



Article A Critical Review of Osmosis-Associated Imbibition in Unconventional Formations

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Abstract: In petroleum engineering, imbibition is one of the most important elements for the hydraulic fracturing and water flooding processes, when extraneous fluids are introduced to the reservoir. However, in unconventional shale formations, osmosis has been often overlooked, but it can influence the imbibition process between the working fluid and the contacting formation rocks. The main objective of this study is to understand effects of fluid–rock interactions for osmosisassociated imbibition in unconventional formations. This paper summarizes previous studies on imbibition in unconventional formations, including shale, tight carbonate, and tight sandstone formations. Various key factors and their influence on the imbibition processes are discussed. Then, the causes and role of osmotic forces in fluid imbibition processes are summarized based on previous and recent field observations and laboratory measurements. Moreover, some numerical simulation approaches to model the osmosis-associated imbibition are summarized and compared. Finally, a discussion on the practical implications and field observations of osmosis-associated imbibition is included.

Keywords: imbibition; osmosis; unconventional formations; shale; EOR; hydraulic fracturing; water flooding

1. Introduction

Imbibition is defined as a movement in which the wetting fluid occupies pore space through the displacement of the non-wetting fluid. Osmosis refers to a process of water molecules' spontaneous movement through a semi-permeable membrane, such as clay, from a low-salinity to high-salinity region against concentration gradient [1]. Previously, the major mechanism of imbibition was narrowed to capillary pressure; however, osmosis due to molecule diffusion and the semipermeable membrane effect has been overlooked.

In unconventional formations, such as shale and tight sandstone, the imbibition exists when the injected working fluid contacts the formation rock during hydraulic fracturing and water flooding. The capillary pressure is considered as one of the driving forces for imbibition. Since this force is in inverse proportion to the pore size, it is particularly significant in the formation of nanopores and micropores. Thus, unconventional formation with smaller pore size usually has much higher capillary pressure and larger imbibition effect. In recent years, the imbibition effect was considered as a potential explanation for the low percentage of flow back after hydraulic fracturing in the shale gas reservoir. Roychaudhuri et al. [2], Makhanov et al. [3,4], and Zhou et al. [5,6] proved that a large volume of the fracturing fluid can be imbibed by the shale samples. Imbibition has also been studied as part of the research related to water flooding to achieve a sweep area as large as possible [7].



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Copyright: © 2021 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https:// creativecommons.org/licenses/by/ 4.0/). Osmosis requires a semi-permeable membrane and concentration differences. Clay can act the membrane because of its salt-exclusionary behavior. In tight clay-rich formations, such as shale, clay distributes on the wall of the porous space so that the membrane has a high efficiency to exclude the passage of salt ions, which is called membrane efficiency. In addition, due to the salinity differences between the injected fluid and formation brine, the imbibition process in clay-rich formations is often associated with osmosis. Fakcharoenphol et al. [8] and Zhou et al. [9,10] both indicated the osmosis effect on water flooding and hydraulic fracturing.

Therefore, besides capillarity, it is necessary to study the effect of osmosis on imbibition for water flooding and hydraulic fracturing in unconventional formations. In this paper, previous studies are reviewed and summarized for the osmosis-associated imbibition. The details and conclusions are described to provide insights about osmosis-associated imbibition in petroleum engineering applications.

2. Imbibition

The main study of imbibition is through experiments. The spontaneous imbibition experimental setup is indicated in Figure 1. There is no extra pressure applied during the spontaneous imbibition. Figure 2 shows the forced imbibition experimental setup, which can apply injection pressure on a sample.



(a)



Figure 1. Two typical spontaneous imbibition experiments (**a**) measuring sample weight change by hanging on the balance; (**b**) measuring fluid volume change in imbibition vessel.



Figure 2. Typical forced imbibition experiment [11].

According to the experimental results, the imbibition rate and volume are significantly affected by various factors including wettability, initial water saturation, temperature, flow direction, fluid and rock properties, and clay content, which are described respectively in the following subsections.

Wettability. Wettability is an important factor that can impact the imbibition process. The wettability indicates the ability of a fluid to adhere to the walls of a solid. The fluid includes gas and liquid phases. When the three phases (gas, liquid, and solid) interact, the contact angles between the gas–liquid interface and the solid–liquid interface can be used to indicate wetting and non-wetting states. In the reservoir, the rock with the smaller contact angle exhibits a faster imbibition rate for the wetting phase [12]. Therefore, adjustment of the contact angle is an effective way to control imbibition and is widely investigated [13–18]. Zhou et al. [5,6] designed experiments to compare imbibition rates in shale samples with various contact angles. The results showed that the imbibition rate was strongly influenced by changing contact angles.

Wettability alteration is one of the main mechanisms to mobilize residual fluid during water flooding. The alteration is dependent on fluid composition, rock surface mineralogy, system temperature, pressure, and saturation history [19–23]. Imbibition process can also alter the wettability of formation rocks. In previous studies, there are several situations of wettability alteration due to imbibition, including the imbibition fluids being acid, water with specific ionic content, and surfactant.

Dilute acid imbibition pre, post, or during hydraulic fracturing could improve the wettability of carbonate-rich shale formations and hence improve production [24–28]. The reaction between acid and rock can alter the wettability of formations by weakening the oil–rock surface bonds on the oil-wet thin layer. The alteration is to improve the pore connectivity; thereby, the trapped oil and gas are easier to be produced.

When the ionic content in water is changed, the wettability of reservoirs can be altered. This usually happens during low-salinity or salinity-modified waterflooding. These mechanisms of the wettability alteration include fines migration and rock dissolution [29–32]; PH increases [33–35]; multi-component ion exchange [36–40]; and surface charge changes or double-layer expansion [41–51].

The purpose of surfactant in imbibition fluid is to mobilize residual saturation [52–55]. Wettability alteration toward the hydrophilic state and a decrease in interfacial tension (IFT) are caused by surfactant during imbibition [55]. Cationic surfactant adsorption in negatively charged sandstone cores can decrease the performance to lower IFT and wettability alteration [56]. Alameri et al. [57] reported that surfactants in combination with low-salinity water flooding could be applied to circumvent the high salinity challenge and improve recovery in oil–wet carbonate reservoirs. Surfactants or a hybrid of surfactant with low-salinity water were observed to improve the wettability alteration (through contact angle measurements) of carbonate formation, sandstone formation, and shale (Three Forks shale formation) comparisons when the bulk fluids are seawater, seawater + CO_2 , and low-salinity water + CO_2 [11].

Contact angle measurements within the pore space are not realistic; thus, the spontaneous imbibition and zeta potential measurements can provide realistic indicators of wettability alteration in porous media, especially in unconventional shale reservoirs [49,51]. Nontheless, Mahani et al. [44] measured contact angle and zeta (ζ)-potential of the carbonate-brine interface on crushed carbonate fragments. Their experiments showed that at lower brine salinities, the ζ -potential of the limestone-brine interface become more negative, which is indicative of a weaker electrostatic adhesion of the rock-brine interfaces and implies a wettability alteration to a less oil-wet condition. Alvarez and Schechter [49] performed spontaneous imbibition, contact angle, and ζ -potential measurements on siliceous unconventional liquid-rich Permian basin reservoir cores using surfactants and fracturing brine. Alvarez and Schechter [49] experiments show anionic surfactants superior wettability alteration.



Figure 3. Contact angle of carbonate (top row), sandstone (middle row), shale (bottom row) core samples after they were soaked in seawater (SW), carbonated seawater (SW+CO₂), and carbonated low salinity water (LS₁+CO₂). The volume of oil droplets ranges from 4 to 15 μ L [11].

Initial Water Saturation. It is difficult to determine the effect of initial water saturation on imbibition through experiments due to several reasons. When the formation has higher initial water saturation, the amount volume of imbibition can be smaller or larger. The smaller imbibition amount was indicated by Blair [61] and Li et al. [62]. The larger imbibition volume was pointed out by Cil et al. [63], Zhou et al. [64], and Morrow et al. [65]. Bennion and Thomas [66] discussed the existence of the state of noncapillary equilibrium in a low-permeability gas reservoir with abnormally low initial water saturation, and the undersaturated matrix will imbibe a significant amount of water during drilling and completion, resulting in phase trap damage to the formation. In addition, some studies indicated there was little effect from the initial water saturation on imbibition [62,67,68]. The reason for the contradictory conclusions is that the capillary pressure and effective permeability both depend on water saturation. The capillary pressure has an inverse correlation to the water saturation, while the effective permeability of water has a positive correlation to the water saturation. Thus, when the initial water saturation is high, the capillary pressure is normally low, but the effective permeability of water is high. The imbibition volume is controlled by the opposite effects from low capillary pressure but high permeability. Therefore, Morrow and Mason [69] said that the influence of initial water saturation should be investigated specific to a formation. Zhou et al. [70] found that in shale, the lower initial water saturation could cause a faster imbibition rate and higher volume of the imbibition. This is due to the very small pore size of the shale, which causes

the capillary pressure to dominate the imbibition process when the initial water saturation is low.

Temperature. Temperature impacts imbibition because wettability and fluid properties change under various temperatures. Handy [71], Pooladi-Darvish, and Firoozabadi [72] indicated that higher temperature caused a faster imbibition rate. Peng and Kovscek [73] proved this conclusion through the forced imbibition experiment system with temperature control. Elevated temperature may result in formation damage due to fine migrations [74].

Flow Direction. The process of same flow direction for wetting and non-wetting phases is called co-current imbibition, which usually happens during the water flooding operation [75]. The opposite flow direction, which is regarded as counter-current imbibition, mainly occurs in unconventional formations and fractured water-wet reservoirs [75,76]. Qin [77] pointed out that the direction of the flow was determined through the wettability of the formation rock, fracture and boundary condition in the reservoir, and injection rate during operation. In the studies of Bourbiaux and Kalaydjian [78], Kantzas et al. [79], Pow et al. [80], and Li and Horne [81], it is found that co-current imbibition can cause a faster rate of recovery than counter-current imbibition.

Fluid and Rock Properties. Fluid viscosity, rock permeability, and pore size can impact the imbibition rate. When water displaces oil and gas in the reservoir, the imbibition rate increases as water viscosity increases [82].

Rock permeability is also a factor to influence the imbibition rate. The higher permeability is expected to have a higher imbibition rate [83,84]. However, Graham and Richardson [12] found that the high permeability ratio of fracture to matrix was difficult to relate to imbibition rate.

Pore size indirectly affects imbibition rate. The small size of pores can cause a high capillary pressure that is one of the driving forces of imbibition. Thus, the imbibition rate would be higher in the small size of pores. However, Egermann et al. [85] indicated that in unconventional formations, the pore size is small, while the permeability is also low. Hence, the imbibition could be still slow in unconventional formation.

Clay Content. In clay-rich formations, such as shale, imbibition is strongly affected by clay mineral [86]. Zhou et al. [6] analyzed the relationship between clay content and imbibition. In shale, the sample with higher clay content could imbibe more volume and at a faster rate than the sample with lower clay content. This was later confirmed in other experimental measurements, such as NMR [87], and the excessive imbibed water beyond capillary-driven water remains as irreducible water in the clay of shale. In addition, the imbibition of fluid with additives was also different in various clay content shale samples. In the high clay content sample, the fluid with 0.07% friction reducer has a greater imbibed volume than the fluid with KCl or KCl substitute (choline chloride, magnesium chloride, and tetramethyl ammonium chloride). However, the fluid with the 2% KCl was imbibed more than other fluids in the shale with less than 10% clay content.

3. Osmosis

Imbibition in tight formations is usually accompanied by osmosis, especially in highsalinity shale formations. Osmosis is a spontaneous net movement of solvent molecules toward a higher concentration region so as to minimize the concentration difference between two sides of a semi-permeable membrane. Solute–membrane interactions are more frequent on the higher solute concentration side than the low concentration side. Thus, more solute particles, such as salt, try to pass through the membrane, but they are excluded by the membrane due to its semi-permeable property. As those particles are pushed, a momentum is generated and pulls water molecules through the membrane from the lower concentration side [88].

Previously, osmosis was overlooked, since its effect is negligible during fluid flow in porous medium of conventional formations. However, in tight (unconventional) formations, which contain high clay mineral contents, a semi-permeable membrane can arise to generate osmosis. Neuzil and Provost [89] observed the anomalous fluid pressure in a

subsurface when they performed osmosis measurements on moderately compacted high clay content Pierre shale. This can be illustrated by electric double layer (EDL) theory [90]. Clay particles are naturally and commonly negatively charged. To neutralize the surface charges, cations or counter-ions will be attracted to the clay surface and form a diffuse double layer. However, the concentration of attracted ions decrease away from the clay platelets as electrostatic force weakens. If there is enough distance between clay platelets, there may exist a charge-neutral zone in the middle. However, due to some compaction effect, the diffused layers overlap each other, where the excessive charges accumulate. This overlap region carries charges and provides exclusion forces to any of the charged particles that try to pass through it but not water molecules [91–94].

Small pore sizes, which are a distinguishing characteristic of porous medium in tight formations, also contribute to osmosis occurrence. First, small rock pores with high clay contents can increase the quantity and quality of semi-permeable membrane. Second, the disassociated ions from salt in the aqueous solution are usually hydrated and complexed by water molecules. Thus, when the pore size is small enough, water molecules are more mobile than the larger-size hydrated ions, which will experience more restriction through the rock. Hence, as being excluded by the small rock pores, those hydrated ions may acquire enough momentum to overcome the diffusive flux and pull the water out of low concentration solution [95].

Hence, osmosis in tight formations has attracted research attention. Osmosis study in drilling engineering is mainly related to wellbore stability, which is strongly affected by water-based drilling fluid. When drilling fluid is invaded into formation rocks, it can decrease rock strength and elastic modulus and increase pore pressure, which are all causes of wellbore instability [96]. In shale formations, osmosis is considered as a significant mechanism to result in fluid invasion [97,98]. However, osmosis is a particular mechanism that allows fluid to have a bi-directional flow through controlling the salinity of the drilling fluid. Abass et al. [99] indicated that a designed drilling fluid can extract formation fluid out of shale to strengthen wellbore. The designed considerations are to increase osmotic flow to the wellbore, which requires increasing the salinity and fluid viscosity as well as reducing the shale permeability. High-salinity drilling fluid can induce osmotic flow to the wellbore. High viscosity and small permeability can inhibit capillary flow into formations. Membrane efficiency is also a consideration that is hard to control but should be considered when designing. Membrane efficiency is a ratio between actual osmotic pressure and theoretical osmotic pressure. Abass et al. [99] measured membrane efficiency in shale samples from the Zuluf field of Saudi Arabia. The measurement showed that its membrane efficiency was 4.2%. This result proves that osmosis cannot be neglected in shale formations. Schlemmer et al. [100] discussed factors that can improve membrane efficiency and hence increase osmosis. These factors are clay type of high cation exchange capacity, shale pore structure with more compacted clay, formation fluid with lower salt concentration, and compositions of drilling fluid that can affect the interface of clay.

However, those studies argued about the actual role of osmosis in fluid movement because it is difficult to distinguish osmotic flow from capillary flow in the imbibition process in tight formations. Zhou et al. [9] indicated this combinational mechanism during fracturing fluid flow in shale gas formation rocks.

In Zhou et al.'s experiments, it was found that the weight of rocks increased and decreased alternately when they were immerged into high salinity fluid, which can cause osmotic extraction [9]. Weight increase indicated that fluid invaded into rocks because capillary-driven imbibition was the dominant force. With the continuous fluid invasion, capillary pressure was decreased so that fluid was imbibed into rocks less and less. When osmotic extraction was stronger than capillary imbibition, the rock weight decreased because fluid flowed out of the tight pores more than it flowed in. However, capillary imbibition became stronger again when fluid saturation was declined, so that the weight of rock increased again after a certain point of time. Hence, it is difficult to distinguish

the capillary pressure and osmotic forces in the fluid movement processes, as they are dynamically changing and interacting with each other.

The osmotic effect can also contribute to the enhanced oil recovery (EOR) mechanism of unconventional shale formations. Recent studies show that low-salinity waterflooding EOR is can significantly improve oil production from shale formations, especially in high-salinity tight shale formations [8,101–104]. The concept is to enhance osmotic flow through a smaller salinity of waterflooding fluid than that of formation fluid. Figure 4 shows osmosis effect in clay-rich rocks. The application also depends on membrane efficiency. Fakcharoenphol et al. [8] and Teklu et al. [102] proved in clay-rich tight formations that osmosis can improve oil displacement under low-salinity fluid. Figure 5 shows experimental results of osmosis effect on oil displacements based on authors' work. However, it is challenging to quantify the osmosis effects on oil recovery, since fluid chemical equilibrium and rock–fluid interactions all change dynamically with salinity change in this extremely complicated process. Thus, direct measurement of osmosis during oil recovery experiments may reveal new important insights.



Figure 4. The schematic showing osmosis effect on fluid flow in clay-rich rocks.



Figure 5. A preserved one-inch diameter Bakken shale core sample submersed in high-salinity brine (240,000 ppm KCl) (**top**) and low-salinity brine (20,000 ppm KCl) (**bottom**) showing oil expulsion vs.

imbibition period. At imbibition Day 5 (**top**), the core was removed from a high-salinity brine beaker and produced/expelled oil was wiped and immersed in low-salinity brine from Day 5 until Day 10 (**bottom**). This shows that more oil is expelled due to osmosis during a low-salinity brine imbibition period.

A study by Padin et al. [103] performed high-pressure high-temperature chemical osmosis-driven fluid flow experiments in carbonate-rich mud rocks (shales). Their experiment showed a gradual, slow (within 120 days of experiment) increase of pressure within the samples. Based on their experiments, they concluded that chemical osmosis in organic-rich carbonate rocks could create a significant amount of driving force for oil mobilization or EOR; also, they stated that water imbibition in their experiment cannot be explained by only capillary forces.

4. Simulation for Osmosis-Associated Imbibition

The model that simulates spontaneous imbibition has been predominately attributed to capillary action [71,105–117]. Osmosis has been overlooked for a long time, as it is not as significant as other mechanisms, such as capillarity and gravity, because the membrane efficiency in a conventional reservoir is too low to make a real impact. However, shale and other unconventional formations present a significant osmosis effect due to their mineralogy and pore size structure [9]. Recently, several modeling efforts have been made to investigate the osmosis effect in unconventional reservoir development.

Fakcharoenphol et al. [118] proposed a triple-porosity fracture-matrix model and incorporated the effects of matrix wettability, capillary pressure, relative permeability, and osmotic pressure to investigate the impact of shut-in time on well productivity. In the model, the fracture forms a continuum of an interconnected network created during the hydraulic fracturing, while the organic and non-organic matrices are embedded in the fracture continuum. Fakcharoenphol et al. [8] used a numerical model to calculate osmotic pressure by tracking the salinity concentration. The simulation results indicated that osmotic pressure can be a viable mechanism by promoting water-oil counter-current flow. Wang and Rahman [119] proposed a numerical model to investigate both capillary pressure and osmosis effects on fluid leak-off during shale gas reservoir stimulation. The results showed that rock composition greatly affects the leak-off rate, and the invaded water due to capillary and osmotic pressures significantly increases the pore pressure. There is a strong non-linear relationship between imbibition volume and square root of time. Li et al. [60] developed a multi-component matrix imbibition model to investigate the effects of low-salinity water and surfactant on unconventional recovery. Simulation results matched with experimental data and revealed some important insights on the effects of water salinity and surfactant that the combination effects of contact angle and interfacial tension determine capillary pressure imbibition and that the concentration of charged ions and surfactant molecules affect the osmosis imbibition. All these processes are associated with different rock components and mineralogy, and there exists an optimum water salinity for maximum imbibition. Different from previous simulation studies, Li et al. [90] proposed a multi-mechanistic numerical shale matrix imbibition model by dividing the rock into nonmembrane and membrane components. Figure 6 introduces the coupling in the model. The model considered capillary pressure and osmotic pressure as a function of water saturation, could track the dynamic water and salt movement, and was validated by matching with experimental measurements. The principles associated with the imbibition and osmosis behind each model of these reviewed works are summarized in Table 1.

Fracturing Fluids				
Nano/micro-pores	Meso/Macro-pores			
 Clay rich Semi-permeable Membrane Osmosis effect 	 Large pores, micro-fractures Capillary effect Salt diffusion 			
Shame Matrix Components				

Figure 6. Numerical model with imbibition and osmosis coupling.

Table 1. Imbibition mechanisms for different models that considered imbibition and osmosis.

Model	Capillarity	Osmosis	Diffusion	Gravity
Fakcharoenphol et al. [118]	Water saturation-based capillary pressure curve for organic, non-organic, and fracture media	Osmotic pressure as a function of salt concentration and membrane efficiency	Fick's Law	Gravity effect between matrix and fracture media
Fakcharoenphol et al. [8]	Water saturation-based capillary pressure curve for matrix and fracture system	Osmotic pressure as a function of salt concentration gradient and membrane efficiency	Fick's Law	Gravity effect between matrix and fracture media
Wang and Rahman [119]	Bundle of capillary tubes associated with pore size distribution for clay, hydrophobic, hydrophilic components matrix system	Osmotic pressure as a function of salt concentration gradient and membrane efficiency	Neglected	N/A
Li et al. [90]	Water saturation-based capillary pressure curve for two-component matrix system	Osmotic pressure as a function of salt concentration gradient and membrane efficiency	Fick's Law	N/A

5. Discussion

In summary, those studies on osmosis-associated imbibition provide a good understanding of the fluid flow in unconventional formations. Osmosis is a critical mechanism of fluid movement especially in clay-rich tight formations, and it can enhance the fluid extraction process as an additional force to other forces, such as capillary pressure. However, further studies are required to investigate the impacts of osmosis on the fluid imbibition process to maximize production for field applications. Here, some discussions on the practical implications of osmosis-associated imbibition are summarized.

The common perception is that water imbibition could cause water blockage and clay swelling, which decrease the permeability of the formation. There were many experiments and studies to indicate the decrease due to water blockage [108,120–123] and clay swelling [124,125]. There was also an argument about whether the decrease is temporary or permanent. On one hand, the damage could be eliminated by increasing drawdown pressure or applying alcohol and alcohol surfactant. Therefore, the damage is temporary to the formation [15,126–130]. However, on the other hand, in some formations,

additives of alcohol have little effect on gas permeability, so that water blockage can be permanent [131–134].

In recent studies, it was found that osmosis-associated imbibition could improve permeability in unconventional formations. In shale, the experiments established the relationship between the amount volume of imbibition and permeability. It was found that imbibition in shale could cause natural fractures instability and regrowth, thereby causing a significant permeability increase [25,70,135,136]. While positive capillary pressure is the main sucking force for strong imbibition in water-wet rocks, the imbibition volume and rate can be significantly boosted by osmotic effect and lead to more natural fracture reactivations and regrowth. However, that conclusion requires further investigation, because those results were taken from the experiments under non-reservoir conditions. In another word, it is not clear how many fractures can be reopened under reservoir high pressure due to osmosis-associated imbibition. Hence, more studies are necessary to determine the relationship between osmosis-associated imbibition and formation permeability under reservoir conditions for unconventional formations.

In addition, there are studies that investigate the influence of osmosis-associated imbibition on water recovery and production in shale. Those studies provided some explanations on the field observations that extended shut-in time after fracturing treatment often results in a lower percentage of water recovery and but higher production in shale [137–141]. One of the potential reasons is that the near wellbore water blockage is mitigated deeper to the reservoir due to strong imbibition enhanced by osmosis during the extended shut-in. However, more evidence is required to establish a more accurate relationship between osmosis-associated imbibition and water recovery and production.

Therefore, the findings through further investigation between osmosis-associated imbibition and permeability change, water recovery, and production will be beneficial for the hydraulic fracturing design and reservoir management, such that the injection amount and fluid types of fracturing treatment and the shut-in time and flowback rate can be specially designed to minimize the water blockage effect but maximize natural fracture reactivations and well production performance.

6. Conclusions

Osmosis-associated imbibition has strong effects on fluid flow in porous mediums in unconventional formations. Those effects are important to be related to production after hydraulic fracturing and during the water-flooding process. Wettability and clay content are the main factors in the imbibition behavior of unconventional formations. Wettability can impact capillary pressure, which is one of the driving forces of imbibition. Clay content has a strong relationship with osmotic pressure. Therefore, understanding those factors can distinguish the dominant mechanism of fluid flow in unconventional reservoirs.

Although imbibition has been extensively studied in formations, it is necessary to further investigate its impact in unconventional formations, especially after hydraulic fracturing treatment. The effect of osmosis on imbibition was neglected before; however, more evidence has shown that osmosis has a significant impact on the fluid flow in clayrich formations, such as shale. Thus, more experimental investigations are necessary to prove its effect, such as high-pressure and high-temperature reservoir conditions with tight pore space. From these further investigations, some insights can be drawn, such as how osmosis-associated imbibition affects the production, and how to manage and control it.

In addition, the numerical modeling for a multi-mechanistic imbibition process has shed some light on the interplay of multiple forces during the imbibition process, especially the changes between capillary pressure and osmotic pressure. The simulation results matched the experimental measurements and field observations, such as the dynamic changes in salt concentration in laboratory and low flow-back recovery in the field. However, further investigations are recommended for simulations under reservoir conditions to match the actual production data with proper upscaling from laboratory-based modeling. **Author Contributions:** Resources, X.L.; Supervision, Z.Z.; Writing—original draft, review, and editing, Z.Z., X.L. and T.W.T. All authors have read and agreed to the published version of the manuscript.

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