UTILISATION OF LOW SALINITY WATER INJECTION IN MARGINAL FIELD DEVELOPMENT AND OPERATIONS FOR CARBONATE'S RESERVOIRS

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APRIL, 2024

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A RESEARCH WORK SUBMITTED TO THE DEPARTMENT OF
PETROLEUM ENGINEERING, FACULTY OF ENGINEERING,
UNIVERSITY OF BENIN, BENIN CITY

IN PARTIAL FULFILMENT OF THE REQUIREMENT
FOR THE AWARD OF BACHELOR OF ENGINEERING

APRIL, 2024.

CERTIFICATION

This is to certify that this work was carried out by **GODSTIME OKOENE OSEBHAHIEMEN, MAT. NO. ENG1805572**, of the Department of Petroleum Engineering, Faculty of Engineering, University of Benin, Benin City, Edo State, Nigeria.

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DEDICATION

I would like to dedicate this research work to my dear parents, Mr and Mrs Donald Okoene, without them, I'm meaningless. They instilled in me a desire to learn and made sacrifices so I would have access to high quality education from an early age. Also, this research work is dedicated to my close friends and course mates who have always supported me throughout my years of studies.

To God Almighty, for his continuous strength and grace, he supplied to me during the process of this research.

ACKNOWLEDGEMENT

First of all, I would like to express my gratitude to God Almighty for enabling me to complete this research work. My sincere gratitude also goes to my project supervisor Dr. A.A Adeniji for his invaluable support and guidance through review, encouragement and constructive criticism throughout the period of this research work.

I would also like to thank who has always been a major source of motivation to me in my petroleum engineering journey. I also convey my gratitude to the respectable ad honourable teachers for putting all efforts in teaching us and ensuring we get the best training in modern day software technology used in the industry. Special thanks go to the Project Coordinator, Dr. O.A Taiwo for his continuous love and guidance towards me, all these years of my stay in school. To my friends Osariemen Manasseh, Alleh Ojo James, Obamen James, thanks a lot for believing in me.

Last words are lacking to express my feelings and indebtedness to my affectionate Parents and siblings for their love, support and unending prayers and encouragements which stood by me mentally and spiritually during the period of the research work.

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ABSTRACT

With a variety of EOR methods explored, the discovery is in tune with Low-salinity water Injection (LSW) as a promising enhancement of the rate at which oil is recoverable from the reservoir. However, the comprehensive understanding of the principal mechanism directing this technique, has not been fully harnessed, causing the difficulty of creating the most favourable salinity condition, and the ionic formation, required for the injected solution. However, a wider school of thought holds that, the driving mechanism in LSWI of the carbonate's reservoir, is vast. Though, the modification in wettability is seen as the primary mechanism driving oil to a more recoverable state, with most literature review proving this, how it works is up for a good intelligent discuss.

This literature attempts to reviews a variety of working states of LSWI, from studies, field investigations, as well as individual recommended mechanisms affecting the oil–rock–brine contact interfaces. Furthermore, the uniqueness of this project, is to provides an extensive evaluation of previous treatises, on LSWI in carbonate reservoirs, the analyses, applications, as well as achievements that have given ground for a mastery of the difficulty of the multicomponent systems and the potential benefits it has on the oil production industry.

CHAPTER ONE

INTRODUCTION

1.1 Background of study

Increasing the profitability and sustainability of the oil industry, depends largely as a function of the maximized amount of crude drilled from existing reservoirs. Although from studies (Maryam H. Derkani, 2018), it is seen that 70% of the oil and gas is not recoverable by conventional recovery method. But an increase in the global oil recovery factor by just 1% has the potential to produce an extra 88 billion barrels of oil, which equals three years of annual oil production, at current rates (Maryam H. Derkani, 2018). Primary oil recovery allows the reservoir to use its natural pressure to push oil out of the well, which gives a rating amount of 10% of the oil deposits in the reservoir. For the secondary oil recovery phase, which is also known as improved oil recovery (IOR), the deployment of waterflooding is utilize to supply the needed pressure support and improve the sweep efficiency (Terry, R.E., 2001). With both methods of conventional oil recovery deployed, only a maximum of 30-35% of the available hydrocarbon from oil reservoirs is extracted (Kokal, S.; Al-Kaabi, A., 2010). The tertiary oil recovery phase, also known as enhanced oil recovery (EOR), chemicals flooding (polymers, alkaline, and surfactants), miscible flooding (carbon dioxide, liquefied petroleum gases, methane, and nitrogen), thermal flooding (steam), microbial flooding (microorganisms), or a combination of them, are introduced, which help to push the recovery of the flow of the oil trapped in the reservoir rock by reducing both the surface tension and viscosity of the crude oil (Kokal, S.; Al-Kaabi, A., 2010). The application of each of these techniques depends on the various factors of the reservoir, including viscosity of the crude oil, the depth of the reservoir, which could be arrived at, when there are changes in the fluid's properties, its interfacial energy singly or in multiple. An additional 5–20% of the original oil in place (OOIP) is recoverable by EOR, which shows a paotential improvement up to 50–70% depending on specific reservoir conditions (Sheng, J. 2010).

The secondary oil recovery phase depict how water waterflooding (formation water) is conventionally used to keep the reservoir pressure above the bubble point pressure of the oil, allowing for an effective sweep efficiency, and displacing oil by water utilizing the advantage of viscous force (Kokal, S.; Al-Kaabi, A., 2010).

Low Salinity Water Injection LSW, also known as designer waterflood, advanced ion management, and smart waterflooding, involves injecting brine with controlled ionic concentration and composition (also known as smart water or dynamic water) into the well (Robertson, E.P. 2007). The devised formulation alters the wettability conditions of the reservoir rock, destabilizing the initial oil–rock–brine system equilibrium, allowing for displacing of oil (Sheng, J. 2010). LSW can produce up to 10% extra crude oil compared to simple waterflooding methods (Kokal, S.; AlKaabi, A., 2010). During LSW, no expensive chemicals are added, showing its cost effectiveness and environmentally friendliness. As well, the technique has no associated injection issues and gives up to 10% extra crude oil compared to simple waterflooding methods (Sheng, J. 2010).

The LSW, undergoes nanofiltration and reverse osmosis water treatment. Nanofiltration process involves the removal of contaminations, such as sulphate, as well as other divalent ions, are to decrease the hardness of the brine and the probability of membrane blockage in the reverse osmosis process (Sheng, J. 2010). The reverse osmosis process utilizes the reduction of salinity, by annihilating the salt particles in the brine. This technique has the following advantages such as lowering operating and capital costs compared to most EOR processes (McGuire, P.; Chatham, J.; Paskvan, F.; Sommer, D.; Carini, F, 2005) its applicability is from the early stages of the oil recovery process (unlike EOR techniques), and yet, will be effectively applied during the late life cycle of the reservoir (Kazankapov, N.,2014: Yousef, A.A.; Al-Saleh, S.; Al-Jawfi, M.S., 2012).

Studies shows that about 60% of the world's oil reserves are domiciled in carbonate fields (limestone, chalks, and dolomites), and a vast portion is located in the Middle East. Carbonates are sedimentary rocks formed of minerals, including those predominately containing carbonate ions, e.g., calcite and dolomite (Myint, P.C.; Firoozabadi, A. 2015). They also include aragonite, anhydrite, ankerite, quartz, chert, glauconite, pyrite, phosphate, clay minerals, and siderite. Originally, the surfaces are that of water-wet, which are containing of positively charged surface electrostatics in a great range of pH. However, the adsorption of the negatively charged carboxylic particles (–COO-), clinging unto the positively charged carbonate rock surfaces, may lead to a mixed-wet or oil-wet characteristics (Karimi, M.; Al-Maamari, R.S.; Ayatollahi, S.; Mehranbod, N., 2015; Myint, P.C.; Firoozabadi, A. 2015).

Studies have shown works whereby improved oil recovery in carbonates was achieved by a considerably higher salinity of injected brine (up to 33 kppm) (Fathi, S.J.; Austad, T.; Strand, S. 2010). Vast studies from different literature works have proven that carbonate rock can have their wetting properties altered, by increasing the concentration level of the divalent anion (e.g., SO_4^{2-},), decreasing the concentration of divalent cations (Ca^{2+}, Mg^{2+},), reducing the salinity of brine, or removing sodium chloride (NaCl) from seawater (Awolayo, A.; Sarma, H.; Al Sumaiti, A.M., 2014). For example, it was reported that the remover of sodium chloride from the injection brine and increasing SO_4^{2-} concentration, at high temperature (above 90 ◦C), could lead to the modification of the rock wettability to a great amount, improving oil recovery from 37% to 62% of OOIP from chalk cores, compared to original seawater flooding (Fathi, S.J.; Austad, T.; Strand, S., 2011). Based on the characteristic nature of the crude oil, the reservoir state, as well as the composition of the brine, various mechanisms have been established to be deciding factors for the evaluation LSWI in carbonate reservoirs. The proposed primary mechanisms include fines migration, rock dissolution, reduction of interfacial tension (IFT), fluid–fluid interaction and formation of microemulsions, multicomponent ionic exchange (MIE), and expansion of electric double layer (EDL) (Purswani, P.; Tawfik, M.S.; Karpyn, Z.T., 2017). The desirable state for the improvement of the oil recoverable from the reservoir, would hinge on the modification of the wettability of rock, which is ascertained by the degree of the rock-fluid interfaces thickness and stability. As an accepted school of thought, LSW bring about an equilibrium in thermodynamics among the rock-oil-water interfaces and formulating a new chemical equilibrium, which establish the wettability, improve oil recovery from reservoir rock pores. This modification in the wettability properties is affected by temperature, pressure, pore water and crude oil chemistry (Hiorth, A.; Cathles, L.; Madland, M., 2010). Hence, a vast understanding of the nature of the interactions at oil–rock–brine interfaces colloidal system, the physiochemical principal mechanisms used in LSW, as well as detection of its applicability to a specific type of reservoir, would give sight to what this technique is capable of implementing, when utilize in the carbonate reservoir.

1.2 Aim

The purpose of this research is to examine the effects of lowering the salinity of the injected water in carbonate marginal field.

1.3 Objectives

The main goal of incorporating low-salinity water in the development and operation of marginal fields is to maximize oil recovery while considering economic and environmental factors. The specific objectives include

1. **Improving Oil Recovery Efficiency:**

Studying the impact of injecting low salinity water on increasing oil recovery in marginal fields through experiments and studies.

Analyzing the reasons behind the enhanced displacement of oil and improved sweep efficiency when using low salinity water, such as alteration in wettability, reduction in interfacial tension, and migration of fines.

2. **Reducing Production Costs:**

Evaluating the economic feasibility of adopting low salinity water flooding in marginal field development by assessing the associated capital and operating expenses.

Analyzing the potential cost savings from using low salinity water compared to traditional enhanced oil recovery methods like polymer flooding or steam injection.

Identifying opportunities to optimize injection and production strategies to minimize energy consumption, water usage, and overall operational costs.

3. **Preventing Formation Damage:**

Investigating the impact of low salinity water on reservoir properties such as permeability, porosity, and clay mineralogy to assess the risk of formation damage during injection and production operations. By optimizing the chemistry of water and injection parameters, we can prevent damage like scale deposition, clay swelling, or fines migration.

To ensure the long-term integrity and productivity of marginal field reservoirs, we implement monitoring and surveillance techniques that detect and address potential formation damage issues in real-time. We establish best practices and guidelines for the implementation of low-salinity water flooding in marginal field development and operation. This facilitates the transfer of knowledge and technology within the industry.

By pursuing these objectives, we aim to unlock untapped hydrocarbon reserves, maximize economic returns, and promote sustainable energy production practices in the oil and gas industry.

1.4 Research questions

This research work aims to answer the following questions:

1. What are the mechanisms governing the improved oil recovery observed with low salinity water flooding in marginal fields?
2. How do the composition and salinity of the injected water influence oil displacement efficiency and sweep efficiency in marginal field reservoirs?
3. What are the economic considerations and cost-benefit analysis associated with implementing low salinity water flooding compared to conventional enhanced oil recovery methods in marginal fields?

1.5 Problem statement

The oil industry is always exploring innovative methods to improve the recovery of oil from natural reservoirs, in the event that conventional methods have reached their limits. This drive of need has brought on low salinity water injection, which has a great potential to significantly increase oil recovery rates. Although, very promising, this method has its complexes in application, leading challenges in its adoption and optimization.

One of the obstacles impending the complete implementation of this method is the absence of a comprehensive understanding regarding the principal mechanisms governing the efficacy of low salinity water injection. Although this method's recovery rate has been tested, and has shown potentials to alter the wettability of reservoir rocks, reduce interfacial tension, and mobilize remaining oil, the specific mechanisms and their interactions within diverse reservoir conditions remain inadequately understood. The implementation hence, is hindered, considering this knowledge gap.

Other complexes presented by this technique could be such that emerge from the variations in the different factors of the reservoir, which will hence require the tailoring of this approach to optimize low salinity water injection to specific field. The factors including rock mineralogy, pore structure, and fluid properties.

Furthermore, the understanding of the cost of water treatment, injection infrastructure, and potential production gains, must be properly accessed to check the economic viability of the procedure. Without this being properly understood, the long-term benefits, the advantages over other EOR, stakeholders may be reluctant to invest in adopting low salinity water injection as a primary recovery strategy.

A comprehensive researched effort is therefore needed to bring about clarity to the underlying mechanisms, optimize operational parameters, and develop predictive models that can guide the successful implementation of low-salinity water flooding for an enhanced recoverable oil. A multidisciplinary understanding approach that drives the utilization of different field concept is key.

This literature tries to bridge the knowledge gap surrounding low salinity water injection, enabling its effective and economic viability implementation as a sustaining solution for optimizing oil recovery from mature reservoirs.

CHAPTER TWO

LITERATUE REVIEW

For a very long time, numerous oil fields have used water flooding to increase oil recovery. For many years, the primary concern with the water flooding design process was formation damage from water injection. To ensure that there was no chance of formation damage, oil firms tested the compatibility of injection and formation waters separately.

The eventual oil recovery from water floods is much enhanced by changing the property nature as well as the salinity of the water, according to recent results of considerable research. Numerous mechanisms, including wettability modification, fine migration, ionic exchange, emulsion, and interfacial reduction, have been recommended in this treatise.

The majority of reservoirs employed high salinity water sources, such as seawater and aquifer water, for water flooding. The impact of water chemistry, or the quantity and makeup of salt in the water used during injection process in oil recovery, has been examined during the past ten years. Several research were taken into consideration to look into the impact of injecting brine with less salinity to enhance waterflooding performance.

In the low-salinity waterflooding procedure, brine with a decreased ionic strength or salt concentration is injected. Compared to formation water or seawater, the ionic strength is usually much lower, ranging from 1000 to 5000 ppm. The equilibrium thermodynamics among the oilbrine-rock system, which has been instituted over a time geology, is shifted by the low salinity waterflooding, which tends to favour an increased in oil recovery.

Numerous studies have been published indicating that the ions responsible for the alteration of wettability in the brine injection process are sulphate (SO_4^{2-}), magnesium (Mg^{2+}), and calcium (Ca^{2+}) (RezaeiDoustet al., 2009). As the temperature rises above 100C, these ions' modification activity increases. The effects of Ca^{2+}, Mg^{2+}, and SO_4^{2-}, on oil recovery from chalky limestone with low water wetness in a spontaneous imbibition process have been investigated by Zhang et al. (2007). The outcomes amply proved that raising SO_4^{2-} in the midst of (Mg^{2+}), at greater temperatures would largely enhance the recoverable oil. Since there was no discernible increase in oil recovery at either 70 or 100°C when NaCl was present, the researchers came to the conclusion that sulphate could not alter the wettability to enhance spontaneous imbibition at low temperature. (Zhang et al. 2007). However, when Ca^{2+}, and/or Mg^{2+} with sulphate were present, there was a notable increase in the imbibition of water, which was attributed to the system becoming more water wet. Zhang et al. (2007) proposed a chemical mechanism for altering wettability, suggesting that if injected water contains Ca^{2+}, and SO_4^{2-}-, sulphate ions will adsorb onto the positively charged chalk surface, leading to a reduction of the positive surface charge; in this scenario, electrostatic repulsion will decrease and more Ca^{2+}, can be attracted to the surface (RezaeiDoustet al., 2009). (RezaeiDoustet al.2009) suggested that Mg^{2+}can displace the Ca^{2+}, that is connected to the carboxylic group, in the same way that Mg^{2+} can. It has been suggested that the clay particles, which carry a negative charge, create a diffuse double layer. This occurs when the clay is surrounded by positively charged water molecules in the aqueous phase. To cause an increase in the double layer's thickness, the saline nature of the water has to be reduced. Within the double layer, the water molecules become rigid or "quasi-crystalline," resulting in a rise in the oil phase relative permeability as it gets more water wet. However, if there is hardness present in the system, such as calcium or magnesium ions, there will be a possibility for binding of the negatively charged oil surface with the clays through an intermediate like calcium ions. Berg et al. (2009) conducted experiments that confirmed wettability modification of clay surfaces as a microscopic mechanism for low salinity flooding. They annulled emulsification, reduction of interfacial tension, fines migration, and selective plugging of water-bearing pores through clay swelling as relevant mechanisms. They identified wettability alterations as the main mechanism and mentioned their efforts to differentiate between the expansion of the double layer and cation exchange, or whether a layer of clay detaches with each oil droplet. They also noted that oil has been released in low salinity systems where clay de-flocculation and formation damage occur. For Montmorillonite clays, there is a salinity range to remove the oil without causing damage.

One of the newly developed EOR process, is the low-salinity water injection, which involves injecting brine (low salinity solution) that is reduced in divalent cations compared with the in-situ brine, into the oil reservoirs. Even with the increasing interest in LSWI, a comprehensive mechanistic theory has not been established. And, this is as a result of complexifying mechanisms and number of parameters underlying this technique. It is further suggestive that this technique may deploy a number of mechanisms, based on the reservoir conditions, and other circumstances.

2. Some of the factors affecting low-salinity water injection

Previous literature works, have suggested that specific reservoir conditions, oil–rock–brine properties, as well as the well pattern to be a factor for the enhancement of the oil recovery during LSWI in carbonates. A summary, giving a structure of the reservoir and injected brine parameters are stated, in this here.

2.1 Reservoir parameters

2.1.1 Formation water composition and pH

By affecting the initial rock wettability and interactions with the injected brine, the composition of the formation water in reservoirs and its pH influence the rate of the recoverable oil from the reservoir. When the charge of the rock-brine interfaces is affected by potential determining ions (PDIs) present in the formation water and pH of the formation water which is slightly basic, the result is the altering of the wettability properties of the reservoir rock (Montaron, B, 2009; Austad, T.; Strand, S.; Høgnesen, E.; Zhang, P., 2005), Though, there's the high buffer capacity of calcium carbonate from the formation water, the pH will remain the same, due to chemical equilibrium at the oil–rock–brine interface. Hence, the suggestive that the wettability modification based on the pH variation is temporary (Austad, T.; Strand, S.; Høgnesen, E.; Zhang, P., 2005). Table 2.1 clearly depicts the variation in composition of brine (formation water and seawater) in different regions, such as the Persian Gulf, Ekofisk and common areas (Sheng, J, 2013; Kasha, A.; Al-Hashim, H.; Abdallah, W.; Taherian, R.; Sauerer, B., 2015). The salinity of the formation water is excessively high (up to 250 kppm), as well as the concentration of Ca^{2+} ions present, while the concentration of the Mg^{2+} ions present is low. Furthermore, in the altering of the wettability conditions of the rock, SO_4^{2-} is known as the active anion. Though, due to the high concentration of Ca^{2+} in the formation water the concentration of SO_4^{2-} ions are very low, especially at high temperatures, leading to the precipitation of anhydrite (CaSO4) (Shariatpanahi, S.F.; Strand, S.; Austad, T., 2011). According to the studies of Shariatpanahi et al. (2011), when little amounts of SO_4^{2-} is dissolve in formation water, the interactions between them and rock surface using chalk cores at 20–130 ◦C shows that even little concentrations of SO_4^{2-} ions

(up to 2 mmol/L) present in formation water, can alter the wettability properties of the carbonate rock reservoir, making it more of the water-wet state. Therefore, to avoid the possibility of reservoir souring and plugging as well as maximize oil production from carbonate reservoirs, much attention must be given as regards the composition of the formation water in the carbonate field before designing the injected brine for LSW.

Type		**Seawater (ppm)**		**Formation Water (ppm)**		
Ionic Composition	Persian Gulf	Ekofisk	Common	Persian Gulf	Ekofisk	Common
Na^+	18,040	10,345	10,890	59,491	15,745	31,275
K^+	0	390	460	0	0	654
Ba^{2+}	0	0	0	0	0	269
Ca^{2+}	650	521	428	19040	9258	5038
Mg^{2+}	2160	1093	1368	2439	607	379
Sr^{2+}	10	0	0	0	0	771
SO_4^{2-}	4450	2305	2960	350	0	0
Cl^-	31810	18719	19766	132060	42437	60412
CO_3^{2-}	30	0	0	0	0	0
HCO_3^-	120	122	0	354	0	0
Total	**57270**	**33497**	**35872**	**213734**	**68050**	**98798**

Table 2.1. Composition of the formation water and seawater compared in different regions

(Sheng, J, 2013; Kasha, A.; Al-Hashim, H.; Abdallah, W.; Taherian, R.; Sauerer, B., 2015).

2.1.2 Initial water saturation

Initial water saturation (Swi) is determined as the amount of water adsorbed on the surface of rock porous channels per pore-volume and exist as free water in the pore space (Bódi, T, 2012). A study of the effect of initial water saturation on wettability alteration of reservoir limestone cores was studied by Strand, S (2008), showing an increase in oil recovery of reservoir limestone cores by increasing the initial water saturation from 9.1% to 14.8%. This experiment revealed the increase of the core with higher initial water saturation production of 15% compared with OOIP. Again, Puntervold et al. (2007) gave an assessment of a data range of initial water saturations, such as 100% oil saturation (Swi = 0), low initial water saturation (Swi = 10%), and high initial water saturation (Swi = 30–50%), which the produce a decrease in water wetness of chalk cores by decreasing the initial water saturation. By contrast, in their later published work (Puntervold, T.; Strand, S.; Austad, T., 2007), two different residual water saturations (10% and 22%) and a crude oil were used, the result showed that the difference in the recovery rate to equal. Hence, a suggestive that initial water saturation only has a little effect on wettability alteration of chalk cores.

2.1.3 Crude oil composition

The success of the LSW process depends on how well the composition of the crude oil was evaluated. The polarity in the functional groups of acidic and basic organic molecules in the crude oil, such as asphaltene and resins, is as a result of the different atoms of Sulphur, Nitrogen, and Oxygen, which can affect rock wettability. To a great extent, asphaltenes give their relevance in prediction of the chemistry as well as properties' nature of crude oil, which is as a result of their high degree density, aromaticity, and polarity nature of their component in the crude oil

(Mullins, O.C.; Sabbah, H.; Eyssautier, J.; Pomerantz, A.E.; Barré, L.; Andrews, A.B.; RuizMorales, Y.; Mostowfi, F.; McFarlane, R.; Goual, L., 2012). The acid number (AN), quantify the value of carboxylic particles in crude oil, which can be analyzed as the number of milligrams of potassium hydroxide necessary to reduce the effect of 1g of crude oil (mgKOH/g). The carboxylic particles in the crude oil can strongly affect the wetting properties of carbonate by the influence of the AN and the chemical properties (Fathi, S.J.; Austad, T.; Strand, S., 2011). According to Austad and colleagues (2009), the low salinity effect is dependent on a mixed-wet state, which would only increase as the AN of crude oil increases. Although, there was no direct correlation between the AN of a crude oil and the rate of improvement in oil recovery by LSW (Lager, A.; Webb, K.J.; Black, C.; Singleton, M.; Sorbie, K.S., 2008). Standnes and Austad (2000) revealed that oil recovery relates with water wetness and the AN, as the increase in either will cause a significant decrease in the other (**Figure** 2.1). Even though the base number (BN) of crude oils are believed to have a minor impact on wettability alteration, according to Puntervold et al. (2007) there will be an improvement in water-wetness of chalk when the BN of crude oil is increased with a given AN.

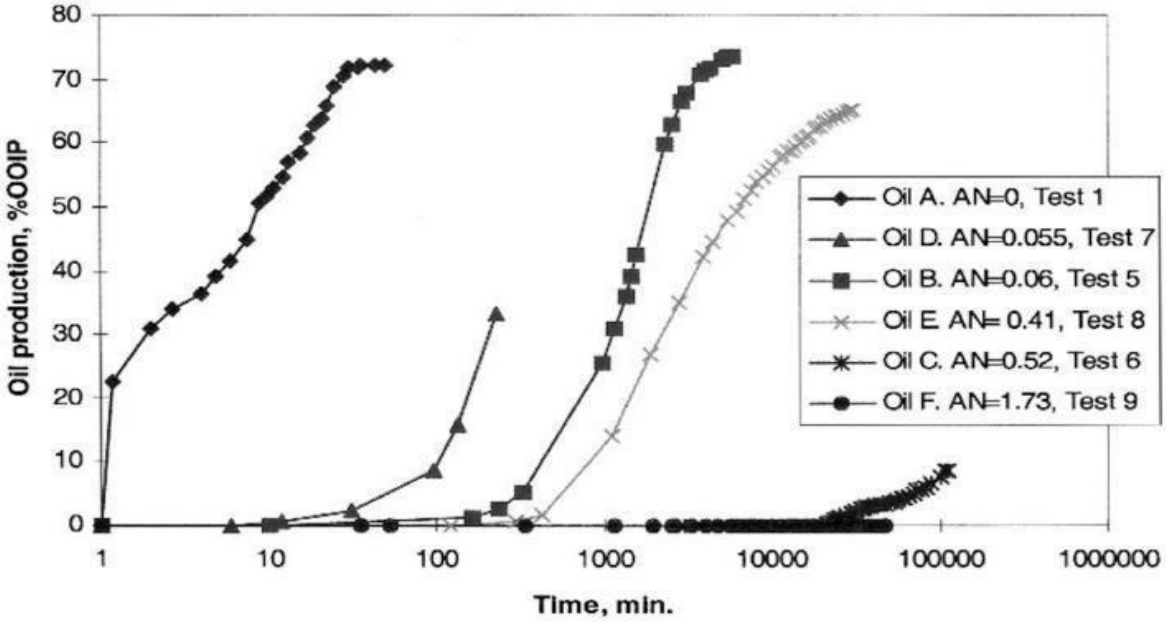


Figure 2.1 Oil production from a chalk core at 40 ◦C, when the core was saturated with crude oils with different AN. Reproduced from Standnes and Austad, J. Pet. Sci. Eng.; published by Elsevier, 2000

The systematic examination of effect of acidic material on wettability alteration of chalk was conducted by extracting water-soluble acids (naphthenic acids) from a crude oil a with high AN (Fathi, S.J.; Austad, T.; Strand, S.; Puntervold, T., 2010). Different chemical compounds such as (carboxylic acids, alcohols, SO_4^{2-}, sulphonates, amines, amino acids, and carbonylated polymers) on surface adsorption, and the subsequent alteration of the wettability of the carbonate minerals (calcite, dolomite, and magnesite), were evaluated by Thomas and co-workers to consider their effects (1993). It was reported that the surfaces of the carbonate rocks readily allow the adsorbing of organic compounds from both organic and aqueous solvents and fatty acid can be adsorbed from aqueous solutions irreversibly. Furthermore, the carbonate surface was more disposed to carboxylic acids and with a long straight chain stabilizing their adsorption, which was due to closed-packed hydrophobic layer, or polymeric structures interactions thereby supplying multiple sites, and hence, changing the rock wettability to strongly oil-wet. After studies of the effect of different fatty acids, such as short chain (heptanoic acid), long chain (stearic and oleic acids), and naphthenic acids (cyclohexane-pentanoic and decahydronaphthalene-pentanoic acids) on the wettability alteration of calcite crystal surfaces by Rezaei Gomari et al. (2006), it was shown experimentally that calcite surfaces are much more prone to altering by the long chain saturated stearic acid, as well as long chain unsaturated oleic acid, making it a more oil-wet state. Hence, it is suggestive that wettability modification of carbonate surfaces towards a more oil-wet state is a function of larger amount of AN of crude oil, and the long chain carboxylic acids.

2.1.4 Aging time, temperature, and pressure

Reservoir temperature is a key factor affecting the activation energy required for the chemical reaction for wettability improvement to occur by LSW (Strand, S.; Austad, T.; and colleagues, 2008). It is suggested that Carbonate rock reservoirs are more water-wet at higher temperatures (James Anderson, 2018) and the reservoir temperature and the AN of crude oil are related to each other: as the reservoir temperature increases, the AN decrease, due to increased decarboxylation of the acidic molecules at high temperature (James Anderson, 2018). A study was performed on the effect of aging time and temperature on the wettability alteration of carbonate surfaces by Heidari et al. (2014), where an intermediate-wet state at 50^0C of aging carbonate slides where reached after 10 days, as opposed to 63 days aging at 25^0C. It was suggested that in other to create the same oil-wet nature of a reservoir, aging was an essential parameter in wettability modification; however, the study proved that rock wettability is not mostly affected by the time aging occurred for the core with oil, but a higher influence is by temperature. Core preparation involves, the usage of solvent for cleaning, Dean–Stark extraction to pull out contaminants then the petrophysical measurements (dimensions and porosity) and wettability restoration. The core is then inundated with the formation water under vacuum, allowing for the determination of the permeability by formation water flooding, applying a range of different flooding rates.

Afterwards, to get the initial water saturation, crude oil is injected to the core, and then, under sufficient experimental temperature and pressure of about 200 psi, the core plug is aged using steel aging cell (Yi, Z.; Sarma, H.K., 2012). For limestone core plugs, Yi and Sarma suggested that, a minimum aging time of three weeks is required according to properties of the rock core and fluids, to replenish the reservoir wettability (Yi, Z.; Sarma, H.K., 2012). They also suggested that if there is a deficiency in aging time, the result could favourable to the recovery process in the secondary oil recovery mode, although, could be limited in the wettability alteration in the tertiary mode. They denoted that, the effect on oil recovery from chalks by the aging time and temperature is negligible, as oil–rock–brine system reaches equilibrium quickly (Sohal, M.A.; Kucheryavskiy, S.; Thyne, G.; Søgaard, E.G., 2017). Again, the wettability of carbonate rock reservoirs may be affected by pressure, which a function of the modification in solubility of compounds in the crude oil.

2.1.5 Rock Mineralogy

The reactivity of limestone and chalk reservoir cores towards the active ions present in seawater, result in wettability alteration. However, a variation could exist in the reactivity of reservoir limestone cores toward PDIs (Ca^{2+}, Mg^{2+}, and SO_4^{2-}). For example, it was shown that after cleaning reservoir limestone cores with toluene and methanol, the wettability of oil-wet improved, and then, when flooded with synthetic seawater at 130 ◦C, the improvement of the water-wet fraction was by approximately 30% (Austad, T.; Strand, S.; Puntervold, T.; Ravari, R.R., (2008). Furthermore, the switching of the flooded brine from formation water to seawater in both secondary and tertiary oil recovery modes resulted in remarkable improvement in the recoverable oil from low permeable reservoir limestone, from 8% to 37% of OOIP. Chalk is composed of CaCO3 (a pure biogenic fragmentary portions of calcite skeletons generated by plankton), having a higher reactivity towards PDIs than limestone (Strand, S., 2008). According, Austad et al. (2011), it was observed that the presence of a high amount of anhydrite is required for a low salinity water flooding to be effective in chalk cores, and could improve the oil recovery (up to 20% of OOIP) in limestone cores. Mahani and co-workers (2017), suggested that different surface reactivity and wettability modification in different carbonate rocks, is dependent on the difference in the brine salinity, pH, and temperature. For the surface reactivity towards alteration in brine concentration and pH, it was shown that chalk surfaces had the highest, while dolomite surfaces the lowest (Mahani, H.; Keya, A.L.; Berg, S.; Nasralla, R., 2017). Again, it was much more palpable in the improvement in wettability of dolomite surfaces at elevated temperature than it was for limestone surfaces (Mahani, H.; Menezes, R.; Berg, S.; Fadili, A.; Nasralla, R.; Voskov, D.; Joekar-Niasar, V., 2017).

2.1.6 Rock Porosity and Permeability

Porosity shows the amount of oil in place, while permeability shows the rate at which the crude oil can be recovered. Depending on the degree of connectivity of the natural fractures present, if it is high, there will be decrease in the viscous displacement of oil from the matrix blocks, by the injected brine, which is a negative impact on capillary pressure, which hinders the adhering of brine from the fractures through the matrix blocks. In contrast, increasing the water saturation in matrix blocks of a reservoir and relative permeability would require the displacement of oil from the matrix block, with injected brine. Therefore, the amount of pore-volume of seawater that flows into the matrix blocks during waterflooding depends on difference between permeability of the matrix and fractures, and, if it is moderate, then a large pore-volume of seawater would flow in

(Korsnes, R.; Strand, S.; Hoff, Ø.; Pedersen, T.; Madland, M.; Austad, T., 2006). Korsnes and coworkers (2006) studied the mechanical properties of high porosity outcrop chalk using synthetic seawater, modified seawater, and distilled water at 130 ◦C. The experiment showed an increase in compaction, by a factor of 2.7, when seawater and SO_4^{2-} ions, was used, rather than pure chemical dissolution of chalk, chemical reactions at the chalk surface was imbibed. Furthermore, it was observed that there was a reduction in permeability, by a factor of 2.5, when brine contained SO_4^{2-} ions compared to 1.7 for brine without SO_4^{2-}. They suggested that due to compaction of chalk with high porosity, there was no considerable reduction in permeability, after using different brines, and permeability of the chalk even at high temperature.

2.2 Injected brine parameters

2.2.1 Ionic Composition and Temperature

An extensively studied of the effects of Ca2+, Mg2+, and so_4^{2-}, three primary PDIs toward carbonate surfaces, was carried out. It was stated that the oil recovery from chalk improved from 15% to 55% of OOIP after 30 days at 70 ◦C (Figure 2a), after increasing the concentration of so_4^{2-}ions at four times the concentration in seawater (Zhang, P.; Austad, T., 2006). In a similar work, Zhang and co-workers stated that the oil recovery were of 28% to 60% of the OOIP, after 30 days at 70 ◦C (Figure 2b) will improve by increasing the concentration of Ca2+ ions at four times the concentration in seawater while keeping the so_4^{2-}concentration the same as in the seawater (Zhang, P.; Austad, T., 2006). Additionally, they also suggested that the surfaces chalk wettability and improved oil recovery can be modified by a simultaneous increase in the concentration of Ca2+ and so_4^{2-}ions in seawater and the initial brine. However, it was noted that when cores were aged with a crude oil, a high concentration of Ca2+ ions did not enhance oil recovery of high AN. There was enhanced water-wetness nature and oil recovery after Ca2+ and

SO_4^{2-}ions were tested on their wettability alteration of chalk surfaces, with increasing temperature (Strand, S.; Høgnesen, E.J.; Austad, T., 2006). However, there was a decrease in the adsorption nature on the surfaces as the ratio of Ca2+/SO_4^{2-} increases, at temperatures beyond 100 ◦C, which was owing to precipitation of anhydrite (CaSO4). In Figure 3 below, a description of oil recovery from a chalk core at two different temperatures (100 ◦C and 130 ◦C) for a fixed oil, where concentration of SO_4^{2-}ions in a synthetic is seawater varied (Zhang, P.; Austad, T., 2006). Figure 4 carefully considers individual observations, putting in consideration, that the system's gain, may not always be possible (Zhang, P.; Austad, T., 2006). The wettability alteration of chalk surfaces was evaluated to ascertain the effect of divalent cations (Mg2+ as well as Ca2+) and an anion (SO_4^{2-}) (Austad, T.; Strand, S.; Puntervold, T., 2009). It was seen that Ca2+ can be substituted by Mg2+ at high temperatures (above 70 ◦C) on the chalk, and the strength of carboxylate complexes. Figure 5 shows that the PDIs can be affected by the equilibria set in with specific seawater concentrations. Finally, it could be denoted that high temperatures do not always lead to a more water-wet nature of the reservoir rock, but depending on specific type of rock, carbonate rock surfaces can be altered to a more water-wet state even at ambient temperature (Brady, P.V.; Thyne, G., 2016).

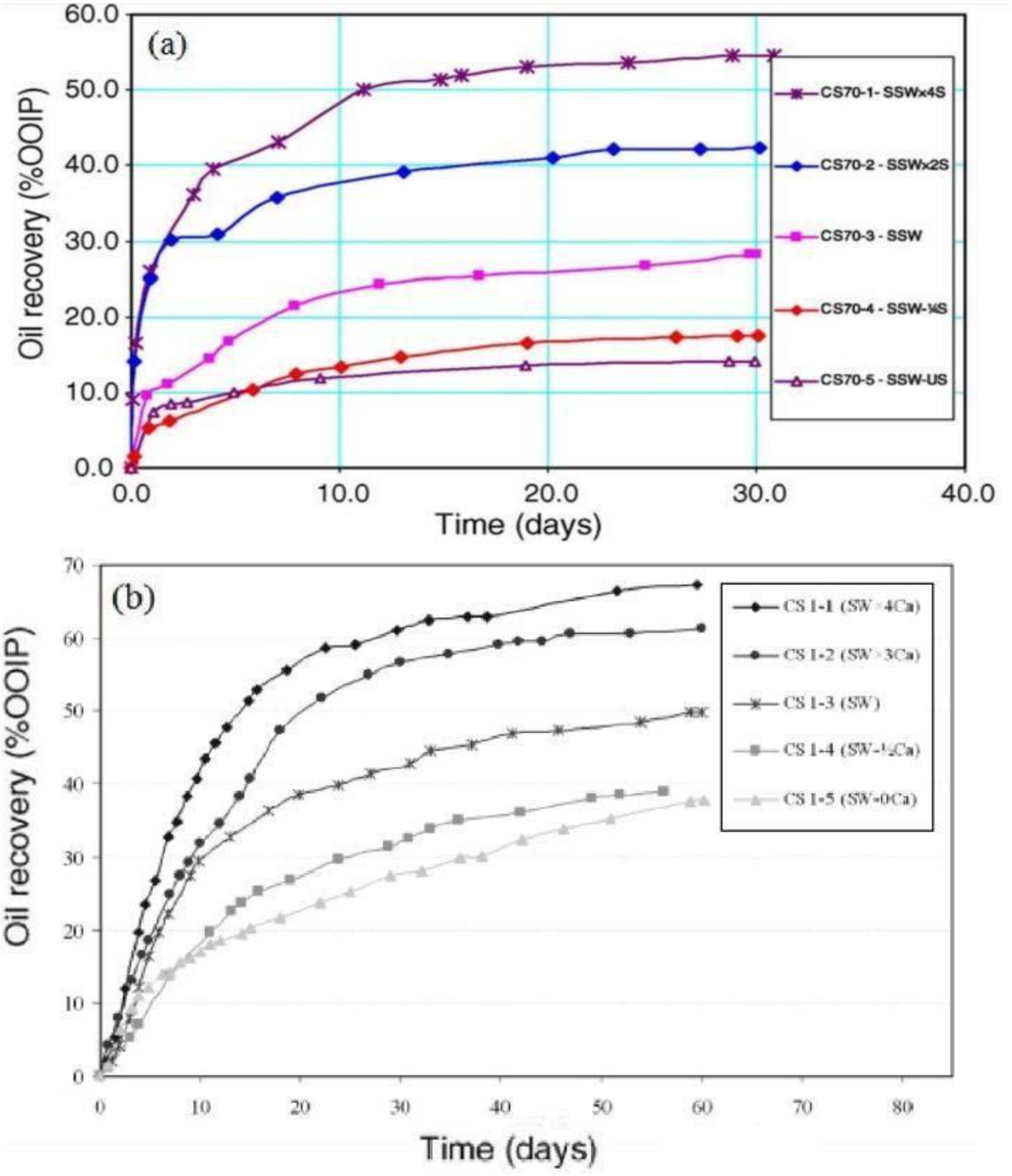


Figure 2.2 Oil recovery from a chalk core 70 ◦C when a synthetic seawater (SSW) with different concentrations used. (reproduced from Zhang et al., Energy Fuels; published by American Chemical Society, 2006).

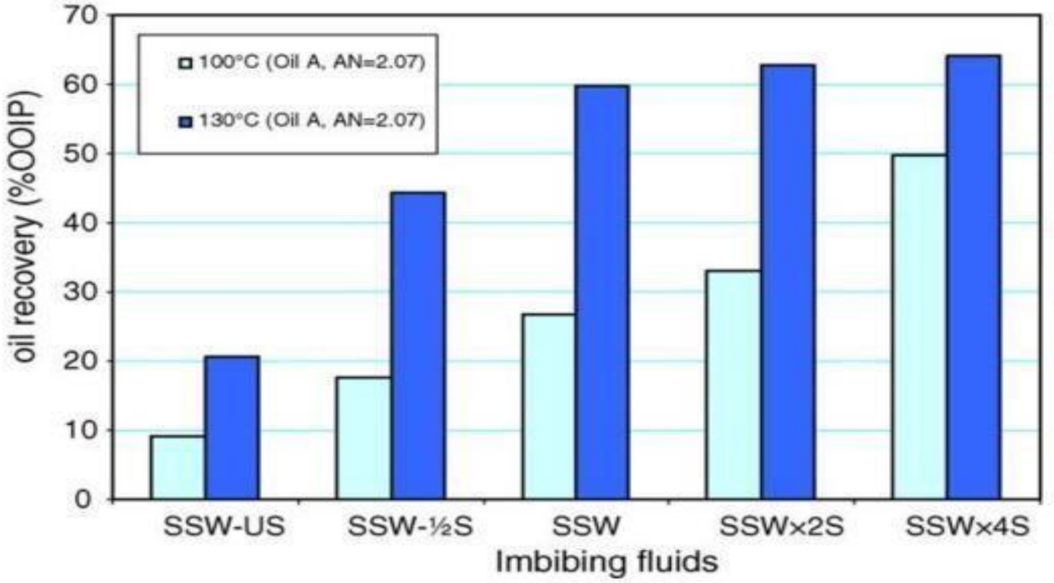


Figure 2.3 Effect of temperature (100 ◦C and 130 ◦C) and different concentrations of so_4^{2-}

Reproduced from Zhang et al., Colloids Surf. A; published by Elsevier, 2006.

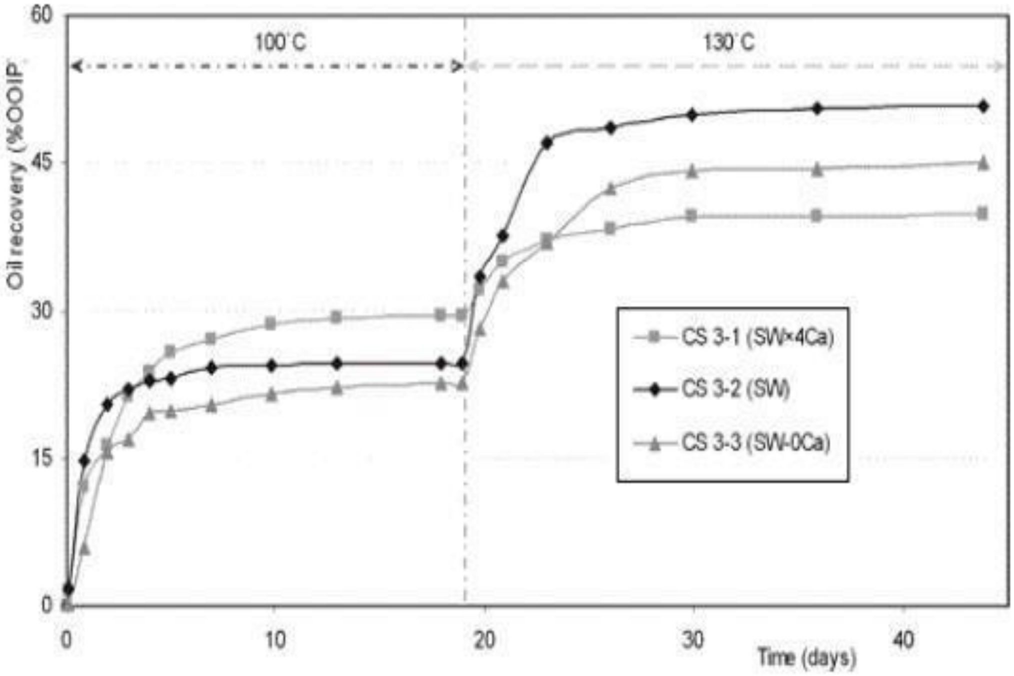


Figure 2.4 Effect of temperature (100 ◦C and 130 ◦C) and different concentrations of Ca2+ ions. Reproduced from Zhang et al., Energy Fuels; published by American Chemical Society, 2006.

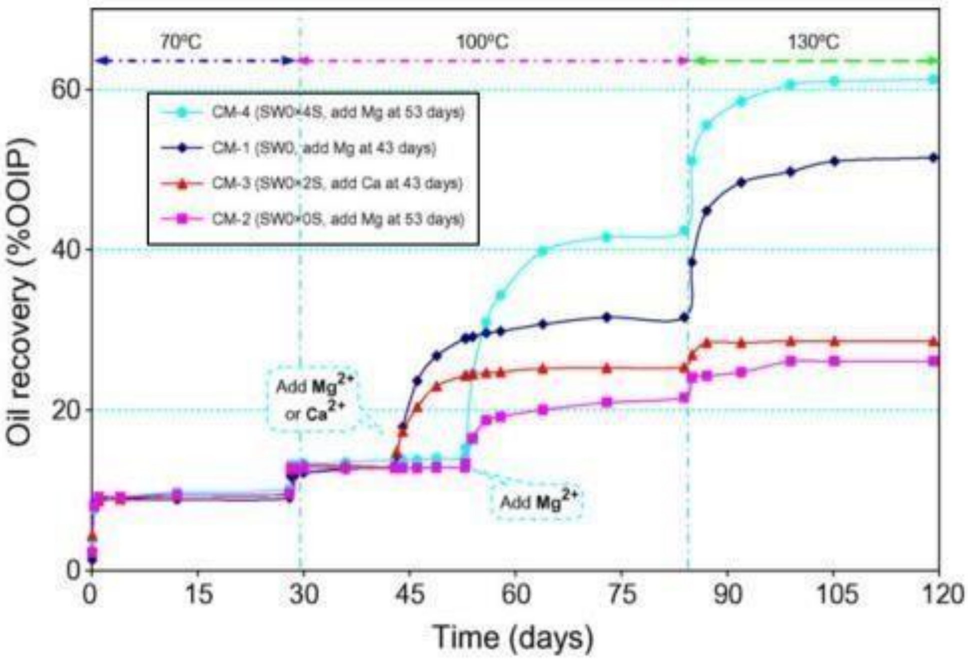


Figure 2.5 Effect of temperature (70 ◦C, 100 ◦C, and 130 ◦C) and PDIs (Ca2+, Mg2+ and SO2 4) on oil recovery from a chalk core when modified seawater depleted in Ca2+, Mg2+ ions and different concentrations of SO2-4 ions. was used as initial imbibing fluids (SW0x0S, SW0x2S, SW0, and SS0x4S) and Ca2+, Mg2+ ions were added later as the same concentration present in seawater (AN = 2.07 mg KOH/g). Zhang et al., Colloids Surf. A; published by Elsevier, 2007.

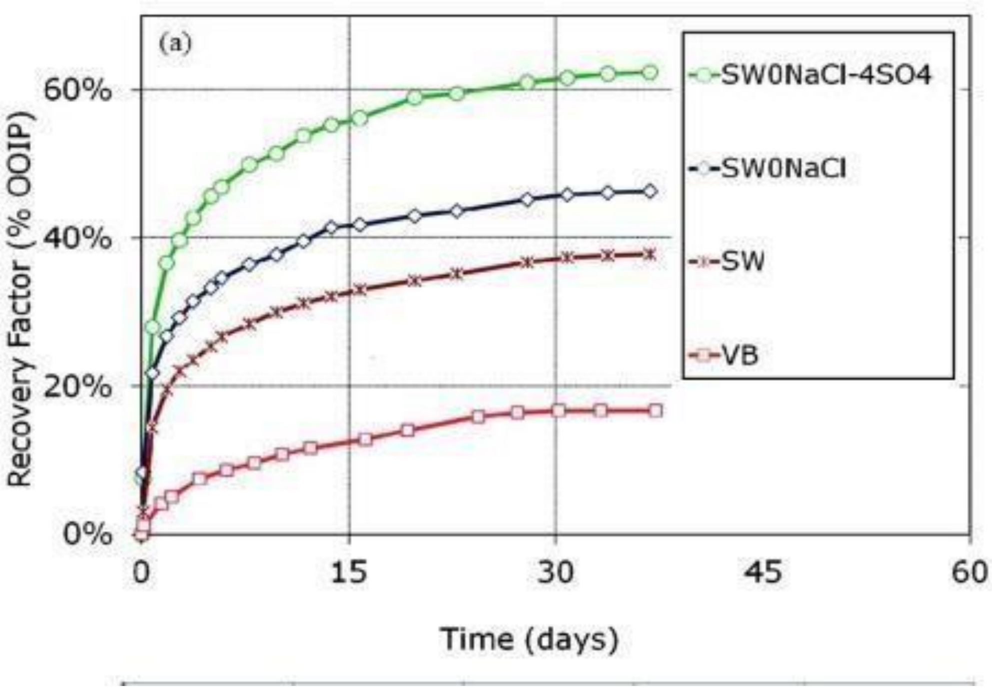
According to Fathi and colleagues work on non-active salt (NaCl), it was suggested that when NaCl is depleted from seawater, in the presence of reactive ions (Ca2+, Mg2+ and so_4^{2-}), at a high temperature of about 120 ◦C, the alteration wettability of chalk surfaces and improved oil recovery would take place (Fathi, S.J.; Austad, T.; Strand, S., 2012). It was observed that there was an improvement in oil recovery by using NaCl depleted seawater, when so_4^{2-}conc. was stepped up, to four-times at 90 ◦C, and in the same vein, a decrease was experienced in oil recovery, for increase the conc. of NaCl in seawater up to four times at 100 ◦C (Figure 6).

Similarly, it was also observed that oil recovery and water-wetness improved when depleted NaCl seawater with four times the so_4^{2-}conc. was used, in comparison to when seawater was used in a carbonate reservoir chalk cores (Kazankapov, N.,2014).

Furthermore, investigation carried out on limestone and dolomite cores free of anhydrite, showed that the modification wettability and enhanced oil recovery in the presence of polyatomic anions, e.g., borate ($BO^{3}{}_{3}^{-}$) and phosphate ($PO^{3}{}_{4}^{-}$), could produce 15–20% of OOIP increasing oil recovery

(Gupta, R.; Smith, G.G.; Hu, L.; Willingham, T.; Lo Cascio, M.; Shyeh, J.J.; Harris, C.R., 2011).

Additionally, Meng and co-workers (Meng, W.; Haroun, M.; Sarma, H.; Adeoye, J.; Aras, P.; Punjabi, S.; Rahman, M.; Al Kobaisi, M., 2015), showed that the wettability of limestone cores can be modified to a more water-wet condition at 90 ◦C, in the presence of large amount of PO3 4- ions (1000 mg/L) in seawater. The erstwhile studies have shown that the injection brine for LSW in carbonates should contain PDIs (Ca2+ and/or Mg2+, $So^{2}{}_{4}^{-}$), with a depleted amount of NaCl, operating at a high temperature (beyond 70 ◦C). However, when considering so_4^{2-}, much attention should be given because, at increasing concentration at high temperature, precipitation of CaSO4 can result in, which could reduce the oil recovery. Although for limestone cores containing anhydrite, depending on the brine salinity/content and temperature the so_4^{2-}ions generated due to dissolution of CaSO4 can increase to oil recovery. In addition, an increasing temperature, will equivalent a decrease in the concentration of so_4^{2-}ions in the brine, which is due to adsorption on the rock surface. On the other hand, the alteration wettability process as well as the oil recovery would see an improvement, when the temperature is increased, as the concentration of NaCl is decreased. Therefore, there is a sharp contrast between the temperature and the non-active salt concentration. Thus, for limestone, to improve the oil recovery in LSW, an optimum temperature within the range of 90–110 ◦C is suggested (Fathi, S.J.; Austad, T.; Strand, S., 2010).



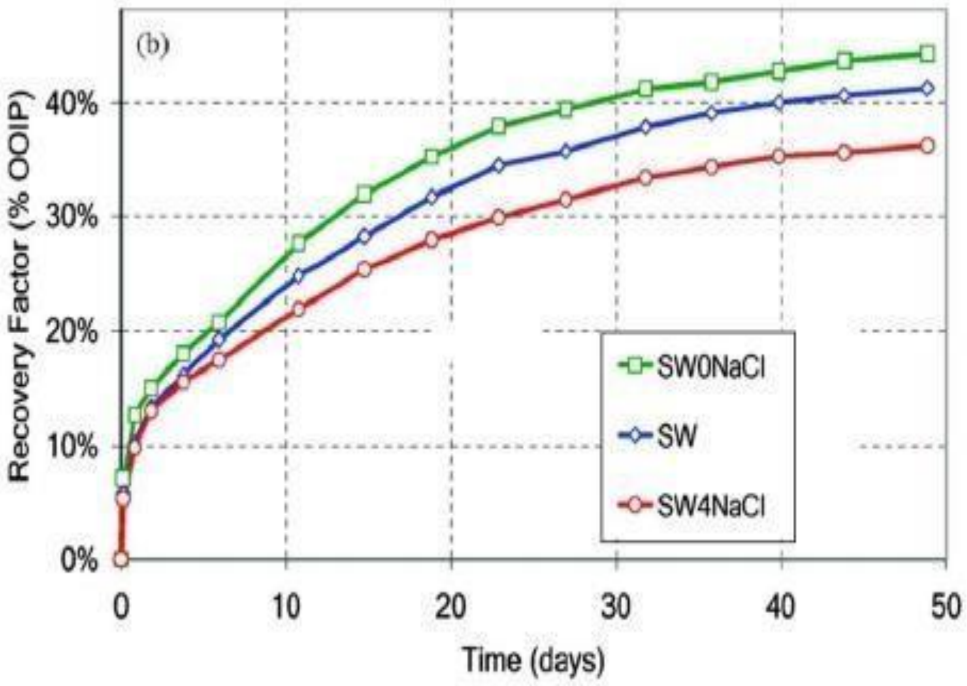


Figure 2.6 Oil recovery from a chalk core at (**a**) 90 ◦C (AN = 0.5 mg KOH/g) and (**b**) 100 ◦C (AN

= 1.90 mg KOH/g) when formation water (VB), seawater (SW), NaCl depleted seawater (SW0NaCl), NaCl depleted seawater spiked with four times the concentration of $so_4{}^2$ions present in seawater (SW NaCl $so_4{}^2$), and seawater spiked with four times the concentration of NaCl present in seawater (SW 4NaCl), were used as imbibing fluids reproduced from Fathi et al., Energy Fuels; published by American Chemical Society, 2011. Reproduced with permission from Fathi et al., Energy Fuels; published by American Chemical Society, 2010.

CHAPTER THREE

METHODOLOGY OF LOW SALINITY WATER INJECTION IN MARGINAL FIELD DEVELOPMENT AND OPERATIONS FOR A CARBONATE RESERVOIR

3.1 Fluid

Abdulrazag Zekri, Hildah Nantongo, Fathi Boukadi (2021) carried out an experiment using a crude oil with an API gravity of 39.5° which was filtered through a 5-mm filter paper prior to any laboratory application.

The authors measured the crude oil viscosity which has an acid number of 0.07 mg KOH/g (measured with ASTM D664 standard titration procedure) using a rolling ball viscometer at 20°C given a value of 2.93 cP.

The brines used in the project include the formation water (FW), the water that is currently injected in the reservoir (IW) and seawaters (SW) with different salinity and sulphate concentrations. Table 1 clearly depicts this project. The classification made for the diluted seawater solutions are: SW/10 is a ten-time diluted solution, SW/50 is a 50-time diluted solution. While spiked solutions are: $2so_4{}^2$ is a SW with a sulphate concentration that has been spiked twice and $6so_4{}^2$ refers to a SW a sulphate concentration that has been spiked six times.

To assess the effect of carbonate rock wettability on the performance of low-salinity flooding, the sequential core flooding experiments for intermediate-wettability oil reservoirs, conducted by Zekri et al. (2020), were repeated in this study in oil- and water-wet environments. The ambient conditions for formation water showed a TDS of 157,488 with a density of 1.1074 and a viscosity of 1.2482 cp. Tables 3.1 displays the brines' composition based on their dilution and sulphate spiking, in seven different sets.

ION	**SW**	**SW/10**	**SW/50**	**SW x 2 $SO^{2}{}_{4}$**	**SW x 6 $SO^{2}{}_{4}$**
Calcium	690	69	13.8	690	690
Sodium	18680	1868	373.6	21748	17475
Magnesium	2132	213.2	42.64	2132	2132
Potassium	672	67.2	13.44	672	672
Bromide	<0.1	<0.1	<0.1	<0.1	<0.1
Zinc	<0.1	<0.1	<0.1	<0.1	<0.1
Phosphate	<0.1	<0.1	<0.1	<0.1	<0.1
Chloride	27370	2737	547.4	17450	15450
Sulphate	3944	394.4	7888	5916	17748
Bicarbonate	123	12.3	2.46	123	123
Nitrate	0	0	0	0	0
Strontium	0	0	0	0	0
Carbonate	0	<0.1	<0.1	<0.1	<0.1
Total	**53611**	**5361.1**	**1072.22**	**48..731**	**54.290**

Table 3.1 The composition of diluted and spiked brines used in the study

3.2 Core Samples

The experiment utilises ten limestone carbonate core samples, which were selected from many core plugs. The Gray in colour limestone with an approximate diameter of 1.5″, had five used in the water-wet experimental runs and five in the oil-wet runs. The formation brine was allowed to age for a minimum of three weeks in formation water prior to the sequential LSWI, while all the core plugs for water-wet reservoir experiments were saturated. In the same vein, the selected core samples for the oil-wet experiments were initially injected with formation brine, and then with Asab (AS) crude oil, which was later allowed to age in the same oil for 3 weeks prior to sequential LSWI with the numerous brines.

3.3 Systems wettability measurements

With the core cut into six diskettes, and water-saturated diskettes allowed to age in the same brine for three weeks, three were saturated with formation brine, while the other three, were saturated with reservoir oil. As recorded by the authors, the cores were allowed to age at temperature and pressure of 90 °C and 200 psia. Following the experimental process, the water-saturated diskettes were placed in a glass beaker filled with formation brine, and Oil droplets were later placed on the surface of the water-saturated diskettes. After which in 24h, the measuring of the contact angles was found to be at around 45°, affirming that the diskettes were water-wet. To confirm total oil wetness, the authors decided to place the oil saturated diskettes in a glass beakers filled with formation brine for more than 24h, and no oil drops appeared on the surface of the diskettes.

3.4 Coreflooding Experiment

Core flooding experiment was designed detect the potentiality of water flooding under dynamic circumstances and in various wettability environments. The flooding experiments were considered ascertain how effective the dilution and sulphate spiking on the displacement efficiency would be.

With respect to annihilating the response of variation in the rocks' petrophysical properties, the cores were injected with specific set of brines. The rate of the injection incorporated in the core flooding was 1 cc/mins. In Table 3.4, the injected brines for every core flooding experiment are displayed following a sequential order. It is well noted, that the effluents were studied comprehensively, for better understanding of the pH, resistivity, turbidity, and total dissolved solids (TDS).

Wettability	**Sample (ID)**	**Water k(md)**	**Porosity (%)**
WW	18	20.60	11.00
WW	38	10.30	11.00
WW	24	11.30	13.00
WW	2	11.60	15.00
WW	8	12.20	16.00

Table 3.3 Basic properties of the core plugs

Sequential	First	Second	Third
I	SW	SW*2 SO4	SW * 6 SO4
II	SW/10	SW/10 * 2 SO4	SW/10 * 6 SO4
III	SW/50	SW/50 * 2 SO4	SW/50 * 6 SO4
IV	SW	SW/10	SW/50
V	IW	SW/10	

Table 3.4 Sequential order of brine injection

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 Low-salinity recovery

Zekri et al. (2020), after carefully examination of the low-salinity sequential injection in intermediate-wet rock, discovered the dominant recovery mechanisms to be rock dissolution and water-in-oil emulsion. The results of that work are matched with this work compared to the performance of sequential brines in oil- and water-wet environments.

4.1.1 Water-wet system

4.1.1.1 Effect of sulphate concentration

The initial core flooding experiments, which was injected with SW first, and later spiked with twice and 6-times the sulfate concentration, used 18 cores with an initial water saturation of around 15.4%. **Fig. 4.1** shows the result of the flooding. After sequential I was flooded SW injection, of 10.6 pore volumes (PVs), it yielded a recovery of 78.50% of the OOIP. There was no more worthy note of oil recovery as the water cut remained constant. The response of sulphate, was tested by injecting the system with SW X $2so_4^2$ (spiked seawater with twice the sulfate concentration) with up to 23.5 PVs. It was recorded that the spiked seawater yielded an improvement of 2.2% in the displacement efficiency, DE. The displacement efficiency is denoted as:

$$DE = \frac{Soi - So}{Soi}$$

Where:

Soi=Initial oil saturation of the flooding

So=Average oil saturation at the end of the flooding

The system was changed to SW X $6so_4^2$ (spiked seawater with 6 times the sulfate concentration), after the flooding with the initial SW and SW X $2so_4^2$, and it was discovered to yield an additional 0.2%, overall DE, estimated 80.93%.

Table 4.1 below displays brines prior- and post-flooding properties, with indication to the changes. A small rise was noted in the pH of the liberated SW as well as the SW X $2So_4^2$, while postflooding, for total dissolved solids and turbidity showed a slight increase.

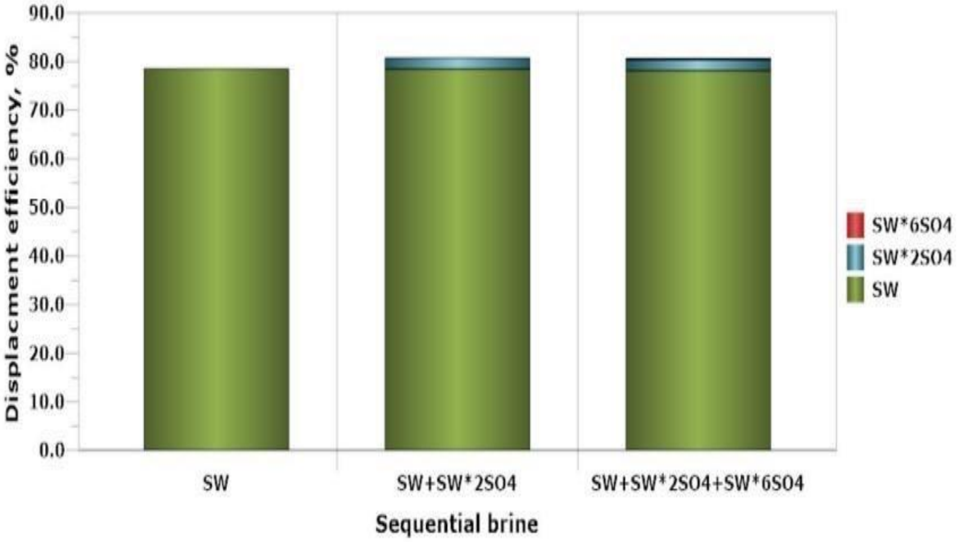


Fig. 4.1 Displacement efficiency of sequential I flooding, water-wet system

Effluent Properties		**SW**		**SW x 2 SO4**		**SW * 6 SO4**	
Parameter	Units	Before	After	Before	After	Before	After
pH	Log(mol/L)	8.1	7.81	8.53	8.14	8.73	8.42
Total Dissolved Solids	Mg/L	53611	61462	48731	55984	54290	72840
Resistivity	Ohm-meter	0.174	0.169	0.177	0.176	0.215	0.212
Turbidity	NTU	0	4	0	6	0	7

Table 4.1 Properties of sequential I brine prior and post flooding, water-wet system

4.1.1.2 Effect of dilution

Using core sample 2, the effect of dilution on the displacement efficiency was performed on a sequential IV flooding (SW, 10-times diluted SW, and 50-times diluted SW). **Fig. 4.2** presents the results of this procedures. From the results, it can be denoted that the dilution of seawater has an effectual response on the displacement efficiency of oil in a water-wet carbonate formation. Based on this data, with an injection of 6.9 PVs, the displacement efficiency from SW flooding was deemed to be around 61.5%. Furthermore, Ten-times and 50-times diluted seawater were then utilized, with an enhancement in the displacement efficiency by 21.9 and 4.6%, respectively, given total displacement efficiency of sequential IV mounted to around 88%. **Table 4.2** presents the results of the experiments.

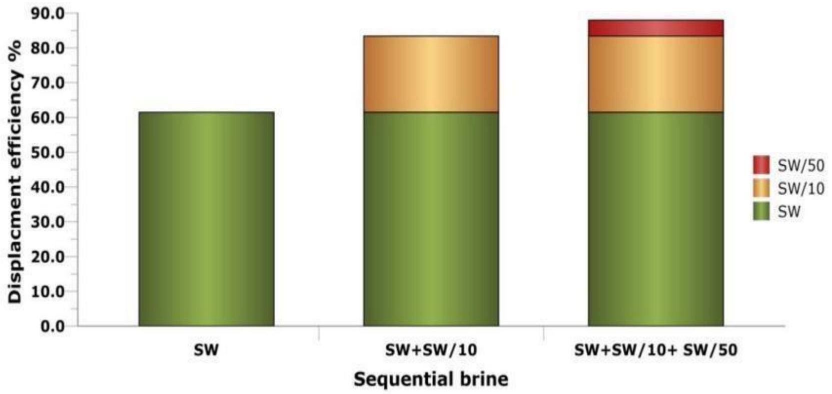


Fig. 4.2 Displacement efficiency of sequential IV flooding, water-wet system

Effluent Properties		**SW**		**SW / 10**		**SW / 50**	
Parameter	Units	Before	After	Before	After	Before	After
pH	Log(mol/L)	8.1	7.74	7.89	8.46	7.84	8.17
TDS	Mg/L	53611	64273	5361	21745	1072	15600
Resistivity	Ohm-meter	0.174	0.172	1.531	0.174	6.271	0.21
Turbidity	NTU	0	5	0	60	0	35

Table 4.2 Properties of sequential IV brines prior and post flooding, water-wet system

4.1.1.3 Effect of dilution and sulphate concentration

The effect of dilution and sulfate spiking was studied, using two sequential experiments (II and III) on water-wet limestone rocks. In sequential II, consisting of SW/10, followed by SW/10 x $2So_4^2$, and then SW/10 x $6So_4^2$, 10-times diluted seawater and the diluted seawater spiked 2 and 6 times with sulphate were incorporated. The overall DE of this system was estimated to be around

76.2%, with slight improvement in the DE, indicating the sulfate spiking of 10-times with diluted SW, as shown in **Figure 4.3** below. The sequential flood consists of injecting SW/50, followed by SW/50 x $2So_4^2$, and then SW/50 x $6So_4^2$ in the sequential III. Experimental results in **Fig. 4.4** showed that, in low salinity environment, sulfate spiking did not play a major role in the enhancement of the recovery mechanism.

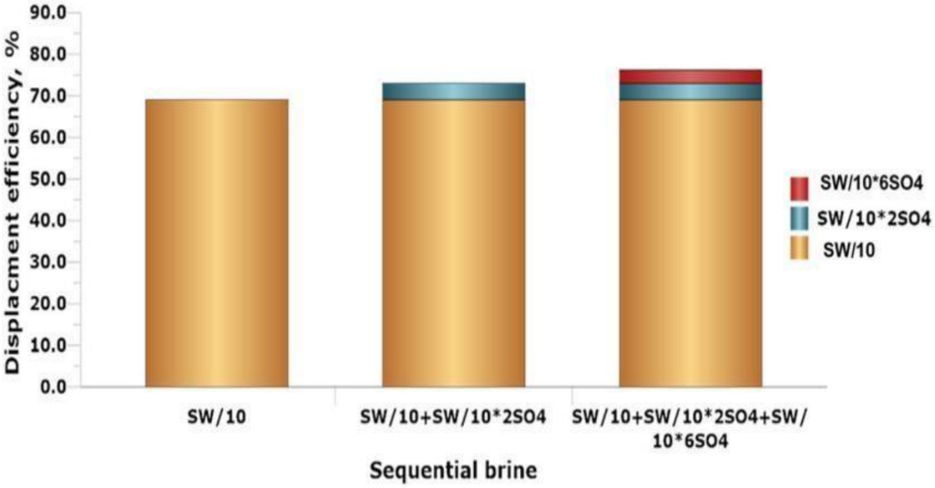


Fig. 4.3 Displacement efficiency of sequential II, water-wet system

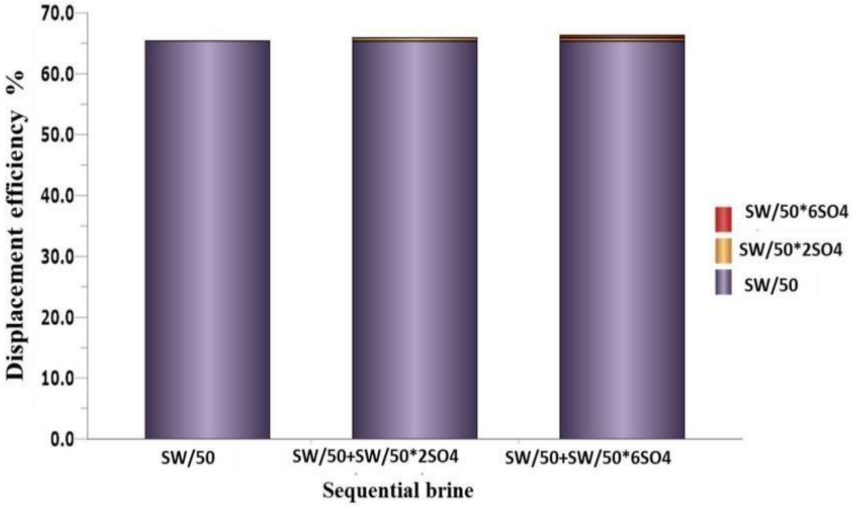


Fig. 4.4 Displacement efficiency of sequential III, water-wet system

Effluent Properties		**SW / 10**		**SW / 10 x 2 So_{24}**		**SW / 50 x 6 $So^{2}{}_{4}$**	
Parameter	Units	Before	After	Before	After	Before	After
Ph	Log(mol/L)	7.89	8.31	8.29	8.51	8.45	8.89
TDS	Mg/L	5361	23789	6606	30164	7068	34847
Resistivity	Ohm-meter	1.531	0.931	0.212	0.215	0.258	0.249
Turbidity	NTU	0	62	0	70	0	44

Tables 4.3 present the brines properties for sequential II and sequential III, prior- and post-flooding.

Effluent Properties		**SW / 50**		**SW / 50 x 2 So_{24}**		**SW / 50 x 6 $So^{2}{}_{4}$**	
Parameter	Units	Before	After	Before	After	Before	After
Ph	Log(mol/L)	7.89	7.96	8.06	8.29	8.4	8.73
TDS	Mg/L	1072	22160	6586	31094	6663	36231
Resistivity	Ohm-meter	6.271	1.821	0.231	0.255	0.28	0.268
Turbidity	NTU	0	62	0	43	0	31

Tables 4.4 present the brines properties for sequential II and sequential III, prior- and post-flooding.

4.1.2 Oil-wet system

4.1.2.1 Effect of sulphate concentration

With core number 22S injected with seawater first, flooding followed by seawater with twice and 6-times the sulphate concentration. And this brine flooding process was not halted until oil stopped. As shown in **Figure 4.3**, the DE during the various sequential injection stages. With results stating that the spiking of seawater with sulphate had no real impact on the DE, and hence, no alteration in the water endpoint relative permeability, which in turn is a statement that wettability could be tag to be a nil.

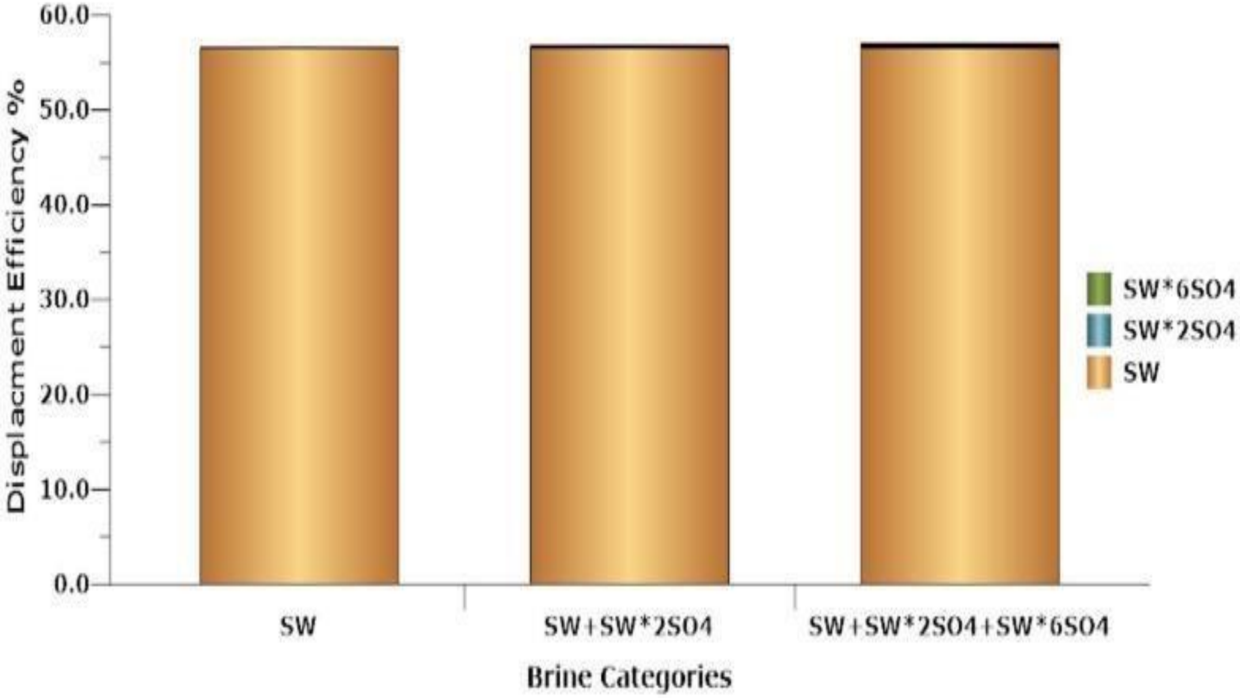


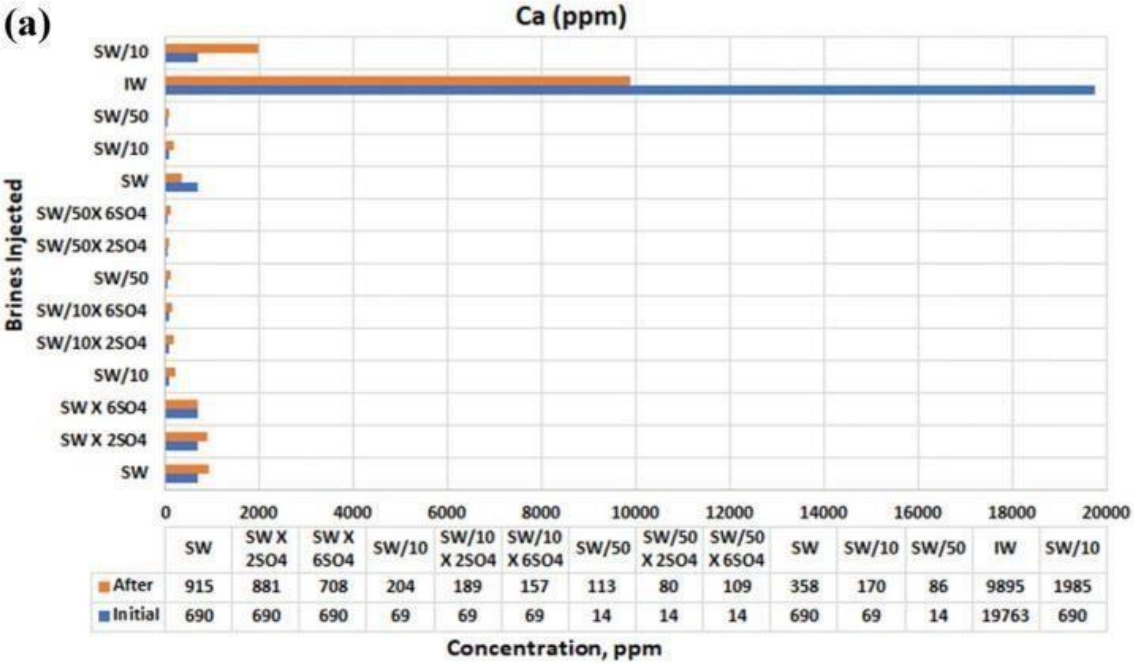
Fig. 4.3 Displacement efficiency of sequential seawater and spiked SW flooding, oil-wet system

Effluent Properties		**SW**		**SW x 2 So^{2}_{4}**		**SW x 6 So^{2}_{4}**	
Parameter	Units	Before	After	Before	After	Before	After
Ph	Log(mol/L)	8.1	7.68	8.58	8.52	8.73	8.3
TDS	Mg/L	53611	59517	48731	62364	54290	69204
Resistivity	Ohm-meter	0.174	0.161	0.177	0.171	0.215	0.206
Turbidity	NTU	0	5	0	8	0	8

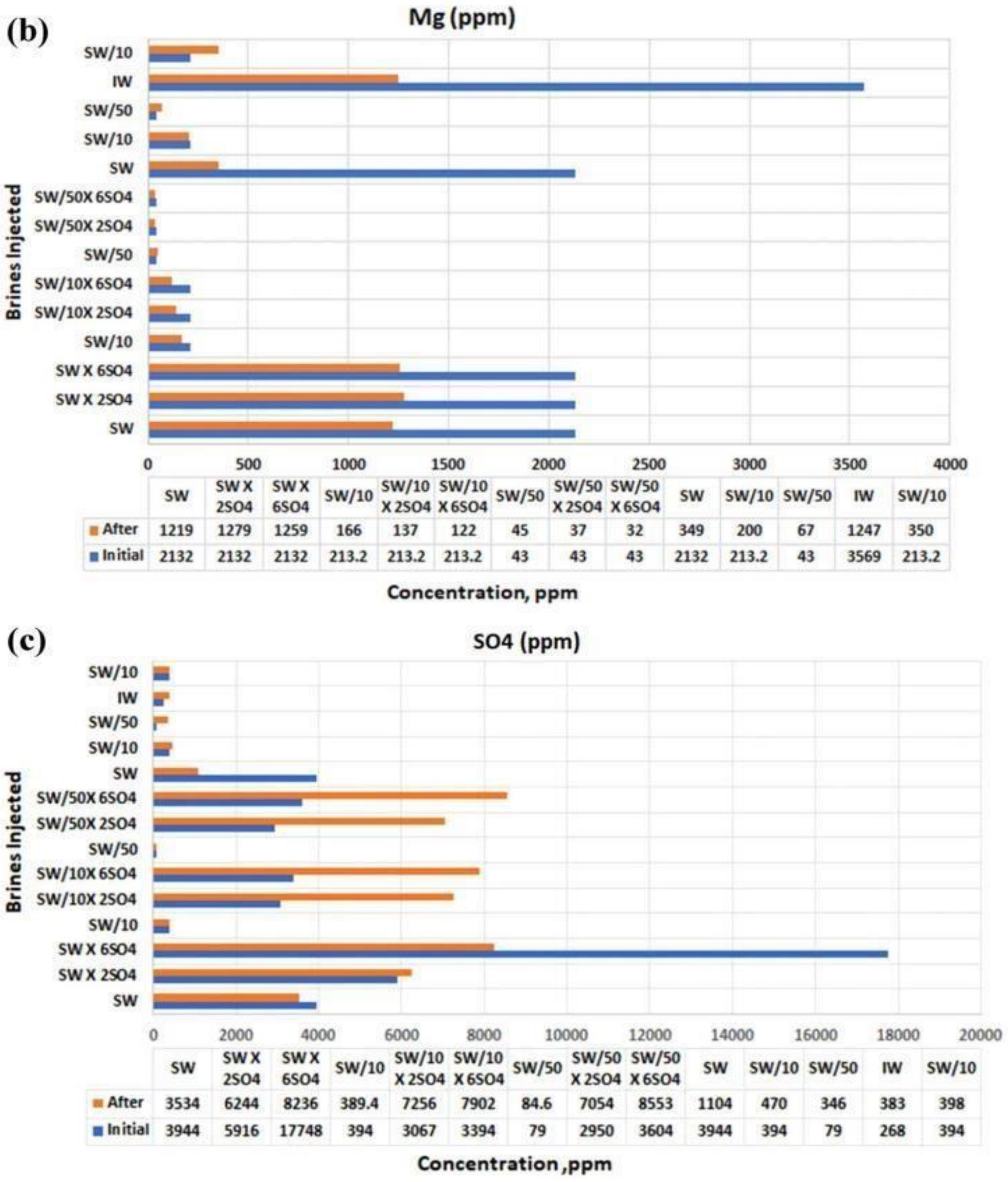
Table 4.3 Properties of SW flooding and spiked SW prior and post flooding, oil-wet system

4.1.2.2 Effect of dilution

The flooding sequence involved seawater, 10-times, and 50-times diluted seawater, which showed the effect of dilution on the displacement efficiency in an oil-wet environment, using sequential IV flooding, indicating the negative impact (see **Fig. 4.4**). Results presents a good enhancement with seawater alone with dissolution and emulsion, favouring mechanisms. Although, these mechanisms could only be enhanced by a higher interfacial activity, as reported by Zekri et al. (2020).



	SW	SW X 2SO4	SW X 6SO4	SW/10	SW/10 X 2SO4	SW/10 X 6SO4	SW/50	SW/50 X 2SO4	SW/50 X 6SO4	SW	SW/10	SW/50	IW	SW/10
■ After	915	881	708	204	189	157	113	80	109	358	170	86	9895	1985
■ Initial	690	690	690	69	69	69	14	14	14	690	69	14	19763	690



	SW	SW X 2SO4	SW X 6SO4	SW/10	SW/10 X 2SO4	SW/10 X 6SO4	SW/50	SW/50 X 2SO4	SW/50 X 6SO4	SW	SW/10	SW/50	IW	SW/10
■ After	1219	1279	1259	166	137	122	45	37	32	349	200	67	1247	350
■ Initial	2132	2132	2132	213.2	213.2	213.2	43	43	43	2132	213.2	43	3569	213.2

	SW	SW X 2SO4	SW X 6SO4	SW/10	SW/10 X 2SO4	SW/10 X 6SO4	SW/50	SW/50 X 2SO4	SW/50 X 6SO4	SW	SW/10	SW/50	IW	SW/10
■ After	3534	6244	8236	389.4	7256	7902	84.6	7054	8553	1104	470	346	383	398
■ Initial	3944	5916	17748	394	3067	3394	79	2950	3604	3944	394	79	268	394

Fig. 4.4 (a) Ionic concentration of injection and production brines (b) Ionic concentration of injection and production brines (c) Ionic concentration of injection and production brines.

4.1.2.3 Effect of dilution and sulphate concentration

The authors recorded that the Sequential II and III were used to run the test of the LSWI in oil-wet environment, which consisted of using two diluted waters (10-times and 50-times) spiked with twice and 6-times the sulfate concentration. In figure 8 presents the effect it has on the DE. As noted by the authors, the decrease in salinity did not enhance the system displacement efficiency and the maximum salinity for the oil-wet system was found to be at 7,000 ppm. Experimental results for Sulphate spiking were indicated as shown in **Fig. 4.5**. However, the overall displacement efficiency increased to 52.7%, with results from the experiments in **Fig. 4.6** indicating that spiking of the 50-times diluted seawater had little or no effect in the displacement efficiency.

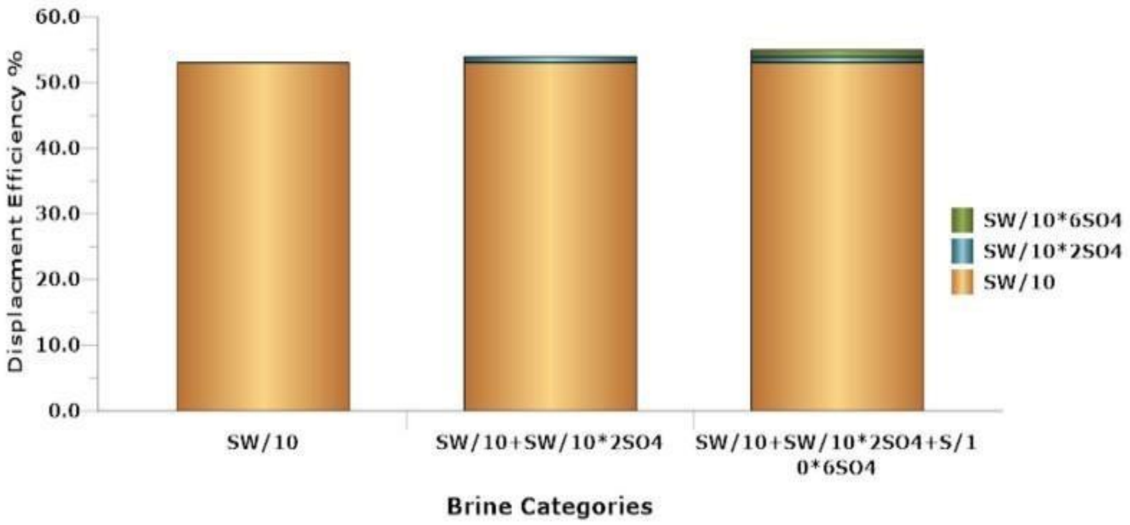


Fig. 4.5 DE of sequential seawater diluted 10 times and spiked, oil-wet system.

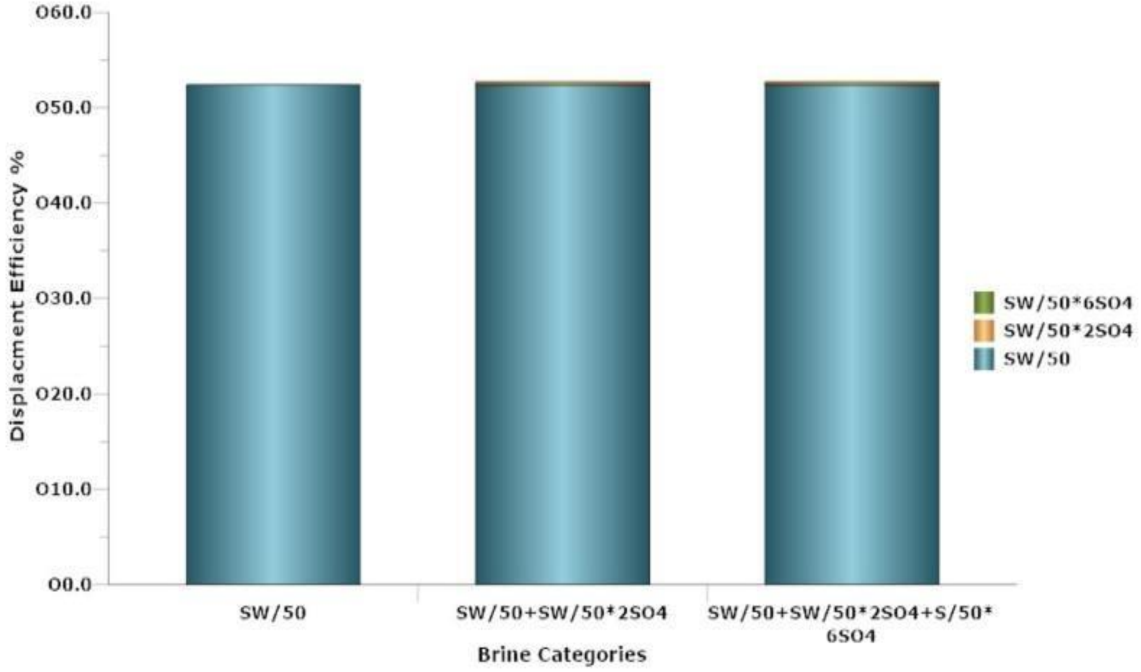


Fig. 4.6 DE of sequential SW diluted 50 times and spiked, oil-wet system

4.1.3 Effect of wettability on the performance of low salinity flooding

Researchers agree that low-salinity flooding works better in carbonate formations mainly through ionic exchange in the absence of clays, although with a higher performance of diluted seawater in a water-wet system than oil-wet and intermediate-wettability systems. It is also worthy of note that water-wet sandstones in the presence of clays, have better low-salinity waterflooding. With emphasis that the enhancement of the displacement efficiency in such systems, was as a result of emulsion and dissolutions playing a major role of oil droplets occupying the larger pores and moving to the middle of the pore space. From our data as presented by the authors analysis, it could be seen that low-salinity 10-times diluted seawater flooding (≤ 5,000 ppm) has more improvement in a water-wet environment, with seawater, (≈ 50,000 ppm) having the greatest displacement efficiency in oil-wet and intermediate-wettability systems. **Figure 4.7** and **Table 14** presents the various data for this experiment.

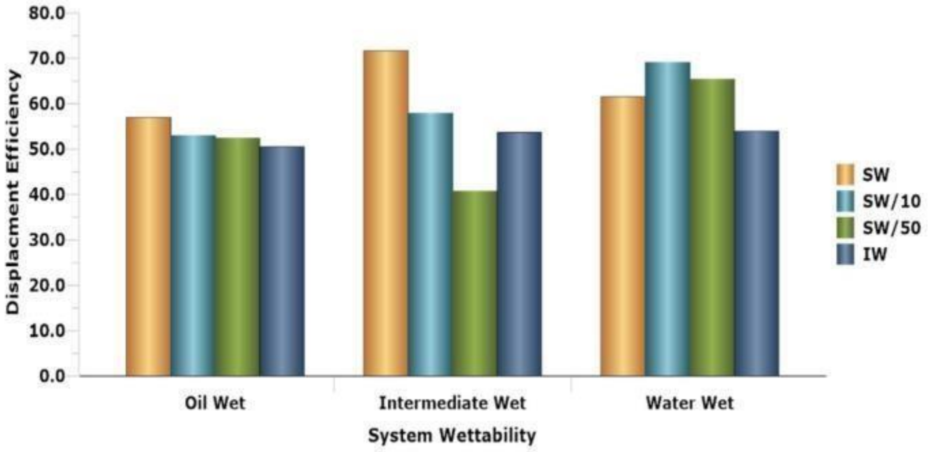


Fig. 4.7 Displacement efficiency of SW, diluted seawater, for different wettability systems

Brine	Oil Wet	Intermediate Wet	Water Wet
SW	57	71.7	61.5
SW/10	53	57.9	69.1
SW/50	52.4	40.8	65.4
IW	50.6	53.7	54

Table 4.4 Displacement efficiency of diluted and IW brines for oil-wet and water-wet systems

Again, as shown in **Fig. 4.8** and **Table 4.4**, the oil-wet system, low-salinity water (10-times and 50-times dilution) shifted the system wettability to water-wet, while the seawater, changed the rock wetness to intermediate presumably through dissolution.

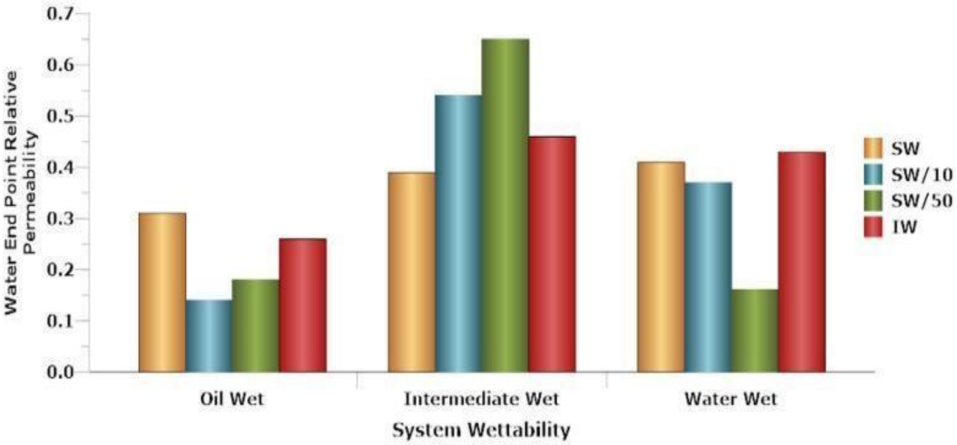


Fig. 4.8 Endpoint relative permeability for the different wettability systems

Brine	Oil Wet	Intermediate Wet	Water Wet
SW	0.31	0.39	0.41
SW/10	0.14	0.54	0.37
SW/50	0.18	0.65	0.16
IW	0.26	0.46	0.43

Table 4.5 Water-endpoint relative permeability fir the different wettability systems

Furthermore, the DE of the sequential systems incorporated in this treatise is affected by the system wettability as displayed in **Fig. 4.8**, with the overall optimum system for sequential injection is sequential IV in water-wet environment system yielding a DE of 88%.

	Oil Wet	**Intermediate Wet**	**Water Wet**
Sequential I	57	40.7	80.09
Sequential II	54	58.12	76.2
Sequential III	52.7	75.09	66.3
Sequential IV	61.4	41.82	88
Sequential V	50.6	70	54.2

Table 4.6 Displacement efficiency of different sequential brine flooding git oil-wet, intermediate-wet and water-wet systems

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

This review collates data displaying the potentiality of utilizing LSWI to enhance the rate recoverable oil in a carbonate reservoir. However, LSWI is a method that hinges on the strength of the comprehensive understanding of the mechanisms that drives the reservoir, or the specific reservoir of interest, as well as the oil–rock–brine interactions. Therefore, with this information, the brine makeup suiting all circumstances wouldn't be feasible. But with proper understanding of the mechanistic attributes of the reservoir, investigation of the response of the ions, whether individually or as a mixture, as well as various oil components on surface charge transformation and wettability modification of different carbonate mineral surfaces, an optimized injection brine can be formulated.

Again, it further proved that sulphate spiking of low-salinity waters had little or no response on the recovery oil efficiency. From the studies, it was estimated that the optimum water salinity around 50,000 ppm for oil and intermediate-wettability environment and 5,000ppm for water-wet system. Furthermore, in a water-wet environment, the optimum displacement mechanism of the studied five sequential schemes, was the sequential flooding IV (seawater/10-times/50-times diluted seawater), with a yield in DE of 88%.

Following the very resourceful works, that have been carried out, evaluating LSWI by major oil field companies and research institutes for the past 20 years, with the studies covering laboratory core floods, single-well reactive chemical tracer tests (SWCTTs) and well-to-well pilots of tertiary LSWI, as well as the analysis of secondary water floods, the push has been to get a better mechanism for a much DE.

Conclusions drawn from this study.

1. LSWI is work in progress EOR method, if well properly understood and harnessed, will yield a potential increase in oil recovery. From literature reviews, it has been reported that, the ranges recovery is between 0 to 15% original oil initially in place, which depends on the rockwater-oil makeup and reservoir state.

2. By synergy, the LSWI supply in a field can be utilised with other water-based EOR methods such as alkaline/surfactant/polymer for even greater potentiality in terms of recoveries rate. With this incorporation, conventional problems such as souring and scaling could be overcome.

3. From studies, it has been recorded that with the many recovery principles recommended by different researched works, there appear no single mechanism which can be taken as dominant, in enhancing oil recovery in LSWI. Therefore, before any field-scale application, a wide range of studies should be conducted on the representative rocks and fluid samples to evaluate the potentiality of the LSWI to enhance recovery rates.

4. Again, it can be drawn that LSWI, if properly harnessed, would be cost effective, bring a balance the economics of the industry.

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