

Article

Assessment and Optimization of Low Salinity Waterflooding via Pore Network Modeling in a Sandstone Reservoir

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Abstract

Low-salinity waterflooding (LSWF) represents a cost-effective enhanced oil recovery (EOR) strategy for mature sandstone reservoirs. However, its success strongly depends on pore-scale transport and wettability mechanisms that conventional reservoir simulators cannot accurately capture. This study implements a pore-network modeling (PNM) framework to evaluate and optimize LSWF performance in sandstone systems. A representative pore network was calibrated to match core-scale petrophysical properties—porosity, permeability, and pore-throat size distributions. The LSWF process was simulated using a coupled advective–diffusive salinity transport model integrated with salinity-dependent wettability alteration, expressed through variations in contact angle and interfacial tension. From the multiphase invasion and flow simulations, macroscopic constitutive relationships were derived, including capillary pressure, relative permeability, and fractional flow curves for different injection salinities. Sensitivity analyses indicate that wettability alteration induced by salinity reduction is the dominant mechanism enhancing oil recovery, as reflected in measurable shifts in the relative permeability endpoints and capillary pressure curves. The model predicts an optimal injection salinity window between 2000 and 4500 ppm, yielding up to 7.2% incremental oil recovery, while extremely low salinities produce non-monotonic trends due to competing interfacial tension effects. Overall, the proposed PNM workflow demonstrates a robust approach for (i) translating pore-scale phenomena into reservoir-scale constitutive laws, (ii) identifying salinity ranges for pilot testing, and (iii) reducing uncertainty in field-scale LSWF simulations.

Keywords: low-salinity waterflooding; pore-network modeling; wettability alteration; Talara Basin



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1. Introduction

The global production of conventional oil has entered a sustained decline due to the depletion of mature reservoirs and the limited discovery of new production sites [1]. This trend has intensified the need for more efficient recovery technologies to maintain energy supply while the world transitions toward alternative energy sources. In Peru, conventional oil fields show a similar pattern: production costs have increased while production continues to decline, widening a supply–demand gap that conventional production methods can no longer address. Current recovery factors in Peruvian fields average around 16%, and in the Talara Basin—one of the country’s most productive regions—this recovery drops to approximately 12% [2], well below the typical global range of 20–40% [1,3]. enhanced oil

recovery (EOR) techniques therefore represent an economically viable strategy to increase production from mature fields, and successful applications in Oman, Egypt, China, and Ecuador demonstrate their scalability and global relevance [4,5].

Among the main categories of EOR, thermal, miscible gas, and chemical methods have shown different levels of success [6]. In recent years, chemical-based approaches, especially low-salinity waterflooding, have gained growing attention due to their favorable balance between cost, implementation simplicity, and recovery performance [7]. Additional advances have highlighted emerging chemical approaches such as viscoelastic polymer flooding, where the combined effects of elasticity and wettability significantly enhance oil mobilization [8]. LSWF has proven effectiveness in both carbonate and sandstone formations, offering operational advantages such as reduced corrosion and scaling, minimal environmental impact, and compatibility with existing water injection facilities. These characteristics make it a promising option for the conditions observed in Peruvian reservoirs.

In Block XIII (Talara Basin), a secondary recovery project initiated in 2015 aimed to increase the recovery factor to 4.1% by 2036 through water injection [9]. Projections suggest that tertiary methods may be required to further increase recovery. Numerical reservoir simulations are used to support development decisions [10], but their performance is limited by reservoir heterogeneity and scale-related uncertainties [11]. Recent studies indicate that the effectiveness of LSWF increases when supported by numerical modeling, particularly in heterogeneous systems where reactive transport and fluid–rock interactions are difficult to quantify experimentally. Numerical analyses have been applied to evaluate hydrate risks in deep-water settings [12], fracture propagation under hydraulic stimulation [13], and broader reservoir optimization workflows [14], reinforcing the value of physics-based simulation frameworks.

Mechanistically, LSWF performance is attributed to several interacting processes, including wettability alteration through desorption of polar components, multicomponent ion exchange, double-layer expansion, interfacial tension (IFT) and pH effects, osmotic phenomena, fines migration, and mineral dissolution–precipitation [7,15–19]. Although multiple mechanisms may coexist, wettability alteration and multicomponent ion exchange are the most consistently associated with positive LSWF responses in sandstones [15,20,21]. The effectiveness of LSWF is reservoir-dependent and typically requires the presence of clays, crude oil with polar components, and significant ionic contrast between formation and injected brines [17,22–24]. Consequently, proper screening must consider characterization of mineralogy, petrophysical properties, fluid chemistry, reservoir heterogeneity, and aging effects [25,26].

Experimental work at core and pore scales demonstrate that moderate salinity reductions enhance oil displacement in core floods, microfluidic visualization, and spontaneous imbibition tests [23,26–29], with many studies reporting an optimal salinity window [23,30,31]. Field-scale projects such as Endicott [32] and pilot projects in West and North Africa [33–35] show incremental recovery when supported by screening, monitoring, and simulations, whereas poorly screened implementations or the presence of geochemical complications yielded marginal improvement [35,36]. Hybrid methods such as low-salinity polymer flooding, foam injection, and LSWF-surfactant/CO₂ sequences have shown positive laboratory results and present viable pathways for pilot designs and field adaptation [37–40].

Alongside laboratory advances, several computational approaches have been proposed to model fluid flow in porous media, including Pore Network Modeling [41–45], Direct Pore-Scale Modeling (DPSM), and Bundle of Capillary Tube Models (BCTM) [46]. Among them, PNM provides a balance between computational feasibility and mechanistic representation, enabling simulation of fluid invasion, salinity dispersion, capillary behav-

ior, and relative permeability at the pore scale [11,47]. With OpenPNM 3.4.1 providing a flexible platform for such modeling, it becomes possible to integrate pore-scale physics and salinity effects.

Despite progress, limited pore-scale numerical evidence exists for sandstone reservoirs with salinity conditions comparable to the Talara Basin. Addressing this gap is necessary to improve prediction of LSWF mechanisms and support field-scale design decisions. Accordingly, this study applies a pore-network modeling approach to quantify the effect of injection salinity on wettability alteration and oil displacement efficiency in a representative reservoir system.

Considering the above, the present study explores the application of Pore Network Modeling through OpenPNM to simulate LSWF processes in sandstone reservoirs representative of the Talara Basin. The objective is to evaluate the effect of brine composition on oil displacement efficiency and to provide a modeling framework that supports the design of optimized tertiary recovery strategies in mature Peruvian fields.

2. Evaluation of Waterflooding Potential

2.1. Waterflooding in Talara Basin

Historical waterflooding operations in the Talara Basin have provided valuable insights into the performance of secondary recovery methods under diverse reservoir conditions. Between 1978 and 1996, Occidental Peruana Inc. implemented a large-scale seawater injection program in the former Block XI—currently part of Block X—targeting the Echino and Halitas formations. Over this 18-year period, approximately 425 million barrels of water (MMBW) were injected, leading to an incremental recovery of about 59 million barrels of oil (MMBO). These results demonstrated the early technical feasibility of waterflooding as an effective secondary recovery strategy in mature sandstone reservoirs.

In 2000, Petrobras launched a pilot water injection project in the Verdún Formation of the Carrizo Field as part of its contractual obligations with Perupetro S.A. to assess enhanced oil recovery potential. Building on favorable results, the company expanded its injection operations to additional sites, including the Laguna Field (Verdún Formation), Somatito B1, Whale 589, and Central ABCDHI, all within the Echinocyamus Formation. The Carrizo Field project commenced in 2001, followed by the Laguna Field in 2002, and later by the reactivation of the Somatito B1 sub-block injection program within Block X [48]. These field-scale projects consolidated the operational know-how and infrastructure necessary for subsequent EOR initiatives in northern Peru.

Earlier developments also illustrate the progressive evolution of water injection strategies in the basin. In March 1968, waterflooding was first introduced in the Providencia Field of Block Z-69 (formerly Z-2B). The practice was later extended to the Peña Negra Field in October 1974 and the Lobitos Field in February 1976, remaining active until 1999. During this period, a cumulative total of approximately 130 MMBW was injected, yielding an incremental oil production of 9.6 MMBO—equivalent to an estimated 3% increase in the recovery factor. The injected water exhibited characteristic parameters including a pH of 7.38, density of 1.015 g/cm³, total dissolved solids (TDS) concentration of 22,600 mg/L, and chloride content of 13,500 mg/L [49].

These historical field applications established a valuable empirical foundation for understanding reservoir responses to large-scale water injection in the Talara Basin. The documented experiences provide essential operational benchmarks—such as injection volumes, fluid quality, and recovery efficiencies—that serve as a baseline for evaluating the potential of LSWF as a tertiary recovery alternative in mature Peruvian sandstone formations.

2.2. Characteristics of the Case of Study

Block XIII is located in the southern sector of the Talara Basin, in the Piura region of northern Peru. This block comprises two subblocks, XIII-A and XIII-B, as illustrated in Figure 1. The block covers an area of approximately 273,358 hectares and comprises a complex geological framework characterized by faulty and compartmentalized reservoirs. Hydrocarbon production primarily originates from the Salina and Zorritos formations, which consist of fine- to medium-grained sandstones interbedded with shales and minor conglomeratic intervals. These formations are known for their high lateral heterogeneity and varying clay content, conditions that influence both permeability distribution and waterflooding performance. As of 2023, Block XIII reported an average daily production of 1357 barrels of oil per day (BOPD) from 48 active wells, with cumulative oil production exceeding 90 million barrels since the onset of field operations [50].

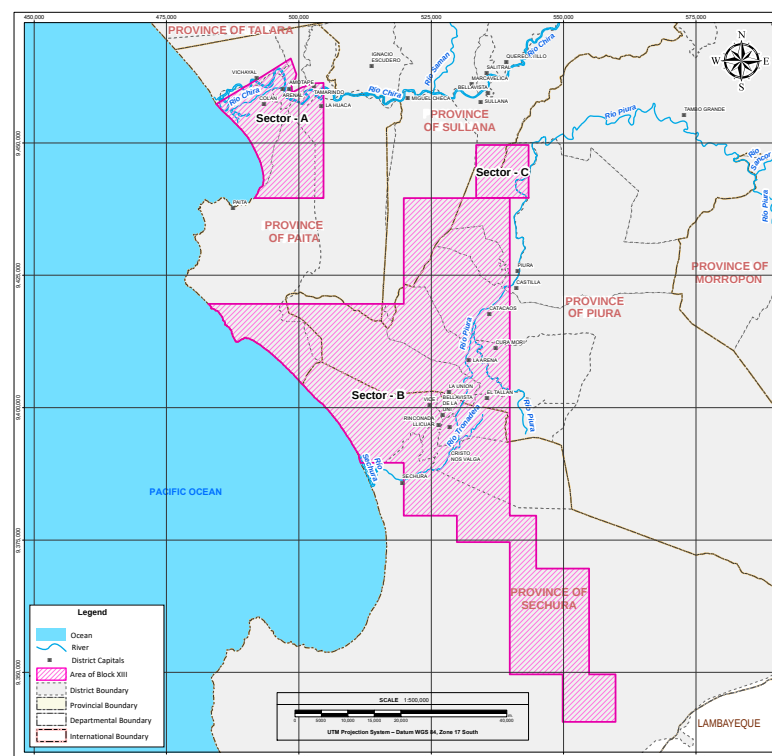


Figure 1. Location of Block XIII in the northwest of Peru.

In January 2015, the Secondary Recovery project was launched in Block XIII by injecting production water into Block I1. Later, in November of the same year, the injection of water in Block I2 began. In February 2016, a campaign was launched to convert three producing wells to injection wells in Blocks I1 and I2. In addition, in January 2016, a drilling campaign was initiated in the area influenced by secondary recovery, with the aim of increasing the oil recovery factor to 4.3% by 2036 [9].

The ongoing waterflooding program employs produced water treated at surface facilities and reinjected at a rate of approximately 3500 barrels of water per day (BWPD). Reservoir pressure monitoring indicates stabilization in the main productive intervals of the Salina Formation, confirming partial displacement efficiency. However, incremental oil recovery has remained below initial projections, suggesting that the system has reached a secondary recovery plateau. These operational results underscore the need to evaluate tertiary recovery alternatives capable of enhancing oil displacement efficiency without major infrastructure modifications.

In this context, Block XIII was selected as a representative case study for assessing the potential of LSWF in Peruvian sandstone reservoirs. Its geological characteristics, existing water injection infrastructure, and availability of core and water samples provide an ideal framework to simulate and analyze pore-scale mechanisms driving wettability alteration and recovery improvement under controlled conditions.

2.3. Formation and Injection Fluids

In this study, characterization of formation and injection fluids is a primary source of knowledge for determination of the characteristics of the water–oil system. Samples of formation and injection water were extracted from production wells to characterize salinity and evaluate its compatibility. The salinity concentration of formation and injection waters are approximately 20,000 ppm and 18,000 ppm, considering sodium chloride (NaCl) as the main component of the concentration. A combination of the fluids shows values of ionic strength between 0.331 and 0.366, and pH values between 6.8 and 7.2. CaCO_3 was found to be the only one with a high saturation index, indicating potential fouling. Table 1 shows the physicochemical analysis corresponding to the dissolved solids in the formation and injection water.

Table 1. Solids content and salinity concentration of formation and injection fluids.

Cations/Anions	Formation Water		Injection Water	
	mg/L	meq/L	mg/L	meq/L
Na^+	6774.93	294.69	6483	281.96
K^+	49	1.25	120	3.07
Ca^{2+}	855	42.66	459	22.9
Mg^{2+}	33	2.72	85	6.99
Fe	0.93	0.03	0.24	0.01
Ba^{2+}	0.81	0.01	2.1	0.03
Sr^{2+}	38	0.87	37	0.84
Total	7751.67	342.24	7185.57	315.81
Cl^-	11,878	335.04	10,901	307.48
HCO_3^-	390	6.39	473	7.75
SO_4^{2-}	39	0.81	28	0.58
CO_3^{2-}	0	0	0	0
Total	12,307	342.24	11,402	315.81

Although the contrast between formation brine (20,000 ppm) and the proposed injection brine (18,000 ppm), both predominantly NaCl-based, is modest compared to the ionic gradients typically associated with strong LSWF responses, these values reflect actual operational constraints in Block XIII rather than an optimized brine design. Therefore, the objective of this study is to evaluate whether incremental wettability alteration can occur under realistic field brine availability, rather than exploring the theoretical upper limit of LSWF performance. Future work may incorporate engineered brines with higher sulfate content or controlled divalent ion modification to enhance ion exchange mechanisms and further amplify the potential of wettability alteration.

2.4. Rock Samples and Core Tests

Basic petrophysics analysis, core flooding tests, and mercury intrusion porosimetry were conducted to obtain properties of porous media, fluids, and waterflooding behavior. Formation pressure and temperature were established for the sake of consistency at values of 1950 psi and 120 °F to simulate reservoir conditions. Rock samples evaluated for waterflooding potential were selected and tested according to the development plan for secondary recovery of Salina Formation, currently executed by the operator of Block XIII (see Table 2).

Table 2. Porosity and permeability of Salina sandstones at reservoirs conditions.

Samples	Depth (ft)	Porosity (%)	Permeability (md)
Salina-1	2289.19	35.1	3238
Salina-2	2289.57	33.6	2466
Salina-3	2302.08	34.5	3261
Salina-4	2398.41	21.1	0.135
Salina-5	2582.21	3.7	0.023
Salina-6	2836.58	27.5	89.3
Salina-7	2837.10	22.7	24.4
Salina-8	2840.98	24.9	85.7

To ensure representative initial wettability and fluid distribution, core samples were conditioned prior to experimentation following established procedures for restoring mixed-wet sandstone systems [51–55]. Each core was cleaned, oven-dried, and evacuated before being fully saturated with synthetic brine matching formation water composition using vacuum saturation, followed by back-pressure loading at reservoir pressure (1950 psi). After brine saturation, crude oil was injected at 120 °F under a constant flow rate until water production ceased, establishing irreducible water saturation (S_{wi}). Measured S_{wi} values ranged between 15 and 18%, consistent with permeability variability among Salina specimens.

Following S_{wi} establishment, samples were aged in crude oil to reproduce reservoir-representative mixed-wet conditions. Aging was performed under static conditions at 120 °F for 21 days, allowing adsorption of polar organic fractions (e.g., asphaltenes and resins) onto clay and mineral surfaces. Both duration and thermal conditions align with published recommendations for restoring wettability memory in sandstone systems [17,23,52].

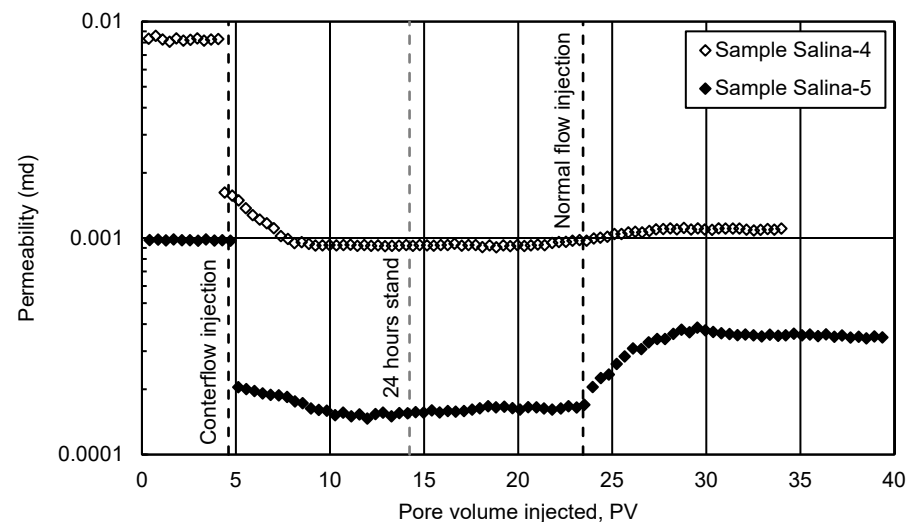
After aging, secondary waterflooding was performed at constant flow rate using formation brine until oil production stabilized, following ASTM D4520-18 [51]. The resulting residual oil saturation (S_{or}) ranged between 13 and 16%, aligning with expected values for intermediate-wet sandstone undergoing secondary waterflooding [15,53–55]. The experimentally determined S_{wi} and S_{or} values were subsequently used as initial conditions for the pore-network simulations to ensure consistency between laboratory measurements and numerical modeling assumptions.

Only the intermediate permeability samples (24.4–89.3 md) were used for network calibration, as these intervals represent the dominant flow-contributing facies under current development conditions. The pore-network was parameterized using statistical pore size distributions rather than a single deterministic geometry to partially capture heterogeneity, consistent with published upscaling practices for sandstone reservoirs.

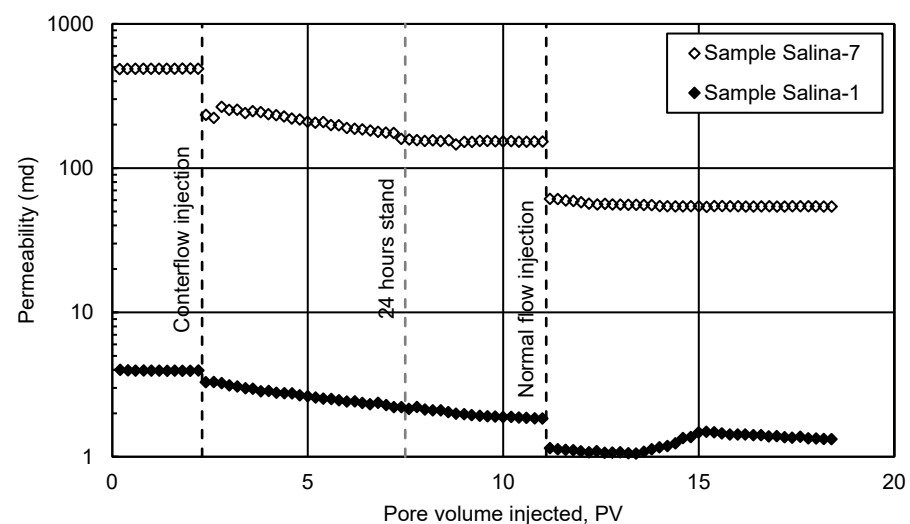
3. Test Results of Waterflooding Compatibility

3.1. Compatibility of Fluids

Performing core floods for determination of injectivity effectiveness is a frequent practice to detect interactions between formation and injection fluids and the formation rock. Typically, permeability losses are measured with a constant-pressure delivery system to measure the impact of chemical interaction with the rock and effects of solids plugging in the porous media [51]. To evaluate the compatibility, core flood tests were performed injecting both waters using a 0.2 µm filter in normal and reversal flow to simulate backflowing. Figure 2 depicts the measured permeabilities and its variation from the initial permeability 0.2 µm filtered formation water. The first stage following Figure 2 consists of the injection of formation water until steady-state flow is reached. Then, reverse flow with formation and injection water is performed with a 24 h stand between the change in the fluids. Finally, the injection mode is changed to normal flow using injection water until no permeability variation is noted.



(a)



(b)

Figure 2. Compatibility of injection water in 4 samples of Salina Formation: (a) 2400 and 2580 ft; (b) 2290 and 2840 ft.

As depicted in Figure 2, samples Salina-4, Salina-5, and Salina-1 recovered permeability after flooding the core with injection water. Total permeability losses are 87%, 64%, 66%, and 89% for samples Salina-4, Salina-5, Salina-7, and Salina-1, respectively. The waterflooding experiment performed over sample Salina-5 shows a recovery from 84% to 64% of original permeability probably caused by a general compatibility between injection water and formation rock. To test the hypothesis, the same test was performed to evaluate fines migration and interactions between the salinity of the fluid and the formation rock. Following the same procedure described for the compatibility of injection water, waterflood compatibility was evaluated using formation water at net over burden pressure (NOBP) and formation temperature. Figure 3 shows the results and permeability decline during the second stage after initial permeability measurement for core samples from Salina-2 and Salina-8. Permeability of the samples is not reduced when injecting formation water in either two samples, showing a slight permeability recovery in the test performed on Salina-8. Fines migration due to formation and injection water appears because permeability did not recover as depicted previously in Figure 2 and later confirmed by the results observed in

Figure 3. In general, all tests indicate a continuous permeability reduction in the samples tested, with very few exceptions showing some recovery after the second stage of injection.

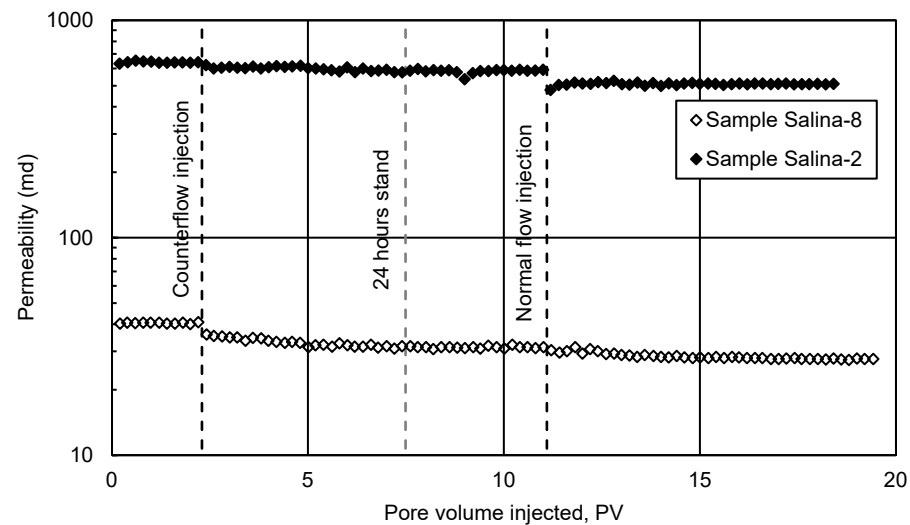


Figure 3. Compatibility of formation water for 2 samples at 2290 and 2840 ft.

3.2. Secondary Recovery by Waterflood Test

Curves of oil production are obtained at reservoir conditions after achieving the irreducible water saturation of the core sample and measuring oil effective permeability. Then, formation water is injected at a constant rate until oil exhibits zero production and water effective permeability is measured. The start of secondary production is achieved when injection water floods the sample and ends after water effective permeability is measured when oil is not being produced at constant rate. The secondary recovery performance of 2 samples was tested, and the results are depicted in Figure 4. Both tests show approximately a 4.5% increase in oil production attributed to secondary production, even though a negligible amount of oil proceeds from injection water.

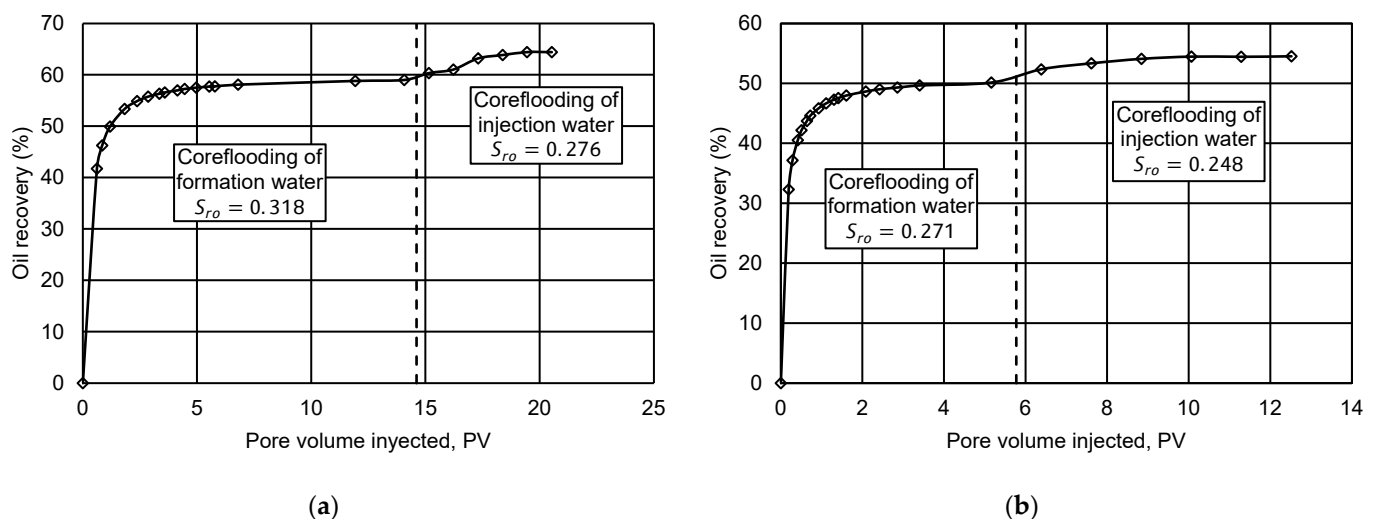


Figure 4. Oil recovery from formation and injection waters as a secondary mode of production: (a) sample Salina-3 at 2300 ft; (b) sample Salina-6 at 2840 ft.

Despite the observed increase in oil mobility during secondary recovery, the severe permeability impairment noted in some samples (up to 89% loss) represents a potential operational constraint for field-scale LSWF implementation. The results suggest that fines migration, compatibility reactions, or pore-throat constriction may play a significant role in

injectivity loss. These effects were not incorporated in the pore-network modeling workflow, which instead isolates wettability-driven mechanisms under idealized assumptions. Therefore, the numerical results should be interpreted as an upper-bound estimate of LSWF performance, and operational mitigation strategies—such as salinity ramping, filtration design, or pre-flush conditioning—should be considered in future field pilots.

4. Theory and Method

The pore network model is a reservoir model that considers the shape and interconnection of pores within a porous medium. Using this model, it is possible to estimate fluid flow and transport properties such as capillary pressure curves, effective permeability, and relative permeability. With this model, it is possible to represent the porous medium the following elements: pore network, geometry of pores and throats, pore-scale physics, and methods to solve physical and constitutive equations. To model the dispersion of salinity in the pore network caused by LSWF, advective–diffusive transport of species is considered with the discretization of the one-dimensional solution of the advection–diffusion equation over individual elements in the network. The flow rate in each element was calculated by solving the transport problem for flow in the network and was used to calculate the correction term (advection) for the diffusive flux. Then, the advection–diffusion problem was solved by upholding species conservation through the network.

4.1. Single-Phase Transport

For the case of a steady flow of an incompressible Newtonian fluid under isothermal conditions flowing through an element of the network, the flow rate is calculated using the Hagen–Poiseuille equation for a cylindrical throat as

$$q_{ij} = G_{ij}^h (p_i - p_j); \quad (1)$$

where p_i is the pressure (Pa) of the element i , and G_{ij}^h is the hydraulic conductance ($\text{m}^4 \cdot \text{s} / \text{kg}$) of the pore–throat–pore (ij) configuration. The hydraulic conductance is calculated as:

$$G_{ij}^h = \left(\frac{1}{g_i^h} + \frac{1}{g_{ij}^h} + \frac{1}{g_j^h} \right)^{-1}. \quad (2)$$

The hydraulic conductance is calculated from the solution of the general equation of viscous flow through in arbitrary shape, which for the geometry of the pore network are half spheres and cylinders [56]. The throat hydraulic conductance is calculated as

$$g_{ij}^h = \frac{\pi d_{ij}^4}{128 \mu L_{ij}}, \quad (3)$$

and the half pore hydraulic conductance is

$$g_i^h = \frac{\pi d_i^3}{32 \mu} \left[\frac{2d_i L_i}{d_i^2 - 4L_i^2} + \operatorname{arctanh} \left(\frac{2L_i}{d_i} \right) \right]^{-1}. \quad (4)$$

In Equations (3) and (4), μ is the fluid dynamic viscosity ($\text{kg} \cdot \text{m}^{-1} \cdot \text{s}^{-1}$), d_i is the width (m) of the element i , and L_i is its length (m). Subsequently, using separate equations solved before the dispersion problem, each pore's pressure p_i in Equation (1) is resolved by upholding mass conservation throughout the network [57]:

$$\sum_j G_{ij}^h (p_i - p_j) = 0. \quad (5)$$

The boundary conditions used to solve the system of equations for single-phase transport to calculate the pressure field, constant values are imposed in the boundary pores of the network (inlets and outlets) to generate constant differential pressure emulating conventional core analysis tests. Fluid exiting only at the outlet pores of the network is imposed implicitly when solving the linear equations in the PNM simulation, implying a no-flux boundary condition in the rest of faces of the network.

4.2. Transient Transport Model in the Pore Network

The salinity transport model is advective–diffusive for each pore and pore-throat of the flow-coupled pore network. The complete model comprises the following discretized equations between each pore and pore-throat. When only the movement forwards and backwards of the throat is considered, disregarding changes along the vertical throat direction, this transmission conforms with the equation for one-dimensional advection–diffusion transfer:

$$\frac{\partial c_{ij}}{\partial t} + q_{ij} \frac{\partial c_{ij}}{\partial x} - D_{ij} \frac{\partial^2 c_{ij}}{\partial x^2} = 0; \quad (6)$$

where c is the salinity concentration (ppm), q is the velocity (m/s), and D is the diffusion coefficient (m^2/s).

Applying the mass balance equation for each pore in the network, the dispersion problem over the network can be described by the steady-state mass balance equation for every individual pore i :

$$\sum_j m_{ij} = \sum_j q_{ij} \left[1 + \frac{1}{\exp(\text{Pe}_{ij}) - 1} \right] (c_i - c_j) = 0; \quad (7)$$

where Pe is the local Péclet number for each pore–throat–pore assembly, and is defined as follows:

$$\text{Pe}_{ij} = \frac{q_{ij}}{G_{ij}^d}. \quad (8)$$

This scheme of discretization represents the exact solution of the one-dimensional advection–diffusion problem. However, when the Péclet number approaches zero, the corresponding terms become numerically indeterminate. To avoid this numerical issue, a small threshold value was introduced, and all local Péclet numbers with $|\text{Pe}| < 10^{-10}$ were clipped to this value [58].

Based on the characteristic throat size, brine velocity, and diffusion coefficient, the resulting local Peclet numbers span from near zero to values well above 50. This distribution places the system in an advection-dominated regime overall, most Peclet numbers are far greater than unity, while diffusion remains locally relevant in smoothing salinity gradients within the smallest or slowest throats and in isolated dead-end pores.

Diffusion coefficients were assigned based on NaCl brine properties at reservoir conditions (120 °F, 1950 psi), with $D = 2.15 \times 10^{-9} \text{ m}^2/\text{s}$. Dispersion was incorporated through a conductance analogy. The diffusive conductance G_{ij}^d (m^3/s) in Equation (8) can be determined using the formula for an element of a circuit in series, like a resistor by analogy of an electrical circuit [59]:

$$G_{ij}^d = \left(\frac{1}{g_i^d} + \frac{1}{g_{ij}^d} + \frac{1}{g_j^d} \right)^{-1}, \quad (9)$$

where the half pore diffusive conductance g_i^d is determined by

$$g_i^d = \frac{\pi d_i D}{2 \operatorname{arctanh}\left(\frac{2L_i}{d_i}\right)}; \quad (10)$$

and the throat diffusive conductance g_{ij}^d is determined by

$$g_{ij}^d = \frac{\pi d_{ij}^2 D}{4L_{ij}}. \quad (11)$$

To solve the series of equations in each element of the network, two types of boundary conditions are imposed to simulate laboratory conditions of core flooding experiments. The fluid with a fixed concentration of a species is injected in the pore medium at the inlet face, meaning a fixed concentration boundary condition for inlet pores. Furthermore, as the native fluid of the porous medium is being displaced, it exits the rock only at the outlet face, meaning an outflow boundary condition at outlet pores. Total mass entering the pore from neighboring pores by means of advection and diffusion is removed only by advection. The expression representing the outflow boundary condition is given as follows [58]:

$$\sum_j \frac{c_i - c_j}{\exp(\operatorname{Pe}_{ij}) - 1} = 0. \quad (12)$$

4.3. Wettability Alteration

Research indicates that salinity of injection fluids consists primarily of NaCl, KCl, CaCl_2 , MgCl_2 , and Na_2SO_4 . The concentration of the components influences wettability alteration, having a positive impact on production when the trend is negative, whereas detrimental if the trend is positive. To estimate the behavior of the oil–water system in Salina Formation, an interpolation of measurements of interfacial tension and contact angle is employed for simulation [52]. Figure 5 shows the results of the experiments performed, employing a liquid composed only by NaCl.

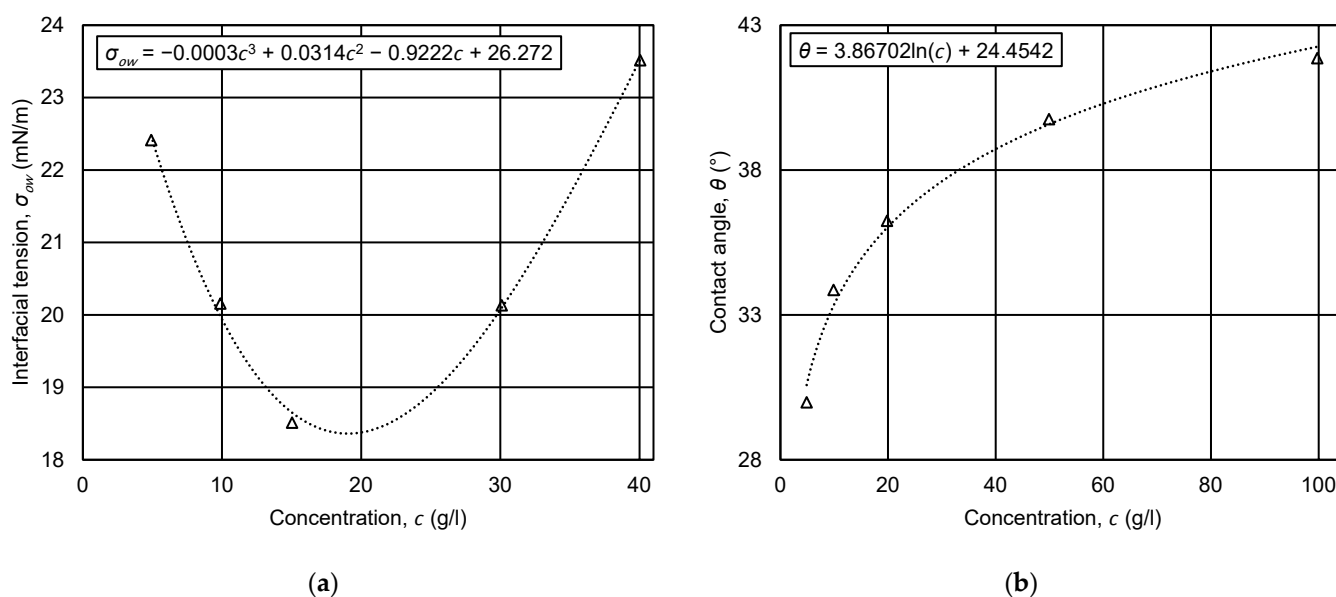


Figure 5. Effect of salinity on interfacial tension properties of the oil–water system. Coefficients of correlation are (a) $R^2 = 0.997$, and (b) $R^2 = 0.990$.

To model wettability alteration during LSWF, a variable contact angle was suggested to evaluate the impact of salinity on wettability by calculating the contact angle of each throat at every time step. Therefore, a salinity-dependent scaling factor $\omega(c)$ was proposed with three different models [60]. All of them follow the next expression:

$$\theta(c) = \omega\theta^{\text{HS}} + (1 - \omega)\theta^{\text{LS}}; \quad (13)$$

where c is the salinity concentration, θ^{HS} and θ^{LS} are the contact angles at the high- and low-salinity stages, respectively. Full Range Interpolation (FRI), Effective Salinity Range (ESR), and Salinity Threshold (ST) are models used to mimic various phenomena, such as abrupt wettability change and time retardation. The models are shown in Equations (14)–(16), respectively.

$$\omega = \frac{c - c^{\text{LS}}}{c^{\text{HS}} - c^{\text{LS}}}; \quad (14)$$

$$\omega = \begin{cases} 1, & c > c^{\text{UT}} \\ \frac{c - c^{\text{LT}}}{c^{\text{UT}} - c^{\text{LT}}}, & c^{\text{LT}} \leq c \leq c^{\text{UT}} \\ 0, & c \leq c^{\text{LT}} \end{cases}; \quad (15)$$

$$\omega = \begin{cases} 1, & c > c^{\text{T}} \\ 0, & c \leq c^{\text{T}} \end{cases}. \quad (16)$$

Interfacial tension (IFT) was correlated to salinity using a third-order polynomial fit derived from experimental data:

$$\sigma_{\text{ow}} = a_0c^3 + a_1c^2 + a_2c + a_3, \quad (17)$$

where σ_{ow} is the oil–water interfacial tension (N/m) and a_0 , a_1 , a_2 , and a_3 are regression coefficients (N/m) obtained from laboratory measurements (Figure 5).

These correlations were applied dynamically during the simulation: at each time step, local salinity in the pore network updated θ and IFT values, influencing capillary pressure and relative permeability calculations.

4.4. Capillary Pressure and Ordinary Percolation

The drainage process consists of increasing capillary pressure, allowing the invasion of one fluid over the network. To simulate the drainage process in a pore network, the capillary pressure at the throat entrances must be calculated using the Washburn equation to make an ordinary percolation and determine the invasion sequence. Capillary pressure values at each throat of the pore network are estimated using the Washburn equation in cylindrical tubes:

$$P_c = -\frac{2\sigma_{\text{ow}}\cos(\theta)}{r}, \quad (18)$$

where P_c is the capillary pressure (Pa), σ is the IFT of the system, θ is the contact angle, and r is the radius (m) of the throat. Once capillary pressures are computed, increments in the capillary pressure of the invading phase are simulated and the invasion sequence is generated when the capillary pressure exceeds the inlet pressure of each throat. By taking each state in the invasion sequence and the pressure at which the invasion occurs, the calculation of saturations can be performed by taking the volume of invaded pores and throats. In this way, the capillary pressure curve for the drainage process in the pore network is obtained.

4.5. Relative Permeabilities and Fractional Flow

Relative permeability is the ratio of absolute and effective permeability, given the same boundary conditions, viscosity, and geometry. Therefore, the calculation of relative permeabilities is calculated as

$$k_r = \frac{Q_e}{Q_{abs}}. \quad (19)$$

In Equation (18), all flow rates are obtained from the inlet face of the network, and Q_e is the flow rate of the phase in the multiphase system (m^3/s), under pseudo-stable conditions, while Q_{abs} is the flow rate of the phase under a single-phase flow (m^3/s) under the same established boundary conditions.

Fractional flow curves are used in the analysis of many EOR techniques to predict trends and properties in a reservoir scale by means of the Buckley–Leverett theory [61]. As fractional flow relative to a phase is the ratio of the phase rate and total rate, the calculation of the fractional flow values is calculated as

$$f_e = \frac{Q_e}{Q_{total}}. \quad (20)$$

In Equation (19), the flow rates are calculated at the outlet face of the network, and Q_{total} is the sum of the flow rates of the phases in the multiphase system (m^3/s). Finally, in OpenPNM [11], the calculation of flow rates is simplified by simulating the flow equations at certain established boundary conditions. However, the model is sensitive only to the invasion states of the network, and the resulting curve profile will not be as smooth as that of a conventional model.

4.6. Pore-Network Extraction and Calibration

The pore network used in this study was generated from a synthetic lattice based on spheres and cylinders, following the generic sandstone template “S2” [62]. This approach was selected due to the absence of high-resolution micro-CT images for Talara Basin cores and the need for computational efficiency in simulating multiple salinity scenarios.

Calibration was performed to ensure that the synthetic network reproduces the petrophysical properties of representative core samples from the Salina Formation. First, porosity matching was performed by adjusting the network porosity by scaling pore and throat diameters until the calculated porosity matched the experimental value. Then, absolute permeability was matched by tuning hydraulic conductance of throats using Hagen–Poiseuille-based calculations to reproduce the measured permeability under single-phase flow conditions. Finally, pore-throat size distribution was matched using mercury intrusion porosimetry (MIP) data to define a log-normal distribution of throat and pore sizes.

Validation was achieved by comparing simulated capillary pressure profiles and relative permeability curves against experimental measures.

5. Results

To simulate transport phenomena and general interactions in Salina Formation, the generic sandstone sample S2 [62] was selected to match pore size distribution, porosity, permeability, and capillary profile of the sample Salina-1. The generic pore network consists of 1945 pores and 4697 throats, and its geometry is based on spheres and cylinders. Its spatial distribution consists of uniformly distributed zones without discontinuities or zones with a dense distribution of pores.

5.1. Pore Network Calibration

In the process of core sampling and analysis, conventional and special petrophysics studies were performed over core samples obtained from Salina Formation. Results of the experiments over a plug extracted from sample Salina-1 are presented in Table 3.

Table 3. Characteristics of the sample selected to recreate the pore network and perform LSWF simulations.

Variable	Symbol	Value	Unit
Depth	h	2500	ft
Permeability	k	3238	md
Porosity	ϕ	35.10	%
Length	l	2.755	cm
Diameter	d	3.624	cm
Volume	V	9.972	cm ³

5.1.1. Mercury Intrusion Porosimetry (MIP) Tests

Pore size distribution curve was obtained from MIP experiments using the curve method $\Delta P/\Delta S$ [63]. To obtain the specific distribution, a log-normal distribution is employed for curve matching, and its expression is

$$f(x) = \frac{1}{\sigma\sqrt{2\pi}} \exp\left(-\frac{(\ln x - \ln m)^2}{2\sigma^2}\right). \quad (21)$$

In Equation (20), x is the pore diameter in m, $\sigma = 0.679$ is the shape parameter, and $m = 4.753 \times 10^{-5}$ is the scale parameter. The center of the curve is $19.71 \mu\text{m}$, and the distribution will generate pore sizes between 5 and $200 \mu\text{m}$. Figure 6 shows the results of the experiment and the adjusted distribution obtained by matching its parameters over MIP experiments performed on core samples of Salina-1.

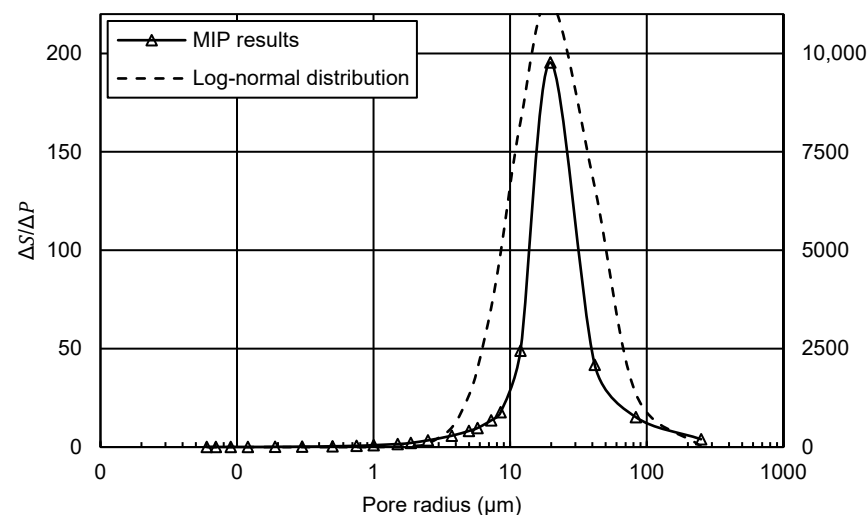


Figure 6. Actual distribution and adjustment of pore size in the core sample.

Capillary pressure profiles of the representative sample obtained by mercury intrusion porosimetry were repeatedly contrasted to correct the profile of the size of throats. The process was carried out by simulating multiphase invasion by drainage of the air–mercury system to obtain the capillary pressure profile. The simulation was carried out under laboratory conditions, and the phenomenon represented an invasion of the non-wetting phase by means of ordinary percolation. Figure 7 displays capillary pressure curves obtained after adjustment and calibration of throat size distribution.

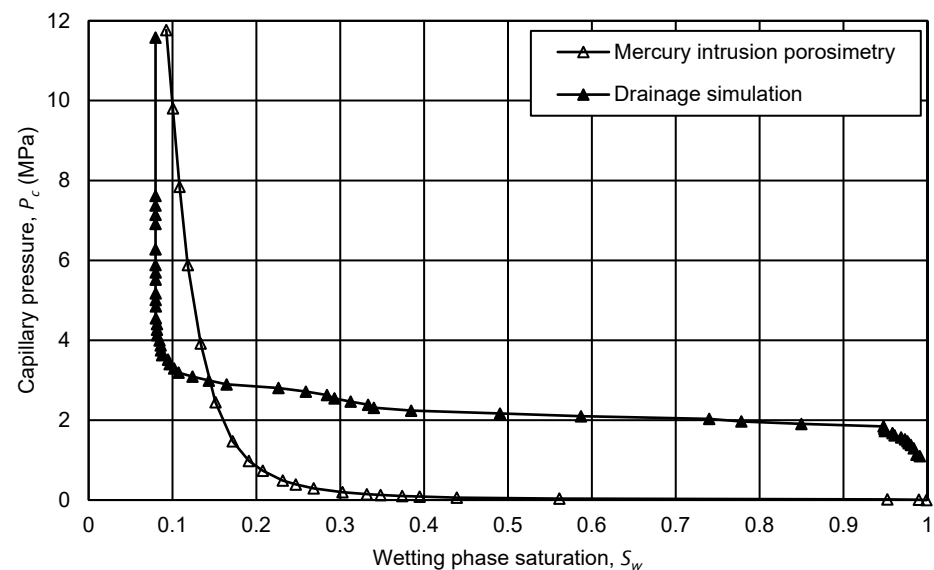


Figure 7. Capillary pressure curves of mercury intrusion in the core sample.

The capillary pressure curve obtained from the drainage simulation ends at wetting phase saturation slightly below 1 due to an initial invasion of inlet pores. As the invading fluid displaces air outside of the network, some pores become trapped as imposed to only exit at the outlet pores. The effect of trapping makes the saturation not reach 1, as some pores and throats become inaccessible to the invading fluid. Furthermore, as illustrated by the capillary pressure profiles obtained from the MIP experiment and simulation, the spatial distribution and connections between pores and throats do not match perfectly, causing the initial peak in capillary pressure of the network. However, for simulation purposes, the distribution of the capillary pressure will not affect the overall behavior of the secondary recovery when dealing with the determination of relative permeabilities.

5.1.2. Salina Network

The pore network adjusted from the generic Sandstone S2 sample is now named Salina. Figure 8 shows the spatial and geometric distribution of the pores and gorges of the Salina network. The network has a length of 2.789 cm and a cross-sectional area of 0.025 cm² after spatial scaling. It should be noted that the consistency of the results obtained after the geometric and spatial scaling of the throats and pores has been corroborated by the fact that no overlapping pores or length and volume of throats with negative values were found.

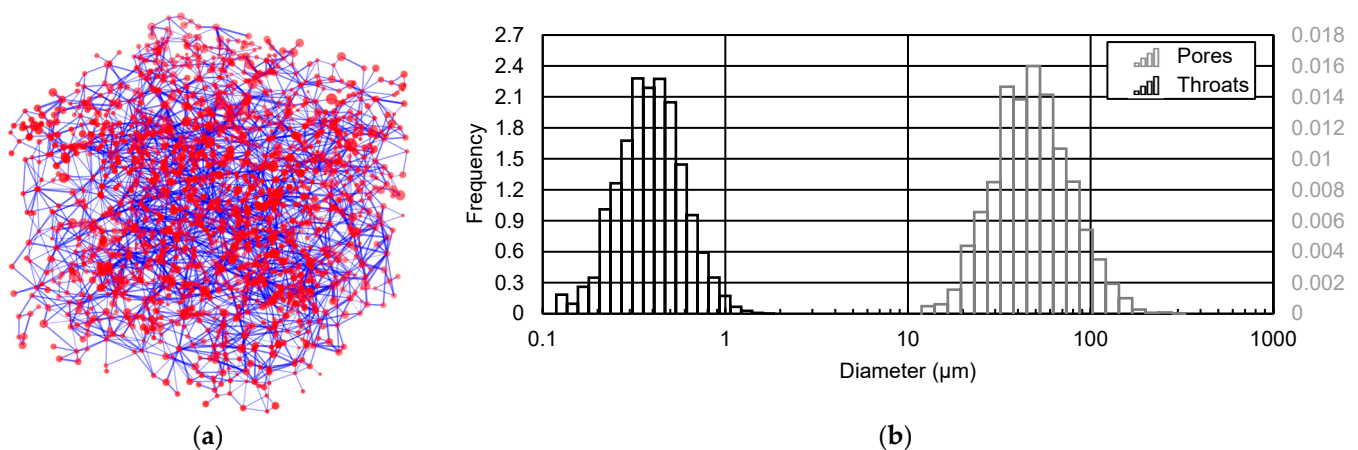


Figure 8. Geometric distribution of the Salina pore network: (a) spatial distribution, (b) distribution of pore and throat diameter.

Subsequently, simulations of conventional core analysis were carried out to find the main physical properties of the Salina pore network. Table 4 shows the porosity, permeability, formation factor and tortuosity obtained. Porosity was obtained by defining the geometry of the lattice as cylinders and spheres. Permeability and tortuosity (flow) were calculated by simulating the single-phase transport of hydraulic properties. The formation factor and tortuosity (diffusion) were obtained by simulating electrical conductivity through diffusion.

Table 4. Physical properties of the pore network extracted from the representative sample of the Salina Formation.

Variable	Symbol	Unit	Value
Porosity	ϕ	%	35.11
Permeability	k	md	4040.11
Formation factor	F	—	18.95
Tortuosity (Fluid flow)	τ	—	8796.37
Tortuosity (Diffusion)	τ	—	6.65

5.2. Properties of Formation and Injection Fluids

To simulate fluid recovery in the injection process, two wetting fluids are considered. The first is formation water or, within the LSWF process, high-salinity (HS) water. The second is the dilute formation water of low-salinity (LS) water. The sensitivity of oil recovery with the change in salinity of the injected water in the low-salinity stage is investigated. In addition, to represent the low-salinity water conditions, the formation properties of Salina at 120 °F and 1950 psi are considered reservoir conditions. The physical properties of the fluids were extracted from the brine tables of [64] to the conditions of the reservoir. Table 5 shows the summary of the properties for the definition of the phases used in the simulation. In terms of crude quality, it has an API grade of 34.9, making it a light oil.

Table 5. Properties of the fluids used in the simulation of pore networks. Viscosity and density values were interpolated from [64]. The values of ITF and contact angle were interpolated from [52].

Concentration (ppm)	Viscosity (mPa·s)	Density (kg/m)	IFT (N/m)	Contact Angle (°)
20,000	0.5806	994.66	0.0184	36.04
18,000	0.5785	994.64	0.0184	35.63
13,500	0.5740	994.62	0.0189	34.52
9000	0.5694	994.59	0.0203	32.95
4500	0.5649	994.56	0.0227	30.27
1800	0.5621	994.54	0.0247	26.73
180	0.5605	994.53	0.0261	17.82

5.3. Salinity Transport in Salina Network

In LSWF simulation in the network, the formation fluid represents the HS fluid, while injection fluid is taken as the LS fluid. The problem of flow and transport is resolved separately. Therefore, the flow in the network is first simulated solving the pressure field in the network. In addition, the entry of fluids into the network is sequential, starting with the HS and LS process in the network. In the numerical simulation of salinity dispersion in the pore network, a total time of 4000 seconds and steps every 10 second is considered. Total computational time in the simulation was calculated based on the boundary conditions, overall fluid velocity in the inlet face of the network, and the total pore volume. The total volume of fluid injected 4000 s is equivalent to 1 pore volume (PV) of Salina network for HS and LS injections. From this simulation, the salinity concentration states of the pore network are obtained, which will allow the change in the contact angle to be determined later.

Initially the rock is saturated by oil, and as the first stage of drainage, water is injected with high salinity (20,000 ppm) as qualitatively observed in Figure 9. The frontal advance

of the water flood in the rock for different computational times: 0 s, 40 s, 400 s, and 4000 s. As the simulation is being performed, LS water will displace mobile oil without changing the irreducible saturation of the oil. Indicating a piston-like displacement in the rock, leaving remaining oil due to its irreducible saturation. From 0 s, salinity concentration of the pores will vary, visually from blue to yellow, indicating at 4000 s, all the movable crude oil has been displaced. After the HS stage, when LS water is injected into the pore network, formation fluids mix with the injection water, which have a lower salinity (18,000 ppm) due to the filtration process applied before the injection. This mixing creates a salinity gradient in the pore network, with a zone of lower salinity water moving forward and a zone of higher salinity water leaving the network. This process is qualitatively depicted in Figure 9 for computational times of 0 s, 40 s, 400 s, and 4000 s. The concentration of the pores represented visually with colors varying from yellow (at 0 s) to blue (at 1000 s), indicating an additional displacement of oil due to a change in the irreducible saturation of the oil. The magnitude of this variation will be determined by the relative permeability curves.

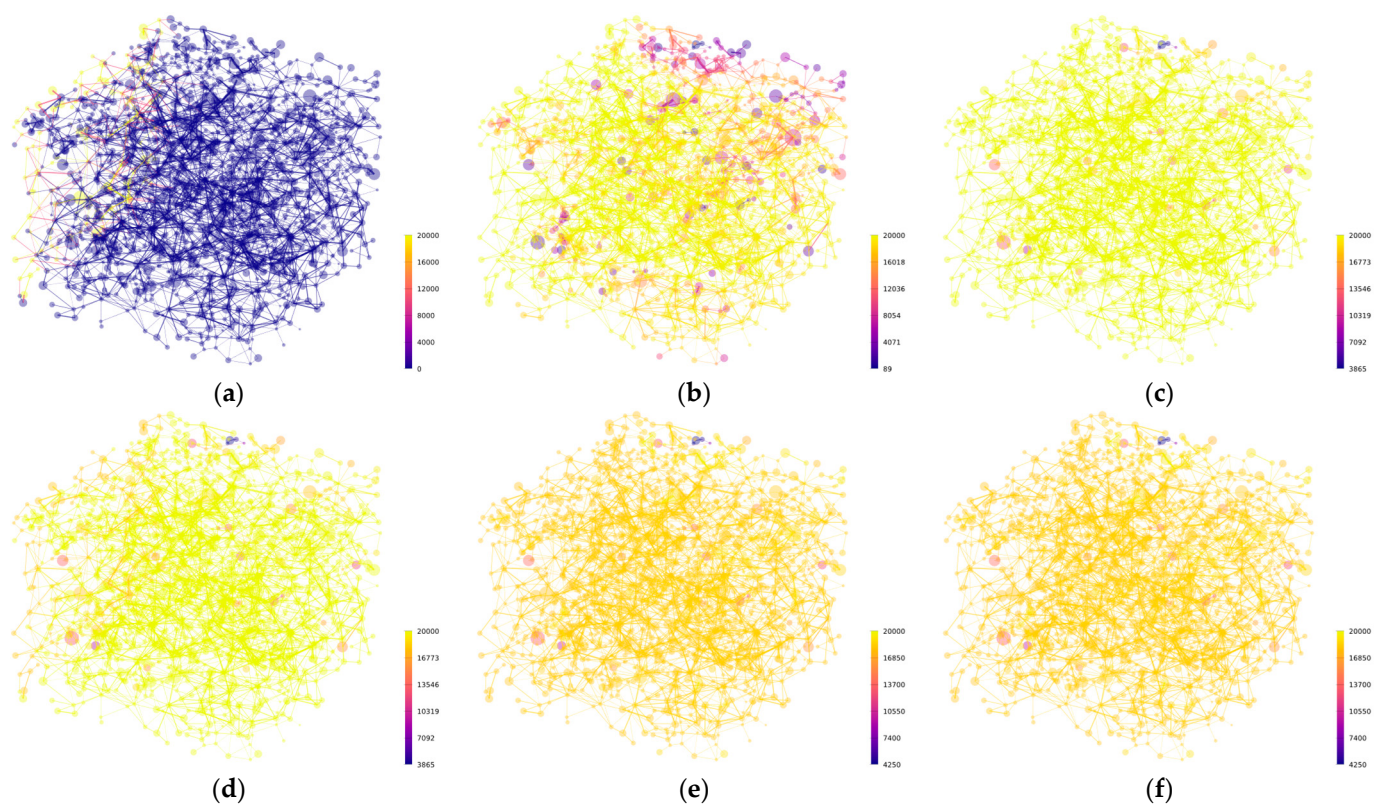


Figure 9. Salinity concentration in Salina network during HS and LS stages. HS stage at (a) 0 s, (b) 400 s, and (c) 4000 s. LS stage at (d) 0 s, (e) 400 s, and (f) 4000 s.

5.4. Wettability Alteration in the Network

Figure 10 illustrates the variation in the contact angle in the HS (20,000 ppm) and LS (18,000 ppm) stages at the end of the simulations after the salinity is dispersed in the network. After the HS stage, most pores and throats of Salina network have a contact angle of 36.0° , indicating a wettability preference for the water, or a water wet rock. As time elapses up to 4000 s, during the HS stage, the contact angle decreases only in parts with low conductivity. At the end of the simulation in the LS stage, the contact angle is further reduced, reaching a minimum of 35.6° , suggesting a change in the wettability of the rock, showing a greater wettability preference for water. Although a minimum change in the contact angle is observed in Figure 10, quantitatively, it will be reflected in the shift in the capillary pressure curve, relative permeabilities, and the final recovery factor.

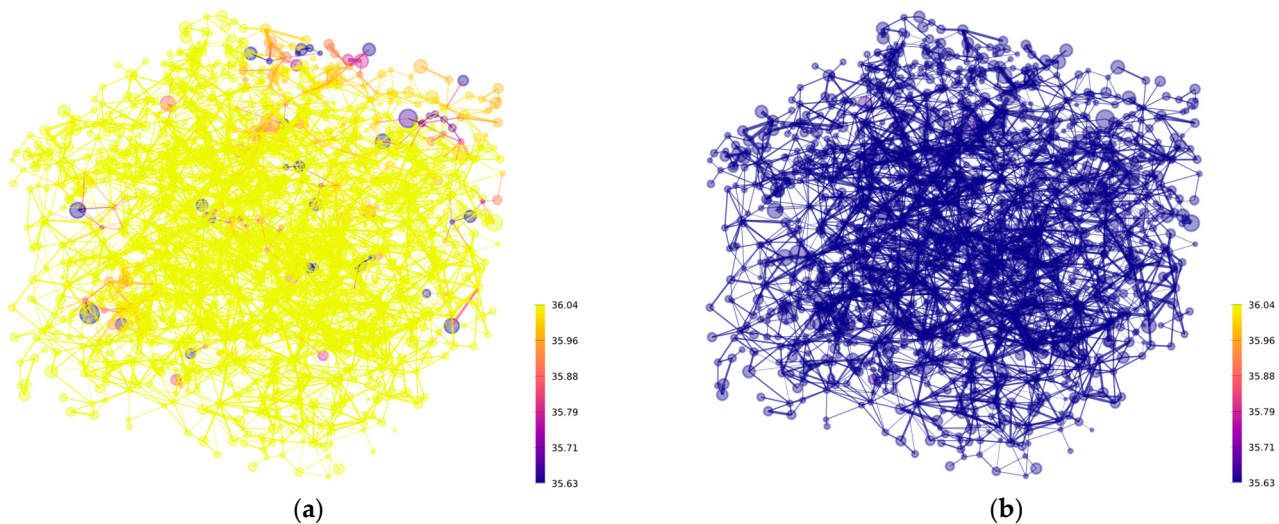


Figure 10. Contact angle for the end of injection stages: (a) HS and (b) LS.

5.5. Capillary Pressure in the Drainage Simulation

Since the concentration of salt has decreased to 90% of the initial concentration (from 20,000 ppm to 18,000 ppm), a shift to the right of the capillary pressure curve of the fluids present in Salina network is observed in Figure 11. The capillary pressure curve in the HS stage has been shifted to the right, showing an irreducible water saturation of 15.78% at approximately 11.12 kPa, and reaching a water saturation of 99.4% with 0.40 kPa of capillary pressure. Furthermore, in the LS stage, the capillary pressure at the irreducible water saturation (15.30%) was approximately 11.24 KPa, and when reaching a water saturation of 99.4%, the capillary pressure was 0.40 kPa. These results indicate the occurrence of a significant variation in the wettability of the rock, and its impact on the incremental recovery of oil will be reflected in the relative permeability curves.

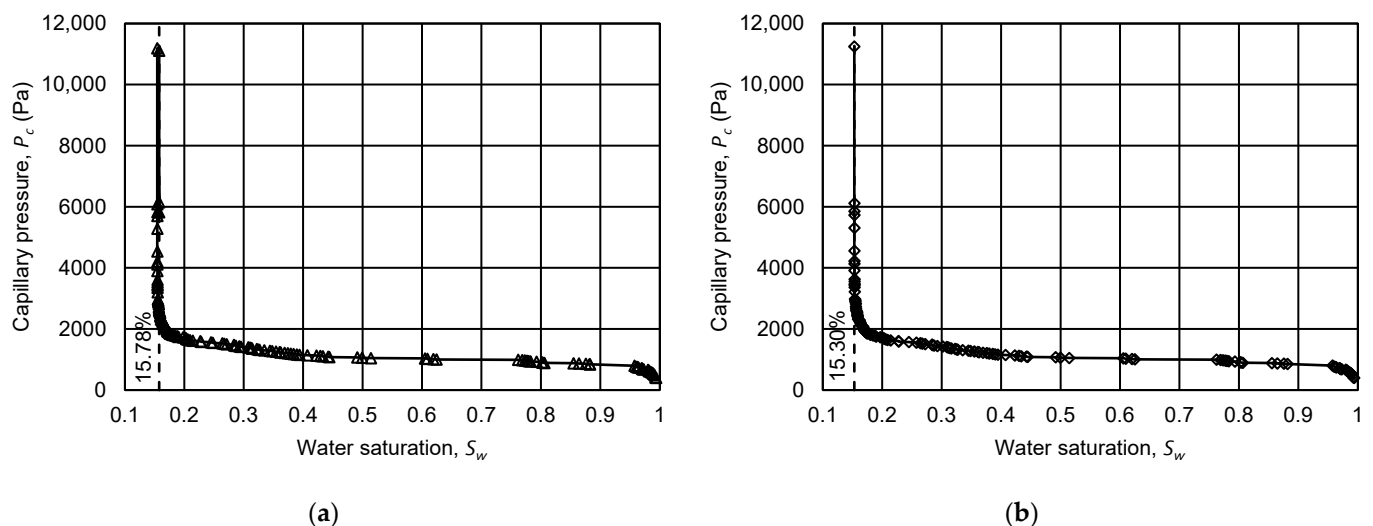


Figure 11. Contact angle for the end of injection stages: (a) HS and (b) LS.

5.6. Relative Permeabilities of the Oil–Water System

Relative permeabilities were obtained performing a drainage simulation at the end of the injection of the fluids (HS and LS stages). After obtaining the relative permeability curves, the results were fitted to the Brooks and Corey model, obtaining the end points and exponents at each stage. Figure 12 presents the calculated relative permeabilities at each stage of invasion of the drainage simulation. In the HS stage, the maximum relative

permeability of oil is 0.8309 at an irreducible water saturation of 15.46%, and a final oil irreducible saturation of 15.95%. In the LS stage, the curves shift to a different intersection, and the end point becomes 0.8325 as the maximum oil relative permeability at an irreducible water saturation of 15.30% and a final oil irreducible saturation of 13.97%. The shift in the relative permeability endpoints implies an improvement in the efficiency of oil recovery due to the LSWF process. Likewise, the relative permeability of water at the endpoint is considerably higher than that of oil, indicating a significant improvement in water mobility in the reservoir. The increased mobility of water facilitates its movement through the porous medium and its ability to move oil into production wells, contributing to more effective oil recovery.

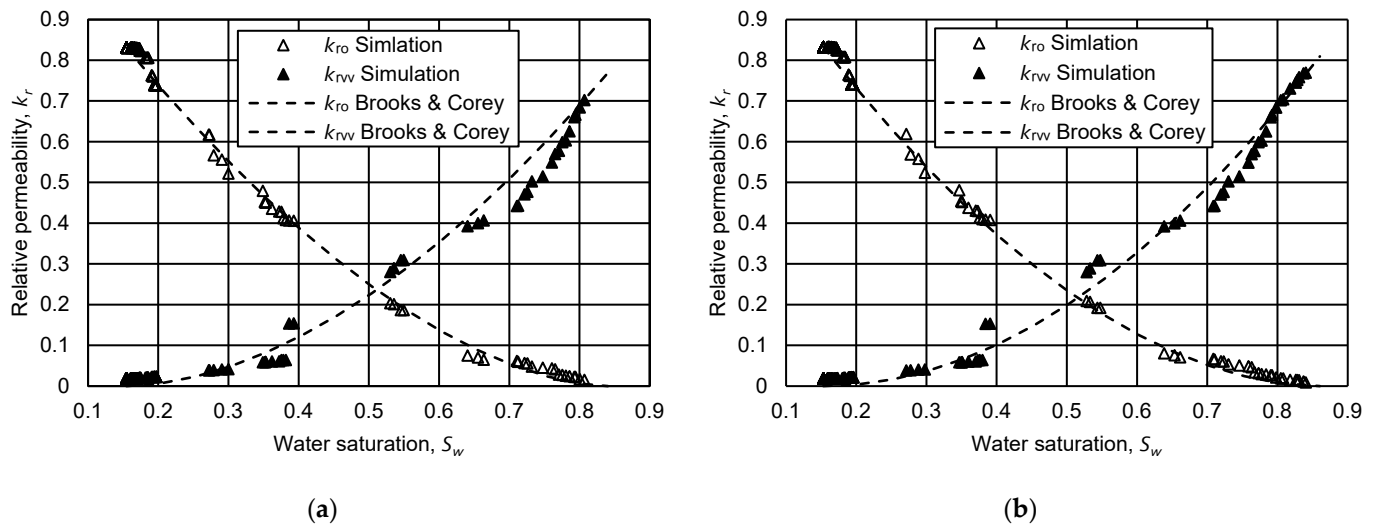


Figure 12. Relative permeability curves obtained after simulation of HS and LS injection in Salina network. The stages represent the secondary recovery process with salinity concentrations of (a) 20,000 ppm and (b) 18,000 ppm.

6. Fluid Properties Optimization and Case Scenarios

To simulate the performance of a secondary LSWF project in Block XIII, several scenarios with fluids with different concentration of salinity are considered for the simulation. As shown in Table 5, six different salinity values were considered to calculate the maximum increment in the recovery of oil through the network. In all cases, an equivalent of 1 PV volume of injection fluid was considered, taking 4000 s as the computational time in the simulations.

6.1. Capillary Pressure Profiles

After sequentially simulating LSWF in different scenarios, each with an HS and LS injection stage, drainage of water after mobilization of oil in the network was simulated in all cases. The capillary pressure profiles obtained for water with salinity concentration of 180, 1800, 4500, 13,500, 18,000, and 20,000 ppm are shown in Figure 13. These profiles show wettability alteration by shifting the capillary pressure curve upwards and shifting to the left to a lesser extent as water salinity decreases. The first phenomenon is explained mainly because of the positive trend of ITF of the oil–water system when salinity decreases, which affects directly the capillary pressure in each element of the network, overcoming the effect of the decreasing trend of the contact angle. In addition, the increment of capillary pressure in pores and throats produces a better mobilization of oil and makes less pores trapped by oil, causing the shift to be left of the curve and reducing the residual saturation of oil. The quantitative effects on the incremental recovery of oil caused by the phenomena mentioned above will be evaluated later when calculating the critical points and residual saturations.

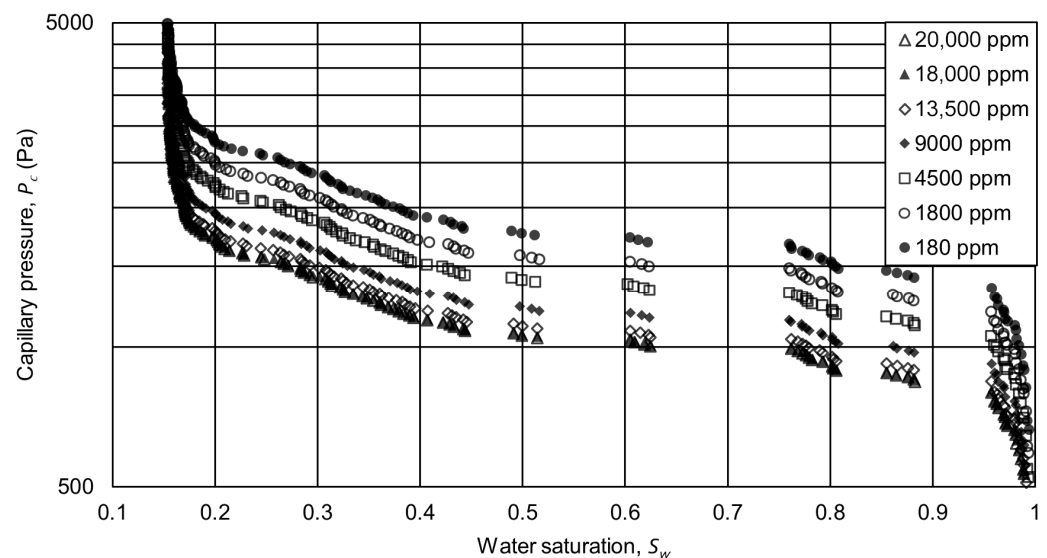


Figure 13. Capillary pressure profiles obtained during different LSWF simulation scenarios in Salina network.

6.2. Relative Permeabilities

In each scenario, relative permeabilities obtained during the LSWF simulation were adjusted to the Brooks and Corey model. The model allowed the determination of the endpoints of the oil–water system to evaluate the increase in the oil recovered. Table 6 shows the endpoints obtained after fitting the relative permeability model for the HS stage and LS stages.

Table 6. Adjusted endpoints of Brooks and Corey model for relative permeabilities in each scenario of the LSWF simulation.

Concentration, C (ppm)	Critical Water Saturation, S_{wc}	Maximum Oil Relative Permeability $k_{ro,max}$	Oil Exponent, n_o	Residual Oil Saturation, S_{or}	Maximum Water Relative Permeability, $k_{rw,max}$	Water Exponent, n_w
20,000	0.1546	0.8309	1.715	0.1595	0.7693	1.805
18,000	0.1530	0.8325	1.875	0.1397	0.8096	1.975
13,500	0.1536	0.8308	1.795	0.1310	0.8116	1.815
9000	0.1551	0.8292	1.815	0.1183	0.8435	1.885
4500	0.1539	0.8309	1.805	0.1102	0.8595	1.815
1800	0.1535	0.8325	1.785	0.1135	0.8562	1.755
180	0.1526	0.8326	1.805	0.1206	0.8410	1.845

Figure 14 depicts the relative permeability curves of each scenario compared to the initial profile obtained in the HS stage of the simulation. A slight shift in the relative permeability curves of oil is observed in all scenarios; however, the relative permeability curves of water remain very close to the initial condition. This phenomenon is attributed to the change in the contact angle between water and rock, which wets the latter in the context of this study. The shift in the permeability curves suggests a change in the wettability of the rock, indicating that the wetting phase tends to adhere to the rock because of the effect of LSWF. This phenomenon is supported by findings from previous research of [53–55]. In addition, an increase in residual water saturation and a decrease in residual oil saturation were recorded as the salinity of the water injected decreases.

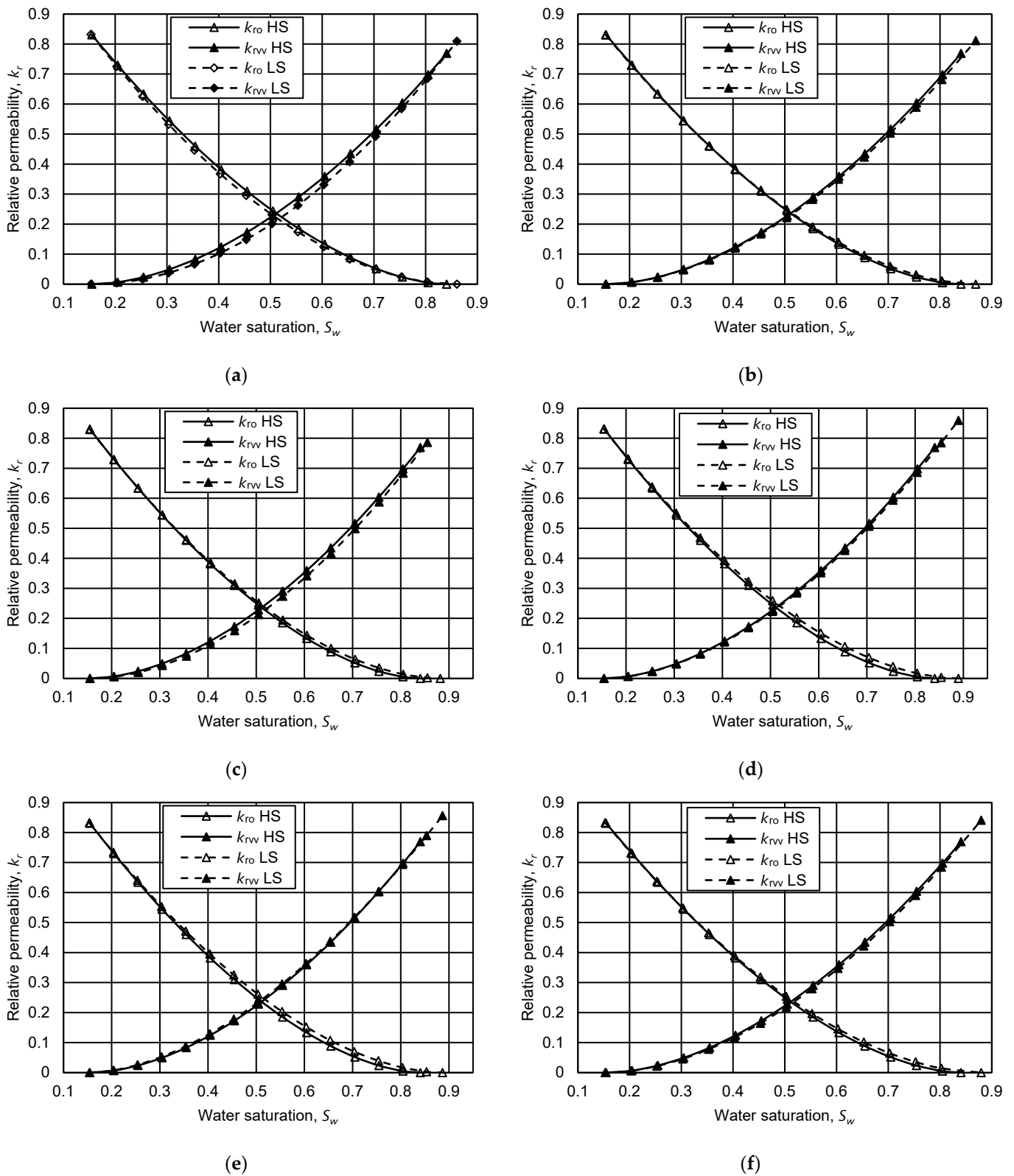


Figure 14. Relative permeability curves fitted to Brooks and Corey model for simulation scenarios: (a) 18,000 ppm, (b) 13,500 ppm, (c) 9000 ppm, (d) 4500 ppm, (e) 1800 ppm, and (f) 180 ppm.

6.3. Recovery Factor Increment

After fitting the endpoints for the relative permeability model in the network, the final recovery factor is calculated as a function of the residual saturation of the oil in the pore network, as follows:

$$RF = \frac{S_{oi} - S_{or}}{S_{oi}}; \quad (22)$$

where, the subscripts i stands for initial, and r stands for residual. In a realistic scenario, the referred saturations may be adjusted to the current stage of development of the reservoir. For research purposes, endpoints are taken as initial and final saturations of the process to simulate a secondary recovery stage after depletion. Figure 15 shows the increment of the recovery factor compared to LS stage (20,000 ppm) in all LS scenarios.

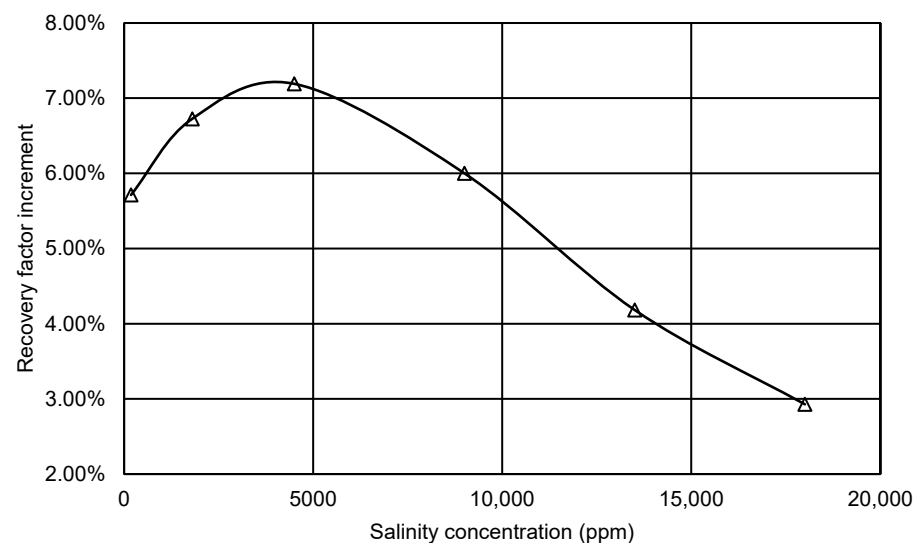


Figure 15. Increase in recovery factor in different scenarios for LSWF optimization.

An increasing trend is observed in the change in the recovery factor, with an optimum range of concentrations between 1800 ppm and 4500 ppm, reaching a maximum increment of 7.2%. This trend is attributed to the more significant effect of salt concentrations within the optimum range on the change in rock wettability (contact angle and interfacial tension), as identified in this study. However, below 4500 ppm, the increment in the recovery factor does not follow the trend and decreases; this phenomenon can be attributed to the increment in the interfacial tension and the values of the cosine of the contact angle, $\cos(\theta \geq 160^\circ) \approx 1$. These results are also reflected in the research carried out in [37], where an optimal range of salt concentration is established below 4000 ppm. As depicted by the increment in the recovery factor, as the concentration of salts is reduced the effect of low salinity does not manifest itself consistently in the increase in the oil recovery factor and is highly influenced by the wettability of the oil–water system and the geometry of the porous medium.

6.4. Fractional Flow Curves

The fractional flow curves for each scenario were calculated using Equation (19) and viscosity ratios varying between 0.25 and 0.26. The data presented in Figure 16 represents a more realistic behavior of the flooding process than a conventional calculation employing only relative permeabilities and viscosities of oil and water. Although viscosity of water decreases slightly with decreasing salinity, the fractional flow profile is maintained and the saturation at which breakthrough occurs is approximately 0.82, reaching a maximum of 0.9 when the salinity is 180 ppm. The saturation state at which breakthrough occurs decreases

as the salinity of the injected water decreases, although the change is negligible considering retardation effects due to salinity dispersion and low changes in density and viscosity of the water.

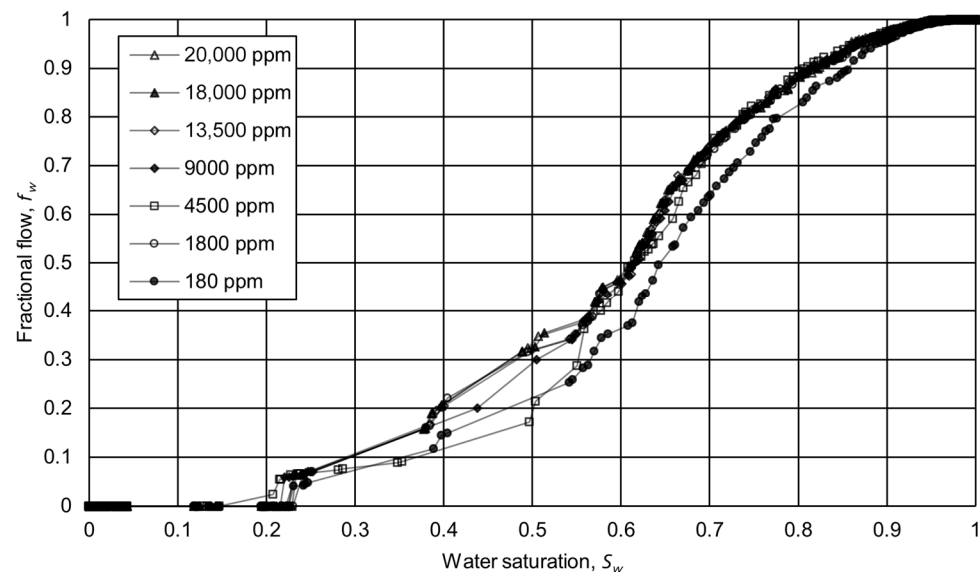


Figure 16. Fractional flow curves obtained during LSWF simulations for each scenario.

7. Conclusions

This study evaluated the feasibility of applying LSWF in a representative sandstone reservoir of the Talara Basin through pore-network modeling in OpenPNM and laboratory coreflood tests. The numerical results indicate that salinity reduction influences oil recovery mainly through wettability alteration, as reflected by changes in capillary pressure behavior and relative permeability relationships.

Quantitatively, coreflood experiments demonstrated an incremental oil recovery of approximately 4.5% under secondary waterflooding, while pore-network simulations predicted potential improvements of 7–10% under idealized low-salinity conditions. Permeability impairment ranged from minor (<10%) to severe (up to 89%), highlighting an important operational constraint for field implementation. These combined findings illustrate both the technical potential and practical risks associated with LSWF in reservoir settings comparable to Block XIII.

Simulation outcomes showed that residual oil saturation decreased from 16% to 9%, and the intersection point of the relative permeability curves shifted from 0.64 to 0.67, confirming a transition toward more water-wet behavior. The effect was strongest when the injection brine was diluted to approximately 10% salinity (~1800 ppm), resulting in a maximum modeled incremental gain of 7.2% in the oil recovery factor.

Although larger salinity contrasts ($\geq 80,000$ ppm) reported in the literature typically yield stronger responses, the results demonstrate that measurable recovery improvements may also occur under moderate salinity regimes such as those in the Talara Basin (20,000 ppm). Therefore, LSWF represents a technically promising EOR strategy for mature sandstone reservoirs in northwestern Peru, particularly if future pilot design incorporates brine-conditioning steps to mitigate fines migration, injectivity loss, and geochemical incompatibility.

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Conflicts of Interest: The authors declare no conflicts of interest.

Nomenclature

The following abbreviations are used in this manuscript:

μ	Viscosity (Pa·s)
$\omega(c)$	Salinity-dependent scaling factor
σ	Shape parameter (dimensionless)
σ_{ow}	Interfacial Tension (N/m)
θ	Contact angle (°)
θ^{HS}	Contact angle at high salinity stages (°)
θ^{LS}	Contact angle at low salinity stages (°)
$\theta(c)$	Variable Contact angle (°)
c	Salinity Concentration (ppm)
c^{LT}	Salinity Concentration at Lower Threshold (ppm)
c^{UT}	Salinity Concentration at Upper Threshold (ppm)
c^T	Salinity Concentration at Threshold (ppm)
D_{ij}	Diffusion coefficient (m ² /s)
d_{ij}	Width of element (m)
$f(x)$	Probability Distribution Function
f_e	Fractional flow of the phase (%)
G_{ij}^d	Diffusive Conductance (m ³ /s)
G_{ij}^h	Hydraulic Conductance (m ⁴ s/kg)
g_i^d	Half Pore Diffusive Conductance (m ³ /s)
g_i^h	Half Pore Hydraulic Conductance (m ⁴ s/kg)
g_{ij}^d	Throat Diffusive Conductance (m ³ /s)
g_{ij}^h	Throat Hydraulic Conductance (m ⁴ s/kg)
k_r	Relative Permeability (dimensionless)
L_{ij}	Length of element (m)
m	Scale parameter (dimensionless)
m_{ij}	Mass of element (kg)
P_c	Capillary pressure (Pa)
Pe_{ij}	Local Péclet number (dimensionless)
p_i	Pressure of element i (Pa)
Q_{abs}	Flow rate of the phase under a single-phase flow (m ³ /s)
Q_e	Flow rate of the phase in the multiphase system (m ³ /s)
Q_{total}	Total Flow rate (m ³ /s)
q_{ij}	Flow rate (m ³ /s)
RF	Recovery Factor (%)
r	Radius of the throat (m)
S_{oi}	Initial Oil Saturation (dimensionless)
S_{or}	Residual Oil Saturation (dimensionless)

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