University of
Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: Petroleum Engineering/ Reservoir Engineering	Spring semester, 2017 Open
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Thesis title: Evaluation of low salinity injection EOR potential in Johan Sverdrup Field	
Credits (ECTS): 30	
Key words: EOR Low Salinity Smart Water Johan Sverdrup	Pages: 83 Stavanger, 15th June 2017 Date/year

Evaluation of low salinity injection EOR potential in Johan Sverdrup Field

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Stavanger, 15th June 2017

Acknowledgements

I would like to express my sincere gratitude to Associate Professor Tina Puntervold and Associate Professor Skule Strand for helping with my thesis through the whole semester. I would like to thank Ass. Prof. Puntervold for giving constructive feedbacks, multiple proof-readings and always being available to reach through e-Mail for advice. I would like to thank Ass. Prof. Strand for the insightful discussions and valuable guidance in the last six months.

I would also like to thank my friends, especially my fellow students by the Department of Petroleum Technology for the meaningful relationships in the past years.

Last but not least, I would like to thank my family, especially my parents that have been supporting me with anything I set myself to do.

Abstract

Low salinity waterflooding is an EOR method that doesn't get mentioned as much as other EOR methods in the current oil industry, but its recognition has been raised in the last few years and BP is also using their own low salinity technology for the whole Clair Ridge Field, UK. As the attention of this method has increased, many more research has been done in the last decade for determining the EOR mechanism that happens when injecting low saline brine into high saline formation brine. The exact mechanism is yet to be concluded, however, EOR effect that happens by this technique is believed to be wettability alteration. In this case, mixed wetting due to crude oil adsorption is essential for achieving an EOR effect. This mechanism is dependent on a CBR system that promotes adsorption, injecting low salinity water would then cause wettability alteration in the reservoir, resulting to a more water-wet state in the formation. If the reservoir lacks adsorption onto the rock formation, EOR effect would most likely not occur since it would be too water-wet initially.

This thesis focuses on evaluating the EOR potential by injecting low salinity brine into the Johan Sverdrup Field. Many papers and sources has been used to find the EOR possibility in the field. As the field is still under development, there are lack of information, such as certain reservoir property values, and thorough evaluation is hard to conduct due to this factor. However, a simplified evaluation could be done by analyzing the low salinity waterflooding mechanism with properties from Johan Sverdrup Field. Research result from the field showed that many of the conditions for a successful EOR effect is met. Polar component in crude oil, divalent cations in formation water, and clay in rock formation are all present. Considering the mentioned factors together with a not too high temperature in the reservoir would promote the adsorption of crude oil onto clay surface, and a mixed wet state is created in the reservoir. Furthermore, a smart way of choosing the water composition for the injected brine is more important than to simply reducing the salinity, as the composition is seen as more crucial than the salinity difference between injected brine and formation water. Considering all the mentioned factors, Johan Sverdrup Field has great EOR potential by injecting low salinity fluid for displacing extra amount of oil in the reservoir, and increase of microscopic sweep efficiency occurs due to wettability alteration from mixed wetting to a more water-wet state.

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1. Introduction

The world’s demand of energy increases as the population and industries around the world increases. Petroleum is essential to contribute to the energy demand in today’s society, and each reservoir should be produced in a way that boosts the productivity and has a recovery factor as high as possible. This could be achieved by application of an EOR method, but implementation of these methods are different for various reservoirs that have different properties.

Low salinity waterflooding is an EOR method that has only been mentioned in the last few decades and tested out in very few field cases. However, low salinity waterflooding, or smart water flooding, has been experimented in laboratories by many and showed positive results (Austad et al., 2010; Ligthelm et al., 2009; McGuire et al., 2005; Piñerez T, 2017; Pu et al., 2008; Tang & Morrow, 1999; Zhang et al., 2007). As the name tells, low salinity water is a fluid that contains low salt concentration, and the chemical equilibrium in the reservoir is disturbed by injecting this fluid. The disruption causes the incremental recovery by reducing the residual oil saturation, but the exact mechanism for how this EOR method works is still under discussion by many researchers. Before applying low salinity waterflooding in a reservoir, thorough evaluation must be made for the reservoir since its EOR potential varies case by case.

Johan Sverdrup Field is located on the Utsira Height in the North Sea, and is one of the five largest oil fields on the Norwegian continental shelf with an estimated peak production that will contribute to 25% of all Norwegian petroleum production at the time. The field is currently under construction, and start of production for Phase 1 is planned in late 2019. A pilot project with polymer flooding is assumed to be executed in around 2021. Johan Sverdrup Field has a great economic value for Norway in the next few decades, and evaluation of EOR methods should be made carefully by laboratory experiments, large scale simulations, and field tests.

1.1. Thesis Objective

The main objective of this thesis is data gathering from multiple literatures/sources, such as papers, books, articles, thesis, etc., and by using the gathered information to evaluate the low salinity injection EOR potential in the Johan Sverdrup Field.

2. Basic Reservoir Engineering Overview

2.1. Oil Recovery Operation Procedures

2.1.1. Primary Recovery

This is the initial stage of production by using the natural energy present in the reservoir to displace the oil. Oil production happens by pressure depletion and the natural energy sources are solution-gas drive, gas-cap drive, natural waterdrive, fluid and rock expansion, and gravity drainage (Green & Willhite, 1998).

The ultimate recovery during the primary recovery stage would vary from 5-30 % of the original oil in place (OOIP). It is due to this low recovery percentage that further alternative recovery methods must be applied after primary recovery (Ahmed, 2010).

2.1.2. Secondary Recovery

Secondary recovery happens by injecting gas or water into the formation to maintain a stable reservoir pressure and for displacing oil toward the production wells after primary recovery due to a pressure decline from oil production. Considering a secondary recovery by injecting gas, the gas is either used as a gas cap for pressure maintenance and gas-cap expansion or into the oil column to displace the oil immiscibly. Waterflooding is one of the most common secondary recovery techniques and the recovery factor could approach to around 35-50% OOIP (Green & Willhite, 1998).

2.1.3. Tertiary Recovery/EOR

EOR methods involves injection of a fluid that has been modified by adding chemicals, changing the fluid composition or increase the temperature of the injected fluid to enhance the recovery from the previous stages. This injected fluid will interact with the crude-oil, brine and rock (CBR) system in the reservoir to create a favorable condition for oil recovery. EOR processes can be roughly divided into five categories as shown in Table 1.

Table 1. *General classifications and examples of EOR processes (Green & Willhite, 1998).*

EOR category	**Example**
Mobility-Control Process	Polymer flooding
Chemical Process	Surfactant or alkaline flooding
Miscible Process	Hydrocarbon or CO_2 injection
Thermal Process	Steam-assisted gravity drainage
Other Processes	Low Salinity Waterflooding

This extra recovery that happens by implementing EOR methods are due to either increase of microscopic or macroscopic sweep efficiencies. Increase of macroscopic sweep occurs by increasing the sweep efficiency both in the area and vertical aspect of the reservoir, while increase in microscopic sweep occurs by reducing the residual oil saturation, S_{or}, to mobilize the oil that is stuck in the formation. These methods require a change in the physical properties of the CBR system or the injected fluid. Some of the relevant properties are wettability of the rock, interfacial tension between the fluids and viscosities of the fluids (Green & Willhite, 1998).

Figure 1 shows flooding by water and polymer from an injector to the production pipe, which is a great example to show improvement in macroscopic sweep efficiency. Macroscopic sweep efficiency relates to the effectiveness of the displacing fluid in contact with the reservoir volumetrically, hence, both areal and vertical sweep efficiencies are important (Green & Willhite, 1998). A good mobility ratio is essential to achieve an increased macroscopic sweep efficiency, and this is defined by Eq. (1). Unstable displacement occurs when $M>1$, causing viscous fingering as seen from waterflooding in Figure 1. By adding polymer that increases viscosity of the injection fluid can make $M<1$, which makes the displacement stable without viscous fingering and increase in the macroscopic sweep efficiency, as observed in Figure 1.

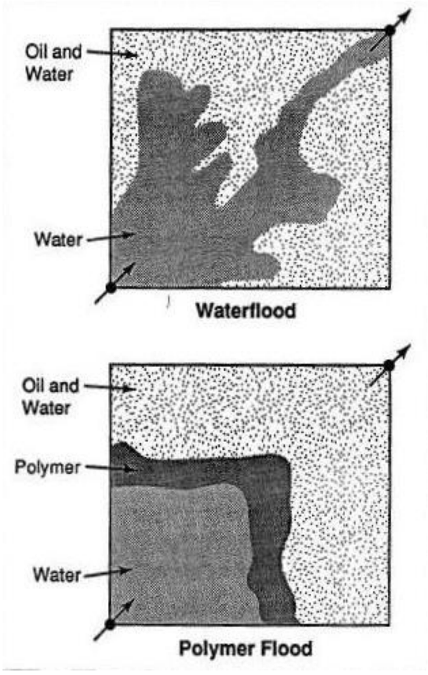


Figure 1. *Illustrative comparison of macroscopic sweep efficiency between waterflooding and polymer flooding (Green & Willhite, 1998).*

$$M = \frac{\frac{k_{rw}}{\mu_w}}{\frac{k_{ro}}{\mu_o}} = \frac{k_{rw}\mu_o}{k_{ro}\mu_w} \tag{1}$$

where

M = Mobility ratio between displacing and displaced fluids

k_{rw} = Relative water permeability

k_{ro} = Relative oil permeability

μ_w = Viscosity of water

μ_o = Viscosity of oil

Microscopic sweep efficiency relates to the displacement or mobilization of oil at pore scale, it measures the effectiveness of displacing fluid mobilizing the oil where the displacing fluid contacts the oil in the rock (Green & Willhite, 1998). Microscopic sweep efficiency is dependent on the wettability and saturation in the reservoir, and can be calculated by Eq. (2). Decreasing the capillary forces can improve the microscopic sweep efficiency.

$$E_D = \frac{S_{oi}-S_{or}}{S_{oi}} \qquad (2)$$

where

E_D = Microscopic sweep efficiency

S_{oi} = Initial oil saturation

S_{or} = Residual oil saturation

The total sweep efficiency (E_T) is then found by multiplying the microscopic sweep efficiency (E_D) with the macroscopic sweep efficiency (E_V), as in Eq. (3):

$$E_T = E_D * E_V \qquad (3)$$

Considering the chronology of the stages, the tertiary recovery would be applied after waterflooding in the secondary recovery. However, there are situations where these chronological classifications could make complications if applied. Primary and secondary recoveries would not be applied in certain cases for beneficial purposes, heavy oil production would be a good example. It is, therefore, better to use the term “enhanced oil recovery” to avoid any misunderstandings (Green & Willhite, 1998).

2.2. Wettability

Wettability of a rock can be explained as the tendency of one fluid to spread on or adhere to a rock surface in the presence of other immiscible fluids (Craig, 1971). Determination of the wettability in the formation is an important task for planning an EOR method that will give the ultimate recovery from the reservoir.

By measuring the wettability, the oil or water preference of the rock can be determined. There is a tendency for water to occupy the small pores and to contact the greater part of the rock in water-wet rocks, while oil will have the same concept with oil-wet rocks (Anderson, 1986). If the rocks are strongly water-wet or oil-wet, the non-wetting phase would flow in the center of the pores. It is also possible that the rock are neutrally wet which means that the rock does not have a strong affinity for either water or oil (Anderson, 1986).

There is third type of wettability which are called as fractional wettability. This heterogeneous wettability defines that the rock surface has varying affinities for oil and water in different part of the rock. Salathiel introduced a new term within the fractional wettability called mixed wettability. Mixed wettability is described where parts of the rock surfaces are strongly oil-wetted and parts are water-wetted (Salathiel, 1973). The special case with this wettability is the continuous water-wet and oil-wet regions on the rock. Considering oil invading into an originally water-wet reservoir, the larger pores would be filled with oil while the smaller pores remained water-wet. Due to that, all the oil are located in the larger oil-wet pores in a rock, a small but finite oil permeability can exist down to very low saturations (Anderson, 1986). This would allow waterflooding to achieve a very low oil saturation. Figure 2 shows what happens when water is injected in oil-wet sand and water-wet sand at pore scale.

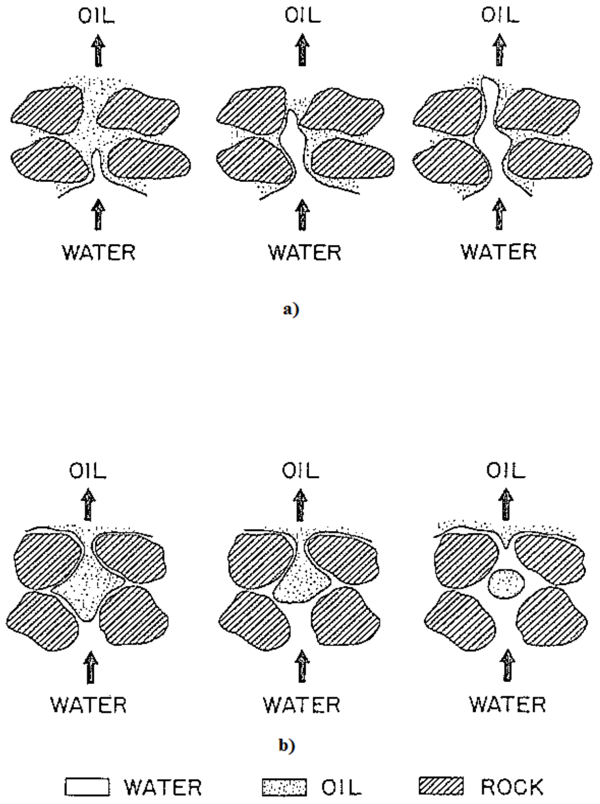


Figure 2. *Oil displacement by water for* ***a)*** *drainage process in oil-wet sand and* ***b)*** *imbibition process in water-wet sand (Craig, 1971).*

The contact angle between a fluid and the rock surface determines what the wetting is, and to some extent how strong the wettability is, as illustrated in Figure 3. The value varies from 0° to 180°, where around 90° implies that the wettability is neutral wetted. The values measured in Table 2 is the angle between water phase and the rock surface.

Table 2. *Contact angle and preferred wettability of the angle (Zolotukhin & Ursin, 2000).*

Contact angle (degree)	Wettability preference
0-30	Strongly water-wet
30-90	Preferentially water-wet
90	Neutral wettability
90-150	Preferentially oil-wet
150-180	Strongly oil-wet

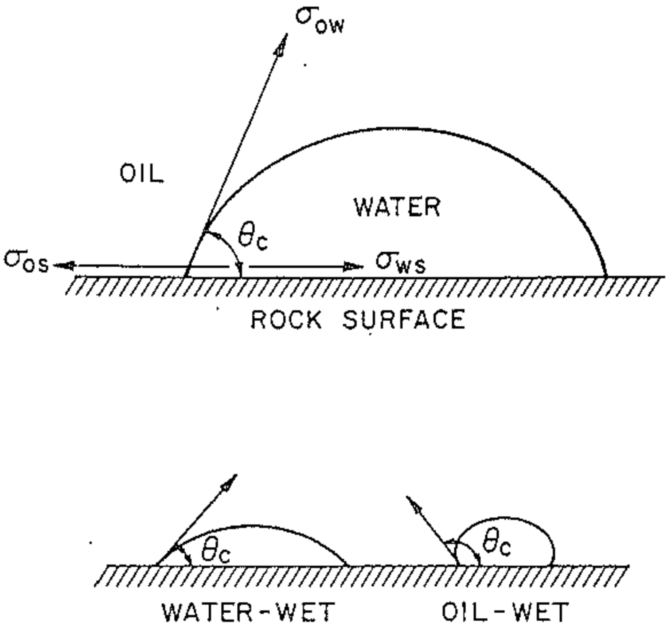


Figure 3. *Contact angle measurement in water phase (Craig, 1971).*

The three interfacial tensions, σ_{os}, σ_{ws} and σ_{ow} are in mechanical equilibrium when the water-oil-solid system is in a static state. The surface energies in the system can be related to the Young-Dupré equation (Craig, 1971):

$$\sigma_{os} - \sigma_{ws} = \sigma_{ow} * \cos\theta \quad (4)$$

where

σ_{os}: Interfacial tension between oil and solid

σ_{ws}: Interfacial tension between water and solid

σ_{ow}: Interfacial tension between oil and water

θ: Contact angle of a fluid at the oil-water-solid interface

2.3. Displacement Forces

There are three main types of forces that are important for a displacement to occur in the reservoir, and these are capillary forces, viscous forces and gravity forces.

2.3.1. Capillary Forces

Capillary pressure can be defined as the molecular pressure difference between two fluids that are in contact with each other, and occurs due to the interfacial tensions between the fluids (Zolotukhin & Ursin, 2000). Capillary pressure can be estimated by subtracting water pressure from the oil pressure in an oil/water system, where the nonwetting phase, oil in this case, has the larger pressure (Green & Willhite, 1998).

$$Pc = \frac{2\sigma_{ow} cos\theta}{r} \quad (5)$$

where

P_c: Capillary pressure

σ_{ow}: Interfacial tension between oil and water

θ: Contact angle measured through water phase

r: Radius of the capillary tube

As seen from Eq. (5), the capillary pressure is related to the interfacial tension and wettability between the fluids, and the pore radii of the medium. Capillary pressure may be positive or negative, depending on which phase the pressure is lower (Green & Willhite, 1998). The lower pressure phase will preferentially wet the capillary, as seen by water in capillary tube for an oil/water system.

The capillary pressure effect depends on if the reservoir is fractured or not. Capillary forces are important for displacement during spontaneous imbibition of water in a fractured reservoir. For non-fractured reservoirs, which are most of the sandstone reservoirs, entrapment of the nonwetting phase could occur for strong capillary forces (Green & Willhite, 1998). It is possible to undo this by reducing the IFT or change the wettability if possible.

2.3.2. Viscous Forces

The viscous forces are reflected in the magnitude of the pressure drop that happens because of flow of a fluid through a porous medium. A simple estimation for the viscous forces are to assume the porous medium as a bundle of capillary tubes. By using this assumption, each of the capillary tubes can be calculated by Poiseuille's law, considering laminar flow (Green & Willhite, 1998):

$$\Delta p = -\frac{8\mu L\bar{v}}{r^2 g_c} \tag{6}$$

where

Δp: Pressure drop across the capillary tube

μ: Viscosity of flowing fluid

L: Length of capillary tube

$\bar{v}$: Average velocity in the capillary tube

r: Radius of capillary tube

g_c: Conversion factor

2.3.3. Gravity Forces

Gravity forces plays an important role for how the fluid flow happens in the reservoir. The density difference between the displacing fluid and displaced fluid will determine how the flow occur. If the displacing fluid is less dense than the displaced fluid, a gravity override occurs and the injected fluid will float above the existing fluid, examples are CO_2 flooding and solvent flooding. A gravity underride can also occur when the density difference is the other way around, waterflood is an example for gravity underride (Green & Willhite, 1998). The equation below gives an estimation of gravity forces:

$$\Delta p = \Delta \rho g h \tag{7}$$

where

Δp: Pressure difference over the oil-water surface due to gravity

$\Delta \rho$: Density difference between oil and water

g: Gravity acceleration

h: Height of oil column

2.4. Sandstone

Sand is medium-sized particles that can be transported by moderate currents and wind that blow sand into dunes. These particles has a diameter range of 0.062-2 mm and lithified equivalent of sand is sandstone (Grotzinger & Jordan, 2010). Sandstone is a type of siliciclastic rock due to its high silica content and other non-carbonic material, and they can be further subdivided by its minerology, such as quartz-rich sandstone and feldspar-rich sandstone. However, it is possible that sand consist of a certain amount of carbonic material, in this case, the sand is called as bioclastic (Grotzinger & Jordan, 2010). Sandstone has an average density of 2.65 g/cm^3 after diagenesis, and a typical porosity around 7-20 % (Zolotukhin & Ursin, 2000).

2.4.1. Clay

Clay is classified as fine-grained siliciclastic particle that has a diameter less than 0.0039 mm (Grotzinger & Jordan, 2010). Clay minerals are characterized as phyllosilicates, and chemically consist of SiO_4^{4-} and metallic cations. The silicon atom is surrounded by four oxygen atoms and forms a pyramid-like shape called silica tetrahedron. These silica tetrahedrons can be linked together to form a sheet/layer (Boggs, 2009). Octahedral configuration would be made instead if the phyllosilicates also contains OH^- ions joined with cations, i.e. aluminum, magnesium and iron, in a sixfold coordination, and these octahedral can also link together and form sheets/layers.

Clay minerals are formed by tetrahedral layers and octahedral layers, different type of clay varies with different combination of these layers. Some clay minerals have one layer of each (1:1), such as kaolinite. These individual layers are further joined by other layers by weak van der Waals bonds. Other phyllosilicates consist of two tetrahedral layers and one octahedral layer (2:1) with octahedral layer being in the middle between two tetrahedral layers. These layers are also bonded with each other by van der Waals bonds (Boggs, 2009). An example for 2:1 structure is montmorillonite. Other clay minerals are further made with 2:1 structure by substituting aluminum ions with other cations.

Cation exchange capacity is a property that defines the amount/capacity of cations that a clay surface can attract and exchange. By substituting aluminum ions with other divalent or monovalent cations will make the clay surface negatively charged (Boggs, 2009). Cations that are exchangeable have different affinities toward the clay surface, and it is assumed that the affinity scale goes as follow: $Li^+ < Na^+ < K^+ < Mg^{2+} < Ca^{2+} < H^+$, where protons are most attracted toward the clay surface (Skjeggestad, 1989).

It is important to know the properties of certain clay types for screening of which fluid is the best choice for flooding. Table 3 shows different properties of clay minerals.

Table 3. *Property of actual clay minerals (IDF, 1982).*

Property	Kaolinite	Illite/Mica	Montmorillonite	Chlorite
Layers	1:1	2:1	2:1	2:1:1
Particle size (micron)	5-0.5	Large sheets to 0.5	2-0.1	5-0.1
Cation exchange capacity (meq/100g)	3-15	10-40	80-150	10-40
Surface area BET-N_2 (m^2/g)	15-25	50-110	3080	140

2.4.2. Feldspar

Feldspar is classified as silicate mineral that is the most abundant class of minerals in Earth's crust that are composed of silicon and oxygen ions in combination with cations (Grotzinger & Jordan, 2010). Typical cations that bonds to silicate ions are sodium, potassium, calcium, magnesium and iron, but the silicate ions can also share the oxygen ions with each other. High temperature minerals can form clay minerals through the exchange of hydrogen ions with cations in the minerals, in the case of feldspar (Velde & Meunier, 2008):

$$\textit{feldspar} + \textit{hydrogen ions} \rightarrow \textit{clay} + \textit{cations, solids, water} \tag{8}$$

Feldspars have an experimental dissolution rate which increases with increasing H^+ activity at pH less than 6, and increasing OH^- activity above pH 8.5 (Blum, 1994). Dissolution rates between K-feldspar and albite are nearly identical when pH is less than 6, but this is in contrast to observations that albite weathers much quicker than K-feldspar (Blum, 1994).

Generally, two major groups of feldspar are K-feldspar (orthoclase, microline, sanidine, anorthoclase) and plagioclase feldspar (albite, oligoclase, andesine, labradorite, bytownite, anothite), and makes up about 10-15% of average sandstone (Boggs, 2009). Potassium (K) feldspars are usually more abundant than plagioclase feldspars in the average sandstone with the exception of sandstones that are derived from source areas that are rich in volcanic rocks that may contain more plagioclase than potassium feldspar.

Also called as alkali feldspar, K-feldspar forms group of minerals in which the chemical composition can vary through a complete solid solution series from $K(AlSi_3O_8)$ through $(K,Na)(AlSi_3O_8)$ to $Na(AlSi_3O_8)$ (Boggs, 2009). The previous mentioned K-feldspars have all the chemical formula of $KAlSi_3O_8$, but the amount of sodium various. K-feldspars are derived particularly from alkali and acid igneous rocks.

Plagioclase feldspars have a solid-solution series varying in composition from $NaAlSi_3O_8$ through $CaAl_2Si_2O_8$, where the sodic plagioclases seems more abundant than calcic plagioclases (Boggs, 2009). The main source for plagioclase is assumed to be basic and intermediate lavas, but it can also be derived from basic intrusive rocks.

2.4.3. Anhydrite

Anhydrite is classified as a sulfate minerals that consist of the sulfate anion and metallic cations. The sulfate ion is a tetrahedron made up of one sulfur ion in the middle with four oxygen ions surrounding it. Gypsum is one of the most common sulfates ($CaSO_4*2H_2O$) and is formed when seawater evaporates (Grotzinger & Jordan, 2010). Ca^{2+} and SO_4^{2-} are abundant in seawater, and during evaporation, these two ions will combine and precipitate as layers of sediment to form calcium sulfate. Anhydrite has a similar chemical formula as gypsum, $CaSO_4$, where the only difference is that anhydrite does not contain water. Regarding stability issues, gypsum is stable at low temperatures and pressures found at Earth's crust, while anhydrite is stable at the higher temperatures and pressures where sedimentary rocks are buried (Grotzinger & Jordan, 2010). Solubility of anhydrite decreases as the temperature increases, and precipitation of anhydrite will start at around 100^{o}C (Austad, 2013), considering enough amount of calcium ions and sulfate ions present.

2.5. Factors Determining the Initial Wetting in Sandstone

There are many factors that determines the initial wetting in a reservoir, the chemical interaction between crude oil, formation brine and rock plays an important role for the initial wetting. All the reservoirs are believed to be strongly water-wet originally in many million years ago because of two facts; that almost all clean sedimentary rock are strongly water-wet and sandstone deposition occurred in aqueous environments (Anderson, 1986). The wettability for these strongly water-wet rocks can change over time when oil invades into the rock and adsorption of polar component on the rock surface happens. It is the polar functional groups that are most important for wettability alteration. Besides that, Standnes (2001) summarized that the following parameters are important for wettability alteration:

- Mineral composition and surface charge of the rock material.
- Brine salinity and concentration of divalent- and other multivalent ions.
- Capillary pressure and thin film forces, disjoining pressure.
- Water solubility of polar oil components.
- Ability for oil to stabilize heavy components.
- Temperature, pressure and initial water saturation.

The following section will discuss how the initial wetting can be determined by the CBR interactions, and how it can be alterated by changing certain parameters.

2.5.1. Crude Oil

Crude oil consists of many different components, and the heavier part of the crude oil are characterized as asphaltene and resin, while the lighter part are characterized as saturate and aromatic. The heavier fraction are known to be able to alterate the wettability of originally water-wet minerals due to the polar molecules that contain oxygen, nitrogen and sulfur (Speight, 1999). The polar molecules can be either acidic or basic, and these molecules can adsorb on the rock surface and serve as anchor molecules. The acidic polar organic molecules are mainly the carboxylic group (-COOH), while the basic component contain nitrogen as part of aromatic molecules (R_3N) with reactive pairs of electrons of pyridine type. Large amount of polar component may lead to generation of electrical charge between both the crude oil/brine interfaces and brine/rock interfaces.

Acid and base numbers measures the amount of acidic and basic components in the crude oil. The definition of acid and base numbers are as follow (Speight, 1999):

- Acid number: Amount of a base that is required to neutralize one gram of crude oil. Unit is given in milligrams potassium hydroxide per gram of oil, mg KOH/g of oil.
- Base number: Amount of an acid that is required to neutralize one gram of crude oil. Given in the same unit as acid number.

Crude oil adsorption on rock surface changes the wettability, and due to the complexity of natural materials, it is believable that more than one interaction mechanism is contributing to the wettability alteration. Studies by Buckley et al. (1998) identified four interaction mechanisms, which included interactions between polar oil component and solid, precipitation on rock surface that depends on solvency of oil phase with respect to its asphaltenes, and acid/base or ion-binding interactions between ionized sites on the oil/brine and solid/brine interfaces. The potential for wetting alteration by crude oil can be estimated by three measurements, its API gravity, acid number, and base number (Buckley et al., 1998).

2.5.2. Formation Water

Initial wetting state in reservoirs are dependent by the pH of the formation water, this property determines the surface activity of active organic components against minerals. In low saline formation water, the initial pH can be low due to acidic gases such as CO_2 and H_2S, but if the rock contains large amount of plagioclase that consist of mono-,di- and trivalent cations, an alkaline environment can be made due to H^+ having the highest affinity and exchange with other cations (Reinholdtsen et al., 2011). A high initial pH will result to reduction of crude oil adsorption onto the clay surface, which makes the rock too water-wet and wetting alteration becomes hard to achieve/not possible.

2.5.3. Rock

The clays are the main wetting material in sandstone, and it is clay that contributes to most of the rock surface. The clay surface have permanent localized negative charge, and acts as cation exchangers (Puntervold & Strand, 2016), where the general order of cation affinity is $Li^+ < Na^+ < K^+ < Mg^{2+} < Ca^{2+} << H^+$. It is clay and its properties, such as cation exchange capacity, that determines the initial wetting state and the potential of wettability alteration in sandstone. The adsorption of crude oil, active cations and proton happens as a competition that is affected by many factors like salinity, pH, temperature, etc. If the rock surface is mixed or oil-wet, an EOR effect can be achieved by injecting low salinity brine that will increase the pH with the following equation:

$$\text{Clay-Ca}^{2+} + H_2O = \text{Clay-H}^+ + Ca^{2+} + OH^- + \textbf{heat} \qquad (9)$$

Increasing the pH will activate the desorption process of organic component in crude oil, making the rock surface more water-wet.

2.5.4. Temperature

Aggregate size of asphaltenes increases as the temperature decreases, which will further lead to reduction of the oil solvency. If the temperature is increased, the solvency will also increase, and this improvement can also lead to enhanced interaction between oil, brine and solid due to kinetic effect that will result in improvement of both adsorption and desorption process (Buckley et al., 1997; Morrow et al., 1998).

3. Low Salinity Waterflooding

3.1. Introduction

One of the first experiments for comparison between a high saline waterflood and low saline waterflood was done by Bernard in 1967. It is known that clays in a reservoir has different reactions with the choice of salinity, and when hydratable clay is present in the rock, fresh water flooding gives a higher recovery than high saline waterflooding, which further results to decrease in permeability and a relatively high pressure drop (Bernard, 1967).

It is uncertain for how injecting low saline water could increase the overall recovery, however, several studies have proposed different mechanism for how this happens (Austad et al., 2010; Lager et al., 2008; Ligthelm et al., 2009; McGuire et al., 2005; RezaeiDoust et al., 2009; Tang & Morrow, 1999). The main concept for this type of flooding is to decrease the salinity of injection fluid to around 1000-2000 ppm, and it works best for sandstone reservoir that contains clay.

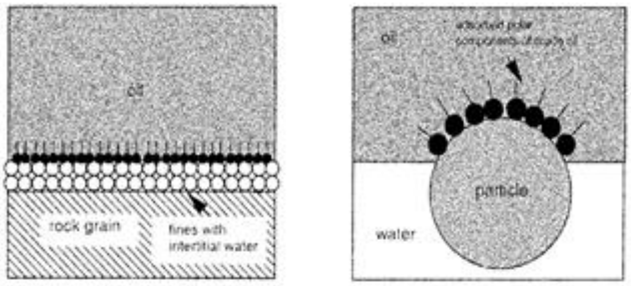
3.2. Fines Migration

Tang and Morrow suggested migration of fines as a low salinity mechanism in 1999. The concept of fines migration is mobilization of particles that has oil adsorbed on their surface in the reservoir.

The experiments were conducted by using cores that includes clays (mainly kaolinite), Berea sandstone that has been fired and acidized, and other cores that has low clay content. Berea sandstone and core with low clay content was insensitive to salinity, but the core that has clay showed a better recovery for low saline water injection (Tang & Morrow, 1999). For the latter case, kaolinite was observed in the effluent.

It is possible to see from Figure 4 that this mechanism happens by firstly oil adsorption onto mobile fines to form mixed-wet fines. The next step is to break these fine particles from the pore walls by waterflooding, making the trapped oil mobile and producible (Tang & Morrow, 1999). Certain criteria have to be met for a low salinity effect by this mechanism:

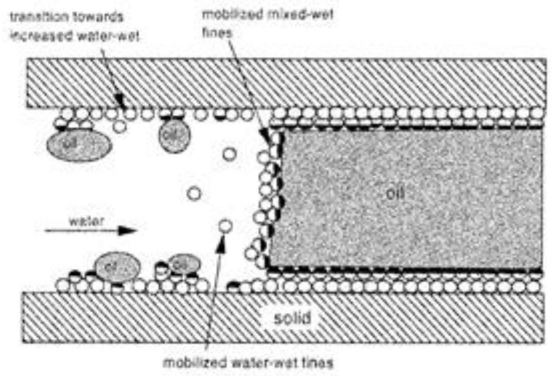
- Clay must be present in sandstone.
- Polar components present in crude oil to achieve adsorption.



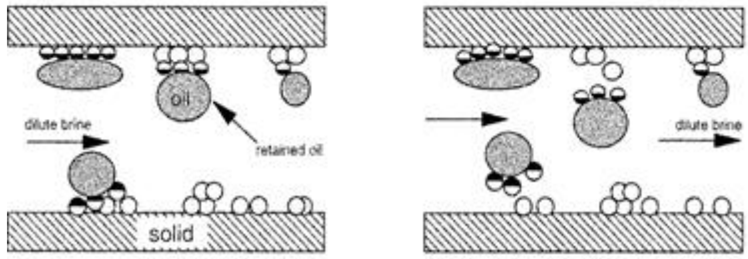
adsorption onto potentially mobile fines at low initial water saturation

mobilized particle at oil-water interface

a)



b)



retained oil before injection of dilute brine

partial mobilization of residual oil through detachment of fines

c)

Figure 4. *Illustrative scheme for low salinity effects by fines production,* ***a)*** *adsorbing polar components from crude oil to form mixed-wet fines,* ***b)*** *partial stripping of mixed-wet fines from pore walls during flooding and* ***c)*** *mobilizing the trapped oil (Tang & Morrow, 1999).*

However, a number of experiments has also observed low salinity effects without migration of fines happening (Lager et al., 2006; Pu et al., 2008; RezaeiDoust et al., 2011; Zhang et al., 2007). Zhang et al. (2007) observed a higher oil recovery without any clay in the production stream, while Pu et al. (2008) managed to achieve a low salinity effect with a very low clay content in the sandstone. In studies from Lager et al. (2006) and RezaeiDoust et al. (2011), LS EOR effect was achieved without observing any fines in the produced water.

3.3. pH Change

McGuire et al. (2005) suggested that the effects from low salinity waterflooding stem from the same mechanism for alkaline flooding and surfactant flooding. It is uncertain for which effect that increases the oil recovery in low salinity flooding, but the increase of pH level that generates surfactants from the residual oil is assumed as an important recovery mechanism. From core scale results, the EOR mechanism appeared to be like alkaline flooding, where in-situ generation of surfactant occurs leading to a wettability alteration, and reducing the interfacial tensions between the oil and water (McGuire et al., 2005).

The pH increase was described as two co-occurring reactions, carbonate dissolution and cation exchange (Lager et al., 2008). The dissolution process happens as:

$$CaCO_3 \leftrightarrow Ca^{2+} + CO_3^{2-} \tag{10}$$

$$CO_3^{2-} + H_2O \leftrightarrow HCO_3^{-} + OH^{-} \tag{11}$$

These reactions happen relatively slow and are also dependent on the amount of carbonate in the rock. Increase of pH can be observed from the reactions, when carbonate dissolves, the amount of hydroxide ions will increase. However, the cation exchange between clay and invading water occurs faster than dissolution. Due to affinity, the rock surface would exchange H^+ in water with previous cations adsorbed. This would result to pH increase because of reduction of H^+ concentration in effluent.

Several studies have shown doubt on this suggested mechanism. From experience, a high acid number is required to generate enough surfactant for wettability alteration, but core testing with low salinity flood on North Sea reservoir cores have shown increase in oil recovery with crude oil that has very low acid number (Lager et al., 2008).

3.4. Multicomponent Ionic Exchange (MIE)

Lager et al. (2006) suggested that cation exchange between the mineral surface and the invading brine is the main mechanism for low salinity effects. Multicomponent ionic exchange (MIE) involves the competition of all the ions in pore water for the mineral matrix exchange sites. A geochemical analysis of low salinity effluents was performed, and several studies have also shown that Ca^{2+} and Mg^{2+} concentrations is less in the effluent than in invading water and connate water.

Effluent analysis of a North Slope low salinity coreflood was performed, where the injected brine and connate water had similar Mg^{2+} concentration. The effluent was observed and a decrease of Mg^{2+} concentration was detected, indicating that magnesium ions were strongly adsorbed on the rock surface (Lager et al., 2006). By adsorbing these divalent ions onto the rock surface, the polar component in the oil will get released from the rock surface, hence, increasing the oil recovery. As shown in Table 4, there are eight different mechanisms that can make organic matter adsorb to clay, and four of them are strongly affected by cation exchange during low salinity waterflooding. These are cation exchange, ligand bonding, cation bridging and water bridging, that are illustrated in Figure 5.

Table 4. *Adsorption mechanism between organic functional groups and soil minerals (Lager et al., 2008; Sposito, 1989)*

Mechanism	Organic functional group involved
Cation Exchange	Amino, ring NH, heterocyclic N (aromatic ring)
Protonation	Amino, heterocyclic N, carbonyl, carboxylate
Anion Exchange	Carboxylate
Water Bridging	Amino, carboxylate, carbonyl, alcoholic OH
Cation Bridging	Carboxylate, amines, carbonyl, alcoholic OH
Ligand Exchange	Carboxylate
Hydrogen Bonding	Amino, carbonyl, carboxyl, phenolic OH
Van der Waals Interaction	Uncharged organic units

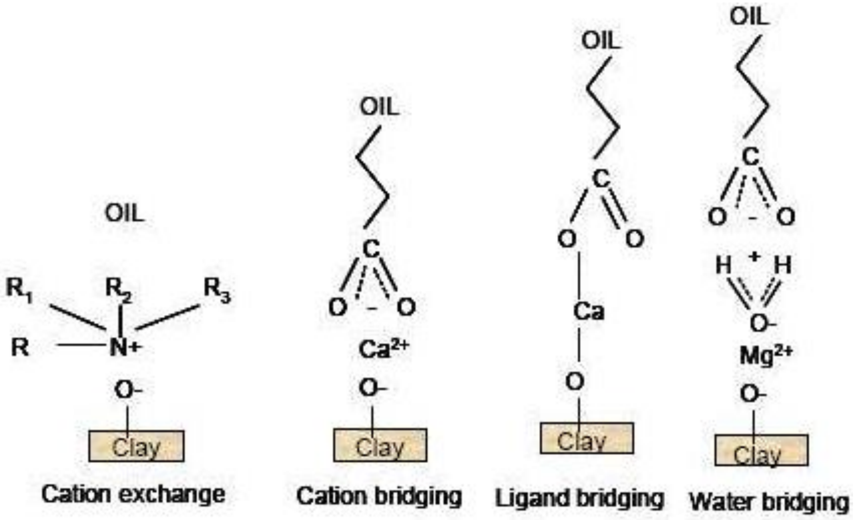


Figure 5. *Different adsorption mechanism happening between clay surface and crude oil (Lager et al., 2008)*

Ca^{2+} and Mg^{2+} plays an important role in wettability alteration for multicomponent ionic exchange theory. It is assumed that Ca^{2+} and Mg^{2+} acted as a connection between clay and the surface-active components in oil. The water-wetness in the reservoir will increase when Ca^{2+} and Mg^{2+} are exchanged by uncomplex cations. Experimental data has also showed that when a core is flushed out of divalent ions to only Na^{+} on the rock surface, a low salinity tertiary flooding with brine containing only Ca^{2+} and Mg^{2+} did not increase the oil recovery after a high saline flood(Lager et al., 2006; Lager et al., 2008).

3.5. Double Layer Effect

Ligthelm et al. (2009) proposed that the low salinity effects happen primarily due to expansion of electrical double layers, and less to cation exchange. By injecting a low saline brine into a core with high saline formation water will reduce the electrolyte content and the multivalent cations in the brine solution. This leads to an expansion of the electrical diffuse double layer that surround the clay and oil particle, which will further increase the electrostatic repulsion between the clay surface and oil (Ligthelm et al., 2009). Multivalent cations, such as Ca^{2+}, has a major role in this mechanism by acting as a bridge between clay and oil. The oil particles get desorbed from the clay surface when the repulsive forces exceed the binding forces, causing a wettability alteration that increases the water-wetness. Figure 6 illustrates the interaction between clay, Ca^{2+} and crude oil in high and low saline brine. Clay deflocculation and formation damage could also occur if the electrolyte concentration is reduced further. This happens due to the repulsive forces that would exceed the binding forces within the clay (Ligthelm et al., 2009).

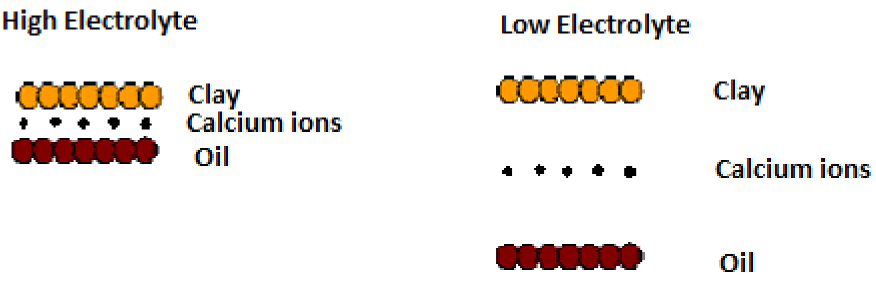


Figure 6. *Illustration of bonding between clay surface and crude oil in high salinity brine and low salinity brine. Redrawn from Ligthelm et al. (2009).*

Double layer mechanism is based on lowering the ionic strength of brine to increase the expansion of the layers. The ionic strength can be reduced by stripping multivalent cations in brine, but this cation stripping process does not seem essential for a wettability alteration (Ligthelm et al., 2009). Also, brine that has low ionic strength initially managed to alternate the wettability from the core experiments done by Ligthelm et al.

3.6. Salting-in Effect

The CBR system in a reservoir has established a thermodynamic equilibrium over a long geological time, and this system is disturbed when injecting a brine with different salinity. RezaeiDoust et al. (2009) suggested that the salting-in effect is the mechanism for low salinity effects. The theory of this mechanism is to change the solubility of polar organic components in water by modifying ion composition and salinity of the injected brine.

The term salting-in/salting-out effects have been used in chemical literatures. Salting-out effect happens when solubility of an organic component in water decreases due to addition of salt, while salting-in effect is the increase of solubility with the addition of salt (RezaeiDoust et al., 2009). The salting-in effect requires that salinity reduces to below a critical ionic strength for increasing the solubility of organic matter in aqueous phase. These processes are illustrated by Figure 7.

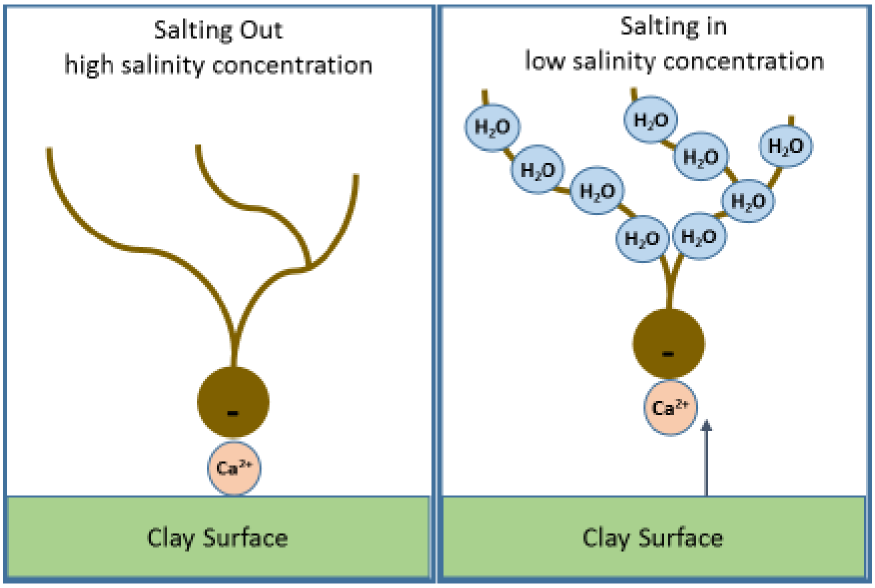


Figure 7. *Illustration of salting out and salting in mechanism (Sajjad, 2015).*

Salting-in mechanism happens due to disturbance in the CBR system that was in equilibrium. This disruption will increase solubility of the organic matter in water, resulting to desorption from the clay surface and increasing the water-wetness of the rock. However, study has showed a higher adsorption of polar oil component in low salinity brine than high salinity brine (Austad et al., 2010).

3.7. Desorption by pH increase

Austad et al. (2010) proposed a new mechanism for increasing the oil recovery by desorption of oil from rock surface. To achieve an enhanced oil recovery, certain requirements must be met: Clay must be present in rock, oil has to contain polar components, and initial formation water composition and its pH are important properties that must be known before application of low salinity waterflooding.

A chemical equilibrium is established in a reservoir before injection of any fluids, for example pH, temperature, pressure etc. are constant before introducing external energy/forces. By injecting a low saline fluid into the reservoir will cause disruption in the equilibrium state, and desorption of Ca^{2+} would occur. Protons, H^+, in water closest to the rock surface will compensate for the loss of cations by adsorbing on the clay surface, causing cation exchange between Ca^{2+} and H^+ where the clay surface initially had basic and acidic organic materials adsorbed onto it, together with inorganic cations (Austad et al., 2010). Figure 8 shows how low salinity effects are achieved from the initial state to the final situation by the process described.

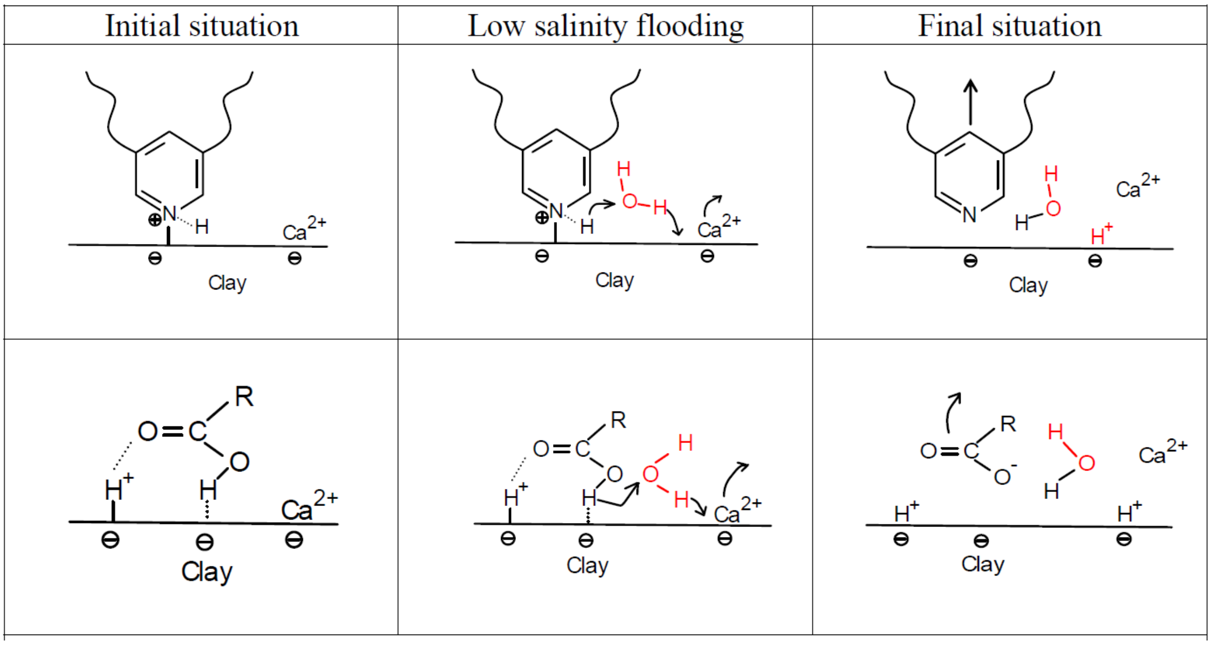


Figure 8. *Proposed mechanism for low salinity effects. Upper part shows desorption of basic material, while lower part shows desorption of acidic material (Austad et al., 2010).*

The chemical reactions that happens during this mechanism are as follow:

$$\text{Clay-Ca}^{2+} + H_2O = \text{Clay-H}^{+} + Ca^{2+} + OH^{-} \qquad (12)$$

$$\text{Clay-NHR}_3^{+} + OH^{-} = \text{Clay} + R_3N + H_2O \qquad (13)$$

$$\text{Clay-RCOOH} + OH^{-} = \text{Clay} + RCOO^{-} + H_2O \qquad (14)$$

As seen from Eq. (12), injection of low saline water will cause the equation to go toward the right side, increasing the pH of mixed fluid between formation water and injected water. A local increase in pH close to the clay surface pushes the reactions Eq. (13) and Eq. (14) toward the right side, desorbing the polar component in crude oil from clay surface and making the reservoir more water-wet.

Adsorption of the organic matter in oil is very dependent on pH, several studies have been conducted to observe how adsorption varies with pH. The studies have showed that adsorption of polar component in oil on clay surface will decrease by increasing pH (Aksulu et al., 2012; Burgos et al., 2002; Madsen & Lind, 1998). The level of adsorption onto clay surface is also dependent on which clay is in the rocks. Quinoline, a basic organic component in oil, adsorption onto clay increases as follow: Kaolinite < Illite < Montmorillonite (Doehler & Young, 1960), which correspond well to the increasing cation exchange capacity of these three clay types.

The initial pH should be low to get a low salinity effect. Aksulu et al. (2012) conducted an experiment where the adsorption of quinoline and pH where observed for both high salinity brine (25000 ppm) and low salinity brine (1000 ppm), as shown in Figure 9. The result showed that in a pH range from 3-8, the low salinity brine always had a higher adsorption than high salinity brine. Hence, a low initial pH within the range will give an increased recovery, while a high initial pH will either give a little increase in oil recovery or nothing at all. Austad et al. (2010) also concluded that the initial pH is preferentially around 5 due to the adsorption of organic matter on clay surface.

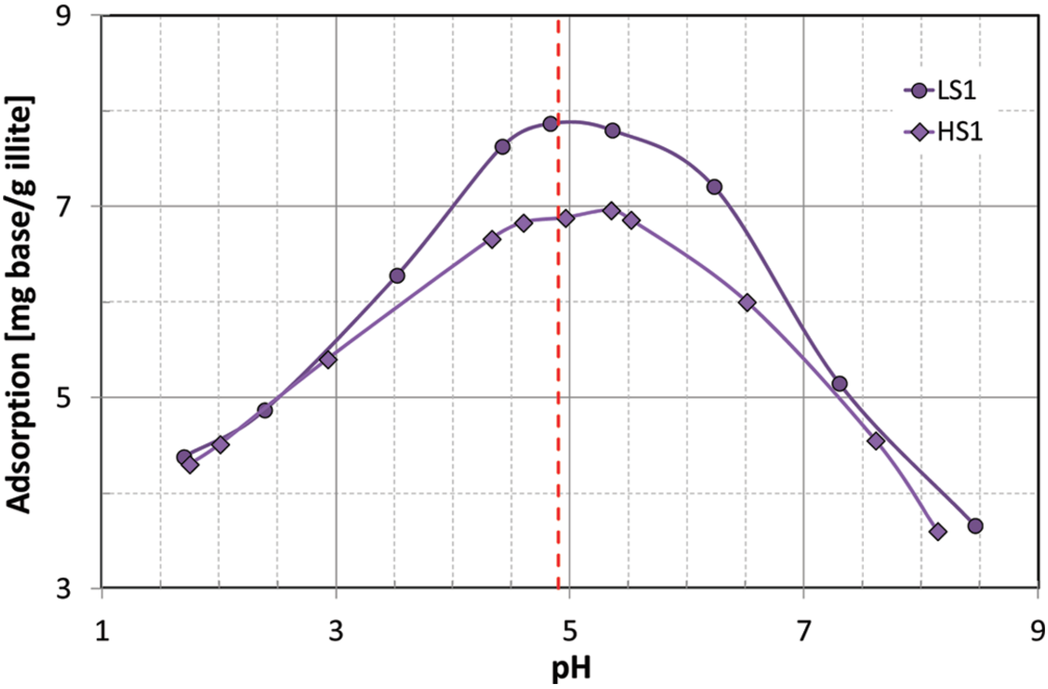


Figure 9. *Adsorption of quinoline vs. pH plot at ambient temperature in low and high salinity brines. LS1 has 1000 ppm and HS1 has 25 000 ppm. Dashed line represents pK*$_a$ *value of quinoline (Aksulu et al., 2012).*

3.8. Conditions for Low Salinity Effects

Not all the sandstones in the world are compatible with low salinity waterflooding, therefore, certain conditions have to be met before applying this type of flooding into a reservoir. Below is a list of conditions put together from several studies (Austad, 2013; Lager et al., 2008; Piñerez T et al., 2016b; Tang & Morrow, 1999):

- Porous medium: Sandstone that must contain clay.
- Oil: Must contain polar components, such as acids and bases.
- Formation water: Must contain divalent cations, such as Ca^{2+} and Mg^{2+}
- Low salinity brine for injection: Preferable a salinity between 1000-2000 ppm, but effects have been observed up to 5000 ppm. "Low salinity effects" have also been observed at 25 000 ppm and 40 000 ppm.
- Produced water: For non-buffered system, a pH increase of around 1-3 units in the effluent for low salinity waterflooding. In certain cases, low salinity effects has been observed together with fines production, but effects without fines production is also observed.
- Permeability: Both increase and decrease in differential pressure over the core has been observed by switching from high to low salinity brine, which may indicate changes in permeability.
- Temperature: From observation, there does not seem like there is any temperature limitations for low salinity effects, but most of the reported studies have been performed at temperatures below 100^oC.

pH is an important chemical parameter for certain proposed low salinity mechanisms. pH is a indicator for the molar concentration of H^+ in aquoues phase, and it is found by calculating the negative logarithm in base 10 of H^+ concentration. A relatively low initial pH is preferred in the reservoir to obtain the best low salinity results, approximately initial pH at 5 (Austad et al., 2010). A preferred initial low pH is essential due to a higher adsorption of polar component toward the clay surface.

RezaeiDoust et al. (2011) tested two cores to observe the low salinity effect with and without CO_2. The recovery results are showed in Figure 10. After preperations, the cores were first injected with high salinity waterflooding ($NaCl + CaCl_2$, 100 000 ppm) which gave a recovery of 41 % and 46 % for without and with CO_2, respectively. A low salinity waterflooding (1000 ppm NaCl) was then injected into the cores, giving an extra recovery of 16 % for the core with

CO_2 and 7 % for the reference core (RezaeiDoust et al., 2011). From Figure 11, the CO_2 buffered core had a smaller increase in pH compared to without, and this effect can be shown by the following reaction :

$$CO_2 + H_2O \leftrightarrow [H_2CO_3] \leftrightarrow H^+ + HCO_3^- + OH^- \leftrightarrow H_2O + HCO_3^- \qquad (15)$$

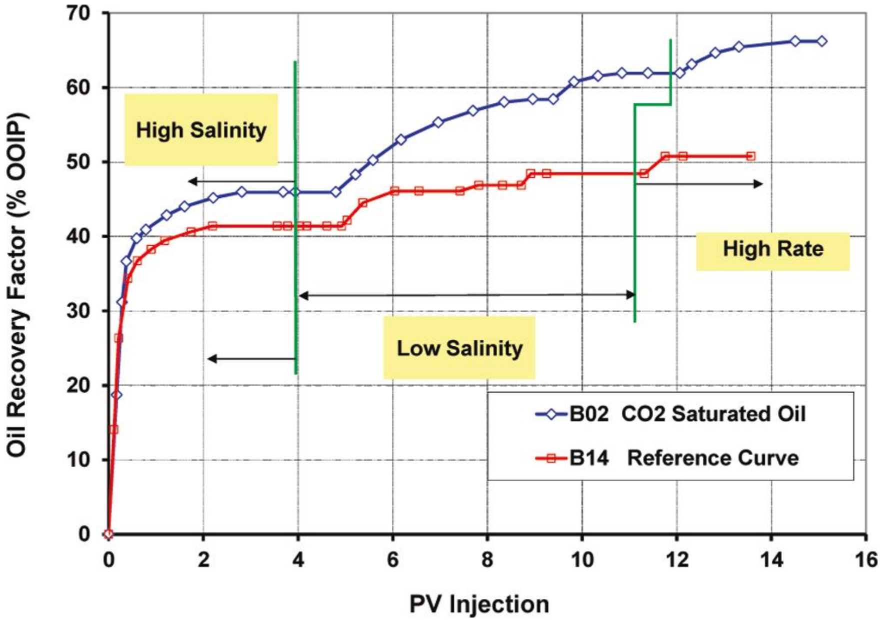


Figure 10. *Effect of initial pH on oil recovery by tertiary low salinity flood (RezaeiDoust et al., 2011).*

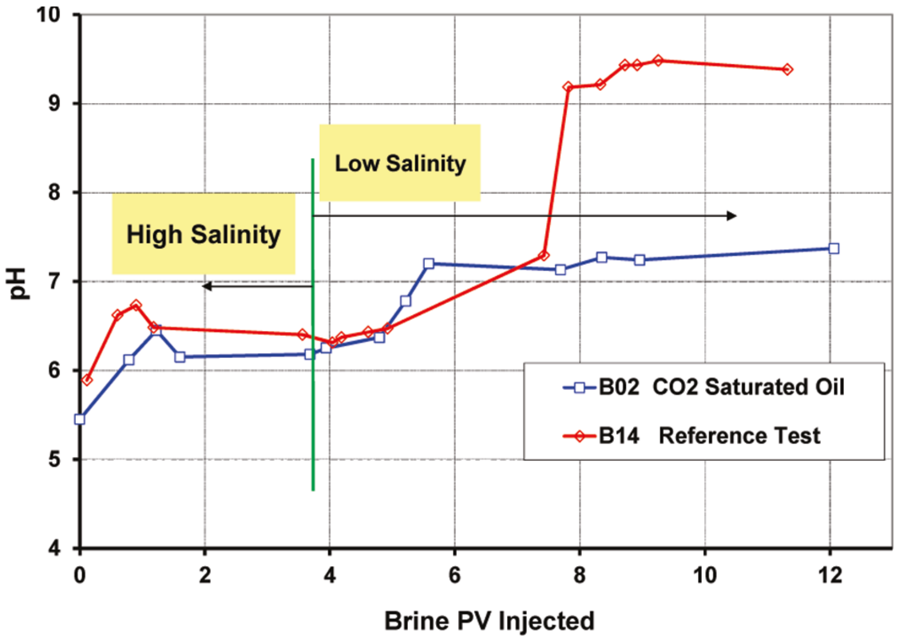


Figure 11. *pH variation of the effluent with and without CO_2 (RezaeiDoust et al., 2011).*

Polar component in crude oil is important for obtaining a low salinity effect. These components are stuck on the clay surface due to the acidic or basic properties, making the reservoir more oil-wet. Acid number and base number are parameters that gives a good indication for how much active polar components are in the oil.

3.9. Low Salinity Waterflooding Screening Conditions for EOR potential

Not all the reservoirs in the world are susceptible for low salinity waterflooding to enhance the overall oil recovery. Many requirements must be met to achieve the low salinity effect. Table 5 shows what the preferred condition for each parameters are before implementing low salinity waterflooding.

Table 5. *Screening conditions for low salinity waterflooding made by Dang et al. (2015).*

Property	Preferred Condition
Reservoir	Sandstones
Crude Oil	Must contain polar components Not too high viscosity for waterflooding
Clay Minerals	Must contain sufficient amount of clay Medium-sand with high CEC clay, porosity, permeability is preferred
Reservoir Minerals	Calcite and dolomite
Formation Water	Presence of divalent ions such as Ca^{2+} and Mg^{2+}
Initial Wettability	Oil-wet or mixed wet reservoirs
Reservoir Temperature	Not limited
Reservoir Depth	Not limited
Reservoir Energy	Sufficient high pressure for achieving miscibility condition
Injected Fluid	Lower salinity concentration than formation water Must contain divalent ions Injected compositions must promote the adsorption of divalent ions Sufficient CO_2 or chemical sources for hybrid low salinity waterflooding implementation

Although sandstone reservoirs are preferred for low salinity flooding application, some carbonate reservoir could also achieve an EOR effect (Dang et al., 2015). Polar component in crude oil is important for the adsorption process to achieve low salinity effect, hence, mineral oil or synthetic oil will not give an EOR effect. The viscosity of the crude oil should preferentially be low for avoiding viscous fingering of injected fluid. Sufficient amount of clay must be present since it is these that oil adsorbs on to make the reservoir into oil-wet or mixed wet state. Further on, the initial wettability must be oil-wet or mixed wet. This is due to that the EOR effect works by altering the wettability of the reservoir to produce the extra oil, therefore, low salinity waterflooding would be ineffective in strongly water-wet reservoirs.

Divalent ions, such as Ca^{2+} and Mg^{2+}, should be present in the formation water to achieve an EOR effect, it is noted from various corefloodings that low salinity effect would not occur if divalent ions does not exist in the formation water (Dang et al., 2015). In this case, desorption of Ca^{2+} and Mg^{2+} can lead to an adverse wettability alteration with no extra oil produced. If the reservoir have calcite and dolomite minerals, it is assumed that the reservoir has a good EOR potential due to these minerals being sources for calcium and magnesium ions.

Low salinity effects is not directly dependent on reservoir temperature and depth, but it can be dependent on what would happen with the formation/reservoir at certain temperatures. Anhydrite is formed at high temperatures, and by using low salinity flooding could dissolve anhydrite and increase the calcium ion concentration, which can further make the low salinity flooding ineffective (Aghaeifar et al., 2015; Aksulu et al., 2012).

A low salinity injection fluid is typically assumed to have a salinity that is in the lower range, around 2500-5000 ppm, as stated in Table 5 previously. However, “low salinity” effects with injected fluid of 25 000 ppm and above in salinity is possible. Sandstone core flooding in tertiary mode have shown increase in overall recovery with injected fluid salinity at 25 000 ppm and 40 000 ppm, where the extra recovery were 10% and 3% OOIP, respectively (Piñerez T et al., 2016b).

Initial pH and how it increases from displacing low saliniy fluid into high saline formation water is also important to obtain an EOR effect. A initial pH of around 5 is preferred in the reservoir, and the increase of pH is correlated to how large the EOR effect will be (Austad et al., 2010; Piñerez T et al., 2016a). High initial pH can result to smaller pH increase when injected by low saline fluid, weakening the low salinity effects as observed from the Snorre Field, which will be described more later.

According to Dang et al. (2015), the injected low salinity water must contain divalent ions, but recent study has shown that low saline NaCl brine is sufficient enough to achieve a LS EOR effect (Piñerez T et al., 2016b). Even though the preferred conditions for injection fluid is given in Table 5, it doesn’t necessarily mean that it is correct as newer research has shown other results. Design of low saline brine for injection purposes varies for different fields, and determining the composition of the injected water is a very delicate subject that requires more research before deciding the general screening conditions.

The enhanced oil recovery that happens by low salinity water injection is due to the wettability alteration and this improves the microscopic sweep efficiency by decreasing the residual oil saturation. Screening of the EOR potential by using low salinity flooding is critical and designing the injection fluid is essential for realizing the best production scenario. The design of low salinity injection fluid is not to just lower the salinity, but the idea is to change the ion composition of injected fluid in a way that will disturb the CBR equilibrium in the reservoir in a positive matter. Therefore, the injected low saline fluid composition varies case by case.

4. Johan Sverdrup Field

4.1. History of Johan Sverdrup Field

Johan Sverdrup Field was first discovered in 20th July 2010 by Lundin Norway AS. It was found by well 16/2-6, with primary purpose to determine the existence of petroleum in Upper Jurassic Formation. A 17-meters oil column was determined in Draupne and Hugin formation in the Upper to Middle Jurassic formations (NPD, 2010b). 15 million Sm^3 producible oil was estimated in 2010, which has a GOR of 40 Sm^3/Sm^3 and a water depth of 115 meters. Figure 12 shows the shape of Johan Sverdrup Field.

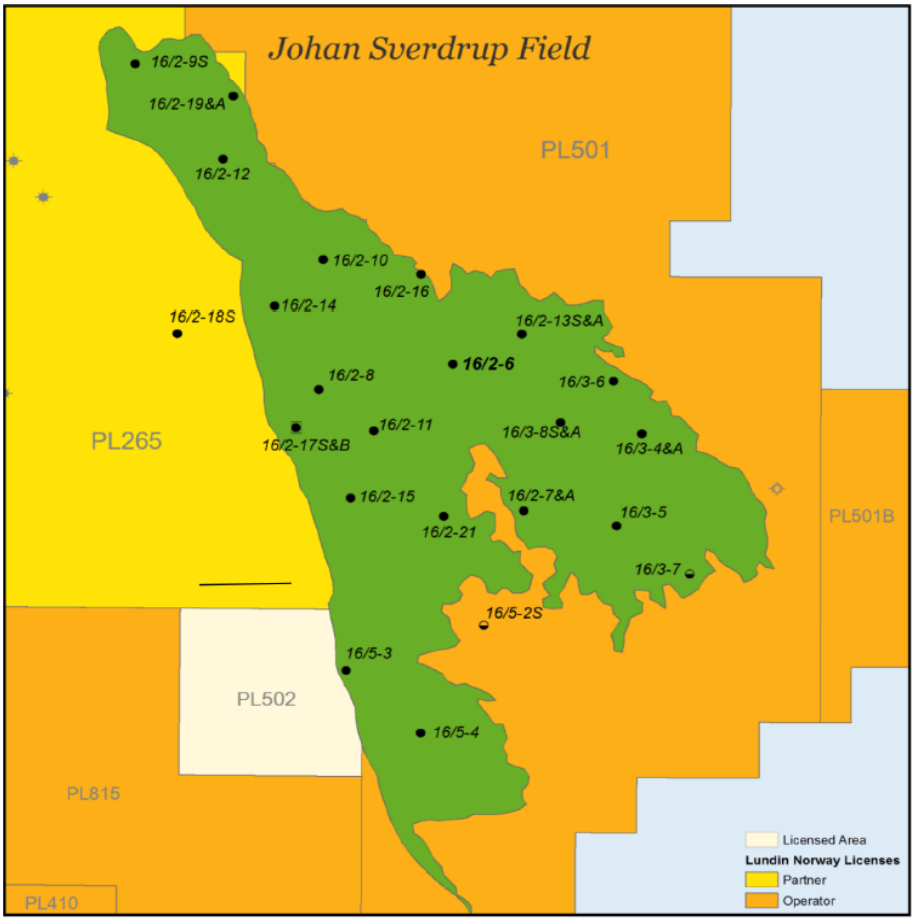


Figure 12. *Outline of Johan Sverdrup Field, where the green part symbolizes the field and the bold number symbolizes the first well (Sætrom et al., 2016).*

The drilling permit for well 16/2-6 was given to Lundin Norway AS in 2010, which was a wildcat well in production license 501. At the time, Lundin had an ownership interest of 40 %, while Statoil Petroleum AS and Maersk Oil Norway AS had 40 % and 20 %, respectively (NPD, 2010a). Over 30 appraisal wells have been drilled from 2011-2014 after the wildcat.

4.2. Field Description

Johan Sverdrup Field is located 160 kilometers west of Stavanger on the Utsira High in the North Sea, and is 40 kilometers south of Grane Field and 65 kilometers northeast of the Sleipner Field. The field has approximately an area of 200 square kilometers and an average water depth of 110-120 meters. With a reservoir apex of around 1800 meters, it is currently classified as the fifth largest oil discovery on the Norwegian continental shelf (Ludvigsen & Le, 2015). The main reservoir has a temperature of around 75.5 ^{o}C to 83.5 ^{o}C (NPD, 2017).

The oil is mainly in the Upper Jurassic intra-Draupne sandstones, originating from the basement subcrop area on Utsira High South (NPD, 2017). The intra-Draupne sandstone is considered as a great type of reservoir rock due to the relatively homogeneity of the rock that has good flow properties. There is also other formation that has oil in the rocks, sandstones in Statfjord and Vestland Groups, as well as in Zechstein carbonates. The main priority for this field is to produce the oil from Upper Jurassic formation.

According to NPD (2017), there is approximately 282.3 million Sm^3 recoverable oil and 8.6 billion Sm^3 recoverable gas in Johan Sverdrup, while the original in-place oil and gas are 573 million Sm^3 and 21 billion Sm^3, respectively. Considering these values, a 49.3 % oil recovery factor is expected as of 2017.

4.3. Geology

Intra-Draupne formation sandstone is the main reservoir in the Johan Sverdrup Field and is distributed across the whole field with the exception of wells located on Utsira High and north of the Geitungen Terrace (Ramstad et al., 2016). The intra-Draupne sandstone is part of the Viking group, which rests uncomfortably on the underlying sandstones and mudstones of Vestland and Statfjord groups, where the latter further overlies on the sandstone-rich Hegre group that also overlies Zechstein group. According to Figure 13, the western part shows that Zechstein group overlies the basement and is uncomfortably overlain by the intra-Draupne sandstone. As of the eastern part, there are absent of Zechstein, Hegre and Statfjord groups, which results to the intra-Draupne sandstone to lie directly over the basement.

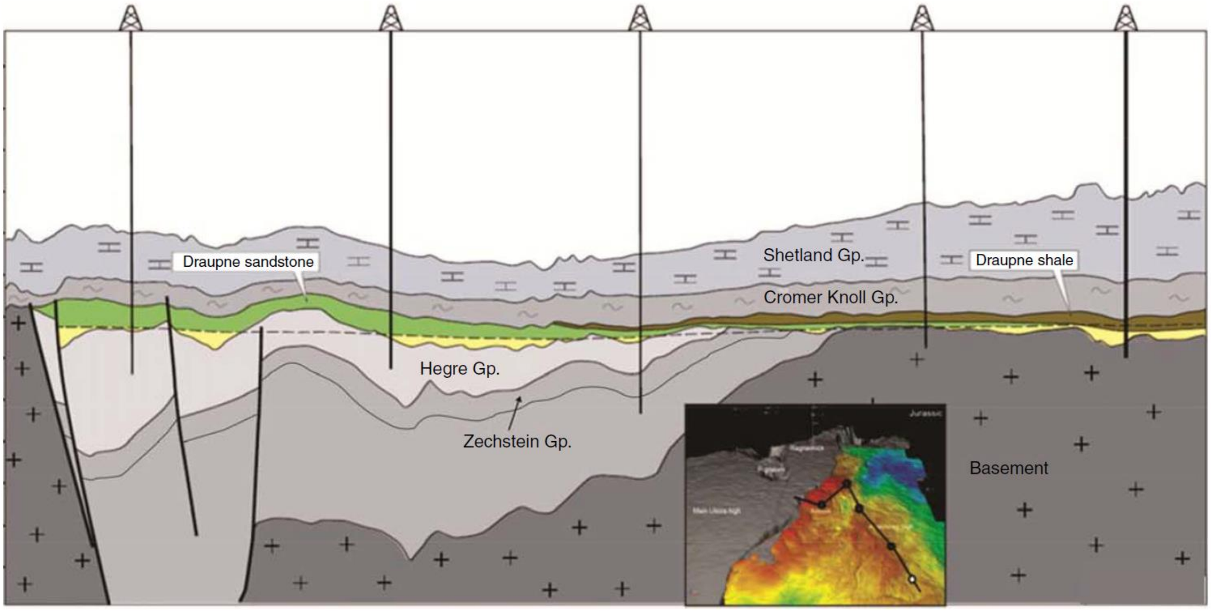


Figure 13. *Sketch cross section across Johan Sverdrup Field from west to east/southeast (Ramstad et al., 2016).*

The Zechstein group can be divided in two, an upper and a lower part. The upper part consists of marl overlain by anhydrite. In the case with well 16/2-7, an 18 meters thick anhydrite layer was determined (Ramstad et al., 2016). The lower part consists of dolomite and limestone, but seismic interpretation has indicated to a mobile layer in the deeper part of the Augvald Graben, left side on Figure 13, which can represent the presence of halite.

4.4. Reservoir Properties

4.4.1. Crude Oil Properties

The oil in Johan Sverdrup is strongly under-saturated that also has a moderate viscosity and density. The oil has a viscosity at approximately 2 cP, oil density at around 800 kg/m^3 and a GOR at around 40 Sm^3/Sm^3 (Ludvigsen & Le, 2015).

4.4.2. Formation Water Properties

Ramstad et al. (2016) did an evaluation of the quality of the water samples/analyses in Johan Sverdrup Field. Formation water composition is listed below in Table 6 for well 16/2-7:

Table 6. *Measured composition of water-based-mud filtrate and formation water samples from well 16/2-7. Mud filtrate contamination was based on tracer measurements (Ramstad et al., 2016).*

Sample Type/Number	Mud Filtrate	FW Sample 1	FW Sample 2	FW Sample 3
Na^+ (mg/L)	7497	14 800	15 385	15 678
K^+ (mg/L)	35 920	2631	572	630
Mg^{2+} (mg/L)	20	542	629	583
Ca^{2+} (mg/L)	466	2671	2872	2905
Ba^{2+} (mg/L)	<1	2	3	4
Sr^{2+} (mg/L)	10	132	144	144
Cl^- (mg/L)	43 144	31 380	31 600	32 140
Br^- (mg/L)	323	152	144	142
SO_4^{2-} (mg/L)	344	322	339	350
SCN^- (mg/L)	505	34	5	5
Formate (mg/L)	1260	72	13	19
Acetate (mg/L)	3241	220	77	157
Ion balance (%)	-1.93	-0.42	-1.10	-1.35
Mud-filtrate contamination (%)	-	6.7	1.0	1.0
Total Dissolved Solids (mg/L)		52958	51783	52757

The following statements were made after the evaluation (Ramstad et al., 2016):

- All the water samples were contaminated by mud filtrate (varying between 0.7 and 67 %).
- Laboratory mud-filtrate-sample analyses for a well can be representative for the water samples that were obtained from the same well which were contaminated by mud filtrate.
- Precipitation of $BaSO_4$ because of mixing the formation water and mud filtrate would not significantly affect the SO_4^{2-} concentration of the water samples due to the low Ba^{2+} concentration in formation water. This implies for all the wells except 16/2-9 S.

- For well 16/2-9 S, precipitation of $BaSO_4$ because of mixing the formation water and mud filtrate would not significantly affect the Ba^{2+} concentration of the water samples due to the low SO_4^{2-} concentration in the mud filtrate.
- Some precipitation of barite and calcite from the water samples after collection was possible because of cooling/depressurization, but this would not significantly affect the Ca^{2+} and SO_4^{2-} concentration of the water samples. Precipitation of barite from well 16/2-9 S water samples is the only exception that might have significantly affected the Ba^{2+} concentrations of these samples.
- Most ion balances were ± 3%, while the range was -4.3 to 6.3%, which may indicate that all major ionic constituents have been analyzed and the major ion analyses are likely to be accurate.
- Some differences were identified between analyses obtained from different laboratories or using different analytical techniques, and these were taking into account when undertaking mud-filtrate-contamination corrections.
- For the wells with multiple test zones, the zones were closely spaced, and common formation water was present across these zones. This allowed the water samples from all the tested zones of a well to be combined into a single data set when estimating the formation water compositions.

Formation water compositions in Table 7 are obtained by means of linear-regression calculations. Barium was estimated by using thermodynamic simulations from estimated SO_4^{2-} formation water concentrations, assuming barite saturation in the reservoir for all the well with the exception of well 16/2-9 S. For well 16/2-9 S, sulfate was estimated similarly from the estimated barium formation water concentrations, with the same assumption as previously (Ramstad et al., 2016). Calculations showed that if precipitation of $BaSO_4$ had happen in the water samples before analysis would indicate to a formation water Ba^{2+} concentration to be as high as 106 mg/L for well 16/2-9 S.

Table 7. *Estimated formation water compositions from multiple water samples (Ramstad et al., 2016).*

Well	16/2-7	16/2-7 A	16/2-8	16/2-9 S	16/2-10	16/5-2 S	16/2-6 T2
Formation/ Group	Draupne	Statfjord	Statfjord	Viking	Statfjord	Draupne	Statfjord
Depth (mTVD MSL)	1938.5	1925-1927	1921.5-1923	1911-1918	1937-1942	1924	1935
Na^+ (mg/L)	15 525±254	16 596 ±476	12 435 ±840	14 898±2982	18 018 ±838	14 806±788	16 718 ±420
K^+ (mg/L)	242 ±36	681 ±1596	1450 ±1005	3722±13 888	296 ±1196	265 ±166	-
Mg^{2+} (mg/L)	602 ±34	687 ±14	336 ±34	399 ±32	897 ±70	527 ±34	638 ±30
Ca^{2+} (mg/L)	2887 ±54	3391 ±183	1372 ±306	2512 ±262	5126 ±516	3099 ±157	3181 ±130
Ba^{2+} (mg/L)	1.6 ±0.1	5.5 ±7.5	(0.9-1.9) ±0.8	65 ±16	3.3 ±1.0	1.2 ±0.1	6.0 ±4.1
Sr^{2+} (mg/L)	144 ±3	133 ±3.6	(91-125) ±32	211 ±32	260 ±11	178 ±20	206 ±6
Li^+ (mg/L)	3.1 ±0.1	4 ±0.4	3.1 ±4	6.3 ±1.6	2.3 ±3.2	2.7 ±0.6	-
Cl^- (mg/L)	31 382±862	30 291 ± 3308	24 270±1786	30 491±3810	40 932±1668	30 995 ±918	32 130 ±348
Br^- (mg/L)	141 ±2	148 ±12	-	-	-	122 ±14	-
SO_4^{2-} (mg/L)	337 ±18	98 ±57	(327-472)±172	8.8 ±2.2	227 ±54	527 ±16	94 ±82
Formate (mg/L)	0 ±12	84.7 ±81	-	-	-	1.8 ±3.6	-
Acetate (mg/L)	60 ±72	409 ±112	-	-	-	80 ±78	-
Ion balance (%)	-0.93	5.51	-4.12	2.69	-1.76	-2.02	1.86
Total Dissolved Solids (mg/L)	51324.7	52528.2	40465.1	52313.1	65761.6	50604.7	52973

Majority of the formation waters are sulfate-rich and barium depleted except the waters in Geitungen Terrace that has it reversed, with the latter case being a typical Utsira High formation water that has an unusual sulfate-rich nature specifically in that region.

4.4.3. Rock Properties

Oil has been observed in many different formations, but the main reservoir rock is the intra-Draupne formation sandstones that resides in the Draupne formation shales. This section will describe the intra-Draupne sandstones and the surrounding of this important rock by various geological studies.

Figure 14 shows an illustrated lithostratigraphy of a location close to Johan Sverdrup. Sleipner and Hugin formations in the South Viking Graben are primarily gas prone, but they have the capability to expel volatile oils (Isaksen et al., 1998). Heather and Draupne formation shales were deposited during a sea-level rise in Late Jurassic, and these rocks are also organic rich oil- and gas prone (Justwan et al., 2005). The Middle Jurassic Hugin and Sleipner formations consists of sandstones, coals and coaly shales. It is the coals and coaly shales that works like a source rock by having the potential to generate gas and volatile oil.

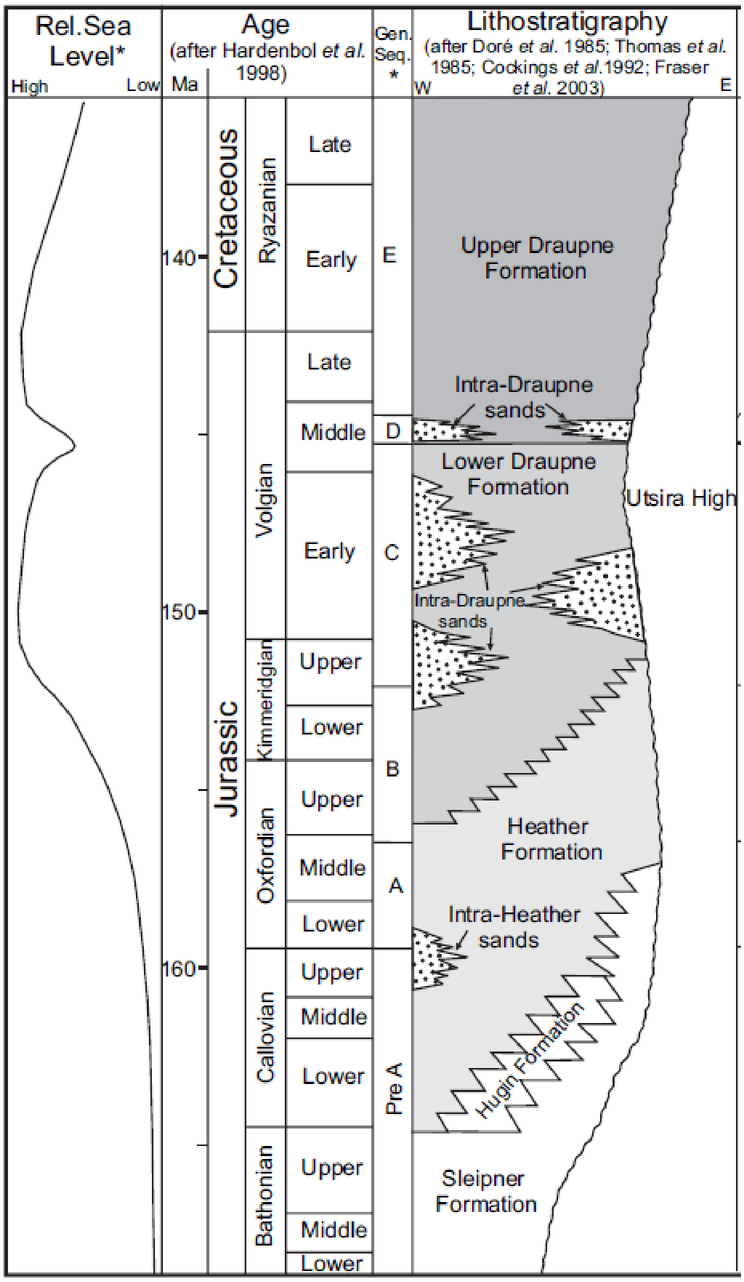


Figure 14. *Lithostratigraphy and depositional age of a location close to Johan Sverdrup Field (Justwan et al., 2005).*

Draupne formation has a TOC up to 12 wt% and hydrogen index that are over 600 g HC/kg C_{org}, but this formation has huge variations in source quality both in lateral and vertical directions (Isaksen & Ledje, 2001). Therefore, Draupne formation can be divided into the Upper Draupne formation and Lower Draupne formation due to the source quality. The Upper Draupne formation has better source quality and richness due to the deposition happened under sedimentation rates that promotes preservation of organic matter (Justwan et al., 2005), while the Lower Draupne formation has a higher content of Type III kerogen (Isaksen & Ledje, 2001).

Riber et al. (2016) observed several results on rocks from Johan Sverdrup Field by testing samples in well 16/3-4. X-ray powder diffraction (XRD) analysis was performed on the samples to determine the composition of the rock in Table 8 and x-ray fluorescence (XRF) was performed to obtain the geochemical data in Table 9.

Table 8. *Results from quantitative Rietveld XRD analysis by Siroquant. Values are in wt% of the specified minerals. Analysis performed on samples from well 16/3-4 (Riber et al., 2016).*

Depth (m)	Quartz (wt%)	Plagioclase (wt%)	K-feldspar (wt%)	Illite+mica (wt%)	Kaolinite (wt%)	Biotite (wt%)	Chlorite (wt%)	Calcite (wt%)
1940.90	46.1	14.8	19.6	7.0	9.1	2.6	0.7	0.1
1941.40	39.2	20.3	21.2	6.5	9.5	2.6	0.7	-
1941.80	44.1	20.6	17.2	9.8	7.4	0.6	0.3	0.1
1942.77	36.1	32.4	17.9	7.1	4.8	1.7	-	-
1943.50	39.3	27.4	15.8	7.9	6.2	3.0	0.2	0.2
1944.05	34.3	30.3	17.4	5.7	8.5	2.8	0.8	0.2
1944.40	38.1	30.8	14.8	8.9	4.7	2.4	-	0.2
1944.80	34.5	32.7	18.6	6.6	5.3	1.8	0.1	0.3
1945.80	31.7	38.8	11.0	12.6	3.1	2.3	-	0.4
1946.50	36.9	33.0	16.9	7.0	3.7	2.4	-	-
1956.40	32.9	37.5	16.5	7.1	1.2	4.5	-	0.2
1957.90	31.9	35.7	22.9	6.6	1.1	1.6	-	0.1
1958.60	37.1	29.2	24.3	6.2	1.2	1.9	-	-
1959.30	32.8	35.6	20.1	8.7	1.2	1.6	-	-
1959.50	34.3	35.4	15.3	9.1	1.3	4.3	-	0.3
1960.40	33.7	38.5	14.4	9.7	1.2	2.3	-	0.2

***Table 9.** Major-element geochemistry of a selection of elements, determined by XRF from well 16/3-4 samples (Riber et al., 2016).*

Minerals	1957.90 m (wt%)	1959.30 m (wt%)	1944.80 m (wt%)	1944.05 m (wt%)	1941.40 m (wt%)
SiO_2	72.7	72.7	72.6	72.5	72.6
Al_2O_3	15.3	15.4	15.9	16.9	17.6
Fe_2O_3	1.32	1.40	1.61	1.58	1.64
MgO	0.46	0.52	0.39	0.43	0.42
CaO	0.82	0.78	0.60	0.53	0.26
Na_2O	3.77	3.73	3.38	3.36	2.15
K_2O	4.43	4.22	3.90	3.66	4.32
P_2O_5	0.07	0.09	0.02	0.02	0.02
LOI	0.05	0.07	0.15	0.17	0.33

The host protolith granite from well 16/3-4 consist primarily of plagioclase, quartz, and K-feldspar and is classified as medium-grained granite. Decrease in abundance of plagioclase compared to quartz was observed in the altered compact rock and altered incoherent rock facies, in which the largest depletion of plagioclase was over 50% relative to quartz in protolith (Riber et al., 2016). For kaolinite, an increase happens from the altered compact rock to the altered incoherent rock.

From Figure 15, the regolith profile for well 16/3-4 can be divided into three altered facies, coherent rock, compact rock and, incoherent rock. The interval for these facies are set as altered coherent rock from base of core to 1955 m and altered compact rock from 1946.5 to 1944.25 m, while from 1944.25 m and upward is set as altered incoherent rock due to appearance of more fragile granite (Riber et al., 2016).

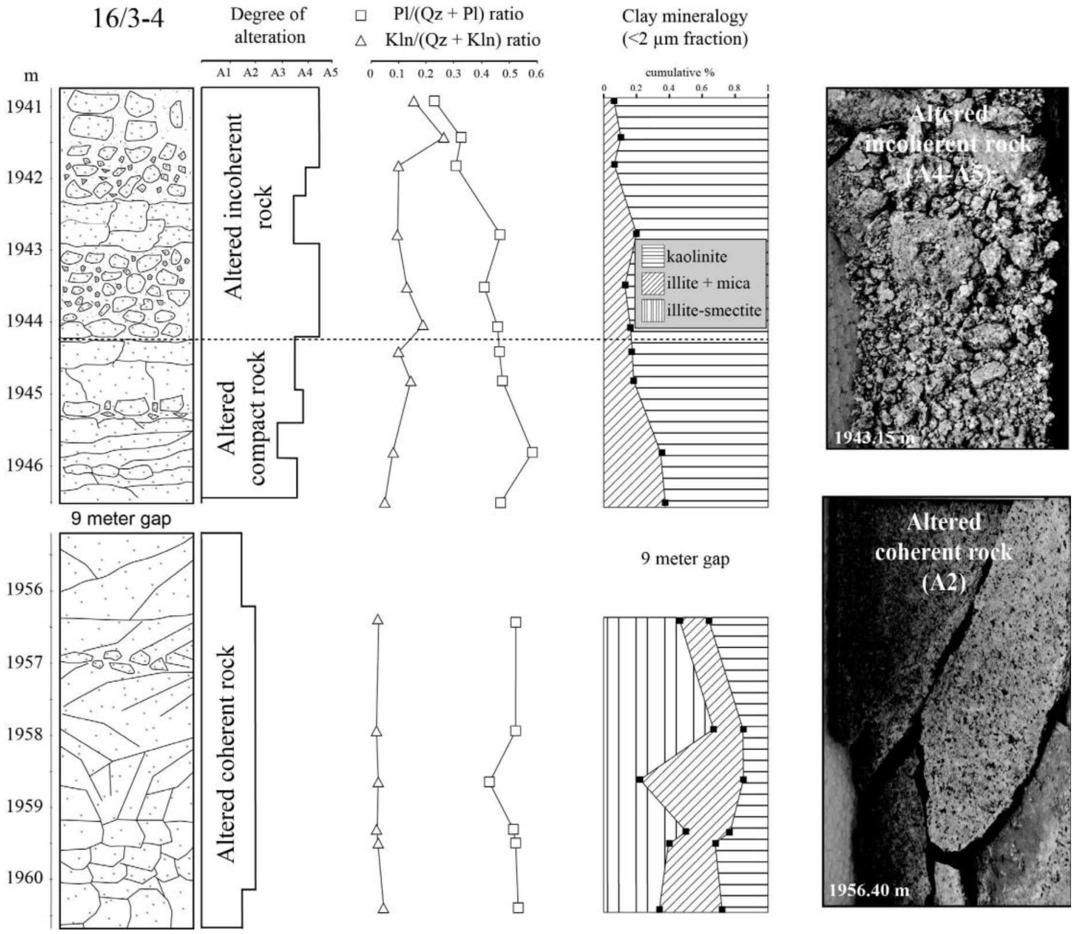


Figure 15. *Sketch from the regolith profile in well 16/3-4 showing the increase in degree of alteration and changes in plagioclase and kaolinite abundances (Riber et al., 2016).*

Riber et al. concluded that the porosity and permeability in well 16/3-4 were made mainly by intense dissolution of plagioclase, and clay minerals was also formed from the plagioclase dissolution. Increase of porosity and clay formation is connected to reduction of bulk density in the altered compact rock and altered incoherent rock facies, and in the latter case, collapse of the rock fabric and clogging of fractures by clay can be reasons for permeability reduction. Table 10 shows a summary of analyzed data for well 16/3-4.

Table 10. *Summary of the main results from petrographical and mineralogical analyses from well 16/3-4 samples. Kln = kaolinite; Pl = plagioclase; Bt = biotite; I-S = R0 illite-smectite; por. = porosity; perm. = permability (Riber et al., 2016).*

Alteration facies	Interval (m)	Degree of alteration (A1-A5)	Whole-rock mineralogy	Clay mineralogy	Microfabric	Reservoir properties
Altered coherent	1960.60-1952	A1-A2	Similar to protolith composition	I-S > I+M > Kln	Incipient dissolution of Pl and alteration of Bt	Por. and perm. controlled by macrofractures. Intracrystalline microporosity
Altered compact	1952-1944.25	A3-A4	Formation of Kln at the expense of Pl and Bt	Kln > I+M	Intensified Pl dissolution and pseudomorphic kaolinitization of Bt	Intercrystalline por. and meso-fractures after Pl dissolution
Altered incoherent	1944.25-1940.80	A4-A5	Pl reduced by 50% relative qz. in protolith	Kln >> I+M	Severe dissolution of Pl and kaolinitization of Bt, massive Kln occupied pore space	Reduction of perm. after collapse of rock structure and clogging by clays

Recently, a paper was published by Olsen et al. (2017) that contains further analyses of the upper Jurassic shallow marine sandstones in the Johan Sverdrup Field. The field was divided into 10 facies that has different contents and reservoir qualities, and Table 11 summarizes the facies relevant to the main reservoir with their properties.

Table 11. *Facies that are related to the reservoir and relevant porosity and permeability values for the facies (Olsen et al., 2017).*

Facies	Porosity of main reservoir (%)	Average porosity (%)	Median permeability (Darcy)
Conglomerate	9	19	2
Stratified medium to very coarse sandstone	9	26-27	14-15
Indistinctly stratified medium to very coarse sandstone	16	26-27	14-15
Bioturbated medium to very coarse sandstone	19	28-30	22-23
Structurless medium to very coarse sandstone	44	28-30	22-23
Very fine to medium-grained stratified and/or bioturbated sandstone	2	27	2
Spiculitic sandstone	1	25	0.04

Main reservoir in Johan Sverdrup Field is composed of unusually coarse grained siliciclastic sediments in the intra-Draupne formation with an estimated average porosity at 28% and an average net-to-gross of 97% (Olsen et al., 2017). Great reservoir properties in addition with good aerial distribution and lateral continuity makes the Johan Sverdrup Field to a very beneficial giant oil field.

These great values of properties are believed to be the result of ideal depositional conditions by having a provenance for very coarse grained sediments and almost no fines, a relatively high energy depositional environment conducive to sorting, reworking, winnowing and the creation of a continuous sheet of sand during transgression, and shallow burial that results to only minor compaction and only minor cementation over most of the area (Olsen et al., 2017).

5. Low Salinity Waterflooding in Johan Sverdrup Field

5.1. Introduction

Johan Sverdrup Field is one of the five largest oil field on the Norwegian continental shelf and is expected for a peak production that will cover 25% of all Norwegian petroleum production at the time (Statoil, 2017a). Statoil has currently the largest ownership interest with 40.0267%, while Lundin Norway, Petoro, AkerBP and Maersk Oil have 22.6%, 17.36%, 11.5733% and 8.44% each, respectively.

Johan Sverdrup Field is developed in two phases, where as of March 2017, Phase 1 is still under development and around 40% completed (Statoil, 2017b). The estimated production start for Phase 1 is at late 2019 and the estimated daily production is at 440 000 barrels per day, with an estimated peak production estimated at 660 000 bbl/D. Phase 1 includes development of four platforms, three subsea installations for water injection, power from shore, export pipeline for oil and gas, where the oil will be transported to Mongstad terminal in Hordaland and the gas to the Kårstø processing plant in North Rogaland via Statpipe (Statoil, 2017b). Estimated CAPEX for Phase 1 is 97 billion NOK, which results to a break-even point of below 20 USD per barrel.

Phase 2 includes development of another processing platform for the field centre and development of Avaldsnes, Kvitsøy and Geitungen satellite areas for processing and export on the field centre (Statoil, 2017b). 28 new wells are planned to be drilled in Phase 2 development and it also includes establishment of an area-wide solution for power from shore for the Utsira High by 2022 (Statoil, 2017b). CAPEX for Phase 2 is estimated to 40-55 billion NOK, excluding IOR, with a break-even point at below 30 USD per barrel. Production start is estimated to 2022 for Phase 2. The break-even price for the full field (Phase 1 + Phase 2) is estimated to be below 25 USD per barrel (Statoil, 2017b).

The production for Phase 1 starts in late 2019 with water injection, and a pilot project with polymer injection is also expected after two years of production, where the pilot project will be performed with minimum one injector and one producer (Statoil, 2016). The goal of using polymer is to increase the injected water viscosity to achieve a greater mobility control that will lead to a more piston-like displacement. At the end, it will increase the macroscopic sweep efficiency, but the microscopic sweep efficiency will stay unchanged, hence, no wettability alteration. Based on reservoir simulations made by Maersk Oil, polymer injection can increase the recovery factor through improved sweep in Johan Sverdrup Field if the viscosity of polymer is retained throughout the reservoir (Ludvigsen, 2016). However, there are challenges by using polymer injection. One of them is thermal degradation that will make the polymer fluid inefficient. That is why Statoil is going to use the polymer pilot project to obtain the necessary information for further application of the whole field, such as in-situ viscosity, EOR effect, well spacing, and etc. Infill drilling and WAG is other IOR methods that have been considered for implementation in Johan Sverdrup Field.

Even though low salinity waterflooding has not been considered as much as the other IOR methods, it is a method that fits many of the criteria's from the Johan Sverdrup Field. With temperature around 80^{o}C, the polar component can still exist in the oil leading to a mixed wet reservoir by adsorption, meaning that wettability alteration could increase the recovery factor even more. This method is not directly temperature dependent, thermal degradation would not be a problem. Low salinity waterflooding in Johan Sverdrup will be evaluated below by using theory and data previously stated in this thesis together with multiple field cases.

5.2. LSWF in Johan Sverdrup Field

5.2.1. Crude Oil in Johan Sverdrup

The oil in Johan Sverdrup Field have viscosity of 2 cP and oil density of approximately 800 kg/m^3, which makes the oil easily moveable considering these two parameters. It can be classified as a light oil with a GOR of 40 Sm^3/Sm^3.

Having low oil viscosity is important for effective displacement by low salinity injection, but the existence of polar components, acids and bases, are important for achieving a low salinity effect. These polar components stem from heteroatoms present in the heavier fraction of crude oil and it is these that will decide the initial wetting and possibility of an EOR effect (Speight, 2006). Therefore, the crude oil should have high TAN, TBN or both so the reservoir could be in a mixed wet state before low saline fluid injection. Acid components in crude oil are dependent on several factors, such as origin sediments for where the oil stems from, burial time and burial depth, where the last one correlates to temperature conditions. High TAN is obtained when it favors biodegradation, given conditions as shallow burial with temperatures lower than 100^{o}C (Meredith et al., 2000). Since the temperature in Johan Sverdrup is well below 100^{o}C, polar component is believable to exist in the crude oil.

From the LSWF screening criteria's made earlier, oil must contain polar components and oil viscosity should not be too high to achieve low salinity effects. In the aspect of crude oil, low salinity injection could increase the recovery in Johan Sverdrup Field by wettability alteration from mixed wet to a more water-wet state.

5.2.2. Formation Water in Johan Sverdrup

The TDS of the three water samples that was taken from well 16/2-7 had an average of 52 500 mg/L, which means that the salinity in the formation water is high, while the average TDS from the estimated composition was around 52 281 mg/L from several water samples (Ramstad et al., 2016). Formation water can also effect the initial wetting in the reservoir to a certain degree, where the important parameter that must be considered is the initial pH of the water. Reservoirs that have sour gases as CO_2 and H_2S would contribute to a low initial pH, which is preferred in low salinity waterflooding. However, considering the case where the initial pH is high will result to too water-wet conditions initially that won't create an EOR effect.

Presence of divalent ions in the formation water is required for an EOR effect. Values given by Ramstad (2016) have shown great amount of Ca^{2+} and Mg^{2+} both from water samples in well 16/2-7 and estimated amount from several wells related to Johan Sverdrup Field. Adsorption of active cations, protons and organic material onto clay surface determines the low salinity effect that can be achieved, where the optimal effect is achieved when the three components are well balanced initially (Austad et al., 2010). During low salinity injection, divalent cations and polar component in crude will be desorbed due to the contrast of high saline formation water and low saline injection fluid, while protons will get adsorbed onto the clay surface, exchanging the cations between formation water and injection fluid. This process raises the initial pH and increases the recovery factor by minimalizing the residual oil saturation, it was mentioned earlier as desorption by pH increase and Figure 8 is an illustration that describes how the mechanism works.

Considering the screening criteria's made for formation water by LSWF, implementation of low salinity fluid in Johan Sverdrup Field has a positive EOR potential. This is due to initially high salinity and presence of divalent ions in the formation water. The EOR potential will then depend on how much the pH could be increased from the initial state, larger increment leads to higher recovery.

5.2.3. Rock formation in Johan Sverdrup

According to Riber et al. (2016), well 16/3-4 in Johan Sverdrup Field contains primarily quartz, plagioclase and K-feldspar. Amount of plagioclase varies between 14.8-38.8%, K-feldspar between 11.0-24.3%, and the total clay content varies between 9.3-19.5% in depth interval between 1940.90-1960.40 m. Clays are the main wetting material in sandstone, and the clays in Johan Sverdrup Field are mainly illite, mica and kaolinite. There must be enough clays in the reservoir for achieving low salinity effects, and the amount of clays seems sufficient according to Table 8, stated previously.

There seems to be large amount of plagioclase in well 16/3-4, and this could affect the EOR potential in Johan Sverdrup Field. In recent years, several studies have shown how plagioclase affects the EOR effect by using low salinity injection in sandstone (Piñerez T, 2017; Reinholdtsen et al., 2011; Strand et al., 2014). Plagioclase in the reservoir can affect the EOR potential both in a positive or negative way. The following reaction is important for explaining how the EOR effect are affected by the initial salinity in FW (Austad, 2013):

$$NaAlSi_3O_8 + H_2O \leftrightarrow HAlSi_3O_8 + OH^- + Na^+ \qquad (16)$$

The reaction will go to the right for FW that has moderate salinities, making the initial pH above 7 (Strand et al., 2014). In high initial pH reservoirs, the rock becomes too water-wet and low salinity effects would unlikely occur. However, plagioclase in the reservoir can have a positive effect if the FW has high salinity, making the reaction go to the left, and reduces the initial pH below 7. This will promote a mixed wet state in the reservoir, increasing the EOR potential. The extra oil is produced by desorbing the polar component in crude oil from the clay surface when low salinity fluid displaces high saline FW, causing the pH to increase.

Anhydrite, $CaSO_4$, might occur in high temperature and high salinity reservoirs, with the condition that enough calcium and sulfate ions are present. As the temperature increases, the solubility of anhydrite will decrease. When low saline fluid displaces high saline formation fluid, a common ion effect occurs due to the dissolution of anhydrite, which will make Eq. (9) go to the left. Desorption of Ca^{2+} from the clay surface is then suppressed, further restricting the increase of the pH gradient that makes the EOR potential less significant (Aksulu et al., 2012). Even though Johan Sverdrup formation water contains Ca^{2+} and SO_4^{2-}, precipitation of anhydrite would likely not occur due to the reservoir temperature being around 80°C. In case where anhydrite already exist in the formation, dissolution of this mineral might occur at lower temperatures, but the amount could be low. The reduced pH increase from anhydrite might be much less significant than the potential of pH increase due to plagioclase in the rock formation, as it seems that Johan Sverdrup Field has large quantities of plagioclase.

For an optimal EOR effect by low salinity waterflooding, sufficient amount of clay must be present, and the sand size is preferable medium-grained with high CEC clay, porosity and permeability. These criteria's seems to be met in the Johan Sverdrup Field, high porosity and permeability in the formations, good clay content, and coarse, medium-grained size sand. In the case of plagioclase in the formation, it will likely have a positive effect when the initial formation water has high salinity, making the initial pH below 7. Presence of sour gases would further reduce the initial pH. Anhydrite precipitation would likely not occur due to the temperature being well below 100^{o}C. In the aspect of rocks in the reservoir, application of low salinity flooding has great EOR potential in Johan Sverdrup Field.

5.3. Estimating the Initial Wettability in Johan Sverdrup Field

Initial wetting in Johan Sverdrup Field must be determined before application of any EOR methods, and it is also an important parameter for estimating the EOR potential that the reservoir has. The wettability in a reservoir is determined by many factors, such as polar component in oil, formation water composition and salinity, and rock composition. The initial wettability in Johan Sverdrup Field will be assumed by using previously stated data's.

It is believed that all the reservoirs started in a strongly water-wet state, meaning that wettability alteration could not occur until oil seeps into the reservoir. The CBR system will create an equilibrium and the wettability is then established after oil has invaded into the reservoir. Temperature and pressure will also affect the initial wetting.

Firstly, the crude oil must contain polar component for altering the wettability by adsorbing on the clay surface. This criteria is met due to reservoir temperature below 100^{o}C and shallow burial in Johan Sverdrup reservoir. The rock in the reservoir must contain clay since adsorption of polar component would not happen without the negatively charged clay surface. The pH of formation water is another parameter that influences the initial wetting since it determines surface activity of active organic components against the rock surface. Initial pH of the formation water is dependent on several factors, such as formation water salinity and amount of plagioclase. As mentioned earlier, plagioclase can have either a positive or negative impact on the pH. This impact is dependent on the salinity of the formation water, by using Eq. (16) shows that the initial pH is low when the reaction goes to the left, and this happens if the formation water has high salinity.

Taking all these parameters and factors into consideration, it is believable that the Johan Sverdrup reservoir is initially in a mixed wet state, and an EOR effect should theoretically occur by wettability alteration.

5.4. EOR possibilities by LSWF in Johan Sverdrup Field

It is certain that the EOR effects by low salinity flooding happens due to wettability alteration from mixed wetting to a more water wet state in the reservoir. The following part of the thesis will summarize factors that are important to achieve wettability alteration in Johan Sverdrup Field, and hence, an EOR effect.

5.4.1. Adsorption of Divalent Cations and Polar Components

Adsorption of both divalent cations and polar components in crude oil are important factors for achieving mixed wetting, the reservoir would remain water-wet if adsorption does not occur. Clay is considered as the main wetting factor in sandstone due to the large surface area and the negative charge (Austad et al., 2010), but adsorption on quartz and feldspar could also occur. Even though quartz and feldspar have smaller surface areas than clay, a negative charge of these minerals could still be obtained at relevant pH (Brantley & Mellott, 2000). This means that in case where clay is insufficient in Johan Sverdrup Field, adsorption of crude oil and cations could still occur due to other minerals present in the formation. A study has shown that high adsorption of polar components onto quartz occurs when the grains are smaller than 2 µm in low salinity brine with pH=5, while the adsorption is negligible if the grains are larger than 2 µm (Abdullah, 2016).

Adsorption of divalent cations, especially Ca^{2+}, in the formation water and onto the wetting material is essential for optimizing the EOR effect. These active cations would be exchanged with protons during low salinity flooding, causing a pH increase in the effluent. This indicates that initial pH and the amount of active cations are related to the initial wetting. The difference of Ca^{2+} concentration between formation water and injected water is also important, Eq. (9) shows that Ca^{2+} would be exchanged with H^+ during low salinity water injection. This would make Eq. (13) and Eq. (14) also go toward right, desorbing both the surface active cations and polar components. The water in the reservoir would at this point have a pH increase. Adsorption and desorption processes of polar component depends on pH, ion composition of the formation water and type of clay mineral in sandstone. Austad et al. (2010) found out that low salinity waterflooding showed similar effect for crude oil with high AN and low BN, and crude oil with low AN and high BN, which concluded to that the type of polar component is irrelevant for achieving a low salinity effect.

5.4.2. Initial pH and ΔpH

Austad et al. (2010) proposed that the wettability alteration during low salinity injection happens due to local pH increase, which will desorb the adsorbed divalent cations and polar components in crude oil. After the proposal, further investigations have been made to find out how pH and its gradient affects the EOR effects (Aksulu et al., 2012; Austad et al., 2010; Piñerez T et al., 2016a; Rezaeidoust et al., 2010; Strand et al., 2014). It is found out that pH screening is important to be performed before low salinity waterflooding since the low salinity effects are dependent on initial pH and how much it can increase.

Initial pH of the formation water is dependent on many factors in the reservoir, such as presence of acidic gases and reactive plagioclase/albite. As mentioned earlier, an initial pH below 7, and preferably 5, is beneficial for observing low salinity effects. The acidic gases, such as CO_2 and H_2S, would decrease the initial pH, while albite will affect the initial pH by Eq. (16) mentioned previously. High salinity formation water will make the reaction toward right and increase the initial pH, while the other way if the formation water has lower salt concentration. Formation water salinity in Johan Sverdrup Field is above 50 000 ppm, which makes the reaction more likely to go toward right, in the case where albite is reactive.

The pH gradient is related to the EOR effects, larger gradient gives better EOR effects. Piñerez T et al. (2016a) studied on six cores to investigate how pH is linked with the EOR effect in sandstones. Similar cores were tested by Winoto et al. in 2012, and it showed low/no LS EOR effects. The formation water used has salinity of 35 604 mg/L and the low salinity water used was diluted 20 times of the FW with salinity of 1780 mg/L, pH of the brines were 5.3 and 5.6, respectively. The flood sequence for all the experiments were formation water→low salinity water→formation water. The result of the corefloodings gave low EOR effects, 0-3.6% of OOIP, and very small pH gradient between 0-1 pH units at 60°C. Other experiments with some of the same cores were also performed with FW that has salinity of 100 000 mg/L and low salinity water with salinity of 1000 mg/L, pH of the brines were 5.5 and 5.7, respectively. This resulted to larger pH gradient that gave an increased EOR effect. Two interesting facts were noticed in the results. Firstly, the pH would change corresponding to different displacement fluids, injection of formation water would lead the pH to a certain value, changing to low saline water would increase the pH, while changing the injection water back to FW would return the pH value back to initially when the core was flooded with FW after a while, shown in Figure 16. The second observation was that higher salinity in formation water would have larger pH gradients, this can be observed by pH graphs in Figure 16 and 17. This happened in the case where the salinity of the formation water was increased from 35 604 mg/L to 100 000 mg/L.

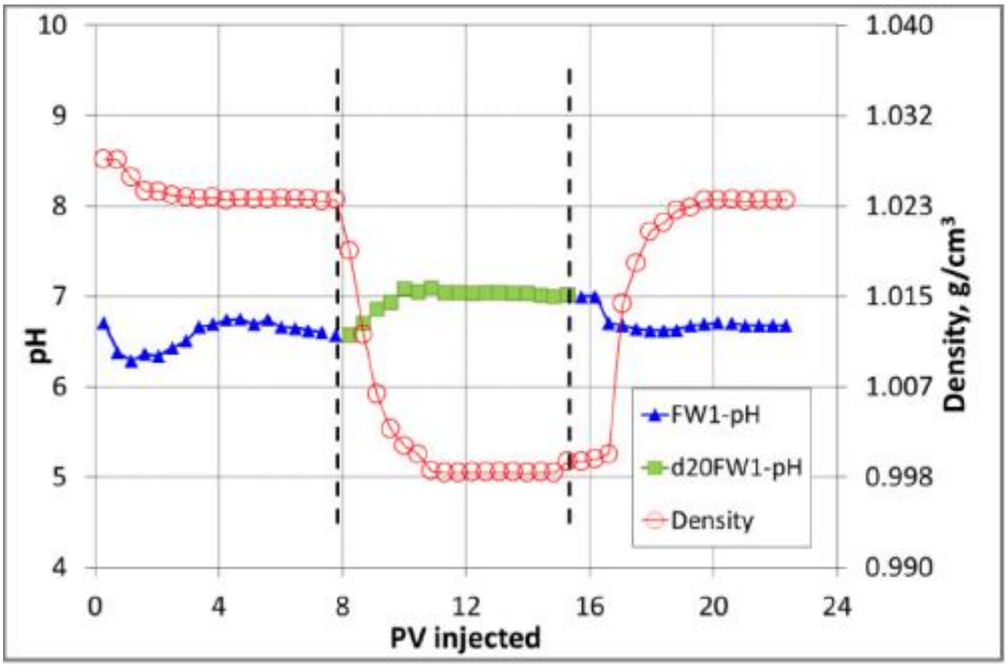


Figure 16. *pH screening for the Cedar Creek core-4 at 60°C with flooding sequence FW1-$_{d20}$FW1-FW1. (Piñerez T et al., 2016a)*

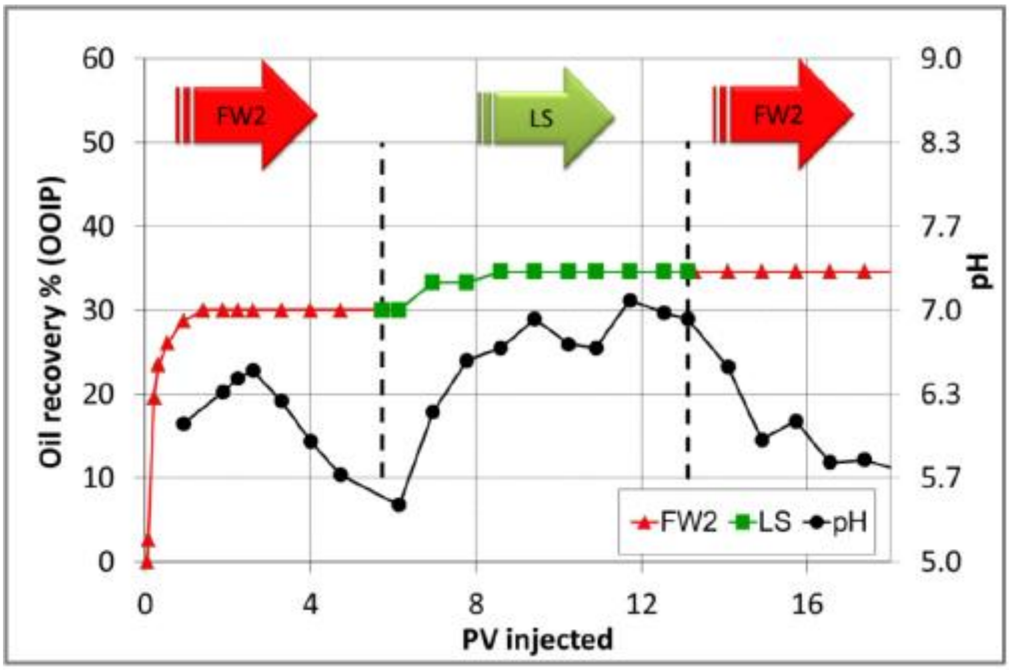


Figure 17. *pH screening and oil recovery for Cedar Creek core-1 at 60°C with flooding sequence FW2-LS-FW2, where FW2=100 000 ppm and LS=1000 ppm (Piñerez T et al., 2016a)*

The initial pH in Johan Sverdrup is most likely below 7 due to the factors mentioned earlier, while the pH gradient cannot be determined until experimental works have been done.

5.4.3. Temperature

Low salinity slug would not be directly affected by the reservoir temperature, unlike chemical EOR techniques that would enhance the degradation process by having a high reservoir temperature. However, high temperature in the reservoir would affect other factors that are important for low salinity effects (Aghaeifar et al., 2015; Aksulu et al., 2012; Piñerez T et al., 2016d).

Decomposition of acidic components in crude oil would occur during geological time and high temperatures, leading to decrease of polar components. Basic components are more stable and would not decompose as easily, therefore, oil with high BN and low AN are usually found in crude oil samples. Partial dehydration of cations could also occur at high temperatures, which will increase the reactivity, and adsorption of divalent cations onto clay increases. In case for anions like SO_4^{2-} and CO_3^{2-} that are solvated by hydrogen bonding to water molecules will have their hydrogen bonds broken at temperatures above 100°C, increasing the reactivity, and decreasing the solubility of $CaSO_4$(s) and $CaCO_3$(s). Presence of anhydrite in reservoir with high saline formation water could also cause problem during low salinity flooding.

Johan Sverdrup Field has a reservoir temperature around 80°C in the different formations, meaning that polar components still exists in the crude oil, and solids, for example anhydrite, would not contribute the EOR effect in a negative way. A relatively low reservoir temperature with FW salinity around 50 000 ppm in the reservoir would not make Johan Sverdrup Field too water-wet (Aghaeifar et al., 2015). In cases where the reservoir temperature is above 100°C with FW salinity around 200 000 ppm would make the reservoir too water-wet, and LS EOR effect would also most likely not be observed.

5.4.4. LSWF as Secondary Recovery Method

Even though low salinity waterflooding can be considered as tertiary recovery method doesn't mean that application of low salinity flooding can't be implemented as a secondary recovery method. Piñerez T et al. (2016c) have studied on response time of low salinity effects during secondary and tertiary recovery. The result showed that secondary recovery gave a faster response time and also higher recovery than tertiary recovery, but the pH of the effluent in secondary low salinity recovery test was smaller compared to tertiary recovery tests. BP has decided to use a low salinity brine, LoSal® EOR technology, from the first day of production in the Clair Ridge Field. More detail about this field is described later.

5.4.5. EOR Potential by injecting Low Salinity Water in Johan Sverdrup Field – Briefing

Many of the factors mentioned previously are dependent by other properties, therefore, a thorough evaluation of EOR potential in Johan Sverdrup Field by LSWF is hard to be made before more testing, i.e. coreflooding experiments, of the field happens. More testing and simulations of the field would give a lot more information for choosing the proper EOR method. With that being said, low salinity waterflooding could be implemented in Johan Sverdrup Field considering the available data about the field. Conditions like presence of clay, active cations in formation water and polar components in crude oil is met. The field already has good flow capacity initially because of the high permeability and porosity, however, it is a large field and properties are destined to change from one location to another. Other positive effects by applying LSWF in a field is that the possibilities of reservoir souring and scaling would be reduced due to the low salt concentration in the injected water. Economically, it would also be cheaper in comparison to chemical flooding since the latter requires chemicals that could be expensive, and adsorption/loss of the chemical fluid could lead to financial problems. At the end, further investigation of Johan Sverdrup Field should be made before any EOR methods are implemented due to the importance of the field that will contribute to many workplaces in the next few decades.

5.5. Other LSWF Field Examples

5.5.1. Snorre Field

Snorre Field is located 150 km from the Norwegian coastline in the North Sea and has 276.9 million Sm^3 recoverable oil according to NPD. The reservoir has a max gross thickness of 1000 m, net-to-gross of 0.45, porosity at 14-32%, permeability at 100 md to 4 darcies, reservoir temperature at 90^oC, and initial pressure at 383 bar. The clay content of the reservoir varied between 5-35%. Skrettingland et al. (2010) performed laboratory test on cores from formations in Upper Statfjord, Lower Statfjord and Lunde by injecting seawater and low salinity fluid. The result showed a 2% increase in recovery of original oil in place in Statfjord formation cores, similar result happened for both injection of low saline seawater and low saline NaCl fluid. No significant increase in recovery was observed by changing the injected fluid from seawater to low salinity fluids. Considering the screening conditions for application of low salinity waterflooding in a reservoir, Snorre Field had the EOR potential in the CBR aspect. Polar component existed in the crude oil (AN=0.02 mgKOH/g, BN=1.1 mgKOH/g), formation water contained divalent cations (Ca^{2+}) and has high salinity, and the rock had clays (Kaolinite) that can be adsorbed on. The EOR potential was quite low by investigating both the laboratory measurements and a field test, this is believed to be due to the wetting conditions in Snorre Field are already optimal, where seawater injection is sufficient enough (Skrettingland et al., 2010). Therefore, a tertiary injection of low saline fluid would at best only change the recovery marginally.

Reinholdtsen et al. (2011) studied core materials from the Lunde formation to find out what the reason was for the small increase in recovery in the Snorre Field. The cores were saturated by CO_2 at 6 bar with the hope for decreasing the initial pH during aging, and they also had a clay content around 15 wt%, AN of 0.07 mgKOH/g and BN of 1.23 mgKOH/g. The flood sequence was FW, SW, and 500 ppm NaCl brine as the low salinity fluid. The results are shown in Figure 18, flooding with FW gave a recovery of around 51% of OOIP, SW gave an extra 3% recovery as the secondary flooding while switching to the low salinity fluid didn’t change the recovery at all. Increasing the flood rate of low salinity injection didn’t affect the recovery either. Even though the salinities between FW (35 138 ppm) and SW (33 400 ppm) are similar, injection of SW increased the recovery and this is expected due to the low amount of Ca^{2+} in

SW in comparison to FW (Austad, 2013). The low salinity mechanism does not happen by the salinity differences itself, but by the composition of the relevant fluids.

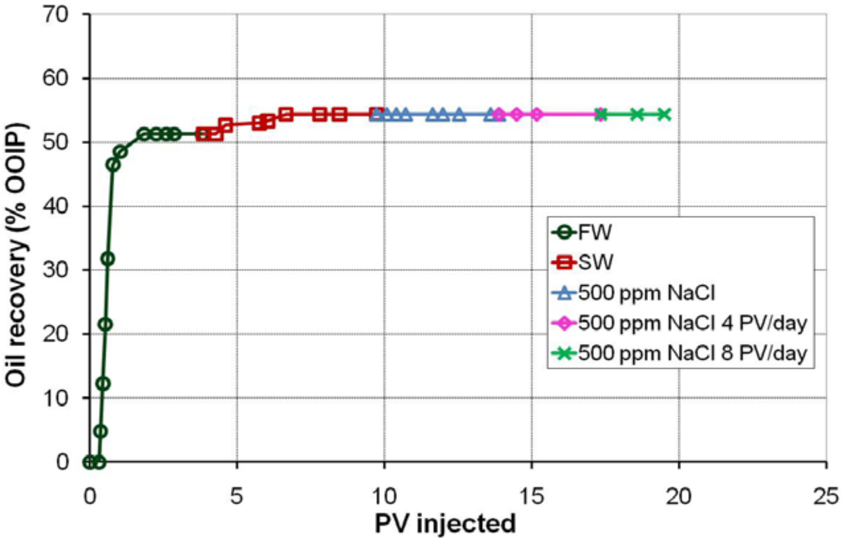


Figure 18. *Recovery vs. PV injected plot showing the recovery by changing the injected brine. Temperature at 90^{o}C. (Reinholdtsen et al., 2011)*

As mentioned earlier, EOR effect is related to the pH increase during water injection, and the effect is almost insignificant for formation water that has high initial pH, resulting to a too water-wet reservoir. There is large amount of plagioclase in Snorre Field, varying between 6-35 wt%. Considering Albite with the chemical structure $NaAlSi_3O_8$, an alkaline solution could be made when plagioclase comes in contact with water, described by Eq. (16) given earlier.

In case for Snorre formation water, Na^+ can be substituted by H^+, increasing the pH of the solution. The effluent from the core had a high pH above 7 considering that the oil was saturated with CO_2, as shown in Figure 19 (Reinholdtsen et al., 2011). Plagioclase minerals seems to have a buffering effect on the FW, and with equilibrium pH above 7 will result to reduced adsorption of polar component on the clay surface (Reinholdtsen et al., 2011). Less adsorbed polar component onto the clay surface leads to more water-wet rock, hence, smaller/none LS EOR effects can be observed.

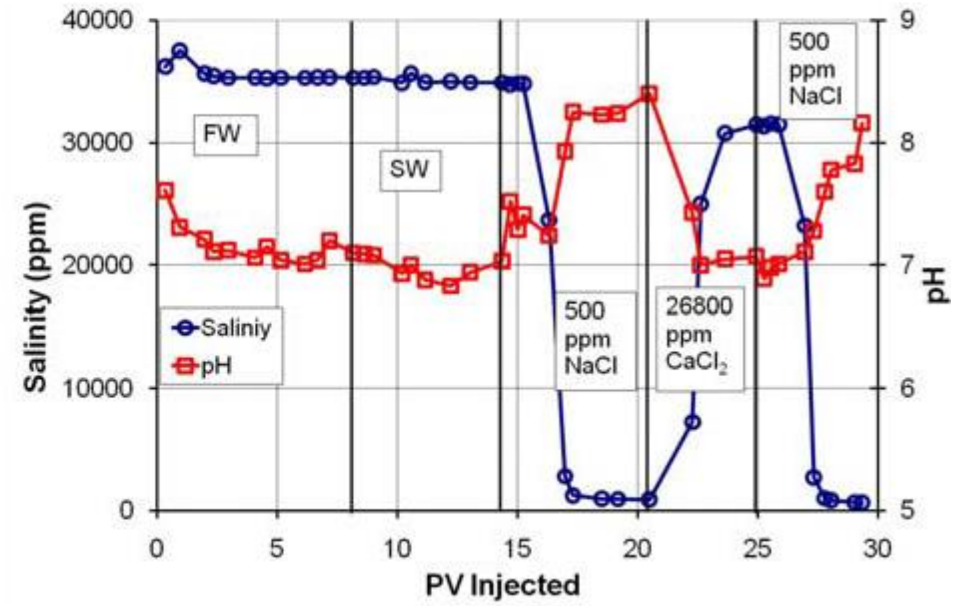


Figure 19. *Salinity and pH vs. PV injected for different injected fluids. (Reinholdtsen et al., 2011)*

5.5.2. Endicott Field

Seccombe et al. (2008) evaluated the EOR potential by low salinity fluid injection in Endicott Field, Alaska. The evaluation was based on coreflood studies, single well chemical tracer tests in multiple wells, numerical simulation and geochemical modeling. Results showed that low salinity fluid injection would cause an additional recovery in tertiary stage, and 40% low salinity slug is expected to be fully effective (Seccombe et al., 2008). An important factor to notice is the high amount of kaolinite in the reservoir.

Low salinity fluid was injected in June 2008 in Endicott Field. This was only a demonstration of low salinity EOR at interwell scale between an injector and a producer 1040 feet apart (Seccombe et al., 2010). An EOR response was detected three months after injection, a drop in watercut was observed from 95% to 92%. The timing of the drop in watercut happened simultaneously with low salinity fluid breakthrough at the producer. 1.3 PV of low saline water had been injected by May 2009, and the increase in recovery is equal to 10% of the total PV in the swept area. Initial oil saturation in Endicott Field is 95%, and tertiary low salinity waterflooding is expected to decrease the residual oil saturation from 42% to 28% in the pilot area. The brine compositions that was used during Endicott Field core tests is given in Table 12.

Table 12. *Brine Compositions used in coreflood experiments (Seccombe et al., 2008).*

Salt /Fluid	Sea Water	Connate Water	Low salinity Water
$SrCl_2*6H_2O$ (mg/L)	0	1372	0
$NaHCO_3$ (mg/L)	191	228	4.17
Na_2SO_4 (mg/L)	3917	0	85.4
$CaCl_2*6H_2O$ (mg/L)	2186	30 610	47.6
$MgCl_2$ (mg/L)	10 640	5027	232
KCl (mg/L)	725	932	15.8
NaCl (mg/L)	3983	54 720	511.8
NaI (mg/L)	50 000	50 000	0
Total Dissolved Solids (mg/L)	71642	142889	896.77

The interesting fact by this interwell scale low salinity flooding project is that the additional oil recovery from pilot data analysis came in agreement with Endicott corefloods and single-well tracer tests, both the corefloods and the pilot gave 10% incremental oil recovery of the total pore volume swept. Mixing the low salinity injection brine and high salinity formation water did not affect the EOR process at inter-well distances. The recovered oil volume from the pilot is the same as the predicted amount from single well chemical tracer tests (SWCTT), meaning that mixing of the fluids didn't cause any problems. Viscous fingering wasn't observed during the pilot either.

5.5.3. Clair Ridge Field

Containing over 6 billion barrels oil in place, the Clair Field was discovered in 1977, but it was not until 2001 that BP and partners tried to come up with a development plan due to lack of appropriate technology at the time (BP, 2017). The Clair Ridge project is the second phase of the development, where low salinity water will be implemented from day one. Target amount is approximately 640 million barrels of recoverable resources, and the construction of the second phase was completed in 2016. Several EOR methods were considered for this field, such as gas flooding, CO_2 flooding, and polymer flooding, but they were all rejected either due to lack of availability or excess operating costs (Robbana et al., 2012). Low salinity flooding was chosen due to multiple conditions, where one of the important factors is that Clair Field is a waterflood reservoir that depends on sweeping large areas of matrix rock between the conductive fractures to optimize the recovery.

Several corefloods were performed from both the Main Field area and Ridge area to support the application of low salinity injection in the Clair Ridge Field. The coreflood experimentations happened where the secondary recovery were flooded by low saline brine at low rate equivalent to around 1 ft/day in the reservoir, around 4 cc/hr (Robbana et al., 2012). The brine composition used for the experiments is given in Table 13.

Table 13. *Brine Compositions in Clair Field (Robbana et al., 2012).*

Brine Components	Clair Ridge (Undoped)	Clair Ridge (Doped)	Clair Main Field (Undoped)	Clair Main Field (Doped)
$NaHCO_3$ (mg/L)	1320	1320	-	-
Na_2SO_4 (mg/L)	40	40	-	-
$CaCl_2*6H_2O$(mg/L)	1370	1370	6700	6700
$MgCl_2*6H_2O$ (mg/L)	220	220	300	300
$BaCl_2*2H_2O$ (mg/L)	10	10	-	-
KCl (mg/L)	200	200	-	-
$SrCl_2*6H_2O$ (mg/L)	70	70	-	-
LiCl (mg/L)	10	10	-	-
NaCl (mg/L)	11 360	-	11 000	0
NaI (mg/L)	-	29 130	0	28 200
Total Dissolved Solids (mg/L)	14 600	32 370	18 000	35 200

The low salinity brine used for the tests were made by diluting the undoped brine composition in Table 13 to 1500 ppm by adding de-ionized water. Results from the corefloods in the Main Field showed incremental recoveries by 9% and 13.1% in the two cores over high saline corefloodings, this corresponded to a change of S_{orw} by 5.5 and 7.9 saturation units, respectively. No tests of Ridge area rock have been tested in secondary recovery mode yet.

A large scale reservoir deployment of low salinity flooding in Clair Ridge Field was chosen due to several factors that have been brought together to support this application. Coreflood, SWCTTs and inter-well trials (Endicott Field) showed that low salinity process works at reservoir scale with a range of responses which can be predicted. Simple models to conduct technical evaluations is more complex for a tertiary flooding than secondary flooding, by using the low salinity flooding early on will lessen the uncertainties (Reddick et al., 2012). Low salinity flooding could also have positive side effects by implementation, for example reservoir souring could be controlled.

6. Other Factors to be considered for Low Salinity Waterflooding

6.1. Economic aspect

Low salinity water used for injection can be made from diluted formation water, where no extra cost of chemicals or water heating system is required. The low salinity injection fluid in itself is not expensive or difficult to make, but the CAPEX for the whole injection-production-recycling system of the low salinity fluid could become expensive.

BP is using their LoSal® EOR technology in the Clair Ridge Field to increase an extra 42 million barrels of oil in comparison to normal waterflooding, and this extra recovery corresponds to a break-even cost of 3 USD per barrel (BP, 2014). Problems like reservoir souring and scaling can also be reduced by low salinity flooding, decreasing the budget required to fix these problems if it occurs. Like the typical steam flood systems, the cost for water treating equipment can be high for offshore water flood where desalination is needed, and it is estimated that the Clair Ridge Field needs desalination equipment for a cost of around 120 million USD (Llano et al., 2013). The operational cost for low salinity EOR flooding is cheaper than other chemical EOR methods since adsorption and other loss of chemicals can give a magnificent deficit during production.

6.2. Environmental aspect

EOR methods usually requires to modify the injection fluids in certain ways, SAGD requires heating up the water to approximately 200^{o}C while polymer and surfactant flooding requires mixing chemicals into the injection fluid. Thermal EOR methods requires energy, and the environment will be affected by the choice of how and where the energy comes from, an example is by burning produced gas to raise temperature of the injected fluid can cause CO_2 emission. Chemical EOR methods can affect the wildlife in the close environment due to seep or leak of the injected fluid, and cleaning and recycling the chemical fluid will also require a certain amount of energy. These EOR methods will have environmental footprints to a certain degree.

In the aspect of low salinity fluid, it does not require energy or chemicals before injection. It can be made by diluting the water that is available, for example formation water, with fresh/deionized water. Theoretically, low salinity flooding would affect the environment the same as a normal secondary waterflooding since low saline water is only water with low salt concentration. However, water treatment and water recycling requires energy, and this can affect the environment. At the end, low salinity waterflooding is a safer choice of EOR method from the environmental point of view.

6.3. Hybrid Methods – Low Salinity Polymer Flooding

In recent years, polymer combined with low salinity brine has been considered as an alternative EOR method that is more efficient than the two methods by themselves, and many experiments have been done to observe the incremental recovery from polymer FW flooding to low salinity polymer flooding (Khorsandi et al., 2016; Piñerez T et al., 2016c; Rotondi et al., 2014; Vermolen et al., 2014).

The objective of adding polymer to low salinity water are to reduce the amount of polymer required to obtain the target viscosity, get the benefits from both polymer and low salinity flooding, increase the elasticity of polymer by using low salinity water that can reduce S_{orw} and increase the recovery (Vermolen et al., 2014). Additional benefits can be better polymer stability, lower sensitivity to polymer degradation and polymer adsorption, and lower scaling and souring tendency. Figure 20 shows viscosity vs. polymer concentration plot for reservoir brine and low salinity brine. The graphs shows that less polymer is required to achieve a certain value of viscosity for low salinity brine than reservoir brine, hence, amount of polymer is cut down significantly.

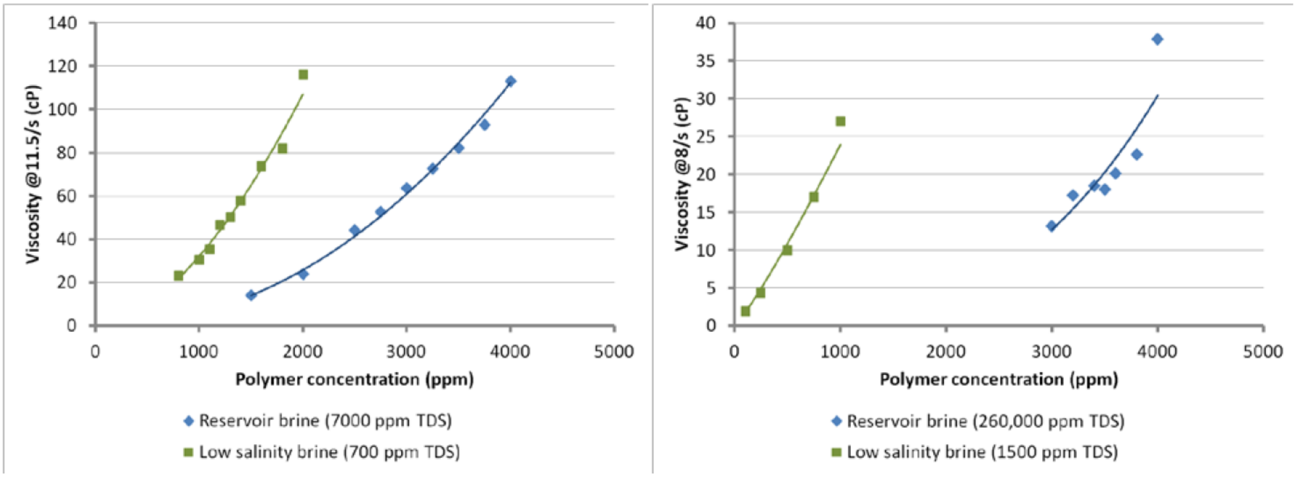


Figure 20. *Viscosity against polymer concentration plot for two cases with two different brines. Both fields are low temperature at* $50^{o}C$ *and viscosities are given at reservoir temperatures for the same polymer (Vermolen et al., 2014).*

Figure 21 shows the oil recovery against PV injected with the following flow sequence: 6000 ppm brine, 1000 ppm with polymer and 250 ppm with polymer. The change from brine to polymer increased the recovery over the double amount, and by using polymer with low salinity brine will further increase the recovery by around 8%. Even though it seems that low salinity polymer flooding is a great EOR method that can increase the oil recovery, more testing should be done before large scale application.

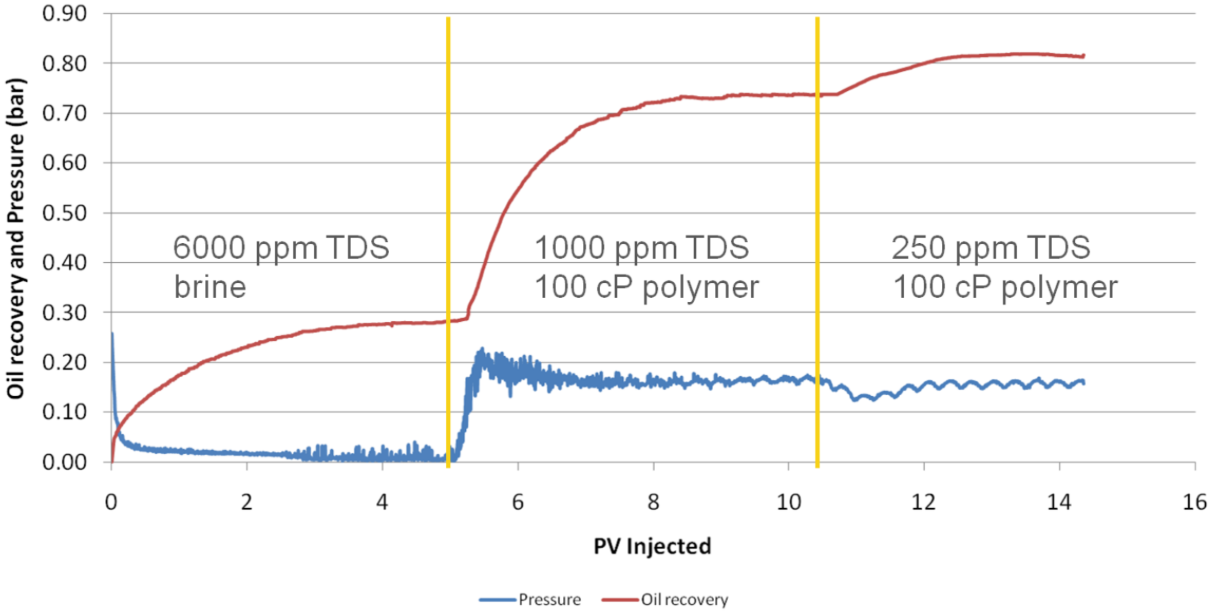
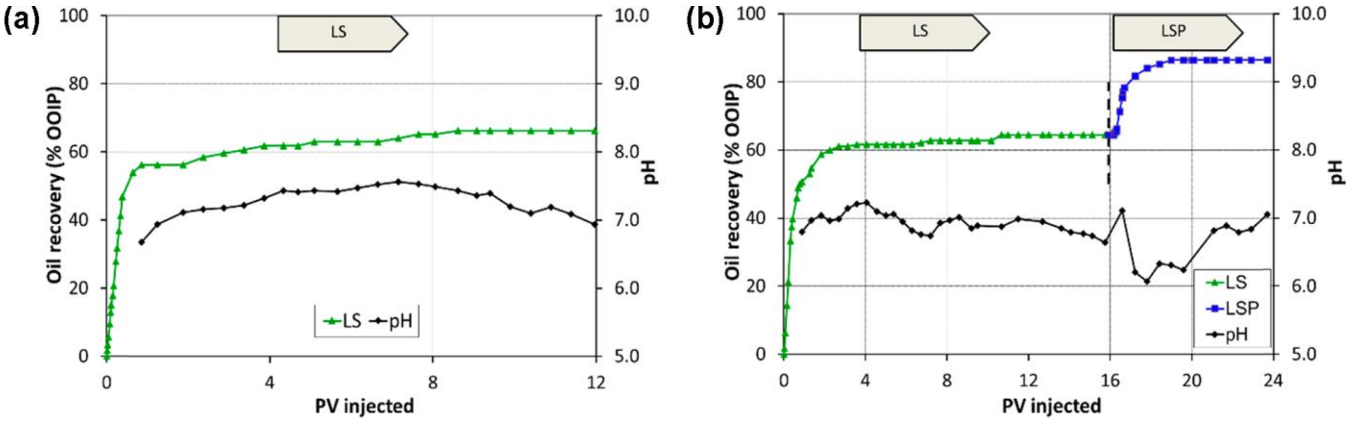


Figure 21. *Pressure and production curve for low salinity polymer oil displacement experiment in reservoir core material (Vermolen et al., 2014).*

A pilot project is going to be employed around 2021 in Johan Sverdrup Field. This project will have at least one injector and one producer pipeline, and polymer is going to be tested to observe any EOR effects and how it affects/reacts with the reservoir. However, there are many risks by using polymer flooding; high OPEX, chemical degradation, influence on oil and water processing facilities due to production of polymer, etc (Statoil, 2016). Many of the risk factors could be avoided by trying out low salinity waterflooding instead. Degradation, high OPEX, and influence on processing facilities won’t cause any problems by implementing LSWF, but a high CAPEX must be expected. LSWF could also be used as a secondary recovery method, where LSP flooding could be used as an EOR method. Piñerez T et al. (2016c) performed coreflooding tests by secondary injection of low salinity brine, and one with low salinity polymer injection after secondary LS injection, note that the core materials used are not from Johan Sverdrup Field. The result are showed in Figure 22. Both plots showed a recovery of approximately 60% of OOIP after 4 PV without pH varying too much throughout the experiments. In Figure 22(b), LSP solution was injected and a rapid increase to around 86% of OOIP occurred. A low salinity environment established at initial water saturation, instead of S_{or}, in the core/formation is important for improving the recovery in such short response time (Piñerez T et al., 2016c; Shaker Shiran & Skauge, 2013). Therefore, LS pilot plant could be a better method to be tested out than polymer due to the risk factors involved with the chemical, but as some studies have shown, an even greater recovery could be achieved by LSP than only LS. This is probably due to the change in mobility ratio, favoring spreading the injection fluid throughout the area, leading to increased macroscopic sweep efficiency by polymer.



__Figur 22.__ Oil recovery test from core at 60°C by secondary injection of LS brine, (a) first restoration and (b) second restoration of the core after mild cleaning with LS in secondary mode followed by LSP flood (Piñerez T et al., 2016c).

Seawater is going to be injected in Johan Sverdrup Field due to the availability. But as mentioned in the previous section, LSWF could also be used from day one of the production, just like the Clair Ridge Field in UK. Considering the wettability alteration mechanism is desorption by pH increase proposed by Austad et al. (2010), LS brine injection increases the pH more than SW injection. The pH differences between LS injection and SW injection can be observed in Figure 19. Low salinity injection has better potential to alter the wettability from mixed wet to a more water-wet state, where the key parameter will be the pH gradient. Desorption of oil from the formation would increase the amount of oil that are mobilized, and LSP injection after LSWF would then increase the total sweep efficiency in the reservoir.

7. Conclusion

Evaluation of EOR potential in Johan Sverdrup Field by low salinity water injection was done by analyzing various papers and literatures. Limited data is given about the Johan Sverdrup Field due to the field is still in the early stages. However, a simple evaluation could be made by screening the reservoir parameters with the required/preferred conditions for observing an EOR effect by low salinity waterflooding:

- A CBR system where polar components in crude oil, divalent cations in formation water, and clay in rock exists. Johan Sverdrup Field is a sandstone reservoir with medium-grain sized sand. Porosity and permeability values are also good.
- No direct data about the wettability was found. However, a mixed-wetting could be assumed due to possible adsorption of polar component in crude oil onto clay or other parts of the rock in the reservoir.
- Reservoir temperature is around 80^{o}C, which is below high temperature reservoirs that is above 100^{o}C. Challenges that is due to high temperatures, such as anhydrite precipitation, would likely not cause a problem. High temperatures can also cause for decrease in amount of acidic polar components.
- The initial reservoir pH is an important property that can influence mechanisms in the reservoir, such as adsorption of crude oil. The pH in FW for Johan Sverdrup Field is not given in any literatures, but it can be assumed as below 7 due to factors like plagioclase in formation with a relatively high FW salinity. Reservoirs that contains acid gases, such as CO_2 and H_2S, are more prone to have lower initial pH. A pH screening of the reservoir should be done before application of LSWF.
- Salinity of the injected brine has less to say than the water composition itself. As studies have shown, high salinity brine also has an EOR effect in sandstone. One important factor is that the injected low salinity brine must have less Ca^{2+} than formation water for observing LS EOR effect.
- In the aspect of EOR methods, LSWF is more environmental friendly and cost efficient than most other EOR methods in the market. Since there are less ions in low saline brines, prevention of reservoir souring and scaling is also possible.
- Further investigation and many more experimental work, such as corefloods, simulations and pilot projects, of Johan Sverdrup Field should be done before implementing EOR methods since it is a large field where any damage done to the reservoir would cause major loss financially.

- Johan Sverdrup Field has great EOR potential by implementing low salinity waterflooding into the reservoir because of all the factors mentioned in the conclusion. By assuming a mixed wetting initially, altering the wettability to a more water-wet state would improve the oil recovery, and by choosing the best water composition for injection will optimize the LS EOR effect. Low salinity polymer flooding could be implemented after the secondary LSWF, in this case, the recovery factor would increase even further due to increase of the total sweep efficiency.

Nomenclature

θ	Contact Angle [°]
Δp	Pressure Drop [Pa]
$\Delta \rho$	Density Difference between Oil and Water [g/cm^3]
σ_{os}	Interfacial tension between oil and solid [mN/m]
σ_{ow}	Interfacial tension between oil and water [mN/m]
σ_{ws}	Interfacial tension between water and solid [mN/m]
μ	Viscosity [cP]
μ_o	Oil Viscosity [cP]
μ_w	Water Viscosity [cP]
AN	Acid Number [mg KOH/g oil]
BN	Base Number [mg KOH/g oil]
CAPEX	Capital Expenditure
CBR	Crude oil-Brine-Rock
CEC	Cation Exchange Capacity [meq/100g]
E_D	Microscopic Sweep Efficiency
E_T	Total Sweep Efficiency
E_V	Macroscopic Sweep Efficiency
EOR	Enhanced Oil Recovery
FW	Formation Water
IFT	Interfacial Tension
IOR	Improved Oil Recovery
g_c	Conversion Factor
g	Gravity Acceleration [m/s^2] equal to 9.8 m/s^2
GOR	Gas-Oil Ratio [Sm^3/Sm^3]
h	Height of oil column [m]
HSI	High Salinity Injection
k_{ro}	Relative oil permeability
k_{rw}	Relative water permeability
L	Length of Capillary Tube [m]
LS	Low Salinity
LSI	Low Salinity Injection
LSP	Low Salinity Polymer

LSWF	Low Salinity Waterflooding
M	Mobility Ratio
MIE	Multicomponent Ion Exchange
NPD	Norwegian Petroleum Directorate
OOIP	Original Oil In Place
OPEX	Operating Expenses
P_c	Capillary Pressure [Pa]
ppm	Parts per Million
PV	Pore Volume
r	Radius of Cylindrical Pore Channel [m]
SAGD	Steam Assisted Gravity Drainage
S_{oi}	Initial Oil Saturation
S_{or}	Residual Oil Saturation
S_{orw}	Residual Oil Saturation after Waterflooding
SW	Seawater
SWCTT	Single Well Chemical Tracer Test
TAN	Total Acid Number [mg KOH/g oil]
TBN	Total Base Number [mg KOH/g oil]
TDS	Total Dissolved Solids [mg/L]
TOC	Total Organic Carbon
$\bar{v}$	Average Velocity [m/s]
WAG	Water Alternating Gas
XRD	X-Ray Powder Diffraction
XRF	X-Ray Fluorscence

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