EOR by Smart Water Flooding in Low Temperature Sandstone Reservoirs

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Abstract

New oil discoveries have dropped dramatically the last decade. For that reason, oil in place from already discovered reservoirs has become one of the most important targets for the oil companies. "Smart Water" flooding is a chemical EOR method that improves oil recovery by wettability alteration, resulting in improved microscopic sweep efficiency by the increasing capillary forces. The parameter that influence the wettability alteration process and consequently the EOR potential is the initial reservoir wetting state. Initial wetting state is affected by the mineralogy, crude oil, formation water composition and the temperature-pressure conditions of the reservoir. According to the published literature, the optimum conditions to observe the EOR effects by "Smart Water" flooding appear to be mixed-wet wettability conditions.

The objective of this thesis was to evaluate the potential EOR effect by Low Salinity "Smart Water" injection in a sandstone reservoir with initial unfavorable conditions. The experimental basis to evaluate the EOR potential with "Smart Water" were screening techniques and the oil recovery tests to validate the observations. This thesis contains literature review, experimental part, results with discussion and finally the conclusions.

Based on the obtained results, even if the sandstone core material does not meet the favorable requirements for the highest EOR potential, an important increase in secondary mode with "Smart Water" injection was observed. Finally, a smaller scale increase was observed with "Smart Water" injection during tertiary mode.

Abstract in Greek

Η ανακάλυψη νέων κοιτασμάτων υδρογονανθράκων έχει μειωθεί δραματικά την τελευταία δεκαετία. Για αυτόν τον λόγο, η πετρελαϊκή βιομηχανία έχει στρέψει το ενδιαφέρον της στην μεγιστοποίηση της απόληψης των αποθεμάτων που ήδη έχουν εντοπιστεί και υπολογιστεί. Η χρήση του "Smart Water" μέσα στον ταμιευτήρα είναι μια χημική μέθοδος βελτιωμένης ανάκτησης πετρελαίου, η οποία έχει ως αποτέλεσμα την βελτιωμένη μετατόπιση του πετρελαίου μέσα στους πόρους, εξαιτίας της αύξησης των τριχοειδών δυνάμεων. Η παράμετρος που επηρεάζει την διαδικασία για αλλαγή της διαβρεχτότητας, και με συνέπεια την δυνητική αύξηση της βελτιωμένης ανάκτησης πετρελαίου, είναι η αρχική διαβρεχτότητα του ταμιευτήρα. Η αρχική διαβρεχτότητα του ταμιευτήρα επηρεάζεται από την ορυκτολογία του ταμιευτήρα, την σύσταση του πετρελαίου, την σύσταση του νερού του ταμιευτήρα και από τις συνθήκες πίεσης-θερμοκρασίας του ταμιευτήρα. Σύμφωνα με την δημοσιευμένη βιβλιογραφία, οι βέλτιστες συνθήκες για να παρατηρηθεί βελτιωμένη ανάκτηση πετρελαίου με την χρήση του "Smart Water" φαίνεται να είναι οι μικτές συνθήκες διαβρεχτότητας.

Ο στόχος της παρούσας διπλωματικής εργασίας είναι να ερευνηθεί το δυνητικό αποτέλεσμα βελτιωμένης ανάκτησης πετρελαίου με την χρήση του Low Salinity "Smart Water" σε ένα ψαμμιτικό ταμιευτήρα πετρελαίου, ο οποίος παρουσιάζει δυσμενείς αρχικές συνθήκες. Η πειραματική βάση για να ερευνηθεί το πιθανό αποτέλεσμα της βελτιωμένης ανάκτησης με το "Smart Water" ήταν πειράματα τα οποία μας έδειξαν την προδιάθεση για βελτίωση της ανάκτησης πετρελαίου και πειράματα ανάκτησης πετρελαίου τα οποία μας επικυρώνουν και ποσοτικοποιούν τις αρχικές μας παρατηρήσεις. Η παρούσα διπλωματική περιέχει ανασκόπηση της βιβλιογραφίας, το πειραματικό μέρος, τα αποτελέσματα των πειραμάτων και στο τέλος τα συμπεράσματα.

Σύμφωνα με τα παρατηρηθέντα αποτελέσματα, ακόμα και αν ο ταμιευτήρας της μελέτης δεν πληροί τις επιθυμητές αρχικές συνθήκες για βελτίωση της ανάκτησης πετρελαίου, μια σημαντική αύξηση παρατηρήθηκε στην δευτερογενή παραγωγή πετρελαίου. Τέλος, μια μικρότερης κλίμακας αύξηση παρατηρήθηκε ακόμα και στην τριτογενή παραγωγή με την χρήση του "Smart Water".

1 Objective

Smart Water is a low cost and environmentally friendly technique, which can be used in most oil reservoirs. Despite the simplicity of the Smart Water EOR concept, the underlying mechanisms seem to be very complicated. The individual chemical properties of the crude oil, brine and rock phases are complex due to large variation in species in each phase [Mamonov, 2019]. The complexity increases even more when all three phases interact in an oil reservoir system.

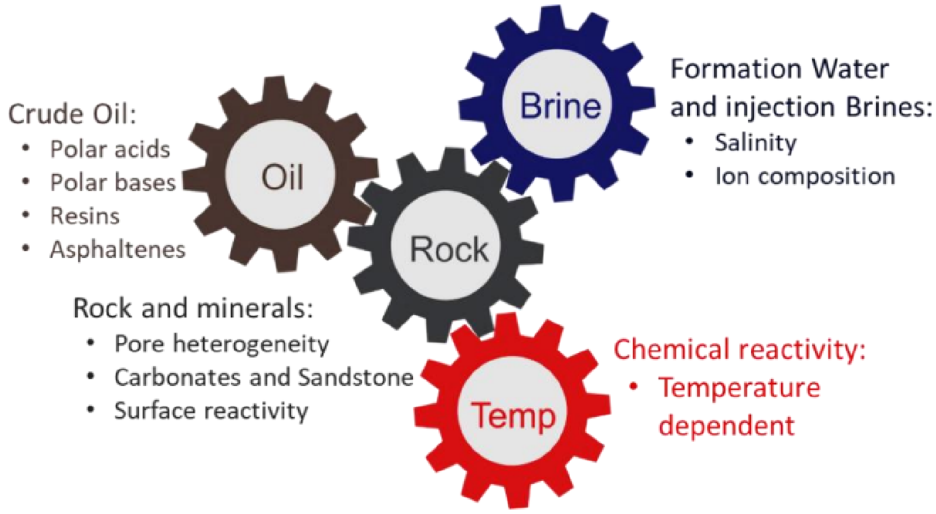


Figure 1: The key parameters to study the "Smart Water" EOR effect in the reservoirs [Aghaeifar, 2020]

The objective of this thesis was to evaluate the EOR effect potential by Low Salinity "Smart Water" injection in a reservoir with low temperature and initial unfavorable conditions. The evaluation was began with a literature review for a better understanding of the processes that take place in a reservoir system and completed with the experimental work. The experimental work includes:

1. Restoration of the cores with the appropriate methods.
2. pH-screening tests to evaluate the potential Enhanced Oil Recovery effect by Smart Water injection.
3. Oil recovery tests with forced imbibition flooding and different injected brines sequences to validate the observations from the screening tests.

2 Introduction

In this part of the thesis will be described the theory behind the most critical parts which are essential for a good understanding of the objective and the "Smart Water" flooding.

2.1 Sandstone

Sandstone is a sedimentary rock that contains mostly quartz, but it can also have significant amounts of feldspar, and sometimes silt and clay. Sandstones with more than 90% quartz are called quartzose sandstones. When the sandstone contains more than 25% feldspar, it is called arkose or arkosic sandstone. Lastly, the sandstones that have significant amounts of clays or silts, are referred as argillaceous sandstones by the geologists. Because it is composed of light colored minerals, sandstone is typically light tan in color [Mineralseducationcoalition.org,]. Rock formations that are primarily composed of sandstone usually allow the percolation of water and other fluids and are porous enough to store large quantities, making them valuable aquifers and petroleum reservoirs.

Figure 2: Sandstone rock

2.2 Sandstone Reservoirs

The majority of petroleum reserves in the world is found in ancient sandstones which have porosity and permeability [Wei, 1982]. When sandstone contains oil that can be extracted by known technology, it is referred to as a sandstone reservoir. Significant impact on the hydrocarbon production has also pore geometry and wettability. The origin and distribution of a reservoir rock are controlled primarily by the processes by which the sand was deposited.

2.2.1 Porosity and Permeability

As mentioned previously, some of the key factors of oil production are porosity and permeability.

Porosity may be described as a value relative to the whole pore space or as the volume of interconnected pores that can allow the fluids flow. That is respectively, total porosity (φ) and effective porosity. Total porosity (φ) is the whole void space to total volume. It includes isolated spaces and spaces occupied by clay-bound water. Total porosity in sandstones ranges between 5% and 35%. Effective porosity is the volume of the interconnected pore space to total volume [Zimmerle, 1995]. Furthermore, the result of effective porosity is the property called permeability.

Permeability (k) is the ability of the rock to transmit fluids and it is measured in Darcies. Formations that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores. Impermeable formations, such as shales and siltstones, tend to be finer grained or of a mixed grain size, with smaller, fewer, or less interconnected pores. Absolute permeability is the measurement of the permeability conducted when a single fluid, or phase, is present in the rock. Effective permeability is the ability to preferentially flow or transmit a particular fluid through a rock when other immiscible fluids are present in the reservoir (for example, effective permeability of gas in a gas-water reservoir) [Schlumberger-Glossary, 2022]

2.3 Oil Recovery

Oil Recovery is the ratio of recoverable oil to initial oil in place. The higher recovery ratio means a more reasonable production. The objective of the industry engineers is to increase the oil recovery factor by good engineering practises. Usually, the oil recovery phases are divided to three phases, based to chronological succession. The three stages are primary, secondary and tertiary oil recovery. Below every phase will be explained more extensive.

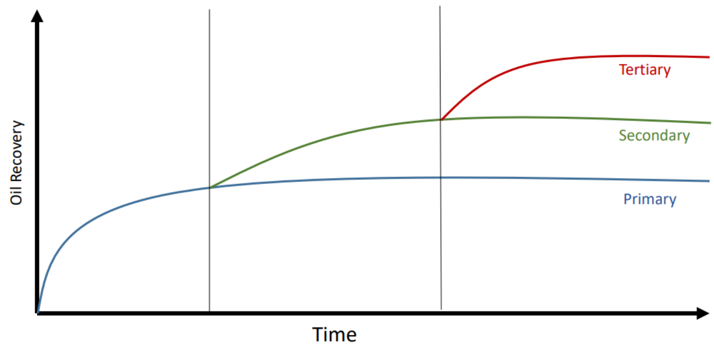


Figure 3: Oil Recovery phases

2.3.1 Primary oil recovery

Primary oil recovery describes the oil production only with the use of natural driving mechanisms present in the reservoir. Initially, the reservoir pressure is significantly higher than the bottom hole pressure inside the wellbore, but as the reservoir pressure declines due to production, the differential pressure is also declines. This reduction in differential pressure is leading to the reduction of the production until a non-profitable point for the company. In most cases, the natural driving mechanism is a relatively inefficient process and results in a low overall oil recovery [Ahmed, 2010].

2.3.2 Secondary oil recovery

Secondary oil recovery is related to the additional recovery that results from the methods of water injection and immiscible gas injection. Waterflooding is perhaps the most common method of secondary recovery. Normally , gas is injected into the gas cap and water is injected into the production zone to sweep oil from the reservoir [Schlumberger-Glossary, 2022]. The secondary recovery stage ends when the injected fluid is produced in large amounts and the production is no longer economical.

2.3.3 Tertiary oil recovery-Enhanced Oil Recovery

Primary and secondary recovery methods typically leave considerable amounts of residual oil. The last stage of production is tertiary oil recovery. However, that concept in not entirely appropriate. There are a lot of cases that use advanced oil recovery techniques from the early development stages. Some fields, instead of secondary oil recovery method are using the tertiary oil recovery method. In contrast to secondary oil recovery methods, tertiary methods aim to altering the oil/rock system properties and improve the mobility of the oil. Thus, the term EOR has become more accepted by the scientific community [Green and Willhite, 1998].

2.4 EOR Methods

No single EOR technique is the cure-all for oil recovery. Reservoirs are complex and the recovery technologies involve a lot of different concepts. Some methods can damage and some other can improve the oil mobility and finally the production. Each EOR process is suitable to a particular type of reservoir. Some screening criteria are available to the engineers to help them for the preliminary evaluation of a reservoir's suitability for EOR. After the technical screening guides have been applied to a given prospect, the more stringent economic screening process must take place before the final decision is made [Taber, 1983]. Candidate reservoirs should contain considerable recoverable oil and be large enough for the project to be potentially profitable. In general, the EOR processes require reservoir temperatures less than $95°C$ and enough permeability to allow the universal spread of injection fluids. Table 1 lists the most common EOR methods by the main driving mechanism.

2.5 Smart Water EOR in Sandstones

The injection of a modified brine to improve oil recovery during waterflooding has been evaluated over the past three decades. Tang and Morrow (1997) observed improved oil recovery by low salinity (LS) waterflooding and spontaneous imbibition in Berea sandstone cores. From then till now, a lot of companies and laboratories around the world continued the studies of the underlying processes. The simplicity and the relatively low cost of water treatment, as well as the reported improvements of oil recovery, 10-30% OOIP [Brady et al., 2015] are the main reasons of this long and widespread interest in this technology.

There are several hypotheses about the main driving mechanism behind the Smart Water EOR effect in sandstones. We can divide in two groups the most proposed hypotheses.

1. Mechanisms describing surface reactions between reservoir fluids and rock minerals.

2. Mechanisms describing reactions at the interface between crude oil and brine in porous media.

Table 1: Classification of EOR methods [Torrijos, 2017]

Chemical EOR	Alkaline Flooding Surfactant Flooding Polymer Flooding Alkaline/Surfactant/Polymer Flooding (ASP) Solvent Flooding Gels for water diversion/shut off
Thermal EOR	Steam Flooding Cyclic steam stimulation In-situ combustion Hot Water Flooding Steam-assisted gravity drainage
Gas Injection EOR	Hydrocarbon injection (miscible/immiscible) CO2 Flooding (miscible/immiscible) Nitrogen injection Flue gas injection (miscible/immiscible) Water-Alterating-Gas (WAG)
Emerging EOR	Smart Water / Engineered Water Low Salinity Water Flooding Carbonated Water Flooding Microbial EOR Enzymatic EOR Electromagnetic heating EOR Surface mining and extraction Nano particles

2.6 Oil recovery forces in sandstone

The evaluation of an EOR method is done by the displacement efficiency factor. The displacement efficiency factor describes the microscopic displacement efficiency in the pore scale and also macroscopic displacement efficiency in the areal and vertical directions towards production wells [Green and Willhite, 1998]. The displacement efficiency factor (E) is described by the equation below.

$$E = E_D \times E_V \tag{1}$$

Where,
E is displacement efficiency
E_D is microscopic displacement
E_V is macroscopic displacement efficiency

Microscopic displacement efficiency (E_D) represents the mobilization of oil at pore space and typically displayed in the magnitude of residual oil saturation (S_{or}). On the other hand, macroscopic sweep efficiency measure how effective the volumetric sweep is [Green and Willhite, 1998]. Microscopic sweep efficiency can be described by the following equation.

$$E_D = \frac{S_{oi} - S_{or}}{S_{oi}} \tag{2}$$

Where,
S_{oi} is initial oil saturation
S_{or} is residual oil saturation

Macroscopic sweep efficiency is also very important and is affected by reservoir characteristics such as porosity, permeability, reservoir homogeneousness and fluid characteristics such as viscosity ratio, density difference etc.

The purpose of modern EOR method is to decrease residual oil saturation and increase microscopic sweep efficiency and it is affected by chemical and physical interaction of the injected fluid during an EOR process. This can be achieved by lowering the Interfacial tension (IFT) or wettability alteration in addition to many other mechanisms.

2.6.1 Capillary forces

The combined effects of wettability and interfacial tension cause the wetting fluid to be simultaneously imbibed into a capillary tube [Elshahawi et al., 1999]. The phenomenon of capillarity is significant in a porous medium saturated with immiscible fluids since the interconnected pores of the medium are on capillary dimensions. Capillary pressure represents the pressure differential that must be applied to the non-wetting fluid in order to displace a wetting fluid. Capillary force can be expressed by the following equation.

$$P_c = P_o - P_w = \sigma_{ow}(\frac{1}{R_1} - \frac{1}{R_2}) = \frac{2\sigma_{ow}\cos\theta_c}{r_c} \tag{3}$$

Where,
P_o is the pressure in the oil phase at interface (Pa)
P_w is the pressure in the water phase at interface (Pa)
σ_{ow} is the interfacial tension at oil water interface (N/m)
θ_c is the contact angle between the phases (°) and
r_c is the pore radius of capillary (m)

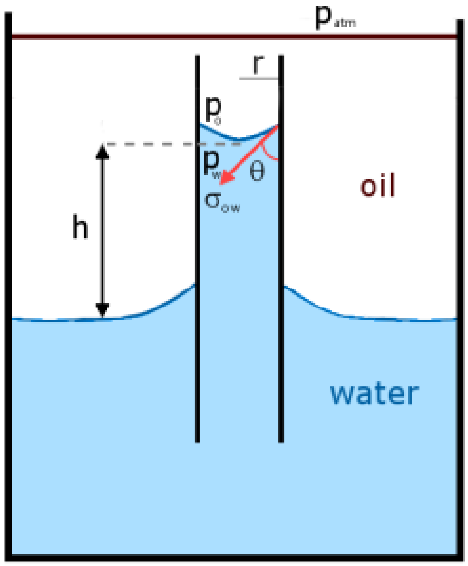


Figure 4: Capillary forces in a capillary tube

2.6.2 Viscous forces

In the case of flow in porous media, viscous forces are reflected in the magnitude of pressure drop that happens as a result of flow through the medium [Green and Willhite, 1998]. If the porous medium is regarded as a bundle of parallel capillary tube then the pressure drop during flow can be calculated by Poiseuille's law.

$$\Delta P = \frac{8\mu L\vec{v}}{r^2 g_c} \tag{4}$$

Where,
ΔP is the difference in pressure over capillary tube (Pa),
μ is the viscosity (Pa·s),
L is the capillary length (m),
$\vec{v}$ is the average flow velocity in the capillary (m/s),
r is the radius of the capillary (m)
g_c is the conversion factor.

2.6.3 Gravity forces

Gravity forces take place when the difference in densities between two immiscible fluids is big enough. Phases separate according to density, where the denser fluid is on the bottom of the column and the less dense is on the top. The gravity forces can lead to positive and negative effects for improved oil recovery methods based on fluids segregation. When the density of the displacing fluid is less than the density of displaced fluid, gravity segregation can generate override. On the other hand, when the density of the displacing fluid is less than the density of displaced fluid under ride can take place. Gravity segregation can lead to an early breakthrough of injected fluid which will decrease the potentiality of oil recovery by EOR fluid [Green and Willhite, 1998]. In oil reservoirs the capillary forces are prevail in relation to gravity forces.

$$\Delta P_g = \Delta\rho g H \tag{5}$$

Where,
ΔP_g is the pressure difference of the oil and water interface due to gravity (Pa),
$\Delta\rho$ is the difference in density of the two phases (Kg/m^3),
g is the gravitational acceleration constant (m/s^2),
H is the height of the column (m).

2.6.4 Correlation of forces, capillary number and bond number

Because of the complexity of a reservoir porous medium, multiple scientists have developed various equations in order to weight the importance of each force in a given condition. The most relevant equations are described below.

2.6.5 Capillary number (Nc)

Capillary number was defined as the ratio of viscous force to capillary force [Tang, 1992]. It is important because it shows the relative importance of viscous forces vs the capillary forces. When the capillary number increases, viscous forces become more dominant, permitting oil mobilization and as a result, increased oil recovery is observed. One of the most commonly used form to describe Capillary number is:

$$N_c = \frac{Viscoseforce}{Capillaryforce} = \frac{V_o \mu_w}{\sigma_{ow}\cos\theta} \tag{6}$$

Where,
N_c is the Capillary number,

V is the velocity (m/s),
σ_{ow} is the interfacial tension between oil and water (N/m),
μ is fluid viscosity (Pa·s)

2.6.6 Bond Number

Bond number (N_b) characterizes the ratio of gravitational forces to capillary forces. A value of $N_b << 1$ implies the flow in question is only weakly dependent on gravitational forces, whereas $N_b >> 1$ implies gravitational forces dominate over interfacial forces [Schlumberger-Glossary, 2022].

$$N_b = \frac{Gravityforce}{Capillaryforce} = \frac{\Delta\rho g b^2}{\sigma_{ow}} \tag{7}$$

Where,
N_b is the bond number,
$\Delta\rho$ is the density difference between oil and water (Kg/m^3),
b is a characteristic length scale of the flow geometry ,
σ_{ow} is the interfacial tension between oil and water (N/m).

2.7 Wettability

Wettability is defined as "the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids" [Craig, 1971]. It is a measure of the rock's affinity for either oil or water in a Crude Oil-Brine-Rock system. When a rock is water-wet, water tends to fill the small pores and to contact the majority of the rock surface. In an oil-wet system, the rock preferentially comes in contact with the oil. The term wettability is used to describe the wetting preference of the rock and does not refer to the fluid that is in contact with. All petroleum reservoirs, were believed to be strongly water-wet at their initial state. As discussed in more detail later, reservoir rock can change from it's original, strongly water-wet condition to less water-wet condition by adsorption of polar compounds or the deposition of organic matter originally in the crude oil [Anderson, 1986b].

2.8 Wettability classification

The wetting state of a reservoir can be split into two categories. Homogeneous wetting and heterogeneous wetting. In a homogeneous wetting reservoir, the rock behave with the same properties throughout the reservoir.

When it comes to this type of system, the wetting categories are water-wet, intermediate-wet and oil-wet. Most of the reservoirs, as very complex systems, present mixed wettability as we observe different wetting states in different parts of the reservoir. Heterogeneous wetting reservoirs are divided in two categories. Mixed-wet and Fractionally-wet.

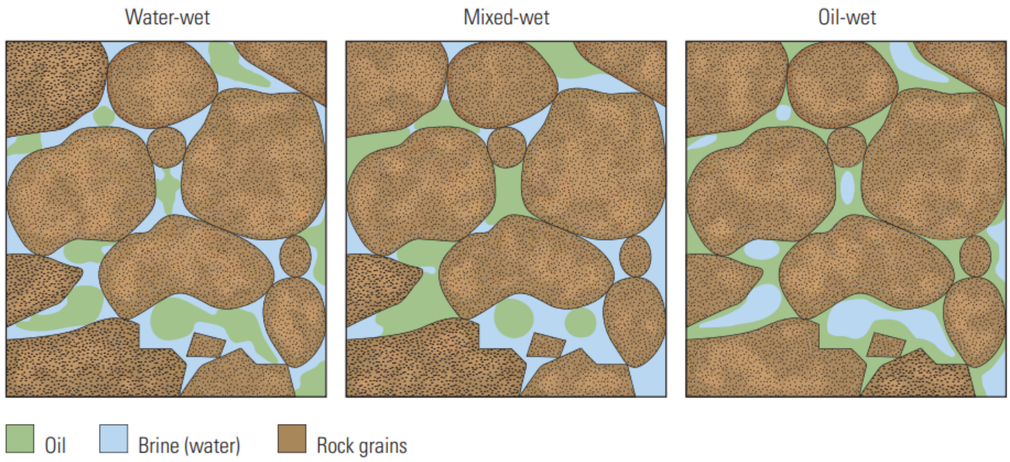


Figure 5: Wettability conditions [Abdallah et al., 1986]

2.8.1 Water-wet system

A Crude Oil - Brine - Rock (COBR) system is considered to be water-wet when more than 50% of its surface is wet by water [Donaldson and Alam, 2008]. Water fills the smaller pores, and it creates a film on the surface of the rock's larger pores that are preferentially water-wet. Oil exists as droplets in the larger pores and may cover some surfaces where preferentially oil-wet minerals exist. At initial water saturation S_{wi} the oil saturation is high enough for oil to exist as a continuous phase through the larger pores but as the water saturation increases the nonwetting fluid quickly becomes discontinuous. Moreover, when a water-wet rock is saturated with oil and the rock is exposed to water, water will spontaneously imbibe into the pores, displacing the oil, until the equilibration of the system.

2.8.2 Intermediate-wet system

2.8.3 Oil-wet system

In an oil-wet system, the oil will be distributed over the rock surface including the smaller pores. If water is present in the larger pores, it is generally in the center of the pores resting on a film of oil. When the water saturation is decreased, water rapidly loses continuity and exists in form of pockets and fingers that are surrounded by oil.

2.8.4 Mixed-wet system

Mixed-wet wettability is a condition where the small pores in the rock are water-wet and saturated with water but the larger pores are oil-wet and saturated with oil that forms a continuous path through the length of the rock [Salathiel, 1973]. Salathiel explained this condition by the original accumulation of oil in a reservoir. If the oil contains surface active compounds, the surface active compounds would gradually displace the remaining films of water from the larger pores, that oil imbibed in, and the wettability will be altered. Due to the high capillary pressure threshold oil will not enter the smaller pores of the rock.

2.8.5 Fractionally-wet system

The term fractionally wettability is used to describe heterogeneous wetting where the preferential wetting is randomly distributed through the rock and there is not continuous oil networks through the rock. This happens by the different and randomly distributed minerals that exist in the pore surfaces.

2.9 Wettability measurements in smooth surfaces

The simplest way to study wettability is by measuring the wettability on smooth surfaces. These measurements are provide high reproducibility, fast wettability estimations and direct comparisons of different systems. A general classification of the wettability as a function of the contact angles is presented in Table 2.

Table 2: Wettability classification as a function of contact angles

Contact angle (°)	Wettability
0-30	Strongly water-wet
30-90	Water-wet
90	Neutral-wet
90-150	Oil-wet
150-180	Strongly oil-wet

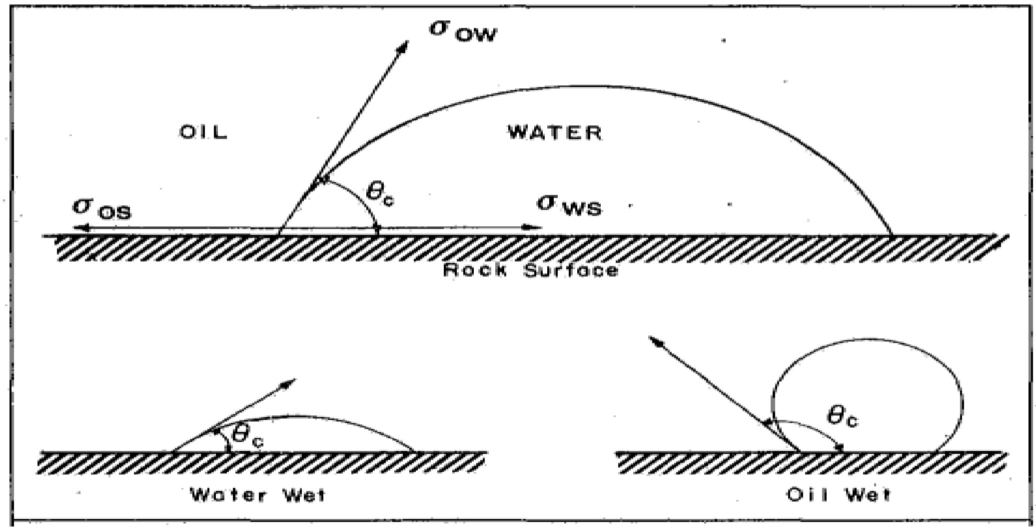


Figure 6: Contact angle in different wettability systems [Anderson, 1986a]

2.9.1 Contact angle

When we use pure fluids and artificial cores the best wettability measurement is the contact angle. Moreover we can use this method to examine the effects of temperature, pressure and brine chemistry on wettability. However, measuring wettability with the contact angle method involves some difficulties when applied to reservoir cores.

2.10 Wettability measurements in porous media

Contact angle measurements can't be representative for the wettability estimation of a porous medium due to the complex pores geometry and structure. However, the proper estimation of a reservoir wettability is critical for the right EOR method selection. Some of the methods used for wettability measurements in porous media are listed below:

1. Spontaneous imbibition
2. Amott Harvey and Amott-IFP
3. USBM and membrane methods
4. Crhomatographic wettability test

2.11 Properties and conditions that affect Wettability

Wettability is affected by several parameters. In order to study wettability it is crucial to understand the factors that it is depended on. Reservoir mineralogy, crude oil, brine composition and Pressure/Temperature conditions are some of the most important factors influence the wettability.

2.11.1 Mineralogy

Mineralogy affects the wettability by the different minerals that exist in different types of reservoirs. For instance, clay is the main wetting mineral in sandstones. The presence of clay makes the sandstones surface negatively charged. As a result, positive charged oil polar compounds adsorb on the surface [Mamonov, 2019]. In contrast, carbonates adsorb negatively charged oil compounds and develop stronger bonds with oil polar compounds which makes their surface usually more oil-wet than sandstones.

2.11.2 Crude Oil

Crude oil is one of the most complex mixtures of organic compounds. Asphaltenes and resins are the main fractions affecting the wettability in porous rock [Buckley et al., 1996]. Asphaltenes are large complex molecules, slightly polar. On the other hand resins are smaller molecules than asphaltenes, they are more polar and they have higher content of nitrogen,sulfur and oxygen (NSO-compounds).

2.11.3 Brine composition

The chemical composition, salinity and the pH of the brine are the most dominating factors in the wetting processes. Both formation and injection water brine compositions can induce surface charge on the rock surface or oil-water interface. As the formation water is in an equilibrium state for a long time, change in charge is not experienced in reservoir condition [Buckley and Liu, 1998]. Many experiments have proved that the pH has a significant function in the development of protonation and deprotonation of polar components in oil phase, which affects the attraction towards sandstone surface and changes the initial wetting [Austad et al., 2010].

2.11.4 Pressure and temperature

It has been observed that the solubility of polar active components in crude oil is increased as pressure and temperature is increased [Anderson, 1986a]. Anderson suggested that the cores could behave less water-wet at atmospheric conditions due to the reduction in solubility of the wettability altering components. It has also been observed in Berea sandstone cores that a high temperature during the aging of the core can lead to a less water-wet system.

2.11.5 Core restoration

Core restoration aims to preserve the native wettability of the reservoir cores and to achieve oil and water saturations as found at the reservoir conditions of study. Core restoration includes three basic steps, which are listed below:

1. Core cleaning
2. Core saturation
3. Aging

One of the most difficult procedures is the core cleaning. It requires the right selection of solvents to remove oil, brines and mud components from core samples, but at the same time to preserve the initial wettability of the reservoir core. The mild cleaning method can preserve the polar components initially adsorbed onto the sandstone core surfaces [Aslanidis et al., 2022]. Despite, all the methods that exist for core cleaning, there is not a common agreement to evaluate which are the best to follow. However, a combination of new screening techniques could help to reduce uncertainty in the evaluation of initial wetting, which is of high importance in the EOR field [Torrijos, 2017]. After the completion of core cleaning, initial water saturation is achieved by vacuum saturation with formation water, FW, the cores. The aging process is essential to assure the adsorption of crude oil components onto the surface of the cores and create a wetting close to initial wettability.

3 Experimental Part

Experimental procedure and materials will be described in this chapter. The objective of the procedure used, is to conclude if there is a possible improved oil recovery with the use of Low Salinity Water in Low Temperature sandstone reservoirs.

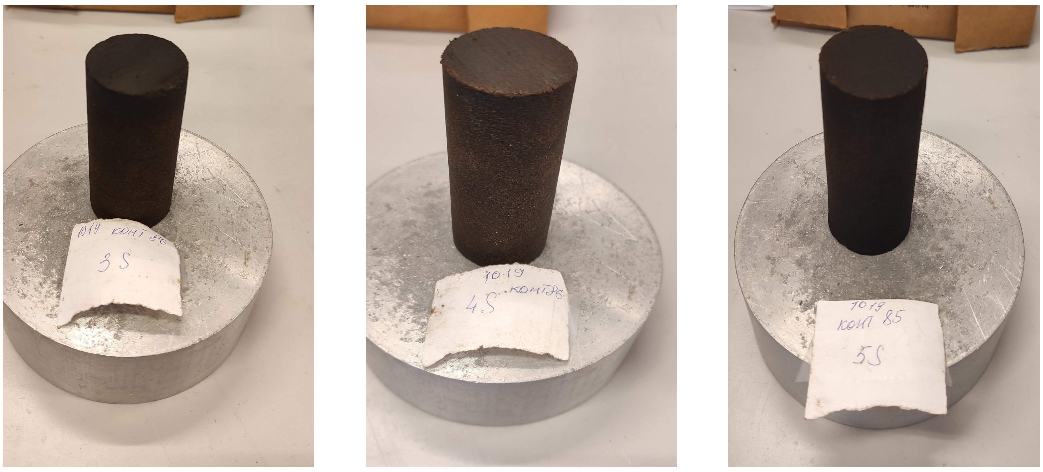
3.1 Materials

3.1.1 Reservoir Cores

Three sandstone reservoir cores that have never been used before for experiments were provided by an oil company. The cores were sandstone from a low temperature reservoir. Physical core properties are given in Table 3 and the mineralogy of the reservoir cores are given in Table 4.

Table 3: Physical properties of the cores

Core	Diameter [cm]	Length [cm]	Pore Volume [ml]	Porosity [%]
3SR	3.77	7.92	24.52	27.73
4SR	3.76	8.39	27.81	29.86
5SR	3.78	8.26	26.44	28.52



(a) 3SR **(b)** 4SR **(c)** 5SR

Figure 7: Sandstone Reservoir Cores

Table 4: Mineral composition of the core material, provided by company. *average absolute permeability measured on 100% water saturated cores.

Minerals	wt%
Quartz	91
Kaolinite clay	2
Microcline (K-feldspar)	2
Mica	4
Calcite	1
BET surface area [m2/g]	0.3
Permeability [mD]*	60

Table 5: Brines composition

	FW	LS-Water
	Concentration [mM]	Concentration [mM]
Na^{+}	2957.5	993.3
Cl^{-}	4547.7	993.3
SO_4^{2-}	12.3	-
Mg^{2+}	375.0	-
Ca^{2+}	300.0	-
TDS [ppm]	262240	1000
Viscosity at $25°C$ [cP]	1.5	0.9
Density g/cm^3	1.167	0.99
pH	6.6	6.26

3.1.2 Brines

For the experiments four different brines were used: Formation Water (FW), Five times diluted formation water (5xDFW), Twenty times diluted Formation Water (20xDFW) and Low Salinity Water (LS). Formation Water compositions are listed in Table 5.

3.1.3 Oil

Crude oil from the same horizon as the cores was used. The oil contains a high amount of asphaltenes and resins ($\approx$ 4% ashphaltenes and $\approx$ 24% resins). It is a very viscous and heavy oil as it is shown in Figure 8. The density of oil was measured using a Anton Paar densiometer at ambient conditions and the viscosity measurement provided by the company.

Table 6: Composition and properties of crude oil

Components	Composition, wt%
Saturates	29
Aromatics	43
Resins	24
Asphaltenes	4
Oil viscocity at 25°C, cP	40
Density at 25°C, g/cm^3	0.91
Reservoir T°C,	25

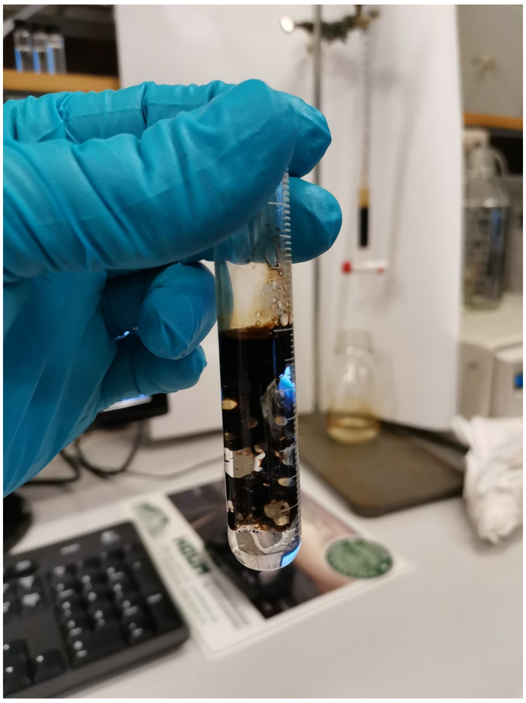


Figure 8: Produced oil sample from oil recovery test

3.2 Core Preparation

3.2.1 Core cutting & shaving

The first step of the core preparation is to cut the cores in desirable lengths and measure all the dimensions needed. The cores were cut in lengths around 8 centimeters. After the core cutting procedure, the edges of the core were smoothed.

3.2.2 Core Cleaning

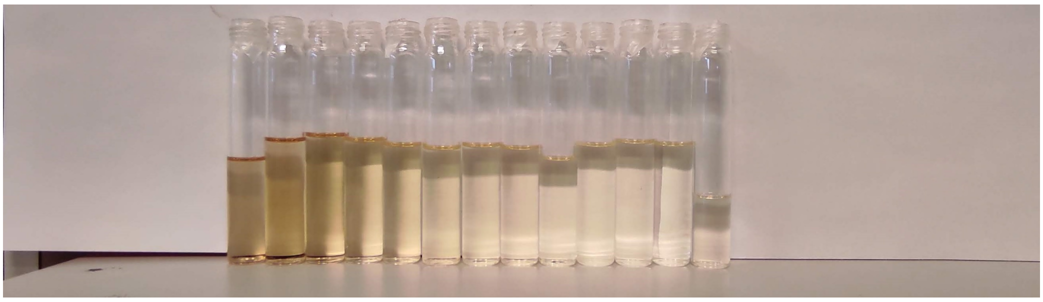
Reservoir cores went through a standard cleaning method. The method that we used for core cleaning is "Mild-Cleaning". The reasons we chose this method is because we wanted to reproduce the wettability of the cores. The "Mild-Cleaning" method includes the injection of Kerosene, n-Heptane and Low Salinity Water. Kerosene is used to remove the mobile oil phase, n-Heptane is used to displace kerosene and Low Salinity Water is used to displace FW and easily dissolvable salts. The exact amounts of injected brines are displayed in Table 7. The setup used is described below.

Table 7: Volumes and injection rate of "Mild-Cleaning" method

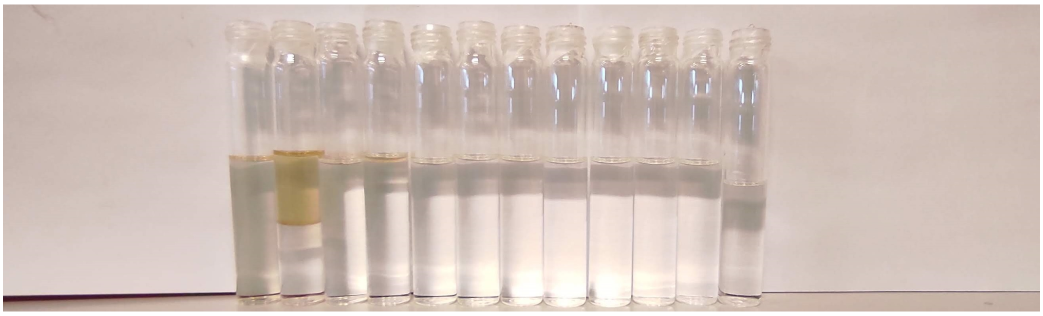
	Volume Injected [PV]	Injection Rate [ml/min]
Kerosene	8	0.1
n-Heptane	4	0.1
LS Water	4	0.1

In Figure 9 are displaced the effluents after the injection of each "Mild-Cleaning" fluid. The efficiency of "Mild-Cleaning" can be evaluated by the color of the effluent solvents. The results show that "Mild-Cleaning" was efficient since the effluent at the end of the flooding sequence had almost transparent color.

(a) Kerosene effluent



(b) n-Heptane effluent



(c) LS Water effluent

Figure 9: Effluent Samples from Mild-Cleaning

The cleaning setup contains:

- Water pump
- Cylinder filled with Kerosene
- Cylinder filled with n-Heptane
- Cylinder filled with LS Water
- Hassler type core holder
- Auto-sampler

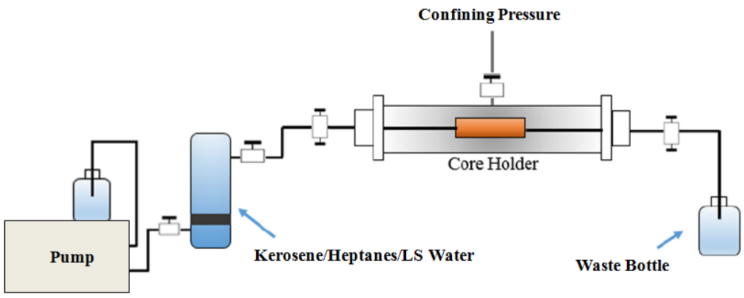


Figure 10: Schematic of cleaning setup

The cores were placed inside a rubber sleeve and then mounted inside the Hassler core holder. To force the injected fluid to enter the core and not going between the rubber sleeve and the core we used a confining pressure equal to 20 bar. The sampling time for the Auto-sampler was set to 80 minutes per sample (8ml per sample).

Finally, the cleaned core was placed in an oven at $90°C$ to evaporate remaining liquids in the core. The core was inside the oven until a constant weight measurement. With this way we are sure that all the liquids had been evaporated.

3.3 Brine Preparation

For the experimental procedures natural FW and synthetic FW were used. The synthetic FW was made by mixing Reagent-grade salts from WVR chemicals company with deionized water (DI). The brines were stirred for twenty four hours and then filtrated using a 0.22 µm filter with the help of a vacuum pump.

More details about brine preparation you can find below:

- FW was created by diluting the salts from table 2 in one liter of water.
- 5xDFW was created by diluting 200ml of FW in 800ml of deionized water.
- 20xDFW was created by diluting 50ml of FW in 950ml of deionized water.
- Low Salinity Water created by diluting 1g of NaCl in 1000ml of deionized water.

3.4 Core Restoration

3.4.1 Initial water saturation

The initial water saturation S_{wi} of the cores was established, using the desiccator technique [Springer et al.,]. The dry core was placed in a plastic container with quartz marbles on the bottom. Then, the plastic container with the core went inside a small glass pot. The setup was vacuumed until all the air was removed completely from the core pores. At that moment 5xDFW was slowly poured inside the plastic container until the complete immersion of the core inside the saturation brine. The schematic of water saturation setup is displaced in Figure 9. After the 100% vacuum water saturation, the core weight was measured again and used for pore volume (PV) and porosity calculations.

$$PV = \frac{m_{wet} - m_{dry}}{\rho_{5xDFW}} \tag{8}$$

Where,
PV= Pore Volume (ml)
m_{wet}= weight of 100% saturated core (g)
m_{dry}= weight of dried core (g)
ρ_{5xDFW}= density of 5xDFW (g/cm^3)

$$\phi = \frac{PV}{V} \tag{9}$$

Where,
PV= Pore Volume (ml)
V= Volume of the core (ml)

Then the core was placed inside a sealed desiccator with silica gel at the bottom. The core removed from desiccator when we have the desired weight of the core which corresponds to desired initial water saturation.

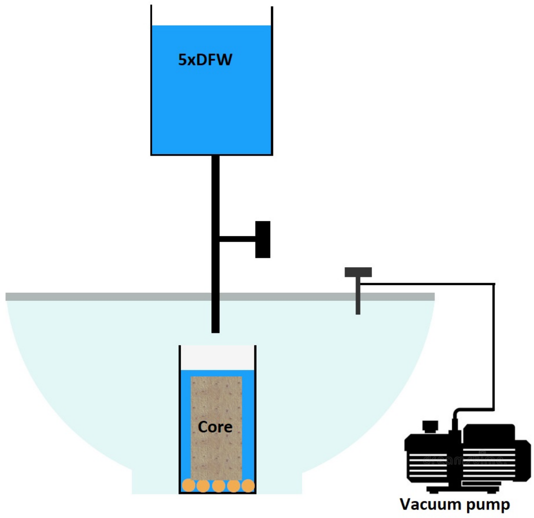


Figure 11: Schematic of vacuum water saturation setup

3.4.2 Initial crude oil saturation

When S_{wi} was established, equilibrated core was mounted in a Hassler type core holder inside a rubber sleeve. At first the lines and the core were vacuumed to remove the air from the system and then oil was injected to the vacuumed system. Oil from both sides was injected until reaching the pressure of 7bars. Next step was to inject 1.5PV of oil from each side of the core. The volume of oil injected, was chosen for the better reproduction of the wettability of the sandstone core [Aslanidis et al., 2022]. Next step was to pressurize from both sides the core with oil. All oil floods were performed at $50°C$. After the completion of the oil saturation the cores went for aging inside an aging cell for two weeks at $60°C$ and atmospheric pressure.

3.5 Permeability measurement tests

Before establishing the initial water saturation, one core was flooded with 5xDFW for measuring the absolute permeability of the core. Three different injection rates were used at ambient conditions. The injection rate was switched after the stabilization of the pressure difference (Δp). Darcy's law was used for absolute permeability calculation by averaging the results from three different injection rates. Absolute permeability calculations are presented in Table 4.

3.6 pH-screening test

pH-screening tests were performed to inspect the chemical interactions between the brines injected and the surface of the sandstone core. After the cleaning and drying of the core, the core was fully saturated with FW. Then the core was mounted inside a Hassler core holder with the confining pressure of 20 bars without backpressure. Three different brines (FW-LS-FW-20xDFW) were injected with the injection rate of 4PV/D. The effluent samples were collected in sealed sampling glasses using an Auto-Sampler. During the sampling procedure the pH of the effluent was measured at regular intervals.

3.7 Oil recovery tests

Oil recovery tests by viscous flooding were performed on restored cores. The cores were mounted in the Hassler core holder with the confining pressure of 20 bars and backpressure of 10 bars. With opened the by-pass valve, the system was left overnight to achieve stability at the pressure and temperature conditions. The cores were flooded with FW and LS brines at a rate of 4PV/Day. Produced oil was collected in a glass burette for volumetric oil recovery measurements with ±0.1ml accuracy. During the oil recovery test, water breakthrough was spotted and recorded. Moreover, pH measurements were made to effluent water samples by draining water from the bottom burette valve.

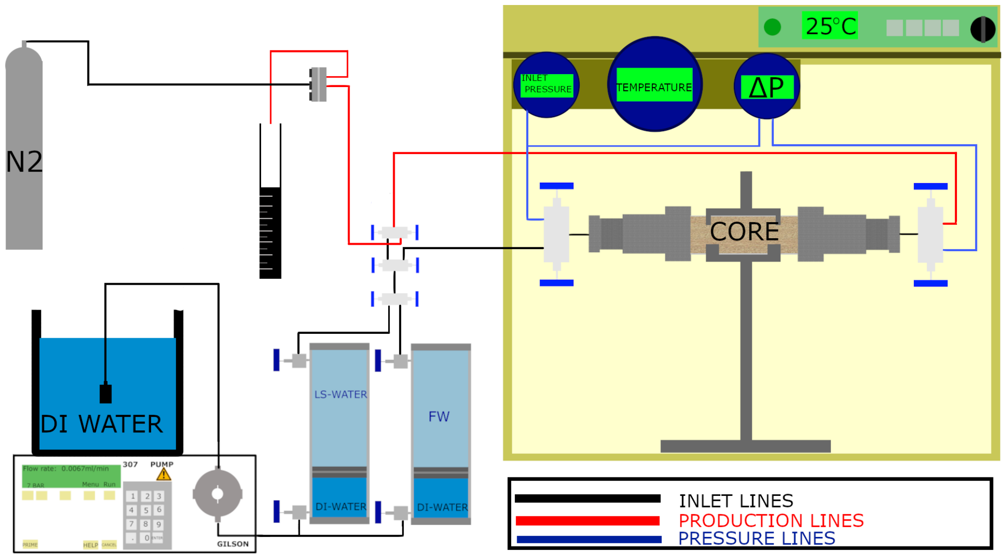


Figure 12: Schematic of oil recovery setup

4 Results and Discussion

The main objective of this thesis was to evaluate whether the presented low temperature sandstone reservoir is a good candidate for Low Salinity Smart Water flooding.

This chapter contains the main results from the experimental procedures which used on the sandstone reservoir core material. Below are presented one (1) pH-screening test and five (5) oil recovery tests performed by different brines injection.

4.1 Cation exchange processes in sandstone reservoir

Laboratory studies have shown that an alkaline pH of the effluent LS Smart Water, accompanies an increase in oil recovery in sandstones. The observed alkalinity can be related to the presence of reactive minerals in sandstone composition. The reactive minerals usually are clay and feldspar minerals, such as kaolinite, illite, smectite and microcline, albite, anorthite. To evaluate the potential EOR effect from Smart Water flooding, a pH-screening test was performed.

4.1.1 pH-screening test on sandstone reservoir core 5SR

The pH-screening test was performed on core 5S by the successive flooding of Formation Water-Low Salinity water-Formation Water-20xDiluted Formation Water. An oil-free core was used in order to estimate the initial pH and the potential pH increase during Low Salinity water injection. Figure 13 shows the development of pH during the pH-screening test at 25°C. The injection rate of the flooding was 4PV/Day and each brine was flooded until a stable plateau was reached.

The results in Figure 13 show that the pH development during FW injection stabilized at approximately at the same pH as the bulk FW pH. During the following Low Salinity Water flooding, the pH increased from 6.26 to almost 7.2 which is almost 1 pH unit above the Low Salinity Water bulk pH. After switching to FW and 20xDFW the pH of the effluent brine does not show any pH response since the pH values are very close to the bulk pH of the brines injected. This pH increase, close to one pH unit, is due to the desorption of cations, especially Ca^{2+}. To equilibrize the loss of cations, H^+, from the water close to the clay surface adsorb onto the clay and a substitution occurs. This process creates a local increase in pH close to the clay surface. The mechanism can be described by Eq.(10).

$$Clay - \mathrm{Ca}^{2+} + \mathrm{H_2O} \Leftrightarrow Clay - \mathrm{H}^{+} + \mathrm{Ca}^{2+} + \mathrm{OH}^{-} \tag{10}$$

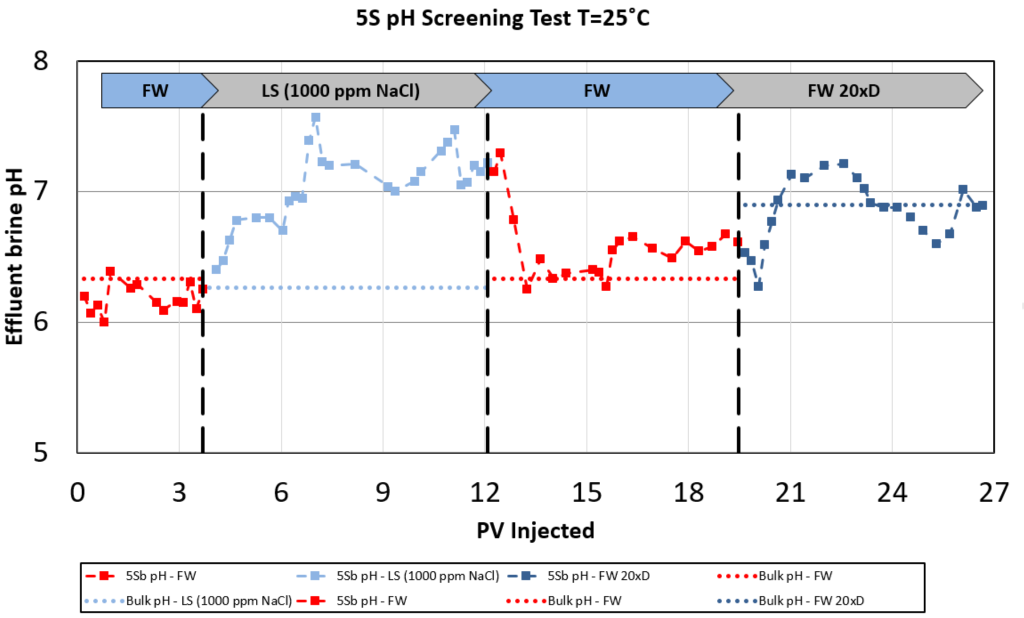


Figure 13: pH-screening test of sandstone reservoir core 5S at 25°C. Sequence of flooding: FW-LS-FW-20xDFW

The pH increase in Low Salinity Water injection indicates the potential EOR effect in our core material, so the evaluation will continue with the Oil Recovery Tests.

4.2 Oil Recovery Tests

Oil recovery tests were the most important experiments in this thesis. With Oil recovery test we can actually compare and evaluate the effect of Low Salinity Smart water by directly set side by side the recoveries from each brine sequence flooded. Five (5) Oil recovery tests were performed under difficult technical-experimental circumstances with a small margin for error. The cores were loosely consolidated due to the shallow reservoir depth and led to a failed and two questionable tests.

As it's described in the objective of the thesis, the goal was to evaluate Low Salinity Smart Water effect in a low temperature reservoir with initial unfavorable conditions. The conditions are described below:

- Low Temperature

  Reservoir's temperature is approximately $25°C$. At this temperature oil viscosity is much higher than the viscosity of Low Salinity Water. That means it will be difficult for the injected fluid (LS) to displace the oil. From Tables 5 and 6, FW viscosity is 1.5cP and LS viscosity is 0.9cP.

- Low content of reactive minerals

  The cores are almost pure Quartz and they have a little amount of clays and feldspars. The amount of clay/feldspar minerals contained in a core material is an indication of the surface reactivity of the core. However, the most important parameter is not the quantity, but the distribution of the minerals within the porous structure.

- Extreme salinity of FW

  The total dissolved salts (TDS) is 262g/l. This situation can lead to an initial water-wet condition. From literature review, the highest oil recoveries from Low Salinity Water flooding achieved with a initial mixed-wet wettability.

- Crude oil contains a lot of resins and asphaltenes

  Resins are approximately 24% and asphaltenes 4% as Table 6 shows. Asphaltenes and resins tend to stabilize formation clays through adsorption [Clementz, 1977]. This can reduce the potential wettability alteration from less water-wet to water-wet conditions.

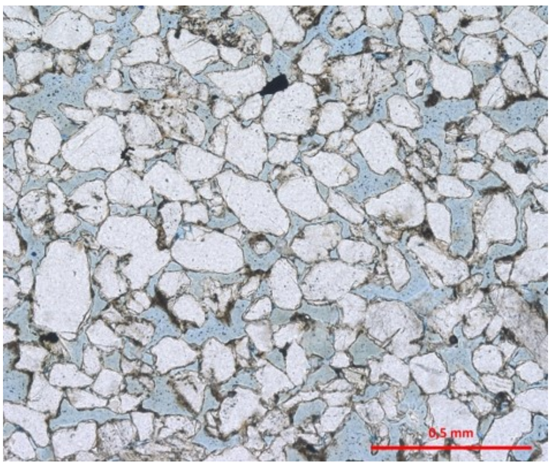


Figure 14: Thin section of the study material

The cores used for the oil recovery tests (3S and 4S) are two sister cores with very similar properties. The experimental plan was to perform two oil recovery test at each core, with switched flooding sequences and then compare the oil recoveries between them.

4.2.1 Oil recovery test on sandstone reservoir core 3SR

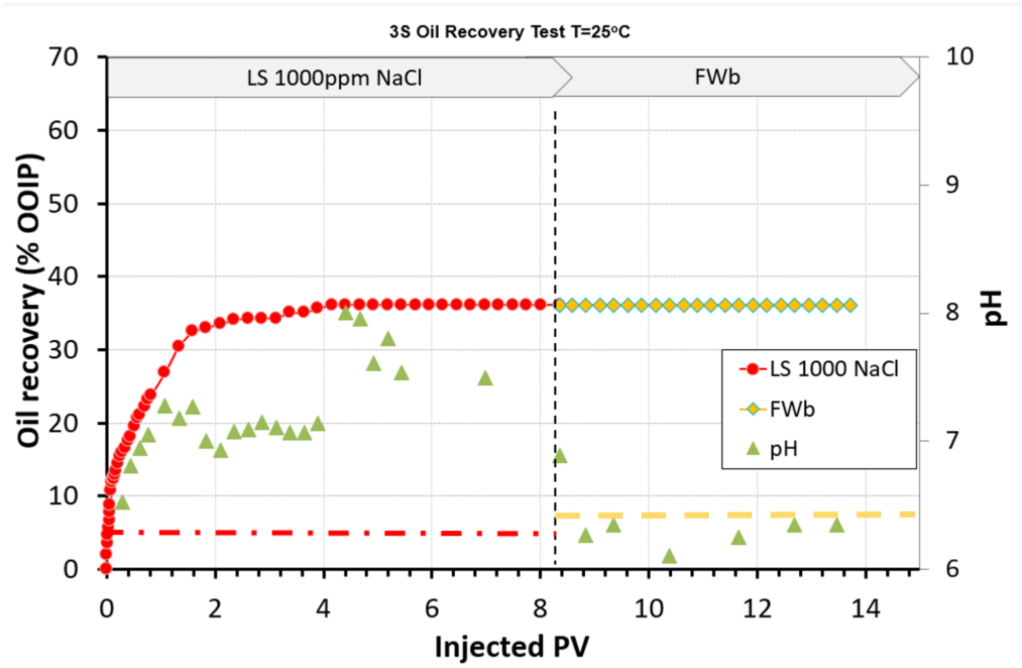


Figure 15: Oil Recovery Test on core 3SR

The first oil recovery test was performed on core 3SR. Low salinity water was injected in secondary mode and Formation water in tertiary mode. The injection rate was 4PV/D, which is a quite common rate used by industry. The test performed at 25°C, with a backpressure and confining pressure 7bar and 20bar respectively. The results in Figure 15 show that an ultimate recovery plateau of 36% of OOIP was achieved after 5PV injected. After reaching a plateau with Low Salinity Water, the injected brine switched to Formation Water. After 6PV of injected Formation Water, no extra oil production was observed. In this case pH showed a good response which means that cation exchanges took place in the porous system. The increase was close to one pH unit and when the injection brine switched to Formation Water the pH of the effluent returned to the initial pH bulk value.

During the oil recovery test, differential pressure data were recorded. As Figure 16 shows, at the beginning of the test we had an average differential pressure value around 25mbar. After the water-breakthrough the value dropped down to 13mbar and when the oil recovery plateau was reached with the Low Salinity Water, differential pressure stabilized at 9mbar. After switching to Formation water brine we notice a small increase in differential pressure average value. That can be explained by the Darcy law and the viscosities of the two injected brines. FW viscosity is almost two times higher than the viscosity of LS. An interesting differential pressure behaviour is presented during the first 5PV injected, where the dP plot seems more scattered. This is an indication of wettability alteration process, as the Low Salinity water starts to imbibe to the smaller pores of the porous system.

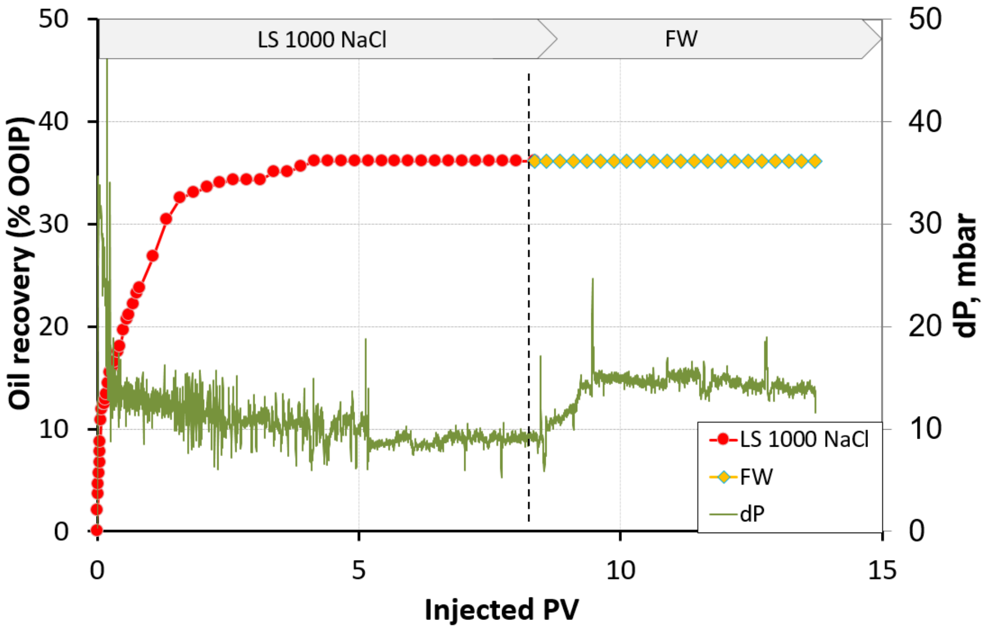


Figure 16: Oil Recovery Test on core 3SR with differential pressure data

4.2.2 Oil recovery test on sandstone reservoir core 4SR

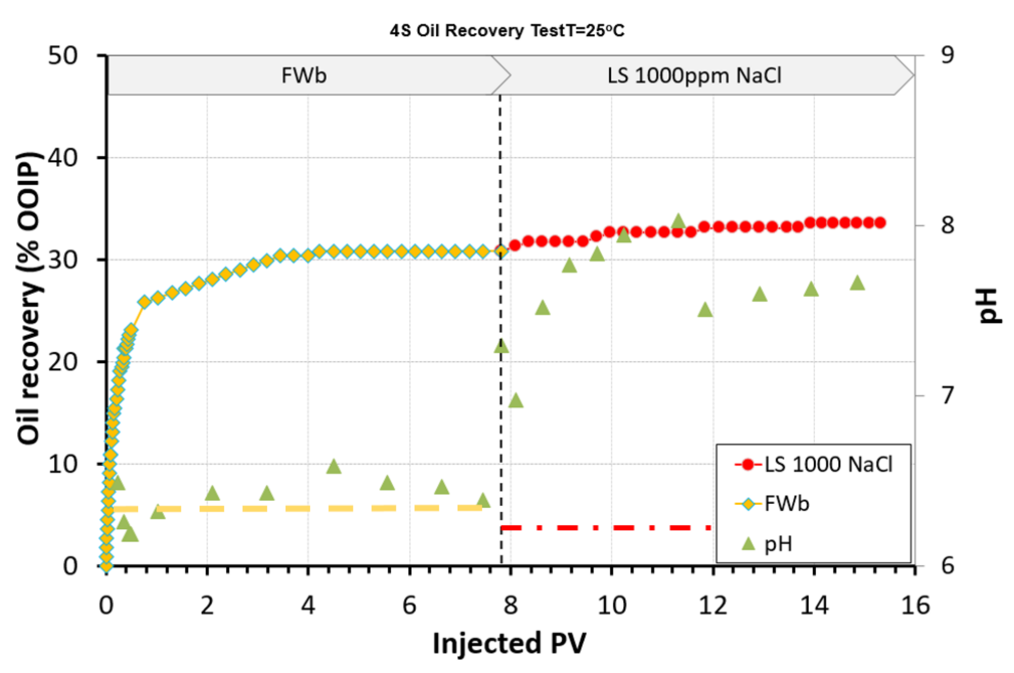


Figure 17: Oil Recovery Test on core 4SR

Next oil recovery test was performed on core 4SR. This time the injection sequence was reversed. The core was flooded with Formation Water in secondary mode and with Low Salinity water in tertiary mode. The injection rate was 0.078ml/min which is equal to 4PV/D. For the oil recovery tests, reservoir conditions were reproduced (Temperature=25°C,Confining pressure=20bars and back-pressure=7bars). The results from the core 4SR are shown in Figure 17. After 4PV of injected Formation Water oil recovery reached the plateau of 31% of OOIP. Replacing FW brine with Low Salinity water resulted in an increase in oil recovery with ultimate recovery plateau of 34% after 15PV injected. pH showed a better response than the previous core with the increase of 2 pH units approximately. During the FW injection the pH value of the effluent was equal with the pH bulk value. The flooding of the core stopped when the production was a clear effluent of water.

From the differential pressure data in Figure 18 we can observe the smooth decreasing performance of the dP curve without the scattered behaviour which was observed on the previous core. Differential pressure stabilized at 15mbar and the oil production stopped. In accordance with the plot, the displacement of the oil during the FW flooding looks like a "piston" like displacement. Differential pressure dropped down to 7mbar when Low Salinity water was injected.

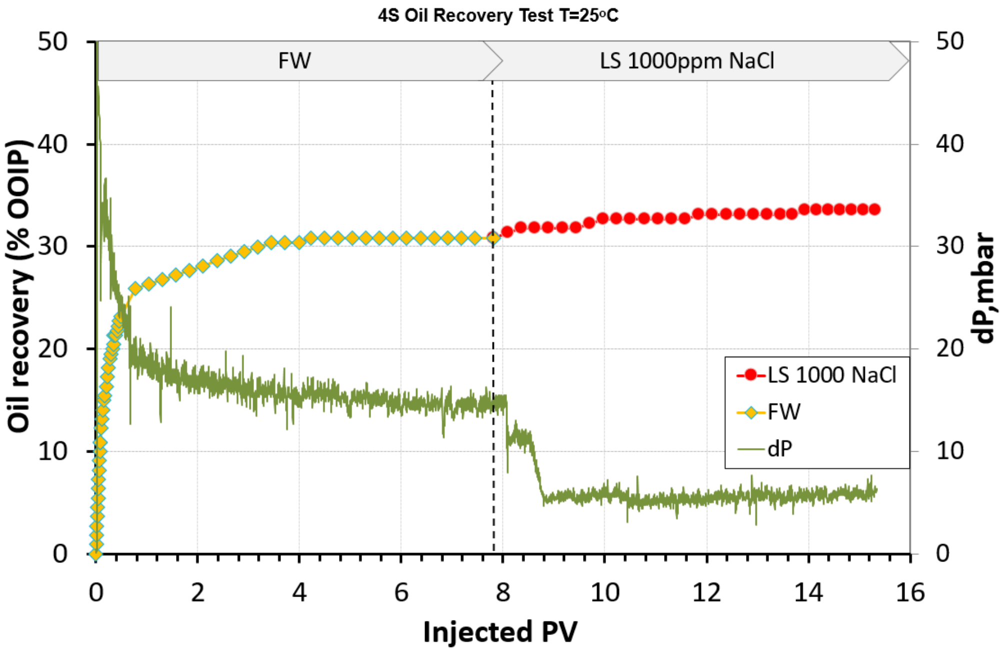


Figure 18: Oil Recovery Test on core 4SR with differential pressure data

4.2.3 Oil recovery test on sandstone reservoir core 3SR2

After the first restorations of the cores and the first oil recovery tests, which showed positive results for Low Salinity water flooding, the decision was made to restore the cores one more time and evaluate the reproducibility and the reliability of the experimental results. The second restoration was made by exactly the same restoration procedure followed for the first restoration.

The restored core 3SR2 mounted in the Hassler core holder and the oil recovery test started with purpose to minimize any possible errors due to the heterogeneity between the two cores. At the last oil recovery test for core 3SR, Low Salinity water was injected in secondary mode. For this oil recovery test, the sequence of the injected brines switched, allowing as to directly compare the oil recoveries from secondary and tertiary flooding mode on the same core.

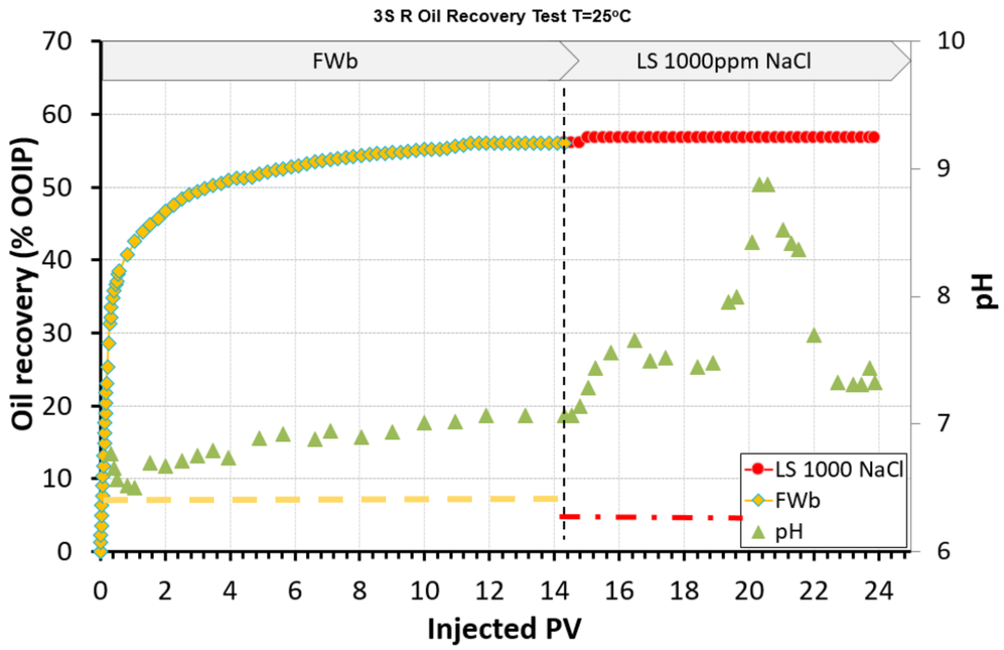


Figure 19: Oil Recovery Test on core 3SR2

In Figure 19 are presented the results from oil recovery test on core 3SR2. An unexpected oil production of 55% OOIP after 14PV of Formation Water injection was produced. After switching to Low Salinity water, only an extra 1% of oil was produced. During the Formation Water injection, pH response almost reached 1 pH unit. This high pH response while the injected brine was Formation Water doesn't follow the same pattern as the previous oil recovery tests. Regarding Low Salinity water injection the pH values show a normal increase after Formation Water flooding. At 19PV a rapid increase of pH values can be observed. It is important to mention that pH is a very sensitive measurement and it can be affected by a lot of factors. The attempt to make conclusions for this rapid increase could lead to speculations. The main observation for the development of pH values during the oil recovery test is that, from acidic values during Formation water injection the pH values goes to the alkaline side during Low Salinity injection.

In Figure 20 are shown the recorded differential pressure data during the oil recovery test. It is easily observed that the differential pressure curve does not follow a clear trend. At the beginning of the test the differential pressure is equal to 18mbar which is similar with the differential pressure recorded from the last tests. After 4PV of Formation Water were injected the differential pressure drops to 0mbar and starts to build up again until 160mbar.

At 9PV a big pressure drop occurs and then the differential pressure started to build up with exponential rate until 17PV.

After that, the differential pressure data present a very scattered response and can't be explained by the physicochemical procedures that take part within the studied core material. The scattered differential pressure image it's possibly due to a technical error as a blockage within the production lines.

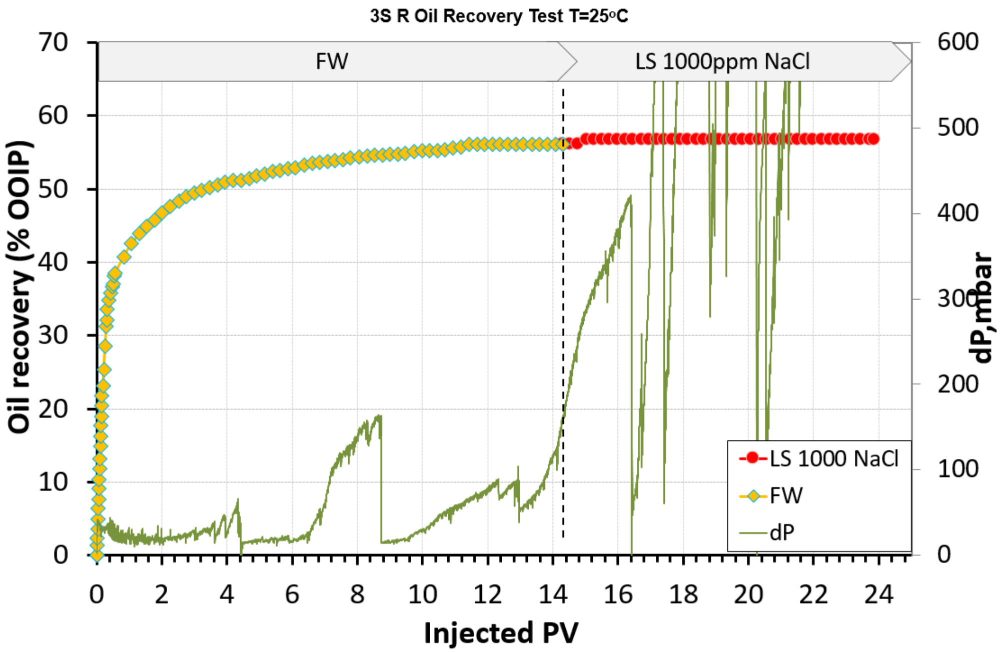


Figure 20: Oil Recovery Test on core 3SR2 with differential pressure data

4.2.4 Oil recovery test on sandstone reservoir core 4SR2

After the second successful restoration of the core 4SR it was time to test the core with Low Salinity water injection in secondary mode. Unfortunately, in a very early stage of the experiment, a blockage in the outlet distributor was occurred. After the depressurization of the system and the unblock of the distributor, the decision to continue the experiment was taken.

After 5PV of injected Low Salinity water the oil production reached the plateau with 41% of oil recovered. After switching to Formation Water, no extra oil production was recorded. The effluent pH values showed an increase close to 2 pH units from the Low Salinity water injection. When the brine was switched to Formation Water the pH values returned close to the bulk pH values.

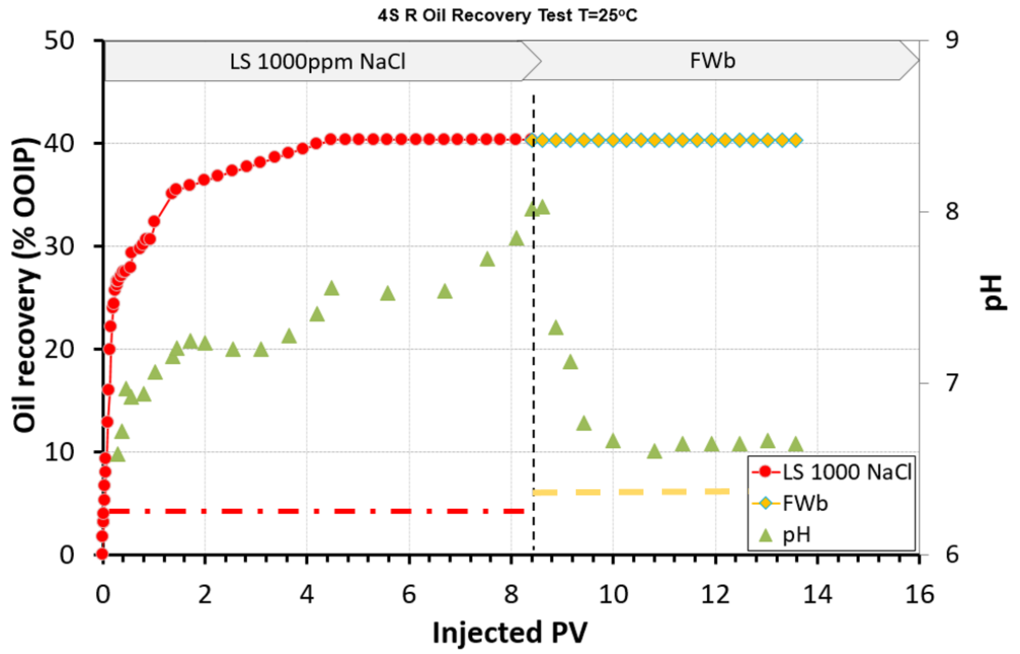


Figure 21: Oil Recovery Test on core 4SR2

Regarding the differential pressure data, we can easily detect the blockage of the outlet distributor that happened after 1.5PV of Low Salinity water was injected. At the beginning of the oil recovery test the differential pressure was at 10mbar, which was quite common for the previous tests also. After 6PV of injected Low Salinity water the differential pressure dropped to 0mbar, which means that a temporary blockage happened. At 9PV the temporary block happened again and then the differential pressure increased and stabilized at 8mbar until the end of the test.

Despite the recovered data after the major blockage, differential pressure data showed an abnormal image. The pressure drops to 0mbar and the main blockage in the outlet distributor prevent us to make trustworthy conclusions from this oil recovery test.

The solution was to restore the core once more and repeat the test. After the restoration of the core with the exact same way, as has been done the previous two times, the core 4SR2 was ready for the final oil recovery test.

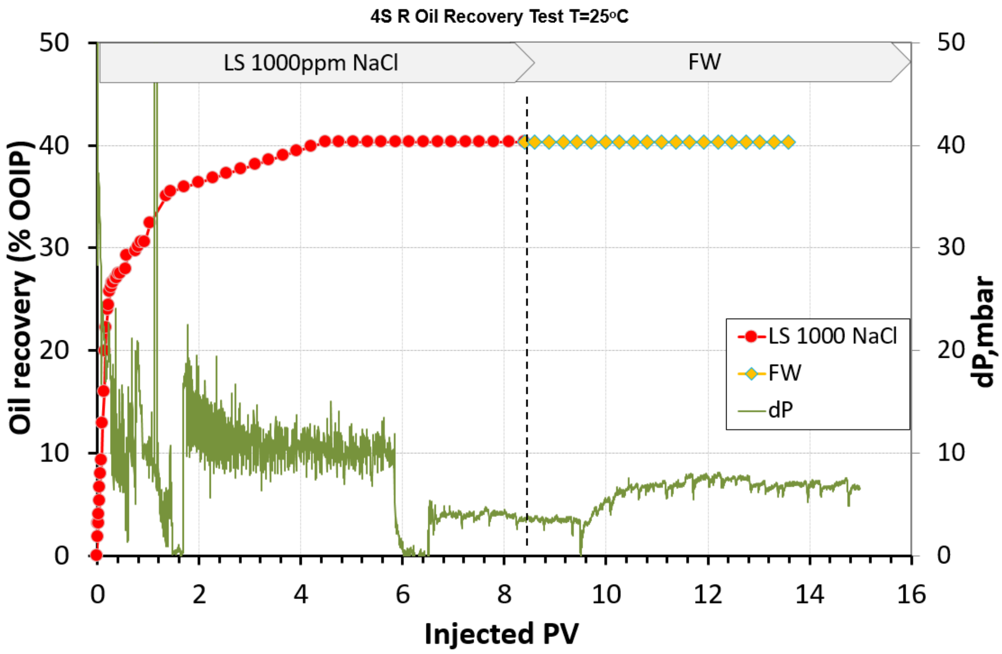


Figure 22: Oil Recovery Test on core 4SR2 with differential pressure data

4.2.5 Oil recovery test on sandstone reservoir core 4SR3

The last oil recovery test was performed on the three times restored core 4SR3. The oil recovery test was carried out with the same flooding sequence as core 4SR. Low Salinity water was injected in secondary mode, Formation Water injected in tertiary mode and at the last step of this test, a high injection rate Formation Water was injected to observe any possible end effects.

The results in Figure 23 show that the ultimate oil recovery plateau of 40% of OOIP was achieved during the first 21PV of Low Salinity water injection. The Low Salinity flooding continued for 5PV more without producing any extra oil. This was the longest Low Salinity water flooding, for plateau to be reached. Previous oil recoveries showed that the maximum flooding to reach plateau was 14PV of injected brine. Replacing Low Salinity water with Formation Water led to non-production of extra oil. From literature review to decrease any possible outlet end effects, the length of the flooded system, the rate of injection or the fluid viscosities should be increased [Kyte and Rapoport, 1958]. For this reason, after the Formation Water flooding, the core was flooded with four times higher injection rate (16PV/D). During the high rate injection flooding, no extra oil recovered after almost 24 hours.

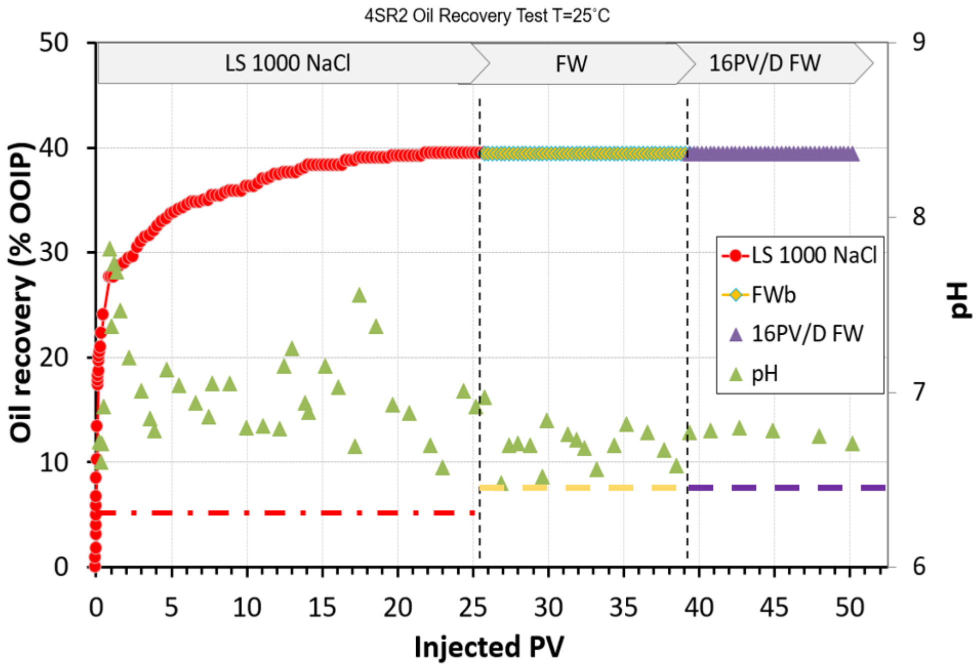


Figure 23: Oil Recovery Test on core 4SR3

pH values present a lower response in comparison with the previous oil recovery tests for core 4SR during Low Salinity water flooding. After three restorations of the core, the majority of the pH values are close to the neutral pH scale (pH=7). Through Formation Water injection, pH values showed a similar behavior with the previous oil recovery tests.

Concerning the recorded differential pressure data from oil recovery test on core 4SR3 it is very difficult to make conclusions. In Figure 24, differential pressure data show a very scattered image. During Low Salinity water injection the differential pressure values varies from 7mbar to 35mbar. Despite the scattered image, it seems that is a trend around 9mbar. On the other hand, differential pressure data during Formation Water injection show a chaotic behavior in which, no trend can be observed. The differential pressure data values are between 0mbar to 130mbar. The reason for this differential pressure behavior can be the high concentration of grains close to outlet distributor or within the back-pressure valve, affecting the proper operation of the experimental setup.

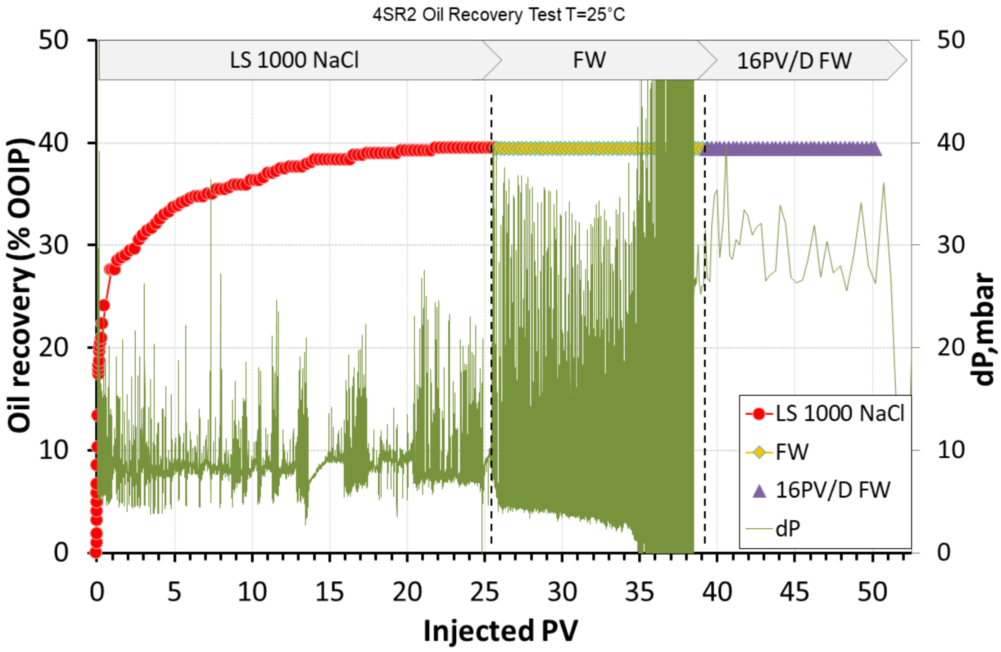


Figure 24: Oil Recovery Test on core 4SR3 with differential pressure data

4.3 Discussion for cores 3SR2,4SR2,4SR3

Sandstone cores 3SR,4SR,4SR2 presented very erratic behaviours during the oil recovery tests. Some blockages and big differential pressure drops affected the experiments and made the experimental results questionable and not trustful. The loosely consolidated condition of the cores lead to a lot of blockages due to intense particle mobilisation within the cores. Even at the cleaning stage of these cores, blockages in outlet production lines were observed. These cores were on the second or third restoration which indicates that the continuous core restorations, do not lead to the initial conditions of the material. The heterogeneity, particle mobilisation, the loosely consolidated cores and the indications for failed restorations of the cores will force us to exclude these three oil recovery tests from the final comparison.

4.4 Comparison between cores 3SR&4SR

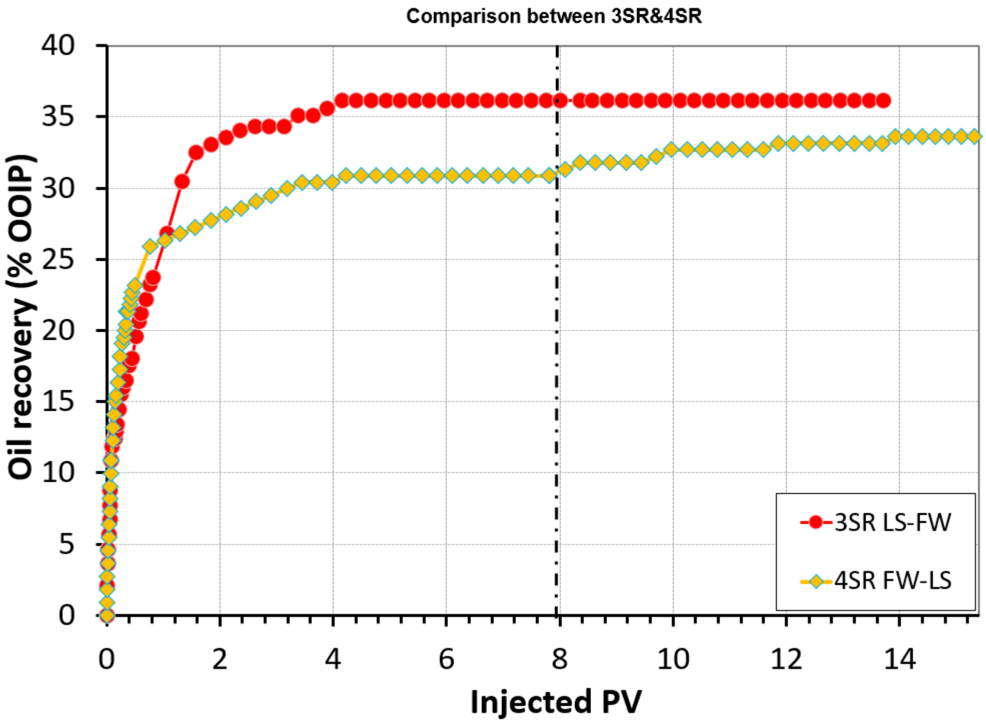


Figure 25: Comparison between cores 3SR and 4SR. Core 3SR was flooded with LS in secondary mode and core 4SR was flooded with LS in tertiary mode.

For comparative analysis, the results from oil recovery tests on cores 3SR and 4SR after the first restoration, were plotted in Figure 25. After the evaluation of the recorded data these cores performed without any indication for failure so they are reliable to make comparisons and conclusions for this thesis. For core 3SR (red line) Low Salinity water was injected in secondary mode for 8PV and then, Formation Water was injected in tertiary mode until the end of the experiment. For core 4SR (yellow line) Formation Water was injected in secondary mode for 8PV and then, Low Salinity water was injected in tertiary mode. The difference between the two ultimate oil recoveries is 3%. An important observation was that Low Salinity Water in secondary mode showed increased ultimate oil recovery compared with Low Salinity water flooding in tertiary mode. More in detail, Low Salinity water in secondary mode reached the oil recovery of 36% and Formation water in secondary mode reached 30%. Water-Breakthrough occurred almost at the same amount of injected brine. A summary of the oil recovery tests from cores 3SR and 4SR is presented in Table 8.

Table 8: Summary of experimental data for cores 3SR&4SR

		Oil recovery (%OOIP)	
Core	Injection sequence	Oil recovery during secondary mode	Ultimate recovery
3SR	LS - FW	36	36
4SR	FW - LS	30	33

5 Conclusions

The performed experimental studies were focused on the evaluation of the potential EOR by Low Salinity Smart water in a reservoir with unfavorable initial conditions. The experimental study was evaluated by comparing a series of oil recovery tests performed on reservoir cores, sampled close to each other. The main observations and conclusions can be summarized as follows:

1. Low Salinity water can improve the oil recovery even if the initial conditions are not favorable. Low Salinity water in secondary mode showed better performance than in tertiary mode.

2. The nature of the cores did not allowed repeated restorations. Strong particle mobilisation and changes of wettability of the cores to more water-wet state after every restoration were observed.

3. A significant increase in effluent produced water pH from initially acidic environment to slightly more alkaline environment, were observed in all oil recovery experiments during Low Salinity water injection.

4. In our case of study, Low Salinity water it is easily accessible due to enough source of fresh water, so it is a highly recommended waterflooding method.

5.1 Future work

Based on the experiments performed, results and observations made in this thesis. The following suggestion can be considered for the future study plans:

1. The evaluation of Low Salinity Smart Water EOR potential for hybrid EOR, i.e. combining with polymers or surfactant
2. The investigation of reduction in scaling during oil production operations using conventional Formation Water flooding versus Low Salinity Water flooding.

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