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UNIVERSITY OF CALGARY

Modeling of Low Salinity Waterflooding in Petroleum Reservoirs

by

Mohammad Hossain Nikpoor

A THESIS

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ABSTRACT

Oil production from reservoirs is traditionally categorized into three phases: primary, secondary, and tertiary (also known as Enhanced Oil Recovery, EOR). Per the US Department of Energy, utilizing primary and secondary methods of production can leave up to 75% of the oil in place. The way to further increase oil production is through EOR. Although more expensive to employ in a field, EOR can increase production from a well up to 75% recovery.

Low Salinity Waterflooding (LSW) is a promising technique for improving oil recovery in petroleum reservoirs because of its relatively simple implementation, lower cost, and fewer environmental problems associated with this process compared to other EOR methods. Worldwide companies (including BP, Shell, Statoil, and Saudi Aramco) are involved in the research and development of this technique.

Most studies on the subject have focused on the experimental and some on the theoretical aspects, with varying, sometimes contradictory conclusions. However, the optimum conditions that improve oil recovery by LSW flooding are still uncertain due to the lack of understanding of the underlying fluid-rock interaction mechanisms. There has been much modeling research on the modeling of the process in sandstone reservoirs in an attempt to understand these mechanisms and identify the main ones that maximize the recovery in order to design successful field applications. Most of these studies have concluded that the macroscopic mechanism for improved recovery in LSW is wettability alteration due to different microscopic rock-fluid and fluid-fluid interactions when low salinity water is introduced to the system. A few investigations have focused on the possibility of fine migration and its potential effect during LSW.

In this thesis, I will review and model the mechanisms in oil reservoirs and focus on fine migration and its similarity to the polymer flooding and asphaltene flow and precipitation whose models exist in commercial

reservoir simulators. Parts of this research will be integrated into a reservoir simulator to test and validate the ideas. At the end, I will extend my work into hybrid LSW processes and their optimization.

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1 Introduction

1.1 General Introduction and Research Motives

The world's population is increasing rapidly, and this growth is associated with improvements in the economics and living standards of this growing population. As a result, energy and raw material demand are rising rapidly in the world to meet the growth requirements.

Hydrocarbon fossil reserves such as oil, gas, and coal are the main source of energy and raw material for numerous products in the world. Oil and gas remain the main source of fuel, while coal is less environmentally friendly due to the high level of CO_2 emissions related to the production and utilization of coal mines.

Oil and gas are formed by burial and diagenesis of solid organic materials in source rocks during geologic time frames as long as several million years by increasing temperature and pressure several kilometers deep in the earth's crust. Then the fluids migrate out of the source rock and accumulate in porous reservoir rocks where impermeable cap rocks block their further migration. The geologic time involved in such a process makes fossil fuels almost irreproducible for all practical purposes. Thus, we try to maximize the recovery from an oil pool once it is found. Nowadays, oil is the main source of fuel due to its higher heating value per volume than gas while gas is the cleaner source as it emits less CO_2 when it is burned.

When an oil reservoir is discovered, the oil (and associated gas and condensates) is produced by drilling wells into oil-bearing zones. If the reservoir pressure is high enough and the oil is mobile enough, oil flows to the surface in a phase that is normally called primary recovery. This production normally declines as the reservoir pressure drops with the production of oil. Sometimes active aquifers supplement the loss of

pressure in a reservoir. There are other sources of primary drives such as solution gas drive, gas cap drive, formation rock expansion, in-situ oil and water expansion and gravitational segregation.

In most cases, when there is no (or insufficient) natural drive to push the oil towards production wells, other methods must be used to produce oil within economical rates. In some reservoirs, their formations are so tight and/or the oil is so viscous that primary recovery cannot result in an economic production rate. One example is the oil sands where the oil viscosity is in the order of a million centipoises and in-situ heating of the oil and mining methods are designed to produce the oil.

Several secondary recovery and EOR methods have been developed over the years to achieve economic rates of production and/or improve the recovery factor associated with the primary recovery. Some of these methods have proved successful as the primary (natural depletion) recovery leaves a lot of the resources behind. In these methods, materials such as water and gas or even energy in terms of steam are injected in a reservoir. Injection of water has been one of the main methods due to its cost and availability. This process is normally called waterflooding.

Waterflooding has a limit to produce additional oil, and in the current economic situation, other recovery methods have gained interest from the industry to the point that major oil companies have built in-house and sponsor academic research centers focusing on these methods. After seeing lab results of additional oil recovery (over that of waterflooding) by low salinity waterflooding (LSW), the industry wants to know how LSW works to improve the oil recovery to understand where they can apply the method to gain profits.

1.2 Waterflooding in Petroleum Reservoirs

Traditionally, waterflooding is considered as the main secondary recovery method in the literature. This method was initially devised to replenish a reservoir's natural energy to achieve additional oil recovery over

the primary recovery which in many old books is considered equivalent to the recovery by natural depletion mechanism.

Carll (1880) was one of the first observers of an increase in oil production through flooding of a reservoir with water. He noted that in part of the Bradford oil field, oil wells had sharply increased in their production due to the entrance of rainwater into some abandoned, unplugged oil wells in a short distance away. After a lot of legal and technical disputes, waterflooding was first used in Pennsylvania's Bradford field in 1907, and then it was widely applied in many North American oil fields within a decade. Many researchers have attempted to study, understand, design, and optimize the waterflooding process. Leverett (1941), Buckley and Leverett (1942), and Welge (1952) are amongst the pioneers who investigated the fundamental displacement mechanisms of water movement in porous media. The fractional flow theory and its later variations are the result of such early studies. Waterflooding is not viewed as a mere pressure maintenance method anymore; nowadays, water is injected to sweep the oil towards production wells.

Waterflooding has been accepted worldwide as a simple, reliable, and economical technique for oil recovery. Most conventional oil reservoirs have been, are being, or will be considered for waterflooding during secondary recovery. Unquestionably, waterflooding will continue to be applied to unlock the hydrocarbon reserves left behind after primary recovery.

Most of the time, especially in offshore oil fields, seawater and/or the produced formation water is injected into a reservoir considering its economics and its compatibility with the reservoir water. However, the compatibility problems with the reservoir, mobility ratio and capillary number, sometimes, limit the performance of such projects. Therefore, many researchers have tried devising additives to the injected water to change the chemistry of the water in a way that it can improve the recovery by waterflooding in secondary or tertiary recovery plans. Many of these attempts proved useful in theory and the lab but somehow unsuccessful in the field due to the price of the additives, heterogeneity of the reservoir, and the capital and operating costs of such projects.

1.3 LSW in Petroleum Reservoirs

When it comes to the chemistry of the injected water, several authors have reported an increase in oil recovery by a factor of up to 40% compared to the traditional seawater flooding when the salinity of the injected water is reduced below a certain level in different sandstone reservoirs (McGuire et al., 2005). The low cost and simplicity of the injection process compared to many other methods have made LSW an attractive subject for research and development.

Morrow and his colleagues were among the first researchers who developed early ideas about LSW by coreflooding experiments in the 1990s. They considered the effect of composition of the injected and resident water and the initial oil as well as the rock (e.g., presence of clay minerals) on the recovery by LSW. They concluded that several phenomena happen during LSW that lead to a change in the wettability of rock to a more favorable condition that reduces the residual oil saturation (S_{or}).

Many have attempted to rationalize the events triggered by LSW through modeling as contradictory observations have been made concerning LSW corefloods. In one experiment LSW led to a higher recovery (we always compare LSW with the normal high salinity waterflooding, HSW) and in another it did not; in one case it caused fine migration, and in another case, it did not. It has been observed that LSW can perform both in secondary (without a prior HSW phase) and tertiary modes (after an HSW secondary phase) and can be combined in a hybrid mode with other injectants (like CO₂ in a water alternating gas-WAG process or polymer).

Much attention has been given to the LSW in sandstones while a major part of the world oil reserves is located in carbonate reservoirs. Saudi Aramco is one of the companies supporting the research in this area. Yousef et al. (2011) at Saudi Aramco reported a decrease of about 16% in S_{or} in carbonate cores by dilution of the injection water twenty times. There are studies (Austad et al., 2011; Zahid et al., 2012) showing that a change in surface charges can be a reason for wettability alteration during LSW in these carbonate rocks while in sandstones, it is mainly the presence of clay minerals that are attributed to the wettability alteration due to ion exchanges. The LSW mechanisms and important ions seem to be different in carbonates from those in sandstones because carbonates do not usually contain a lot of clay.

1.4 Problem Statement and Research Motives

Although corefloods and other tests have shown an improvement in recovery over the conventional waterflood, there are still debates on why one LSW coreflood shows a better performance in producing the OOIP (original oil in place) than the other one and why some effects such as fine migration are present in some cases and not in others. A consistent approach is yet to emerge to explain all these observations due to the following challenges in the LSW modeling:

- Several phenomena happen during the LSW each of which can affect the recovery through a mechanism. Often these mechanisms have cross effects, which is why contradictory observations are made in corefloods. Until a model does include all these mechanisms and their cross effects, LSW modeling will be a subject of debate.
- 2. Mathematical modeling of these mechanisms can be extremely difficult as many underlying factors such as the modeling of each pore surface, size, lithology, surface roughness, shape and size of fine particles, and an electrical double layer must be included in the highly nonlinear equations to model the phenomena.

- 3. Including all the required nonlinear equations to model all the mechanisms in a reservoir simulator to be used in the industry is almost impossible. The run-time and convergence problems along with many unknown and empirical factors in each equation make the process of modeling a prefect reality impossible. As an example, we tried to model the electrical double layer expansion to be used in fine migration modeling in a pure programming study (a 1D single phase water flood) and it never produced satisfactory results due to the convergence and empirical factors such as surface potentials of a collector and particles and a highly nonlinear algebraic system of equations that produced several roots under different initial guesses (only one solution is acceptable).
- 4. Upscaling such micro-scale mechanisms into concepts such as relative permeability and a resistance factor to be used in a commercial reservoir simulator can be a challenge as this upscaling ignores several mechanisms and their cross effects.

The main objective of this thesis is to address the fourth difficulty mentioned in the challenges above: to include the effect of salinity, surface tension and fine migration in a reservoir simulator, validate the methodology, and run sensitivity analysis to understand the effect of geology on the LSW performance.

I will extend the existing relative permeability interpolation into a more general multi-variable interpolation that allows for interpolation of relative permeability curves for not only saturation, but also interfacial tension, concentration of fines, salinity, and generally, an unlimited number of interpolants. The method is mathematically proved to produce consistent results for interpolation and extrapolation, and it removes the problem of need for neural networks that is currently being used for this purpose. The new method is suitable for programming and hand calculations as well and can be extended to other concepts such as capillary pressure interpolation.

Another important objective in our research is to extend the model to include fine migration. I will modify and generalize the model and validate the results for consistency. This fine migration model

will be coupled with our newly developed wettability alteration and multi-variable interpolation technique to allow for the modeling of fine migration that happens during some LSW corefloods. I will also validate the methodology in a commercial reservoir simulator.

2 Literature Review

2.1 A Brief Background of Waterflooding

2.1.1 Conventional Waterflooding

Water has been the number one candidate for injection into reservoirs to displace the oil so that the oil can be produced (a voidage ratio was a term used to show the performance of such a process) while the reservoir natural drive is maintained. Water injection was initially used to supplement a reservoir with extra energy to push additional oil towards production wells; it was viewed as a pressure maintenance mechanism. Most of the time when a strong aquifer exists, waterflooding is not performed, but sometimes such an aquifer is absent or not strong enough to keep the reservoir pressure in a level that the pressure gradient causes oil to be produced at economical rates; in such cases waterflooding is customarily done as a replacement for a strong aquifer. Nowadays, waterflooding is a concept that immediately comes to the engineer's mind when the natural energy of an oil reservoir is not enough to make economic production.

The waterflooding performance depends on many factors including (but not limited to) the water injection rate and pattern, lithology, reservoir porosity and permeability, wettability of the rock, in-situ fluid properties and saturations, well spacing and well pattern. Other factors like an oil price, a water source, and legislations will also determine whether the designed waterflooding project is economical or not and to which degree it can be done. As a result, waterflooding (and any other production strategy) is not just a pure modeling and prediction task through reservoir simulation, but also includes consideration of economics, viability, and legislations.

2.1.2 Role of Wettability in Waterflooding and Other EOR Processes

Interface science plays an important role in the performance and design of EOR processes (Huang and Varadaraj, 1996). The accepted microscale viewpoint in EOR is to reduce the water/oil interfacial tension to mobilize capillary trapped oil through either interfacial active agents, e.g., surfactants, or by reaching miscibility, e.g., miscible gas or solvent flooding. The capillary number is used to describe and correlate the effectiveness of this approach at the microscale. On the other hand, the macroscale view is preventing fingering or unstable displacement to improve sweep efficiency which traditionally relies on either reducing the displaced-phase viscosity (as in thermal recovery methods or solvent mixed with the oil) or increased injecting fluid viscosity as in polymer injection. A mobility ratio is used to describe this approach. In this thesis, I will mainly focus on the microscale viewpoint.

There are interfaces between a rock and fluids that must be viewed at the microscale. If a rock surface preferentially attracts oil, oil will stick to the surface as a film instead of flowing as a bulk in the middle of rock pores, and it will also tend to occupy smaller pores where there is a more (specific) rock surface. This preference of the rock surface to attract one fluid in the presence of other immiscible fluids is called wettability. The more strongly attached phase is called the wetting phase, and the other phase is the nonwetting phase (Green and Willhite, 1998). Thus, wettability affects the distribution and flow of fluids in a reservoir (Puntervold, 2008). A capillary force is an attractive force between a rock surface and a fluid phase; since this force is greater between the rock surface and the wetting phase than that between the rock surface and the nonwetting phase, the wetting phase tends to move with more difficulty once a pressure gradient is applied on the fluids, and stays where there is more rock surface per unit volume, i.e., smaller pores.



Figure 2-1 Contact angle description of wetabbility. An oil drop (green) surrounded by water (blue) on a strongly water-wet surface (left) forms a bead. The contact angle θ is approximately zero. On a strongly oil-wet surface (right), the drop spreads, resulting in a contact angle of about 180°. An intermediate-wet surface (center) also forms a bead, but the contact angle comes from a force balance between the interfacial tension terms, which are γ_{so} and γ_{sw} for the surface-oil and surface-water terms, respectively, and γ_{ow} for the oil-water term. (Abdallah et al., 2007)

Figure 2-1 shows a schematic description of the wettability concept in terms of a contact angle. A drop of a preferentially wetting fluid will displace the other fluid; at the extreme, it will spread over the entire surface. In an opposite situation, if a nonwetting fluid is dropped onto a surface already covered by the wetting fluid, it will bead up, minimizing its contact with the solid. If the condition is neither strongly waterwetting nor strongly oil-wetting, the balance of forces in an oil/water/solid system will result in a contact angle, θ , between the fluids at the solid surface. A contact angle is normally measured through the heavier phase and in case of an oil-water or oil-gas-water system that is faced in reservoir engineering problems, it is measured through the water phase.

In a system containing reservoir rock, oil, and water, the solid is water-wet if $\theta < 90^{\circ}$ and oil-wet if $\theta > 90^{\circ}$. A contact angle approaching 0 indicates a strongly water-wet system, and an angle approaching 180 indicates a strongly oil-wet rock. The rock is intermediate/neutral-wet when both fluid phases tend to wet the solid, but one phase is only slightly more attracted to the rock than the other ($\theta = 90^{\circ}$) (Green and Willhite, 1998). This classification has slightly changed over time, and a system is water-wet if $\theta < 75^{\circ}$, and oil-wet if $\theta > 105^{\circ}$, and is considered intermediate-wet if $75^{\circ} < \theta < 105^{\circ}$. Other classifications and wettability measurement methods based on different factors and normal lab experiments are available in the literature (Mittal, 2003).

Most of oil reservoirs are heterogeneous, and their pore and pore throat mineral composition can change from one point to the next. In this condition, the wettability changes throughout a reservoir. There are different names for such phenomenon such as spotted and mixed wettability conditions (Mittal, 2003). When shale is involved heavily in such systems, having flow functions such as relative permeability curves as a function of lithology can lead to a better representation of a reservoir. This shows the importance of a correct geological understanding of a reservoir.

Wettability is found to have a large effect on key flow and recovery properties such as residual saturation, relative permeability, capillary pressure, and capillary desaturation. A wetting phase tends to have a larger critical saturation (when the fluid starts moving in bulk) and a lower relative permeability at the same saturation of a nonwetting phase, and the endpoint in the relative permeability curve is lower than that of the nonwetting phase. When relative permeabilities of phases are correlated with a phase (or effective phase) saturation using a power-law function ($k_{r,phase} = k_{r0,phase} \times (S^*_{phase})^{n_{phase}}$), the wetting phase has a higher exponent and lower coefficient (endpoint) which make its relative permeability curve to be more curved downward.

Since wettability is a surface phenomenon depending on the solid-fluid surface interaction forces, changing the properties of the fluids and/or solid involved leads to a change in the wettability. Examples of such practice are surfactant and alkaline flooding.

In a waterflooding process to produce oil, if the injected water is the wetting phase, oil (as the nonwetting phases) will move more easily, and less oil will remain behind as residual oil saturation. Sometimes, we

can design a waterflood that changes the wettability in a direction in which more oil is produced, and LSW is such a process as we will show in this thesis.

2.2 LSW and Its Mechanisms

In most of waterflooding field applications, water that is used in the process comes from seawater and formation water both of which have high salinity (but usually of different compositions). Formation water tends to be more saline than the seawater due to geological events that lead to the formation of hydrocarbon reservoirs. In recent years, it has been proposed that more oil can be recovered from reservoirs if low salinity water is used in the waterflooding process instead of high salinity water. This has been shown in several coreflooding experiments. The coreflooding experiments of Morrow and his colleagues (Jadhunandan and Morrow, 1995; Yildiz and Morrow, 1996) were amongst the first published observations on the effects of the brine composition on the oil recovery in coreflood lab experiments. Their works and findings were followed by numerous lab experiments (Tang and Morrow, 1997; Morrow et al., 1998; Tang and Morrow, 1999b; Zhang and Morrow, 2006; Zhang et al., 2007; Morrow and Buckley, 2011) and the researchers at BP (Lager et al., 2008; Webb et al., 2004, 2005a, 2005b; McGuire et al., 2005; Jerauld et al., 2008). All these lab reports pointed to a potential higher recovery than the conventional waterflooding when the salinity of the injected water is reduced below 5,000 ppm.

However, it has not been confirmed unequivocally what makes LSW work to produce more oil. Some lab experiments and the subsequent discussions favor one mechanism and the other experiment favors another while some other lab experiments show no change in the recover factor over that of a normal high salinity flood. Researchers have been trying to investigate the mechanisms that cause an increase in recovery through laboratory experiments and analysis. In this section, we review some of the proposed mechanisms of LSW.

2.2.1 LSW Mechanisms

Different LSW effects have been proposed and rationalized by researchers over time such as wettability alteration, permeability change, and interfacial tension (IFT) reduction (Hughes et al., 2012). Wettability alteration, which is the most accepted recovery-enhancing phenomenon in the literature, causes additional oil recovery from LSW by shifting the wettability of reservoir rocks from oil-wet toward water-wet. As the reservoir rocks become more water-wet, less oil is held by a rock surface and it allows the oil to flow more easily. A permeability change can also cause an increase in oil recovery by LSW in two ways. First, an increase in absolute permeability in some areas of a reservoir due to rock dissolution or fines migration will create bigger paths for all fluids to flow. Second, blockage of some high permeability zones by the migrated fines can divert the water to non-swept areas of the reservoir and increase the sweep efficiency which will eventually increase the oil recovery.

There are several factors that can cause the effects mentioned above. Usually, these mechanisms have crosseffects and they work together to produce an overall effect such as wettability modification. Several of these mechanisms are discussed in this thesis: electric double layer (EDL) expansion, multi-ion exchange, local pH increase, salting-in, mineral dissolution, and fine migration. Some of these mechanisms may work only for specific lithologies such as sandstones in the presence of clay materials while others may have different requirements. The effectiveness of LSW has been confirmed from coreflooding experiments and field trial tests for different geological systems (Vledder et al., 2010; Yousef et al., 2012).

2.2.1.1 Electrical Double Layer Expansion and Multi-Ion Exchange

The van der Waals attraction and electrostatic repulsion between a charged surface and ions in a liquid medium (here, the water phase) create two layers of ions on the rock surface that is called an electrical double layer (EDL). One layer is strongly charged and is strongly attached to the solid surface (specially

charged clay surfaces) and it is called the adsorbed or stern layer. The other layer contains positive and negative ions in motion and is called the diffuse layer (Figure 2-2) (Lee et al., 2011). The cations play an important role here; Na^+ is the main monovalent cation while Ca^{2+} and Mg^{2+} are the main divalent cations. Divalent cations are more attracted to a negatively charged clay surface due to their size and charge and, therefore, can neutralize the negative charge more effectively and, as a result, shrink the EDL. Injection of LSW and replacing some of these divalent cations with monovalent cations expand the EDL.



Figure 2-2: A schematic of the EDL (Lee et al., 2011)

In oil reservoirs, some oil droplets are strongly attached to the charged solid particles of a formation because of the polar components existing in the oil. During LSW, the EDL expands due to a decrease in the salinity which means a decrease in the ionic strength (Figure 2-3). This expansion reduces the adsorption of some oil droplets to pore walls and helps them to be stripped. This phenomenon changes the rock wettability towards more water-wet and increases the oil recovery (Lee et al., 2011).



Figure 2-3: Effect of salinity on EDL thickness (Lee et al., 2011)

Clay minerals that are found abundantly in petroleum reservoirs tend to have negatively charged surfaces; as a result, clay minerals play a major role in this mechanism. Some clays are more charged than the others due to their special atomic compositions and structures, and, as a result, researchers have used the concept of cationic exchange capacity (CEC) to correlate the type and concentration of such clays in the reservoirs for reservoir simulation studies. CEC is a measure of how many moles of positive charges can be held by such negative surfaces per unit bulk volume of a reservoir rock. Because of a distribution of "shaliness" in the reservoir, CEC can have a distribution in the reservoir as well which can affect the performance of the LSW in different parts (or grid blocks) of the reservoir.

We can conclude that the presence of a charged surface (mainly clay) and the absence of divalent cations are the main factors in EDL expansion during LSW which may cause additional oil and migration of fines (mainly Kaolinite) and not solely the salinity of the injected water. Furthermore, the attraction and release of oil droplets from a mineral surface depend on the polar components in the oil, because these components are attracted to the rock surface through the EDL. This is the reason that LSW does not recover additional mineral oil from some of the corefloods. EDL expansion can be studied at the microscale, but is very difficult to model in commercial reservoir simulators.

2.2.1.2 Local pH Increase and IFT Reduction

Tang and Morrow (1999a) found during coreflooding experiments that the injection of low salinity water raises the pH from a value near 7.0 to a value near 9.0-10. They stated that this increase was due to a combination of ion exchange and mineral dissolution. An increase in the pH will lead to a formation of surfactant in a reservoir similar to what happens during an alkaline injection process. Surfactant helps to reduce the IFT between oil and water which increases the oil recovery from a reservoir (McGuire et al., 2005). Lager et al. (2008) eliminated an pH increase from being a true mechanism for the effect of LSW. They stated that the coreflooding experiments that showed an increase in the pH due to the LSW were not performed under real reservoir conditions because most of the oil reservoirs contain CO₂ which acts as a pH buffer and prevents the pH from rising. An example is shown in Figure 2-4.



(a) After McGuire et al. (2005)





It has been noticed that the in-situ crude oil must have an acid number greater than 0.2 mg KOH/g to generate enough surfactant to induce wettability reversal and/or emulsion formation in alkaline flooding (Ehrlich et al., 1974; Jensen and Radka, 1988); however, most of the crude oil samples used in the LSW experiments had an acid number less than 0.05mg KOH/g. It is difficult to conclude, therefore, that the

additional oil recovery is mainly from in-situ surfactant generation. Additionally, LSW showed good performance even when it was conducted with a low initial pH value (6.0) and a final pH value of 7.5 (Rivet et al., 2010).

2.2.1.3 Multi-component Ionic Exchange

Lager et al. (2008) suggested that the main mechanism that causes the oil gain from LSW is the multicomponent ionic exchange between minerals in a rock surface and the injected water. They presented this suggestion based on a laboratory experiment on a North Slope core sample. The sample was flushed extensively with brine that contained only sodium chloride (NaCl) to remove calcium ions (Ca²⁺) and magnesium ions (Mg²⁺) from the core sample. After that, the sample was aged in crude oil and the initial water saturation was established. It was then flooded with high salinity brine that contained only NaCl and the recovery was 48% of original oil in place (OOIP). Next, the sample was flooded with low salinity brine that contained only NaCl and no increase in the recovery was observed. In addition, one more flood was performed using low salinity brine that contained Ca²⁺ and Mg²⁺ and again, no increase in oil recovery was observed. The results of this experiment indicated that when the multi-ion exchange was eliminated, no oil gain was observed from LSW. This was the first noted result where no oil recovery improvement was observed from LSW. This indicates that multi-component ionic exchange could be a mechanism that causes the oil gain from LSW.

2.2.1.4 Salting-in

The solubility of polar organic components in water is affected by the salinity and the ion composition of the water. Salting-out and salting-in are two terms that are used in the chemical literature to describe the effect of salinity on solubility. The solubility of polar organic components can be decreased by increasing the salinity of the water and this is called the salting-out effect. On the other hand, the solubility of polar
organic components can be increased by decreasing the salinity of the water, which is called the salting-in effect. During LSW, because of the salting-in effect, some of the oil droplets that are attached to formation walls will dissolve into the injected water. This will make the rock wettability change toward more waterwill which increase the oil (RezaeiDoust 2009). wet recovery al., et Salting-in is a suggested mechanism for the effect of LSW in sandstone reservoirs. It cannot happen in carbonate rocks because of the strong bond between the organic material and the formation (RezaeiDoust et al., 2009). The salting-in effect, however, cannot explain the role of clay mineral composition and a pH increase in LSW, and, therefore, it cannot be the main mechanism in LSW.

2.2.1.5 Mineral Dissolution

Pu et al. (2010) suggested that the dissolution of anhydrite could be a mechanism for the effect of LSW. This suggestion was based on a coreflooding experiment on a dolomitic reservoir core sample. Both high salinity water and low salinity water cause the anhydrite to dissolve. However, an increase in sulfate content in the effluent was observed using LSW compared to the sulfate content in the effluent using HSW. That was considered an evidence for an increase in the anhydrite dissolution using LSW. The dissolution of minerals changes the permeability of a formation and this can contribute to an increase in oil recovery during LSW.

2.2.1.6 Fines Migration

Formation damage is defined as the impairment of the permeability of petroleum reservoir formations by various processes. It can occur during various phases of recovery including drilling, completion and workover, and production operations. Various methods for prevention, assessment, and remediation has been developed over the years to tackle the formation damage problem (Civan, 2000). Several formation damage mechanisms have been identified in the literature such as chemical, mechanical, biological,

thermal, hydrodynamic, and particulate. Proper experimentation and modeling of the expected formation damage mechanisms can lead to a better understanding, assessment, prevention, and remediation of such phenomena. Formation damage reduces the well productivity, and often, the recovery efficiency from petroleum-bearing formations. As a result, the economical aspects of a field development and production plan can be affected by formation damage. In our work, we focus on the formation damage due to the movement and trapping of particulates, a phenomenon that is conventionally called fine migration. Fine migration is the mobilization and settlement of loose fine particles in a formation that can be triggered by various factors such as an increase in fluid velocity and a change in the fluid composition that is in contact with fine particles and a rock surface.

Clay swelling and particles migration, when low salinity water is injected into a formation, has always been a matter of research in the petroleum industry; this phenomenon has been a major caution in drilling, completion, and workover operations. When clays are exposed to low salinity or fresh water, water molecules are positioned in the clay structure to hydrate the metallic corners of the clay crystal and this increases the size of the clay structure which is traditionally called clay swelling. The swelled clay can block pores and pore throats and reduce the permeability because of the added size. On the other hand, the clay particles can be mobilized, migrate and be trapped at pore throats by the movement of the water in water pathways and reduce the permeability. Water plays an important role in fine migration because the metallic compounds have crystalline structural corner points that have the potential for hydrogen bonding, and, as a result, hydration. These clays are very common in petroleum reservoirs.

An important finding from comprehensive experimental studies (Kia et al., 1987a,b) is that small proportions of calcium or magnesium in a formation and injected brine can significantly restrain clay blocking. Additionally, a gradual decrease in salinity gradient also prevents permeability damage (Valdya and Fogler, 1992). Fines migration occurs when the ionic strength of the injected brine is less than a critical

flocculation concentration, which is strongly dependent on the relative concentration of divalent cations. However, whether clay fine migration happens or not or to what degree it happens depends also on the lithology of a formation rock; poorly cemented clay particles are the ones that migrate when they contact a low salinity water (Boston et al., 1969).

When crude oil originally migrated from its source rock to the trap, the polar components of the crude oil adhered to formation rock grains which were originally in contact with water before the migration happened. That caused some of the fine particles to be mixed-wet. During waterflooding, the mixed-wet fine particles tend to position themselves in an interface between oil and water (Figure 2-5). However, not all particles will separate from formation walls because they do not see a sufficient force to move them. As the salinity of the injected water decreases, the EDL around the fine particles will expand and the attraction forces between the wall and the fine particles will decrease due to the lower charges associated with LSW. That will make it easier for more fine particles to separate from a formation pore wall (Figure 2-6). As a result, that will change the wettability of the formation to more water-wet and will increase oil recovery (Tang and Morrow, 1999b).



Figure 2-5: Movement of some of the mixed-wet fine particles from formation pre walls during waterflooding (Tang and Morrow, 1999b)



Figure 2-6: Effect of fine migration on the mobilization of trapped oil droplets during LSW (Tang and Morrow, 1999b)

Tang and Morrow (1999b) reported a gradual reduction in the absolute permeability of a sandstone core sample when it was flooded with low salinity water. This reduction was due to the migration of fine particles and their blockage of some pore throats. This can divert the injected water to some non-swept areas and eventually increase the oil recovery (Hughes et al., 2012).

Tang and Morrow (1999b) did several coreflooding experiments and found four factors that affect the fine migration by LSW. The first factor is the adsorption of polar components of the crude oil into fine particles on formation walls. When refined oil with no polar components was used instead of crude oil during coreflooding experiments, no oil gain was observed from the LSW. The second is the presence of movable fine particles. When the movable fine particles were stabilized by firing and extensive flooding, the effect of LSW was eliminated. Third, high clay content must be present in a formation. The effect of LSW was reduced with rocks that have low clay content. Finally, initial water saturation must be present in a formation. The effect of LSW was eliminated when a core was initially saturated with crude oil.

2.3 Laboratory and Field Observations

When Morrow and his colleagues (Jadhunandan, 1990; Jadhunandan and Morrow, 1991, 1995; Yildiz and Morrow, 1996; Tang, 1998; Tang and Morrow, 1997, 1999a) studied LSW through lab studies and

confirmed that it could yield a higher recovery over HSW, they stated that whether more oil could be obtained depended on specific conditions of crude oil/brine/rock systems. Their work was followed by active research in British Petroleum (BP) (Webb et al., 2004, 2005a, 2005b; McGuire et al., 2005). BP's works included numerous core floods at ambient and reservoir conditions with live oils in both secondary and tertiary modes, single-well chemical tracer tests (SWCTT), and log–inject–log tests. Webb et al. (2005) concluded that LSW could be beneficial when the salinity is lower than 4,000 ppm. The researchers from several oil companies (e.g., TOTAL, Shell and Statoil) and universities worked and are working on this topic as well. Most of these experiments were done on sandstone samples, but some were performed on carbonate samples (Yousef et al., 2011). In most of these corefloods, additional recovery was observed while in some cases, no incremental (or even less) oil recovery was gained by LSW (Zhang and Morrow, 2006).

Tang and Morrow (1999b) and Zhang et al. (2007) observed a permeability reduction during their corefloods. The maximum pH that was measured during LSW was about 9.0 during their experiments.

Tang and Morrow (1999a) found that initial water saturation is needed for LSW; otherwise, it gives the same recovery as HSW, and they stated in another work (1999b) that LSW performance increased with initial water saturation. Filoco and Sharma (1998) found that the salinity of connate water was the main factor in LSW and not the salinity of the injected water, and the oil recovery was greater for lower connate brine salinities. Mixed-wet cores showed lower residual oil saturations than strongly water-wet or strongly oil-wet cores (Jadhunandan and Morrow, 1995). Such a result that higher oil recovery was obtained with the lower salinity of connate water is also supported by McGuire et al.'s (2005) data and Zhang and Morrow's (2006) data. What we find from these experiments from an overall view is that the salinity and composition of both connate and injection water are important. Injected water must have a lower ionic

strength than the connate water while the connate water must have an ionic strength low enough to activate the benefits of LSW floods.

One way of measuring the success of a flood or quantifying the reservoir oil saturation for EOR is by use of SWCTT (Deans and Majoros, 1980). This test is an in-situ method for measuring (residual) oil saturation in a reservoir. Chemical tracers are injected along with water in specified batch volumes into the reservoir through a single wellbore, and then, after a certain period of reaction time, the flowback and the concentration of the chemical tracers are measured and analyzed to decide the in-situ oil saturation. SWCTT in Alaska and North Slope by BP confirmed their lab corefloods and showed a reduction in residual oil saturation by LSW (McGuire et al., 2005, Seccombe et al., 2010 and Webb et al., 2004). Lightelm et al. (2009) presented results of an LSW in a Middle Eastern sandstone reservoir; they observed a temporary drop in the water cut. Robertson (2007) compared three cases in Wyoming, where lower salinity of the injected water correlated with a higher recovery. However, Trantham et al. (1978) and Pursley et al. (1973) observed no benefit from LSW pre-flush before chemical floods and LSW was observed not to be superior to HSW in several fields in Wyoming (Thyne and Gamage, 2011) and a Norwegian Sea field (Skrettingland et al., 2011).

From the field and lab observations, we conclude that the mechanisms under which LSW works may not be the same for all the formations, and the result depends on the mineralogy of the existing rock, composition, and saturation of connate water and oil, the condition of pressure and temperature of a reservoir and many other factors aside from composition of the injected water. Therefore, LSW, like many other EOR methods, is not a magic solution to increase the oil recovery and decrease the water cut, but it needs an in-depth study of the underlying reactions between the phases involved.

3 Mathematical Modeling of LSW

3.1 Introduction

In this chapter, we review the previous and current mathematical modeling by Dang and his associates (Dang et al., 2013a,b; Dang et al., 2014; Dang et al., 2015a-e) in modeling LSW for commercial reservoir simulators. This chapter shows the current stage of the commercial reservoir simulator before we add the features of wettability alteration model and fine migration model.

3.2 Literature Review

There are not many extensive modeling works in the literature despite a great volume of the experimental works on LSW. Jerauld et al. (2008) used a Buckley and Leveret waterflooding model, added total salinity (TDS) as a component to the water phase, and made relative permeability and capillary pressure dependent on the TDS. An empirical weighting factor was used to interpolate between LSW and HSW curves, including the residual oil saturation. This model does not give an accurate description of the phenomenon as reactions happen in the ionic level and these reactions determine a change in properties as we reviewed in the last chapter and not simply the TDS. Wu et al. (2009) used the same strategy and their modeling work lacks the same descriptive aspects of LSW mechanisms. Mahani et al. (2011) modeled a wettability change during LSW when TDS is decreased below a threshold value.

PHREEQC (Parkhurst and Appelo, 1999) was used by Rueslatten (1994) to model their LSW experiment and they could produce only an approximate pH variation observed in the experiment as the software is not designed to handle difficult reservoir simulation problems.

Omekeh et al. (2012) considered multiple ion exchange (MIE), dissolution and precipitation of carbonate minerals and a black oil model that included ions in the water phase. A relative permeability change during

LSW was made with the concentration of the divalent cations. A more comprehensive computational model was implemented by Dang et al. (2013a,b) in the GEM Equation of State (EOS)-based compositional reservoir simulator focusing on MIE and geochemical reactions to interpolate residual oil saturation, relative permeability, and capillary pressure curves.

It is noteworthy that while LSW considered with the injection water salinity of lower than 5000 ppm of dissolved salt concentration, in this study, we can see it is the concentration of specific ions like divalents that is more important.

3.3 LSW Simulation in Reservoir Simulators

Any LSW numerical model that is to be used must be able to explain some of the main observations from the LSW coreflood reports in the literature: 1. Wettability alteration upon LSW (and its results in terms of changes in residual oil saturation, relative permeability, and capillary pressure), 2. role of clay and importance of specific types of clays, 3. role of water composition (and not just the TDS), especially the divalent ions, 4. pH increase, 5. role of in-situ oil composition (acid number), 6. fine migration modeling 7. role of temperature, and 8. Mineral dissolution and precipitation.

As we discussed in the previous chapters, LSW performance depends on the conditions of the water injected, in-situ water and oil, and the rock. Several microscopic mechanisms were briefly reviewed in the last chapter and some of them have cross-effects while they, as a total, can lead to macroscopically observable changes such as wettability alteration or fine migration. Microscopic study of the changes during LSW can describe the role of injected water, in-situ fluids, and rock composition and their role in fine migration; it can also describe the effect of LSW rate on particle release and permeability modification, and it seems this is the proper micro-scale way of justification of observations in the lab. Temperature affects the reaction rates and directions; it favors some reactions over others. However, micro-scale changes cannot

be modeled in a commercial reservoir simulator because of the difficulty in describing so much phenomena involved in EDL modifications; these phenomena are either so hard to model, or the existing models involve so many assumptions, parameters, and unknowns that make the microscopic model impractical. In a reservoir simulator, there are the quantities (such as relative permeability) that describe macro-scale properties that must be fed into simulation equations. Therefore, a macro-scale model must be justified by observations and rationales in the micro-scale.

When it comes to clay minerals, they have two roles in LSW. First, they are the main ion-exchange sites on the surface of the rock which control the changes in the wettability. Second, the mobilized and migrated fines are thought to be mostly the clay minerals because they have the ability to be mixed wet particles. Furthermore, as they are the charged ion-exchange sites on the rock surface, they comprise the main locales where oil droplets are attached to the rock surface through the polar constituents in the oil.

CMG GEM is an EOS-based, fully coupled compositional reservoir simulator developed by the Computer Modelling Group Ltd. This tool is capable of capturing complex phase behaviors needed to simulate primary, secondary, and EOR methods. A detailed description of GEM equations, basic assumptions, and related topics can be found in the works by Nghiem and his colleagues at the Computer Modelling Group (1986, 1989, 2004a, 2004b, 2009, 2011). Recently, an MIE model with geochemical reactions was developed and integrated into this software specifically for the modeling of LSW and it has been well tested and documented (Dang et al., 2013a,b; Dang et al., 2014; Dang et al., 2015a-e). We have used this reservoir simulator for our studies.

3.3.1 Flow and Equilibrium Equations

The component molar balance with Darcy's law for velocity, diffusivity, aqueous phase reactions, sink/source term, and accumulation in an adaptive implicit scheme is given below (Nghiem 2004a). First, the components that can exist in hydrocarbon phases satisfy:

$$\psi_{i} \equiv \sum_{a=o,g,w} \Delta T_{a}^{u} y_{ia}^{u} (\Delta P^{n+1} + \Delta P_{ca}^{u} - \tilde{\rho}_{a}^{u} g \Delta d) + \sum_{a=o,g,w} \Delta D_{ia}^{u} y_{ia}^{u} + V\sigma_{i,aq}^{n+1} + q_{i}^{n+1} - \frac{V}{\Delta t} (N_{i}^{n+1} - N_{i}^{n}) = 0, i = 1, \dots, n_{h}$$
(3-1)

where *T* is the transmissibility, *y* is the mole fraction, *P* is pressure, *D* is the diffusion factor, *V* is the grid block volume, σ is the volumetric generation rate (in reactions) and *N* is the total moles of component *i* in a gird block.

And then the aqueous components (ions) that cannot be in the hydrocarbon phases satisfy:

$$\psi_{j} \equiv \Delta T_{w}^{u} y_{jw}^{u} (\Delta P^{n+1} - \tilde{\rho}_{w}^{u} g \Delta d) + \Delta D_{jw}^{u} y_{jw}^{u} + V\sigma_{j,mn}^{n+1} + q_{j}^{n+1} - \frac{v}{\Delta t} \left(N_{ja}^{n+1} - N_{ja}^{n} \right) = 0, j = 1, \dots, n_{a}$$
(3-2)

where the mineral components in this equation can be only in the dissolution/precipitation reactions (no flow or sink/source or diffusion terms):

$$\psi_k \equiv V \sigma_{k,mn}^{n+1} - \frac{V}{\Delta t} \left(N_k^{n+1} - N_k^n \right) = 0, k = 1, \dots, n_m$$
(3-3)

Thermodynamic equations in an oil/gas/water system are expressed by equality of the fugacity of components across phases:

$$g_{i,1} = f_{ig} - f_{io} = 0, i = 1, \dots, n_h$$
(3-4)

$$g_{i,2} = f_{ig} - f_{iw} = 0, i = 1, \dots, n_h$$
(3-5)

where the component fugacities, f, in the hydrocarbon phases are calculated using EOS while those in the water phase are calculated using Henry's model. At the end of this work, we will introduce a novel way of equilibrium calculations using EOS.

Volume constraint equations for grid blocks are also solved during simulation:

$$\phi^{n+1} - \sum_{a=o,g,w} \frac{N_a^{n+1}}{\rho_a^{n+1}} = 0 \tag{3-6}$$

In the adaptive implicit method, superscript n and n+1 show explicit and implicit grid blocks, respectively, while u can be explicit for some grid blocks and implicit for others and it determines the number of unknowns and the size of a Jacobian.

3.3.2 Aqueous Phase Reaction Equilibrium Equations

Reaction equilibrium equations and rate-controlled mineral dissolution and precipitation reactions are described in this section. Any reaction equilibrium is expressed by the following atomic and charge balance equation (called mass action equation of the reaction):

$$\sum_{k=1}^{n_a} v_k A_k = 0 \tag{3-7}$$

where v shows the stoichiometric coefficient and A denotes the element/compound in the reaction.

For a reaction to be in an equilibrium state, it must satisfy the following condition:

$$Q_{\alpha} - K_{eq,\alpha} = 0, \alpha = 1, \dots, R_{aq} \tag{3-8}$$

 K_{eq} is the reaction equilibrium constant and depends on temperature; it can be calculated from correlations and analytical models. Q is the activity product of a reaction and is calculated from:

$$Q_{\alpha} = \prod_{k=1}^{n_{aq}} (a_k)^{\nu_{k\alpha}} \tag{3-9}$$

where a_k is the activity of the species and can be calculated through different empirical correlations (Parkhurst and Appelo, 1999) and depends not only on the species and the reaction temperature, but also on the ionic strength of the water. These equations show how different parameters, such as temperature, can favor a reaction over another in a specific direction where these reactions involve common ions.

Aqueous species follow the reaction equilibrium equations we have mentioned here while the minerals follow kinetic reactions which are time-dependent (rate-controlled); some minerals dissolve (or precipitate) faster than others and the rate depends on temperature, a reactive surface area of the minerals, and also the deviation of the mineral activity product from the mineral solubility constant through the following equation:

$$r_{\beta} = \hat{A}_{\beta} \left[1 - \frac{Q_{\beta}}{K_{eq,\beta}} \right], \beta = 1, \dots, R_{mn}$$
(3-10)

where \hat{A} is the surface area of the minerals available to the dissolution/precipitation. More details on the reaction equilibrium and kinetics can be found in the PHREEQC user guide while an application of such concepts in the reservoir simulator can be found in Nghiem et al.'s work (2004a,b).

3.3.3 Ion Exchange on the Surface of Clay Minerals

Before LSW, the ions in the formation water and those adsorbed on a mineral surface are in chemical equilibrium. When water with different composition is introduced into the system, this chemical equilibrium is perturbed into a new equilibrium. New equilibrium means new ions and charges (and a

different number of ions per surface area) at a rock-fluid surface, and this means a change in the rock-fluid relationship that reflects in the property of wettability. Two examples of such ion-exchange reactions are mentioned here:

$$Na^{+} + \frac{1}{2}(Ca - X_2) \rightleftharpoons (Na - X) + \frac{1}{2}Ca^{++}$$
 (3-11)

$$Na^{+} + \frac{1}{2}(Mg - X_2) \rightleftharpoons (Na - X) + \frac{1}{2}Mg^{++}$$
 (3-12)

where *X* denotes the clay mineral on a surface of the formation rock in contact with water. Like the aqueous phase reactions, these reactions have mass action equations and reaction constants where ion activities appear. The activity of solid species can be calculated through solid solution theories. CEC of the rock is defined as the number of charges that can be absorbed on its surface (or in another word, how many of these accessible X^{-} exchange positions exists per unit pore volume of the rock). This property is used in the reservoir simulator equation setup as follows (for the two reactions mentioned above):

$$N_{Na-X} + 2N_{Ca-X_2} + 2N_{Mg-X_2} = \phi. (CEC)$$
(3-13)

This means that there is a definite capacity for the rock unit volume to adsorb cations (or in a better word, to absorb positive charges), adsorption of one cation means release of the other, and this selectivity in adsorption and release of cations from a clay surface depends on the equilibrium conditions of the aforementioned mass action equations. Thereby, the ionic material balance equations in the reservoir simulator will include the number of not only the ions in solution that can flow, but also the number of ions absorbed on the rock surface that cannot flow. For a more complete discussion of CEC, refer to Breeuwsma et Al. (1986).

In GEM, it is the number and type of the absorbed ions that (per unit bulk volume of rock) determine the wettability; an example is shown in Figure 3-1. An "equivalent fraction" of each cation is defined and used 48

for interpolating between HSW and LSW permeability curves by Dang et al. (2015). In a system of cations A^{a+} , B^{b+} , C^{c+} , ... the equivalent fraction of each cation can mathematically be defined as:

$$\zeta_{(A-X_a)} = \frac{a.N_{(A-X_a)}}{a.N_{(A-X_a)} + b.N_{(B-X_b)} + c.N_{(C-X_c)} + \dots}$$
(3-14)



Figure 3-1: HSW and LSW relative permeability curves (Dang, 2015)

3.4 A Basic LSW Model

In this section, we show how a basic LSW model works with ion exchange and relative permeability interpolation that was reviewed in the previous section and the difference between the outputs of LSW and HSW. All reservoir properties and well configuration and constraints are the same for both LSW and HSW

while the LSW model allows for aqueous phase reactions, the injection water has a lower salinity (and different composition) than the initial reservoir water, and calcite and dolomite exist in a reservoir by 2% of the volume of the total rock. The minerals are allowed to dissolve, the ions exchangers exist in the reservoir (with CEC of 50) that can react with the water, and the Na-X equivalent fraction on a rock surface is used to interpolate between the two relative permeability sets of the two limits of HSW and LSW. The reservoir model is homogeneous with constant porosity and directional permeability throughout the formation.

The model under study is an inverted 5-spot pattern with 1 injection well in the center and 4 production wells on the corners. The following figures show a comparison between the field performance under the two modeling methods.

In the LSW model in the reservoir simulator, the initial reservoir water composition can be specified in the data file or the simulator can produce the correct composition by doing equilibrium calculations between the water and the minerals in the reservoir that are allowed to dissolve.



Figure 3-2 Oil saturation comparison, LSW on the left and HSW on the right



Oil Recovery Factor SCTR - FIELD

Figure 3-3 Cumulative oil recovery factor, LSW vs. HSW





Figure 3-4 Field water cut comparison at the production wells, LSW vs. HSW



Figure 3-5 Field oil production rate comparison at the production wells, LSW vs. HSW





Figure 3-6 Field gas-oil ratio comparison at the production wells, LSW vs. HSW

As we can see in these figures, the overall effect of LSW is to change the wettability of the reservoir rock to a more water-wet condition to mobilize more oil. The modeling approach in this simple study is to use the aqueous phase reactions to calculate the primary interpolant, Na-X in this case, to interpolate between relative permeability tables in the simulator. Figure 3-2 shows lower residual oil saturation in LSW as compared with HSW. Figure 3-3 shows the cumulative recovery factor of the field is higher in LSW while Figures 3-4 and 3-5 compare the water cut and oil production rate from the field production wells. It can be seen that LSW improves the economy of the project not only by increasing the ultimate recovery factor, but also by controlling the water cut and oil production rate at all time from the production wells. Figure 3-6 shows that the producing GOR is lower for LSW while in both cases, the reservoirs are completely undersaturated in the whole production period; this means that LSW is more successful in recovering the heavier components of the oil.

Well #5 in this study is the central water injection well and the composition of the injected water can be specified in the well data section along with well completion and perforation data. In both cases, water is injected at the same rate all the time.

This study showed a simple homogeneous model where grid block properties remained the same and the effect of heterogeneity was neglected. In heterogeneous models where the shale and mineral fractions and porosity and permeability changes throughout the reservoir, and the same principles are applied as we used in this study, the outputs and results are more complex, however.

4 Relative Permeability Interpolation in LSW Applications

4.1 Introduction

The wettability alteration during LSW can be simulated in a variety of ways. In this chapter, we review the existing method and then propose a new, more general interpolation strategy in such a way that not only the salinity is involved, but also other factors can be incorporated as long as relevant relative permeability data exists.

4.2 Two Methods of Relative Permeability Interpolation

Traditionally, in the case of LSW studies, two relative permeability curves are produced by lab experiments, one for high salinity and a second one for low salinity. Each curve can produce a relative permeability (k_r) value at any desired saturation state and have different characteristics of endpoints and curvature. If relative permeability is desired at a salinity between the low and high salinity extremities at any saturation, two situations can happen: a) $k_{r, LS}$ and $k_{r, HS}$ are calculated at the desired saturation and then k_r for the new salinity is computed by a linear interpolation between the two salinity limits; b) the endpoints and curvature of the curve for the new salinity are computed by interpolating between the two salinity limit curve characteristics and then a new curve is generated which can then be used to find k_r at the desired salinity and saturation. In this chapter, we will show why the second method is superior and how it can be generalized not only to salinity interpolation but also other factors such as IFT, polymer or fine concentration.

4.3 Comparison between the two Relative Permeability Interpolation Methods

Let us consider a few situations and see how the two methods work. In this study, we use Corey's relative permeability correlations, and for simplicity, we consider only an oil-water case; the discussion can be easily generalized to other phases. Corey's relative permeability correlations for oil-water systems are:

$$K_{rw} = K_{rwiro} \left(\frac{S_w - S_{wc}}{1 - S_{wc} - S_{or}}\right)^{N_w}$$
(4-1)

$$K_{ro} = K_{rocw} \left(\frac{S_o - S_{or}}{1 - S_{wc} - S_{or}}\right)^{N_{ow}}$$

$$\tag{4-2}$$

As we can see in these two correlations, relative permeability at any water saturation can be obtained as long as the six parameters of S_{wc} , S_{or} , K_{rwiro} , K_{rocw} , N_{w} , and N_{ow} are known. These parameters are critical water saturation, residual oil saturation, water relative permeability at residual oil saturation, oil relative permeability at critical water saturation, water relative permeability curvature parameter, and oil relative permeability curvature parameter. In this section, we consider two imaginary experiments, one set of parameters for an LSW and another one for HSW in the next table.

	S_{wc}	\mathbf{S}_{or}	K _{rwiro}	Krocw	N_{w}	Now
LSW, 5000 PPM	0.3	0.35	0.06	1	3	1.2
HSW, 50000 PPM	0.25	0.4	0.25	0.9	2	1.5

Table 4-1 Corey-type correlation parameters for LSW and HSW

Using these parameters sets, we can create two sets of relative permeability curves in Figure 4-1.



Figure 4-1 Relative permeability curves based on Corey correlations for LSW and HSW

Now, we consider the situation when a relative permeability value is needed for salinities between 5,000 and 50,000 PPM in these three regions: $0.25 < S_w < 0.3$, $0.3 < S_w < 0.6$ and $0.6 < S_w < 0.65$ for method a (find rel perms and then interpolate for the salinity value) and method b (interpolate for the six relative permeability Corey parameters to build a new curve and then compute the relative permeability). Table 4-2 shows some results. Note that we have used linear interpolation for salinity and Corey equations for relative permeabilities.

Salinity (PPM)	Sw	Krw(a)	Kro(a)	Krw(b)	Kro(b)
5100	0.26	0.0000	0.9997	0.0000	0.9998
5100	0.27	0.0000	0.9996	0.0000	0.9998
5100	0.28	0.0000	0.9995	0.0000	0.9998
5100	0.29	0.0000	0.9994	0.0000	0.9998
49900	0.61	0.2495	0.0002	0.2496	0.0000
49900	0.62	0.2495	0.0001	0.2496	0.0000
49900	0.63	0.2496	0.0001	0.2496	0.0000
49900	0.64	0.2496	0.0000	0.2496	0.0000

Table 4-2 Some numerical results for Corey LSW and HSW correlations and interpolation

As we can see in this table, method a stretches the relative permeability limits; i.e., S_{wc} becomes equal to the smaller value of $S_{wc,LS}$ and $S_{wc,HS}$ and the same goes for S_{or} , while method b wisely finds a correct value for the endpoints S_{wc} and S_{or} , then judges whether the required saturation exceeds the endpoints or not, and, finally, finds the relative permeability values. Method b, in other words, assures that the new relative permeability curves are meaningful as long as the input permeability curves are all right.

4.4 Relative Permeability Interpolation in Higher Spaces

In the previous section, we concluded that, theoretically, it is better if we first set up new relative permeability curves for the new salinity value and then find the relative permeabilities at the required saturation. The question that arises now is that what happens if we have more parameters than just salinity, such as IFT or asphaltene precipitate saturation or the concentration of the strained fine particles. In this section, we examine different solutions to this problem. Here, we consider a data set of three undisclosed lab relative permeability measurements presented in Table 4-3. We show the process of refining the data and curve fitting as well.

Salinity (ppm)	IFT (mN/m)	SW	Krw	Kro
36320	23.5	0.2400	0.0000	1.0000
36320	23.5	0.2530	0.0001	0.9430
36320	23.5	0.2650	0.0025	0.8964
36320	23.5	0.2866	0.0002	0.8152
36320	23.5	0.2986	0.0024	0.7718
36320	23.5	0.3097	0.0026	0.7328
36320	23.5	0.3263	0.0030	0.6762
36320	23.5	0.3429	0.0032	0.6218
36320	23.5	0.3599	0.0033	0.5681
36320	23.5	0.3760	0.0035	0.5195
36320	23.5	0.3995	0.0005	0.4524
36320	23.5	0.4111	0.0006	0.4211
36320	23.5	0.4272	0.0006	0.3791
36320	23.5	0.4429	0.0047	0.3403
36320	23.5	0.4631	0.0075	0.2930
36320	23.5	0.4783	0.0061	0.2597
36320	23.5	0.5005	0.0089	0.2145
36320	23.5	0.5249	0.0157	0.1692
36320	23.5	0.5534	0.0225	0.1223

Table 4-3 Raw data of LSW and HSW ASP relative permeability curves

36320	23.5	0.5802	0.0280	0.0843
36320	23.5	0.6028	0.0308	0.0566
36320	23.5	0.6000	0.0320	0.0598
36320	23.5	0.6180	0.0376	0.0403
36320	23.5	0.6239	0.0403	0.0344
36320	23.5	0.6336	0.0430	0.0254
36320	23.5	0.6474	0.0471	0.0139
36320	23.5	0.6631	0.0539	0.0027
36320	23.5	0.6788	0.0580	0.0000
36320	23.5	0.6908	0.0661	0.0000
36320	23.5	0.7000	0.0702	0.0000
5000	16.5	0.2400	0.0001	1.0000
5000	16.5	0.2700	0.0002	0.9050
5000	16.5	0.3005	0.0002	0.8155
5000	16.5	0.3369	0.0004	0.7119
5000	16.5	0.3719	0.0032	0.6157
5000	16.5	0.3995	0.0032	0.5423
5000	16.5	0.4207	0.0087	0.4874
5000	16.5	0.4465	0.0101	0.4224
5000	16.5	0.4714	0.0223	0.3616
5000	16.5	0.4991	0.0332	0.2960
5000	16.5	0.5249	0.0522	0.2368
5000	16.5	0.5566	0.0806	0.1664
5000	16.5	0.5820	0.1171	0.1124
5000	16.5	0.6032	0.1482	0.0686
5000	16.5	0.6248	0.1928	0.0253
5000	16.5	0.6460	0.2455	0.0000
5000	1.24E-02	0.2400	0.0000	1.0000
5000	1.24E-02	0.9990	1.0000	0.0000
5000	1.24E-02	1.0000	1.0000	0.0000

A brief inspection of this table shows some experimental errors such as a decrease in relative permeability while phase saturation increases at some points. This also shows that interpolation between lab measured relative permeability raw data is not advised and a curve fitting can help screen data and find a smoother and more meaningful trend that can be used for flow simulation. As a result, the data in Tables 4-4 to 4-6 has been extracted from these data.

Salinity (ppm)	IFT (mN/m)	SW	Krw	Kro
36320	23.5	0.24	0	1
36320	23.5	0.2530	0.0001	0.9430
36320	23.5	0.2650	0.0025	0.8964
36320	23.5	0.2866	0.0002	0.8152
36320	23.5	0.2986	0.0024	0.7718
36320	23.5	0.3097	0.0026	0.7328
36320	23.5	0.3263	0.0030	0.6762
36320	23.5	0.3429	0.0032	0.6218
36320	23.5	0.3599	0.0033	0.5681
36320	23.5	0.3760	0.0035	0.5195
36320	23.5	0.3995	0.0005	0.4524
36320	23.5	0.4111	0.0006	0.4211
36320	23.5	0.4272	0.0006	0.3791
36320	23.5	0.4429	0.0047	0.3403
36320	23.5	0.4631	0.0075	0.2930
36320	23.5	0.4783	0.0061	0.2597
36320	23.5	0.5005	0.0089	0.2145
36320	23.5	0.5249	0.0157	0.1692
36320	23.5	0.5534	0.0225	0.1223
36320	23.5	0.5802	0.0280	0.0843
36320	23.5	0.6028	0.0308	0.0566
36320	23.5	0.6000	0.0320	0.0598
36320	23.5	0.6180	0.0376	0.0403
36320	23.5	0.6239	0.0403	0.0344
36320	23.5	0.6336	0.0430	0.0254
36320	23.5	0.6474	0.0471	0.0139
36320	23.5	0.6631	0.0539	0.0027
36320	23.5	0.6788	0.0580	0.0000

Table 4-4 Screened data of LSW and HSW ASP relative permeability curves, dataset 1

Salinity (ppm)	IFT (mN/m)	SW	Krw	Kro
5000	16.5	0.2400	0.0001	1.0000
5000	16.5	0.2700	0.0002	0.9050
5000	16.5	0.3005	0.0002	0.8155
5000	16.5	0.3369	0.0004	0.7119
5000	16.5	0.3719	0.0032	0.6157
5000	16.5	0.3995	0.0032	0.5423
5000	16.5	0.4207	0.0087	0.4874
5000	16.5	0.4465	0.0101	0.4224
5000	16.5	0.4714	0.0223	0.3616
5000	16.5	0.4991	0.0332	0.2960
5000	16.5	0.5249	0.0522	0.2368
5000	16.5	0.5566	0.0806	0.1664
5000	16.5	0.5820	0.1171	0.1124
5000	16.5	0.6032	0.1482	0.0686
5000	16.5	0.6248	0.1928	0.0253
5000	16.5	0.6460	0.2455	0.0000

Table 4-5 Screened data of LSW and HSW ASP relative permeability curves, dataset 2

Table 4-6 Screened data of LSW and HSW ASP relative permeability curves, dataset 3

Salinity (ppm)	IFT (mN/m)	SW	Krw	Kro
5000	1.24E-02	0.24	0	1
5000	1.24E-02	0.999	1	0

Further screening and curve-fitting of these three datasets using Corey's correlations result in Figures 4-2

to 4-4.



Figure 4-2 Relative permeability set #1, relative permeability interpolation study



Figure 4-3 Relative permeability set #2, relative permeability interpolation study



Figure 4-4 Relative permeability set #3, relative permeability interpolation study

Furthermore, the fitted Corey's correlation parameters are shown in Table 4-7.

Table 4-7 Corey correlation parameters for LSW and HSW ASP relative permeability curves

Salinity (ppm)	IFT (mN/m)	Swc	Sor	Krwiro	Krocw	Nw	Now
36320	23.5	0.24	0.3212	0.0580	1	1.9573	1.6734
5000	16.5	0.24	0.3540	0.2455	1	3.5601	1.2115
5000	0.0124	0.24	0.001	1	1	1	1

Now, to use method b in the previous section to find the relative permeability at any salinity, IFT, and saturation, we have two methods:

b1) Knowing that we have three sets of data, we can produce straight-line fits to find any Corey parameter (such as S_{wc}) in terms of Salinity and IFT: $Swc = a \times Salinity + b \times IFT + c$; (a,b,c) can be found by solving for the three sets of parameters (Salinity, IFT and S_w).

b2) Using weighting factors such as a reciprocal of distance, weighted by a sum of the reciprocals, in other words:

$$w_i = \frac{\frac{1}{d_i}}{\sum 1/d_i}, d_i = \sqrt{(Sal - Sal_i)^2 + (IFT - IFT_i)^2}$$
(4-3)

$$S_{wc}(Sal, IFT) = \sum w_i S_{wc,i}$$
(4-4)

While the first method looks sounder mathematically, especially for extrapolation, the second method is more general as the first method is applicable only when the number of sets is exactly equal to the number of interpolating parameters. We will further illustrate the performance of each method in detail in Figures 4-5 to 4-7.



Figure 4-5 Interpolation vs extrapolation IFT = 14 mN/m, Salinity = 6000 ppm



Figure 4-6 Interpolation vs extrapolation IFT = 20 mN/m, Salinity = 20000 ppm



Figure 4-7 Interpolation vs extrapolation IFT = 30 mN/m, Salinity = 35000 ppm

As we can see in Figures 4-5 to 4-7, as long as the salinity and IFT are within an experimental data range, both methods work adequately, but when they are out of a range, the extrapolation method b1 can give

wrong results. Method b2's results are always reasonable; however, having IFT or salinity out of an experimental range will not mean that extrapolation will happen. Overall, method b2 seems more robust and reliable.

4.5 A Few Notes on the New Relative Permeability Interpolation Technique

The new relative permeability interpolation technique is general with one important limitation: all the experimental data sets must be scaled to curves of the same shape; i.e., all must be fitted into Corey's equation, or all in the polynomials of degree three, for instance. This also ensures that scattered lab data is screened out, and as long as the lab data and fitted curves are meaningful, the resulting relative permeability curves are guaranteed to be meaningful, too. We also compared the extrapolation and weighting factor methods and concluded that using the interpolation by weighting factors is always more general. We used the reciprocal of a distance function; however, any other method can be used as long as the sum of weights is equal to 1.0. This interpolation can be especially important when a process changes fluid-rock interaction such as asphaltene precipitation (changing the rock to more oil-wet), steam injection (increase in temperature, more water-wet), and fine migration.

As for reservoir simulation purposes, we used salinity to show our interpolation technique; however, the correct way of interpolation will be something like an Na-X or Ca-X equivalent fraction on a rock surface, because it is the rock surface composition that determines the wettability and not just the mere water salinity in each grid block.

4.6 A Simple Case Study Model

In this section, we study a simple 2D horizontal LSW example which is equivalent to a quarter of an inverted 5-spot pattern. The three Corey-type relative permeability correlations found in the previous sections of this

chapter are used to simulate an imaginary system where the low salinity flood is associated with a surfactant to lower the interfacial tension. Low salinity water with known composition is injected from a corner of the 2D system and is produced from the opposite corner of the system initially at connate water saturation.

The Peng-Robinson EOS is used to model the hydrocarbon phases, and Henry's model along with GEM built-in correlations are used to model the water phases and the solubility of components, especially the CO_2 component. CO_2 solubility in water is important when there is CO_2 in the hydrocarbon phases and/or when there are carbonate rocks in a system where low salinity water can dissolve them and modify the wettability; CO_2 will be present in these cases in the aqueous phase reactions and, as we mentioned before, because the divalent cations Ca^{2+} and Mg^{2+} have a profound effect on the performance of the LSW and they can react with carbonate ions, correct modeling of CO_2 and its solubility is very important.

The imaginary surfactant component we used in this study must be fractionated between the water and oil phases and a surfactant model must be included in the fluid model. There are other calculations, such as solubility of the surfactant in oil and water, critical micelle concentration (CMC) associated with the surfactant, and changes in water volume and density with the fraction of surfactant, which can be found in the simulator user manuals. The three relative permeability curves that were developed in the previous sections are specified in the rock-fluid model and they are used in this case study.

Two interpolation parameters are used to find the new relative permeability curves; the first one is the equivalent fraction of Na-X on a rock surface which brings the effect of salinity and rock surface composition and the second one is the IFT value that brings up the role of surfactant. Other parameters, such as the composition of oil and water (injected and in-situ), temperature, and EOS parameters, affect these two interpolation parameters as well. Also, as before, the initial volume fractions of calcite and dolomite are set to 2% in the model. Figures 4-8 through 4-13 show the performance of the model.



Figure 4-8 A simple case study model on relative permeability interpolation, water saturation



Figure 4-9 A simple case study model on relative permeability interpolation, water relative permeability



Figure 4-10 A simple case study model on relative permeability interpolation, water salinity



Figure 4-11 A simple case study model on relative permeability interpolation, the equivalent fraction of Na-X



Figure 4-12 A simple case study model on relative permeability interpolation, pH



Figure 4-13 A simple case study model on relative permeability interpolation, cumulative injection, and production Figures 4-8 through 4-11 show the invasion of the low salinity water injected from the injection well, and they also show how this water mixes at the front with the reservoir connate water and how the water

saturation front is ahead of the Na-X front both of which affect the distribution of the water relative permeability. The low salinity water ions are filtered and reacted with the rock as the low salinity waterfront propagates into the system.

The dissolution of the minerals can affect the pH in Figure 4-12, Ca-X and Mg-X are replaced by Na-X, and the calcite and dolomite slightly dissolve in the injected low salinity water. The pH reaches the alkaline flood near the injection well but not far into the reservoir. As we can see, several factors can affect the relative permeability in such a simple system in which we cannot study the effect of one factor without considering the other factors. Figure 4-13 shows the cumulative oil produced (corrected for the standard condition) and the cumulative water injected. The injection and production follow a straight line as the production well does not produce any water and the produced oil is simply replaced by the injected water.
5 Fine Migration Modeling and Theoretical Backgrounds

5.1 Introduction

A permeability reduction (a pressure drop increase) has been noticed in several LSW coreflood experiments (Jones, 1964; Bernard, 1967; Sarkar and Sharman, 1990, Tang and Morrow, 1999b). This phenomenon is attributed to the mobilization and entrapment of fines during LSW and it can be used in order to achieve a higher sweep efficiency if the phenomenon is modeled correctly and the injection process is designed and executed optimally; it can also be properly controlled and mitigated if it has a negative effect on oil production and recovery. One of our research goals is to add this feature to a commercial reservoir simulator and validate the simulator with lab corefloods in the literature. The results can be used to model fine migration not only during LSW as an EOR process but also in any other similar processes where the phenomenon of solid particle movement in fluids gains interest.

5.2 Rock Surface, Pores and Pore Throats

In order to understand the significance of fines and fine migration, we must understand a structure of a porous medium where fine migration happens. A particulate medium can be approximated as a network of pores (chambers) connected through pore throats. Thus, there is a distinction between pore chambers and pore throats: pore chambers are characterized by volumes, whereas pore throats are characterized by sizes. Migratory fines (fines with a potential to migrate) may lie on pore walls or be suspended in a pore fluid. In most cases, the retention of fines occurs in pore throats, where fines may form a bridge and clog a formation; bigger fines have a more chance of clogging smaller pore throats. Thus, relative pore throat sizes and pore throat size distributions are critical for establishing the clogging potential in a formation.

The composition of the material that constitutes pore surfaces has a significant effect on the release of adhered fines. A typical sandstone is composed of 90% quartz, 6% feldspars, and 4% calcite and siderite carbonates (Khilar and Fogler, 1983). The composition of a rock surface affects the electric charge on the surface which causes the attraction of a thin layer of counter ions to the surface of rock and particles called an electrical double layer (EDL), as mentioned in the previous chapter. The electric potential at the boundary of the EDL is known as the zeta potential of particles or a rock surface and has a value that typically ranges between +100 and -100 mV. As the magnitude of this zeta potential increases, the colloid around the rock surface becomes more stable and less likely to flocculate.

A fines-free porous medium has a zeta potential and a surface charge, which, to a certain extent, determine the adhesion and repulsion characteristics of a pore surface - fine particle interface. The zeta potential of minerals is dependent on pH and ionic concentration, and, in general, changes from positive to negative with increasing pH (Sharma and Yortsos, 1987; Kia et al., 1987b; Vaidya and Fogler, 1990) or decreasing the ionic strength. The surface charge of pore surfaces is usually estimated from cation exchange capacity measurements, which must be determined from fine-free sandstone specimens (Khilar and Fogler, 1998).

5.3 Migratory Fine Particles

Petroleum reservoir formations usually contain various types of clay and other mineral species attached to pore surfaces. Fine particles that occur in a particulate medium and are free to move within a pore space are called migratory fines. These species can be released by colloidal forces or mobilized by the hydrodynamic shear of a fluid flowing through porous media. Fine particles can be indigenous to an initial rock-fluid system or be introduced into the system via other processes.

Fine particles can be generated by deformation of rock during compression and dilatation. This is due to a variation of the net overburden stress and of the integrity loss of rock grains. They are unleashed and

liberated because of the integrity loss of rock grains by chemical dissolution of the cementing materials in porous rock, such as acidizing or caustic flooding. These are the typical internal sources of indigenous fine particles.

Chemicals like iron colloids from wellhead equipment along with mud clays, fine sand, and other drilling/completion/acidizing/workover fluids are carried into a reservoir. Injected water during waterflooding always contains chemicals and fine particles that are introduced into the reservoir and they are injected in varying rates and temperatures. Particles can also be produced when incompatible injected fluids react with the existing reservoir fluids.

As fine particles move along the preferential tortuous flow pathways existing in porous media, they are captured, retained, and deposited within the porous matrix. Consequently, the texture of the matrix is adversely altered to reduce its porosity and permeability. Frequently, this phenomenon is referred to as formation damage, measured as permeability impairment.

These migratory fines can lie on pore walls, be trapped in pore throats, or be suspended in a pore fluid, and they can be from in-situ or external sources. Dullian and Dhawan (1974) included pore and pore throat size data for several Berea cores with pore throat sizes of 0.5 to 5.0 μ m and consequent chamber sizes of 5 to 50 μ m. Fines can form a bridge, clog pore throats and reduce the permeability while pore chambers are much larger than the throats and less likely to be clogged and affect the permeability. Thus, relative pore throat sizes and pore throat size distributions are critical for establishing the clogging potential of a formation.

The characteristics of a pore surface play a critical role in fines mobilization: surface roughness alters particle-pore interaction forces (Sharma et al., 1992) and generates restraining torque during the detachment of particles by hydrodynamic forces (Khilar and Fogler, 1998).

Formation damage in porous rocks is triggered by salinity, temperature, and velocity shock as a result of the alteration of concentration, temperature, and velocity relative to their critical values required for particle detachment. Physico-chemical, chemical, hydrodynamic, biologic, and mechanical processes often lead to the mobilization, generation, migration, and deposition of fine particles, which, in turn, cause formation damage in terms of permeability reduction. One such easy example is precipitation and migration of asphaltene even during the normal pressure depletion in some reservoirs (Amaefule et al., 1988).

The wettability of formation grains affects the detachment of fines. The wettability of a rock depends on its mineralogy and its wetting history. Fines that are held by water-wet pore surfaces are more likely to be released in the presence of water, while fines adhering to strongly oil-wet pore surfaces are more likely to be released in the presence of oil (Khilar and Fogler, 1998).

An electrochemical interaction between pore fluids, pore surfaces, and fines results in a complex phenomenon that is generally named "chemically induced fines migration." A schematic of a typical zeta potential and the EDL is shown in Figure 5-1.



Figure 5-1. Diagram showing the ionic concentration and potential difference as a function of distance from the charged surface of a particle suspended in a dispersion medium (Nasrallah and Nasr-El-Din., 2014).

During LSW, pH increases and a change in surface charge can then trigger the fine migration. There are several forces involved in detachment and trapping of fines; EDL expansion decreases the electrostatic attraction force between a wall and migratory fines while an increase in the injection water velocity increases the lift and drag forces responsible for lifting and moving the fine particles. These factors have been discussed in the literature and experimental observations are reported (Bernard 1967; Khilar and Fogler 1998). The detachment of fines from a pore throat causes an increase in permeability (flushing) while plugging it causes a decrease (clogging).

The fines in which we are interested in this thesis are migratory fines. Fine particles that occur in a particulate medium and are free to move within a pore space are termed migratory fines. These particles are generally kaolinite, montmorillonite, illite, mica, and quartz. Clay minerals present in a formation can

reduce permeability, increase sensitivity to low salinity fluids (due to high ion exchange capacity and specific surface), and increase irreducible water saturations (Khilar and Fogler, 1998; Gaida et al., 1987). The typical chemical composition of migratory clay fines (Khilar and Fogler, 1998) is presented in Table 5-1.

Clay	SiO ₂	Al ₂ O ₃	Fe ₂ O ₃	TiO ₂	CaO	MgO	K ₂ O	Na ₂ O
Kaolinite	40-49	35-40	0-13	0-2	0-0.8	0-0.5	0-0.1	0-0.2
Illite	50-56	18-31	2-5	0-0.8	0-2	1-4	4-7	0-1
Chlorite	31-38	18-20				35-38		
Montmorillonite	45-55	19-50	0-3					

Table 5-1: Typical Composition of migratory clay fines (Khilar and Fogler, 1998)

Migratory fines are platy, flaky, and/or rod-shaped. Studies with idealized spherical particles may provide insight into fundamental behavior; however, experimental results have shown that a particle shape, as it pertains to pore throat plugging, is important. The size of migratory fines in typical Berea sandstones varies from 0.1 to 5 μ m, and fines are rarely larger than 10 μ m (Khilar and Fogler, 1983). The relevant size for the problem of fines migration is the dimension perpendicular to the longer dimension, since suspended particles tend to orient their larger dimension along the direction of flow (Khilar and Fogler, 1998). Another important factor is the surface charge because the interaction forces between fines and the surface depend on it.

5.3.1 Properties Affecting Fine Migration

The properties used in most of the fine migration models can be summarized as follows: D_p and D_g are particle and porous media grain diameters, respectively; ρ_s is the density of particles; ρ and μ are the density and viscosity of the carrier liquid, respectively; v_a is the convective velocity; g is the gravitational acceleration, and T is the absolute temperature. These quantities will be used subsequently.

Civan (2007) explained: "Fluid moves faster, and particles experience more fluid shear-stress force and are more easily detachable from the pore wall in long, tortuous paths than in short straight paths." The convective velocity, v_a , of a particle moving through a porous medium is strongly related to the interstitial velocity, v, by:

$$v = \frac{u\tau}{\phi} \tag{5-1}$$

where *u* is the superficial (Darcy) velocity of the fluid, τ is the tortuosity, and ϕ is the porosity of the porous medium. Frequently, the convective velocity of fine particles is approximated as being equal to the interstitial velocity; that is, $v_a = v$. Note that Eq. (5-1) neglects the pore volume occupied by the immobile fluids, that is, the connate water, residual oil, and trapped gas; in other words, *u* and ϕ are the Darcy velocity and the porosity fraction of the fluid carrying the fine particles.

5.3.2 Forces Active in Fine Migration

Several forces act on a particle to cause particle release, flow, precipitation, trapping, and dislodgement. Consider a spherical particle resting on a pore wall (surface), and subject to the drag force of a moving fluid. The discrete nature of ions and water molecules gain relevance when the inter-particle distance is less than ~10-20A. At these distances, ions and water molecules resemble spherical particles that geometrically impede the particle from approaching a surface. Some of the forces act within this distance and a spherical assumption is good while others such as a drag force do not act in this distance and shape factors must be included in any mechanistic model.

Some of these forces are significant only when a particle is on a pore wall while they are negligible when the particle is moving with the carrier phase, and some are only significant when the particle is trapped in a pore throat as Figure 5.2 depicts. We have listed some of them in dimensionless groups here. Civan (2015) classified the various forces acting on particles in a flowing suspension of particles in three categories as (1) forces related to the transport mechanisms, (2) forces related to the attachment mechanisms, and (3) forces related to the detachment mechanisms and characterized in terms of the relevant dimensionless groups as described in the next sections. For a full description of these forces refer to Civen (2015).



Figure 5-2 Particles in porous space, after Civan (2015)

5.3.2.1 Forces Related to Transport Mechanisms

The forces causing particle migration (movement with a fluid) in a porous medium are described below.

5.3.2.1.1 Inertia Force

Objects tend to keep moving in a straight line at a constant speed when no forces are upon them, and this aspect is also called inertia. The inertia force can be expressed by the dimensionless group as (Civan, 2015):

$$I = \frac{\rho_s D_p^2 v_a}{18\mu D_q} \tag{5-2}$$

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5.3.2.1.2 Gravity Force

As a result of the density difference between particles and a carrier liquid, particles tend to move in the gravity direction. The gravity force acts upward when particles are lighter and, therefore, buoyant. The gravity force acts downward when particles are heavier and, therefore, tend to settle. The gravity force can be expressed by a dimensionless group called the gravity number as (Civan, 2015):

$$N_g = \frac{g(\rho_s - \rho)D_p^2}{18\mu\nu_a}$$
(5-3)

5.3.2.1.3 Diffusion Force

Particles smaller than 1.0 mm diameter tend to move irregularly in a liquid medium and disperse randomly. This phenomenon is called Brownian motion. The diffusivity of fine particles undergoing Brownian motion is given by Einstein (McDowell-Boyer et al., 1986):

$$D = \frac{kT}{3\pi\mu D_p} \tag{5-4}$$

where k is Boltzmann's constant. The diffusion force can be expressed by the Peclet number as the ratio of the convection velocity to the average Brownian velocity given by (Civan, 2015):

$$N_{Pe} = \frac{D_g v_a}{D} = \frac{3\pi D_p D_g v_a}{kT}$$
(5-5)

5.3.2.1.4 Hydrodynamic Force

Hydrodynamic forces are fluid-shearing and pressure forces (Wojtanowicz et al., 1987, 1988). Fine particles move along with the flow as a result of the motion of the fluids, thus causing the particles to drift. The dimensionless group expressing the hydrodynamic force is the Reynolds number given by:

$$N_{Re} = \frac{v_a D_g \rho}{\mu} \tag{5-6}$$

For small particles, usually, the velocity of the particles is taken to be equal to the carrier fluid velocity.

5.3.2.2 Forces Related to Attachment Mechanisms

These forces act on particles when they are near a grain surface at less than a 1.0 µm distance (Civan, 2015). These forces and the characteristic dimensionless groups are described below.

5.3.2.2.1 London-van der Waals Force

This is the attractive force due to the electromagnetic waves generated by the electronic characteristics of atoms and molecules. The attraction force is expressed by (Civan, 2015):

$$F_{VW}(s) = \frac{1}{(s-2)^2} F_n\left(\frac{s-2}{\overline{\lambda}}\right)$$
(5-7)

in which $\overline{\lambda}$ is a dimensionless wavelength of the dispersion force, *s* is the dimensionless separation distance, and *F_n* is a function assuming different forms for $\frac{(s-2)}{\overline{\lambda}}$ less and greater than unity.

The mathematic expressions for the London-van der Waals interaction forces between various objects are different, depending on geometric shapes of these objects (Hamaker, 1937; Tadmor, 2001). If *l* is the separation distance between a surface and a particle, R_p is the particle radius, and $s=l/R_p$ is the dimensionless separation distance, the London-van der Waals potential for $l/R_p <<1.0$ for a spherical particle near a flat plate is predicted as (Hamaker, 1937):

$$V_{LVA}(h) = -\frac{H}{6} \left[\frac{2(1+s)}{s(2+s)} + \ln\left(\frac{s}{2+s}\right) \right]$$
(5-8)

where *H* is the Hamaker constant for the case of particles and plate surfaces interacting through a pore fluid present between them. For example, Schembre and Kovscek (2005) reported $H=0.61\times10^{-20}$ J for a silica-water-silica system, $H=2.23\times10^{-20}$ J for a calcite-water-calcite system, and $H=2.26\times10^{-20}$ J for a silica-water-kaolinite system.

5.3.2.2.2 Friction-Drag Force and Hydrodynamic Thinning

Particles approaching grain surfaces experience a flow resistance because they must displace the liquid at the surfaces radially as they attach to the grain surfaces (Civan, 2015; Khilar and Fogler, 1987).

5.3.2.3 Forces Related to Detachment Mechanisms

The forces causing particle detachment from a pore surface in porous media are described below.

5.3.2.3.1 Shearing Force

This is the drag force of a moving fluid exerted on particles. Newton's law gives the shear stress as:

$$\tau = \mu \frac{dv}{dr} \tag{5-9}$$

where r is the distance from a particle surface. Civan (2015) stated that a proper dimensionless group, rigorously expressing the hydrodynamic force, is not available. Civan (2015) pointed out that the Reynolds number is given by:

$$N_{Re} = \frac{v_a D_g \rho}{\mu} \tag{5-10}$$

and its other forms, such as those "relating to the shear gradient, the relative velocity between particle and liquid, the angular velocity of the rotating particle, and the frequency of pulsation liquid have been suggested."

Potanin and Uriev (1991) predicted the critical shear stress required for detachment of particles by using:

$$\tau_{cr} = \frac{H}{24D_p l^2} \tag{5-11}$$

where *H* is the Hamaker coefficient (given above), D_p (cm) is the average particle diameter, and *l* (cm) is the separation distance between the particle surfaces in a filter cake.

Khilar and Fogler (1987) expressed the hydrodynamic lift force pulling a spherical particle off a pore surface by the following equation given by Hallow (1973):

$$F_L \cong 8D_p^2 (\mu \rho b)^{\frac{1}{2}} u_s \tag{5-12}$$

where u_s is the slip velocity, b is the linearized velocity gradient near the particle, and D_p is the diameter of the spherical particle.

When a fluid flows over the face of a cohesionless bed of particles, such as sand or gravel, and drill cuttings, the particles can be detached and lifted off in case the fluid shear stress exceeds the minimum critical shear stress. Yalin and Karahan (1979) developed a dimensionless correlation to predict the critical conditions for the onset of particle mobilization (or scouring) by fluid shear. Following their approach, Tremblay et al. (1998) developed:

$$N_{M_{cr}} = 0.122 N_{Re_{cr}}^{-0.206} \tag{5-13}$$

in which $N_{Re_{cr}}$ is the critical particle Reynolds number given by:

$$N_{Re_{cr}} = \frac{v_{cr} D_p \rho}{\mu} \tag{5-14}$$

where v_{cr} is the critical shear velocity, D_p is the mean particle diameter, and ρ and μ are, respectively, the density and viscosity of the fluid flowing over the particle bed. $N_{M_{cr}}$ is the critical mobility number given by:

$$N_{M_{cr}} = \frac{\rho v_{cr}^2}{\gamma_s D_p} \tag{5-15}$$

where γ_s denotes the specific weight of the particles suspended in the fluid. Applying Eq. (5-13), Tremblay et al. (1998) correlated their experimental data of laminar flow of various liquids over a loose bed of sand particles linearly on a full logarithmic scale and obtained the following expression for the critical shear velocity:

$$v_{cr} = 0.385 \left(\frac{\mu}{\rho}\right)^{0.0934} \gamma_s^{0.453} D_p^{0.36} \rho^{-0.453}$$
(5-16)

Then, they predicted the critical shear stress on the scouring face by:

$$\tau_{cr} = \rho v_{cr}^2 \tag{5-17}$$

These results may also apply to the detachment of loose particles from a pore surface because the correlations have been expressed in dimensionless groups.

5.3.2.4 Electrostatic Double-Layer Force

These forces are created due to the ionic conditions measured by pH and ionic strength. When particles and grain surfaces carry the electrostatic charges of the same sign, they repel each other. The repulsive force is expressed by (Civan, 2015):

$$F_R(s) = \frac{\exp[-\kappa D_p(s-2)]}{1 + \exp[-\kappa D_p(s-2)]}$$
(5-18)

where *s* is the dimensionless separation distance expressed as the ratio of the radial separation distance divided by the particle radius ($D_p/2$), D_p is the particle diameter, and, κ is the Debye-Huckel reciprocal double-layer thickness given by:

$$\kappa = e_{\sqrt{\frac{2n_o}{(\varepsilon_o \varepsilon kT)}}}$$
(5-19)

where *e* denotes a single-electron charge, n_o is the fluid ionic concentration, ε_o is the free space permittivity, ε is the fluid dielectric constant, *k* is the Boltzmann constant, and *T* is the absolute temperature. When the ionic strength is higher, then the double-layer thickness is smaller and hence κ is larger.

5.3.2.5 Born Repulsion Force

This force is generated as a result of the overlapping of electron clouds (Wojtanowicz et al., 1987, 1988). For example, Kia et al. (1987b) expressed the Born repulsion potential for a particle near a flat surface as follows:

$$V_{BR} = \frac{H\delta^6}{7560} \left[\frac{8R_p + l}{(2R_p + l)^7} + \frac{6R_p - l}{l^7} \right]$$
(5-23)

where δ is a collision diameter (δ =0.5 nm, Khilar and Fogler, 1987), R_p is the particle radius, and H is the Hamaker coefficient. The separation distance is denoted by *l*.

5.4 The Classical Filtration Theory

In a two-phase oil-water flow, migratory fines are either water-wet or become water-wet when LSW is introduced into the system (Muecke, 1979); as a result, when they move with water, they can potentially block pathways and pore throats through which water flows, decrease the relative permeability for water and the absolute permeability, and act as mobility control agents like polymer. This theory has been confirmed in the lab works and well productivity analysis of Liu and Civan (1996), Bennion and Thomas (2005), and Civan (2007). This also shows that when a rock is more water-wet, a permeability reduction will be larger (Sarkar and Sharma, 1990); it, furthermore, explains the role of the existence of an oil saturation when fines are mobilized and trapped.

Zhang and Morrow (2006) and Morrow and Buckley (2011) suggested that the formation of emulsions, stabilized by fines, their migration and straining, may result in mobility control. Some low-salinity coreflood studies have reported the release of significant amounts of fines (Bernard, 1967; Tang and Morrow, 1999; Pu et al., 2010), while others showed no evidence of fines migration (Lager et al., 2008; Jerauld et al., 2008; Rivet et al., 2010) even though additional oil was recovered.

Designing an LSW project in a way that fine migration can help not only in reducing the residual oil saturation (in a conventional wettability change sense) but also in improving the sweep efficiency of the process can greatly improve the economy of the project. If fine migration has an adverse effect, the industry wants to quantify its damage and mitigate the fine release if such a remedy is economical or the LSW project may be totally rejected. If models can capture this phenomenon correctly, design and performance

prediction of such a project will be possible. Hence, applying a rationalized model in a reservoir simulator is necessary to study this phenomenon.

Kinetic microscale rate models (Liu and Civan, 1996; Tufenkji, 2007; Ju et al., 2007; Rousseau et al., 2008; Yuan and Shapiro, 2010; Civan, 2010) assume that a detachment rate is proportional to a difference between current and critical detachment factors such as velocity and salinity. These models do not agree with the lab observations of Ochi and Vernoux (1998) and Bedrikovetsky et al. (2012) in the sense that the instant particle release that is observed in the lab has an asymptotic stabilization behavior in the models when the time goes to infinity. These models are called "the classical filtration theory," and in a 1-D set-up, they follow this general form:

$$\frac{\partial}{\partial t}(c+\sigma) + U\frac{\partial c}{\partial x} = D\frac{\partial^2 c}{\partial x^2}$$
(5-24)

$$\frac{\partial\sigma}{\partial t} = \lambda(\sigma)cU - k_{det}\sigma \tag{5-25}$$

In the first equation which is the fines material balance, c and σ are dimensionless volumetric concentrations of suspended and retained particles, respectively; U is the flow velocity, and D is the diffusion coefficient. In the second equation that shows the capture/release rate, the capture term is proportional to the advective particle flux; the proportionality coefficient, λ , is called the filtration coefficient. The detachment term is proportional to the retained fine concentration; the proportionality coefficient k_{det} is called a detachment rate coefficient or detachment factor. The theoretical dependence of the filtration coefficient on factors such as a particle size and velocity has been developed (Nabzar and Chauveteau, 1997; Chauveteau et al., 1998; Tufenkji and Elimelech, 2004; Rousseau et al., 2008; Yuan and Shapiro, 2011). On the other hand, the detachment factor is an empirical constant determined by tuning a model with experimental data. Noteworthy is that these two equations do not differentiate between the fines that are attached to a pore body surface and the fines that were mobilized and then strained in pore throats; this is a major shortcoming as the first type of fines do not change the permeability while the second type can greatly change it. Additionally, this theory does not recognize the role of microscopic forces and mechanisms we reviewed in this chapter.

5.5 Maximum Retained Concentration Function

A mechanistically better approach than the classical approach is proposed by Bedrikovetsky et al. (2011) where the maximum fine concertation σ_{cr} as a function of detachment factors was derived using mechanical equilibrium on migratory fines and a model predicted an instant particle release upon a change in the detachment factors. Figure 5-3 shows the forces acting on a particle attached on the wall of a pore, and a drag force is in the direction of advective flow.



Figure 5-3. Forces on a fine particle: F_d , F_e , F_g , and F_L are drag, electrostatic, gravitational, and lifting forces, respectively; I_d and I_n are lever arms for drag and electrostatic forces, respectively (You et al., 2015)

For the particle in Figure 5-3 to start rolling around the contact point, the torques balance yields:

$$F_d l_d + F_l l_n = F_e l_n + F_g l_n \tag{5-26}$$

If the left-hand side of this equation is larger than the right-hand side, the particle will start moving. Also, if we define the normal force as:

$$F_n = F_e + F_g - F_l \tag{5-27}$$

it will yield:

$$F_d l_d = F_n l_n \tag{5-28}$$

where the drag torque is the driving torque and the normal torque is resistive. Mathematical expressions for each of these forces are given by Khilar and Fogler (1998).

You et al. (2015) showed that for working conditions that happen in core-scale and field-scale LSW, gravitational and lifting forces are negligible compared to the electrostatic component of the normal force, and it follows that:

$$Torque = F_d(U, r_p)l(r_p) - F_e(\gamma, r_p), l_r = \frac{l_d}{l_n}$$
(5-29)

It is shown that the drag force depends on the velocity of the fluid carrying particles, U (the water phase) and the particle size, r_p , and the electrostatic force depends on the ionic strength of the fluid carrying the particles, γ and r_p while the lever arm ratio, l_r , depends on r_p . For sandstone rocks and illite/chlorite fine particles, $l_r = 0.0021$ (Kalantariasl and Bedrikovetsky, 2013). Short expressions for the drag and electrostatic forces are followed here:

$$F_d = \frac{\omega \mu \pi r_s^2 u_p}{r_p} \tag{5-30}$$

where u_p is the interstitial water velocity and can include the effects of water saturation, porosity, and tortuosity as

$$u_p = \frac{\tau u}{\Phi S_w} \tag{5-31}$$

$$F_e = -\left(\frac{\partial V}{\partial h}\right)_{h=h_1} \tag{5-32}$$

where h_l is when F_e is the maximum, i.e.:

$$\left(\frac{\partial F_e}{\partial h}\right)_{h_1} = 0 \tag{5-33}$$

In addition, V is the electrostatic potential:

$$V = V_{LVA} + V_{DLR} + V_{BR}$$
(5-34)

$$V_{LVA} = -\frac{A_{132}}{6} \left[\frac{2(1+Z)}{Z(2+Z)} + \ln\left(\frac{Z}{2+Z}\right) \right], Z = \frac{h}{r_s}$$
(5-35)

$$V_{DLR} = \varepsilon_0 D_e \frac{r_s}{4} \left\{ 2\psi_{01}\psi_{02} \ln\left[\frac{1 + \exp(-\kappa h)}{1 - \exp(-\kappa h)}\right] - (\psi_{01}^2 + \psi_{02}^2) \ln[1 - \exp(-2\kappa h)] \right\}$$
(5-36)

$$V_{BR} = \frac{A_{132}}{7560} \left(\frac{\sigma_{LJ}}{r_s}\right)^6 \left[\frac{8+Z}{(2+Z)^7} + \frac{6-Z}{Z^7}\right]$$
(5-37)

where V_{LVA} , V_{DLR} and V_{BR} are the London-van der Waals attraction, double layer repulsion, and Bourne repulsion, and they involve experimental and theoretical parameters and expressions that can be found in the literature (Kalantariasl and Bedrikovetsky, 2013).

This and the expressions for the electrostatic force show that the resultant torque is a monotonically increasing function of r_p (an electrostatic force increases with the ionic strength, particle size and temperature but the dependence on r_p is less than linear). It means that when LSW starts, first, the largest particles start detaching, and it continues until a "critical particle radius" where the resultant torque is zero and torque balance happens. As a result, at equilibrium, if we solve the toque balance equation to be zero:

it should give the minimum particle size movable by the current condition of U and r_p .

It becomes apparent that r_{pcr} decreases with velocity and increases with the ionic strength. A decrease in r_{pcr} means a larger portion of the initially attached particles will be detached. It is noteworthy that an increase in temperature tends to stabilize the fine particles and less fine migration will happen; this point is important in correlating lab coreflood data into the field scale simulation. As a result, a dimensionless maximum retention function is defined that shows the portion of the initially attached particles will remain attached (and they have smaller radii than the critical radius):

$$\sigma_a = \sigma_{cr}(U, \gamma) = \int_0^{r_{pcr}(U, \gamma)} f(r_p) dr_p$$
(5-39)

where f shows a distribution function of fine particles. Usually, a normal distribution function is assumed with the average particle size and the variance coefficient either measured in LSW core floods or used as tuning parameters. An increase in the velocity or a decrease in the ionic strength of water decreases the maximum concentration function which means more particles will be released from a rock surface. A normal distribution function and its integration are shown in Figure 5-4.



Figure 5-4: Normal distribution function and the cumulative distribution function

$$\varphi(x|\mu,\sigma^2) = \frac{1}{\sqrt{2\pi\sigma^2}} exp\left(-\frac{(x-\mu)^2}{2\sigma^2}\right), PDF$$
(5-40)

$$\Phi(x|\mu,\sigma^2) = \frac{1}{2} \left[1 + erf\left(\frac{x-\mu}{\sigma\sqrt{2}}\right) \right], CDF$$
(5-41)

where x is a parameter (a particle radius in our case), μ is the average and σ^2 is the variance. σ is called the standard deviation.

Before the LSW, if we solve Eq. (5-28), it will yield the minimum particle size movable by HSW. This particle radius will be a large value and, as a result, substituting that particle size in Eq. (5-41) yields the initial attached particle concentration which is the maximum attached particle concentration. After the introduction of the LSW, solving Eq. (5-28) yields a smaller value, which means a smaller attached particle concentration, and the difference between these two concentrations results in a sum of the mobile particles in the water phase plus the strained particles that are those mobilized particles that have been trapped in pore throats.

As we can see, solving for the maximum retained fine concentration involves highly nonlinear equations with several constants, roots and assumptions which may make use of this model unsuitable for reservoir simulation. But for the sake of completeness, we have brought a general overview of this model in the next section.

5.6 Mechanistic Fine Migration Model

In this section, we use the concept of the maximum concentration function to summarize the equations needed for LSW with fine particle migration in a 1-D simulation; derivation of the model is given by You et al. (2015) and we discuss this model in some detail. It is very important to know that when particles are released from a pore body, a negligible increase in the permeability happens, while when they are strained in pore throats, a remarkable decrease in permeability occurs. The main governing equations are mass balance for water, salt, and particles, a linear expression for the capture rate, an equation of state for water and Darcy's law to account for a permeability reduction due to particle straining; these equations are as follows in the order that are stated:

$$\frac{\partial}{\partial t} [(\phi - \sigma_a - \sigma_s)(1 - C)\rho_w] + \nabla [(1 - C)\rho_w U] = 0$$
(5-42)

$$\frac{\partial}{\partial t} [(\phi - \sigma_a - \sigma_s)(1 - C)\gamma \rho_w] + \nabla [(1 - C)\gamma \rho_w U] = 0$$
(5-43)

$$\frac{\partial}{\partial t} [(\phi - \sigma_a - \sigma_s)C + \sigma_a + \sigma_s] + \nabla [C\alpha U] = 0$$
(5-44)

$$\frac{\partial \sigma_s}{\partial t} = \lambda_s \frac{c}{\phi} \alpha |U| \tag{5-45}$$

$$\rho_w = \rho_{w0} \exp[c_w (p - p_0)] \tag{5-46}$$

$$U = -\frac{k}{\mu} \nabla p, k = -\frac{k_0}{(1+\beta_s \sigma_s)}$$
(5-47)

where ϕ is the porosity; *C*, σ_a , and σ_s are suspended, attached, and strained concentrations. Additionally, α is called a drift-delay factor (which accounts for particles to move slower than water) and β_s is a formation damage coefficient.

The mechanistic model differentiates between the particles attached to pore walls (σ_a) and those strained in pore throats (σ_s). The particles that are attached to the pore walls can be released if water is injected fast enough or if the salinity is lowered enough while the strained particles are trapped in the pore throats and create bridges by attaching to other trapped particles and they are difficult to flush. The attached particles can modify the in-situ porosity if they migrate, while the strained particles can modify the in-situ permeability because permeability is strongly controlled by the pore throats. For practical reservoir simulation studies, the strained particles can be assumed unflushable as the velocity requirement for flushing the particles from the pore throats cannot be reached in reservoir conditions.

Attached particle concentration can be equal to the maximum (critical) concentration at its maximum and an instant release is expected if σ_a exceeds σ_{cr} at the in-situ condition by the amount of $\sigma_a - \sigma_{cr}$. This situation can happen if water is injected with excess suspended fines in it or when the LSW front reaches an unswept zone, for example. This condition is important in simulating and programming of the mechanistic model.

The permeability damage factor comes from the straining of the mobilized particles. We assume that a negligible permeability increase happens in detachment of particles from a pore body while a significant permeability reduction happens in straining of these particles that depends on the concentration of the strained particles, and hence:

$$k = \frac{k_0}{1 + \beta_s \sigma_s} \tag{5-48}$$

The constants λ_s and β_s are the coefficients that can be found by matching lab data.

The classical filtration theory assumes that the mobilized particles move at the same velocity of the carrier fluid. This assumption, along with the instant particle release, leads to zero outlet particle concentration after 1 pore volume (PV) injection which contradicts with laboratory data (Lever and Dawe, 1984; Ochi and Vernoux, 1998). This can be explained by slow particle movement near a rock surface and different semi-empirical approaches have been proposed to model this phenomenon each of which have deficiencies. Here, a drift-delay factor ($\alpha < 1$) is used to account for this phenomenon and this factor depends on the critical particle size (larger particles that are released easier, and tend to move slower as they can roll along the surface) which depends on the salinity and velocity; as a result, α is a function of salinity and velocity neglecting the effect of a particle size distribution.

More details about the model, assumptions, mathematical expressions for each factor and solution of the equations in 1-D idealized conditions are given in Bedrikovetsky's works (Bedricovetsky et al., 2011; You et al., 2015; You et al., 2016). They have shown the similarities between the formation damage during LSW and the polymer flooding; knowing that both work towards lower water transmissibility, there is a possibility of using the existing polymer models to define the fine migration in reservoir simulators.

We tried to involve this model in a simple 1-D water injection model with no success due to the high number of very sensitive parameters and highly nonlinear equations with multiple roots involved in the calculations of the maximum fine concentration model.

5.7 The Classical Fine Migration Model vs. the Mechanistic Model

A major shortcoming in the mechanistic model is that it assumes momentum balance to find the attached fine concentration and uses this concept even after a fine particle flows along with the fluid. When a particle is flowing, the same momentum balance does not rule the precipitation as there is no contact point to have 95 different arms for the momentum balance equation and the electrostatic force becomes infinitesimal. It also always assumes fines to be attached to the bottom of a pore pathway while fines can be attached to the top, and then the gravitational force is a driving force instead of a resistive force. Another shortcoming is a high number of unknowns and (semi-) empirical factors and when the number of tuning factors is high, extrapolation becomes tricky. The last shortcoming that makes that model impractical for reservoir simulation studies is the involvement of highly nonlinear equations that must be solved iteratively along with the flow and phase behavior equations during the simulation.

Hence, the application of the organic deposition model (a modified version of the classical filtration theory) described by Civan (2015) is recommended for reservoir simulation studies. We will review this model in the next chapter and will use this model in our numerical simulation studies.

6 Fine Migration Modeling: A Numerical Model

6.1 Introduction

In the previous chapter, we showed the fine migration models in the literature and their shortcomings and strengths. In this chapter, we will modify Civan's asphaltene model (Civan, 2015) for a fine migration model that is normally associated with low salinity water injection. We will review the mathematical model and then bring a few examples that signify the performance of the model. We will also include a wettability alteration model we have devised in this thesis and include the required equations as the asphaltene flow and deposition are somewhat similar to fine migration, but their nature is not exactly equal to the nature of asphaltene precipitation and migration. One such difference is that asphaltene exists in the oil phase and can deposit on a rock surface and EOS is involved in fractionating the asphaltene-forming components into precipitating and non-precipitating parts while fines can exist on a rock surface or be carried by and in the water phase and can also be introduced into the system by the injection water. Fines do not follow EOS and they normally exist in higher amounts than the asphaltenes in a system.

6.2 Mathematical Model in Detail

The material balance equation for fines involves the total fines in a grid block, the fines flowing with the water phase and the deposited and plugged fines:

$$\frac{v_{td}^k - v_{td}^n}{\Delta t} = \beta_{sfce} c_f^k - \beta_{entr} V_d^k (v_{iw} - \beta_{vlcr}) + \beta_{plug} (1 + \beta_{snow} V_{td}^n) v_{sw} c_f^k$$
(6-1)

where $V_{td} = V_d + V_p$, V_{td} is the total deposited volume (dimensionless), V_d and V_p are the deposited and plugged volumes (dimensionless), c_f is the flowing fine concentration (dimensionless), v_{iw} is the interstitial water velocity (m/Day|ft/Day), β_{sfce} is a surface deposition parameter (1/Day), β_{entr} is an entrainment parameter (1/m|1/ft), β_{vlcr} is a critical velocity for entrainment (m/Day|ft/Day), β_{plug} is a plugging parameter (1/m|1/ft), and β_{snow} is the snowball effect parameter (dimensionless). V_d and V_p are dimensionless as the volume of the fines is divided by the grid block volume. c_f^k is also dimensionless as it equals the volume of flowing fines divided by the volume of the aqueous phase. Therefore, the unit of the equation is 1/Day, but in general, any consistent unit system can be used.

Typical values for the constants used in this equation are given in Table 6.1. Note that most of these parameters are used as tuning parameters in history matching the coreflood data. Additionally, the critical velocity is given as a function of salinity which certifies the fact that the required velocity to mobilize the fines depends on the salinity of the water; this is along with the mechanistic model where the electrostatic force depends on the ionic strength of the water.

Table 6-1. Typical parameters for the fine migration model

Surface deposition parameter (1/Day)	90			
Entrainment parameter (1/m)	35			
Critical velocity for entrainment (m/Day)	0.001 below 5000 PPM Salinity			
Critical velocity for entrainment (m/Day)	3.3 at 7000 PPM Salinity			
Critical velocity for entrainment (m/Day)	20 above 35000 PPM Salinity			
Plugging parameter (1/m)	1.63			
Snowball effect parameter	1.45			

In the above equation, the term on the left-hand side is the accumulation term for both deposition and plugging. The terms on the right-hand side are deposition, entrainment, and plugging in order. The first term on the right-hand side is the surface (pore body) deposition; it assumes the deposition rate is proportional to the fine concentration in the water phase. The second term on the right-hand side is the entrainment term which states that the deposited fines can be carried away from a rock surface if the interstitial water velocity is higher than a critical value and the entrainment rate is proportional to the

deposited fine concentration and the difference between the interstitial water velocity and the critical interstitial water velocity. The third term is the plugging rate which is proportional to the flow velocity, concentration of the fines in the water phase and the snow-ball effect which illustrates that the more fines deposited, the more chance for the next fines to be plugged in the same pore throat due to the higher restriction in the pore throats by the phenomenon of bridging.

6.3 Case Study 1, A Gradual Comparative Study

In this case study, we start from a simple model and add more features in a stepwise manner to reach the final full fine migration model and we will show the difference between the performance of the model for each case. We are comparing a total of five cases for the same inverted 5-spot pattern. The gird system is $21\times21\times8$ cartesian with horizontal permeability of 200 mD and vertical permeability of 20 mD. The grid dimensions are $100\times100\times50$ ft and the initial porosity in this homogeneous model is 20.01%. The chosen fluid model is the Peng-Robinson EOS for the 4-component system of CO₂, CH₄, n-butane and n-decane for the hydrocarbon phases and CO₂ can dissolve in the water phase according to Henry's law. One type of fines is defined for this study. The final model will allow the relative permeability to be a function of fine concentration as well as the saturation.

The reservoir is initialized with and initial fine concentration of 50 kg per m³ of the bulk rock volume (707 metric tons per grid block), and all the fines are initially attached to the pore surfaces (deposited). Each of the wells is perforated in the 1-5 top layers. Production wells are controlled with a minimum bottom hole pressure of 17,237 kPa and the injector operates a maximum stock tank water rate of 795 m³/day with a maximum bottom hole pressure of 18,000 kPa. Since the salinity effect is not modeled in this case study, the ionic compositions of the reservoir and injected waters are not important here. The model is run from January 01, 1986 till January 01, 1996.

In case 1, fines are defined without any additional features. In case 2, the purpose is to include the fines with only the entrainment calculations. Once a fine component mobilizes, it cannot deposit back onto the rock. It can be seen that moving water mobilizes the fines. In case 3, surface deposition is added to the second case; once the moving water slows down, the mobilized fines can be deposited. Case 4 adds the plugging to case 3 and once fines are plugged, they are immobilized permanently. Case 5 adds the formation damage due to the plugging in case 4 through a resistance factor calculation. The outputs compared consist of: 1. deposited fines mass, 2. flowing fines mass, 3. plugged fines mass, 4. total fines mass, 5. water flux magnitude, 6. resistance factor, 7. oil saturation, 8. porosity, 9. pressure, 10. water saturation, and 11. production in 3D distribution at the end of the simulation.

Figure 6-1 shows the deposition performance comparison between the 5 cases we designed. It shows that the injected water tends to sweep the deposited fines away from the injection well and towards the production wells as the water velocity decreases in that direction. It also shows that the classic fine migration model where fines are considered either deposited or flowing is not representative of what can happen in the reservoir, model #3 is almost identical to the simple classic fine migration model. It also shows that plugged fines tend to stop the injected water from carrying the deposited fines far away from the injection well as we can see in cases 4 and 5. Case 2, where the fines cannot be deposited once they are mobilized, is very unrealistic as it shows the water is carrying fines freely towards the production wells.

Figure 6-2 compares the flowing fine mass between the 5 cases. The same observations as in Figure 6-1 can be drawn. Note that in case 5 vs case 4, when the resistance factor is included, fines are flowing less freely after the water velocity decreases away from the injection well because the resistance factor tends to reduce the velocity and hence the ability of water to carry fines. Fines are flowing towards the production wells where the velocity is increased again due to the pressure gradient.

Figure 6-3 shows that plugged fines mass is not remarkably affected by the resistance factor. The reasons are the system being homogeneous and also once the fines are plugged, they do not move anymore in our modeling approach.

Figure 6-4 compares the total mass of fines in each grid block across all cases. Fines are being carried away from the injection well and produced at the production wells. The fines that are produced at the production wells are almost immediately replaced by those moved away from the injection well, that's why the total fine concentration is constant around the production wells.

Figure 6-5 compares the water flux between the five cases. We can see the effect of fines on the water flow path. In case 1, the breakthrough happens and there is already a free water break from the injection well to the production wells while the same is not seen when the fine deposition and plugging are considered.

Figure 6-6 shows the distribution of resistance factor due to the plugged fines; we tested our first four models as well to assure the accuracy of the keywords for the resistance factor being enabled or disabled. We can see the effect of gravity that forces the water to carry fines downward. Figure 6-7 shows that the plugging of fines slightly enhances the sweep efficiency.









a: Initial fines without migration

- b: Entrainment
- c: Entrainment and deposition
- d: Entrainment, deposition, and plugging
- e: Entrainment, deposition, plugging, and formation damage

Figure 6-1 Gradual comparative study, deposited fines mass









- a: Initial fines without migration
- b: Entrainment
- c: Entrainment and deposition
- d: Entrainment, deposition, and plugging
- e: Entrainment, deposition, plugging, and formation damage

Figure 6-2 Gradual comparative study, flowing fines mass









- a: Initial fines without migration
- b: Entrainment
- c: Entrainment and deposition
- d: Entrainment, deposition, and plugging
- e: Entrainment, deposition, plugging, and formation damage

Figure 6-3 Gradual comparative study, plugged fines mass









- a: Initial fines without migration
- b: Entrainment
- c: Entrainment and deposition
- d: Entrainment, deposition, and plugging
- e: Entrainment, deposition, plugging, and formation damage

Figure 6-4 Gradual comparative study, total fines mass











a: Initial fines without migration

- b: Entrainment
- c: Entrainment and deposition
- d: Entrainment, deposition, and plugging
- e: Entrainment, deposition, plugging, and formation damage

Figure 6-5 Gradual comparative study, water flux magnitude




















Figure 6-8 Gradual comparative study, cumulative water injected



Figure 6-9 Gradual comparative study, cumulative oil produced



Figure 6-10 Gradual comparative study, producing water cut

Figures 6-8 and 6-9 compare the total field performance in injection and production and they match which is due to the special and equal wellbore constraints and the homogeneity in all models. Figure 6-10 shows the producing water cut is decreased by plugging of fines.

As a result, we can say that fine migration can be a problem to the injectivity of water and a correct modeling can infer the skin factor that reduces the wellbore performance. Fine migration can work almost like a polymer effect that creates a water bank around the injection well. The field performance was not noticeable due to the simple homogeneous system we considered and the size of the field against the injection rate and time.

6.4 Case Study 2, A Moderately Heterogeneous Model

In this section we use case 1 and case 5 from the previous section where both cases involve fines while case 1 treats fines as a part of the rock which does not move and case 5 involves mobilizing (entrainment),

settling the fines on the pore surfaces (surface deposition), straining of fines (plugging, trapping permanently) in the pore throats and modifying the permeability for the amount of fines plugged. We have defined a vertical permeability distribution where the permeability is maximum in the middle of the reservoir and decreases towards the top and the bottom as 125 150 175 200 175 150 125 100 md from top to the bottom of the reservoir and the vertical permeability is kept as a tenth of the horizontal permeability. The distribution of parameters and field performance factors are shown in Figures 6-11 through 6-19.



Figure 6-11 A moderately heterogeneous model, total fines mass comparison. Left: no fine migration; right: fine migration



Figure 6-12 A moderately heterogeneous model, oil resistance factor comparison. Left: no fine migration; right: fine migration



Figure 6-13 A moderately heterogeneous model, oil saturation comparison. Left: no fine migration; right: fine migration



Figure 6-14 A moderately heterogeneous model, pressure comparison. Left: no fine migration; right: fine migration



Figure 6-15 A moderately heterogeneous model, oil velocity comparison. Left: no fine migration; right: fine migration



Figure 6-16 A moderately heterogeneous model, water velocity comparison. Left: no fine migration; right: fine migration



Figure 6-17 A moderately heterogeneous model, water saturation comparison. Left: no fine migration; right: fine migration



Figure 6-18 A moderately heterogeneous model, reservoir production comparison



Figure 6-19 A moderately heterogeneous model, oil recovery comparison

Figure 6-11 shows how the injection water is mobilizing the fine particles away from the injection well. Figure 6-12 illustrates the resistance factor due to the plugging of fines; this plugging happens mostly around the injection well but moderately around the production wells because fines can be mobilized around the production well due to the pressure gradient and can be plugged at the pore throats and affect the well performance. Because there is less mobile water and less pressure gradient around the production wells, this plugging happens in a more limited area in these regions.

Figures 6-13 and 6-17 show the distribution of fluid phases in the field and it is shown that plugged fines are forming a skin-like effect that causes the water to sweep more oil around the injection well. As Figures 6-14 shows, the pressure distribution is highly affected by fine mobilization and deposition. This means using a permeability-porosity correlation to calculate the resistance factor for the case of fine migration is not correct because it is the fines that create a resistance factor, which in turn changes the permeability.

Oil velocity distribution is almost identical for the two cases as Figure 7-15 illustrates while the water is produced and has found a channel through the more permeable layers in Figure 7-16, the effect is more pronounced in the case where fine migration effect is ignored which is also shown in Figure 7-18 where the water cut and water break-through happens a lot faster for the no-fine case but the plugged fines affect the oil production at later times and the water cut rises fast for the case with fine migration. Figure 7-19 shows that for this study and the current phases of development of the simulator, the oil is recovered at almost the same rate when the fine migration effect is ignored, and the ultimate recovery is the same. However, the water cut and fine production at the production wells can be significant in later times when fine migration happens.

In our study, the conventional resistance factor based on permeability vs. porosity correlation is disabled and the resistance factor is tabulated against the plugged fines concentration. How we tabulate the resistance factor against the plugged fines concentration can affect the results of the simulation.

6.5 Case Study 3, A Moderately Heterogeneous Model, Fines are Making the Rock More Water-wet

In this section, we compare the two cases we compared in the previous section, while we include the effect of plugged fines on the wettability change. The fines are carried in the water phase and it seems they should plug the water-invaded pore throats and flow paths more than they plug the oil phase. Figures 6-20 through 6-25 show the comparison.



Figure 6-20 A moderately heterogeneous model with wettability change, resistance factor comparison Left: no fine migration; right: fine migration



Figure 6-21 A moderately heterogeneous model with wettability change, water velocity comparison Left: no fine migration; right: fine migration



Figure 6-22 A moderately heterogeneous model with wettability change, oil saturation comparison Left: no fine migration; right: fine migration



Figure 6-23 A moderately heterogeneous model with wettability change, oil relative permeability interpolator distribution (plugged fine mass per block volume)



Figure 6-24 A moderately heterogeneous model with wettability change, reservoir production comparison



Figure 6-25 A moderately heterogeneous model with wettability change, oil recovery comparison

As we can see in Figures 6-20 through 6-25 and comparing the other property distribution in the reservoir at the end of the simulation, we don't see a remarkable effect when the wettability change is included. This can be since the resistance factor is highly affecting both phases while it must affect the water phase more and the effect of fines on the wettability change is masked. Turning off the resistance factor and having a

more aggressive change in the wettability due to plugging and/or deposition may solve the problem. We can see in Figure 6-22 that the residual oil saturation is lower when fine migration happens, this can be due to the fact that fines are making the rock more water-wet. This is the study in the next section.

6.6 Case Study 4, A Moderately Heterogeneous Model, Fines are Making the Rock More Water-wet, No Permeability Damage

In this section, we have turned off the resistance factor effect, and we are studying only the effect of the wettability change due to the fine plugging. When the system is more water-wet, it is predicted that the system does better when the water is injected, and the plugged fines create a water-bank life effect similar to the polymer bank. We have compared the results in Figures 6-26 through 6-28.



Figure 6-26 A moderately heterogeneous model with wettability change without resistance factor, water velocity comparison. Left: no fine migration; right: fine migration



Figure 6-27 A moderately heterogeneous model with wettability change without resistance factor, reservoir production comparison



Figure 6-28 A moderately heterogeneous model with wettability change without resistance factor, oil recovery comparison As we can see in Figure 6-26, the water has created a path from the injection well to the production wells for both cases, but the flow path of water for the case where wettability is modified is narrower (contrary to the case when resistance factor is used). This is shown in Figure 6-27 where the water cut for the wettability change model is always below the simple case and Figure 6-28 shows that the recovery is always better for this case as well, although the effect is minimal. While a more aggressive change in wettability and/or applying resistance factor only on the water phase (or more on the water phase than the oil phase) may solve the problem, the resistance factor modification for only water phase (the phase that carries the fines and can be blocked by the plugged fines) is the main way of describing the true phenomenon that might happen in the field.

6.7 Case Study 5, A Moderately Heterogeneous Model, Fines are Making the Rock More Water-wet, No Permeability Damage, Salinity Effect

At this phase of development of the simulator, the MIE has not been coupled with fine migration which means the true modeling of fine migration during low salinity water flooding is not possible with this reservoir simulator. However, the fine migration model allows for the correlation of critical interstitial water velocity, v_{ler} with salinity; it also allows salinity to be defined in terms of a total salt content both in the connate water and the injected water and calculate the water salinity in each grid block through mixing and salt mass balance. The wettability modeling does not allow the relative permeabilities to be a function of salinity, only saturation and plugged fines content are allowed. As a result, we have included the effect of salinity on the v_{ler} and showed how the model responds.

Note that in the model without salinity, v_{lcr} is considered as a constant of magnitude 0.1 m/day while it is assumed to be zero for up to 0.05 molality or 2760 ppm by weight which is considered very low saline water and we are injecting LSW with 2000 ppm of salinity in our case. The v_{lcr} increases linearly to 0.01 with salinity till 5500 ppm which is considered in the literature as the upper limit of LSW and then increases to a constant value of 2 m/day for higher salinities, 2 m/day is higher than the interstitial water velocity that is achieved in the reservoir which means below this velocity, water cannot carry the deposited fines back into the mobile water phase. The injection well is created as before; we add a line in the data file for the injection water salinity of 2000 ppm. The reservoir is initialized in the reservoir initialization part of the data file with connate water of 100,000 ppm in salinity and we assume only NaCl contributes to this salinity.

We have compared the final model in the previous section (wettability changes as a function of plugged fines with no resistance factor inclusion) with the same model but when v_{lcr} is tabulated versus salinity and the results are shown in Figures 6-29 through 6-33.



Figure 6-29 A moderately heterogeneous model, fines are making the rock more water-wet, no permeability damage, salinity effect on the final plugged fines mass



Figure 6-30 A moderately heterogeneous model, fines are making the rock more water-wet, no permeability damage, salinity effect on the interstitial water velocity



Figure 6-31 A moderately heterogeneous model, fines are making the rock more water-wet, no permeability damage, salinity effect on the final water saturation

Note that according to the fines mass balance equation, as shown below, having v_{lcr} as a function of salinity can only indirectly affect the plugged fines concentration as v_{lcr} is included in the entrainment term only.

$$\frac{v_{td}^k - v_{td}^n}{\Delta t} = \beta_{sfce} c_f^k - \beta_{entr} V_d^k (v_{iw} - \beta_{vlcr}) + \beta_{plug} (1 + \beta_{snow} V_{td}^n) v_{sw} c_f^k$$
(6-1)



Figure 6-32 A moderately heterogeneous model, fines are making the rock more water-wet, no permeability damage, water salinity distribution



Figure 6-33 A moderately heterogeneous model, fines are making the rock more water-wet, no permeability damage, salinity effect on the production characteristics



Figure 6-34 A moderately heterogeneous model, fines are making the rock more water-wet, no permeability damage, salinity effect on the oil recovery

As Figure 6-29 shows, the inclusion of salinity and injecting a lower water salinity causes more fines to be plugged in the reservoir. The interstitial water velocity profile remains almost unchanged, as Figure 6-30 shows because the plugged fines concentration is not high enough to change the porosity and we did not include the resistance factors. Figure 6-31 shows that the water saturation profile is slightly changed as the 124

plugged fines reduce the water relative permeability near the wellbore and the same water injection rate cause water to travel deeper in the reservoir and slightly increase the sweep efficiency, this is a very important observation; however, as we explained before, the resistance factor should be included in the calculation to affect only the water phases, this needs a massive reprogramming of the simulator which is still under study. Finally, Figures 6-33 and 4-34 show that including the salinity effect in the manner that we performed here, improved the reservoir performance by a slight fraction.

6.8 New Development: Multi-ion Exchange and Fine Migration Coupling

In this section, we review the latest reservoir simulator development where the reservoir simulator allows for the fine migration along with the multi-ion exchange and ASP flooding. This model should be, theoretically, able to capture the fine migration that happens during an LSW flood. More research and development will be needed in the future to allow for the fine detachment due to the salinity shock. At the time being, the salinity effect comes directly in correlating the critical water velocity needed for fine detachment and indirectly, through changing the wettability and water velocity dependence on the wettability. We will use the moderately heterogeneous model we synthesized in this chapter to demonstrate the coupled effect of multi-ion exchange and fine migration. Additionally, the new model allows for the mobile fines (flowing fines) to act as a surfactant in the wettability alteration modeling. As we mentioned in Chapter 2, the mixed wet fines can position themselves between the water and oil phase and ease the movement and release of oil droplets.



Figure 6-35 Aqueous salinity distribution after 1 year of LSW, fine migration coupled with LSW model



Figure 6-36 Plugged fine mass (per grid block) distribution after 1 year of LSW, fine migration coupled with LSW model



Figure 6-37 Flowing fine mass (per grid block) distribution after 1 year of LSW, fine migration coupled with LSW model



Figure 6-38 Na-X equivalent fraction distribution after 1 year of LSW, fine migration coupled with LSW model



Figure 6-39 Calcite dissolution/precipitation after 1 year of LSW, fine migration coupled with LSW model Figures 6-35 to 6-39 show the volumetric distribution of flow-related properties at the end of simulation. Figure 6-37 shows that the flowing fines move in a frontal manner while the plugged fines remain behind and damage the formation in Figure 6-36 while Figures 6-38 and 6-39 show that the calcite is dissolved near the injection well because of the LSW (negative numbers show dissolution and positive show precipitation) and the released calcite ions replace the sodium ions on the shale surface in the formation.

Figures 6-40 to 6-44 compare the performance of the model under no fine migration and the new model. As it is seen, the model responds almost like a weak ASP flood. The break-through time is delayed, and the residual oil saturation has been increased. Also, the injection has increased to match the water injection requirements. Some fines flow to the production well and the recovery factor has increased by as much as 5%.





Figure 6-40 Oil rate comparison, fine migration coupled with LSW model



Water Cut SC - Group - Default-Field-PRO

Figure 6-41 Water cut comparison; fine migration coupled with LSW model





Figure 6-42 Injection well BHP comparison, fine migration coupled with LSW model



Cumulative Fine Mass - PRD1

Figure 6-43 Cumulative fine mass comparison, fine migration coupled with LSW model





Figure 6-44 Cumulative oil recovery factor comparison, fine migration coupled with LSW model

It is noteworthy that both models we have compared here include the effect of low salinity water to improve the recovery over that of the high salinity water and an additional recovery improvement if seen because of the fine migration. Also, Figure 7-43 shows that more than one metric ton of fines has been produced at the production well which can be problematic for the perforation and well deliverability and surface facilities if this amount of fine is ignored. Knowing that the density of the fines is assumed to be equal to that of water and the bottom-hole radius can be as large as 30 cm, these fines can block more than 4.3 meters of the wellbore considering different packing geometries between the fines if they deposit at the bottom of the wellbore and the liquid rate is not enough to carry them upward.

6.9 Validation

In this section, we investigate the performance of the model by matching the coreflood data of Tang and Morrow (1999b). In their experiments, Tang and Morrow injected synthetic reservoir brine and diluted reservoir brine into a CS sandstone core 3.8 cm in diameter and 7.6 cm in length. They initially saturated the core with CS crude oil until an initial water saturation of 23.6% was reached. They flooded the core

with 9 pore volume of water with known composition, then with diluted water (10 times diluted) for another 9 pore volumes and finally with the same diluted water but increased the calcium concentration of the injection water to the original water and injected another 9 pore volumes. They recorded the recovered oil and the pH of the produced water. In their work, they have recorded the approximate porosity, permeability, oil viscosity and density amongst other challenges they had in performing the experiments. They observed mild fine migration, however, the produced fines were not quantified. We have used our newest model which incorporates the multi-ion exchange with the fine migration to study their lab data. Figures 6-45 to 6-47 compare the model performance with the lab observations.



Figure 6-45 Comparison between the simulator and the coreflood cumulative oil produced (Tang and Morrow, 1999)



Figure 6-46 Comparison between the simulator and the coreflood effluent water pH (Tang and Morrow, 1999) During our history matching, we used the variables not mentioned in the coreflood experiments to obtain a match such as CO₂ content of the oil, rock CEC, and the relative permeability. We observed that the initial CO₂ content which is available in many reservoirs can act as a pH buffer and matching the pH data in Figure 6-46 becomes impossible as a sudden change in pH does not occur at 4-hour time of the experiment. A small percentage of CO₂ in the reservoir oil can prevent the pH value to increase when a sudden change in the injection water composition is applied. Additionally, the effect of the LSW in increasing the recovery diminishes when divalent ions such as Ca is added to the injection water, this can be seen in Figure 6-45, at the final (third) flood where the salinity is still low, increasing the Ca concentration to the original water results in no additional recovery.



Figure 6-47 Fine production estimated in the coreflood

When we observed the plugged fine concentration, the first flood did not cause any fine migration, the second flood caused a mild fine migration and plugging, and finally, the third flood resulted in no fine migration and plugging, the addition of Ca ions, stabilized the mobile fines. This is shown in Figure 6-47. The fine mass produced was not measured in the original experiment and we have added 5% of mobile sandstone fines to investigate the fine migration in this study.

An important observation is how the divalent ions are important in masking the fine migration model and eliminate the benefits of LSW although the LSW is still operating at conditions where the injected water has a very low salinity. For the wettability alteration model, in this part, we chose the Ca-X to be the primary wettability interpolation species instead of Na-X which was chosen for the rest of our studies. This shows the importance of the ions and composition of the water over the traditional way of classifying HSW and LSW based merely on the total salinity.

6.10 Conclusions

We used the model we developed in the simulator for fine migration that has the features of calculations of each three types of fines (deposited, plugged, entrained) and can include the modification of overall permeability (not effective phase permeability) by a resistance factor as a function of plugged fines because plugged fines restrict the pore throats and this can reduce the permeability. However, as it is the water phase that carries the fines, these fines are only plugged in the water pathways and it should be only the water phase permeability (or transmissibility) that must be divided by the resistance factor calculated. If we were to deal with asphaltenes, the plugged asphaltenes should influence the oil phase as it is this phase that carries asphaltenes. This can be done in future works.

We did a series of sensitivity analyses to show the effect of heterogeneity, wettability change by the plugged fines (in an attempt to replace the effect of phase-dependent resistance factors) and total salinity (without ion exchange) on the performance of the developed model. Homogeneous reservoir shows almost no change in performance by fine migration and plugging which can act almost like polymer floods and it seems heterogeneity can play a very important role in determining the effects of fine migration. The main difference between polymer flood and fine migration, however is that polymers are injected along with the water and their behavior is controlled by the type of the polymer we choose, while fines are in the reservoir and we cannot control what is naturally in the formation.

One thing that can be told at this stage of the development is that the fine migration will for sure cause a loss of injectivity and formation damage; however, the correct modeling of the reservoir properties and the phenomena involved in LSW can tell whether a better oil recovery can be achieved or not under the desired constraints.

At the end of this chapter we presented our newest achievement, coupling the fine migration with multi-ion exchange model which allows for studying the fine migration under not only viscous forces, but also the change in the injected brine composition, lithology, and oil composition. Then we used the data in the literature to validate our model. While most of the studies try to classify the water injections based on the salinity, we observed that it is the type of concentration of ions, especially divalent ions, that is important, not the total salinity.

7 Application of the Model for Hybrid Processes in Synthetic Models

7.1 Introduction

In this chapter, we briefly design EOR processes and study them using our newly developed simulator that couples the effect of multi-ion exchange with the fine migration concepts. Our goal is how to design a process to produce more oil over what LSW offers or inject a less volume of LSW without sacrificing the added oil recovery associated with LSW. We will also briefly show how to model works in predicting asphaltene problem as well.

7.2 Batch LSW Design

In all our studies, we have injected LSW continuously except for the validation phase in the previous chapter. However, in that experiment, the initial volume of LSW was in the order of 3 pore volumes which is still a very large amount of LSW. In this section, we have designed a quarter of a homogeneous inverted 5-spot pattern where we are injecting 0.1 pore volumes of LSW and then switch back to HSW. We then, compare the results with a full LSW and a full HSW. Figures 7-1 to 7-5 compare the results.



Figure 7-1 Cumulative oil production comparison, LSW, Batch LSW, and HSW



Figure 7-2 Oil production rate comparison, LSW, Batch LSW, and HSW



Figure 7-3 Producing water cut comparison, LSW, Batch LSW, and HSW



Figure 7-4 Injection well BHP comparison, LSW, Batch LSW, and HSW





Figure 7-5 Cumulative fine mass production, LSW, Batch LSW, and HSW

From the figures, we can conclude that the batch LSW injection has the benefit of higher oil production rate and recovery and lower water cut, along with the benefit of lower amount of fine production which also affects the injection pressure needed due to the formation damage around the wellbores. The mass of fine produced is more than 1.3 metric ton for the case of LSW and 0.9 metric ton for the case of batch LSW and the volume of LSW required is much less. We can clearly see the benefits of a batch LSW project.

7.3 LSW and Solvent Injection

In this study, we will compare the result of a pure LSW and an LSW WAG process. In both cases, the injection and production scheme is a quarter of an inverted 5-spot pattern for two years. The rock is mostly sandstone with 4% calcite, 2% dolomite, and 1% anhydrite minerals. The homogeneous and isotropic reservoir is initially saturated with connate water and a 6% initial fine concentration. We have chosen the homogeneous and isotropic reservoir in order to confine the effect of other parameters and study the inclusion of a batch solvent (CO_2 and hydrocarbon) injection in the LSW. The injection pattern is comprised

of 1 month of initial LSW, 1 month of solvent injection followed by LSW. Figures 7-6 and 7-7 compare the results.



Figure 7-6 Oil recovery factor, batch LSW vs batch LSW-WAG



Figure 7-7 Water cut, batch LSW vs batch LSW-WAG

As we can see the inclusion of a miscible solvent batch has marginally improved the water cut and oil recovery. The fact that in this experiment, the added recovery and the delay in the water breakthrough is only due to the volume of the oil (solvent) injected, makes us pick the pure batch LSW over the batch LSW-141 WAG process as it is cheaper and yields the same results. The possible variation of the LSW-WAG process would be the injection of an immiscible gas instead of a miscible solvent, this process and its benefits has been discussed in the literature. In this experiment, slight fine migration happens, but no fine is produced.

7.4 Asphaltene Precipitation, Flow, and Deposition Modeling

In this section, we use the fine migration model to simulate a synthetic reservoir system where the oil flows to production wells by the depletion mechanism and a pressure reduction causes precipitation, flow and deposition of asphaltene.

The imaginary system is a circular bounded (no flow boundary) sector with a single production well under the natural depletion mechanism. The main static properties of the system are listed in Table 7-1. The wellbore is completed and perforated in the three bottom layers. The single production well produces from the reservoir under the depletion mechanism for five years. We have compared the results in the case where the wettability alteration due to asphaltene deposition is accounted for and the case where the wettability alteration is ignored. The chosen model is homogeneous with no aquifer and the initial water saturation equal to the initial connate water saturation of 0.2. Oil flows towards the production well and asphaltene is precipitated, deposited, and flowing due to the pressure reduction. An *i*-direction grid size is calculated logarithmically. Figure 7-8 shows the reservoir with a cutting plane through its center.

Table 7-1 A simple cylindrical model for asphaltene study: basic static reservoir model parameters

Reservoir Radius	Reservoir Height	Well Radius	Grid Configuration	Depth of the bottom grid	Total length of prod	Horizontal Permeability	Vertical Permeability	Porosity
2390 m	40 m	0.1 m	15x1x8	1000 m	5 years	30 md	15 md	0.2



Figures 7-9 and 7-10 show that when the wettability alteration is accounted for, more asphaltene is precipitated and deposited since the rock surface becomes more oil wet.



Figure 7-8 A simple cylindrical model for asphaltene study, 3D view

Figure 7-9 Simple asphaltene flow model, asphaltene precipitated per bulk volume, with wettability alteration on the left, without wettability alteration on the right


Figure 7-10 Simple asphaltene flow model, asphaltene deposited per bulk volume, with wettability alteration on the left, without wettability alteration on the right



Figure 7-11 Simple asphaltene flow model, oil saturation, with wettability alteration on the left, without wettability alteration on the right



Figure 7-12 Simple asphaltene flow model, oil resistance factor, with wettability alteration on the left, without wettability alteration on the right

Figure 7-11 shows that more oil remains in the reservoir when we consider a wettability change, especially when we look at the region close to the production well, which is because rock becomes more oil-wet and the residual oil saturation is increased. Figure 7-12 shows the resistance factor distribution in the two cases; there is more resistance when the rock becomes more oil-wet and more asphaltene is deposited.



Figure 7-13 Simple asphaltene flow model, oil relative permeability, with wettability alteration on the left, without wettability alteration on the right



Figure 7-14 Simple asphaltene flow model, pressure distribution, with wettability alteration on the left, without wettability alteration on the right

Figure 7-13 shows that if we ignore the wettability change, in this reservoir where there is initially no free water, there will be no free water and, hence, the oil relative permeability will always be equal to 1.0 in the

regions where there is no gas (immediately around the wellbore); when the wettability is changed more towards oil-wet, some water is freed up and this reduces the oil relative permeability. Figure 7-14 shows the pressure distribution in the two cases; asphaltene deposition tends to create a skin-like effect around the wellbore which does not let the pressure drop travel through the reservoir easily. In our model, we have set the wellbore to produce at a constant oil rate which is the same in both cases.

8 Conclusions and Recommendations

8.1 Conclusions

In this study, we reviewed the mechanisms involved in the LSW process and the associated fine migration phenomenon. We have discussed the forces involved in the fine migration and showed that if we had complete knowledge about fines, minerals, the velocity of water, and the means of calculating the momentum balance, we could use this knowledge towards a mechanistic model capable of predicting the onset of fine migration. As such knowledge and such means of precise computation are rarely available, we have chosen a flow model that was initially developed to predict the flow and deposition of asphaltenes and modified it for fine migration phenomenon. Asphaltenes are attributed to the oil phase and can be deposited on the rock surface. Initially, this model could change the permeability by modifying the porosity (using a permeability-porosity correlation). In this study, the model can allow for the change of wettability to account for asphaltene deposition using our wettability alteration model.

Fines are different from asphaltenes and polymers in the sense that they are not a part of any fluid phase, they are a part of the porous media, however. They modify the local porosity by moving in the reservoir and cause formation damage in terms of pore throat plugging. Fine migration is affected by the composition of the injected water amongst other factors as we observed in this study.

We have developed the means to correlate general ASP and LSW floods with wettability alteration and concepts such as mixed-wet fines being involved in reducing the oil-water IFT to mobilize oil globules and reduce the residual oil saturation in ASP and LSW. We have validated the model with the limited data published in the literature.

The new model can be used to predict the performance of ASP and LSW floods and the fine migration associated with such floods. The new wettability alteration model is general and can be used in modeling

any process that involves a change in wettability, and, as a result, a change in relative permeability without the shortcomings of the previous methods. These two models can be used to screen, design, and predict the performance of floods and remediate the possible adverse effects of fine migration.

The focus of this study is primarily on reservoir simulation applications and the methods suggested here are suitable for compositional reservoir simulators where a robust solver can overcome the computation cost of solving highly nonlinear equations involved in modeling complex processes such as LSW. I tried to develop a 1D oil-water simulator with injection and production wells on either ends of a system to simulate coreflood experiments. The effort failed due to the number and nonlinearity of the equations involved in LSW, even with highly simplified equations. The wettability alteration model is suitable for programming, however, as the mathematical method used in this method is exact and it does not need any neural network calculation that is normally used to find relative permeability at any desired condition.

The importance of geology in predicting the performance of LSW flood and the extent of fine migration is shown throughout this work where the composition and distribution of the initial water and the deposited fines are highly dependent on the mineralogy and clay content of the rock. Any modeling attempt, irrespective of how exact the modeling approach is, will fail to generate precise predictions when the initial conditions and the critical parameters are not defined correctly.

We can conclude through this study that while having screening criteria for LSW success is desirable, there are many factors that can change the outcome of LSW for a field that seem a perfect candidate for LSW. Mineralogy and geology of the reservoir, injected and resident water compositions, well constraints and completion, oil type, and many other factors.

8.2 **Recommendation for Future Developments**

We started our reservoir simulation with asphaltenes and generalized it to fine migration. We also had a brief modeling effort to generalize the fine migration model to proppants. Modeling of proppants in reservoir simulation has been a topic that has not been tried in this thesis and further works are needed in this aspect. Wettability alteration has a minimal effect in proppant floods and a non-Newtonian viscosity model for the proppant flurry gains prime importance in this topic.

We developed a model for the capillary pressure alteration (as a part of wettability alteration) but we did not utilize it as the capillary pressure data was not available in the LSW floods in the literature; further investigation is needed in this area. We highly recommend implementation of our new wettability alteration model in thermal reservoir simulators where change in the temperature or addition of solvents can lead to a change in the rock-fluid interactions.

We briefly showed the performance of miscible solvent injection and LSW; further investigation is needed in the case of LSW WAG operation where gas is not miscible at the reservoir condition and the CO_2 and LSW can produce carbonic acid which can dissolve the carbonate rocks and also change the pH and, as a result, change the performance of LSW.

Accurate and controlled lab measurements are needed in terms of coreflood experiments with complete composition measurements of the initial fluids, injected fluids and the effluents in order to completely validate the models developed here. History matching and optimization tools are available to assist such studies.

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