot of heterogeneities in the reservoir, and the permeability on the east flank and in the north parts of the reservoir is generally not as good as the rest. The heterogeneities are not just within in a layer, but also between the different 34 layers in the model. Figure 6.6 shows the huge variations in permeability between the layers for a cross section in the middle of the reservoir. This can cause fingering of the fluids injected, and challenging seen from a sweep efficiency point of view.

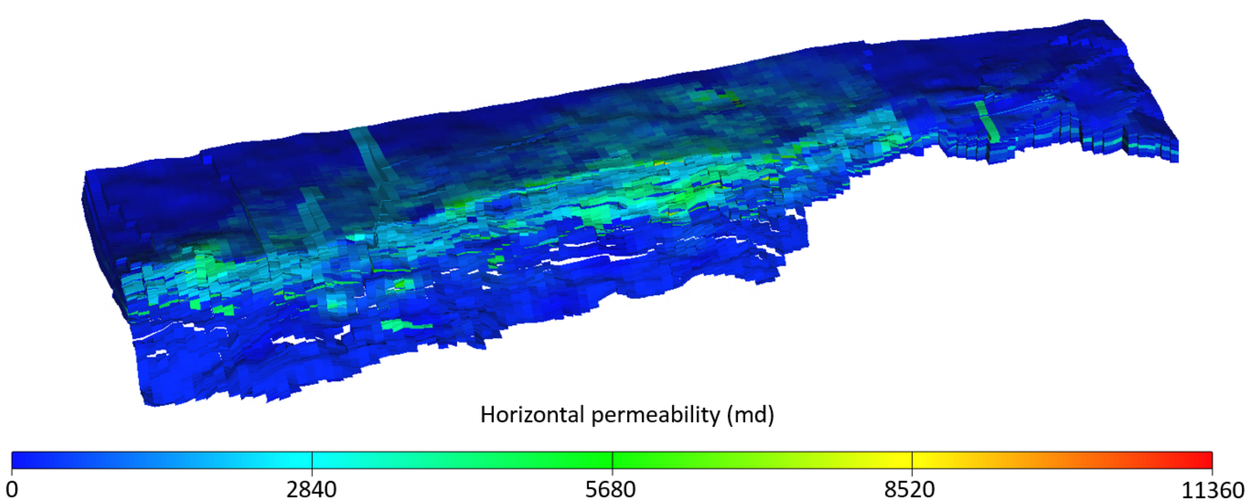


Figure 6.5: Permeability distribution for the whole reservoir, seen from the top.

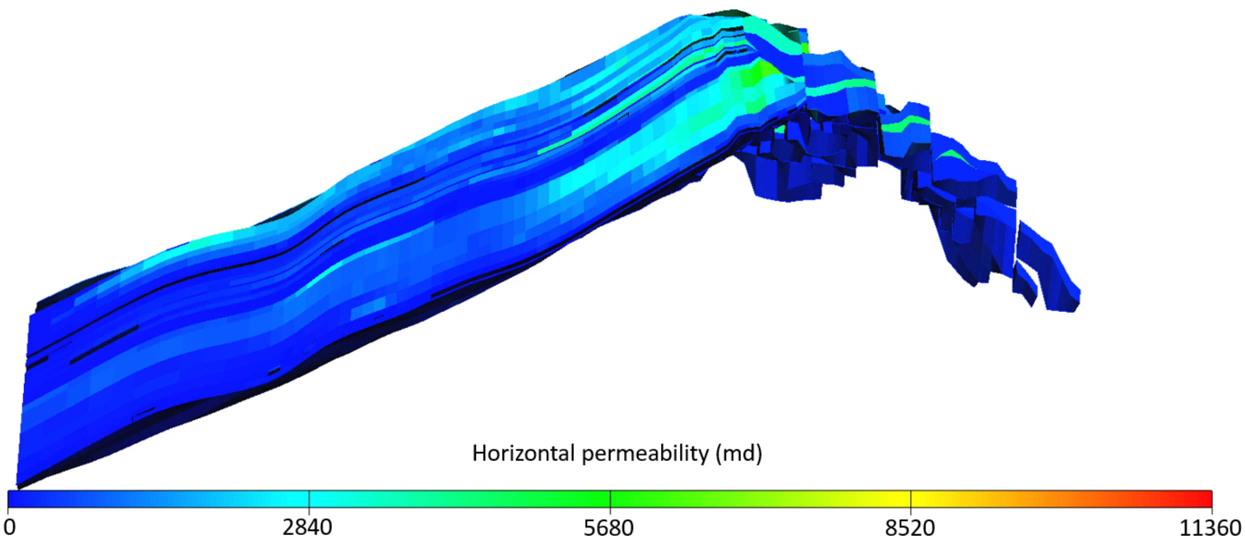


Figure 6.6: Permeability distribution cross section of the Brent reservoir.

## 6.4 Status after production stop

Production stop is in 2025, and the oil saturation in the reservoir in year 2031 is shown in Figure 6.4. A cross section in the middle of the reservoir is illustrated in Figure 6.7, and shows that a lot of oil is still left in the reservoir. Due to the depressurization strategy in the late life of the oil field, the reservoir pressure is very low, with an average pressure of around 70 bar for the whole reservoir. The total amount of oil remaining in the reservoir after production stop, is about 250 $MSm^3$. This means a lot of oil is potentially left behind, if not new techniques or methods are being adopted. For comparison, a recently developed oil field with an own platform on the Norwegian continental shelf called Ivar Aasen started production in 2016. The recoverable oil volumes for this oilfield are estimated to be 23 $MSm^3$ (NPD, 2017a). More than 10 times this volume, is still remaining in the Brent reservoir, which means there is a huge potential. Most of the wells are planned to be plugged at this time. The Statfjord A platform is planned to produce until 2022 and the B and C platform until 2025 (NPD, 2017b).

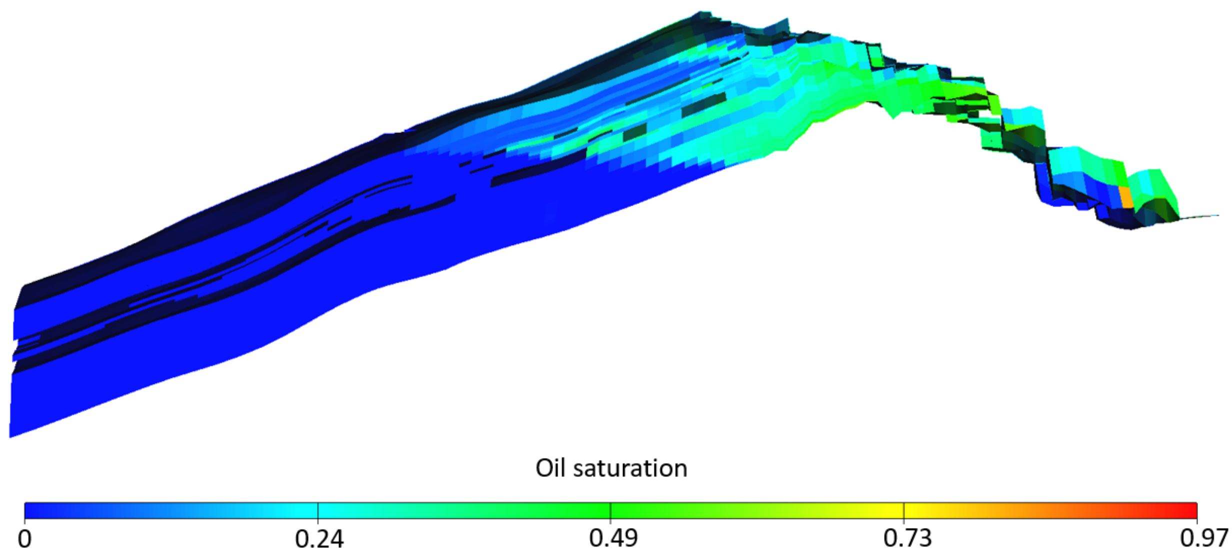


Figure 6.7: Oil saturation in the middle of the Brent group, cross section view.

## 6.5 Brent group compared to screening criteria

Comparing the screening criteria for $CO_2$ flooding presented in previous sections, to the reservoir properties in Table 6.1, the gravity and viscosity of the Brent oil are favorable for $CO_2$ flooding. The composition of the oil in the model, has a high percentage of the two components containing $C_3$-$C_6$ and $C_7$-$C_{19}$. The screening criteria suggest a high percentage of $C_5$-$C_{12}$, and is more or less satisfied, because of the high content of the components mentioned. The remaining oil saturation is suggested be more than 20%, and the Figures 6.4 and 6.7, show that many parts of the reservoir have oil saturations above this level. The lithology of the reservoir is sandstone, which also is favorable according to the screening criteria. The MMP for the reservoir oil and the $CO_2$ is 270 bar (found using PVTSIM), but the pressure in the reservoir in 2031 is only around 70 bar. This is far below the MMP, and miscibility between the oil and the $CO_2$ will not be achieved under these circumstances. Arshad et al. (2009) suggest a minimum permeability of 5 md necessary for a $CO_2$ project to succeed, and the permeability in this case is far above, with permeabilities in the Darcy scale. The permeability heterogeneities in the reservoir are not positive when comparing to the screening criteria, where the possibility for success is bigger when reservoirs are more homogenous.

## 6.6 Simulation scenarios

The main point of this study is to investigate how much extra oil that can be extracted using $CO_2$. All the scenarios are starting 1. January 2031, after the license period for production at the oil field has expired. The simulations can be divided into two main time periods. Since the pressure in the Brent group is just 70 after production stop, a pressure build up is required to try to achieve miscibility conditions. After the pressure is built up, production can start. To have a limited timeframe, it was decided to look at the following scenario; How to build up the pressure to 270 bar most efficiently for a period of 10 years, and then produce for 15 years after pressure build up. The following three strategies were evaluated for pressure build up:

- Pure $CO_2$
- Combination of $CO_2$ and water
- Pure water

After the pressure build up, a continuation of the different injection strategies was done during production to maintain the pressure in the reservoir and miscibility conditions. The injection of pure water was to have some kind of base case to compare the $CO_2$ injection with. Because of the large volumes of $CO_2$ required in pure $CO_2$ injection, some combinations of $CO_2$ and water were also simulated. In addition to investigating the total potential on a field scale, a study of a pair of an injector and a producer was done. This was to analyze compositional effects between the injected $CO_2$ and reservoir oil, which can be hard to see on a field scale, since a lot of other factors will influence the performance. Looking at this pair of injector/producer, the production observed at the producer will more or less be a direct function of the injection strategy. In this way injection strategies can be analyzed, in addition to compositional effects as change in viscosity, density and residual oil.

## 6.7 Selection of wells

The Statfjord Field consists of hundreds of wells (NPD, 2017b). It was decided to try to use existing wells, and an overview of the wells in the Brent group in 2015 is shown in Figure 6.8. The placement of wells is often very detailed studied, in terms of maximizing injectivity/productivity, reservoir contact and flowing pattern. To find and select the optimal placement of wells is very comprehensive, so by using the existing wells, this time can be saved. The strategy when building up the pressure, was to try collect as much of the oil as possible, in some parts of the reservoir. Because of the depth differences in the reservoir, a natural choice was to inject down-dip, so the oil would be forced to the top of the reservoir, and later start to produce from the upper parts of the reservoir. Since most of the oil will be in the upper parts at the time of injection start, up-dip injection would maybe just spread the oil more. When the total volumes of $CO_2$ and water required for the pressure build up had been found, the total number of injectors was chosen taken the capacity of a single well into account. Using a logical mindset, the injectors were placed under the oil-water-contact, so most oil as possible was contacted during the pressure build up. By first using a set of injectors/producers, and then analyze the performance, some wells were kept and some were switched out with other wells. This strategy was used until the final selection of wells was obtained. For the scenarios with a combination of $CO_2$ and water injection, different injectors for the $CO_2$ was tested and also a circulation of where the $CO_2$ was injected.

For choosing a pair of injector/producer to study compositional effects, the main argument for the selection was where effects in the production well could be clearly observed. Also, the movement of the fluids between the wells, should mainly a function of what was injected.

## 6.8 Constraints for injection and production wells

The wells used for production and injection in the simulations, need to be given some constraints for getting realistic results. Reasons for the constraints can be production capacity, fracturing pressure etc. The constraints used for the wells in the simulations, are summarized in

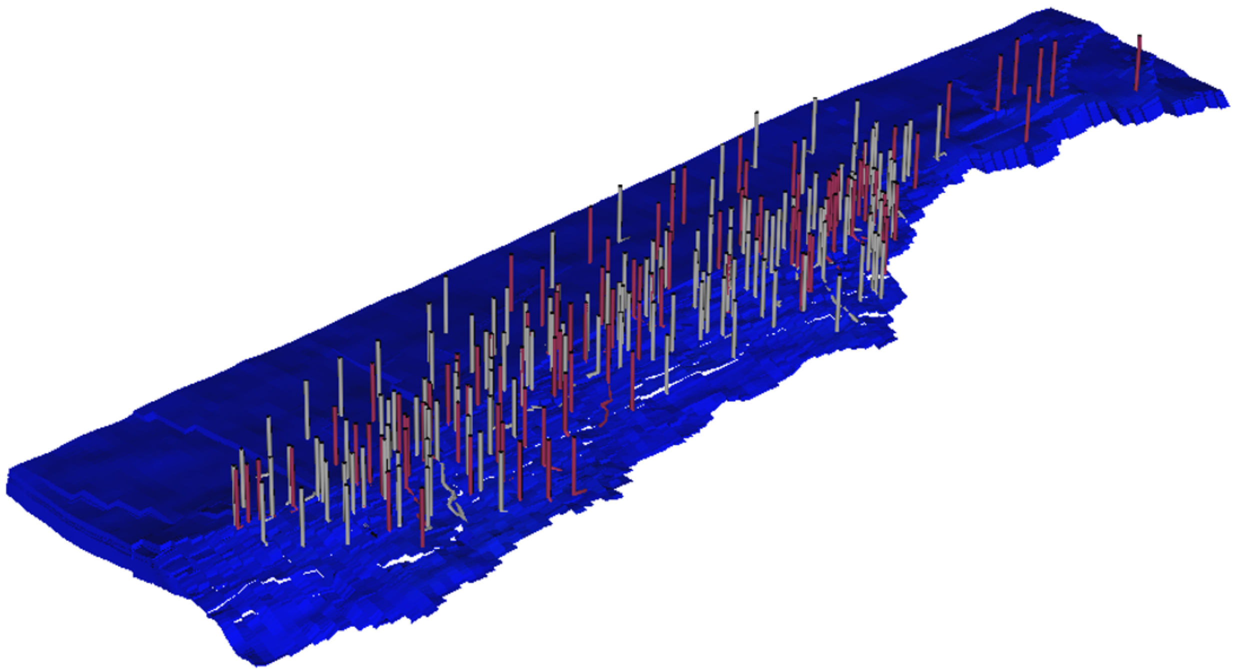

Figure 6.8: Overview wells in the Brent group in 2015.

Table 6.2. To ensure miscibility conditions around the producers, a minimum BHP of 270 bar for the producers were used. The upper liquid production rate was set, due to rates over this level can cause huge erosion issues due to sand production.

Table 6.2: Constraints for injection and production wells.

| **Injectors** | |
|---|---|
| Limiting BHP | 400 bar |
| Target rate water | 4500 $Sm^3/d$ |
| Target rate $CO_2$ | 1 MTY |
| **Producers** | |
| Minimum BHP | 270 bar |
| Upper liquid production rate | 4000 $Sm^3/d$ |

# Chapter 7

# Results

In the following sections the results for the simulation scenarios will be presented. Just the final choice of wells will be presented, and all the results are based on this best combination of wells. Results on a field scale and a pair of an injector and a producer will be presented.

## 7.1 Field Scale

### 7.1.1 Volumes required for pressure build up

The first results obtained were the volumes of $CO_2$ that were required for the pressure build up. By the use of pure $CO_2$ an injection rate of 20 million tons per year (MTY) over the build up period for 10 years was needed to increase the reservoir pressure to the MMP of 270 bar. Due to the well constraint for the production wells of a minimum BHP of 270 bar, a little higher build up was needed to make the production wells able to produce from the start after 10 years. All the production wells are located in the top of the reservoir, and the pressure here are lower than the average reservoir pressure. Taken all this into account, a total injection rate of 22 MTY for the 10 year period was required to make sure the wells could produce. When the volumes needed were found, the number of injection wells required could be found. A total number of 20 injectors was needed for injecting these amounts, where each well was injecting 1.1 MTY $CO_2$. The same

20 wells were used for the base case scenario, where pure water was injected during the build up. A total amount of 90000 Sm3/d of water was required for the build up, divided into 4500 Sm3/d for the each of the injectors. For the same 20 wells, a combination of $CO_2$ and water was used. A total amount of 5 and 1 MTY $CO_2$ were tested. In these cases, 5 $CO_2$ injectors and 15 water injectors, and 1 $CO_2$ injectors and 19 water injectors were used respectively. For the water and $CO_2$ wells here, the injection rates are the same as given in Table 6.2

### 7.1.2 Final combination of wells

The final combination of wells used for injection and production is shown in Figure 7.1. This combination was obtained after trying and fail with various combinations. The set of wells used here is maybe not the optimum combination, but the best of the scenarios tested in this study. Since the problem not can be characterized to be a linear problem, the best option was to just use logical thinking. The wells with an arrow pointing down are injectors, and the ones where the arrow is pointing up are producers. The scenario with injection of 5 MTY $CO_2$ and water is the one illustrated in the figure.

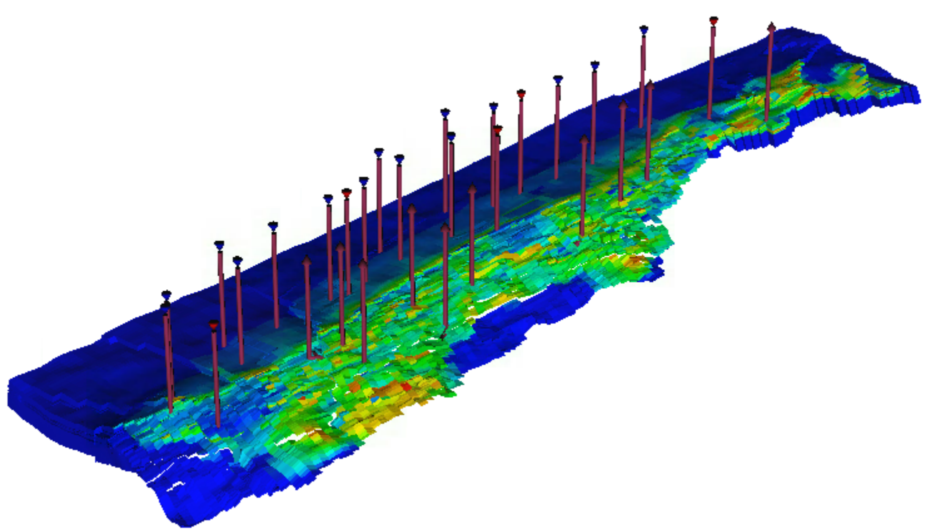

Figure 7.1: Final combination of injectors (arrow pointing down) and producers (arrow pointing up). Red arrows symbolize $CO_2$ and blue water. This is the scenario with injection of 1 MTY $CO_2$ in 5 wells and 4500 Sm3/d water in 15 wells.

### 7.1.3 Collection of oil after pressure build up

A comparison of how the oil is collected at the top of the reservoir for the scenarios with pure water and pure $CO_2$ are illustrated in Figure 7.2. In both cases, the oil is collected in the upper parts of the reservoir, which also was the strategy and reason for placing the injectors down-dip. Comparing Figure 7.2 to the initial oil saturations in Figure 6.4, it can be observed that oil saturations in the upper part of the reservoir have increased dramatically. The figures are seen from the top, and are not showing how the oil saturation has changed in lower layers of the reservoir. It can be observed that the $CO_2$ looks to sweep better in the southern and middle part of the reservoir. The case where a combination of $CO_2$ and water are injected, will be a mix between the figures and can be seen in the appendix.

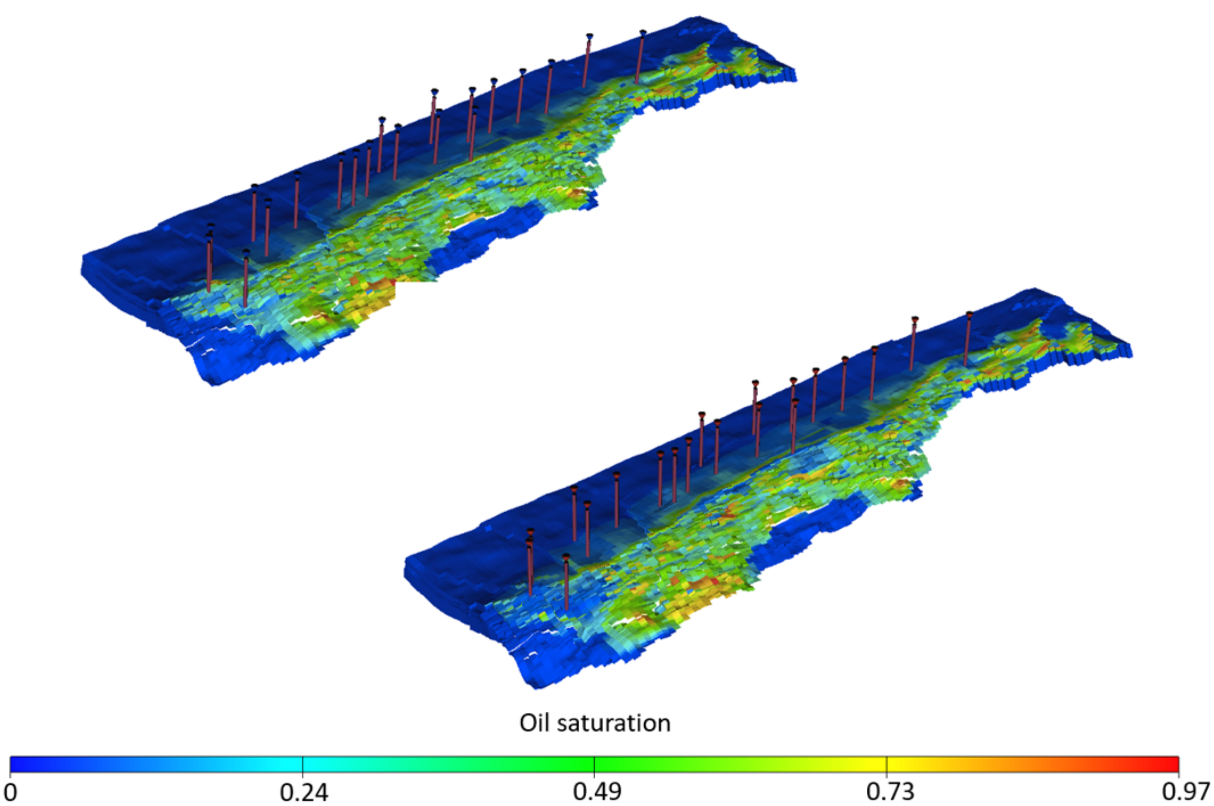


Figure 7.2: Comparison of how the oil is collected after pure water and pure $CO_2$ injection. The red arrows symbolize $CO_2$ and blue water.

### 7.1.4 Oil production

The oil production rates for the main scenarios are shown in Figure 7.3. The best production by far, is the production from the use of pure $CO_2$, and the use of pure water gives the lowest production. Except for the case with pure $CO_2$, the production for the other cases stays at a more or less stable level for the production period of 15 years.

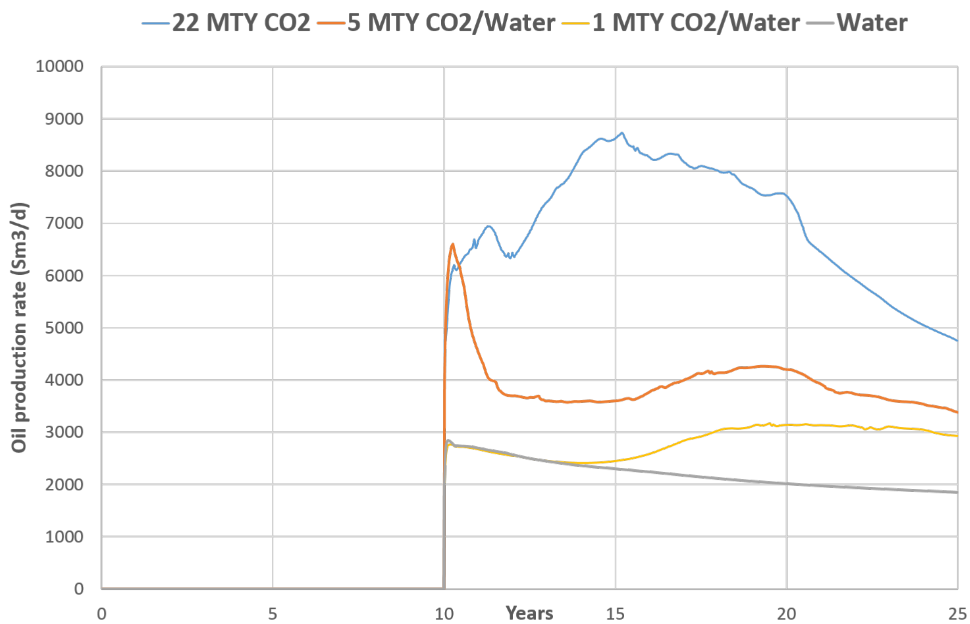


Figure 7.3: Oil production rate for the scenarios with injection of pure $CO_2$, water and a combination of $CO_2$/water.

Figure 7.4 shows the cumulative oil production for the different scenarios. The same trends as in Figure 7.3, can be observed here, where pure $CO_2$ gives the highest production of oil. The volumes produced by the use of 22 MTY and 5 MTY $CO_2$, are respectively about 38 MSm3 and 22 MSm3. Like mentioned in previous sections, the recoverable oil at the new development Ivar Aasen is 23 MSm3, for comparison (NPD, 2017a). Production per well can be found in the appendix.

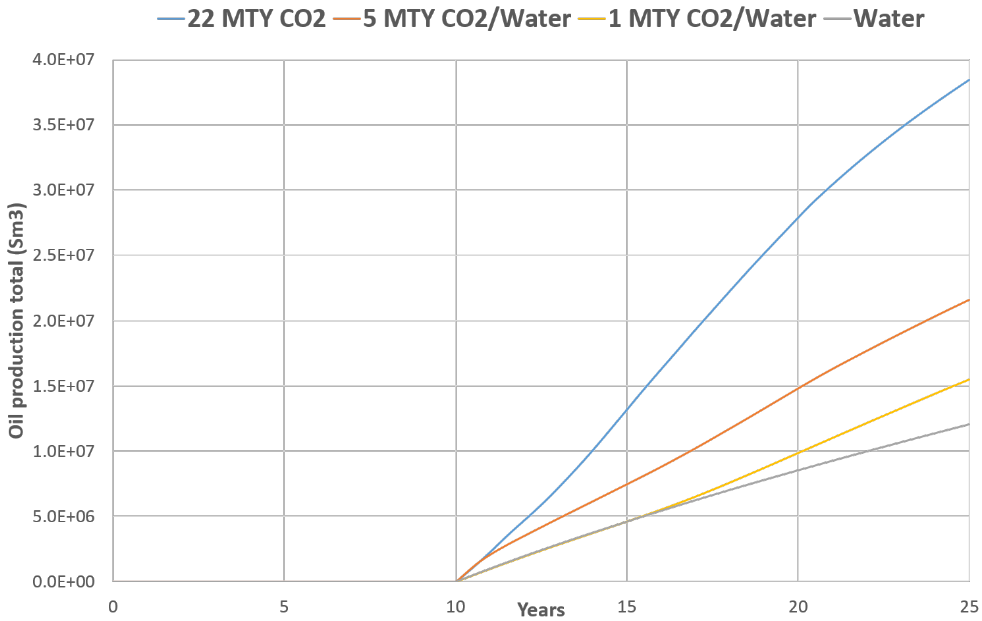


Figure 7.4: Cumulative oil production scenarios with injection of pure $CO_2$, water and a combination of $CO_2$/water.

With an original oil in place (OOIP) of about 720 $MSm^3$, the extra percentage of recovered oil for the scenarios are summarized in Table 7.1 (Haugen et al., 1988).

Table 7.1: Total oil production for the different scenarios, and increase recovery.

| Case | Pure $CO_2$ 22 MTY | 5 MTY $CO_2$/water | 1 MTY $CO_2$/water | Water |
|---|---|---|---|---|
| Total oil production $MSm^3$ | 38.4 | 21.6 | 15.5 | 12.1 |
| % of OOIP | 5.4% | 3.0 | 2.2 | 1.7 |

### 7.1.5 Water cut and gas-oil-ratio

The gas-oil-ratio (GOR) for the scenarios are shown in Figure 7.5. Like expected, the more $CO_2$ injected, the higher the GOR of the production gets. For pure water injection, the GOR of the production is very low, but gets higher the more $CO_2$ that is injected. The increasing GOR for the scenarios involving $CO_2$, can be explained by the increasing production rate of the $CO_2$ component, which can be observed in the production rate of the different components. More and more $CO_2$ will break through in the production wells, and a consequence is an increasing GOR.

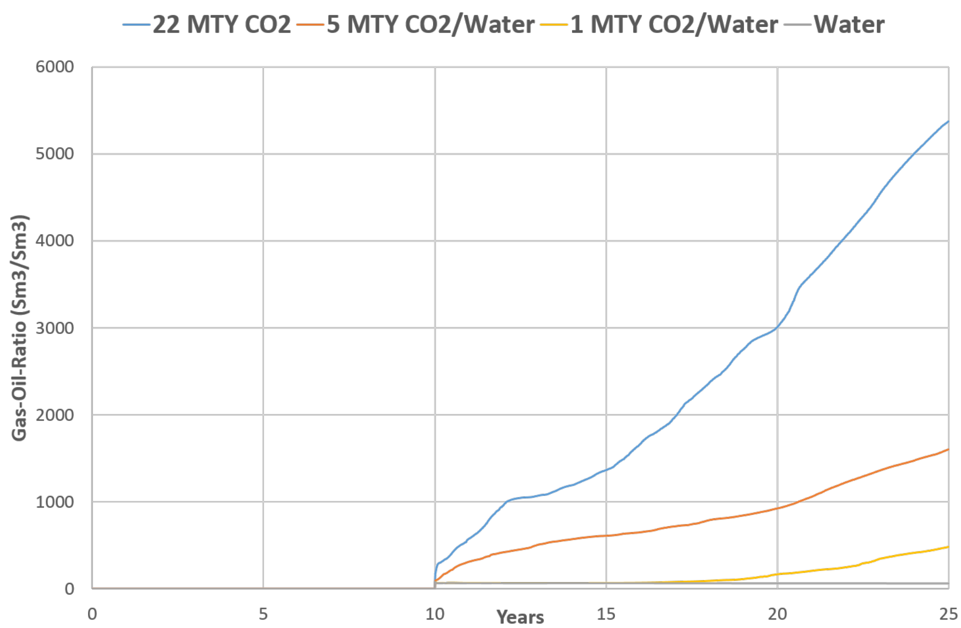


Figure 7.5: GOR for the scenarios with injection of pure $CO_2$, water and a combination of $CO_2$/water.

Since there is a lot of water in the upper parts of the reservoir where the producers are located, a high percentage of water is expected to be produced. Figure 7.6 shows the water cut for the scenarios. Pure water injection, gives the highest water cut, and pure $CO_2$ the lowest. This was expected, since a lot more gas is produced when the $CO_2$ is present and due to this a lower water cut. The water cuts are more or less stable during the whole production period. For pure $CO_2$ it is at a level of about 75 % and the water cut moves towards 95 % as less $CO_2$ is injected. The pure water case, gives a water cut of up to 95 %. The water cuts are in general very high, but was excepted since the oil and water saturations are about the same in the areas around the production wells.

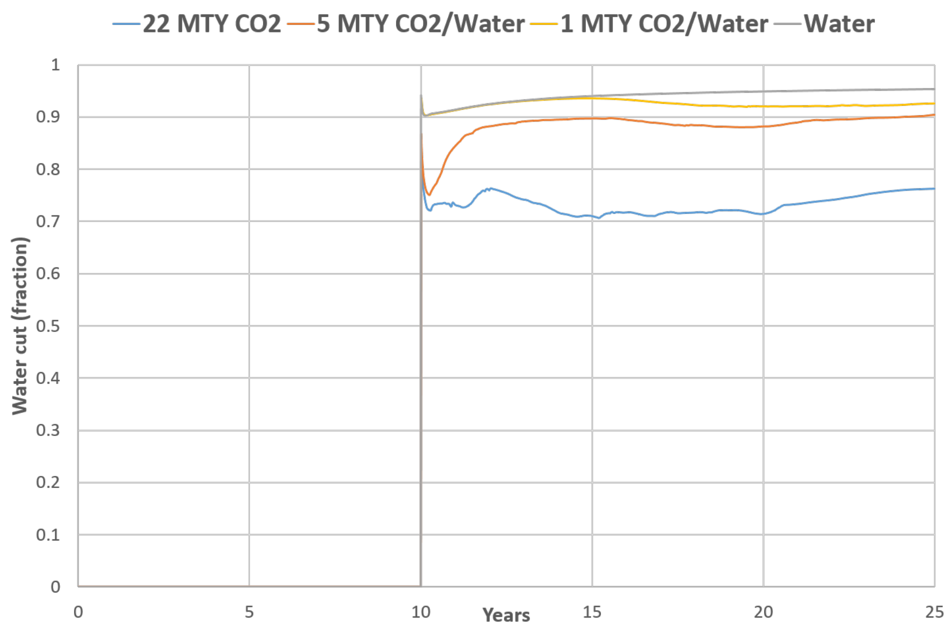


Figure 7.6: Watercut for the scenarios with injection of pure $CO_2$, water and a combination of $CO_2$/water.

### 7.1.6 Composition of oil production

When injecting different fluids, it can be interesting to look at the composition of the produced oil, if different components are being produced. Figure 7.7 shows the distribution of the different components in the produced oil for the case with 5 MTY $CO_2$ and water injection. By far the most produced component is $CO_2$, and keeps on increasing as more and more $CO_2$ is breaking through at the producers. The pseudocomponent with the hydrocarbons $C_7$-$C_{19}$, is the most frequent hydrocarbon component produced followed by $N_2$+$C_1$+$C_2$ and $C_3$-$C_6$. The same distribution was observed for the pure $CO_2$ injection, but the $CO_2$ rates much higher. This can be found in the appendix.

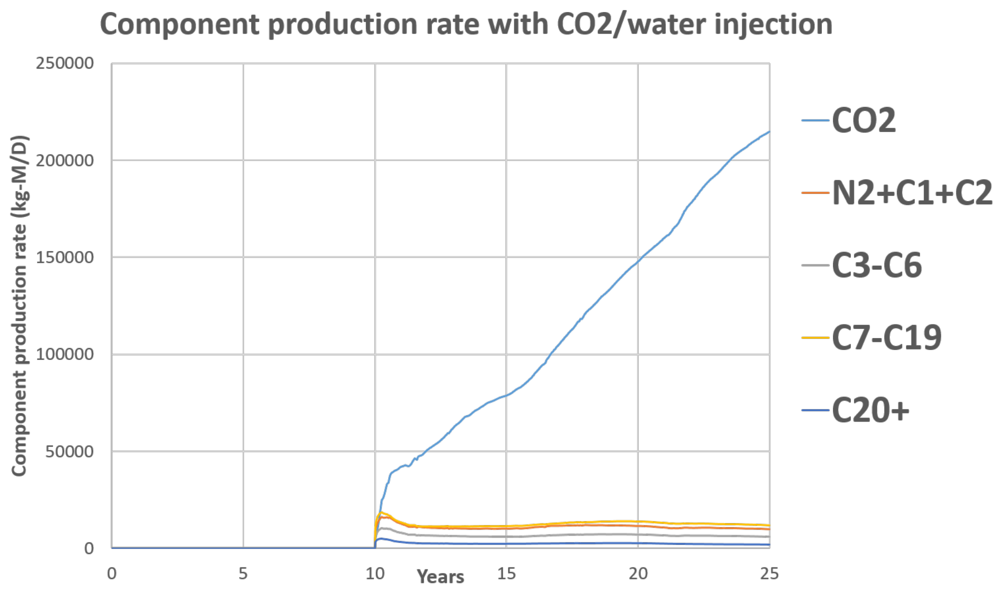


Figure 7.7: Composition of produced oil for the scenario with injection of a combination of 5 MTY $CO_2$ and water.

Figure 7.8 shows the production of the different pseudocomponents for the base case of pure water injection. No $CO_2$ is produced here, as expected since no $CO_2$ is injected. The distribution between the different components of the oil has about the same look as for the cases with $CO_2$, except lower rates. Looks like the same components of the oil are being produced independent of the types of injection fluid.

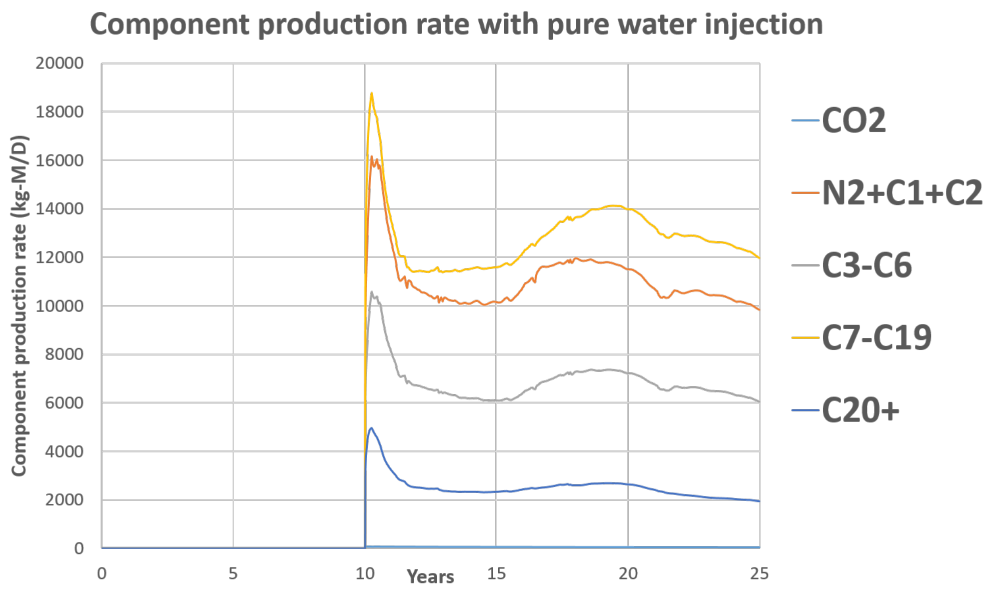


Figure 7.8: Composition of produced oil for the scenario with injection of pure water.

### 7.1.7 $CO_2$ balance and storage

Table 7.2 shows an overview of the total amounts of $CO_2$ injected, produced and the storage percentage for the different cases. The storage percentage shows, that 72-90% of the $CO_2$ stays in the reservoir. The produced $CO_2$ can also be reinjected, which also will increase the storage percentage. If all of the produced $CO_2$ will be reinjected, the storage percentage can ideally be up to 100 %. For comparison, the total Norwegian emission of greenhouse gases in $CO_2$ equivalents was about 54 million tons in 2015 (SSB, 2016). This shows the enormous potential for $CO_2$ storage in the Brent group, which can store more than 10 times the total Norwegian emission of greenhouse gases each year.

Table 7.2: Volumes of $CO_2$ storage in the reservoir.

| Case | Pure $CO_2$ 22 MTY | 5 MTY $CO_2$/water | 1 MTY $CO_2$/water |
|---|---|---|---|
| Mton $CO_2$ injected total | 550 | 125 | 25 |
| Mton $CO_2$ produced | 155 | 28 | 2.6 |
| Storage percentage | 72 % | 77 % | 90% |

Figure 7.9 shows the $CO_2$ production rates for the scenarios with $CO_2$ injection, for the 25 years simulated. Like expected, an increasing $CO_2$ production rate over time. This can be challenging when thinking about the processing of the production, but this will also reduce the amounts of $CO_2$ required significantly after production starts. The reduced amounts of $CO_2$ required, can be a positive effect of reinjection of the produced $CO_2$ and maybe the associated gas.

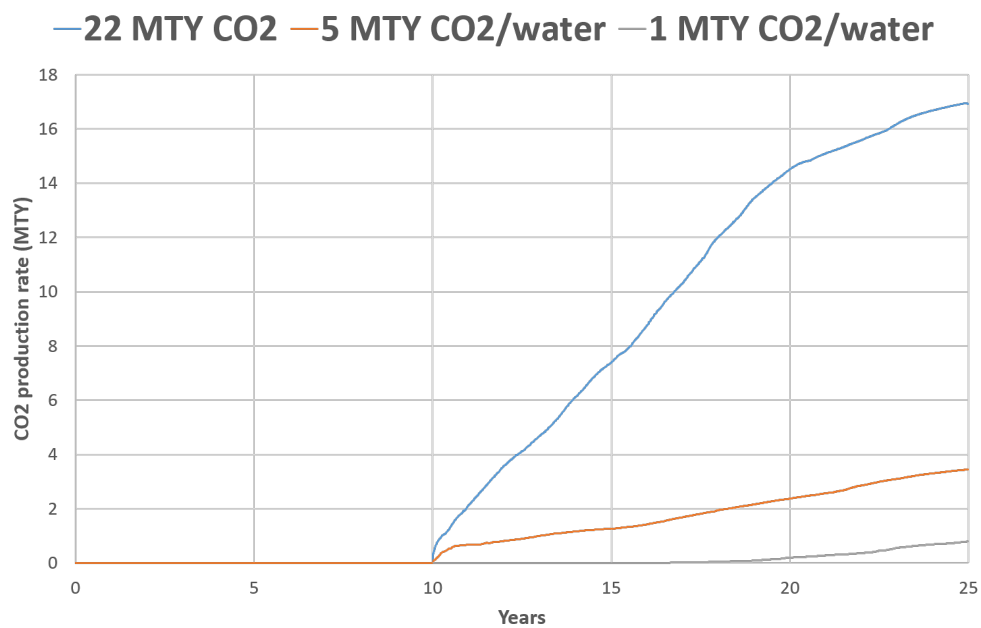


Figure 7.9: $CO_2$ production rate for the cases with injection of pure $CO_2$ and $CO_2$/water.

### 7.1.8 Effect of reinjection of produced gas

A question that comes up in $CO_2$ EOR, is what should be done with the produced $CO_2$ and the associated gas, since this can be hard and expensive to separate. An alternative is to reinject all the produced gas. Figure 7.10 shows the production rates and total production for the cases pure $CO_2$ injection and injection of $CO_2$ and the produced gas. The differences are minimal, and actually the case where the produced gas is reinjected gives a slightly better production.

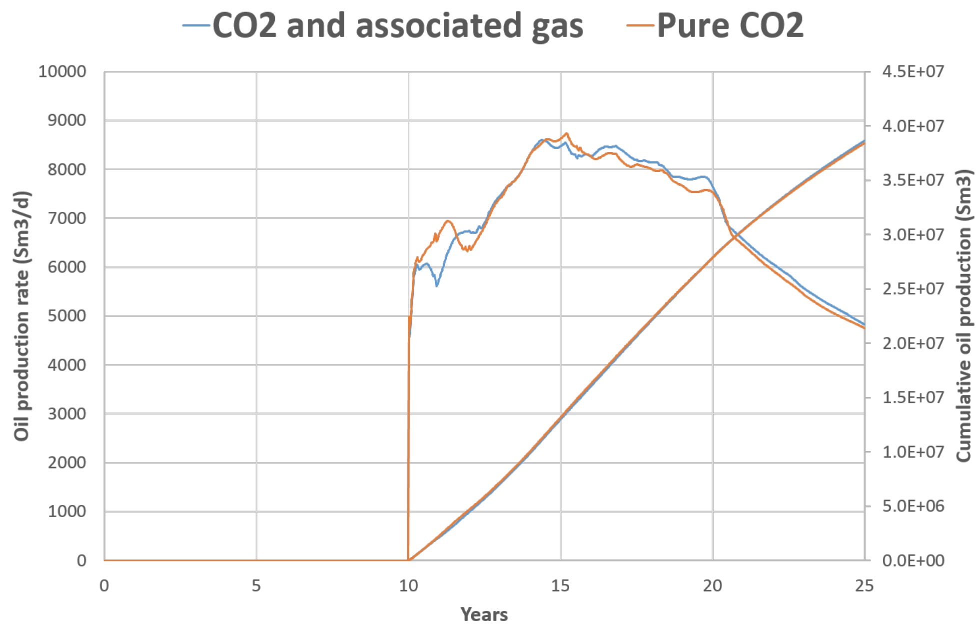


Figure 7.10: Oil production when the produced gas is reinjected for the scenario with pure $CO_2$ injection.

Figure 7.11 shows how the composition of the injection gas is changing during the lifetime of the simulation. After production starts, the gas produced is reinjected into the reservoir again. Most of the produced gas is $CO_2$, like illustrated in figure 7.7. This will reduce the required amount of $CO_2$ after production starts. The injection rates of $CO_2$ drops after 10 years, when production starts, but are being compensated by an increase in the injection rates of the associated gas produced together with the $CO_2$. Another observation is that most of the associated gas is mainly the lighter components. This is due to these components will exist as gases at the surface at standard conditions. The heavier components will exist in liquid phase, as oil.

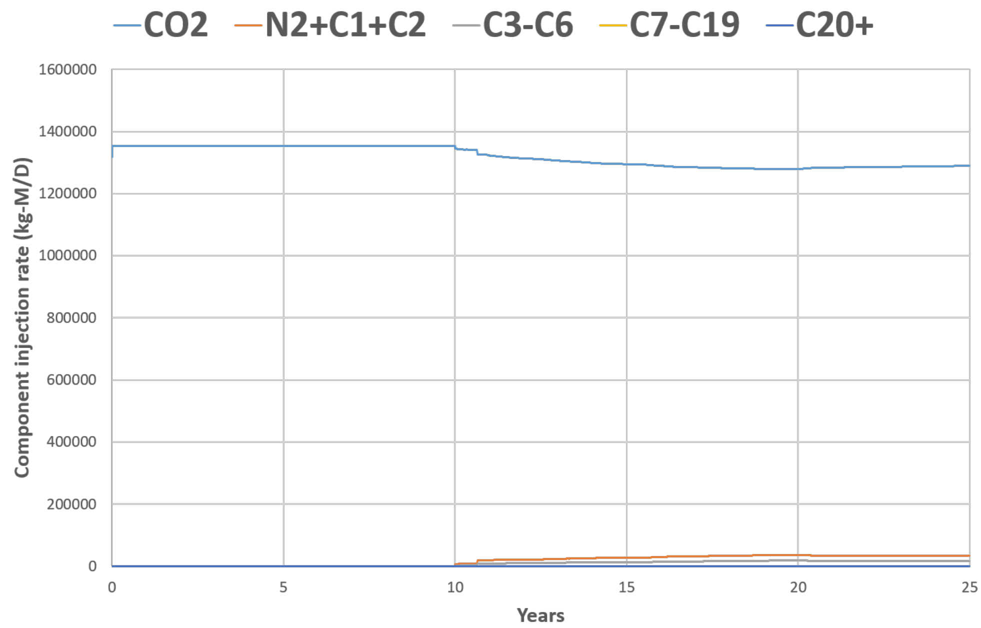


Figure 7.11: Composition of the injected gas for the scenario where all the produced gas is reinjected together with the $CO_2$.

### 7.1.9 NPV Calculations

Some economic calculations have been done for the different cases at the field scale level. The net present value (NPV) for the different scenarios for the total simulation time of 25 years, are summarized in Table 7.3. The calculations are based on project start up in 2031. Costs, prices and other inputs for the economics are shown in Table 7.4. All the wells used in the simulations are planned to be plugged at the time of start up for the project, so all the 20 injectors and the 10 producers need to be drilled. Due to uncertainty in the price of $CO_2$, different prices have been used. Almost all the scenarios have a negative NPV, which means the projects are not sustainable. The only positive NPVs are obtained with a $CO_2$ price of 10 USD/bbl. More details about the calculations can be found in the appendix.

Table 7.3: NPV for the simulation scenarios in billion NOK, for different $CO_2$ prices.

| Case | Pure $CO_2$ 22 MTY | 5 MTY $CO_2$/water | 1 MTY $CO_2$/water | Water |
|---|---|---|---|---|
| Free $CO_2$ | 8.6 | 1.6 | -1.3 | -2.3 |
| 10 USD/ton $CO_2$ | 2.5 | 0.16 | -1.6 | -2.3 |
| 50 USD/ton $CO_2$ | -21.9 | -5.42 | -2.77 | -2.3 |
| 100 USD/ton $CO_2$ | -52.3 | -12.4 | -4.27 | -2.3 |

Table 7.4: Operation costs, investments, prices as input for NPV calculations.

| | |
|---|---|
| Oil price | 80 USD/bbl |
| Discount rate | 0.08 |
| Exchange rate | 8.40 NOK/USD |
| Operating a platform | 850 million NOK/year |
| Drilling a well | 250 million NOK |
| Initial upgrades topside, tie-back etc | 6 billion NOK |

## 7.2 Pair of injector and producer

To see effects of injection strategy more clearly, and look at compositional effects a pair of an injector and a producer was investigated. The injector and producer chosen are shown in Figure 7.12

All the other 19 injection wells are injecting 4500 $Sm^3/d$ water the whole lifetime. Just the well B.C34A has another injection strategy. A total of six different injection strategies were tested and are described below:

- **$CO_2$:** Pure $CO_2$ 1 MTY injection in well B.C34A
- **Water:** Pure water 4500 $Sm^3/d$ injection in well B.C34A.
- **$CO_2$ WAG, 1 year cycles:** 1 MTY injection of $CO_2$ alternating with 4500 $Sm^3/d$ water, in 1 year cycles.

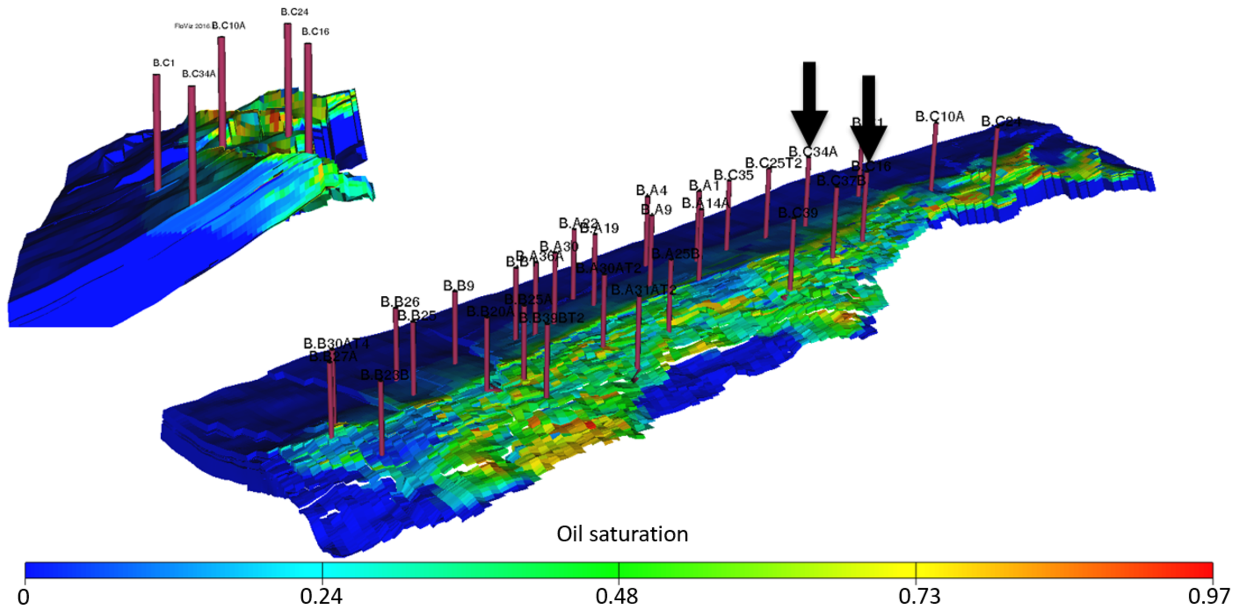


Figure 7.12: Pair of injector (B.C34A) and producer (B.C16) chosen to investigate injection strategies and compositional effects. Seen from the top to the right, and a cross section between the wells at the left.

- **$CO_2$ WAG, 6 month cycles:** 1 MTY injection of $CO_2$ alternating with 4500 $Sm^3/d$ water, in 6 month cycles.
- **$CO_2$ WAG, 3 month cycles:** 1 MTY injection of $CO_2$ alternating with 4500 $Sm^3/d$ water, in 3 month cycles.
- **$CO_2$, produced gas reinjected:** 1 MTY injection of $CO_2$, and all the produced gas is reinjected together with the $CO_2$ at the same injection rate.

### 7.2.1 Oil production

Figure 7.13 is showing the oil production rate in well B.C16 for the six different injection strategies and Figure 7.14 shows the cumulative oil production. Like for the results on a field scale, also here the pure $CO_2$ injection gives much better production compared to pure water. Also, all the $CO_2$ WAG scenarios are giving less production. Looks like the length of the cycles in the $CO_2$ WAG does not matter, since the oil production for the WAG scenarios is more or less the same. Because of the indication of no effects of the cycles, only one of the WAG scenarios will be compared in the rest of the analysis.

The best scenario is when all the produced gas is reinjected together with the $CO_2$, which is very positive since it can be hard to separate the produced $CO_2$ and the hydrocarbon gas. This is the same as observed for the production on a field scale. The scenario with reinjection is following the production for pure $CO_2$ to around 13 years, then it starts to produce more. This can be explained by that the same injection strategy is being applied in both cases the first 10 years, but then it changes. Probably it takes some years of injection of the produced gas, until effects can be observed in the producer. The composition of the injected gas in the scenario with reinjection, is shown in Figure 7.15. If this is compared to the case at the field scale in Figure 7.11, the hydrocarbon gases have a much larger portion of the injected gas, since only 1 MTY $CO_2$ is injected here, compared to 22 MTY on the field scale. Since the portion of the hydrocarbon gases is larger here, the effects will bigger here.

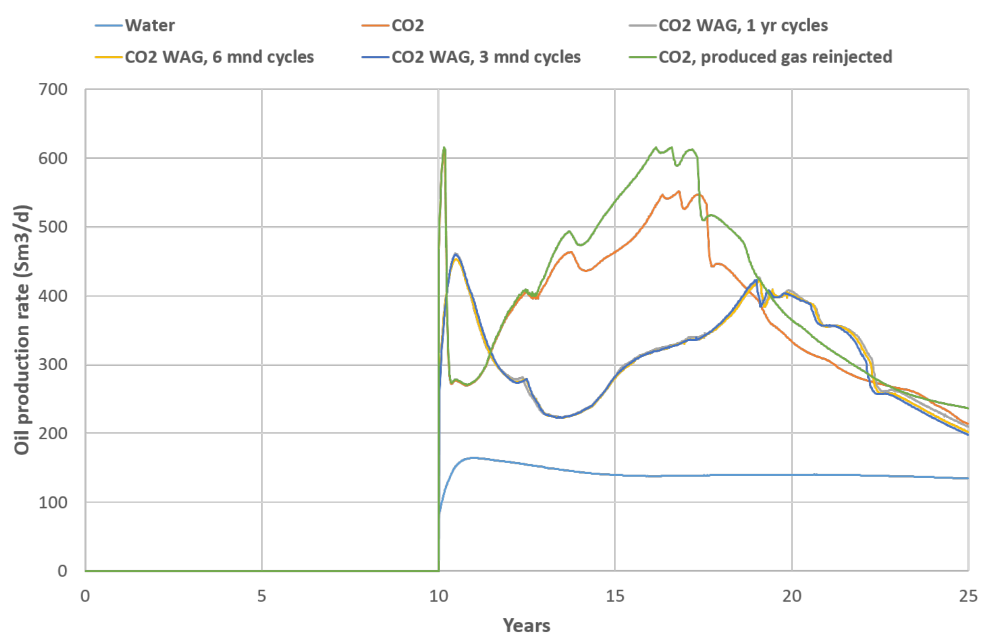


Figure 7.13: Oil production rates for well B.C16 for the difference scenarios.

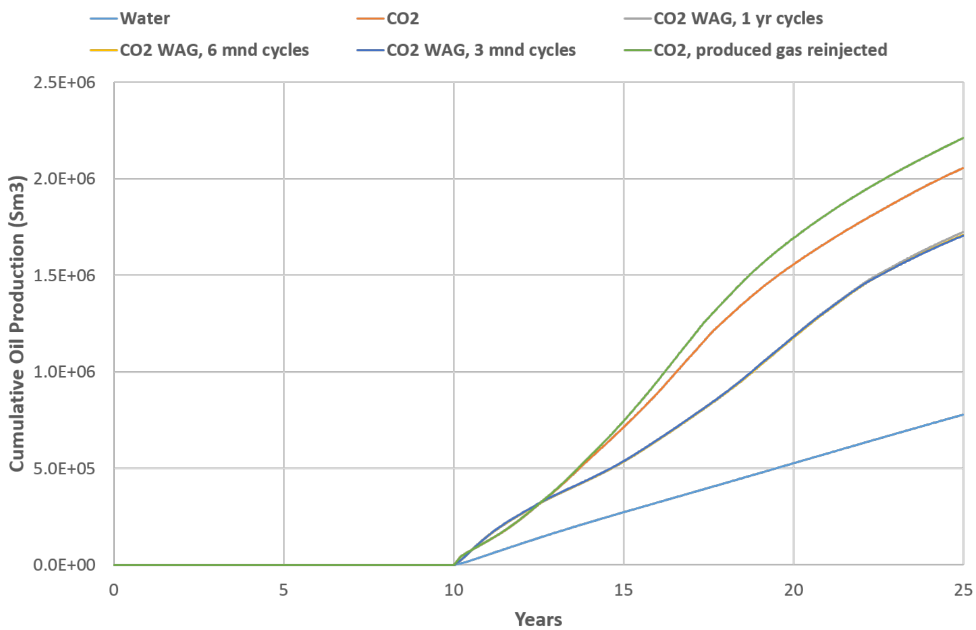


Figure 7.14: Cumulative oil production for well B.C16 for the difference scenarios.

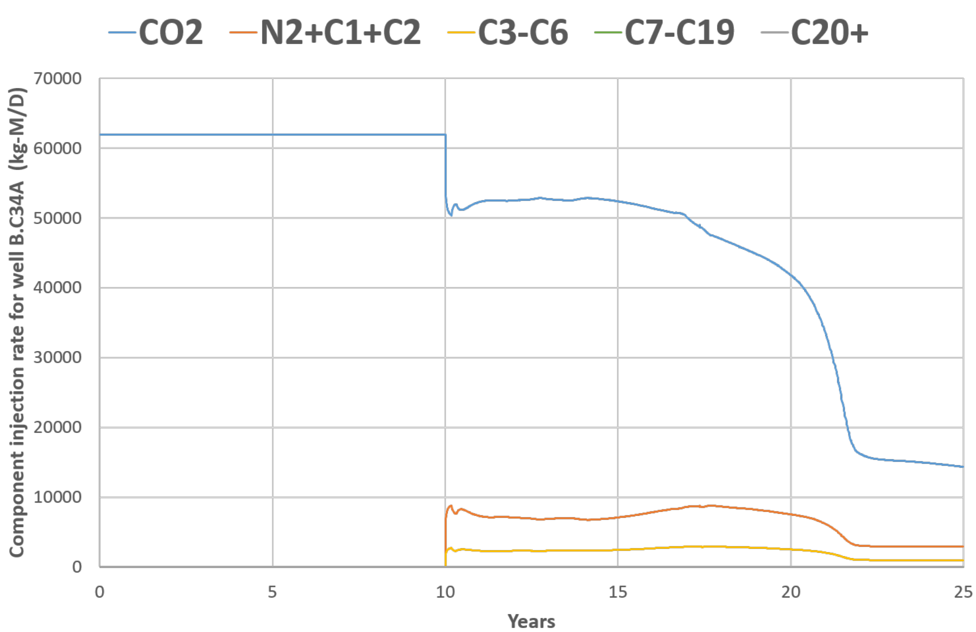


Figure 7.15: Composition of injection gas in well B.C34A for the scenario where produced gas is reinjected.

### 7.2.2 Residual oil between injector and producer

Figure 7.16 shows the cross section of the reservoir between the injector and producer investigated here. It can be observed that more oil is swept in the case with $CO_2$. The injected fluid is injected in the lower parts of the reservoir. Figure 7.17 shows how the oil saturation for a gridblock (40,72,26) in the swept area is changing for the different scenarios. The scenario with pure $CO_2$ is leaving less oil behind after it has swept the gridblock. All the scenarios seem to flat out, except for the case of pure water. So, if the simulation had been run for some more years, it looks like water would have approached the others more and more. See appendix for more detailed information about the gridblock studied and the area between the injector and the producer.

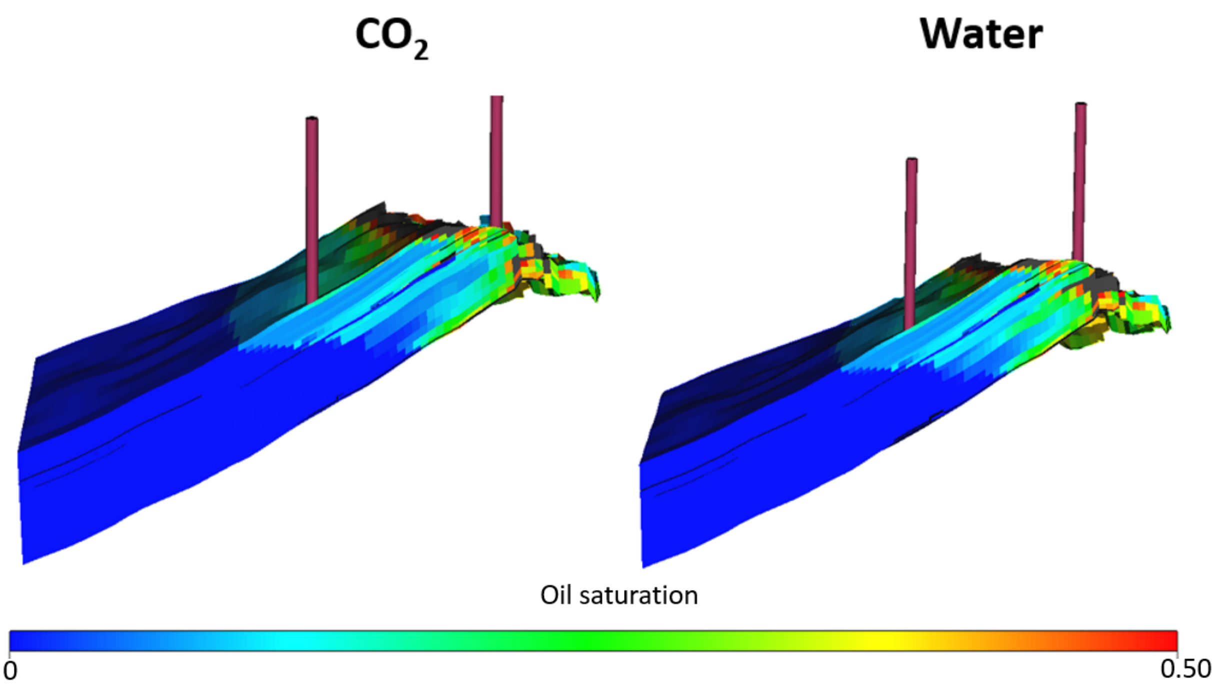


Figure 7.16: Comparison of oil saturations after 25 years of injection of $CO_2$ and water.

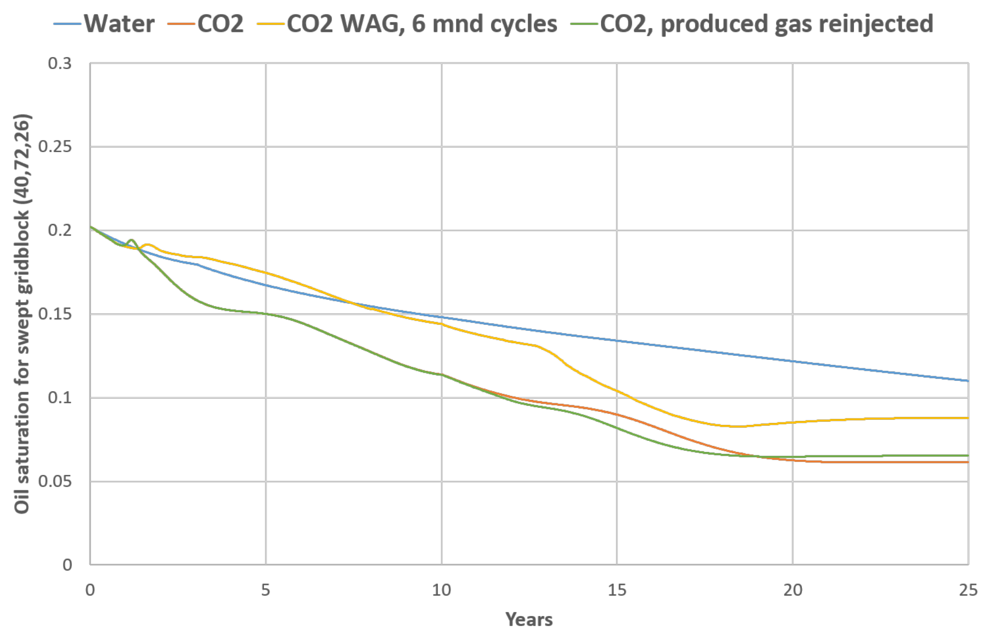


Figure 7.17: Comparison of oil saturation in gridblock (40,72,26) after 25 years with different injection strategies.

### 7.2.3 Viscosity change

The change in viscosity of the oil in a gridblock (40,72,26) in the swept area between the injector and the producer is illustrated in Figure 7.18 for the different scenarios. The changes are small in the $CO_2$ WAG and water case. But for the scenarios with pure $CO_2$ injection and reinjection, the viscosity increases dramatically after production starts after 10 years. This can be due to the lighter components of the oil are being produced, and only the heavy components left behind, which will increase the viscosity of the oil. In general the viscosity decrease for all scenario in the start, when the pressure increases and more gas are solved into the oil.

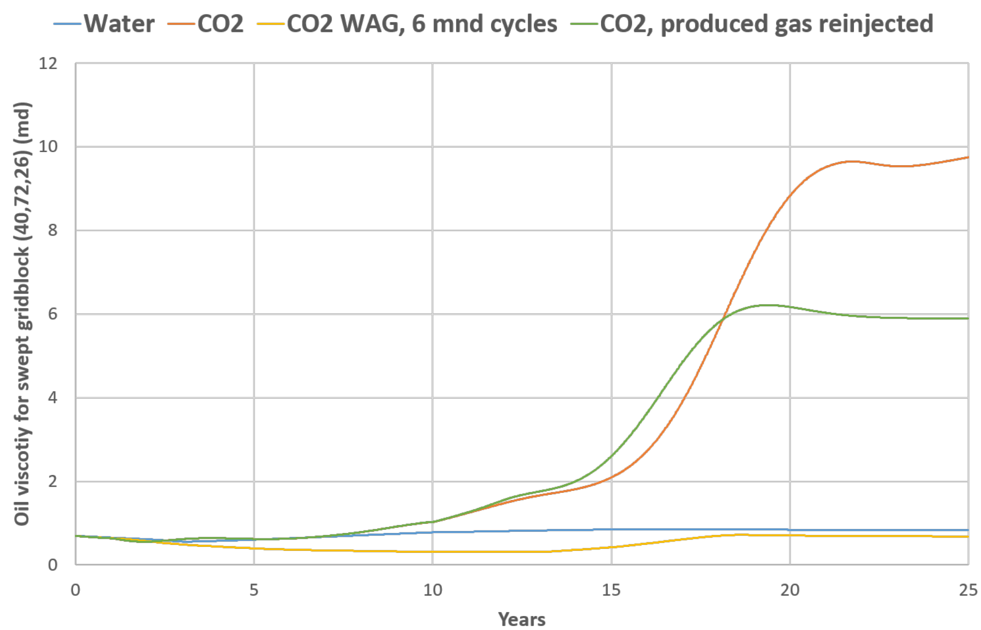


Figure 7.18: Comparison of oil viscosity in gridblock (40,72,26) during 25 years with different injection strategies.

### 7.2.4 Density change

The same trends as observed for the viscosity can be seen for the density for the gridblock (40,72,26) in Figur 7.19. The density increases as a lot of oil leave the area. This is also probably due to lighter components are flowing away from the area. For the $CO_2$ WAG case, the change in density is much more significant compared to the viscosity change.

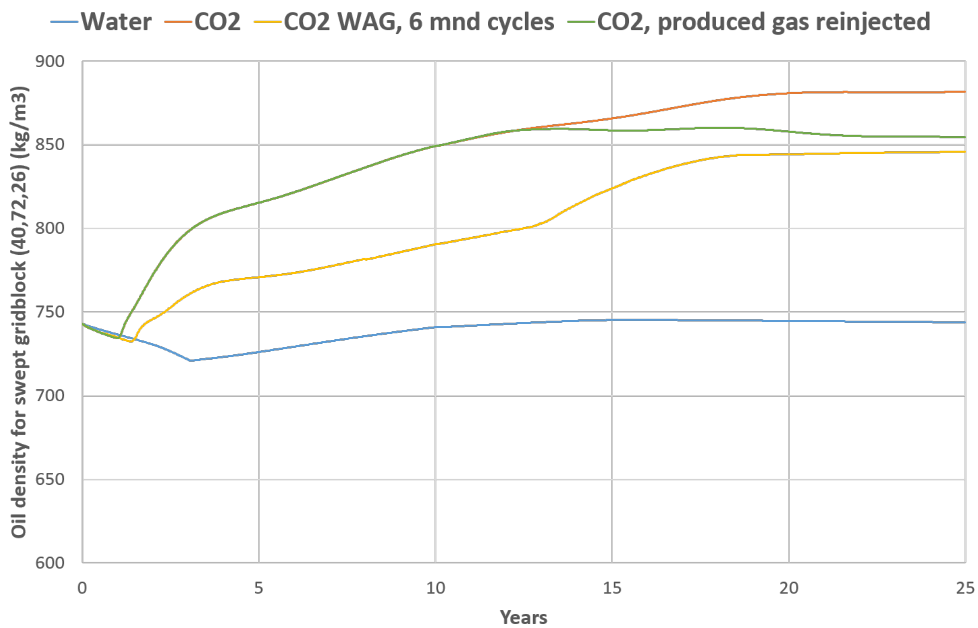


Figure 7.19: Comparison of oil density in gridblock (40,72,26) during 25 years with different injection strategies.

# Chapter 8

# Discussion

## 8.1 Volumes of $CO_2$ required and availability

As the results show, large amounts of $CO_2$ are required for enhancing the oil production from the Brent group significantly. The scenario with the best production, required 22 tons of $CO_2$ each year, which are enormous volumes. But about 60 % of these volumes can be produced with the use of 5 tons of $CO_2$ each year, which are more realistic amounts. A total production of 22 MSm$^3$, is about the same recoverable volumes of the Ivar Aasen field, which started production in 2016 (NPD, 2017a). The volumes used in this study, can be compared to two active $CO_2$ storage projects on the NCS, at Sleipner and Snøhvit. At Sleipner, 1 million tons of $CO_2$ are injected each year (Institute, 2017a). At Snøhvit 0.7 million tons are injected each year (Institute, 2017b). Other possible sources for $CO_2$ can be industry sources where the $CO_2$ emissions are high and that can be captured. A recent study showed that a total of 1.5 million tons of $CO_2$ could be captured from three industry sources in Norway (Nilsen, 2016). Since there are no natural sources of $CO_2$ in the North Sea or in the vicinity, it needs to be transported by ship or pipelines from facilities on land. Other sources for $CO_2$ can be refineries like Kårstø and Mongstad (Agustssen and Grinestafr, 2004). There are sources where $CO_2$ can be captured and collected in Norway, but the sources are still small compared to the volumes used in this study.

## 8.2 Production facilities and upgrades

The large volumes injected in the scenarios here will require a platform at the field, and the platforms existing at the field would probably require comprehensive upgrades. Most of the wells at the oil field will be plugged at the time this project is supposed to start, and because of this most of the wells used in this study need be drilled or upgraded for $CO_2$ injection. Production systems, new injection systems, additional pipelines and additional material upgrades are other modifications that need to be evaluated (Agustssen and Grinestafr, 2004).

## 8.3 Pressure build up

Because of the low reservoir pressure, a pressure build up is required for achieving miscibility between the $CO_2$ and the oil. Since the reservoir is just around 70 at injection start, not a lot of energy is needed for injection. Maybe not for the injection of the $CO_2$, but a hydrostatic column of water to a depth of around 2400 m, will have a much higher pressure. Because of this water will be "sucked" into the reservoir, due to high pressure differences. For the use of pure $CO_2$, unrealistic amounts are required, which means water more or less need to be used in addition.

## 8.4 Section of wells

The wells presented in the final results are just the best combination of wells of the scenarios simulated in this study. Most likely, other combination of wells could have given better results. By the use of more producers for example, more of the oil could maybe have been produced for a shorter time period. To find the optimum solution could be an own study itself, since it would be really comprehensive. The problem cannot be categorized to be linear, so to optimize the well placements is very hard. Also the wells more suitable for $CO_2$ flooding do not necessary mean that these well locations are the best for water flooding. The locations were first of all chosen because it was suitable for $CO_2$ injection.

## 8.5 Brent group for $CO_2$ storage

The amounts of $CO_2$ injected in this study are huge, and shows the potential for the Brent formation for storage of $CO_2$. Since it has been a petroleum system where petroleum has been sealed, it is well known to be a good trap. This is very important to know, that the $CO_2$ you inject will stay in the underground and not leak out of the reservoir. Also, since the reservoir pressure is as low as 70 bar, large volumes of $CO_2$ can be injected before the reservoir pressure reaches the initial reservoir pressure of 383 bar (Haugen et al., 1988). Even if the pressure reaches the initial reservoir pressure, it is known that the reservoir can handle this pressure and not fracture, which can destroy the trap. Another factor that should be investigated further before using the reservoir for $CO_2$ storage, is how the plugged wells in the reservoir will handle the environment with $CO_2$ in the reservoir. This may not have been taken into account when the wells were plugged. If for example corrosion is taking place for the plugged wells, this can cause a significant risk concerning leaking of $CO_2$ from the reservoir.

## 8.6 Effect of reinjection of produced gas

It can be hard and expensive to separate the $CO_2$ from the produced gas, compared to separate the $CO_2$ and the oil. Since the produced gas has a very high content of $CO_2$, the $CO_2$ needs to be removed if the hydrocarbon gas is going to be sold. Another option is to reinject all the produced gas together with the $CO_2$. In this way less amounts of $CO_2$ will be required. In the field scale case of injection of pure $CO_2$, the reinjection of the produced gas does not look to have any effect at all. In the pair of injector/producer case on the other hand, it is actually increasing the production significantly. The difference is probably due to the fact that the produced associated hydrocarbon gas has a larger fraction of the injected gas in the pair of injector/producer case. This makes that the effects of the reinjection can be seen easier here. The increased production can be due to the sweep efficiency gets better, due to the gravity difference between the injected components. Since $CO_2$ has been injected already for 10 years before the injection of the produced gas starts, the paths where the $CO_2$ has been flowing are already good swept. The hydrocarbon gas has another gravity and will because of this sweep other parts of the reservoir.

The component $C_3$-$C_6$ has a higher gravity, and will because of this sweep lower layers better.

In the pair of injector/producer study, all the produced gas for the whole field is injected into the one injection well that is studied here. The composition of the injected gas can be seen in Figure 7.15. Since all the hydrocarbon gas injected is the two lightest hydrocarbon components in the model, the production of these will also increase a lot in the production well studied. Almost no gas of the two heaviest components are injected, but a significant increase in the production of these can be observed. The extra oil production because of reinjection, can be explained by the increase in production rate of these two components. Especially the $C_7$-$C_{19}$ component. This component is the main reason for the increased oil production. The component production rates due to the reinjection can be observed in Figure 8.1, for the two heaviest components.

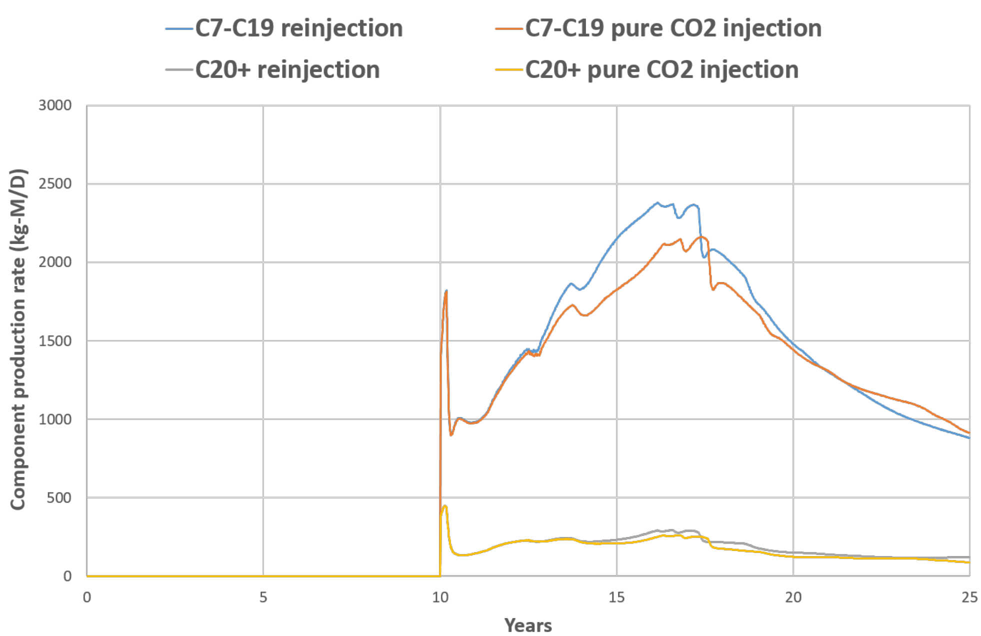


Figure 8.1: Component production rate for cases of pure $CO_2$ injection and injection of $CO_2$ and produced gas.

## 8.7 Component production

The same trends in the production of the different components can be observed both in the simulation on the field scale, but also for the pair of injector/producer study. The $C_7$-$C_{19}$ component is in all the scenarios the component with highest production rates, and this is probably due to the high content of this component initially. Since the oil field has been turned into a gas field in the late life of the field, a lot of the lightest components have most likely been produced during this period. But significant amounts of the lightest components are still left, which can be observed in the component production rates.

## 8.8 Economics

The economical calculations show some negative results for the scenarios looked at in this study, except if the price of the $CO_2$ is lower than 10 USD/bbl. Since the production is supposed to start late, after 10 years of injection, the discount rate for the NPV calculations gets really low. Even if significant volumes of oil are being produced, the total economic prospects of the project are negative. Also, there are a lot of uncertainties in these numbers. All the costs, price of $CO_2$ and the economic benefits of storing the $CO_2$ are very uncertain.

## 8.9 Effect of permeability heterogeneities

Due to permeability heterogeneities within the Brent formation, the injected $CO_2$ is not flowing as a shock front through the reservoir. The $CO_2$ flows much faster in the layers with higher permeability. Arshad et al. (2009) consider the performance of the $CO_2$ as a strong function of how homogeneous the reservoir is, since more of the oil will be contacted in this way. Low vertical permeability in addition to heterogeneities in horizontal permeability, makes the vertical sweep efficiency not so good in this case. Figure 8.2 shows how the $CO_2$ flows faster in layers with high permeability, due to heterogeneities. The gravity differences have also a big impact on the flow pattern. See appendix for the permeability distribution between the two wells.

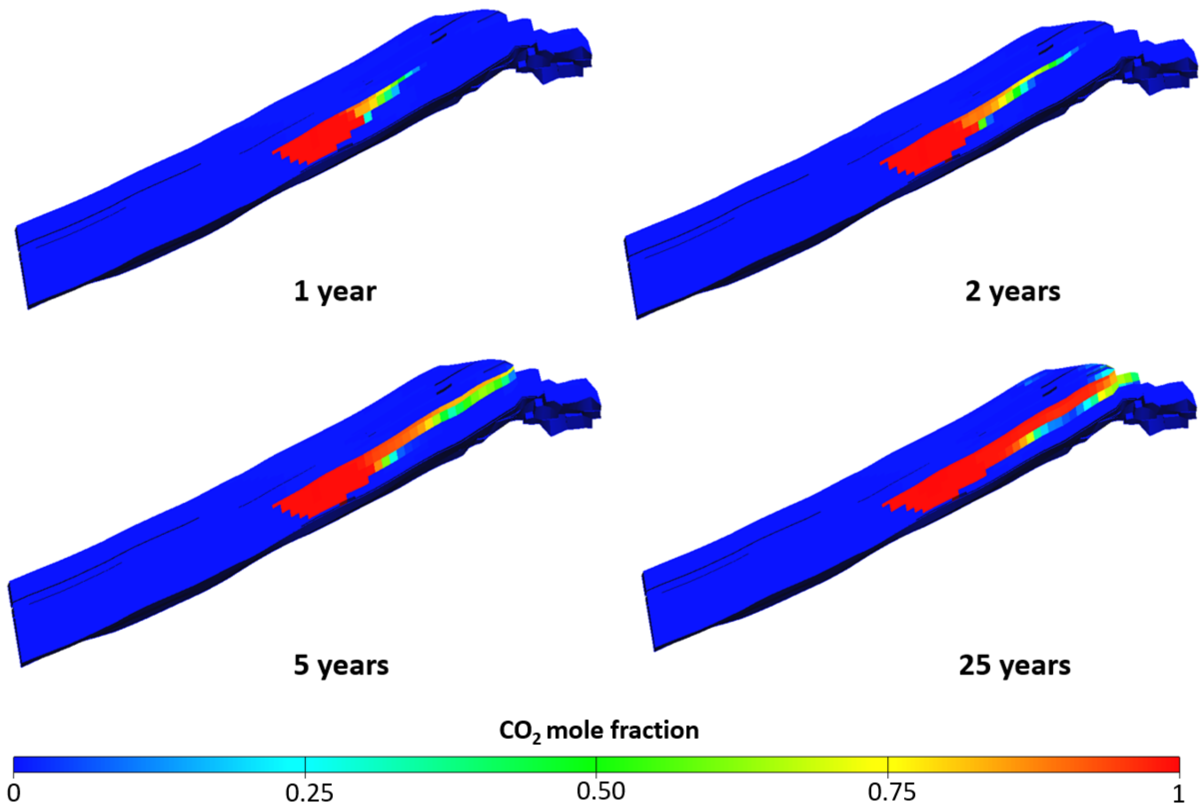


Figure 8.2: Movement of $CO_2$ between the injector and producer studied.

## 8.10 Oil production

The volumes of oil produced here are a function of the length of the simulations. The longer the simulations are, the more oil will be produced. It was decided at the start of the project, to set a limited timeframe and look at the potential within this period. Of course, different time-frames could have been chosen and may lead to different results. An extended simulation of 25 years can be seen in Figure 8.3 for the scenarios with 22 MTY and 5 MTY $CO_2$ injection. These simulations were done to see how the oil production would continue in the years after 2056. As Figure 8.3 shows, a lot of oil can be still produced with the same wells, after the timeframe used in this study. After 25 more years of production, the total oil production is doubled for the two scenarios.

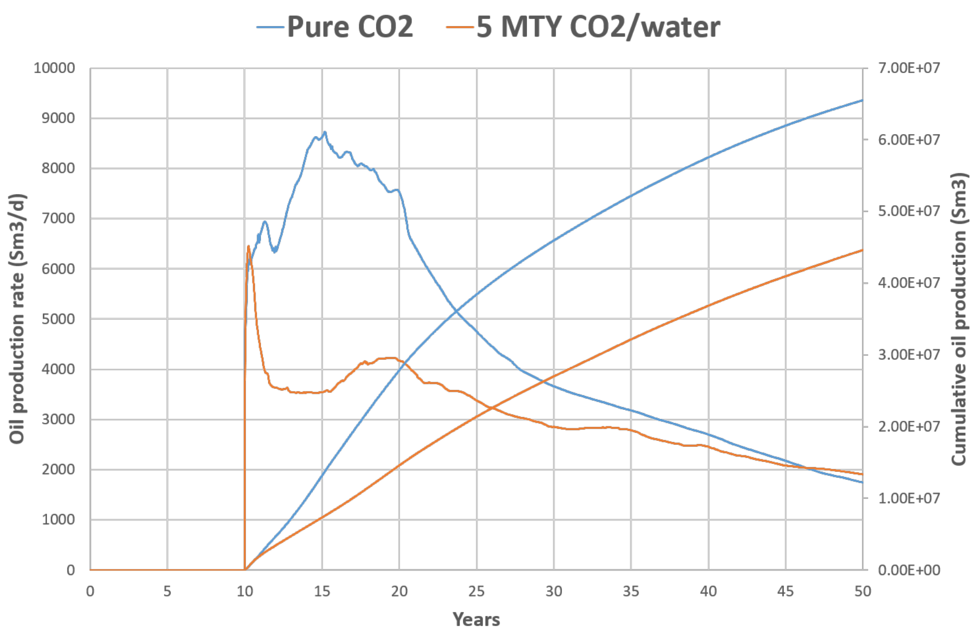


Figure 8.3: Oil production for extended simulation time, for the scenarios with injection of 22 MTY and 5 MTY $CO_2$.

## 8.11 Density/viscosity change and residual oil

The big changes in viscosity and density for the gridblock studied between the injector and the producer, can be explained by Figure 8.4. Because of the high pressure, the components will be in liquid state after pressure build up. The figure is showing the change in the liquid component mole fraction in the gridblock studied earlier, for the scenario of pure $CO_2$ injection. The content of all the hydrocarbon components is decreasing, except the component containing $C_{20+}$. This can explain the increase in viscosity and density for the gridblock presented in the results. The higher hydrocarbon components are more viscous and denser compared to the lighter. The oil left in the gridblock will because of this get a higher viscosity and density. This can maybe also explain the residual oil left in Figure 7.17. It indicates that the heaviest component is not fully miscible with the $CO_2$ and due to this not produced as effectively. Change in density, viscosity and oil saturation for other gridblocks can be observed in the appendix.

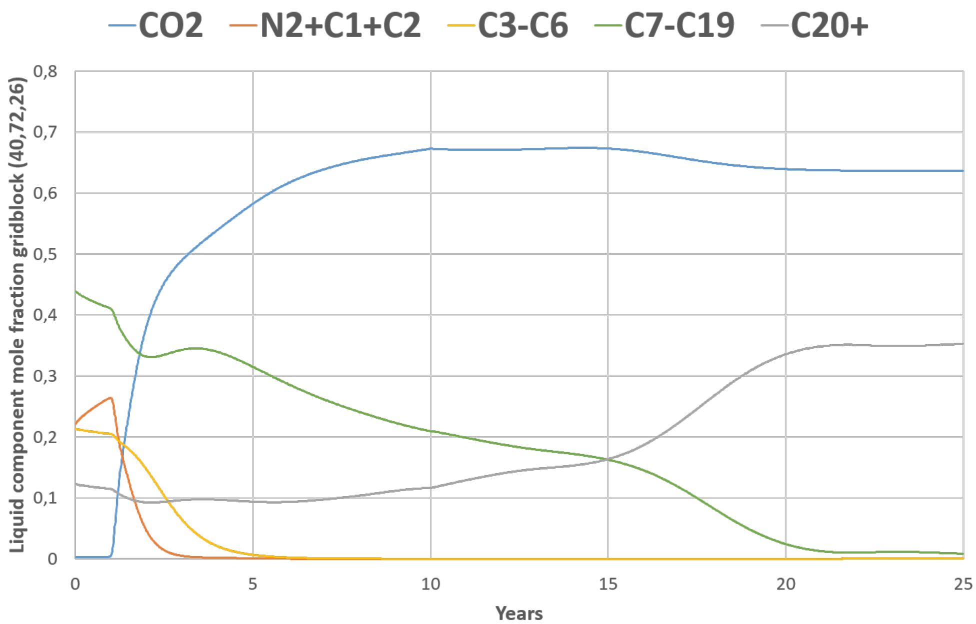


Figure 8.4: Liquid component mole fraction in gridblock (40,72,26) between the injector and the producer for the case of pure $CO_2$ injection.

## 8.12 Injection strategies

As the results show, the best injection strategy in this study was continuous $CO_2$ injection, or with reinjection of produced gas. This was surprising, since a $CO_2$ WAG process was expected to have a better sweep efficiency, with a more favorable mobility ratio and a better vertical sweep efficiency. A reason can be that large amounts of oil are in the upper layers, where the $CO_2$ is flowing, and a certain amount is needed for mobilizing all this oil. Also, the water in the lower layers is not flowing as easily upwards, towards the production wells as the $CO_2$, due to gravity and viscosity. Just half the amount of $CO_2$ is injected in the WAG scenarios, and consequence can be that the layers where the $CO_2$ is flowing, are not as good swept as for continuous $CO_2$ injection. It is worth mentioning that hysteresis effects were not taken into account for the WAG simulations, which should be done since the relative permeability of the fluids is dependent on the direction of saturation change (Petrowiki.org, 2016b).

# Chapter 9

# Conclusions

- The EOR potential on the Norwegian continental shelf is great, with an expected recovery for oil fields just 46 %.
- Due to miscibility between $CO_2$ and oil, viscosity reduction, interfacial tension reduction, oil swelling and small density contrasts, $CO_2$ can improve both the displacement efficiency and the volumetric sweep efficiency.
- The reservoir properties for the Brent group after production stop are matching well with the screening criteria presented, except the heterogeneities in permeability and the reservoir pressure. Due to this a pressure build up is required for achieving miscibility between the reservoir oil and the $CO_2$.
- MMP for the $CO_2$ and the oil is 270 bar, and a yearly injection of 22 million tons of $CO_2$ over 10 years is required for starting production with a reservoir pressure above MMP.
- Evaluated injection strategies during the pressure build up and production are injection of pure $CO_2$, pure water and a combination of $CO_2$ and water. Pure $CO_2$ gives the best results.
- Of the injection strategies studied in this thesis, continuous $CO_2$ looks to be the most efficient injection strategy.
- The length of the cycles in a $CO_2$ WAG does not matter in the scenarios tested here. About

the same results are obtained for the different cycle lengths.

- For a scenario with 10 years of pressure build up and 15 years of production, an enhanced oil recovery of 5.4% of OOIP was achieved for the best scenario.
- The injection strategy does not seem to have an effect on the distribution of the produced oil components.
- The heaviest component in the compositional model $C_{20+}$ seems to not be fully miscible with the $CO_2$ under the conditions used here.
- 72-90% of the $CO_2$ injected is stored in the Brent group and the percentage will be higher if the produced $CO_2$ is reinjected.
- The Brent group is excellent for $CO_2$ storage since large amounts of $CO_2$ can be injected before reaching the original reservoir pressure.
- Reinjection of the produced gas together with the $CO_2$ gives a higher oil production. In addition, reinjection of the produced gas will limit the required amounts of $CO_2$ after production starts.
- Large amounts of $CO_2$ are required for enhancing the oil recovery significant, and probably more than are available in 2031.
- Large investments need to be made for production facilities, wells, transportation and other upgrades to handle the challenges associated with $CO_2$.
- Unless $CO_2$ can be brought to the oil field for 10 USD/bbl or less, the NPV for the project is negative during the timeframe used here. There are big uncertainties in the input for the economic calculations, but can be used for guidance.
- An increasing viscosity and density of the oil can be observed for the swept areas, and this is due to the heaviest oil component, $C_{20+}$, is not being produced as easy as the lighter components.

## 9.1 Suggestion for further work

- Study the potential for immiscible $CO_2$ flooding in the Brent group, since this will require less amounts of $CO_2$. Also, production can start earlier, due to less pressure build up and this may be positive seen from an economic point of view.
- Compare up-dip injection of the $CO_2$ to the down-dip strategy used in this study.
- Try other combinations of wells, and also more producers where more oil can be produced for a shorter time period.
- Study a smaller oil field, where smaller amounts of $CO_2$ can make a certain difference in oil recovery.

# Nomenclature

| | |
|---|---|
| $E_R$ | Recovery efficiency |
| $E_D$ | Displacement efficiency |
| $E_V$ | Volumetric sweep efficiency |
| $E_A$ | Areal sweep efficiency |
| $E_I$ | Vertical sweep efficiency |
| k | Permeability |
| M | Molecular mass |
| P | Pressure |
| $P_c$ | Capillary pressure |
| r | Pore radius |
| T | Temperature |
| $\lambda$ | Mobility |
| $\mu$ | Viscosity |
| $\sigma$ | Interfacial tension |

# Abbreviations

| | |
|---|---|
| API | American Petroleum Institute gravity |
| atm | Atmosphere |
| bbl | Barrel |
| BHP | Bottom hole pressure |
| C | Celsius |
| cc | Cubic centimeters |
| cp | Centipoise |
| d | Day |
| EOR | Enhanced oil recovery |
| EOS | Equation of state |
| F | Fahrenheit |
| FCM | First contact miscibility |
| ft | Feet |
| FVF | Formation volume factor |
| g | Gram |
| GOR | Gas oil ratio |
| HCPV | Hydrocarbon pore volume |
| IOR | Improved oil recovery |
| kg | Kilo gram |
| km | Kilo meter |
| m | Meter |
| MCM | Multi contact miscibility |

| | |
|---|---|
| md | Millidarcy |
| mnd | Month |
| MMP | Minimum miscibility pressure |
| MTY | Million ton per year |
| NOK | Norske kroner |
| NPD | Norwegian Petroleum Directorate |
| NPV | Net Present Value |
| OOIP | Original oil in place |
| ppm | Parts per million |
| psi | Pounds per square inch |
| psia | Pounds per square inch absolute |
| PV | Pore volume |
| SAGD | Steam Assisted Gravity Drainage |
| scf | Standard cubic feet |
| $Sm^3$ | Standard cubic meter |
| STO | Stock tank oil |
| UK | United Kingdom |
| US | United States |
| USD | US Dollar |
| WAG | Water alternating gas |
| yr | Year |

# References


Agustssen, H. and Grinestafr, G. (2004). A study of ior by co2 injection in the gullfaks field, offshore norway. Society of Petroleum Engineers. doi:10.2118/89338-MS.

Akervoll, I., Bergmo, P. E., et al. (2010). Co2 eor from representative north sea oil reservoirs. In *SPE International Conference on CO2 Capture, Storage, and Utilization*. Society of Petroleum Engineers. doi:10.2118/139765-MS.

Arshad, A., Al-Majed, A. A., Menouar, H., Muhammadain, A. M., Mtawaa, B., et al. (2009). Carbon dioxide (co2) miscible flooding in tight oil reservoirs: A case study. In *Kuwait International Petroleum Conference and Exhibition*. Society of Petroleum Engineers. doi:10.2118/127616-MS.

Bjørnå, P. A. (2016). Co2 injection for enhanced oil recovery.

Boge, R., Lien, S. K., Gjesdal, A., Hansen, A.-G., et al. (2005). Turning a north sea oil giant into a gas field-depressurization of the statfjord field. In *Offshore Europe*. Society of Petroleum Engineers. doi:10.2118/96403-MS.

Brnak, J. J., Petrich, B., Konopczynski, M. R., et al. (2006). Application of smartwell technology to the sacroc co2 eor project: A case study. In *SPE/DOE Symposium on Improved Oil Recovery*. Society of Petroleum Engineers. doi:10.2118/100117-MS.

Crogh, N. A., Eide, K., Morterud, S. E., et al. (2002). Wag injection at the statfjord field, a success story. In *European Petroleum Conference*. Society of Petroleum Engineers. doi:10.2118/78348-MS.

Devegowda, D. (2016). Lecture notes from improved recovery techniques spring 2016. *University of Oklahoma*.

FN-Sambandet (2017). Dette er parisavtalen. Retrieved 27.05.2017 from `http://www.fn.no/Tema/Klima/Klimaforhandlinger/Dette-er-Paris-avtalen`.

Gao, P., Towler, B. F., Pan, G., et al. (2010). Strategies for evaluation of the co2 miscible flooding process. In *Abu Dhabi International Petroleum Exhibition and Conference*. Society of Petroleum Engineers. doi:10.2118/138786-MS.

Green, D. W. and Willhite, G. P. (1998). *Enhanced oil recovery*, volume 6 of *SPE textbook series*. Henry L. Doherty Memorial Fund of AIME, Society of Petroleum Engineers, Richardson, TX.

Habermann, B. et al. (1960). The efficiency of miscible displacement as a function of mobility ratio. Society of Petroleum Engineers.

Haraldsen, H. and Pedersen, B. (2016). karbondioksid. Retrieved 23.11.2016 from `https://snl.no/karbondioksid`.

Haugen, S. A., Lund, O., Hoyland, L. A., et al. (1988). Statfjord field: development strategy and reservoir management. *Journal of petroleum technology*, 40(07):863–873.

Holm, L. et al. (1986). Miscibility and miscible displacement. *Journal of Petroleum Technology*, 38(08):817–818.

Institute, G. C. (2017a). Sleipner co2 storage project. Retrieved 23.05.2017 from `https://www.globalccsinstitute.com/projects/sleipner%C2%A0co2-storage-project`.

Institute, G. C. (2017b). Snøhvit co2 storage project. Retrieved 23.05.2017 from `https://www.globalccsinstitute.com/projects/sn{\T1\o}hvit-co2-storage-project`.

Jarrell, P., Fox, C., Stein, M., and Webb, S. (2002). *Practical aspects of CO2 flooding*, volume 22 of *Henry L. Doherty series*. Henry L. Doherty Memorial Fund of AIME, Society of Petroleum Engineers, Richardson, TX.

Kossack, C. (2013). Eor processes - miscible gas injection. Retrived 03.12.2016 from `http://www.ipt.ntnu.no/~kleppe/pub/Kossack_Lecture_2013-EOR-Miscible.pdf`.

Kuuskraa, V., Wallace, M., et al. (2014). Co2-eor set for growth as new co2 supplies emerge. *Oil & Gas Journal*, 112(5):92–92.

Lake, L. W. (1989). *Enhanced oil recovery*. Prentice Hall, Englewood Cliffs, N.J.

Manrique, E. J., Thomas, C. P., Ravikiran, R., Izadi Kamouei, M., Lantz, M., Romero, J. L., Alvarado, V., et al. (2010). Eor: current status and opportunities. In *SPE improved oil recovery symposium*. Society of Petroleum Engineers. doi:10.2118/130113-MS.

Nilsen, J. (2016). Norsk co2-fangst og -lagring kan koste 12,6 milliarder. *Teknisk Ukeblad*.

NPD (2011). Improved recovery without side effects. Retrived 12.11.2016 from http://www.npd.no/en/Topics/Improved-Recovery/Temaartikler/Improved-recovery-without-side-effects/.

NPD (2014). *PETROLEUM RESOURCES ON THE NORWEGIAN CONTINENTAL SHELF*. Retrieved 17.10.2016 from http://www.npd.no/Global/Engelsk/3-Publications/Resource-report/Resource-report-2014/Resources-2014-nett.pdf.

NPD (2016). Fem milliarder fat olje og gass fra statfjord-feltet. Retrived 10.05.2016 from http://www.npd.no/no/Nyheter/Nyheter/2016/Fem-milliarder-fat-olje-og-gass-fra-Statfjord-feltet-/.

NPD (2017a). Factpages norwegian petroleum directorate: Ivar aasen. Retrived 11.05.2016 from http://factpages.npd.no/factpages/Default.aspx?culture=nb-no&nav1=field&nav2=PageView%7CAll&nav3=23384520.

NPD (2017b). Factpages norwegian petroleum directorate: Statfjord. Retrived 11.05.2016 from http://factpages.npd.no/FactPages/default.aspx?nav1=field&nav2=PageView%7CAll&nav3=43658.

Petrowiki.org (2015a). Compositional simulation of miscible processes. Retrived 20.03.2017 from http://petrowiki.org/Compositional_simulation_of_miscible_processes.

Petrowiki.org (2015b). Peh: Miscible processes. Retrieved 14.09.2016 from http://petrowiki.org/PEH%3AMiscible_Processes#Solvent_Trapping_and_Solvent_Relative_Permeability_Hysteresis.

Petrowiki.org (2015c). Phase behavior of pure fluids. Retrieved 18.12.2016 from http://petrowiki.org/Phase_behavior_of_pure_fluids.

Petrowiki.org (2016a). Enhanced oil recovery (eor). Retrieved 14.05.2017 from http://petrowiki.org/Enhanced_oil_recovery_(EOR).

Petrowiki.org (2016b). Relative permeability. Retrieved 22.11.2016 from http://petrowiki.org/Relative_permeability#Hysteresis.

Schlumberger (2016a). oil swelling. Retrieved 14.11.2016 from http://www.glossary.oilfield.slb.com/Terms/o/oil_swelling.aspx.

Schlumberger (2016b). scale. Retrieved 15.11.2016 from http://www.glossary.oilfield.slb.com/Terms/s/scale.aspx.

Søndenå, E., Henriquez, A., et al. (2011). A new spring for eor in norway. In *20th World Petroleum Congress*. World Petroleum Congress.

SSB (2016). Utslipp av klimagasser. Retrieved 23.05.2017 from https://www.ssb.no/natur-og-miljo/statistikker/klimagassn/aar-endelige.

Taber, J., Martin, F., Seright, R., et al. (1997). Eor screening criteria revisited—part 2: applications and impact of oil prices. *SPE Reservoir Engineering*, 12(03):199–206.

Todd, M., Longstaff, W., et al. (1972). The development, testing, and application of a numerical simulator for predicting miscible flood performance. *Journal of Petroleum Technology*, 24(07):874–882.

Whitson, C. H., Brulé, M. R., et al. (2000). *Phase behavior*, volume 20 of *Henry L. Doherty series*. Henry L. Doherty Memorial Fund of AIME, Society of Petroleum Engineers, Richardson, TX.

Yuan, H., Johns, R. T., Egwuenu, A. M., Dindoruk, B., et al. (2005). Improved mmp correlation for co2 floods using analytical theory. *SPE Reservoir Evaluation & Engineering*, 8(05):418–425.

# Appendix A

# Additional Information

## A.1 Coefficients for pure $CO_2$ MMP correlation by Yuan et al. (2005)

$a_1$ = -1.4634 E+03, $a_2$ = 0.6612 E+01, $a_3$ = -4.4979 E+01, $a_4$ = 0.2139 E+01, $a_5$ = 1.1667 E-01, $a_6$ = 8.1661 E+03, $a_7$ = -1.2258 E-01, $a_8$ = 1.2283 E-03, $a_9$ = -4.0152 E-06, $a_{10}$ = -9.2577 E-04

## A.2 Coefficients for impure $CO_2$ MMP correlation by Yuan et al. (2005)

$a_1$ = -6.5996 E-02, $a_2$ = -1.5246 E-04, $a_3$ = 1.3807 E-03, $a_4$ = 6.2384 E-04, $a_5$ = -6.7725 E-07, $a_6$ = -2.7344 E-02, $a_7$ = -2.6953 E-06, $a_8$ = 1.7279 E-08, $a_9$ = -3.1436 E-11, $a_{10}$ = -1.9566 E-08

# Appendix B

# Additional results and figures

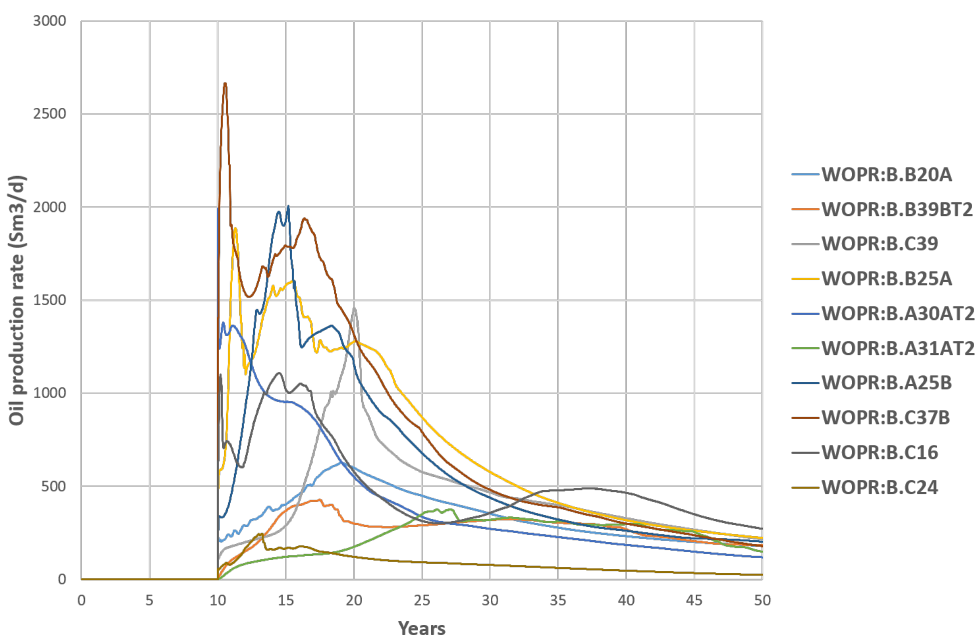


Figure B.1: Oil production for the different wells with injection of 22 MTY $CO_2$.

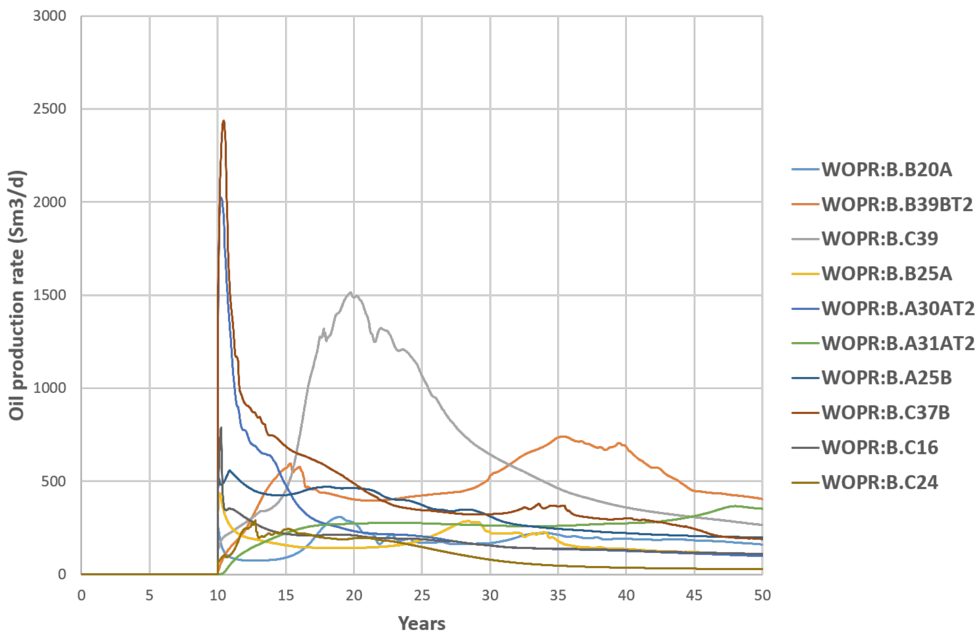


Figure B.2: Oil production for the different wells with injection of 5 MTY $CO_2$.

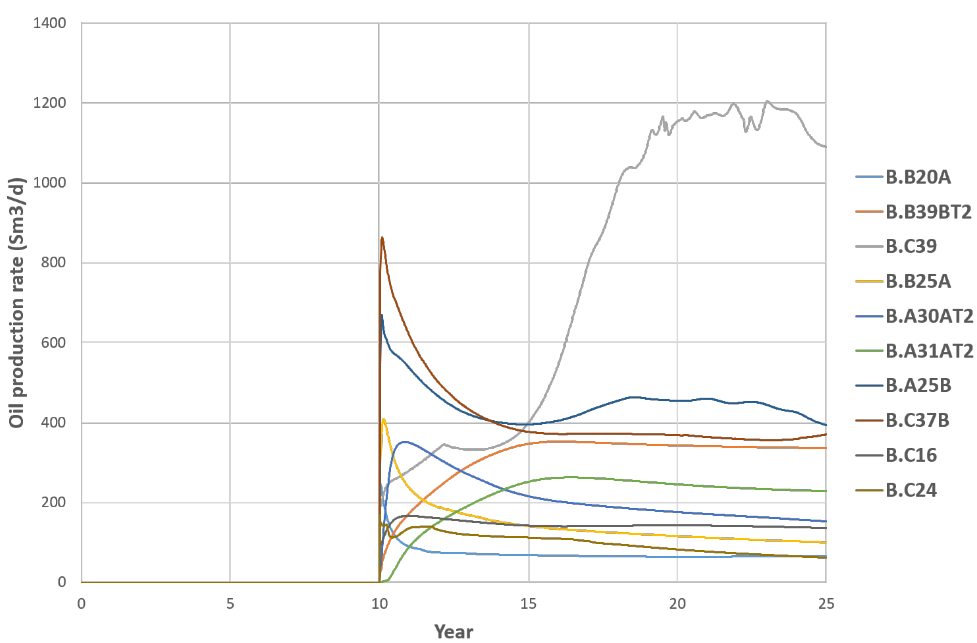


Figure B.3: Oil production for the different wells with injection of 1 MTY $CO_2$.

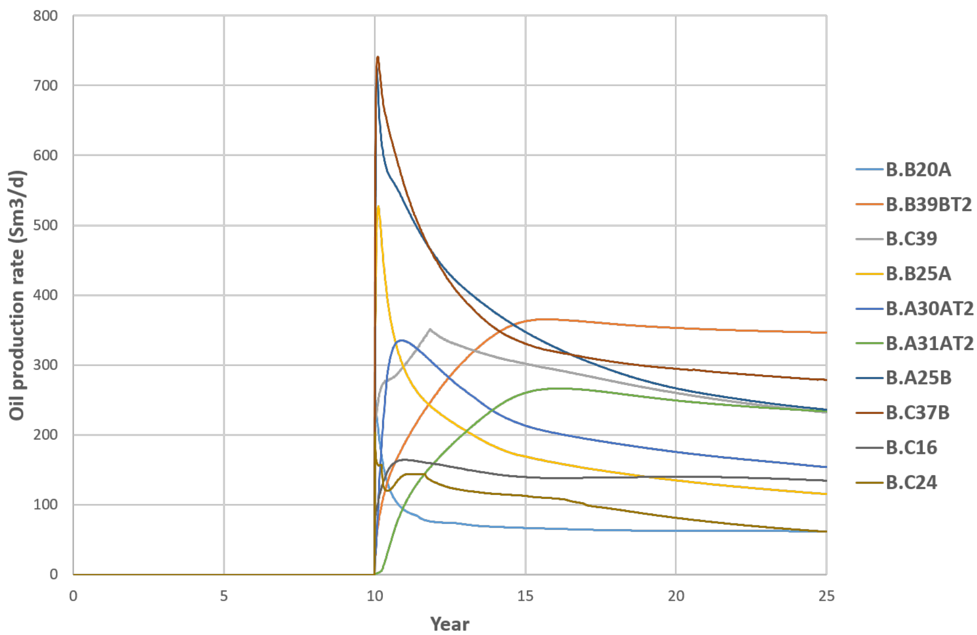


Figure B.4: Oil production for the different wells with injection of pure water.

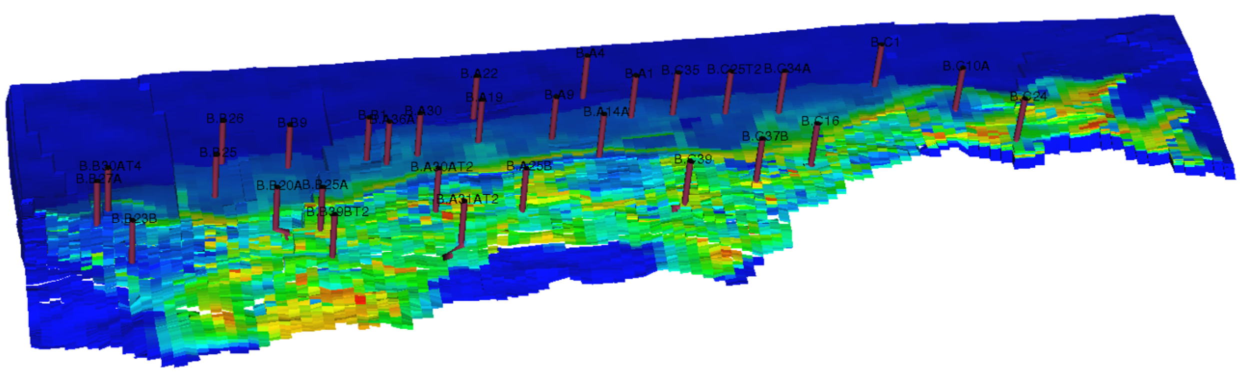

Figure B.5: Overview of wells used in best scenario with well names.

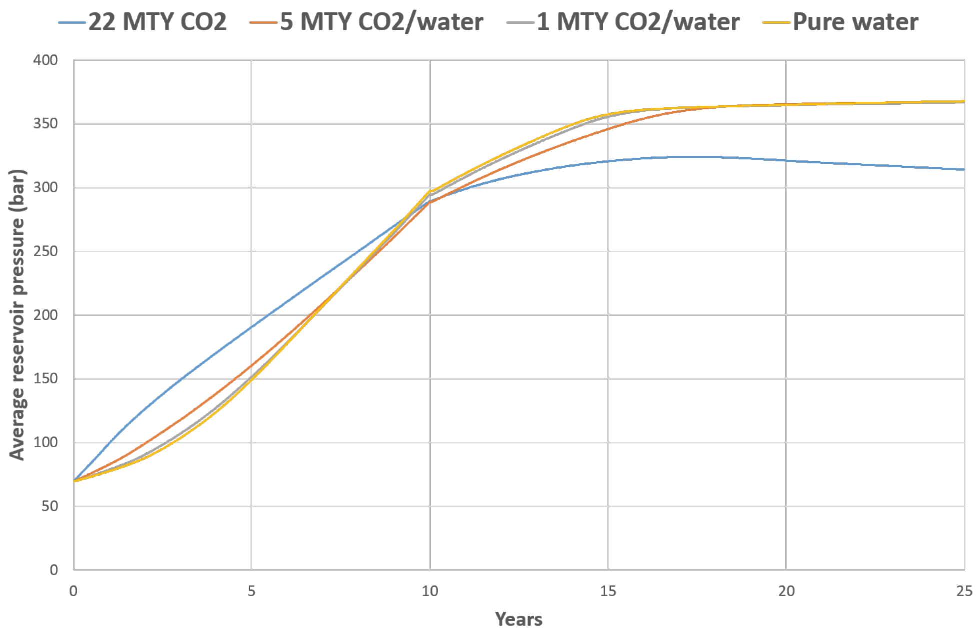


Figure B.6: Average reservoir pressure for scenarios on the field scale simulations.

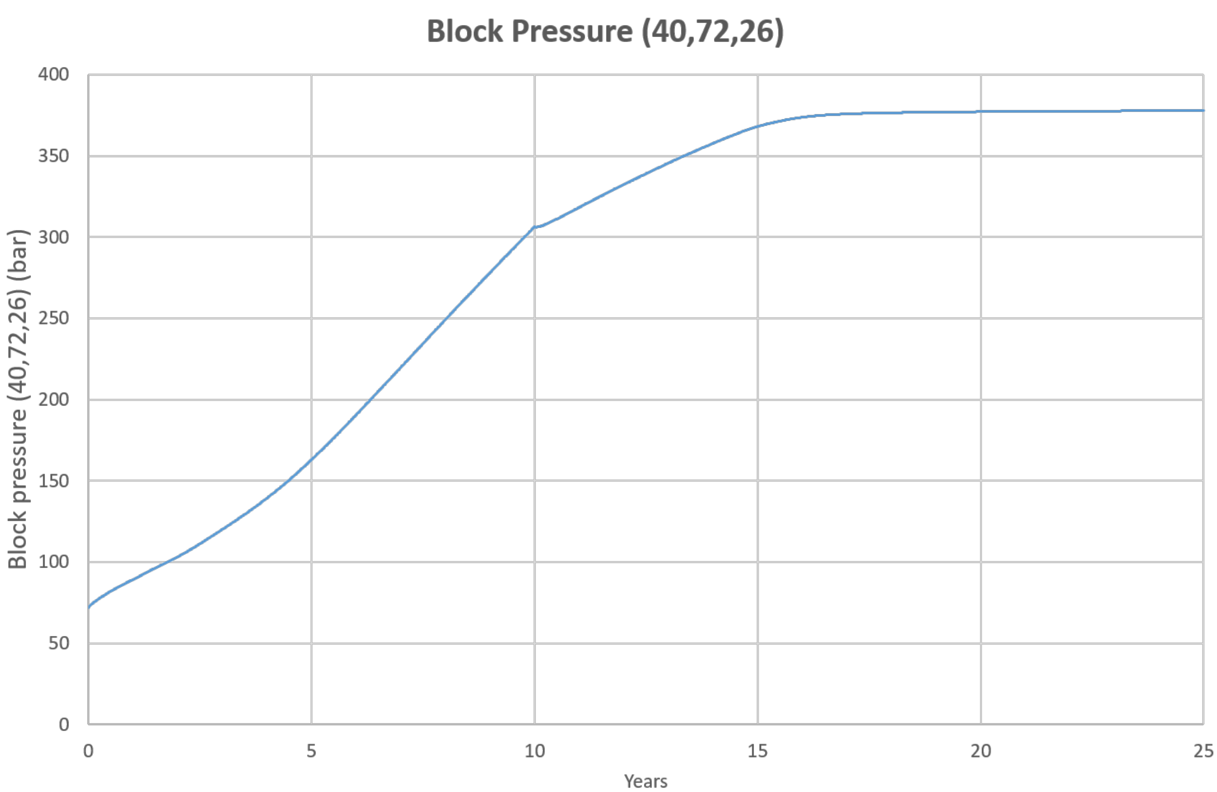


Figure B.7: Pressure in gridblock (40,72,26) for the pair of injector/producer studied.

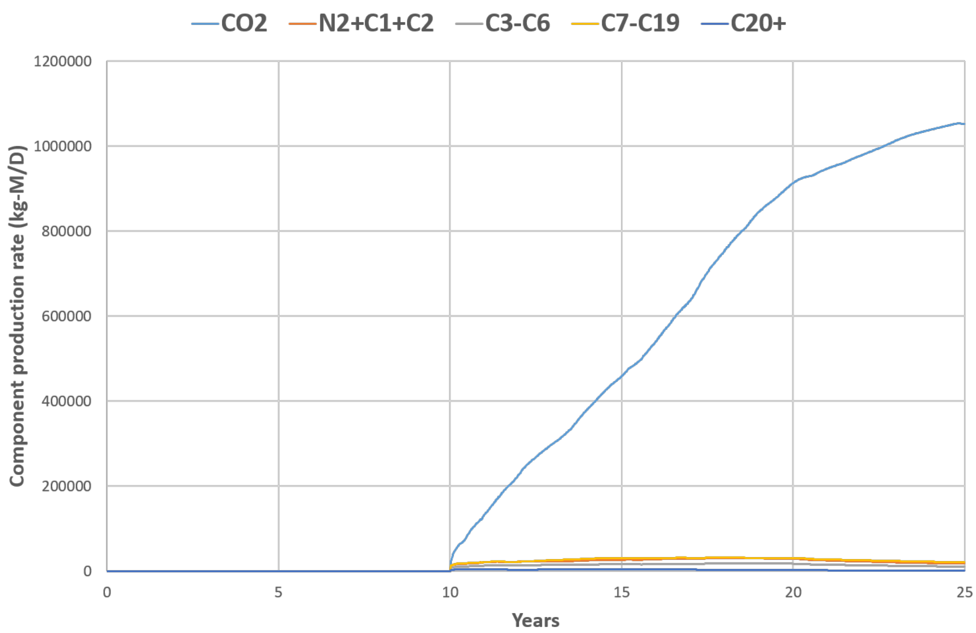


Figure B.8: Component production rate for the case with pure $CO_2$ injection, 22 MTY.

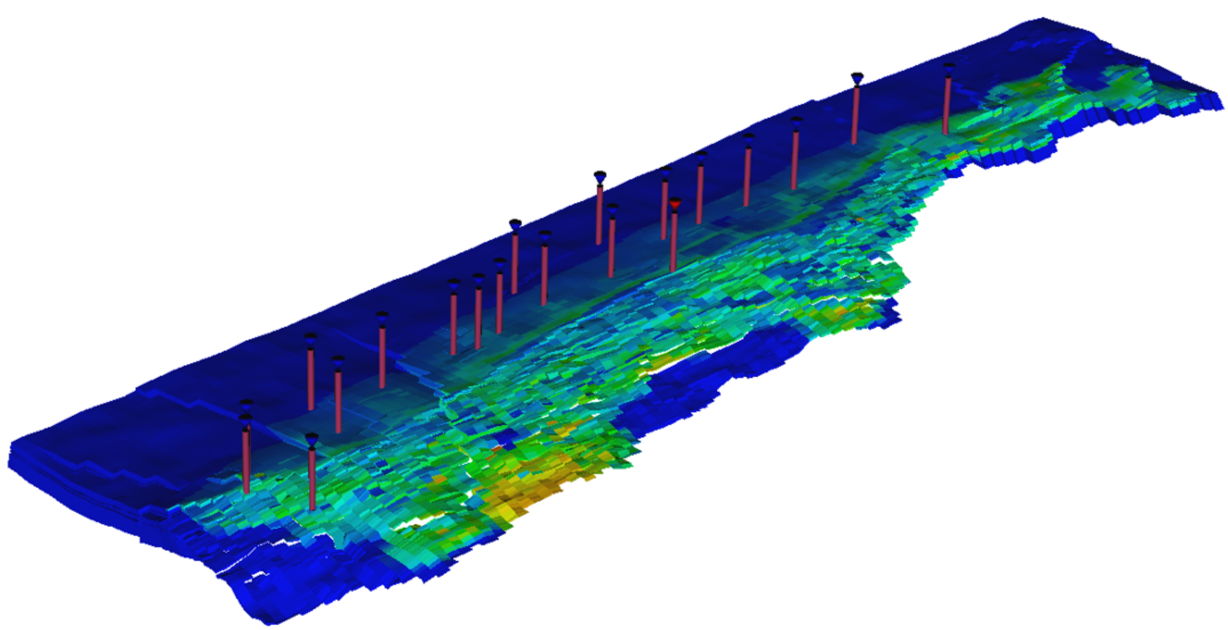

Figure B.9: Best scenario for the use of 1 MTY CO2. Injection of 1 MTY $CO_2$ in well B.A14A, and the rest water injection.

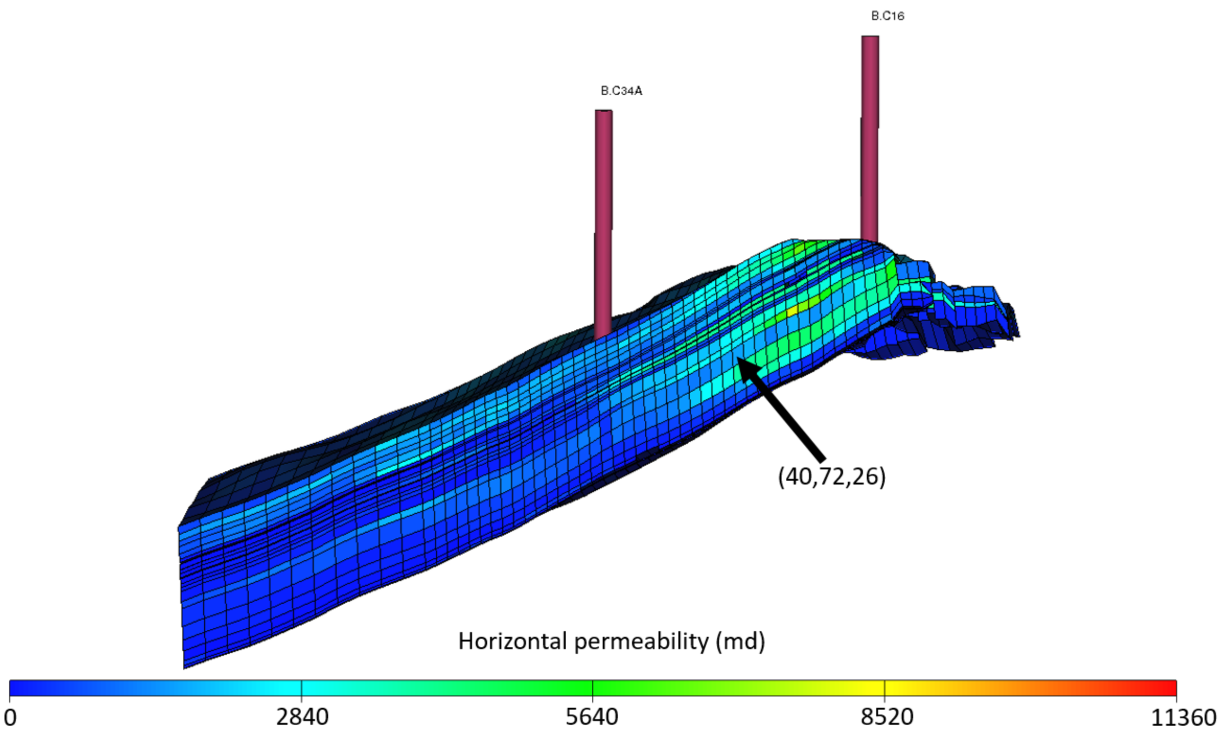


Figure B.10: Permeability between pair of injector and producer.

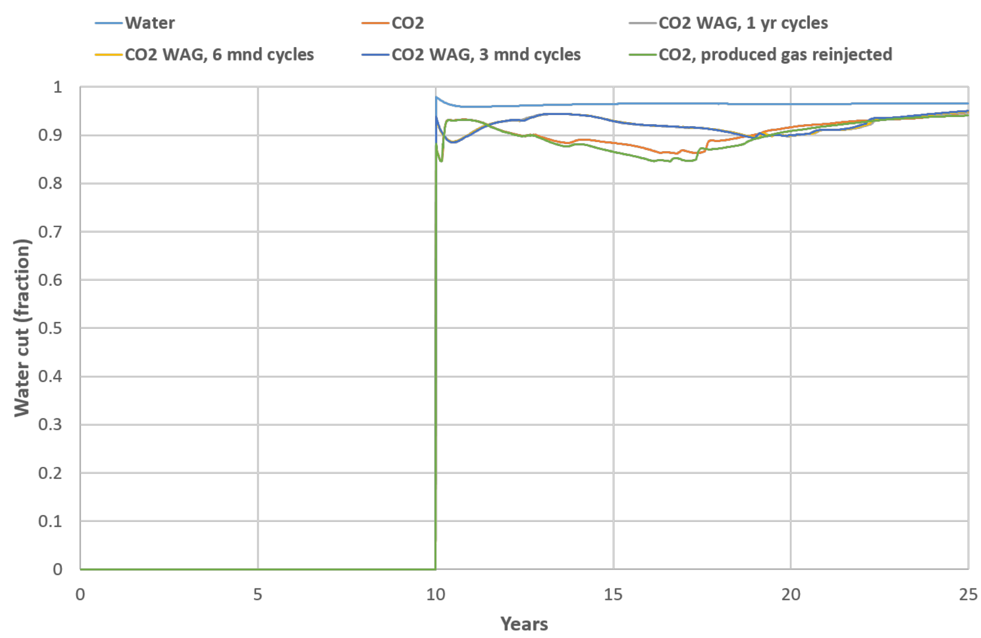


Figure B.11: Water cut for the different injection strategies in the study of an injector and a producer.

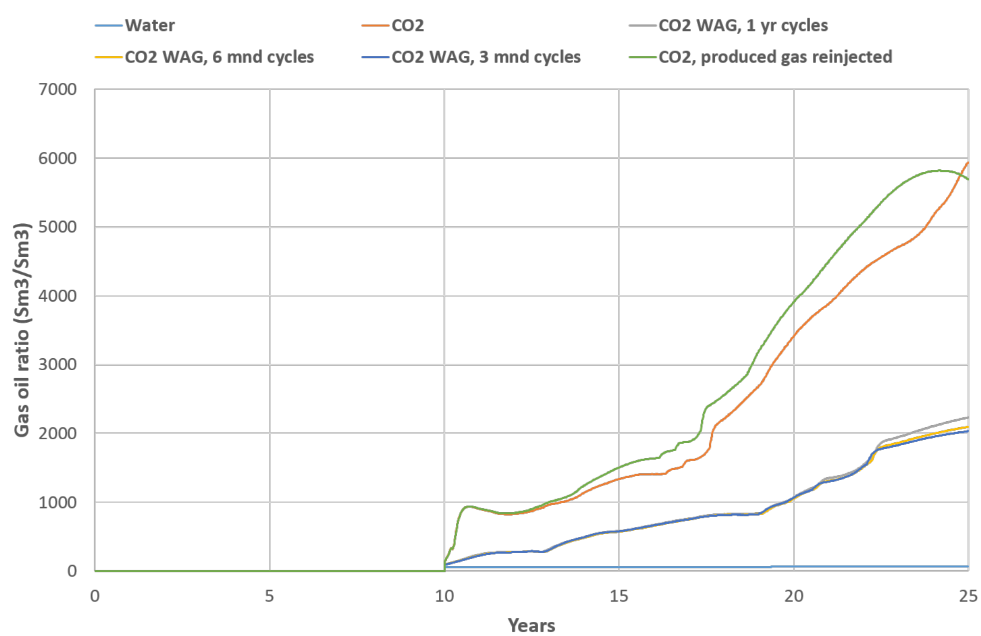


Figure B.12: GOR for the different injection strategies in the study of an injector and a producer.

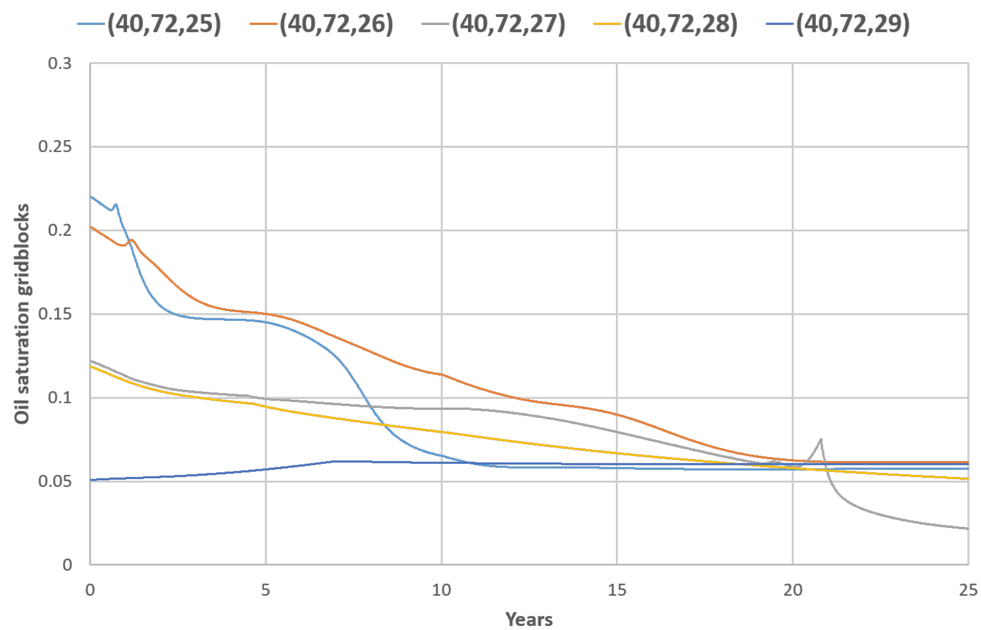


Figure B.13: Oil saturation for gridblocks between the injector and the producer with the injection of pure $CO_2$.

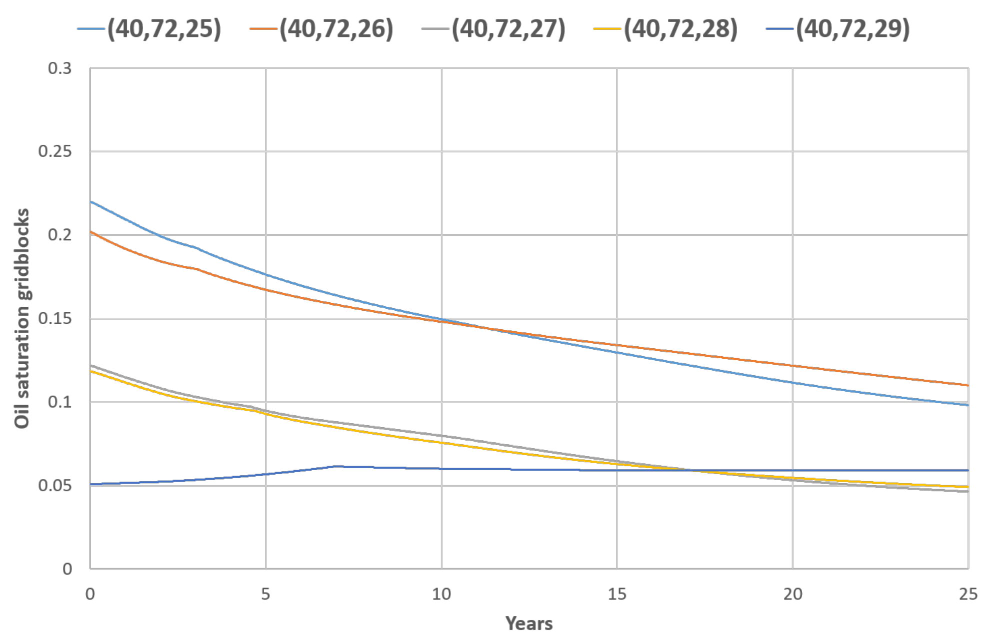


Figure B.14: Oil saturation for gridblocks between the injector and the producer with the injection of pure water.

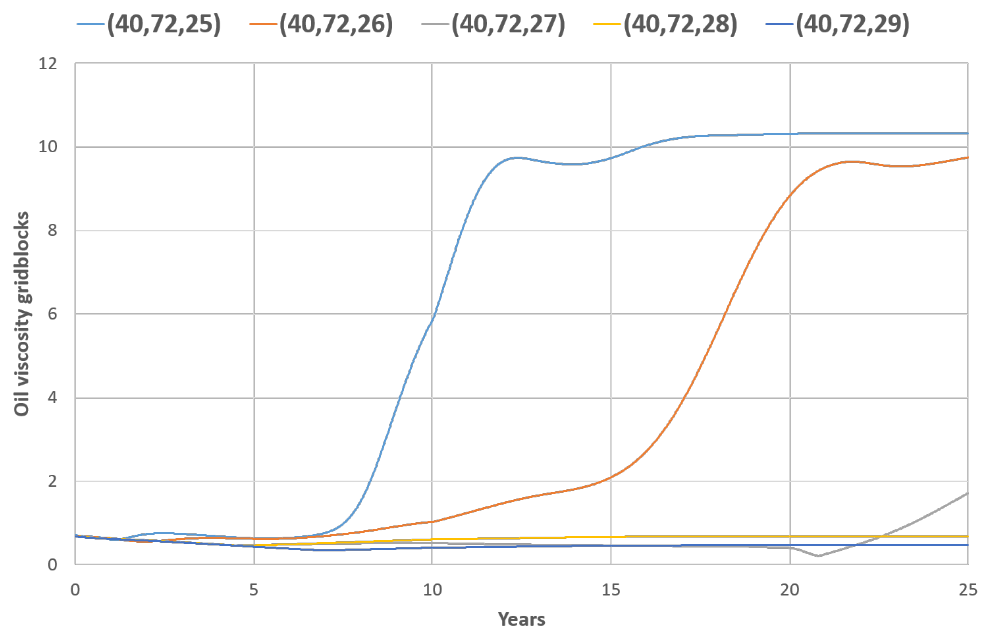


Figure B.15: Oil viscosity for gridblocks between the injector and the producer with the injection of pure $CO_2$.

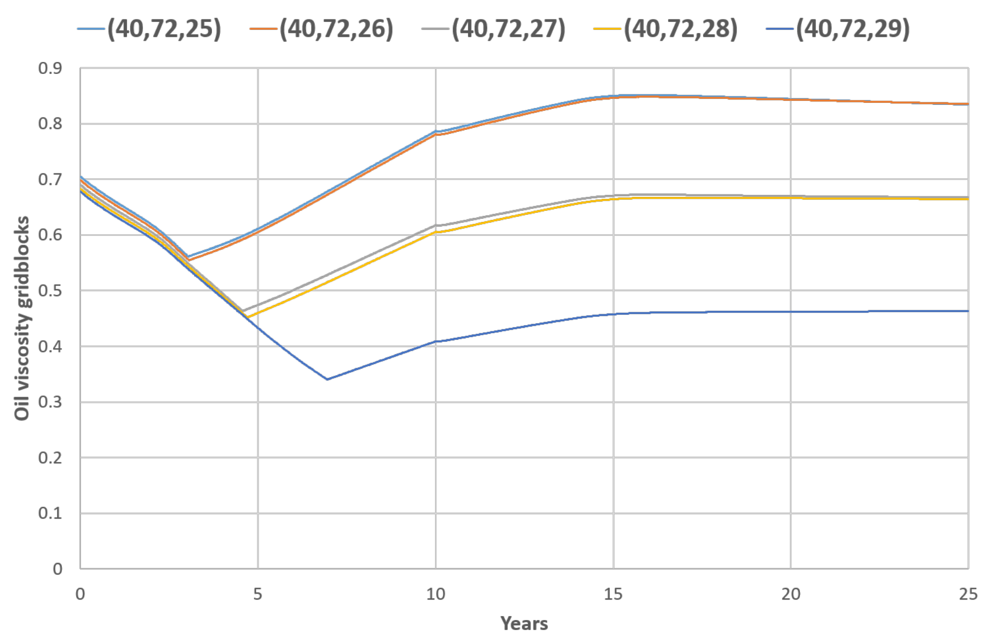


Figure B.16: Oil viscosity for gridblocks between the injector and the producer with the injection of pure water.

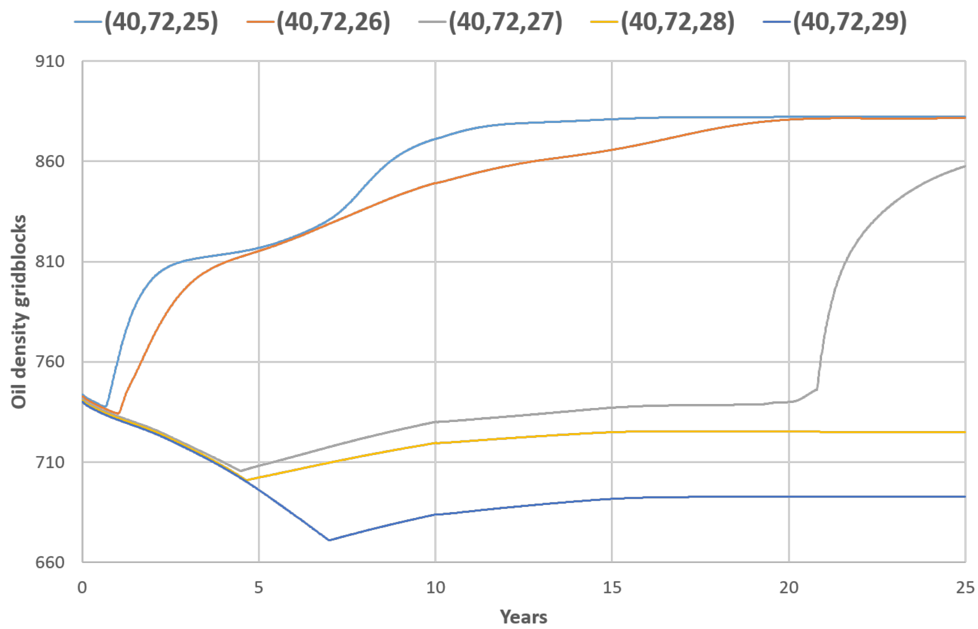


Figure B.17: Oil density for gridblocks between the injector and the producer with the injection of pure $CO_2$.

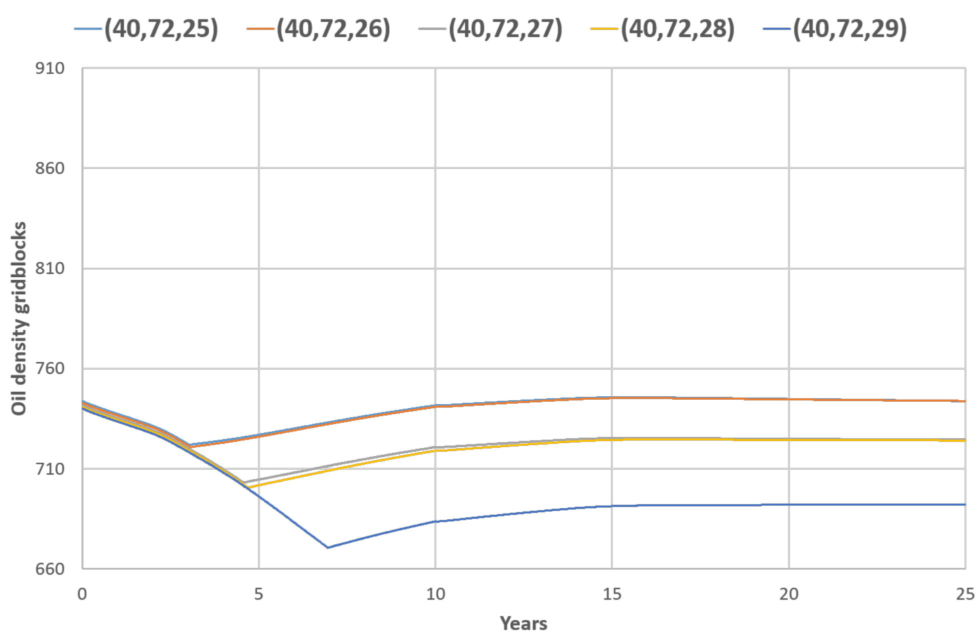


Figure B.18: Oil density for gridblocks between the injector and the producer with the injection of pure water.

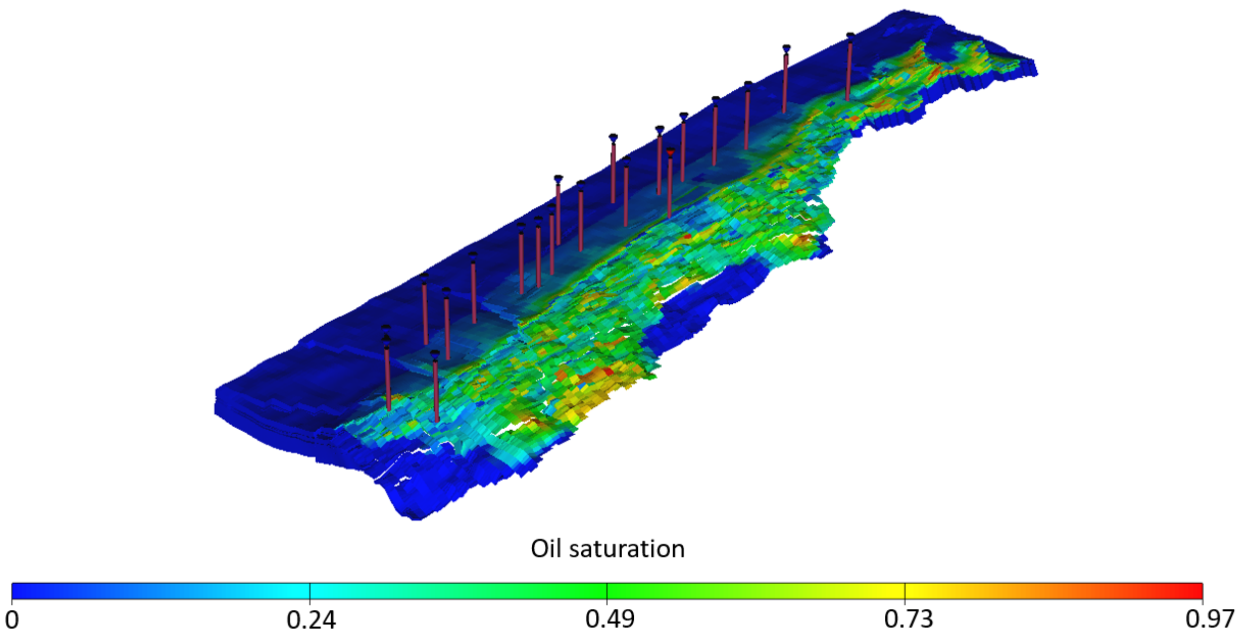


Figure B.19: Collection of oil after 10 years of injection with 1 MTY $CO_2$ and 19 water wells.

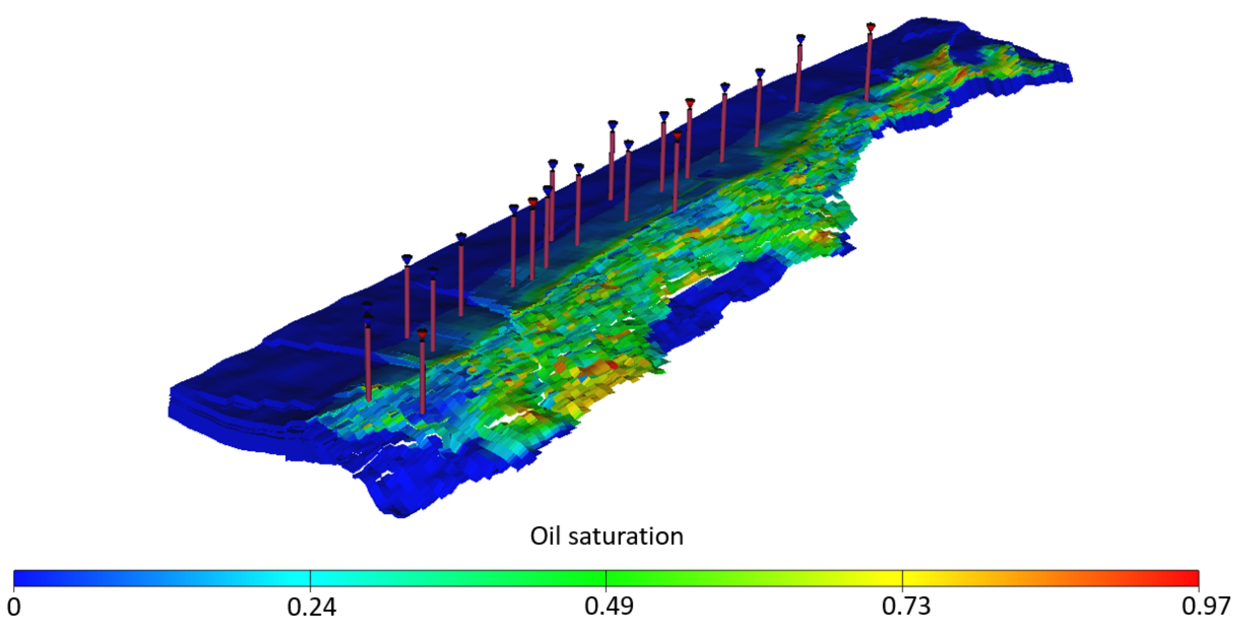


Figure B.20: Collection of oil after 10 years of injection with 5 MTY $CO_2$ and 15 water wells.

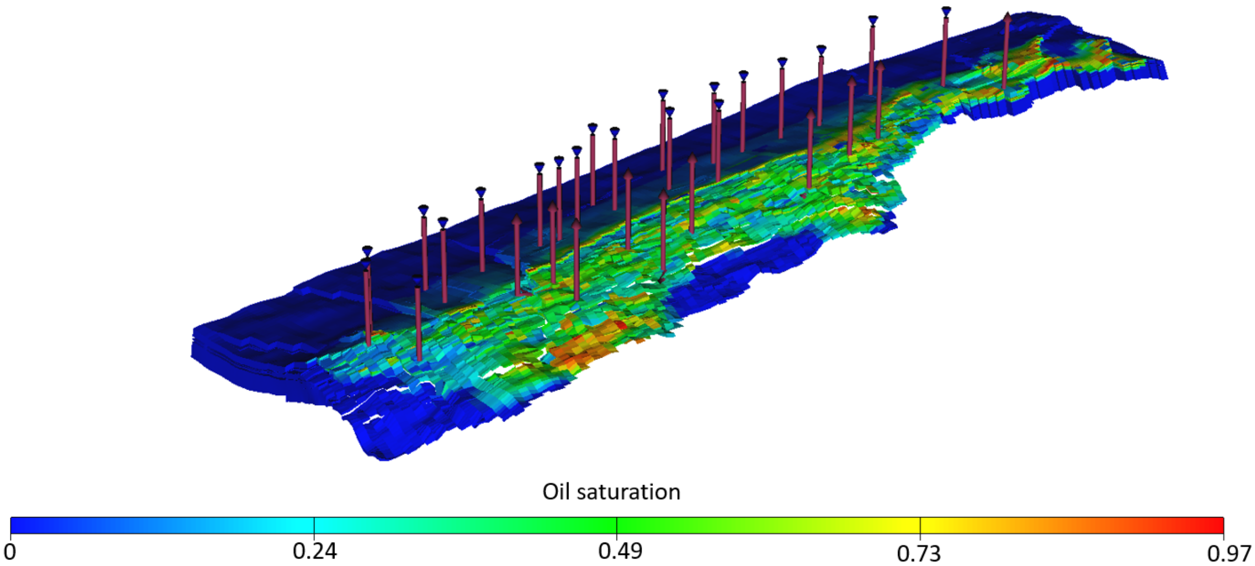


Figure B.21: Oil saturation in the reservoir after production stop in 2056 for pure water injection.

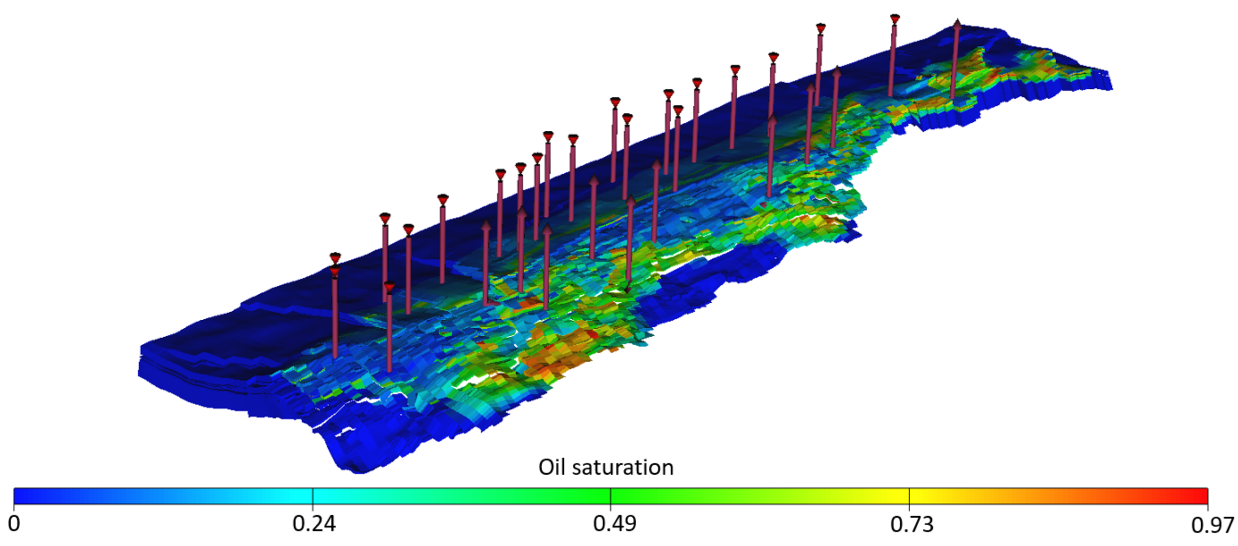


Figure B.22: Oil saturation in the reservoir after production stop in 2056 for pure $CO_2$ injection.

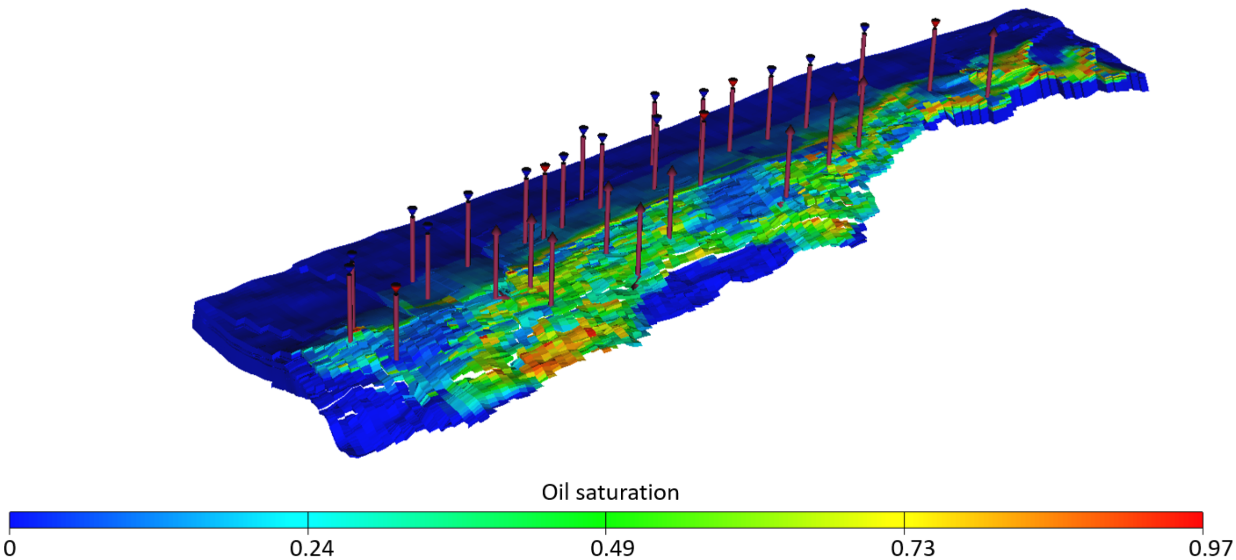


Figure B.23: Oil saturation in the reservoir after production stop in 2056 for 5 MTY $CO_2$ and water injection.

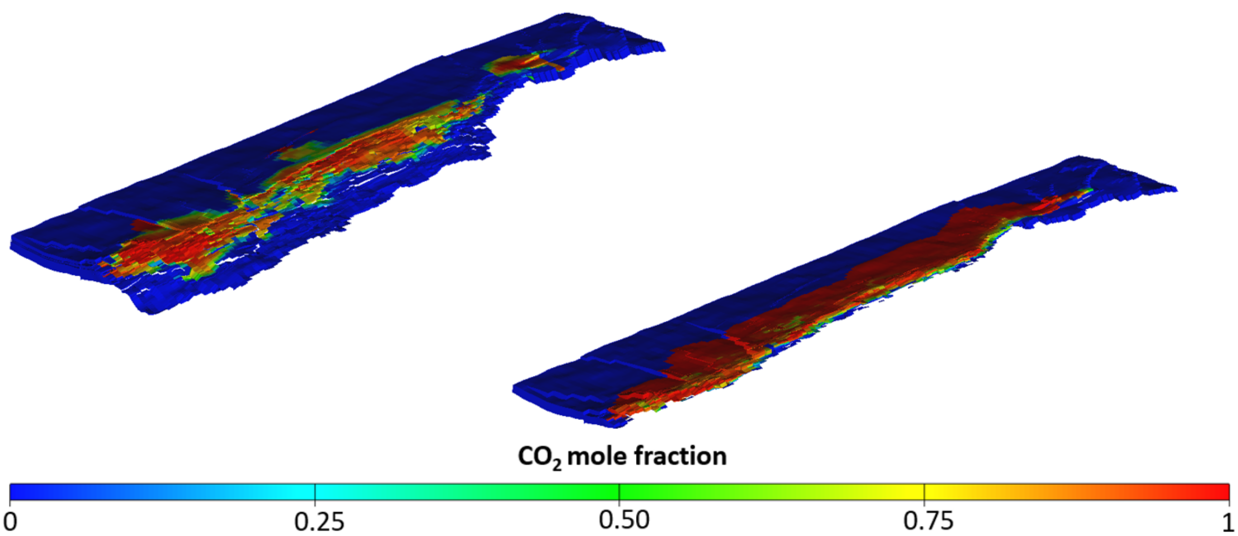


Figure B.24: $CO_2$ stored in the reservoir after production stop in 2056 for pure $CO_2$ injection.

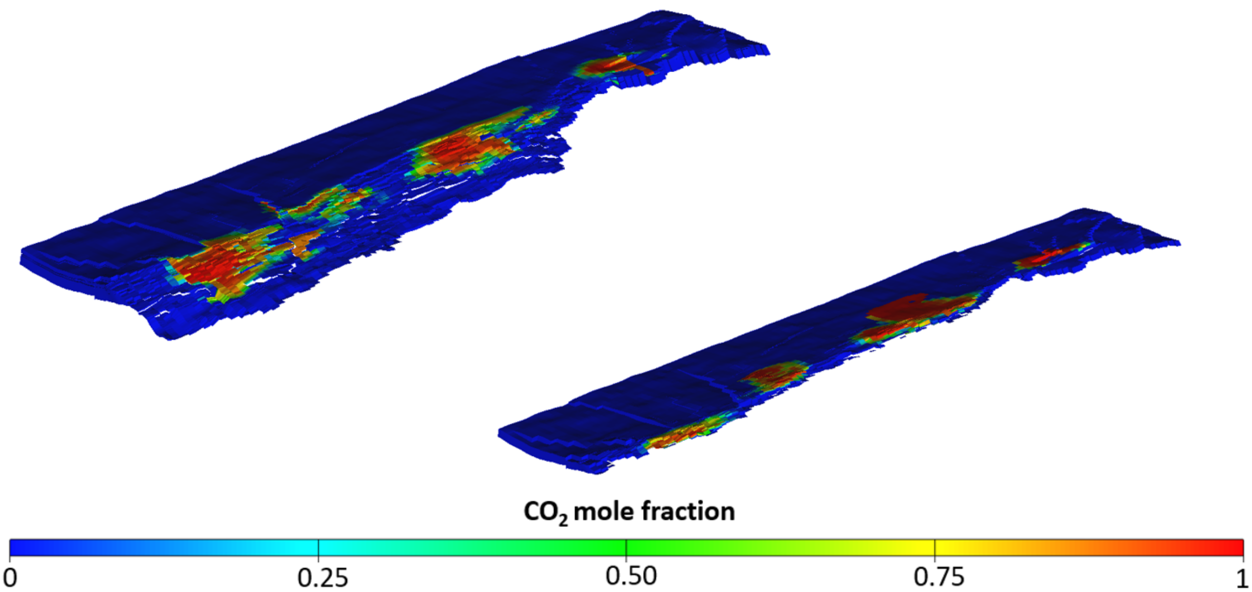


Figure B.25: $CO_2$ stored in the reservoir after production stop in 2056 for 5 MTY $CO_2$ and water injection.

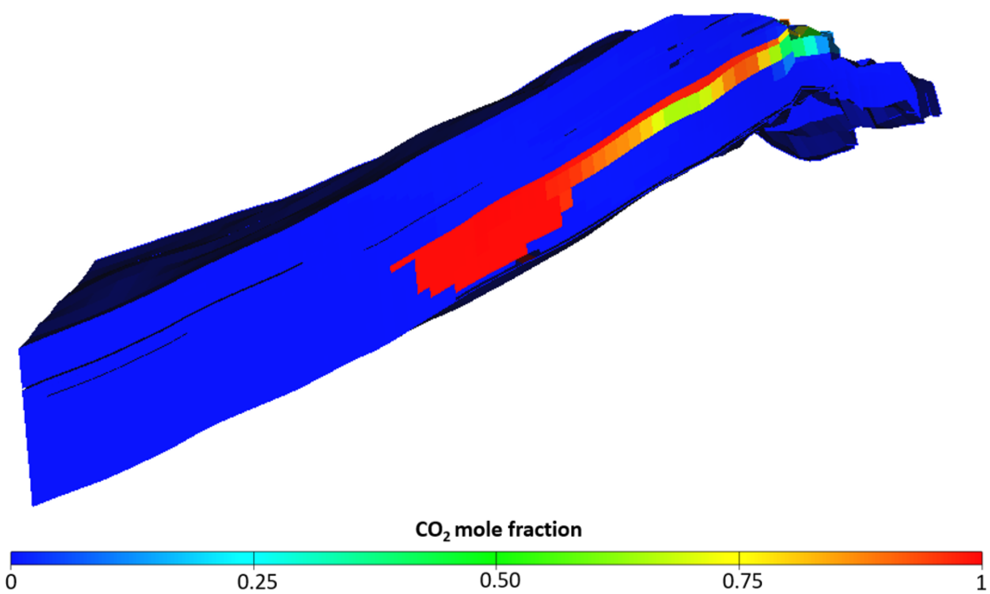


Figure B.26: Movement of $CO_2$ between the injector and producer studied for $CO_2$ WAG with 6 month cycles.

| | | |
|---|---|---|
| **Oil Price** | 80 | USD/bbl |
| | 503.2 | USD/Sm3 |
| | 4226.88 | NOK/Sm3 |
| **Discount rate** | 0.08 | |
| **Year now** | 2017 | |
| **Start project year** | 2031 | |
| | | |
| | | |
| **Conversion factors** | | |
| 6.29 | bbl/Sm3 | |
| 8.40 | NOK/USD | |
| | | |
| Costs | | |
| **Running a platform** | 8.50E+08 | NOK/year |
| **Prize per well** | 2.50E+08 | NOK |
| **CO2 Price** | 50 | USD/ton |
| | 420000000 | NOK/MT |
| Investments | | |
| **Number of injectors** | 20 | |
| **Number of procucers after 10 yrs** | 10 | |
| **Upgrades topside, tie-back etc** | 6.00E+09 | NOK |
| | | |
| **CO2 injection rate** | 22 | MTY |

| Year | Oil production (Sm3) | Volumes CO2 required (MTY) | Income (NOK) | CAPEX (NOK) | DRILLEX (NOK) | OPEX (NOK) | Total costs (NOK) | Cash flow (NOK) | Discount rate | Discounted cash flow (NOK) | NPV (NOK) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2031 | 0.00E+00 | 22 | 0.00E+00 | 6.00E+09 | 5.00E+09 | 1.01E+10 | 2.11E+10 | -2.11E+10 | 0.34 | -7.18E+09 | **-7.18E+09** |
| 2032 | 0.00E+00 | 22 | 0.00E+00 | 0.00E+00 | 0 | 1.01E+10 | 1.01E+10 | -1.01E+10 | 0.32 | -3.18E+09 | **-1.04E+10** |
| 2033 | 0.00E+00 | 22 | 0.00E+00 | 0.00E+00 | 0 | 1.01E+10 | 1.01E+10 | -1.01E+10 | 0.29 | -2.95E+09 | **-1.33E+10** |
| 2034 | 0.00E+00 | 22 | 0.00E+00 | 0.00E+00 | 0 | 1.01E+10 | 1.01E+10 | -1.01E+10 | 0.27 | -2.73E+09 | **-1.60E+10** |
| 2035 | 0.00E+00 | 22 | 0.00E+00 | 0.00E+00 | 0 | 1.01E+10 | 1.01E+10 | -1.01E+10 | 0.25 | -2.53E+09 | **-1.86E+10** |
| 2036 | 0.00E+00 | 22 | 0.00E+00 | 0.00E+00 | 0 | 1.01E+10 | 1.01E+10 | -1.01E+10 | 0.23 | -2.34E+09 | **-2.09E+10** |
| 2037 | 0.00E+00 | 22 | 0.00E+00 | 0.00E+00 | 0 | 1.01E+10 | 1.01E+10 | -1.01E+10 | 0.21 | -2.16E+09 | **-2.31E+10** |
| 2038 | 0.00E+00 | 22 | 0.00E+00 | 0.00E+00 | 0 | 1.01E+10 | 1.01E+10 | -1.01E+10 | 0.20 | -2.00E+09 | **-2.51E+10** |
| 2039 | 0.00E+00 | 22 | 0.00E+00 | 0.00E+00 | 0 | 1.01E+10 | 1.01E+10 | -1.01E+10 | 0.18 | -1.86E+09 | **-2.69E+10** |
| 2040 | 0.00E+00 | 22 | 0.00E+00 | 0.00E+00 | 0 | 1.01E+10 | 1.01E+10 | -1.01E+10 | 0.17 | -1.72E+09 | **-2.86E+10** |
| 2041 | 2.24E+06 | 20.7 | 9.49E+09 | 0.00E+00 | 2.50E+09 | 9.53E+09 | 1.20E+10 | -2.55E+09 | 0.16 | -4.02E+08 | **-2.90E+10** |
| 2042 | 2.41E+06 | 18.6 | 1.02E+10 | 0.00E+00 | 0 | 8.64E+09 | 8.64E+09 | 1.56E+09 | 0.15 | 2.29E+08 | **-2.88E+10** |
| 2043 | 2.50E+06 | 17.1 | 1.06E+10 | 0.00E+00 | 0 | 8.05E+09 | 8.05E+09 | 2.53E+09 | 0.14 | 3.42E+08 | **-2.85E+10** |
| 2044 | 2.88E+06 | 15.8 | 1.22E+10 | 0.00E+00 | 0 | 7.50E+09 | 7.50E+09 | 4.67E+09 | 0.13 | 5.85E+08 | **-2.79E+10** |
| 2045 | 3.11E+06 | 14.5 | 1.32E+10 | 0.00E+00 | 0 | 6.93E+09 | 6.93E+09 | 6.23E+09 | 0.12 | 7.22E+08 | **-2.72E+10** |
| 2046 | 3.06E+06 | 13.1 | 1.30E+10 | 0.00E+00 | 0 | 6.36E+09 | 6.36E+09 | 6.59E+09 | 0.11 | 7.07E+08 | **-2.65E+10** |
| 2047 | 3.02E+06 | 11.6 | 1.28E+10 | 0.00E+00 | 0 | 5.73E+09 | 5.73E+09 | 7.05E+09 | 0.10 | 7.00E+08 | **-2.58E+10** |
| 2048 | 2.95E+06 | 9.8 | 1.25E+10 | 0.00E+00 | 0 | 4.97E+09 | 4.97E+09 | 7.51E+09 | 0.09 | 6.91E+08 | **-2.51E+10** |
| 2049 | 2.88E+06 | 8.1 | 1.22E+10 | 0.00E+00 | 0 | 4.24E+09 | 4.24E+09 | 7.92E+09 | 0.09 | 6.75E+08 | **-2.44E+10** |
| 2050 | 2.76E+06 | 6.8 | 1.17E+10 | 0.00E+00 | 0 | 3.70E+09 | 3.70E+09 | 7.98E+09 | 0.08 | 6.30E+08 | **-2.38E+10** |
| 2051 | 2.53E+06 | 6.0 | 1.07E+10 | 0.00E+00 | 0 | 3.37E+09 | 3.37E+09 | 7.31E+09 | 0.07 | 5.34E+08 | **-2.32E+10** |
| 2052 | 2.26E+06 | 5.6 | 9.56E+09 | 0.00E+00 | 0 | 3.18E+09 | 3.18E+09 | 6.37E+09 | 0.07 | 4.31E+08 | **-2.28E+10** |
| 2053 | 2.07E+06 | 5.1 | 8.74E+09 | 0.00E+00 | 0 | 2.99E+09 | 2.99E+09 | 5.75E+09 | 0.06 | 3.60E+08 | **-2.24E+10** |
| 2054 | 1.92E+06 | 4.7 | 8.10E+09 | 0.00E+00 | 0 | 2.81E+09 | 2.81E+09 | 5.29E+09 | 0.06 | 3.07E+08 | **-2.21E+10** |
| 2055 | 1.80E+06 | 4.4 | 7.59E+09 | 0.00E+00 | 0 | 2.69E+09 | 2.69E+09 | 4.90E+09 | 0.05 | 2.63E+08 | **-2.19E+10** |

Figure B.27: NPV pure $CO_2$

| | | | |
|---|---|---|---|
| **Oil Price** | 80 | USD/bbl | |
| | 503.2 | USD/Sm3 | |
| | 4226.88 | NOK/Sm3 | |
| **Discount rate** | 0.08 | | |
| **Year now** | 2017 | | |
| **Start project year** | 2031 | | |
| | | | |
| | | | |
| **Conversion factors** | | | |
| 6.29 | bbl/Sm3 | | |
| 8.40 | NOK/USD | | |
| | | | |
| **Costs** | | | |
| **Running a platform** | 8.50E+08 | NOK/year | |
| **Prize per well** | 2.50E+08 | NOK | |
| **CO2 Price** | 50 | USD/ton | |
| | 420000000 | NOK/MT | |
| **Investments** | | | |
| **Number of injectors** | 20 | | |
| **Number of procucers after 10 yrs** | 10 | | |
| **Upgrades topside, tie-back etc** | 6.00E+09 | NOK | |
| | | | |
| **CO2 injection rate** | 5 | MTY | |
| | | | |
| | | | |

| Year | Oil production (Sm3) | Volumes CO2 required (MTY) | Income (NOK) | CAPEX (NOK) | DRILLEX (NOK) | OPEX (NOK) | Total costs (NOK) | Cash flow (NOK) | Discount rate | Discounted cash flow (NOK) | NPV (NOK) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2031 | 0.00E+00 | 5 | 0.00E+00 | 6.00E+09 | 5.00E+09 | 2.95E+09 | 1.40E+10 | -1.40E+10 | 0.34 | -4.75E+09 | **-4.75E+09** |
| 2032 | 0.00E+00 | 5 | 0.00E+00 | 0.00E+00 | 0 | 2.95E+09 | 2.95E+09 | -2.95E+09 | 0.32 | -9.30E+08 | **-5.68E+09** |
| 2033 | 0.00E+00 | 5 | 0.00E+00 | 0.00E+00 | 0 | 2.95E+09 | 2.95E+09 | -2.95E+09 | 0.29 | -8.61E+08 | **-6.54E+09** |
| 2034 | 0.00E+00 | 5 | 0.00E+00 | 0.00E+00 | 0 | 2.95E+09 | 2.95E+09 | -2.95E+09 | 0.27 | -7.97E+08 | **-7.34E+09** |
| 2035 | 0.00E+00 | 5 | 0.00E+00 | 0.00E+00 | 0 | 2.95E+09 | 2.95E+09 | -2.95E+09 | 0.25 | -7.38E+08 | **-8.08E+09** |
| 2036 | 0.00E+00 | 5 | 0.00E+00 | 0.00E+00 | 0 | 2.95E+09 | 2.95E+09 | -2.95E+09 | 0.23 | -6.84E+08 | **-8.76E+09** |
| 2037 | 0.00E+00 | 5 | 0.00E+00 | 0.00E+00 | 0 | 2.95E+09 | 2.95E+09 | -2.95E+09 | 0.21 | -6.33E+08 | **-9.39E+09** |
| 2038 | 0.00E+00 | 5 | 0.00E+00 | 0.00E+00 | 0 | 2.95E+09 | 2.95E+09 | -2.95E+09 | 0.20 | -5.86E+08 | **-9.98E+09** |
| 2039 | 0.00E+00 | 5 | 0.00E+00 | 0.00E+00 | 0 | 2.95E+09 | 2.95E+09 | -2.95E+09 | 0.18 | -5.43E+08 | **-1.05E+10** |
| 2040 | 0.00E+00 | 5 | 0.00E+00 | 0.00E+00 | 0 | 2.95E+09 | 2.95E+09 | -2.95E+09 | 0.17 | -5.02E+08 | **-1.10E+10** |
| 2041 | 2.05E+06 | 4.5 | 8.67E+09 | 0.00E+00 | 2.50E+09 | 2.75E+09 | 5.25E+09 | 3.42E+09 | 0.16 | 5.40E+08 | **-1.05E+10** |
| 2042 | 1.44E+06 | 4.0 | 6.10E+09 | 0.00E+00 | 0 | 2.51E+09 | 2.51E+09 | 3.59E+09 | 0.15 | 5.24E+08 | **-9.96E+09** |
| 2043 | 1.35E+06 | 3.8 | 5.69E+09 | 0.00E+00 | 0 | 2.44E+09 | 2.44E+09 | 3.25E+09 | 0.14 | 4.39E+08 | **-9.52E+09** |
| 2044 | 1.30E+06 | 3.6 | 5.51E+09 | 0.00E+00 | 0 | 2.35E+09 | 2.35E+09 | 3.16E+09 | 0.13 | 3.95E+08 | **-9.13E+09** |
| 2045 | 1.31E+06 | 3.4 | 5.53E+09 | 0.00E+00 | 0 | 2.28E+09 | 2.28E+09 | 3.26E+09 | 0.12 | 3.78E+08 | **-8.75E+09** |
| 2046 | 1.33E+06 | 3.2 | 5.64E+09 | 0.00E+00 | 0 | 2.20E+09 | 2.20E+09 | 3.44E+09 | 0.11 | 3.69E+08 | **-8.38E+09** |
| 2047 | 1.43E+06 | 2.9 | 6.05E+09 | 0.00E+00 | 0 | 2.07E+09 | 2.07E+09 | 3.98E+09 | 0.10 | 3.96E+08 | **-7.98E+09** |
| 2048 | 1.49E+06 | 2.6 | 6.29E+09 | 0.00E+00 | 0 | 1.93E+09 | 1.93E+09 | 4.36E+09 | 0.09 | 4.01E+08 | **-7.58E+09** |
| 2049 | 1.53E+06 | 2.3 | 6.47E+09 | 0.00E+00 | 0 | 1.81E+09 | 1.81E+09 | 4.66E+09 | 0.09 | 3.97E+08 | **-7.19E+09** |
| 2050 | 1.55E+06 | 2.0 | 6.55E+09 | 0.00E+00 | 0 | 1.70E+09 | 1.70E+09 | 4.85E+09 | 0.08 | 3.82E+08 | **-6.80E+09** |
| 2051 | 1.51E+06 | 1.8 | 6.38E+09 | 0.00E+00 | 0 | 1.60E+09 | 1.60E+09 | 4.77E+09 | 0.07 | 3.49E+08 | **-6.45E+09** |
| 2052 | 1.37E+06 | 1.5 | 5.78E+09 | 0.00E+00 | 0 | 1.49E+09 | 1.49E+09 | 4.29E+09 | 0.07 | 2.90E+08 | **-6.16E+09** |
| 2053 | 1.34E+06 | 1.2 | 5.68E+09 | 0.00E+00 | 0 | 1.36E+09 | 1.36E+09 | 4.32E+09 | 0.06 | 2.71E+08 | **-5.89E+09** |
| 2054 | 1.31E+06 | 0.9 | 5.52E+09 | 0.00E+00 | 0 | 1.25E+09 | 1.25E+09 | 4.27E+09 | 0.06 | 2.48E+08 | **-5.65E+09** |
| 2055 | 1.26E+06 | 0.8 | 5.34E+09 | 0.00E+00 | 0 | 1.17E+09 | 1.17E+09 | 4.18E+09 | 0.05 | 2.24E+08 | **-5.42E+09** |

Figure B.28: NPV 5 MTY $CO_2$

| | | |
|---|---|---|
| **Oil Price** | 80 | USD/bbl |
| | 503.2 | USD/Sm3 |
| | 4226.88 | NOK/Sm3 |
| **Discount rate** | 0.08 | |
| **Year now** | 2017 | |
| **Start project year** | 2031 | |
| | | |
| | | |
| **Conversion factors** | | |
| 6.29 | bbl/Sm3 | |
| 8.40 | NOK/USD | |
| | | |
| **Costs** | | |
| **Running a platform** | 8.50E+08 | NOK/year |
| **Price per well** | 2.50E+08 | NOK |
| **CO2 Price** | 50 | USD/ton |
| | 420000000 | NOK/MT |
| **Investments** | | |
| **Number of injectors** | 20 | |
| **Number of procucers after 10 y** | 10 | |
| **Upgrades topside, tie-back etc** | 6.00E+09 | NOK |
| | | |
| **CO2 injection rate** | 1 | MTY |

| Year | Oil production (Sm3) | Volumes CO2 required (MTY) | Income (NOK) | CAPEX (NOK) | DRILLEX (NOK) | OPEX (NOK) | Total costs (NOK) | Cash flow (NOK) | Discount rate | Discounted cash flow (NOK) | NPV (NOK) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2031 | 0.00E+00 | 1 | 0.00E+00 | 6.00E+09 | 5.00E+09 | 1.27E+09 | 1.23E+10 | -1.23E+10 | 0.34 | -4.18E+09 | **-4.18E+09** |
| 2032 | 0.00E+00 | 1 | 0.00E+00 | 0.00E+00 | 0 | 1.27E+09 | 1.27E+09 | -1.27E+09 | 0.32 | -4.00E+08 | **-4.58E+09** |
| 2033 | 0.00E+00 | 1 | 0.00E+00 | 0.00E+00 | 0 | 1.27E+09 | 1.27E+09 | -1.27E+09 | 0.29 | -3.71E+08 | **-4.95E+09** |
| 2034 | 0.00E+00 | 1 | 0.00E+00 | 0.00E+00 | 0 | 1.27E+09 | 1.27E+09 | -1.27E+09 | 0.27 | -3.43E+08 | **-5.29E+09** |
| 2035 | 0.00E+00 | 1 | 0.00E+00 | 0.00E+00 | 0 | 1.27E+09 | 1.27E+09 | -1.27E+09 | 0.25 | -3.18E+08 | **-5.61E+09** |
| 2036 | 0.00E+00 | 1 | 0.00E+00 | 0.00E+00 | 0 | 1.27E+09 | 1.27E+09 | -1.27E+09 | 0.23 | -2.94E+08 | **-5.90E+09** |
| 2037 | 0.00E+00 | 1 | 0.00E+00 | 0.00E+00 | 0 | 1.27E+09 | 1.27E+09 | -1.27E+09 | 0.21 | -2.72E+08 | **-6.18E+09** |
| 2038 | 0.00E+00 | 1 | 0.00E+00 | 0.00E+00 | 0 | 1.27E+09 | 1.27E+09 | -1.27E+09 | 0.20 | -2.52E+08 | **-6.43E+09** |
| 2039 | 0.00E+00 | 1 | 0.00E+00 | 0.00E+00 | 0 | 1.27E+09 | 1.27E+09 | -1.27E+09 | 0.18 | -2.34E+08 | **-6.66E+09** |
| 2040 | 0.00E+00 | 1 | 0.00E+00 | 0.00E+00 | 0 | 1.27E+09 | 1.27E+09 | -1.27E+09 | 0.17 | -2.16E+08 | **-6.88E+09** |
| 2041 | 9.84E+05 | 0.9 | 4.16E+09 | 0.00E+00 | 2.50E+09 | 1.24E+09 | 3.74E+09 | 4.16E+08 | 0.16 | 6.56E+07 | **-6.81E+09** |
| 2042 | 9.51E+05 | 0.9 | 4.02E+09 | 0.00E+00 | 0 | 1.22E+09 | 1.22E+09 | 2.80E+09 | 0.15 | 4.09E+08 | **-6.40E+09** |
| 2043 | 9.21E+05 | 0.9 | 3.89E+09 | 0.00E+00 | 0 | 1.22E+09 | 1.22E+09 | 2.67E+09 | 0.14 | 3.61E+08 | **-6.04E+09** |
| 2044 | 8.79E+05 | 0.9 | 3.71E+09 | 0.00E+00 | 0 | 1.22E+09 | 1.22E+09 | 2.49E+09 | 0.13 | 3.12E+08 | **-5.73E+09** |
| 2045 | 8.84E+05 | 0.9 | 3.74E+09 | 0.00E+00 | 0 | 1.22E+09 | 1.22E+09 | 2.51E+09 | 0.12 | 2.91E+08 | **-5.44E+09** |
| 2046 | 9.15E+05 | 0.9 | 3.87E+09 | 0.00E+00 | 0 | 1.22E+09 | 1.22E+09 | 2.65E+09 | 0.11 | 2.84E+08 | **-5.16E+09** |
| 2047 | 1.00E+06 | 0.9 | 4.24E+09 | 0.00E+00 | 0 | 1.21E+09 | 1.21E+09 | 3.03E+09 | 0.10 | 3.01E+08 | **-4.85E+09** |
| 2048 | 1.06E+06 | 0.8 | 4.48E+09 | 0.00E+00 | 0 | 1.20E+09 | 1.20E+09 | 3.28E+09 | 0.09 | 3.02E+08 | **-4.55E+09** |
| 2049 | 1.12E+06 | 0.8 | 4.75E+09 | 0.00E+00 | 0 | 1.18E+09 | 1.18E+09 | 3.57E+09 | 0.09 | 3.04E+08 | **-4.25E+09** |
| 2050 | 1.15E+06 | 0.7 | 4.84E+09 | 0.00E+00 | 0 | 1.14E+09 | 1.14E+09 | 3.70E+09 | 0.08 | 2.92E+08 | **-3.96E+09** |
| 2051 | 1.16E+06 | 0.6 | 4.92E+09 | 0.00E+00 | 0 | 1.10E+09 | 1.10E+09 | 3.82E+09 | 0.07 | 2.79E+08 | **-3.68E+09** |
| 2052 | 1.13E+06 | 0.5 | 4.77E+09 | 0.00E+00 | 0 | 1.06E+09 | 1.06E+09 | 3.71E+09 | 0.07 | 2.51E+08 | **-3.43E+09** |
| 2053 | 1.13E+06 | 0.4 | 4.76E+09 | 0.00E+00 | 0 | 1.00E+09 | 1.00E+09 | 3.75E+09 | 0.06 | 2.35E+08 | **-3.19E+09** |
| 2054 | 1.12E+06 | 0.2 | 4.75E+09 | 0.00E+00 | 0 | 9.34E+08 | 9.34E+08 | 3.82E+09 | 0.06 | 2.21E+08 | **-2.97E+09** |
| 2055 | 1.09E+06 | 0.1 | 4.59E+09 | 0.00E+00 | 0 | 8.85E+08 | 8.85E+08 | 3.71E+09 | 0.05 | 1.99E+08 | **-2.77E+09** |

Figure B.29: NPV 1 MTY $CO_2$

| | | |
|---|---|---|
| Oil Price | 80 | USD/bbl |
| | 503.2 | USD/Sm3 |
| | 4226.88 | NOK/Sm3 |
| Discount rate | 0.08 | |
| Year now | 2017 | |
| Start project year | 2031 | |
| | | |
| | | |
| Conversion factors | | |
| 6.29 | bbl/Sm3 | |
| 8.40 | NOK/USD | |
| | | |
| Costs | | |
| Running a platform | 8.50E+08 | NOK/year |
| Prize per well | 2.50E+08 | NOK |
| CO2 Price | 0 | USD/ton |
| | 0 | NOK/MT |
| Investments | | |
| Number of injectors | 20 | |
| Number of procucers after 10 yrs | 10 | |
| Upgrades topside, tie-back etc | 6.00E+09 | NOK |
| | | |
| CO2 injection rate | 0 | MTY |

| Year | Oil production (Sm3) | Volumes CO2 required (MTY) | Income (NOK) | CAPEX (NOK) | DRILLEX (NOK) | OPEX (NOK) | Total costs (NOK) | Cash flow (NOK) | Discount rate | Discounted cash flow (NOK) | NPV (NOK) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2031 | 0.00E+00 | 0 | 0.00E+00 | 6.00E+09 | 5.00E+09 | 8.50E+08 | 1.19E+10 | -1.19E+10 | 0.34 | -4.03E+09 | **-4.03E+09** |
| 2032 | 0.00E+00 | 0 | 0.00E+00 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | -8.50E+08 | 0.32 | -2.68E+08 | **-4.30E+09** |
| 2033 | 0.00E+00 | 0 | 0.00E+00 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | -8.50E+08 | 0.29 | -2.48E+08 | **-4.55E+09** |
| 2034 | 0.00E+00 | 0 | 0.00E+00 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | -8.50E+08 | 0.27 | -2.30E+08 | **-4.78E+09** |
| 2035 | 0.00E+00 | 0 | 0.00E+00 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | -8.50E+08 | 0.25 | -2.13E+08 | **-4.99E+09** |
| 2036 | 0.00E+00 | 0 | 0.00E+00 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | -8.50E+08 | 0.23 | -1.97E+08 | **-5.19E+09** |
| 2037 | 0.00E+00 | 0 | 0.00E+00 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | -8.50E+08 | 0.21 | -1.82E+08 | **-5.37E+09** |
| 2038 | 0.00E+00 | 0 | 0.00E+00 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | -8.50E+08 | 0.20 | -1.69E+08 | **-5.54E+09** |
| 2039 | 0.00E+00 | 0 | 0.00E+00 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | -8.50E+08 | 0.18 | -1.56E+08 | **-5.70E+09** |
| 2040 | 0.00E+00 | 0 | 0.00E+00 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | -8.50E+08 | 0.17 | -1.45E+08 | **-5.84E+09** |
| 2041 | 9.97E+05 | 0 | 4.21E+09 | 0.00E+00 | 2.50E+09 | 8.50E+08 | 3.35E+09 | 8.65E+08 | 0.16 | 1.36E+08 | **-5.71E+09** |
| 2042 | 9.63E+05 | 0 | 4.07E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 3.22E+09 | 0.15 | 4.70E+08 | **-5.24E+09** |
| 2043 | 9.22E+05 | 0 | 3.90E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 3.05E+09 | 0.14 | 4.12E+08 | **-4.82E+09** |
| 2044 | 8.72E+05 | 0 | 3.69E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.84E+09 | 0.13 | 3.55E+08 | **-4.47E+09** |
| 2045 | 8.51E+05 | 0 | 3.60E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.75E+09 | 0.12 | 3.19E+08 | **-4.15E+09** |
| 2046 | 8.30E+05 | 0 | 3.51E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.66E+09 | 0.11 | 2.85E+08 | **-3.86E+09** |
| 2047 | 8.17E+05 | 0 | 3.45E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.60E+09 | 0.10 | 2.59E+08 | **-3.61E+09** |
| 2048 | 7.77E+05 | 0 | 3.28E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.43E+09 | 0.09 | 2.24E+08 | **-3.38E+09** |
| 2049 | 7.63E+05 | 0 | 3.22E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.37E+09 | 0.09 | 2.02E+08 | **-3.18E+09** |
| 2050 | 7.45E+05 | 0 | 3.15E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.30E+09 | 0.08 | 1.81E+08 | **-3.00E+09** |
| 2051 | 7.36E+05 | 0 | 3.11E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.26E+09 | 0.07 | 1.65E+08 | **-2.83E+09** |
| 2052 | 7.11E+05 | 0 | 3.00E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.15E+09 | 0.07 | 1.46E+08 | **-2.69E+09** |
| 2053 | 7.03E+05 | 0 | 2.97E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.12E+09 | 0.06 | 1.33E+08 | **-2.55E+09** |
| 2054 | 6.92E+05 | 0 | 2.93E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.08E+09 | 0.06 | 1.20E+08 | **-2.43E+09** |
| 2055 | 6.82E+05 | 0 | 2.88E+09 | 0.00E+00 | 0 | 8.50E+08 | 8.50E+08 | 2.03E+09 | 0.05 | 1.09E+08 | **-2.33E+09** |

Figure B.30: NPV pure water