https://doi.org/10.53656/nat2023-2.01

Experiments

ENHANCED OIL RECOVERY IN TERRIGENOUS OIL FIELDS USING LOW-SALT WATER

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Abstract. In order to improve the development of reserves, optimal technologies must be introduced to meet the regular increase in demand for hydrocarbons. Injection of low-salinity water is one of these technologies that have been shown to be effective in solving this problem. Accordingly, low-salt water is investigated as a potential method to increase terrigenous oil recovery. Based on modelling the flooding of solutions with different salinities, the effect of salt concentration on oil displacement efficiency during re-injection was assessed. Salinity reduction efficiency was examined by comparing oil recovery after flooding with high salinity water. Due to active interactions at the oil-water interface, including an increase in viscoelasticity, the oil recovery factor increased with a decrease in salinity. Oil recovery increased by 1.3 – 2% as water salinity decreased.

Keywords: enhanced oil recovery; low-salt water; oil-water interface; viscoelasticity; waterflooding

1. Introduction

The constant increase in demand for oil and its derivatives causes an active interest in new methods of extracting hydrocarbons from productive formations. Conventional methods of oil displacement by reservoir water are ineffective when affecting residual oil, which is contained in isolated reservoir zones, as well as in low-permeability, water-flooded regions. Therefore, the urgent task is to develop and implement alternative technologies that will impact the productive reservoir in order to fully develop it. To solve these problems, methods of enhanced oil recovery using chemical reagents such as polymers, and surfactants, as well as thermal methods are used. During the past few decades, low-salt waterflooding (LSW) of the productive formation has gained much international attention. The effectiveness of this technique has been confirmed through numerous experiments, where control over the component properties and salinity of the injected water has led to very satisfactory results.

Low-salt waterflooding (LSW) technology is a decrease in the concentration of salts and dissolved solids in the water injected into the reservoir and manipulations with its ionic composition in order to increase the oil recovery factor (RF) and reduce residual oil saturation. Low salinity is usually achieved by diluting the formation water with distilled water. The low salinity waterflooding technique is a very widely studied technique in the laboratory, with active research beginning in the 1990s. (Allan & Farad 2019; Ding & Rahman 2017; Al-Obaidi & Khalaf 2019).

The effectiveness of the low-salt method of enhanced oil recovery (EOR) was proven both in secondary and tertiary development methods, where an increase in oil production by up to 15% was observed. When using the secondary recovery method, the use of the technology under discussion results in a later water breakthrough into the well compared to the injection of seawater or high-salinity water (Mahmoud, Elkatatny & Abdelgawad 2017; Al-Samhan et al. 2020; Al-Obaidi 2016). During the tertiary recovery method, lightly salted water has shown the potential to displace additional oil (Rock et al. 2018; Maya Toro et al. 2020). Successful results in the form of increased oil recovery in the course of core tests performed led to attempts to implement low-salt water injection in fields with both carbonate and terrigenous reservoirs. A decrease in residual oil saturation in the bottom hole zone of the reservoir after waterflooding with a solution with a reduced salt concentration was noted in such fields as Omar and Endicott (field of the northern slope of Alaska) (Tayanne, Alexandre Vaz & Larissa Chequer 2021; Hofmann, AL-Obaidi & Chang 2023; Aljuboori et al. 2020).

The main effect of low-salt water injection into an oil-bearing formation is a change in the wettability of the reservoir rock, which leads to a decrease in capillary forces and hydrophobization and, accordingly, an improvement in the oil displacement efficiency. Moreover, low salinity enhances interfacial interactions between oil and water (Peyman Rostami et al. 2019; Fanli Liu & Moran Wang 2020). Various mechanisms are responsible for the effectiveness of this technology, and there are still discussions about the presence of one dominant mechanism. Low-salt water functions differently in carbonate and terrigenous reservoir rocks because of their different mineral compositions.

1.1. *Criteria for low-salt flooding*

To achieve high efficiency of low-salt EOR in terrigenous reservoirs, the salt content in the injected water must be significantly lower than in the formation water, thereby creating a salinity gradient between them. Nevertheless, some sources claim that injecting water below 5000 mg/l will achieve the effect of low-salt water (Chavan et al. 2019; Smirnov. & Al-Obaidi 2008; Zhang et al. 2021). As well as salinity, the ionic composition of the injected water may play a significant role in increasing oil recovery. $CaCl_2$ and NaCl solutions were prepared, for example, when studying low-salt waterflooding on core (Lie Yang et al. 2016; Al-Obaidi 2021; Hidayat, Erfando & Maulana 2018). Having the same salinity of 5000 mg/l, the sodium solution increased the oil recovery factor by 7% more than the calcium solution. It is therefore important to consider the ionic composition of the injecting agent when planning EOR with low-salt water. An increased concentration of divalent cations can negatively affect the outcome; therefore, reducing the amount of these ions is considered a desirable procedure in the development of this EOR.

Reservoirs with a high content of clay minerals are ideal candidates for injecting low-salt water since they have the ability to better "absorb" the polar components of oil (tars and asphaltenes). Therefore, maximum hydrophobicity is provided to observe the expected effect of water with a low salt concentration (Hassan Mahani & Geoffrey Thyne 2023; Saheli Sanyal et al. 2017; Jiang Shan, Pingping Liang & and Yujiao Han 2018; Chang, Al-Obaidi & Patkin 2021).

1.2. *Low-salt flooding mechanisms*

As a result of the comprehensive studies, scientists have identified a number of low-salt flooding mechanisms responsible for high efficiency and improved wettability in terrigenous rocks. Among them, the most common are multicomponent ion exchange, an increase in pH, a decrease in the intersurface tension between water and oil, the migration of small particles, and the expansion of an electric double layer (EDL).

Multivalent and divalent ions, Ca^{2+} and Mg^{2+}, present in the ionic composition of formation water, on the one hand, are attached to clay minerals, and on the other hand, to the polar components of oil, and create organometallic compounds. In addition, in other cases, the listed polar oil compounds are adsorbed immediately on the rock surface without the help of ions (Fig. 1). Both cases lead to an increase in the hydrophobicity of the medium. Low salinity and higher content of simple univalent ions Na^{+} and K^{+} in low-salinity water in comparison with reservoir water provoke multicomponent ion exchange. The bottom line is that simple ions replace multivalent ions that are adsorbed on the surface of the rock, thereby releasing oil along with them. Furthermore, monovalent ions can replace the oil itself through ion exchange (Fig. 2). This exchange of ions results in a change in wettability and an increase in the amount of recoverable oil (Nguele et al. 2016; Hakan Aksulu et al. 2012).

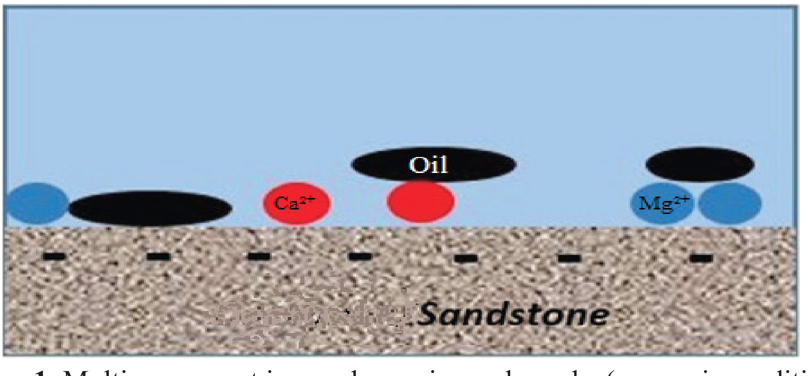

Figure 1. Multicomponent ion exchange in sandy rocks (reservoir conditions)

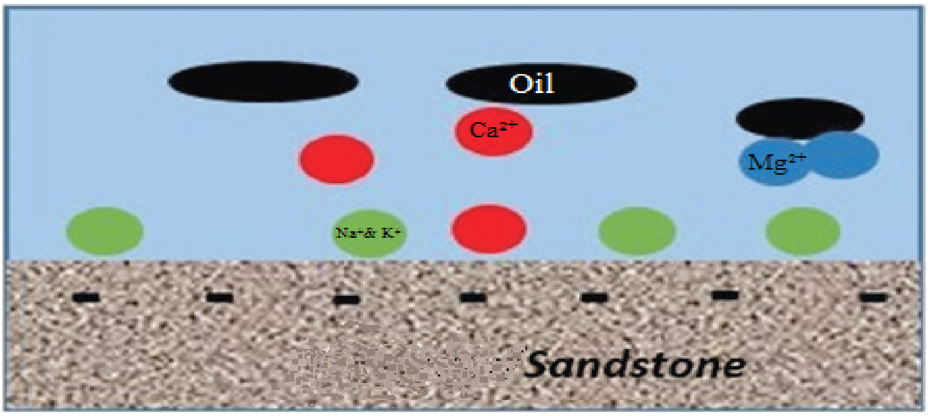

Figure 2. Multicomponent ion exchange in sandy rocks
(Environment with low salinity)

Many researchers believe that the increase in pH caused by low-salt water entering the reaction with the rock improves oil recovery and changes wettability. An increase in pH is considered to be the outcome of the replacement of Ca^{2+} ions by hydrogen ions (H^{+}), which are abundant in a low-salt solution. As a result of the described exchange, OH^{-} is released, which ultimately causes an increase in pH.

As a result of the created alkaline environment, acidic and basic components in the oil composition are easily detachable from the rock surface (Austad, RezaeiDoust & Tina 2010; Al-Obaidi 2015; Qirui Ma, Haitao Li & Ying Li 2020). At the same time, high pH values contribute to an increase in the magnitude of the negative charge of some minerals, which unequivocally positively affects the expansion of the EDL.

In the aquatic environment, the surface of sandstones and clay minerals in terrigenous rocks is negatively charged as well as oil components (-COO^{-}), which should lead to the formation of Coulomb repulsion. However, according to the double layer theory, in a highly saline medium, such as formation water, ions with a charge opposite to that of the surface itself gather around and near the electrostatically charged surface. This provokes the formation of an electric double layer of counterions, which shields the electrostatic forces of repulsion and promotes the "sticking" of oil to the rock. Low-salt water, on the other hand, exhibits a deficit of ions, causing a thicker EDL due to scattered ions, which do not overlap, but instead increase the repellent force. Consequently, in low-salt flooding, due to the wide EDL, oil is repelled from the rock, and electrostatic forces resist further adsorption of hydrocarbons (Patrick et al. 2015; Adango, David & Mumuni 2023; Al-Obaidi, Patkin & Guliaeva 2003; Tetteh et al. 2020).

The mechanism for reducing intersurface tension in the oil-water system is not so popular, because it is believed that the reduction of tension by low-salt EOR is insignificant to the observation of high oil recovery factors (Abhijit, Ganesh & Jitendra 2020; Deng et al. 2021). It should be noted that the pH of the aquatic environment after a low-salt solution is not high enough. Since the decrease in intersurface tension between lightly salted water and oil depends on pH, it may not be noted due to unsatisfactory pH values. Therefore, this mechanism is not the main explanation for the increase in the oil recovery factor. Separate studies however are provided (Xuefen Liu et al. 2022; Cheraghian & Hendraningrat 2016; Al-Obaidi 2016), where a positive reaction was observed in the form of an improvement in hydrophilicity due to a decrease in interfacial tension.

The mechanism for the migration of small particles is to clog the reservoir pore channels with fine particles of clay. The bottom line is that low-salt water increases the electrostatic repulsive forces between clay particles and the rock itself to which they are attached. Further, the detached particles accumulate and block the paths, and the water flow, due to the inability to pass further, is redirected to hard-to-reach regions of the pore space, where oil may be located, and thereby ensuring effective cleaning (Derkani et al. 2018; Tian & Wang 2018; Nasralla, Bataweel & Hisham 2013). The described mechanism requires the presence of clay particles in the reservoir in order to achieve a certain increase in oil recovery. Particular attention should be paid to the content of clays that do not swell namely kaolinite and illite. Nevertheless, there are cases in the literature where the effect of low-salt waterflooding was also observed in the absence of fine clay fractions.

Methods and materials Characterization of the field

The field under study is located in the west of Kazakhstan. Exploration wells have opened 4 productive oil reservoirs composed of Upper Permian rocks, which are being developed as one production facility. The rocks are predominantly clayey, among which sandstones and silts stand out, serving as reservoir rocks. Since the object is multilayer, there are problems with drainage and low-permeable rocks during the development. Based on the relative phase permeability curves (RPP), it can be concluded that the rocks interact with a particular liquid. Based on the curves, the RPP equal point corresponds to water saturation of SW > 0.5, so water is the wetting phase (Fig. 3).

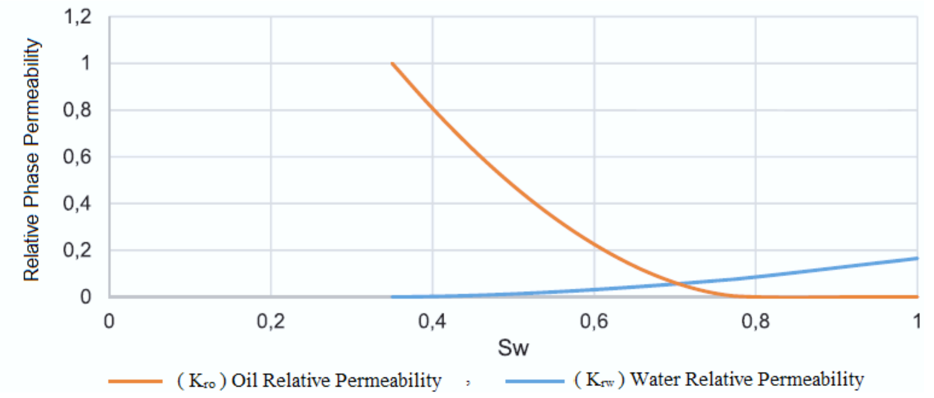

Figure 3. Curves of relative permeability of the investigated field

The main properties of the oil and the reservoir are listed in Table 1.

Table 1. An overview of the studied field's main characteristics

Parameter	Value
oil density, kg/m³	756
oil viscosity, mPa*s	1,33
Gas content, m³/m³	107,7
Oil volume factor	1,282
Saturation pressure, MPa	12
Initial reservoir pressure, MPa	31
Reservoir temperature, C	57

With a total salt content of 317 kg/m3, the formation waters of productive horizons are hard and highly saline. The component composition of these waters is dominated by Na^+ and Cl^- ions (Table 2). The field is developed by maintaining reservoir pressure by injecting water from water wells.

Table 2. The ionic composition of the reservoir water and the injected water

Ions, kg/m³	Formation water	Injected water
$Na^{+}+K^{+}$	118,7–120,9	10,1
Cl^{-}	189,5–192,9	15,3
SO_4^{2-}	1,603	0,881
Ca^{2+}	3,4–3,6	0,16
Mg^{2+}	0,4–0,6	0,061
HCO_3^{-}	0,268	0,336
Total salinity, kg/m³	317	26,9
Ph	6,5–6,7	7,54

2. Modeling

The low saltwater flooding simulation was implemented through the three-phase ECLIPSE 100 simulator. This simulator has a low-salinity water option, which is activated via the keyword "LOWSALT" in the RUNSPEC section. It relates the total salinity of the water to relative phase permeability curves. To do this, it is necessary to determine the relative permeability curves for waters with high and low salt content. Waters with salinities between these two curves are interpolated using the LSALTFNC (low-salt) function.

In this work, the injected water from water wells with a total salinity of 26.9 kg/m³ will act as high-salinity (HS) water. After analyzing the RPP for water with high salinity and selecting the degrees of the Corey function, it is possible to construct a curve for low-salinity water. This is easily done by determining the value of residual oil saturation (S_{or}) after low-salt flooding. Since the efficiency of low-ion water has not yet been studied in this field, the central challenge was to determine how low salinity could affect residual oil saturation. In order to achieve this, the works of previous years were studied, which describe the use of low-salt EOR on the scale of the field, rather than on the scale of the core. According to (McGuire et al. 2005), in a terrigenous reservoir, dilution of high-salinity water by a factor of 10 lowered S_{or} by 9%. Therefore, we can assume that for the studied field, a 10-fold decrease in salinity can reduce the residual oil saturation by 9%: water with a salinity of 2.69 kg/m³ would lower S_{or} from 0.206 to 0.116 (Fig. 4). In addition, the effect of water dilution 2 times (13.45 kg/m³) was considered. The RPP curves for a given salinity value were interpolated according to the F1 coefficients for LSALTFNC (Table 3).

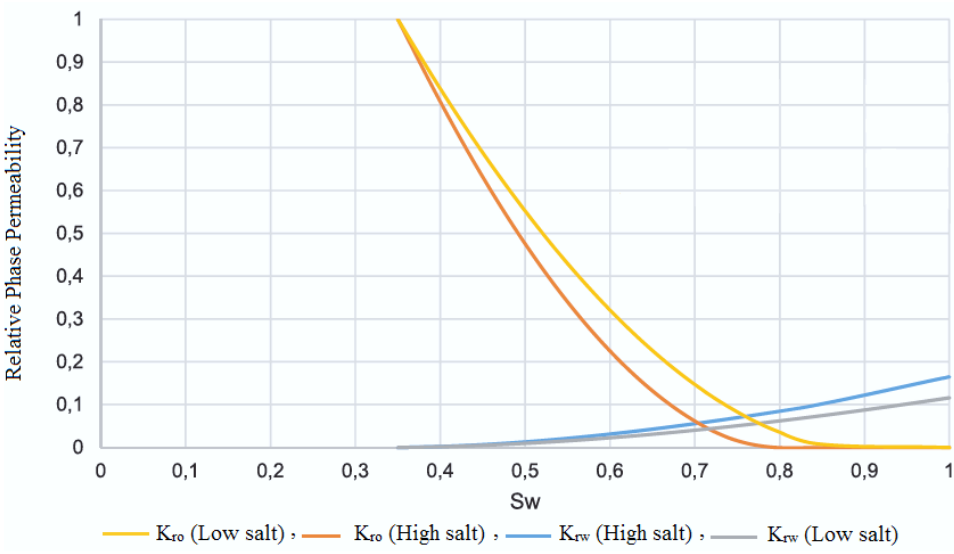

Figure 4. High-salt and low-salt water relative phase permeability curves (K_{ro} – Oil relative permeability, K_{rw} – Water relative permeability, Sw – water saturation)

There was no change in the distribution of injection and production wells for the simulation in the study. The wells are vertically directed. With a target flow rate of 100 m^3/day, all 14 production wells were opened simultaneously for simulation. The bottom hole pressure limit in production wells has been set at a level that is greater than the saturation pressure in order to prevent degassing of reservoir oil. The operation of three injection wells was limited by the bottom hole pressure of 65 MPa, which did not exceed the formation fracture pressure.

Table 3. The coefficients of the LSALTFNC function

Salinity, kg/m³	F_1
2,69	1
13,45	0,5
26,9	0

3. Results and discussions

3.1. *Results*

The impact of salt concentration on production and oil displacement efficiency in the considered field during re-injection was determined by simulating the flooding of solutions with a salinity of 26.9 kg/m³ (HS), 13.45 kg/m³ (2d x HS) and 2.69 kg/ m³ (10d x HS). The model was run for 18 years, or approximately 6500 days. Analysis of salinity reduction efficiency was carried out by comparing the oil recovery after flooding with high salinity (HS) water.

Figure 5 shows that a solution with an ion concentration of 26.9 kg/m³ displaced about 15.6% of the original reserves. Figure 6 illustrates the cumulative oil and water production curves. According to the data received, the oil began to be produced immediately, while water took longer to break through into the well.

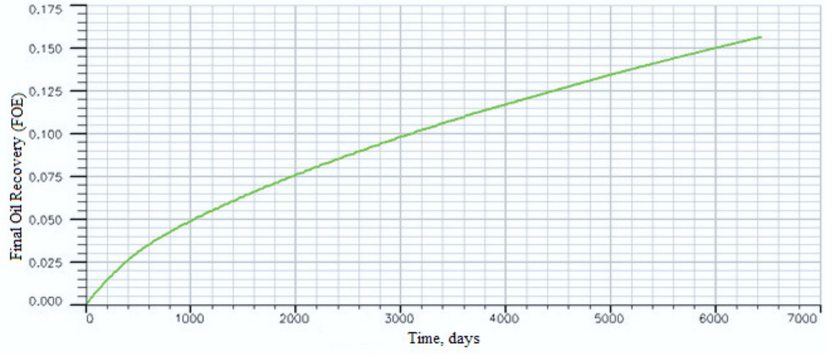

Figure 5. Oil recovery efficiency by high salinity (HS) water (26.9kg/m^3)

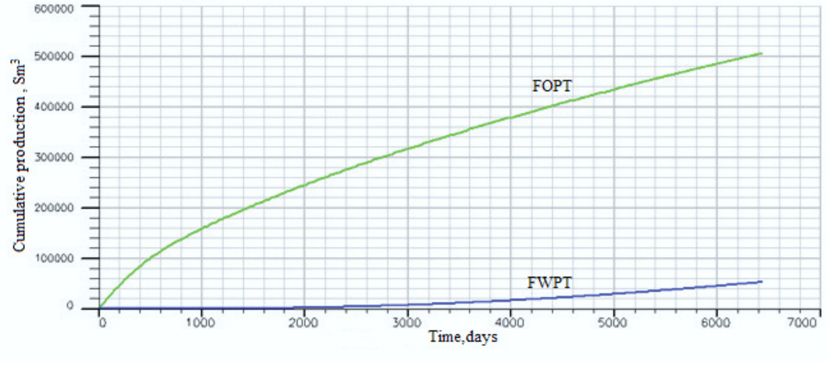

Figure 6. The cumulative production of oil (FOPT) and water (FWPT) during high salinity (HS) water flooding (26.9 kg/m^3)

Since the salt content of the injected agent is much lower than that of the formation water (317 kg/m³), solids are present in the produced water, as shown in Figure 7. The presence of salts is a consequence of the presence of a salinity gradient and the establishment of a new chemical equilibrium.

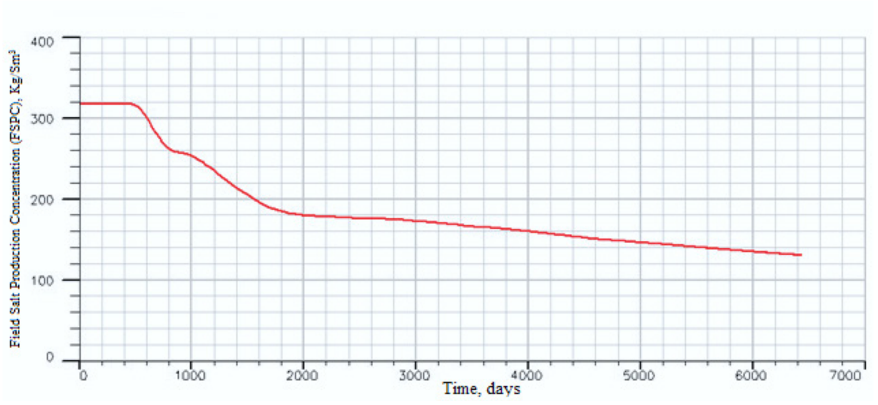

Figure 7. Produced water salt concentrations after injection of high Salinity (HS) water (269kg/m³)

Further, when using solutions diluted 2 times (2d x HS) and 10 times (10d x HS), an increase in oil production and an increase in its recovery factor by 1.3% and 2%, respectively, are observed (Fig. 8,9).

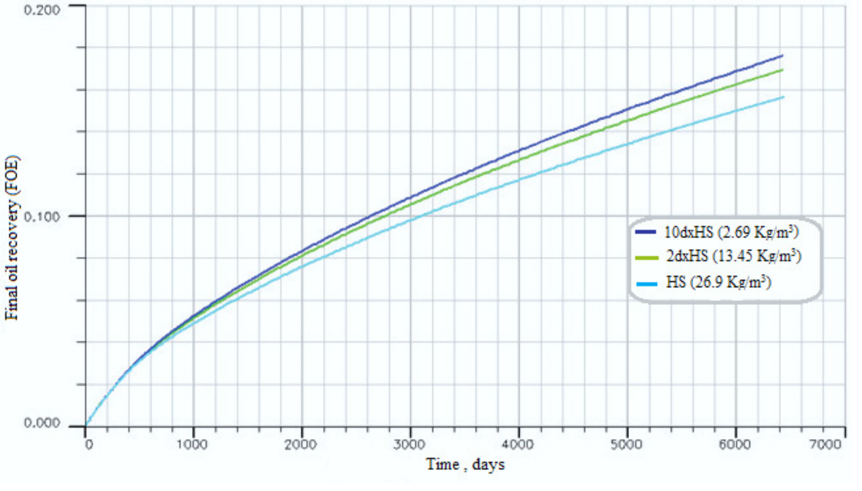

Figure 8. Oil recovery efficiency using dilution solutions

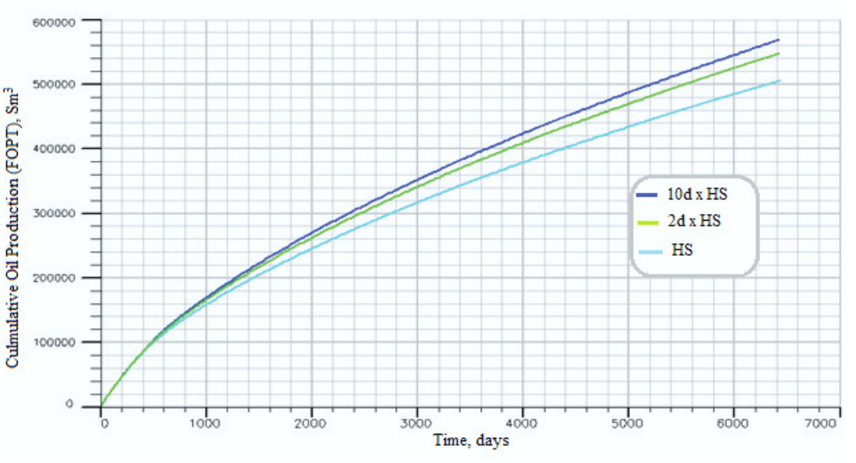

Figure 9. Cumulative oil production using dilution solutions

Thus, a 2-fold decrease in salt concentration provokes an increase in oil recovery efficiency by ~1.3%, while diluting the initial salinity by 10 times produces an additional ~2% of oil. According to the curves of cumulative oil production and water, it took about 500 days for the activation of low-salt solutions and for the necessary reactions between water and rock/oil to occur. The difference in growth rate (0.7%) between low-salt water types suggests that there is an optimal salt concentration below which further oil recovery may not increase. As the salinity of the injected water decreases, the salt content of the produced water decreases (Fig. 10).

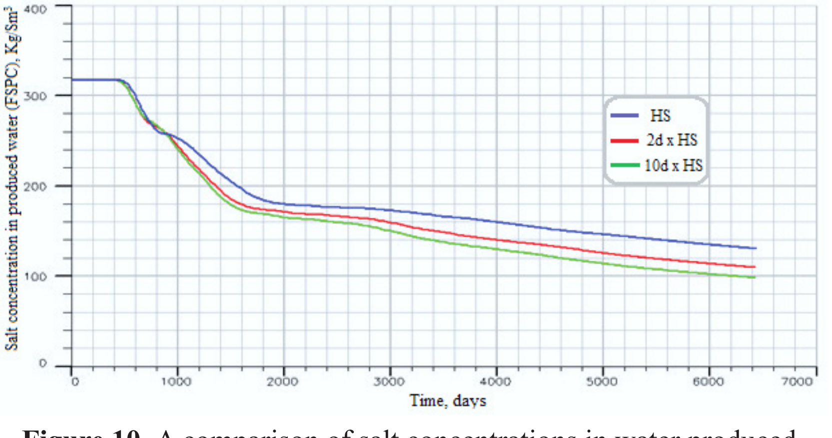

Figure 10. A comparison of salt concentrations in water produced after injection with HS water

3.2. *Discussions*

The effect of low-salt water was not as significant as expected. This is due to the fact that the rock surface was initially hydrophilic. There was not enough adsorbed oil for low-salt water to exert the necessary influence and change wettability. Hydrophilicity is determined by the low concentration of divalent ions (Ca^{2}+ and Mg^{2}+) in the formation water and, accordingly, by the low content of organometallic compounds. It follows that the divalent ions present in the formation water and rock-bound oil are necessary attributes for multicomponent ion exchange. At the same time, a slight increase in production may be due to the possibility that the HS water considered in this work (26.9 kg/m^3) may act as low-salt in comparison to formation water (317 kg/m^3). Moreover, it may not make an enormous difference in hydrocarbon recovery when comparing two solutions with different solids contents (26.9 kg/m^3 and 2.69 kg/m^3).

As noted, a lithological replacement of permeable sandstones with clay-rich rocks is observed in the section of productive formations. Therefore, the supposed reason for the increase in the oil recovery factor may be that low-salt water releases clay particles due to an increase in electrostatic forces. As a result, free fine particles clog pores in highly permeable layers. Thus, the flow of water is redirected and gets access to less permeable oil regions and cleans them. However, more experimental studies are needed to be fully confident in this process.

An explanation for the observed increase in production can be a change in interactions not only on the surface of the rock but also at the oil-water interface. Moreover, given the hydrophilicity of the reservoir rock, it can be assumed that such an outcome is quite acceptable. The low salt concentration contributes to an increase in viscoelasticity when oil interacts with water. The created viscoelastic medium prevents the breakage of the oil phase and the formation of ganglia/droplets during the movement of oil from one pore to another. Most often, the detached ganglia become immobile due to capillary forces and remain in the pores. Consequently, the viscoelastic boundary provokes the merging of all oil ganglia into one whole phase (Zhang, Yue & Guo 2008; Zheyu Liu et al. 2019; Yazhou Zhou et al. 2017; Al-Obaidi, Hofmann & Smirnova 2022) and ensures the subsequent displacement of oil toward production wells. As this effect/mechanism is activated through the reaction of low-salinity water with oil, injecting water with low salinity in this field can increase oil production. It should be noted that an increase in the oil recovery factor may be a consequence of the synchronous action of several mechanisms, and not just one. Many factors influence the factor of oil recovery, including wettability, the characteristics of the formation oil, as well as formation temperature and pressure, and so on.

To obtain an accurate description and deep reasoning, it is recommended to conduct a laboratory experimental analysis using the rock and the above liquids. The nature of the study also changes depending on its scale. The interaction of water with oil in a low-salt environment can be described at the pore scale, while the reaction of a hydrophobic rock in contact with low-salt water can be studied both at the pore scale and at the core scale. Experimental waterflooding with a low-salt solution on core material makes it possible to evaluate the behaviour of relative permeability curves. This, in turn, guarantees an accurate prediction of the effectiveness of the discussed EOR.

5. Conclusions

In this paper, the criteria and well-known mechanisms of low-salt water flooding have been listed and described. In addition, an assessment was made of the effectiveness of low-salt water in extracting oil from a terrigenous hydrocarbon field. Based on the results obtained, the following conclusions were made;

When modelling low-salt waterflooding at a terrigenous hydrocarbon field, it turned out that a decrease in the salt content in the injected water by 2 and 10 times led to the observation of an increase in the oil recovery factor of 1.3% and 2%, respectively. The insignificant difference between the studied low-salinity waters in the efficiency of oil displacement indicates the presence of the optimal salinity of the injected water.

The initial hydrophilicity of the reservoir rock surface excludes wettability change as a reason for the increase in oil production. A likely explanation for the increase in oil production can be the formation of a viscoelastic boundary between oil and low-salt water, which provokes the coalescence of separate oil droplets into a single whole and subsequent extraction.

A study of low-salt waterflooding on core material from the field under investigation is recommended to obtain accurate relative permeability curves and to understand how low salinity affects oil distribution.

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