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Review and data analysis of low salinity water effect through induced fine migration

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REVIEW AND DATA ANALYSIS OF LOW SALINITY WATER EFFECT

THROUGH INDUCED FINE MIGRATION

by

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ABSTRACT

Low salinity water flooding (LSWF) is well proved to be an effective EOR technology both in laboratory and field tests, however, the conditions for LSWF to work and EOR mechanism is still debatable. Up till now, many mechanisms have been proposed to explain the incremental oil recovery in sandstone by LSWF, for instance, fine migration, ionic exchange, wettability alteration and pH increase.

In this study, we only focus on low salinity water flooding effect through induced fine migration mechanism. The objective of this study is to conduct a comprehensive analysis using statistical analysis methods and explaining the mechanism of fine migration and its impact during low salinity water flooding in sandstone reservoirs. First, we extracted data from a large number of LSWF flooding tests using sandstone core samples that have been published to date (by January 2019), and analyzed the permeability and injected pressure difference change during the flooding process results collectively. In most of the sandstone flooding experiments, the permeability will decrease because of the migration of fine particles except some cores with extremely high initial permeability. Secondly, according to the particles detachment model six rock/fluid system properties are pointed out to be the reason of particles detachment in porous media, including clay minerals concentration, injection brine velocity, brine salinity, brine pH, divalent ion concentration and oil viscosity. Experimental results are collected, organized and analyzed, from different papers, different authors and comprehensive analysis were made to reveal the impact of high relative rock/fluid system properties on permeability change and oil recovery.

ACKNOWLEDGMENTS

I would like to thank my advisor, Dr.Mingzhen Wei. Her help and advice helped me successfully complete the research; her encouragement to me always supports me when I am perplexed; her advice to me always wakes me up when I am most helpless. No words can express my gratitude to her help. In addition, I would like to thank my committee members, Dr. Baojun Bai and Dr. Ralph Flori Jr, without their valuable advice, I will not be able to complete my research.

I am also thankful to my great research group members, Jianqiao Leng and Ya Yao, their suggestions and opinions always help me find the right research direction, they can always provide me with the right solution when I have a problem. It is my great honor to be in the same research group with you. Thank you all for being with me whenever I need help.

At last but not least, I want to express my deepest love to my family. Especially my beloved, He Wang, her support and understanding is the greatest help to me.

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NOMENCLATURE

Symbol	Description
LSWF	Low Salinity Water Flooding
EOR	Enhanced Oil Recovery
LSW	Low Salinity Water
SPE	Society of Petroleum Engineerings
Ko	Original permeability
Po	Original Pressure Difference Here
mD	Millidarcy
cP	CentiPoise
OOIP	Original Oil In Place

1. INTRODUCTION

Water flooding is the most frequently implemented oil recovery worldwide to maintain reservoir pressure and displace oil. Basically, seawater or produced water with high salinity is injected back into the reservoir to displace the oil in place. Over the last two decades, many experimental results and field tests have shown that, comparing to the traditional water flooding, low salinity water can achieve higher oil recovery factors and lower residual oil saturation. However, the conditions for LSWF to work and EOR mechanisms associated with LSWF are still unclear. No accurate model exists to estimate the extent of low salinity water effect. LSWF studies started decades ago, the concept of Low Salinity water flooding was introduced by Bernard back to 1967 (Bernard, 1967). But, people believed that injected low salinity water will decrease the permeability of the reservoir which will cause damage to the formation. As a result of this concern, not many researchers really interested in this topic. Until 1990, the EOR potential was recognized by Morrow and his co-workers (Tang 1997, Jadhunandan 1991, Yildiz 1996, Zhang 2006), they observed from their experiment during 1990 to 1999 that water composition will affect oil recovery. First, in 1991, Jadhunandan and Morrow found that changes in injection brine composition affected oil recovery. Later in 1996, still in the same research group, Yildiz and Morrow confirmed Jadhunandan's hypothesis, and did further research on whether specific condition of the oil/rock and brine systems would affect oil recovery. Till the end of 1990s, after Tang did relevant experiments, people began to really think highly of the effect of low salinity water on oil recover factor. Credit to Morrow and his co-workers attributes to the LSWF study, more and more researchers have been interested in the EOR potential of LSWF at the end of last century, many experiments were carried out using different combination of injection brine salinity and connate water salinity.

Nowadays, eight mechanisms have been widely investigated, which are (1) fine migration, (2) wettability alteration, (3) increased pH and reduced interfacial tension, (4) surfactant-like behavior, (5) multiple ion exchange, (6) double layer effect, (7) mineral dissolution and (8) osmotic pressure. However, some mechanisms are still under debate, for instance salt-in effect, emulsification effect and salinity shock. Among all of these mechanism, fine migration was mentioned earliest back to 1967 by Bernard (Bernard, 1967). As research continues, people have a deeper understanding of the fine migration mechanism. Fresh water flooding resulting in the release of clay particles and a dramatic reduction in permeability was reported in 1987 (Kia et al. 1987). Valdya and Fogler (1992) found that a gradual reduction in salinity kept the concentration of mobilized particle low, which would limit formation damage or totally avoided it. In some degree, their research result helps to reduce the formation damage problem. Tang and Morrow (1999) discovered that the fine mobilization (Mainly kaolinite) would increase oil recovery with the decrease in brine salinity. However, Lager (2006) reported that no fine migration or permeability reductions was observed during numerous core flooding process although these core floods had all shown increased oil recovery. On the contrary, no LSW effect in their experiments but with sand production was mentioned by Boussour (2009). Thus, whether fine effluent could be the evidence of the LS effect is still not clear, further research is needed to investigate the relationship between fine effluent and LSWF induced EOR affect. In recent years, during 2000 to 2015, researchers tried to build the model to describe particle detachment for single phase flooding process, no integrated model for two phase flow accompanied by fine migration could be found. Bedrikovetsky (2010) used the maximum retention function to describe the rate of particle detachment and Yuan and Shapiro (2011) proposed the kinetic relationships for particle detachment for single-phase flow. Why the migrated fine has EOR potential? Till now, it is widely accepted that, when fine migrated, the clay particles will plug the smaller pores or pore throat, then the formation permeability is reduced, and the water is forced take other flow paths. As a result, the sweep efficiency is improved.

The objective of this research: focus on the fine migration mechanism, collected core flooding experiments and results data to investigate the related parameters and their effect on fine migration and oil recovery factor during LSW flooding process.

2. LITERATURE REVIEW AND DATASET CONSTRUCTION

This thesis carries out a study of low salinity water flooding in sandstone reservoirs based on laboratory coreflooding experimental data. The data were collected from 56 published literatures which conducted at least one coreflooding experiments each, between the published year of 1955 to 2019, shown in Figure 2.1. The bars in the figure indicate the number of articles collected according to the number of years, as introduced earlier, although the LSW study began in the 1950s, it was not until about 2000 that people began to really pay attention to this field. A dataset was built based on the experimental results from 281 sandstone core samples included in these 56 papers, important experimental setup parameters are recorded, for instance, core length, core diameter, clay concentration, oil density, oil viscosity, injected water salinity, injection rate. In addition, detailed experimental results are also included, like permeability change, pressure change alone the core sample, wettability change, pH of the effluent water, etc. After all of these experiment-related parameters were collected, Tableau, a dataset analysis tool, was applied to visualize the data and have a better understand of the core flooding process.

2.1. SUMMARY OF THE COLLECTED PAPER

In total, there are 976 rows of laboratory experiment data that were collected from these 281 sandstone core samples. The dataset includes both core flooding experiments and spontaneous imbibition tests. The data sources are SPE conference papers, SPE journal papers, books and technical reports. A summary of the parameters collected in the database is presented in Table 2.1. It is necessary to note that the flooding stage (single-phase, secondary and tertiary) was considered an important category in the flooding experiments examined in this work to analyze the effects of the changes of related properties during single-phase flooding and secondary and tertiary recovery.

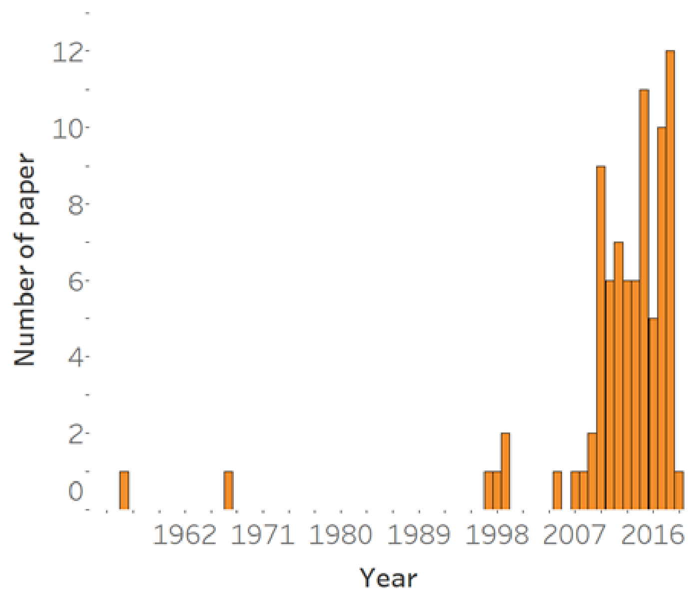

Figure 2.1 Referenced paper distribution by published year.

Some parameters from the laboratory experiments have large proportion of missing values, such as the pH of the rock-brine system, the zeta potential of the brine and oil and the concentration of some ions, due to unpublished datasets or different experimental objectives. Therefore, this analysis was completed based on the available data, and the missing data are neglected intentionally.

As mentioned, all lab experiments are classified into three different types: single-phase flooding, two-phase secondary flooding and two-phase tertiary flooding. As the initial conditions of the core samples are different, results from different types of experiments were analyzed separately. As shown in Figure 2.2, and the height of bars show the amount of rock sample in different flooding stages. The single-phase flooding experiment is an ideal model as it helps to verify whether fine is produced in the effluent and to determine the permeability change during the flooding process. Therefore, there are less single-phase flooding experiments than two-phase experiments.

Table 2.1 Recorded parameters and concentration of missing data.

Recorded Parameters and Concentration of Missing Data		
Parameters	Available Counts	% of Missing Data
Rock Type	746	2%
Clay Concentration (%)	174	77%
Rock Diameter (mm)	721	5%
Rock length (mm)	709	7%
Initial Permeability (mD)	692	9%
Porosity (%)	704	7%
Oil Viscosity (cp)	650	15%
Oil Density (g/cm3)	603	21%
Formation Water Salinity (ppm)	685	10%
Maximum LSW Salinity (ppm)	633	17%
Injection Rate (ml/min)	583	23%
Total Salinity (ppm)	723	5%
Temperature (degree)	409	46%
Permeability Change (md)	56	93%
Pressure drop (psi)	241	68%
Calcium Ion Concentration (ppm)	52	93%
Magnesium Ion Concentration (ppm)	51	93%
Sulfate Ion Concentration (ppm)	45	94%
PH of effluent	193	75%
Contact Angle (degree)	106	86%
Interfacial Tension (dyne/cm)	51	93%
Residual Oil Saturation (%)	105	86%
Oil Recovery (OOIP%)	531	30%

Single-phase flooding: most of the single-phase flooding experiments followed the same procedure: before performing the core flooding experiment, cores were initially flushed with carbonate dioxygen gas for several hours (typically 2 to 3 hours) and saturated with high salinity synthetic brine, which represented formation water salinity. In addition, a back pressure was maintained throughout the experiments to ensure there was no more free gas come out from the core. Then, the saltwater was displaced by low-salinity water, and the permeability of the core was calculated by a monitored pressure drop across the core sample (Zeinijahromi.A, 2013).

Two-phase secondary flooding: as with the single-phase flooding experiments, synthetic brine or formation water was injected into dry and clean core samples. The brine was then displaced with oil until irreducible water saturation was attained. Finally, the oil was displaced by low-salinity water until irreducible oil saturation. This kind of experiment focuses on the effect of LSW flooding during the secondary flooding mode by applying LSW flooding before any other EOR method. It explains the pressure difference between LSW flooding and normal water flooding.

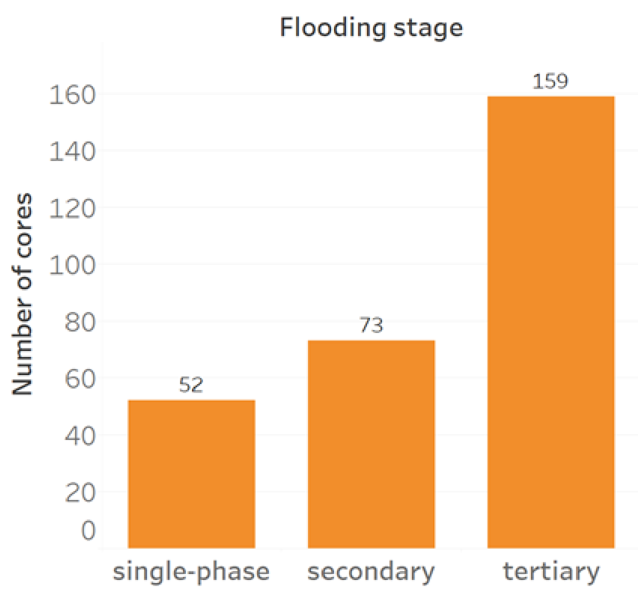

Figure 2.2 Number of core samples during different flooding stages.

Two-phase tertiary flooding: In the two-phase flooding experiments, dry and clean core samples were initially saturated in brine or formation water. Then, oil was injected until irreducible water saturation was attained. Afterwards, oil was displaced by high-salinity water to establish residual oil saturation. Subsequently, the core was percolated with oil until the same irreducible water saturation was attained again. Finally, low-salinity water was injected to displace the oil. This kind of experiment examines the effect of LSW application after the application of normal water flooding. It tries to determine the improvement of the LSW flooding based on the high-salinity water flooding performance.

2.2. MODIFIED DETACHMENT MODEL

The modified particle detachment model uses the maximum retention function to describe the ratio of particle detachment (Bedrikovetsky et al. 2010). In this model, retained particles reach a maximum concentration when the static equilibrium of forces acting on a particle. Fluid velocity may changes the maximum retained concentration below the current retained concentration, causing more particles releasing into the porous media. The assumptions of this model are: (1) all particles are assumed to be perfect spheres of equal radius and of the same material, (2) porous media are represented by cylindrical tubes and filled will injected fluid. Figure 2.3 clearly shows the forces acting on the fine particles during the flooding process in porous media. Under these assumptions, the main force acting on the surface of internal particle are drag, gravity, lift and total electrostatic force.

Drag and lift force caused whenever a particle was flowed over by the fluid, and are proportional to fluid velocity, size of the particle and fluid viscosity. The gravity force is the buoyant weight of the particle immersed into any fluid. Because the size of the particle is really small and the density of the rock material is much larger than the fluid, the gravity force is insignificant compared with other forces, thus, in this model, and it can often be ignored. At last, the electrostatic force describes the interaction between fine particles and pore wall, which is independent of fluid velocity. The impact on electrostatic force due to the interaction of the rock, oil and brine system is relative complex. To sum up, electrostatic force is taken as the maximum value of the sum of van der Waals, electrical-double-layer, and Born forces described by the Derjaguin, Landau, Verwey and Overbeek (DLVO) theory (Lemon.P 2011). As the conclusion of this theory, electrostatic force is related to the pH and fluid composition. Considering all the significant forces acting on the particles and related parameter of the three-phase system. This paper tries to describe the fine migration based on the analysis of change of six parameters during the flooding process, which are clay minerals concentration, fluid velocity, brine salinity, brine divalent ion concentration, injected brine pH and oil viscosity.

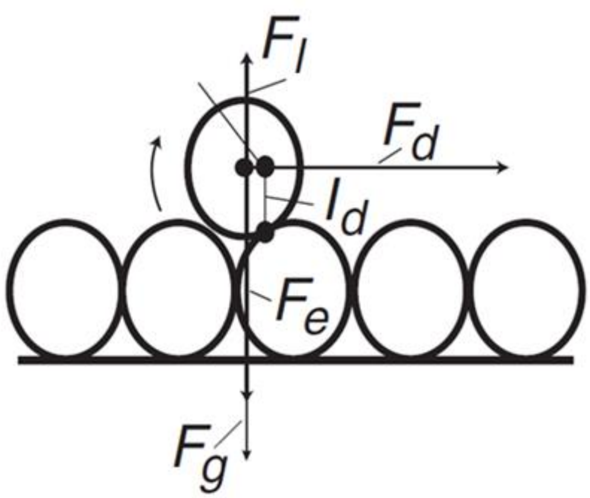

Figure 2.3 Force acting on attached particle during flow in porous media.

2.3. FINE MIGRATION EFFECT QUANTIFICATION

Before the presentation of the results of the dataset analysis, it must be clarified that the quantification of fine migration is difficult to accomplish because of two reasons: first, it is hard to tell whether fine migration happened or not in the core samples. Second, it is almost impossible to measure how many particles have migrated during the flooding process. Because there is still debatable that weather the effluent of fine particles can be the evidence of the fine migration induced low salinity water effect. Take some experimental results for instance, although, some laboratory tests have reported significant amount of released fines during core-flood with low salinity effect (Lever and Dawe, 1984; Pu et al., 2010; Fogden et al., 2011). Experimental results do exist that low salinity effect with no evidence of fines release, but with an additional oil production (Yildiz and Morrow, 1996; Jerauld et al., 2008; Lager et al., 2008; Rivet et al 2010). However, lack of observation of fines at the core outlet does not rule out the possible local migration of in-situ fines at the pore scale, which are hard to detect in the produced oil phase (Fogden et al., 2011).

To solve this problem, in many papers, the authors tried to use the permeability change during the single-phase flooding and pressure change alongside the core samples during the secondary and tertiary flooding stages to reflect the impact of fine migration on the core samples. In this study, the ration of the permeability and pressure change are applied to reveal this impact:

$$\frac{K}{Ko} = \frac{Permeability_{LSW}}{Permeability_{HSW}} \tag{1}$$

$$\frac{P}{Po} = \frac{Pressure\ change_{LSW}}{Pressure\ change_{HSW}} \tag{2}$$

K/Ko is the ratio of rock sample permeability under LSW flooding process to the permeability under a formation water flooding process during single-phase flooding. P/Po means the ratio of the pressure difference along the core samples under an LSW flooding condition to the pressure difference under its original flooding fluid condition; it does not matter if it is formation water, seawater, or high-salinity water, only if the salinity of the original fluid is recorded. When P/Po = 1 or K/Ko = 1, it means that the pressure difference or permeability of the core samples do not change during an LSW flooding process. The relationship between K/Ko, P/Po and other parameters are shown below to reveal the impact of fine migration on core samples.

3. RESULTS AND DISCUSSION OF LINKING EXPERIMENTAL PROPERTIES

Basic information on the linking experimental conditions (rock, oil and water) is presented in this section. Statistical analysis tools, such as the bar chart, histogram, and box-plot and cross plot, are used to visualize and analyze the data. All of the plots were generated in MS Excel and Tableau, a dataset visualization software.

3.1. CORE SAMPLES PROPERTIES

Figure 3.1 details the dataset distribution of each type of sandstone that was used in the core flooding experiments and its average permeability. The permeability recorded in databases is the absolute permeability measured by the authors before the core flooding experiment to ensure uniformity of permeability. Of the 32 different types of sandstone core samples, one is unknown. The most used sandstone in the collected core flooding experiments is Berea sandstone, which is a sedimentary rock whose grains are predominantly sand-sized and are composed of quartz held together by silica, totaling 229 samples. The relatively high porosity and permeability of Berea sandstone make it a suitable reservoir rock.

Core lengths and diameters from the core flooding experiments are shown in Figure 3.2. Most of the core samples are 37 mm in diameter and 77 mm in length. Some core samples with relatively larger sizes (up to 500 mm in length) are composed of different small core samples together to achieve certain porosity and permeability.

Porosity and permeability in the data distribution are illustrated in Figure 3.3 and Figure 3.4, respectively. The porosity range of the most used type of core samples is from 18% to 24%, which is the typical porosity value of Berea sandstone.

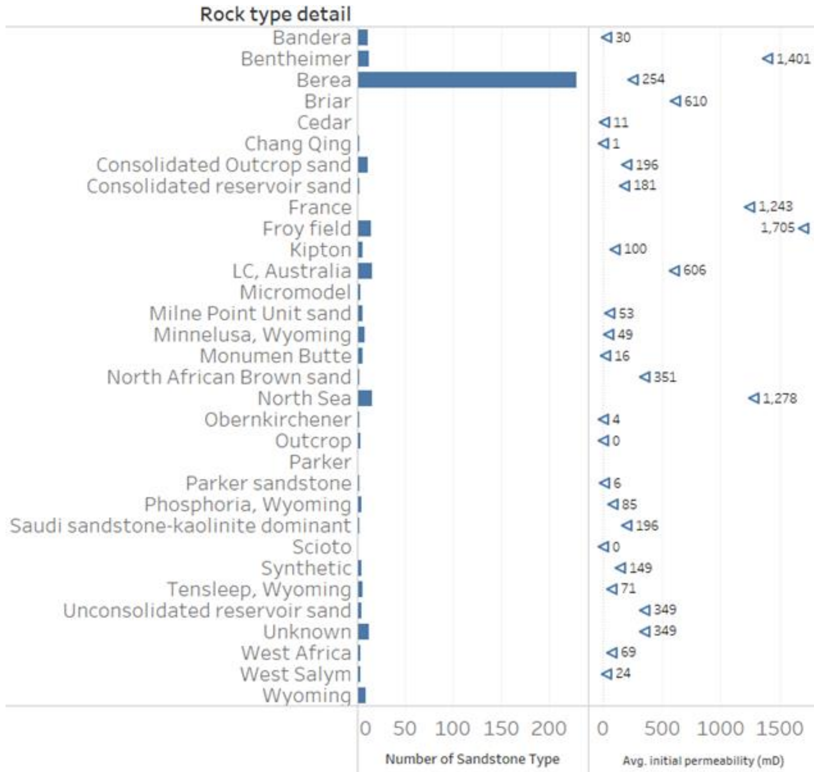

Figure 3.1 Number of different sandstone core samples and average initial permeability.

The minimum value of porosity is 5%, found in sandstone from West Africa, and the maximum value of porosity can reach 40% in a core sample of North Sea sandstone. Nearly 98% percent of core samples' permeability are in the range of 0 to 1000 mD. Only 2 to 3 core samples have relatively higher permeability in the dataset, which can reach 5000 mD; this upper limit is ignored in the analysis, and the permeability under 1000 mD distribution is shown in Figure 3.4. Most of the core samples have permeability around 100 mD, and the lowest value is 0.3 mD in a core of Chang Qing sandstone from China. The highest value is 1006 mD from a Bentheimer sandstone core sample. These figures clearly show the permeability and porosity of different cores.

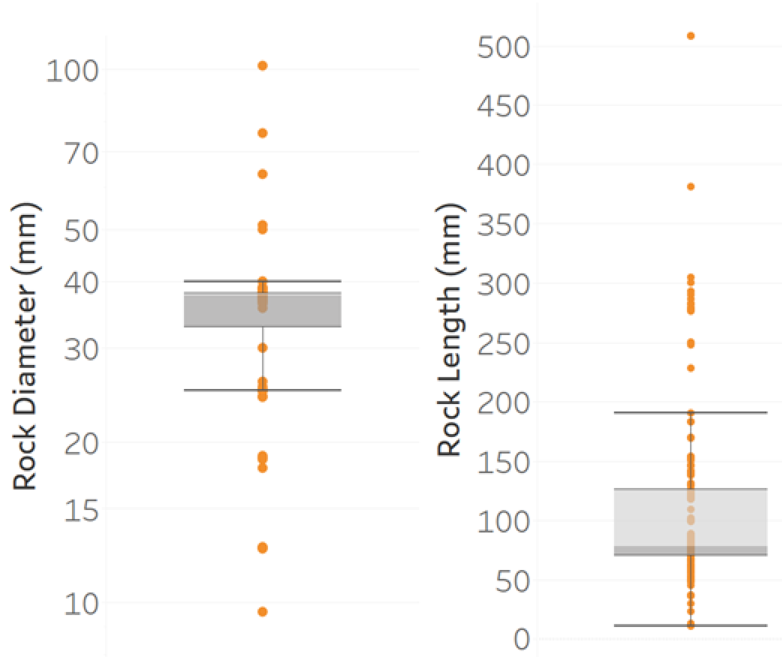

Figure 3.2 Diameter and length of rock samples.

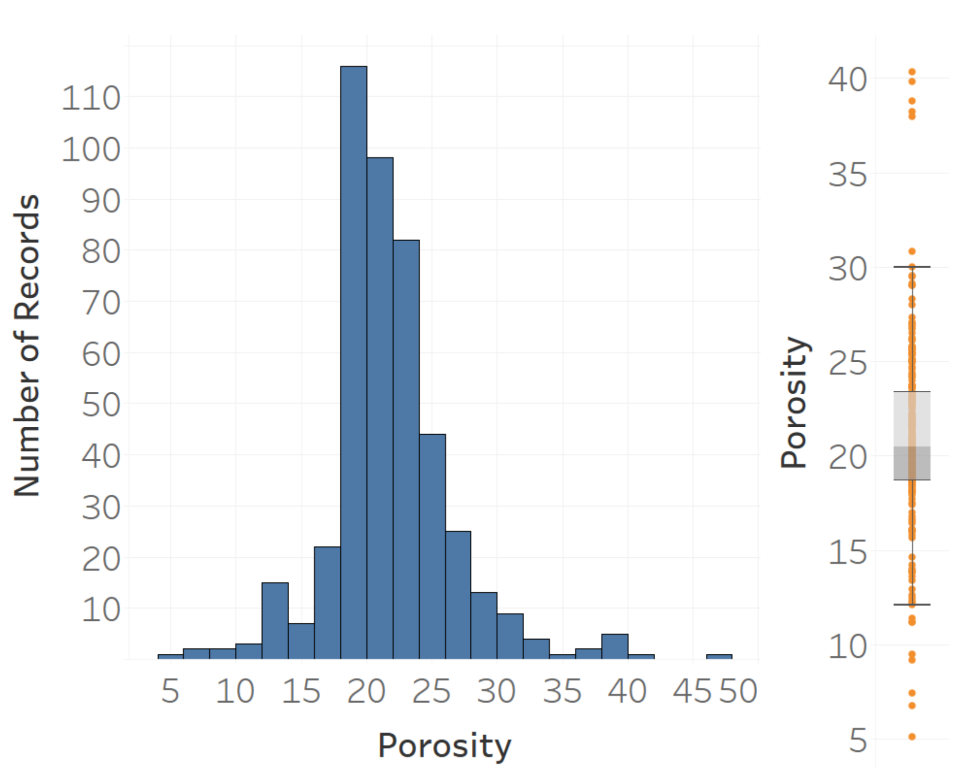

Figure 3.3 Porosity distribution of rock samples.

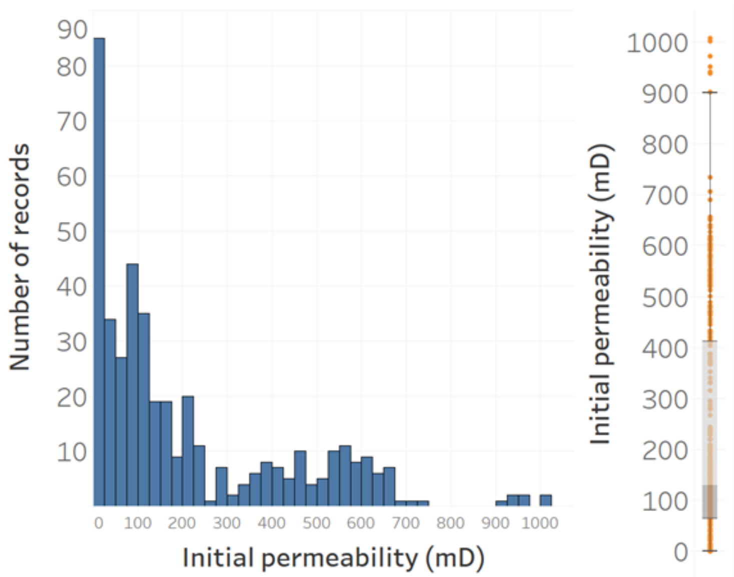

Figure 3.4 Initial permeability distribution of rock samples.

3.2. OIL PROPERTIES

For oil, viscosity and density are two important experimental properties that most of the authors considered in their articles. Figure 3.5 and Figure 3.6 indicate the distribution of the used oil viscosity and density and relationship between these two parameters. Most of the core flooding experiments used oil with viscosity in the range of 3.5 cP to 25cP. The heaviest oil that was used, Kuwait medium-heavy oil, has a viscosity of 110 cP, and the lightest oil has a value of 0.3 cP from the North Sea. The cross plot in the middle indicates the relationship between oil density and viscosity, and the box plot on the right illustrates the oil density distribution. The density of the oil used during the core flooding process ranges from 0.7 g/cm^3 to 0.93g/cm^3. The cross plot shows that as the density of the oil increases, the viscosity of the oil also increases. The figures below clearly show the distribution of oil viscosity and density.

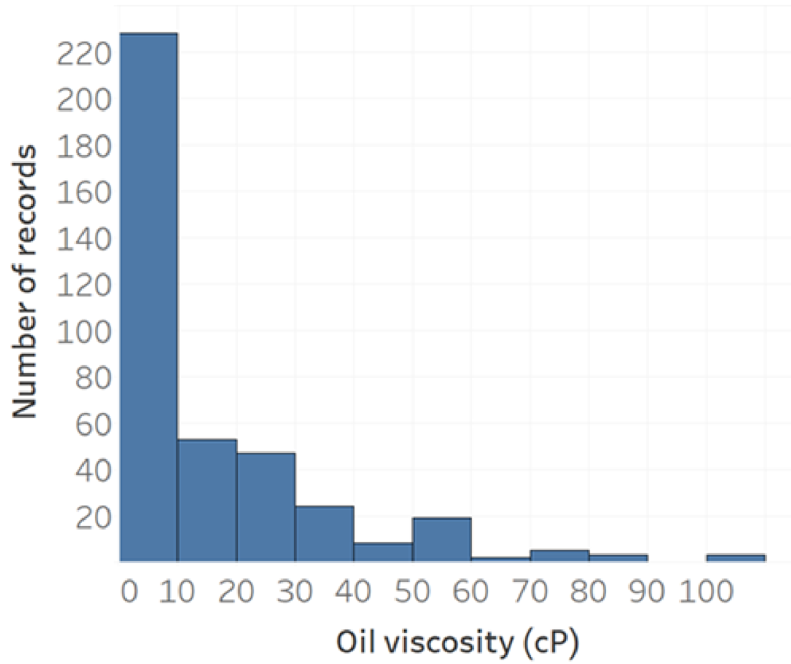

Figure 3.5 Oil viscosity distribution.

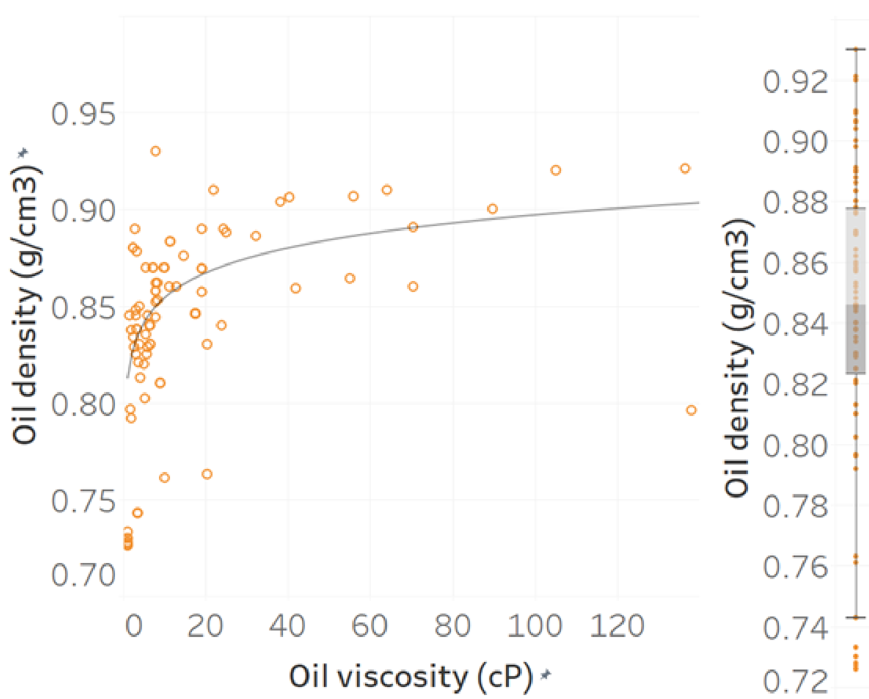

Figure 3.6 The relationship between oil density and viscosity.

3.3. BRINE PROPERTIES

The formation and injected low-salinity water flooding properties are described in this section in terms of their salinities. Figure 3.7 shows the distribution of formation brine salinity in the dataset. The majority of the formation brine salinity data points fall between 24,000 and 213,000 ppm. The lowest formation salinity is 106 ppm; the reason for such a low formation water salinity is that the core samples were aged with low-salinity water and then flooded with the same low-salinity water to investigate the LSWF effect on the core samples under relatively low formation water conditions. In one word, this relatively low formation water salinity experiment is generally for the purpose of comparative experiments (Fjelde,I 2013).

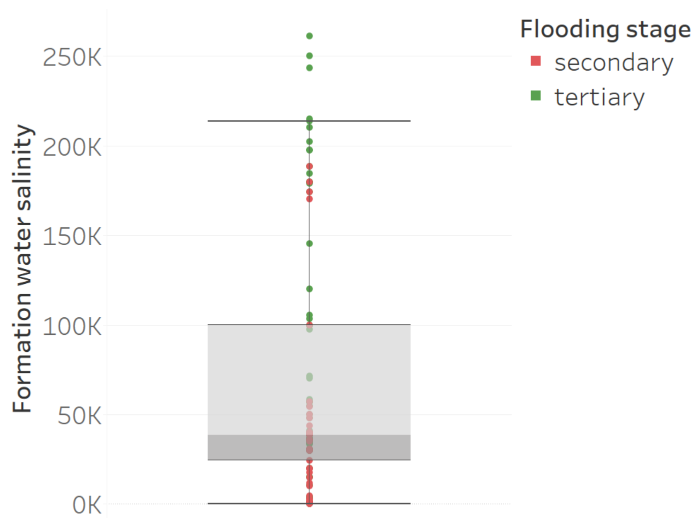

Figure 3.7 Boxplot of the formation water salinity during secondary and tertiary flooding stages.

Figure 3.8 depicts the relationship between the injected LSW salinity and the formation water salinity under secondary (red dot) and tertiary (green dot) flooding stages, respectively. The majority of the green dots are distributed on the right side of the graph, which means LSW flooding more often occurs during the tertiary flooding stage when the salinity of the formation water is higher than 30,000 ppm.

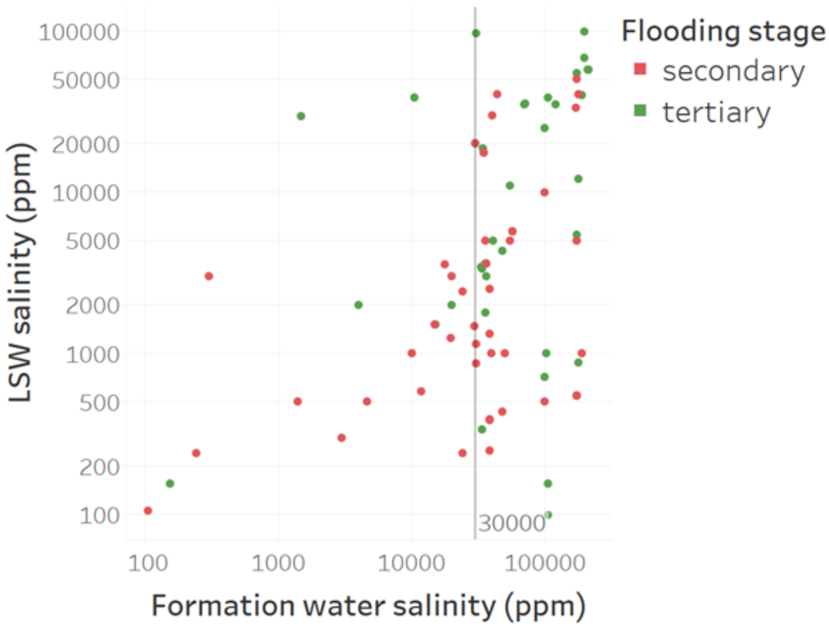

Figure 3.8 Cross plot of the formation water salinity and injected water salinity during secondary and tertiary flooding stages.

4. RESULTS AND DISCUSSION OF EXPERIMENTAL RESULTS PROPERTIES

4.1. CLAY MINERALS

Clay is a significant mineral material mainly referring to kaolinite, illite and smectite groups. Widely spread in sandstone formations, clay minerals are considered the main cause of LSWF by fine migration. The detachment and migration of clay particles result in the decrease of core sample permeability and increased injection pressure.

4.1.1. The Effect of Clay Minerals on Fine Migration. Figure 4.1 to 4.3 indicate the effect of clay mineral concentration on fine migration; the Y-axes of the three figures represent P/Po. Figure 4.1 illustrates the relationship between pressure difference and clay mineral concentration, which includes kaolinite, illite and montmorillonite, three clay minerals, together. Figure 4.2 and Figure 4.3 show the effect of kaolinite and illite concentration, respectively. As for montmorillonite concentration (smectite group), analysis is not available because of missing data; hardly any montmorillonite clay concentrations were measured in the flooding experiments. Only two authors mentioned the montmorillonite concentration when they prepared they experiments: Bernard specified that, during their experiments, their synthetic cores containing 86% sand, 2% montmorillonite and 12 % Lucite (Bernard,G. 1967). The other author who mentioned the montmorillonite concentration, did a detailed x-ray diffraction test to get the montmorillonite concentration which equal to 0.5% in the core samples (Skrettingland, K, 2010).

Figure 4.1 shows that clay concentration affects the pressure difference. The higher the clay concentration is, the greater the pressure difference can be during the flooding process, and the maximum pressure difference ratio can increase by 10 times when the clay concentration is 10% of the total composition. The situation for kaolinite looks a bit different (Figure 4.2). Though the kaolinite concentration also plays an important role during the process, the largest pressure difference appears when the kaolinite concentration is 4%. With more kaolinite in the rock, the pressure difference may not increase during the low-salinity water injection. As for illite shown in Figure 4.3, when the concentration of illite is zero, the pressure difference also changes, possibly due to the existence of other clay minerals. However, illite greatly affects the pressure difference when its concentration reaches 4% to 6%; fine migration may also occur when there is no illite at all in the rock samples.

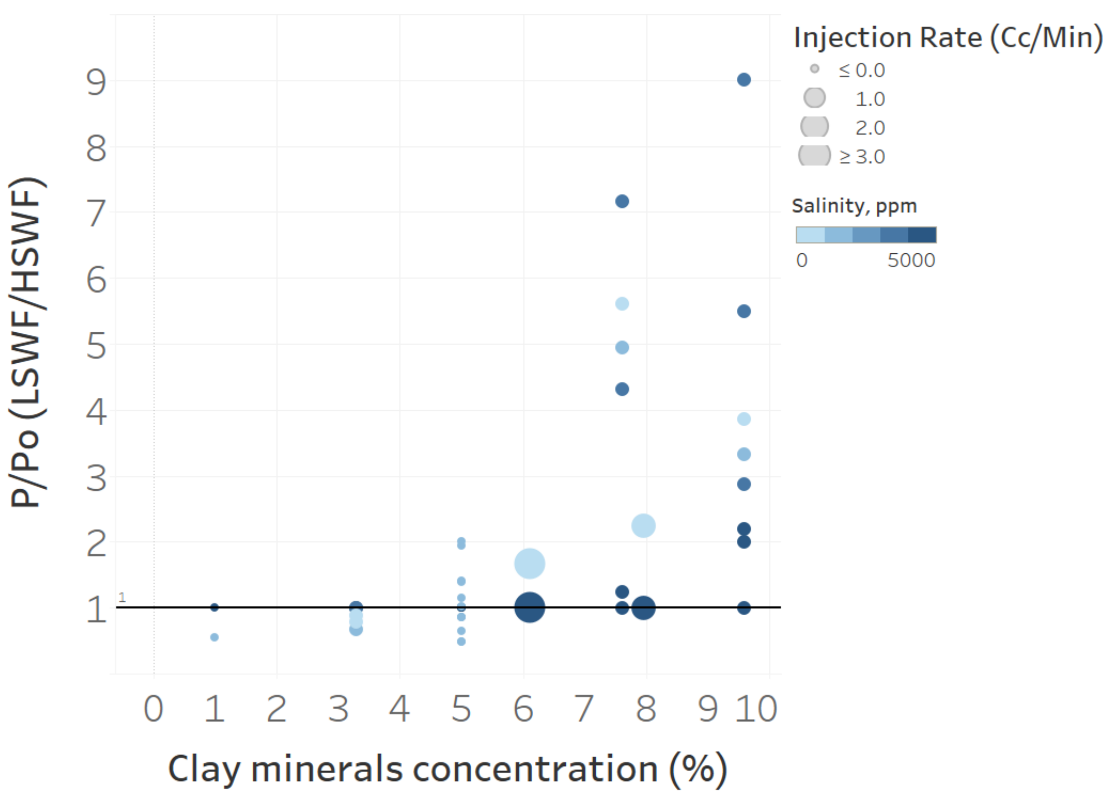

Figure 4.1 Effect of clay minerals concentration on pressure difference ratio.

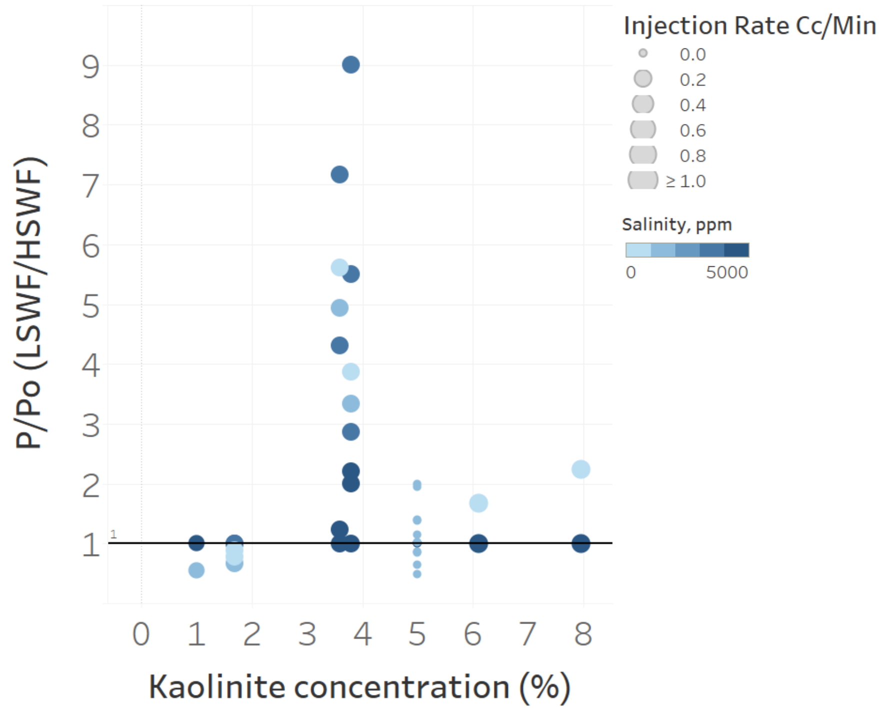

Figure 4.2 Effect of Kaolinite concentration on pressure difference ratio.

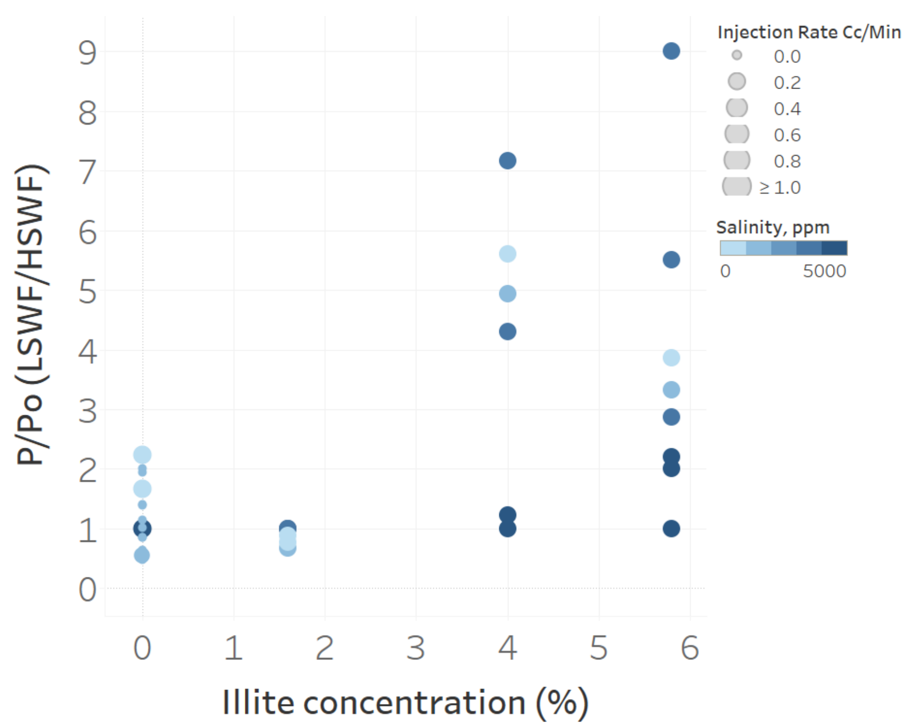

Figure 4.3 Effect of illite concentration on pressure difference ratio.

4.1.2. The Effect of Clay Minerals on Oil Recovery Factors. The cross plots below show the relationships between the injected brine salinity, incremental oil recovery and mineral concentration. For the incremental oil recovery factor, the larger the size of the circle, the higher the incremental oil recovery is. These figures (Figure 4.4, 4.5 and 4.6) indicate there is almost no oil recovery when the salinity of the injected brine is higher than 5000 ppm. Oil recovery improvement only occurs when the salinity of the brine is under 5000 ppm. Clay concentrations in the range of 1% to 10% increase the likelihood of incremental oil recovery (Figure 4.4). The same effect is also shown in Figure 4.5 and Figure 4.6. The cross plots present the relationships between salinity, incremental oil recovery and the concentrations of kaolinite and illite, respectively. Similarly, oil recovery only increases in the range of less than 5000 ppm in salinity and 1% to 10% in kaolinite and illite concentration.

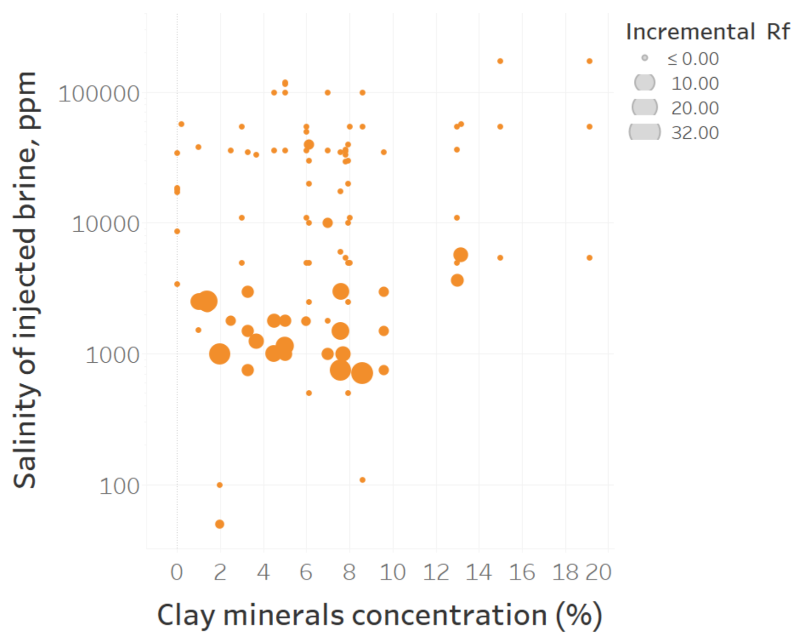

Figure 4.4 Cross plot of incremental oil recovery, clay concentration and injected brine salinity.

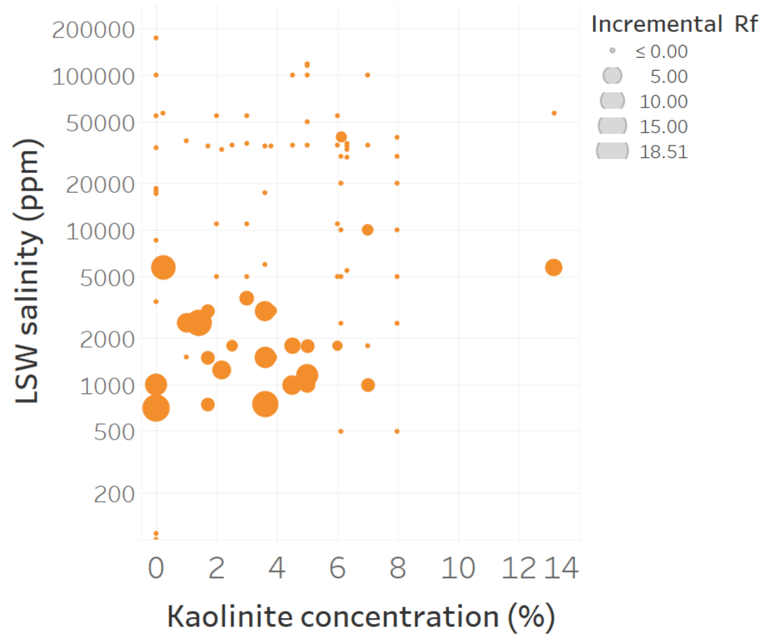

Figure 4.5 Cross plot of incremental oil recovery, kaolinite concentration and injected brine salinity.

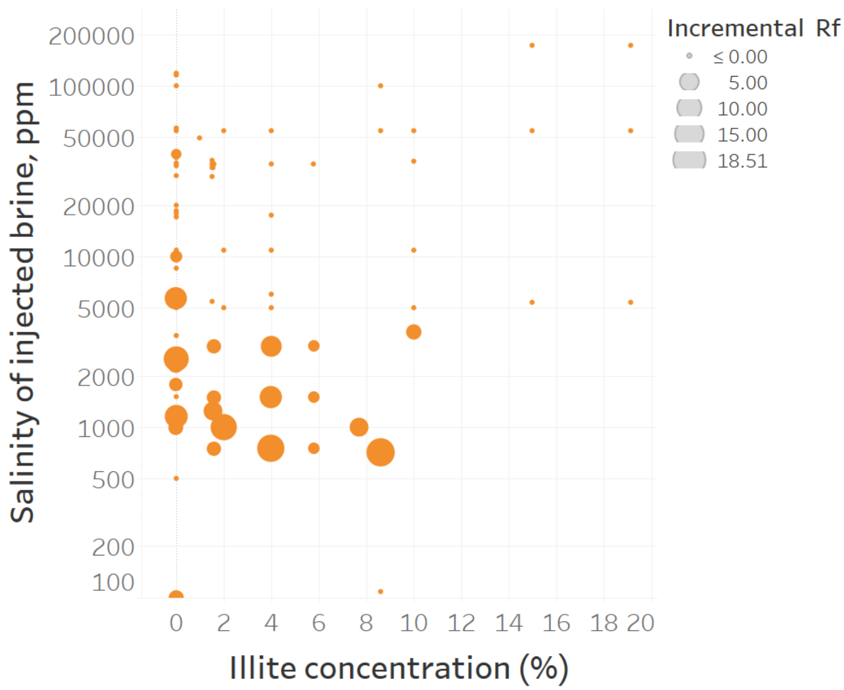

Figure 4.6 Cross plot of incremental oil recovery, illite concentration and injected brine salinity.

4.2. INJECTION RATE OF BRINE

As mentioned, the fluid velocity is proportional to the drag and lift force in the particle detachment model, and the pressure difference ratio is used to describe the fine migration in the core samples. Unfortunately, according to Darcy's law, the pressure difference between the inlet and outlet of the core sample is proportional to the fluid velocity; thus, the pressure change cannot reflect the fine migration situation during the flooding process. The data analysis of the relationship between velocity change and pressure change cannot be used to infer a relationship between velocity change and fine migration.

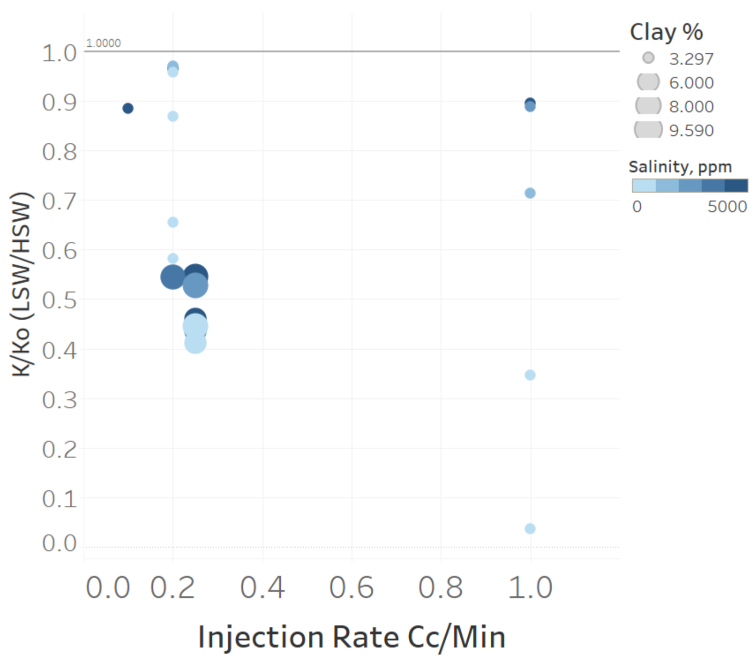

Figure 4.7 Effect of injection rate on fine migration.

However, at least from the detachment model, it is indicated that with increased fluid velocity, it is probable that more fine particles will detach and migrate in porous media. Figure 4.7 shows the relationship between the brine injection rate and incremental oil recovery factor. Most of the experiments used a relatively low injection rate, which is around 0.2 cc/min in the lab. The maximum incremental oil recovery can reach 32% OOIP. Although, from this figure, it can be concluded that injection rate is not a necessary contributor to incremental oil recovery; it is a common observation that the injection rate is linked to incremental oil recovery in LSWF.

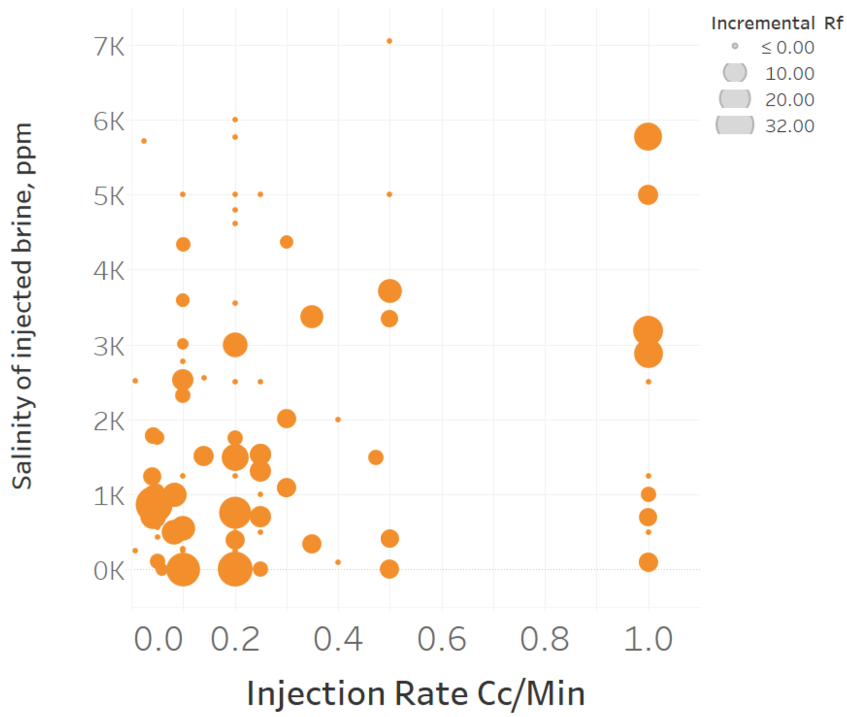

Figure 4.8 The effect of injection rate on oil recovery factor.

4.3. INJECTED BRINE SALINITY

According to the detachment model, injected brine salinity is significant because its effects on the interaction between fine particles and pore wall. Higher the injected brine salinity is, lower the distance between the fine particles and pore wall is which means the electrostatic force is higher, thus, it is harder for the particles to detach from the pore wall in the relative high salinity system. On the contrary, if the salinity of the injected brine is relatively low, the electrostatic force between fine particles and pore wall will become lower, and more portion of fines are willing to detach, causing more significant fine migration effects.

4.3.1. The Effect of Salinity on Fine Migration Effect. For single phase flooding, Figure 4.9 shows the relationship between the permeability change and salinity of injected brine during the LSW flooding process in a single-phase flooding stage. K/Ko on the y-axis is the ratio of the permeability of the core sample under an LSW flooding process to the initial permeability of the core sample. Permeability change during a flooding process reflects the migration of fine particles. During a single-phase flooding process, permeability can be easily calculated based on Darcy's law. Keeping the injection rate constant, permeability change during the flooding process is recorded.

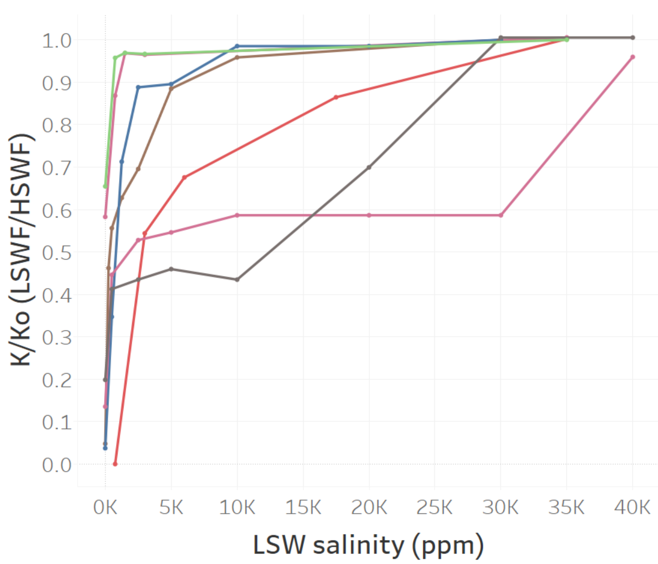

Figure 4.9 Permeability change with injected brine salinity during single-phase flooding stage.

As shown in Figure 4.9, permeability decreases when the injected water salinity decreases, which means when the low-salinity water is injected into the rock samples, more fines migrate and block the throat and channels in the rock; most of the decrease occurs under 5000 ppm. Each line on the graph represents one core sample. Compared to the bottom line in the figure, the upper line core samples have higher initial permeability. This means it is more difficult to observe permeability decreases in the high initial permeability rock samples, and the lower initial permeability means the permeability of the core sample is more likely to increase during the LSW flooding process.

For two phase secondary flooding stage, in the dataset, the pressure difference between the inlet and outlet are measured to evaluate the conductivity of the rock samples. All the experimental results reveal the pressure difference increases when low-salinity water is injected into the core sample, shown in Figure 4.10. During the experimental process, the injection rate is kept constant. A pressure increase means that the conductivity of the core sample decreases. Higher inlet pressure causes higher viscous force, which makes it possible for the water to flow through the small pore throat, which it could not before. Thus, more oil is displaced by the injected water, and the recovery factor increases. During the two-phase flooding process, relative permeability is introduced in Darcy’s law; thus, permeability does not easily reflect the conductivity change of the core samples. That is the reason for measuring the pressure difference along the core samples to investigate the conductivity change of the core samples. Each line in the figure shows the permeability change of one core sample. If the salinity of the injected brine does not change, there is only one dot on the figure. There are only three core samples under the constant line, which means the pressure along the core samples decreases during an LSW flooding process. All three of these core samples have relatively high initial permeability, which is around 1000 mD.

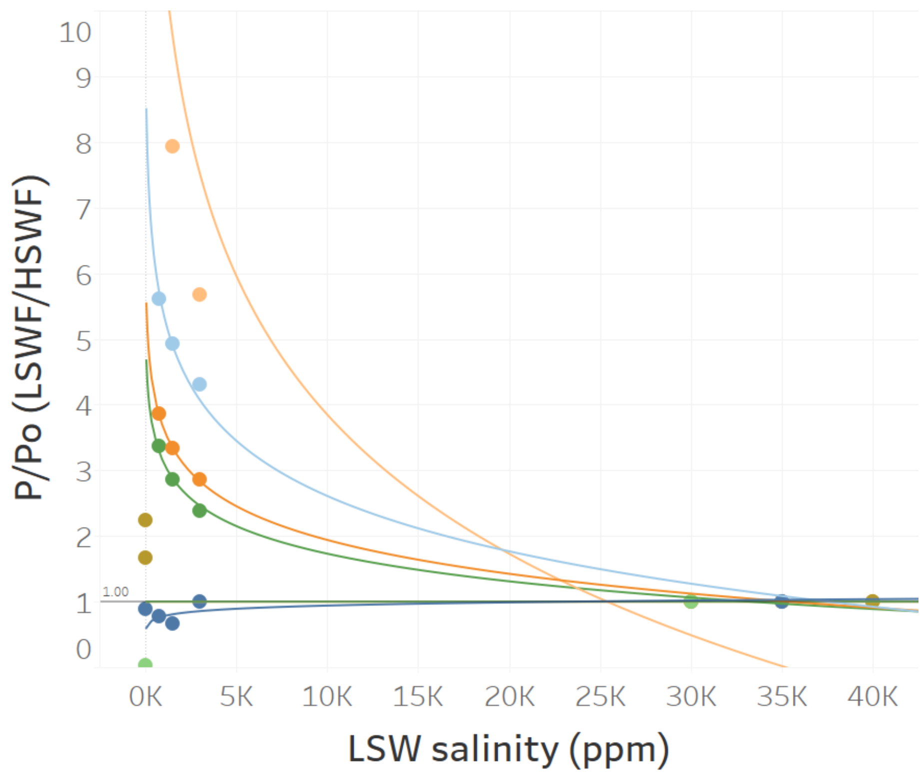

Figure 4.10 Pressure ratio change with injected brine salinity during secondary flooding stage.

In the two phase tertiary flooding experiments, most authors conducted one to two core tests. Results from different papers are presented in Figure 4.11. The pressure difference before LSW was injected over the pressure difference after LSW was injected is nearly equal to 1 when the salinity of the injected water is higher than 5000 ppm. However, the ratio of the pressure before and after the injection of LSW increases when the salinity is lower than 5000 ppm. This means, in sandstone rock samples, LSW increases the viscous force; thus, similar to the mechanism in the secondary recovery mode, LSW flows through the pore throat, which it could not before, and the oil recovery factor increases.

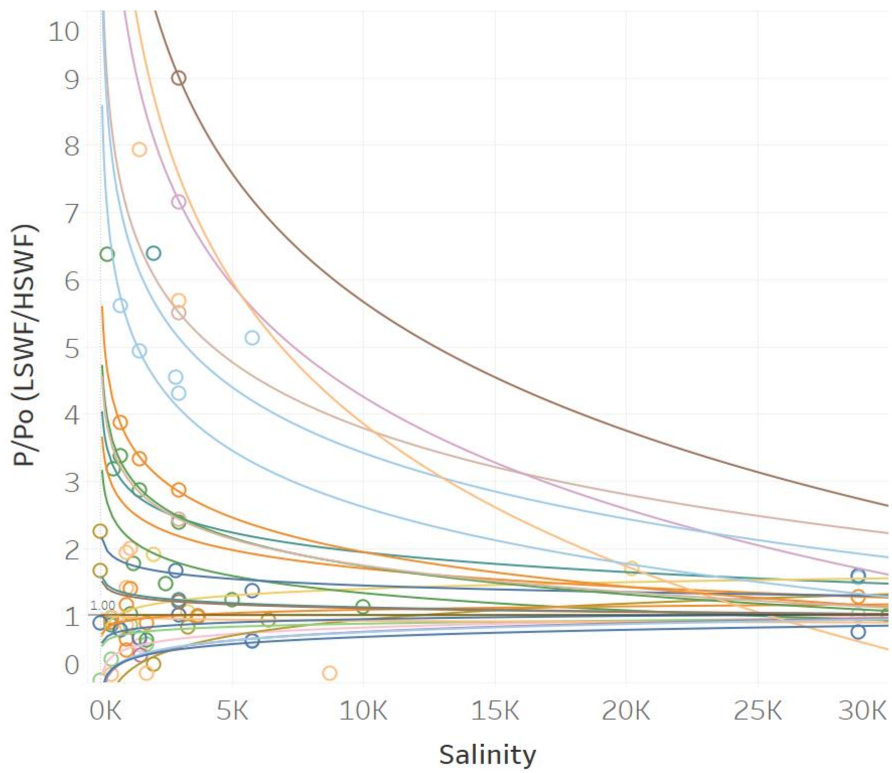

Figure 4.11 Pressure ratio change with injected brine salinity during secondary flooding stage.

4.3.2. The Effect of Salinity on Oil Recovery. Figure 4.12 shows the relationship between three parameters: P/Po, injected brine salinity and incremental oil recovery factor. Incremental oil recovery factor is defined as the oil recovery during the high-salinity water flooding stage minus the oil recovery during the low-salinity water flooding stage, which is indicated by the size of the circle in the figure. The larger the size of the circle, the higher the incremental oil recovery is. When the salinity of the injected brine is higher than 30,000 ppm, the pressure difference maintains the same value along most of the core samples; pressure difference incense only happened in two core samples. Moreover, oil recovery factors do not change during the relatively high-salinity water injection. When the salinity of the injected brine decreases to under 3000 ppm, most of the pressure difference along the core samples increases 1.5 to 10 times, and the increment in the oil recovery factor also happens during the low-salinity water flooding stage.

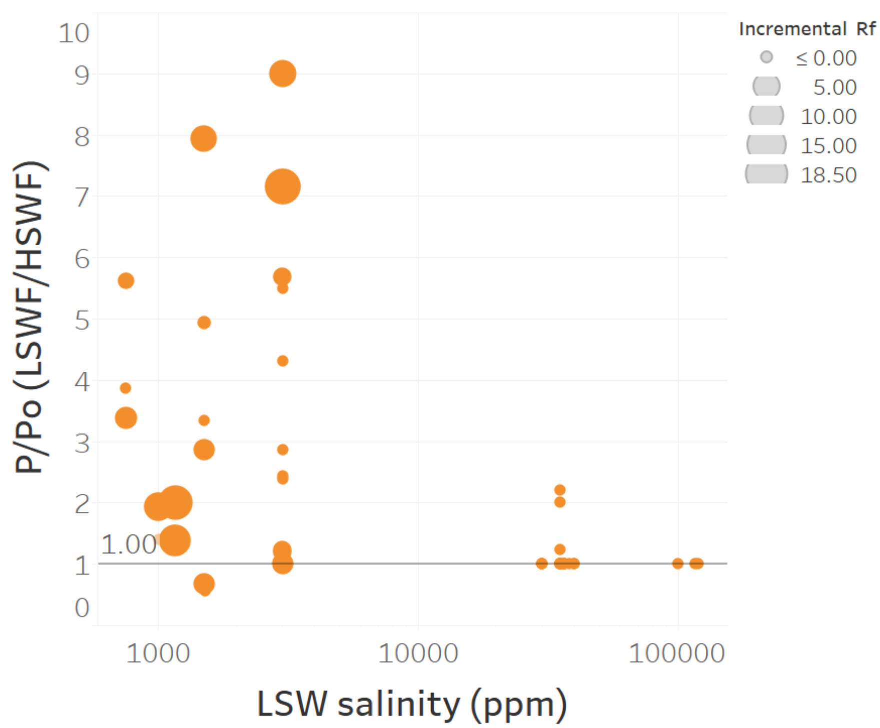

Figure 4.12 The effect of injected salinity on oil recovery factor.

4.4. INJECTED BRINE DIVALENT ION CONCENTRATION

The figures below (Figure 4.13 and 4.14) show the impact of injected brine divalent ion concentration on fine migration; Figure 4.13 depicts the pressure change. Although the divalent ion has an effect on the pressure difference, the effect is not as significant as other parameters, like injected brine salinity or clay mineral. The largest ratio is 2.5, much smaller than the salinity-caused pressure change, which could be 10 times higher than formation water flooding. The incremental oil recovery is shown in Figure 4.14. Divalent ion in the injected brine increases the oil recovery factor, but there is no clear trend in the relationship between ion concentration and the incremental oil recovery factor. Overall, there is no oil recovery increment when the divalent ion concentration is low, under 2%. When divalent ion concentration is greater than 2%, the maximum incremental oil recovery can reach 18%, which leads to the conclusion that the existence of divalent ion is a necessary condition for fine migration.

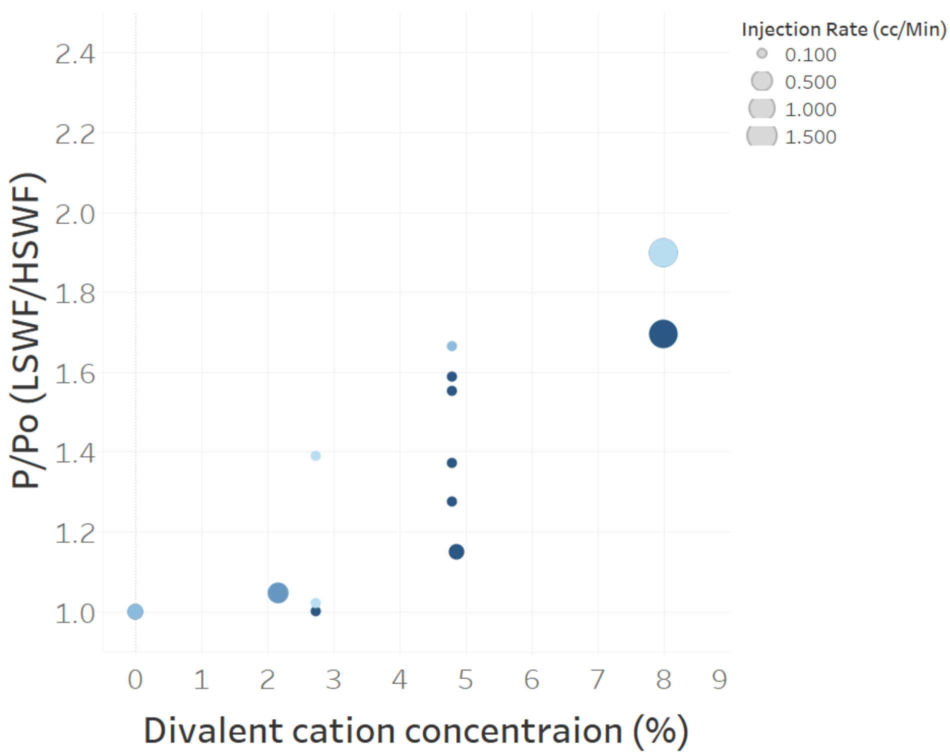

Figure 4.13 Effect of divalent cation on fine migration.

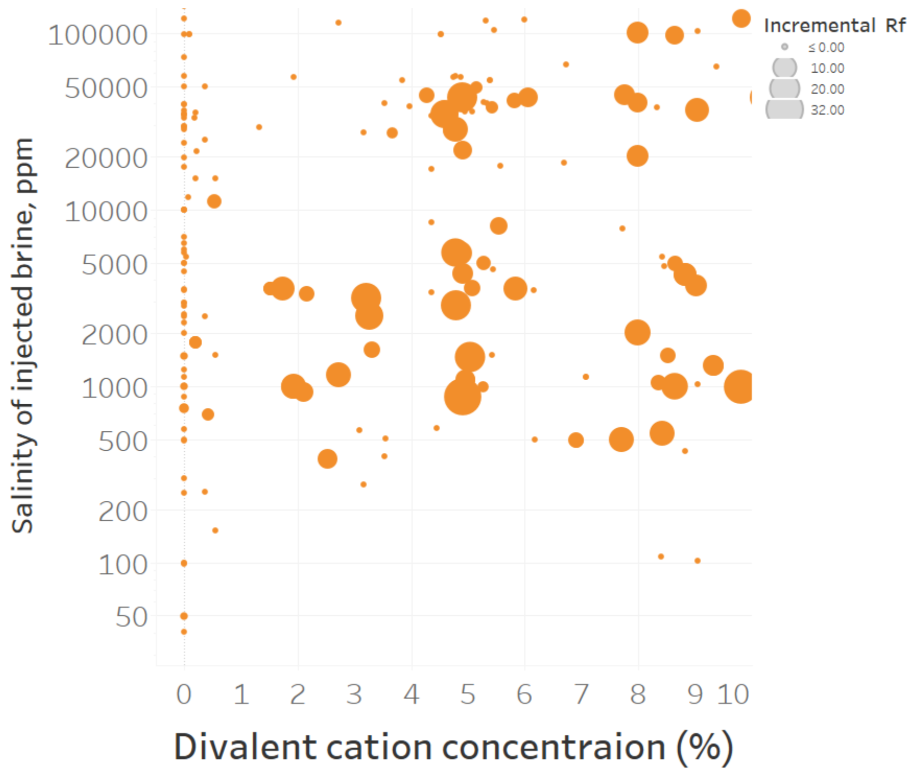

Figure 4.14 Effect of divalent cation on oil recovery.

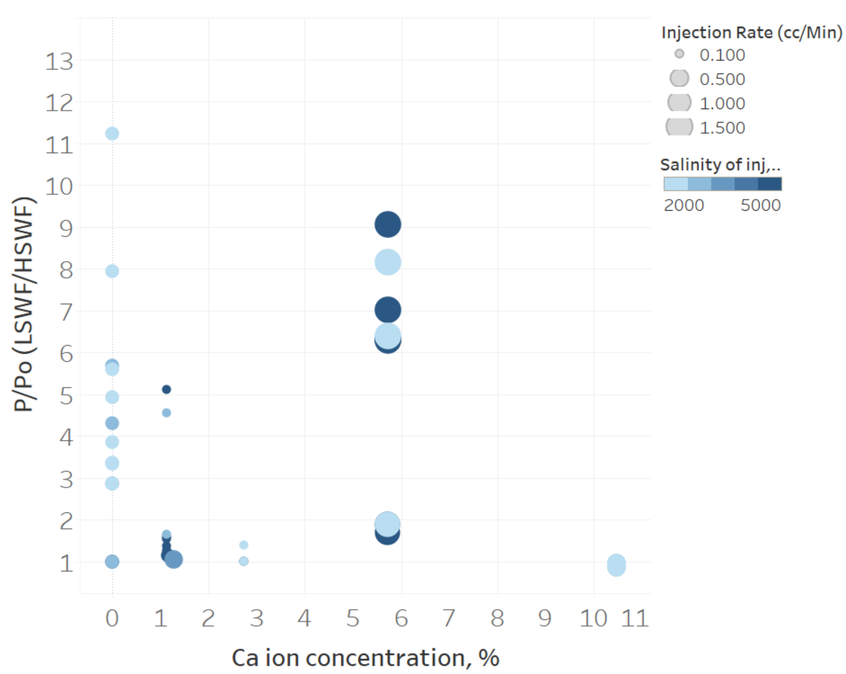

Figure 4.15 Effect of calcium ion on fine migration.

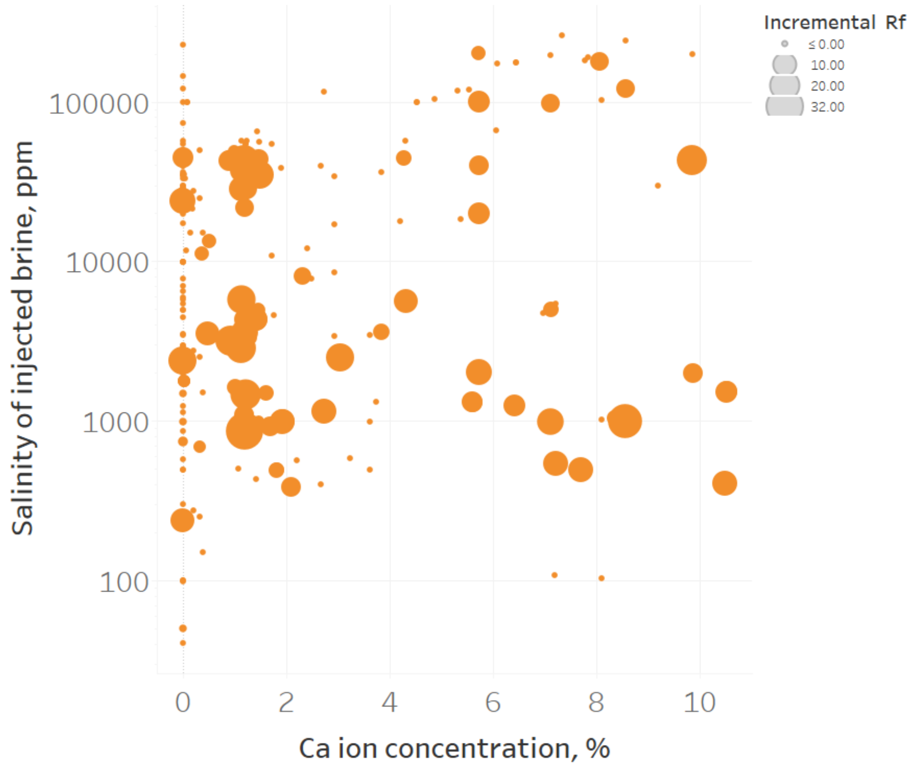

Figure 4.16 Effect of calcium ion on oil recovery.

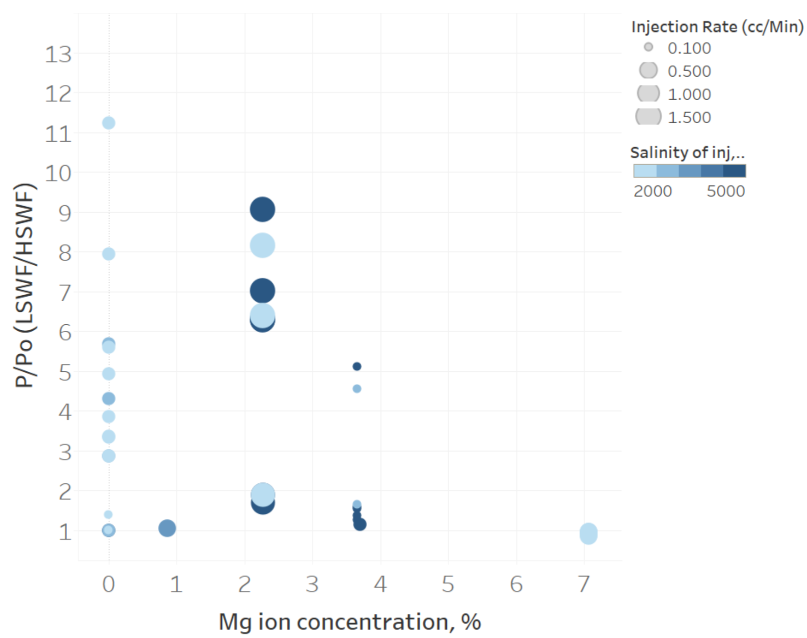

Figure 4.17 Effect of divalent cation on fine migration.

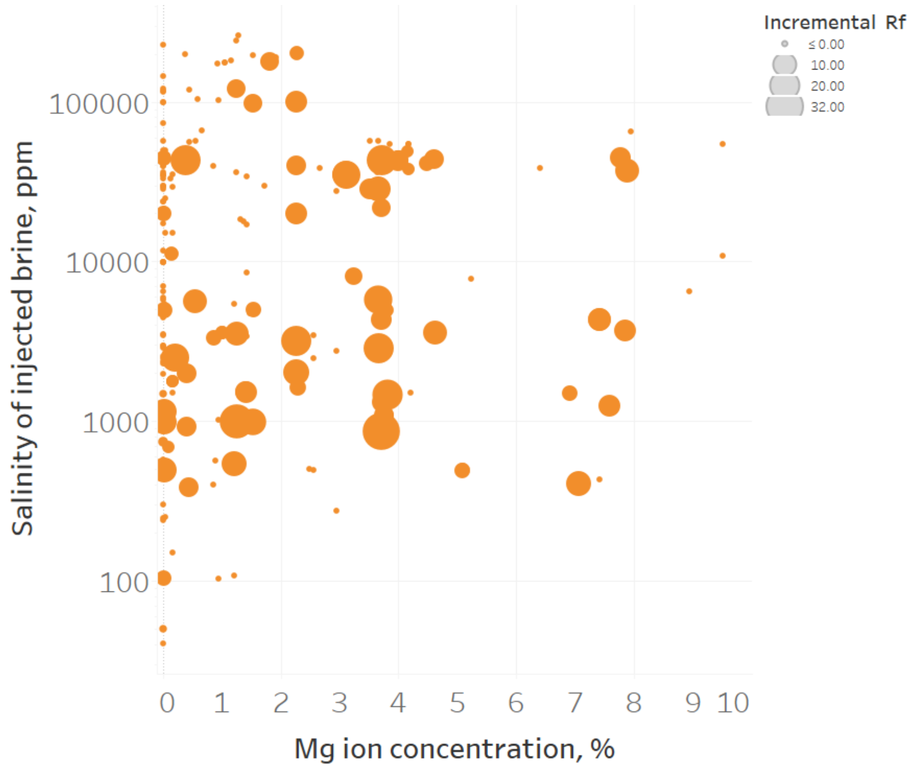

Figure 4.18 Effect of divalent cation on oil recovery.

4.5. PH OF EFFLUENT

The figures below (Figure 4.19 and 4.20) present the impact of the fine migration due to injected brine pH; the left cross plot shows the relationship between the pressure difference ratio and injected brine pH. Although the amount of recorded data point is low, the trend is still clear that when the pH is 7.0 to 8.0, there is almost no pressure increase during LSW flooding. However, the pressure increases when the injected brine pH is higher than 8.0. The largest pressure difference ratio is 6.0 when the pH is equal to 8.4. Then, the pressure difference ratio decreases when the pH increases. Therefore, the hypothesis can be made that there exists a range of pH values that cause fine detachment in porous media.

The relationship between brine pH and incremental oil recovery is shown in Figure 4.20. When the pH is extremely low, around 6, the oil recovery increment is almost zero. Though, for higher pH levels of injected brine, incremental oil recovery appears randomly on the plot, which means that the high pH of injected brine is a necessary condition for low salinity effect However, it is difficult to determine if oil recovery increases when fine migration occurs and pH increases.

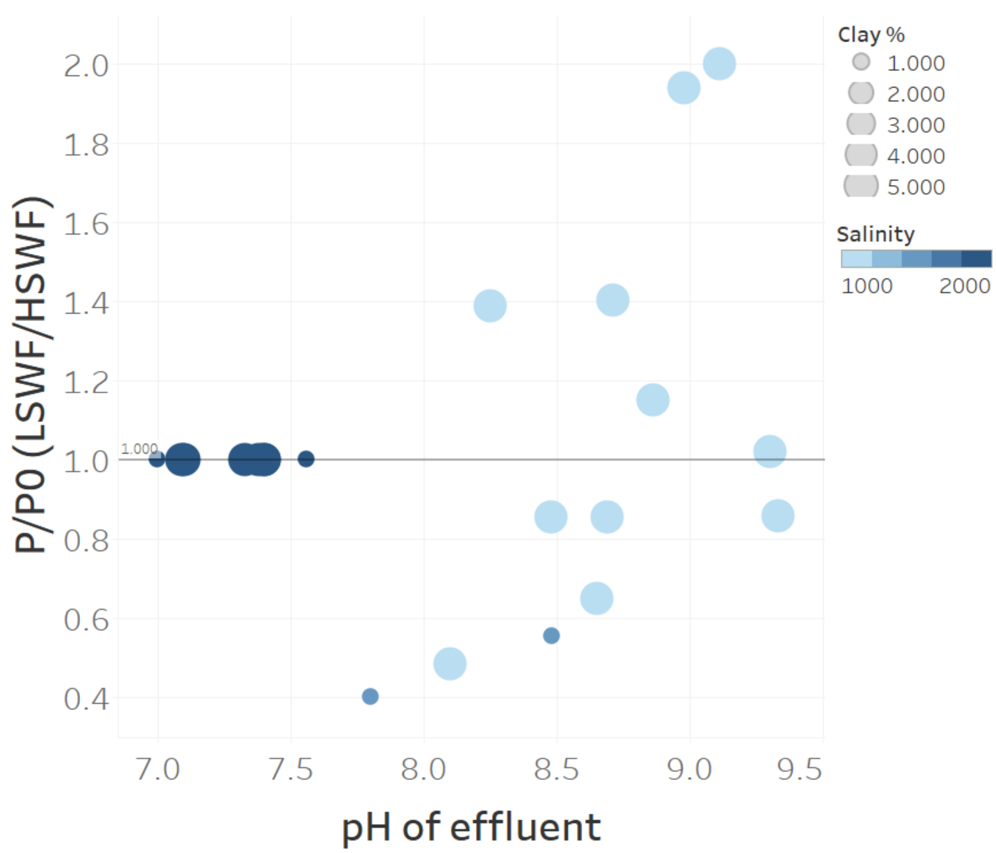

Figure 4.19 Effect of pH in effluent on fine migration.

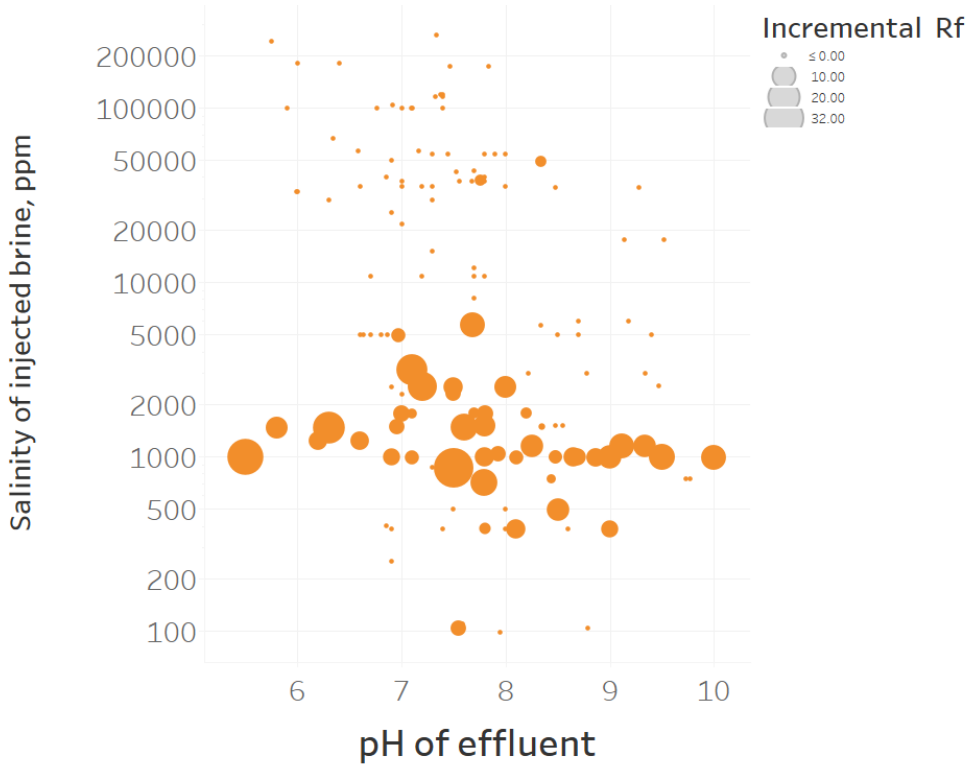

Figure 4.20 Cross plot of incremental oil recovery and pH of effluent.

4.6. OIL VISCOSITY

The impact of the pressure difference ratio due to the oil viscosity change is described in Figure 4.21. Indeed, when oil viscosity is smaller than 4 cP and increases, it is indicated on the plot that the pressure difference ratio also increases, which means that fine is more likely to migrate in a higher viscosity fluid system. As for the data point in the lower right corner of the plot, although the viscosity is relatively higher, the pressure difference ratio is low. The main reason is that the initial permeability of these data points is extremely low, only 5 to 10 mD, which means the pressure difference alongside the core sample during the flooding process is quite high so that the influence of the oil viscosity is negligible. The oil recovery factor is similar to other parameters in that when the viscosity was extremely low (lower than 1.5 cP), almost no increase in recovery was observed in any of the experiments. Yet, when the viscosity is greater than 1.5 cP, the highest recovery can reach 24% with the oil viscosity equal 3.0 cP. Notably, as shown in Figure 4.22, when the viscosity increases, the oil recovery factor does not always increase. When the viscosity is greater than 10 cP, the incremental oil recovery factor yields decreases.

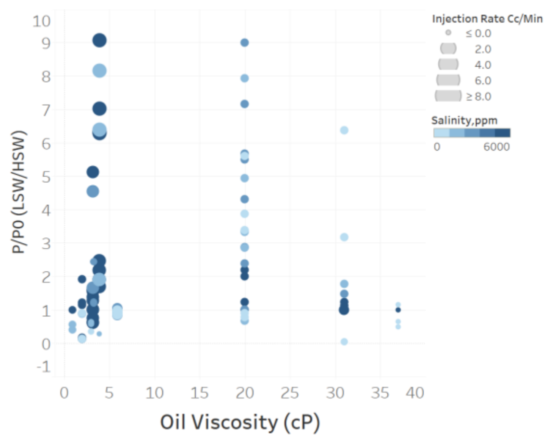

Figure 4.21 Effect of oil viscosity on fine migration.

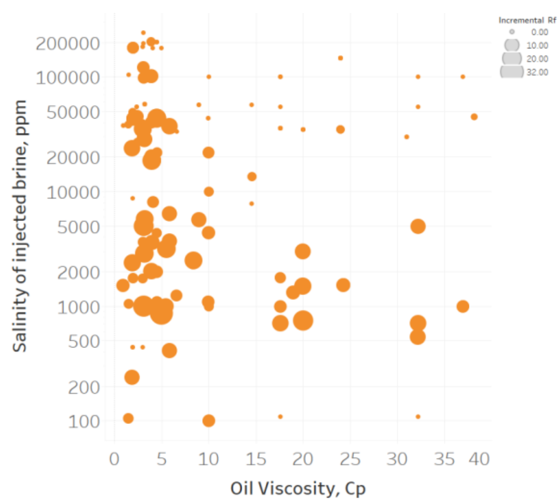

Figure 4.22 Effect of oil viscosity on oil recovery factor.

5. CONCLUSIONS

Clay mineral concentration, velocity, salinity, brine divalent cation concentration, pH and oil viscosity are six important properties which are related to fine migration effect during the LSW flooding process. Reduction of permeability caused by fine migration was observed in most of experiments, except the core samples with relatively higher initial permeability (larger than 500 md).

To avoid the total block of the core samples or damage to the reservoir, total salinity of the injected brine should be carefully controlled during the flooding process. And the criteria for incremental oil recovery in lab experiments: controlling the clay mineral composition from 0% to 10% is more possible to observe incremental in Rf. Salinity of the injected brine should be strictly controlled according to the value of injection rate, oil viscosity and pH. Divalent cation is necessary for occurrence of fine migration. However, the effect of divalent cation concentration needs further research due to the complex interactions between brine and oil, rock system. When the pH of the effluent is in the range of 7 to 8, fine migration causing by the injection of low salinity is more likely to happen in the core samples during the flooding process.

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