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Investigating Low Salinity Waterflooding Recovery Mechanisms in Carbonate Reservoirs

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Abstract

Manipulating the injected brine composition can favorably alter the reservoir wetting state; this hypothesis has been validated in sandstone reservoirs by several scientists. A total of 214 coreflooding experiments were conducted to evaluate low salinity waterflooding (LSWF) secondary recovery and 188 experiments were conducted to evaluate tertiary recovery, for sandstone reservoirs. Although the incremental recovery potential in carbonate reservoirs is greater than in sandstones, only a few imbibition and coreflooding experiments have been conducted. The simulator and recovery mechanisms presented by Aladasani et al. (2012) are used and their suitability and validity to low salinity waterflooding in carbonate reservoirs has been confirmed. This has been achieved by comparing simulated LSWF secondary and tertiary recoveries with published coreflooding experiments. Furthermore, the prediction profiler in JMP was used to examine incremental recovery for the following variables: (a) acid number and interfacial tension (IFT) sensitivities, and (b) 2^{nd} stage injected brine and 3^{rd} stage injected brine anion contents. In weak water-wet conditions, the incremental recovery is driven by low capillary pressures, and the underlining recovery mechanism is the increase in oil relative permeability. Therefore, wettability modification is ideal when achieved by shifting the wetting state from oil-wet or water-wet to a maintained intermediate wetting condition irrespective of the injected brine salinity dilution. If the wettability is shifted to a strong water-wet system, then it would be more favorable to use brine with anions to shift the wettability back to an intermediate wetting state. IFT has a bigger impact on LSWF in carbonate reservoirs; however, contact angle is more significant to the final oil recovery. Future work should consider studying the impact of cationic and anionic ions on coreflooding recovery separately and using cores with different initial wetting states, preferably strong oil-wet cores.

Introduction

Manipulating the injected brine composition can favorably alter the reservoir wetting state; several researchers have validated this hypothesis in sandstone reservoirs. A total of 214 coreflooding experiments were conducted to evaluate incremental recovery during secondary recovery, of which 188 also evaluated incremental recovery during the tertiary recovery (Aladasani et al. 2012b). Although the incremental recovery potential in carbonate reservoirs is greater than in sandstones due to greater reserve volumes (Okasha et al. 2009) and the lower dilution ratio observed in coreflooding experiments (Yousef, et al. 2010), both imbibition and coreflooding experiments investigating the optimal injected brine composition are limited.

The first low salinity coreflooding experiments on carbonate reservoirs were conducted by Bagci et al. (2001). The effects of divalent and monovalent anion and cation concentrations in low salinity waterflooding (LSWF) were investigated. Some of the results indicate an increase in oil recovery as salinity decreases, especially when the concentration of potassium chloride is reduced and when divalent cations are absent from the injected brine. The aforementioned experiments did not consider the role of polyatomic anions; in addition, no wettability or IFT measurements were recorded. Furthermore, all the cores were prepared with an initial waterwetting state. Later studies did consider sulfate concentrations, IFT and wettability measurements in LSWF.

The first low salinity imbibition experiments on carbonate reservoirs investigated the effects of sulfate concentrations and temperature on chalks (Zhang and Austad, 2005) and limestone cores (Hognesen et al. 2005). In the latter work, two formation waters were used to distinguish high salinity brine concentrations typically found in Middle Eastern limestone. The studies on oil-wet cores concluded that sulfate concentrations modify wettability to a more water wetting state through a process that is accelerated with higher temperatures and that does not improve oil recovery in formation brines that have significant calcium ion concentrations due to precipitation issues. However, oil recovery doubles with the addition of cationic surfactant to the injected brine in Middle Eastern limestone cores. Hognesen et al. (2005) presented the first distinction between LSWF recovery mechanisms in sandstone and carbonate reservoirs. Sulfate's role in wettability modification was reiterated by Webb et al. (2005); capillary pressure desaturation curves demonstrated how the capillary pressure, magnitude and convention favorably change with seawater containing sulfate.

Okasha and Al-Shiwaish (2009) conducted IFT readings of Arab-D dead and live oil/brine with varying pressures, temperatures and salinities. In live oil/brine, the IFT at 90 °C decreased from 31.37 to 20.10 dynes/cm as the salinity changed from a high to a low salinity system. The decrease in brine salinity encompassed both cations and anions; which ionic species impacts IFT is unknown.

Yousef et al. (2010) investigated the impact of decreasing ion concentrations in seawater flooding. The experiments were conducted on four and six core plugs placed in a series. In addition, IFT measurements for

connate and injected brines were measured, along with contact angle values. Yousef et al. (2010) identified wettability as the recovery mechanism for low salinity seawater flooding in carbonate reservoirs, which is demonstrated effectively by measuring the capillary conditions, as emphasized by Aladasani et al. (2012). However, the reservoir cores were all prepared with an intermediate wetting state. Although IFT readings decreased as salinity decreased, wettability was modified unfavorably from intermediate wetting conditions to water-wet conditions, as concluded by Chattopadhyay et al. (2002). This observation explains why further dilution of the injected brine salinity from 20% to 100% does not improve oil recovery.

Gupta et al. (2011) investigated: (1) the impact of sulfate ions, in addition to phosphate and borate salts, on seawater flooding, (2) the impact of plug orientation on oil recovery, and (3) the impact of cations on formation waterflooding. The results suggested that seawater flooding improved oil recovery and reduced the pressure drop more so than formation water flooding. The removal of sulfate ions from seawater flooding augmented oil recovery. The addition of phosphate and borate salts to seawater free of sulfate ions further improved oil recovery. The decrease in calcium concentration and, by the same magnitude, the increase in potassium ion concentration is highlighted during the increase in seawater incremental recovery. The removal of calcium ions continues to improve oil recovery despite an increase in magnesium ions in formation waterflooding. Although IFT readings were taken and the paper emphasized the role of wettability modification to a more water wetting state, no contact angle readings were recorded.

The objective of this paper is to investigate the recovery mechanisms in modified salinity waterflooding in carbonate reservoirs. The methodology will involve simulating modified salinity waterflooding based on research by Aladasani et al. (2012) and comparing the simulation results with published carbonate coreflooding experiments. Furthermore, based on carbonate coreflooding experiments in the literature, prediction profilers will be used to examine the impact of the acid number and IFT, in addition to the secondary and tertiary stage injected brine anion content, on incremental recovery.

Methodology

Simulating LSWF in carbonate reservoirs involves the following steps: (1) identifying phase behavior in porous media, (2) handling immobile water zones, (3) establishing relative permeability and capillary pressure functions for LSWF in carbonate reservoirs, and (4) validating the model analytically. These steps will be discussed in detail through the remainder of this paper.

(1) Reservoir simulation is based on the law of conservation, constitutive equations and equations of state. The reservoir is considered a controlled volume containing three phases and various mass components. The saturation occupied by each phase in the porous media represents the fractional phase volume. Therefore, using material balance equations, the mass component in the gas, oil and water phases can be derived. The fluid flow in a reservoir can be expressed as shown in Equation 1. Constitutive equations are needed to determine the

phase pressure and relative permeability, which is achieved by relating the phase, saturations and mass components (Equations 2 and 2a). As a result, it is possible to derive the capillary pressure and relative permeability expressions as a function of phase saturations and mass component fractions (Equations 3 through 9). The equation of state describes phase density or viscosity as a function of temperature and pressure; this is represented by the phase formation factor (Equations 10 through 13).

$$\nabla(\rho v) + q = \frac{\delta}{\delta t} (\phi \rho) \tag{1}$$

$$v = \frac{k}{\mu} \left(\nabla \Phi \right) \tag{1a}$$

$$\Phi = \nabla P - \rho g \nabla d \tag{1b}$$

Expanding Equation 1 to represent the oil phase yields the following flow equation:

$$\nabla (\rho_o v_o) + q_o = \frac{\delta}{\delta t} (\phi S_o \rho_o)$$
(1c)

The oil phase is present only in its associative state, whereas the gas phase is present in both its associative state and when dissolved in oil. Therefore, gas volume is a function of both gas and oil saturation, in addition to gas density and dissolved gas density, respectively.

$$\left[\left(\rho_g v_g\right) + \left(\rho_{dg} v_o\right)\right] + q_g = \frac{\delta}{\delta t} \phi\left[\left(S_g \rho_g\right) + \left(S_o \rho_{dg}\right)\right] \tag{1d}$$

The water phase has two mass components, water and salt. To account only for the water component in the water phase, the following expression is generated (Equation 1e). The constitutive equation mandates that the mass components of the entire phase equal unity.

$$\nabla \left(\rho_w X_w v_w\right) + q_w = \frac{\delta}{\delta t} \left(\phi S_w X_w\right) \tag{1e}$$

In LSWF, salt is considered a mass component in the water phase, which is expressed by the product of the reservoir's porosity, water saturation, water density and salt mass component; as such, salt is transported by advection. Additionally, because the salt mass component in the water phase is transported by diffusion and because, in sandstone reservoirs, cations are prone to adsorption on the reservoir rock, an expression is required to differentiate the fate of adsorbed salt and salt transported by diffusion (based on Equation 2a). A tortuosity term is added to account for increases in the distance that molecules must travel in a porous media.

$$\nabla \left[(\rho_w X_c v_w) + (\phi S_w \Delta X_c \rho_w D_m \tau) \right] + q_c = \frac{\delta}{\delta t} \left[(\phi S_w X_c \rho_w) + (1 - \phi) \rho_w \rho_r X_c K_d \right]$$
(1f)

Constitutive equations are needed to determine the phase pressures, saturations and phase relative permeabilities; this is achieved by relating the phase, saturations and mass components. The sum of the saturations of hydrocarbon phases equals unity, as does the sum of the mass components in any phase.

$$S_g + S_o + S_w = 1 \tag{2}$$

$$X_w + X_c = 1 \tag{2a}$$

The phase pressure is, by definition, the difference between the non-wetting phase and the wetting phase. The non-wetting phase always has a higher pressure than the wetting phase, and gas is always the non-wetting phase in hydrocarbon reservoir rocks (Satter et al. 2008). The three-phase capillary pressures between the oil and gas interface and between the water and oil interface are shown in Equations 3 and 4, respectively. The water phase consists of two mass components, so both mass fractions are a function of water-oil capillary pressure. This relationship makes it possible to consider the effects of LSWF on capillary pressure. In addition, capillary pressure correlations, such as in Parker et al. (1987), do not consider IFT parameters in the capillary function. Therefore, a J-function can be used to relate both IFT and contact angle changes occurring as a result of LSWF.

$$P_{\rho} = P_{\rho} - P_{ceo}(S_{w}, S_{\rho}) \tag{3}$$

$$P_o - P_w = P_{cow}(S_w, S_o, X_c)$$
(4)

$$P_{cow} = \sigma(X) \cos \theta(X) P^0_{cow}(S_w, S_o)$$
⁽⁵⁾

By definition, the relative permeabilities are functions of the saturations occupying the porous media and also should include the phase mass components, as shown in Equations 6 through 8. The Stone correlation, method II (Aziz and Settari, 1979), can be used if no three-phase relative permeability data are available, as shown in Equation 9. This correlation provides three-phase relative permeability data based on two sets of two-phase flow relative permeabilities.

$$\mathbf{k}_{\rm rg} = \mathbf{k}_{\rm rg} \left(\mathbf{S}_{\rm g}, \mathbf{X}_{\rm c} \right) \tag{6}$$

$$\mathbf{k}_{ro} = \mathbf{k}_{ro} \left(\mathbf{S}_{w}, \mathbf{S}_{g}, \mathbf{X}_{c} \right)$$
(7)

$$k_{rw} = k_{rw}(S_w, X_c)$$
(8)

$$k_{ro} = k_{ro}^{*wo} \left[\left(\frac{k_{ro}^{wo}}{k_{ro}^{*wo}} + k_{rw} \right) \left(\frac{k_{ro}^{og}}{k_{ro}^{*wo}} + k_{rg} \right) - \left(k_{rw} + k_{rg} \right) \right]$$
(9)

The equation of state describes phase density as a function of temperature and pressure; this is represented by the phase formation factor shown in Equations 10 and 11. The water phase density is a function of temperature, pressure and the salt mass component, as shown in Equation 12. Gas and oil viscosities are treated as functions of phase pressure only, and the water phase viscosity is a function of the salt mass component, as shown in Equations 13 and 14. The water phase viscosity is a function of the salt mass component used to evaluate the mobility ratio during LSWF.

$$\rho_g = \frac{\left(\rho_g\right)_{STC}}{B_g} \tag{10}$$

Where,

$$B_g = \frac{P_{STC}}{T_{TSC}} T \frac{z}{p}$$
(10a)

$$\rho_o = \frac{1}{B_o} \left[\left(\rho_o \right)_{STC} + R_s \left(\rho_g \right)_{STC} \right] \tag{11}$$

Where,

$$B_o = B_{ob} [1 - C_o (P - P_b)]$$
(11a)

$$\mathbf{R}_{s} = \mathbf{R}_{s} \left(\mathbf{P}_{o}, \ \mathbf{P}_{b} \right) \tag{11b}$$

$$\rho_w = \frac{\left[\rho_w(X_c)\right]_{STC}}{B_w} \tag{12}$$

Where,

$$B_{w} = \frac{B_{w}^{o}}{1 + C_{w} (P_{w} - P_{b}^{o})}$$
(12a)

$$\mu_{\beta} = \mu_{\beta} (P_{\beta}) \tag{13}$$

$$\mu_{\rm w} = \mu_{\rm w}(X_{\rm c}) \tag{14}$$

(2) Immobile or residual water zones of *in-situ* brine within porous pores can be handled as separate domains containing immobile water only, such as "dead" pores, acting as additional continuums with zero permeability. The salt within the immobile zones will interact with mobile water zones by diffusion only. This diffusion process is described by the same governing equations and numerical formulations discussed above as a special no-flow case.

(3) The model considers the adopted relative permeability and capillary pressure formulations that suggest a linear relationship between salt content and residual fluid saturations (Jerauld et al. 2008) and contact angle, as shown in Equations 19 and 20, respectively. Published improved oil recovery (IOR) mechanisms for LSWF include decreasing residual oil saturation. Therefore, relative permeability functions are modified accordingly to include the effects of salinity. The Brooks-Corey function (Honarpour et al. 1986) is used with the following modifications: (1) decrease in the relative permeability of the water phase as salinity decreases, and (2) increase in the relative permeability of oil phase as salinity decreases. The Brooks-Corey exponential index φ (Corey, 1954) is adopted, and two normalized fluid saturations are described in Equations 17 and 18. The residual oil saturation is considered a function of salinity in the aqueous phase and, hence, a function of water's relative permeability. Jerauld et al. (2008) first proposed a linear relationship between the salt mass component and residual oil saturation and treated salt mass concentration as a function of both oil and water's relative permeability. In Equation 19, S_{or1} is the maximum residual oil saturation at high salt mass fraction X_{c1}, and S_{or2} is the minimum residual oil saturation at low salt mass fraction X_{c2}

$$k_{rw} = \left(\overline{S}_{w}\right)^{2+\varphi} \left[\overline{S}_{w}(X_{c})\right]$$
(15)

$$k_{ro} = (\overline{S}_o)^2 \left[1 - (\overline{S}_w)^{\varphi} \right]$$
(16)

$$\overline{S}_{w} = \frac{S_{w} - S_{wr}}{1 - S_{wr}} \tag{17}$$

$$\overline{S}_o = \frac{S_o - S_{or}(X_c)}{1 - S_{wr}}$$
(18)

$$S_{or}(X_{c}) = S_{or1} + \frac{X_{c} - X_{c1}}{X_{c1} - X_{c2}} (S_{or1} - S_{or2})$$
(19)

The capillary pressure functions are modified to include the effects of salinity. A linear relationship with residual oil saturation is introduced between the salt mass fraction and contact angle so that a decrease in the salt mass fraction would favorably alter wettability to intermediate wetting conditions, as shown in Equation 32. In this equation, θ_{or1} is the contact angle at high salt mass fraction X_{c1} , and θ_{or2} is the contact angle at low salt mass fraction X_{c2} .

The capillary pressure function from van Genuchten (1980) and Parker et al. (1987) is used for the oil-water system, with the addition of the cosine of contact angles of the oil and water phases on the rock's surface to include the effect of low salinity on the contact angle, as shown in Equation 21, where α_{vG} , γ and β are parameters of the van Genuchten functions (van Genuchten, 1980), with $\gamma = 1 - 1 / \beta$. (Wu et al. 2009)

$$\theta(X_{c}) = \theta_{or1} + \frac{X_{c} - X_{c1}}{X_{c1} - X_{c2}} \left(\theta_{or1} - \theta_{or2} \right)$$
(20)

$$P_{cow} = \frac{\cos\theta\rho_w}{(\cos\theta\rho_w)^o} \left(\frac{g}{\alpha_{vG}}\right) \left[\left(1 - S_w\right)^{-1/\gamma} - 1 \right]^{1/\beta}$$
(21)

The fluid relative permeability functions in Equations 17 and 18 and the capillary pressure function in Equation 21 are illustrated in Figures 1 and 2, respectively. When oil becomes the wetting phase, the capillary pressure and salinity magnitudes increase away from intermediate wetting conditions, and the capillary pressure changes to a negative convention, as shown in Figure 2.





Figure 2. Capillary Pressure Curves



(4) The model must be validated analytically. In Problem 1, we considered the one-dimensional transport of a chemical component in a homogeneous, water-saturated, 10-meter-long porous medium similar to the one used by Wu et al. (1996). It has a steady-state flow field with a 0.1 m/day velocity. A chemical

component is introduced at the inlet (x=0) with a constant concentration, and transport begins at t=0 by advection and diffusion. This problem is solved numerically by specifying both the inlet and outlet boundary elements with constant pressures, which yields a steady-state flow field with a 0.1 m/day pore velocity. The constant pressures are determined by specifying the following reservoir properties: permeability of 0.898×10^{-12} m², viscosity of 0.898×10^{-3} Pa.s and a 10-meter-long domain with a unit cross-sectional area. The analytical solution to Problem 1 is generated by a computer program based on the analytical solution reached by Javandel et al. (1984). A comparison of the salt concentrations along the rock column from the numerical and analytical solutions is shown in Figure 3 for t=10, 20 and 60 days, respectively. The results, shown in Figure 3, indicate good agreement between the analytical and numerical solutions.



Figure 3. Analytical Versus Numerical Solution to Problem 1

Application

Problems 2 and 3 are designed to validate the numerical model's ability to simulate low salinity seawater injection in carbonate reservoirs and are based on the research of Aladasani et al. (2012b). The objective is to construct the core plug's petrophysical properties published by Yousef et al. (2010) and contrast the recovery factors with the simulation results. The flooding experiments conducted by Yousef et al. (2010) are used for validation because they include residual oil saturation, IFT and contact angle measurements for the five seawater mixtures. The IFT and contact angle measurements represent capillary conditions; as such, wettability

modification in LSWF can be evaluated. Moreover, six core plugs are used in a series for the coreflooding experiment, each with varying petrological properties. This provides a better representation of reservoir waterflooding. The flow domains in Problems 2 and 3 consist of a one-dimensional, horizontal, homogeneous, and isotropic porous media. The injected brine properties are shown in Table 1.

A linear relationship may not exist between the salt concentration and the residual oil saturation, contact angle and IFT, which would create a variance between the coreflooding experiments and the simulation results. The residual oil saturation, contact angle and IFT for each salinity concentration are examined, as shown in Appendix A and Figures 8, 9 and 10, respectively. The salt concentration has a near linear relationship with the residual oil saturation, contact angle and IFT.

In Problem 2, the coreflooding experiment consists of four core plugs oriented in a series measuring 16.25 cm in length and 3.8 cm in diameter, as shown in Figure 4. The properties of the core plugs are shown in Table 2. The flow domain is represented by a one-dimensional radial mesh comprised of 400 uniform grid blocks, each of which is assigned a cross-sectional area of 11.34 cm² and a uniform mesh spacing of $\Delta x = 0.0406$ cm.

In Problem 3, the coreflooding experiment consists of six core plugs oriented in a series measuring 23.65 cm in length and 3.8 cm in diameter, as shown in Figure 5. The properties of the core plugs are shown in Table 3. The flow domain is represented by a one-dimensional radial mesh comprised of 600 uniform grid blocks, each of which is assigned a cross-sectional area of 11.34 cm² and a uniform mesh spacing of $\Delta x = 0.0394$ cm.

Property	Connate	Seawater	Seawater Diluted Seawater			
	Water		50%	10%	5%	1%
TDS (ppm)	213,734	57,670				
Density (kg/m ³)	1108.3	1015.2	995.9	981.2	978.2	977.9
Viscosity (cp)	0.476	0.272	0.242	0.232	0.212	0.193
Mean IFT	39.3	33.7	32.8	32.2	31.85	31.5
(Dynes/cm)						
Contact Angle (°)	90°	90°	80.9°	69.0°	63.0°	62.2°

Table 1. Carbonate Coreflooding Fluid Properties at 212 °F (Taken from Yousef et al. 2010)



Figure 4. Schematic for Numerical Problem 2

Table 2. Carbonate Core Plug Properties	(Taken from Yousef et al. 2010)
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Sample #	Length (cm)	Diameter (cm)	Brine (mD) Permeability	Porosity (% OOIP)	Swi (% OOIP)
13	4.25	3.81	53.80	20.80	13.5
74	3.93	3.80	30.55	28.70	8.60
73	4.02	3.80	45.71	28.90	6.80
10	4.04	3.81	35.00	22.10	14.3



23.65 cm

Figure 5. Schematic for Numerical Problem 3

Sample #	Length (cm)	Diameter (cm)	Brine (mD) Permeability	Porosity (% OOIP)	Swi (% OOIP)
159	3.94	3.81	74.34	22.57	12.6
55	4.16	3.81	59.44	27.73	14.7
91	3.83	3.81	73.26	24.97	6.60
66	3.77	3.81	64.51	25.65	19.0
61	4.02	3.81	73.25	26.60	17.6
128	3.93	3.81	65.26	20.36	15.7

Table 3. Core Plug Properties (Taken from Yousef et al. 2010)

The system initially is saturated with oil and water, the latter of which is at its irreducible saturation. Seawater with five different salinities is injected as a displacing fluid into the inlet to drive oil out of the porous medium, and the injected brine composition is shown in Table 2. The published experiments begin with a constant injection rate of 1 cubic centimeter (cc) per minute until no oil is produced. Subsequently, the injection rate is increased to 2 cc and then to 4 cc per minute to ensure that all of the mobile oil is recovered. This study

adopts a different injection scheme in which the 1 cc injection rate is maintained until all of the mobile oil is recovered in order to ensure an accurate pore volume count. The waterflooding scheme in this case is successive and represents both the secondary and tertiary stages of recovery. Therefore, the saved primary thermodynamic variables for all of the grid blocks are used to define the initial boundary conditions for the subsequent floods.

The residual oil saturation, contact angle and IFT are all functions of salinity, so this entails revising the oil saturation, contact angle, salinity, residual oil, irreducible water range and IFT value for each simulation run. In addition, because the salinity range will vary for each simulation run based on the maximum and minimum concentrations, the corresponding viscosity and density for each salinity concentration also should be defined.

The published incremental recovery and simulation results for the first and second cores are shown in Tables 4 and 5, respectively, and the recovery curves for the simulation results are shown in Figures 6 and 7, respectively. The results indicate good agreement between the coreflooding experiments and the simulation. The aggregate values of the variance for the first and second cases are 6.81% and 10.95%, respectively, and are thought to result from the unknown pore volume count for each corresponding injection rate in the coreflooding experiment.

Injected Seawater (TDS)	Incremental Recovery (%) (Taken from Yousef et al. 2010)	Incremental Recovery (Simulation)	
57,670	67.04	67.65	
28,835	6.99	4.67	
5,767	9.12	5.68	
2,883.5	1.63	1.97	
5,767	0.00	1.03	
-	84.97	78.16	

Table 4. Carbonate Case 1 Simulation versus Coreflooding Results (Taken from Yousef et al. 2010)

Table 5. Carbonate Case 2 Simulation versus Coreflooding Results (Taken from Yousef et al. 2010)

Injected Seawater	Incremental Recovery (%)	Incremental Recovery	
(TDS)	(Taken from Yousef et al. 2010)	(Simulation)	
57,670	74.12	66.0	
28,835	8.48	5.20	
5,767	9.95	5.90	
2,883.5	0.95	3.50	
5,767	0.00	1.60	
-	93.65	82.70	



Figure 6. Simulation Recovery Curve



Figure 7. Simulation Recovery Curve

Data Analysis of Coreflooding Experiments

A database containing 18 coreflooding experiments has been constructed. The coreflooding experiments were taken from Yousef et al. (2010) and Gupta et al. (2011). While the dataset pool is not adequate for prediction modeling, the prediction profiler in JMP (statistical software) is used to examine incremental recovery for the following variables: (a) acid number and IFT sensitivities, as shown in Figure 11, Appendix A, and (b) 2nd and 3rd stage injected brine anion content, as shown in Figure 12, Appendix A. In Figure 11, the increase in water wetness improves secondary stage oil recovery; however, an opposite effect is seen at the tertiary stage. This suggests that a reduction in the sulfate concentration continues to increase water wetness, thereby increasing the capillary pressure. In contrast to the former observation, decreasing the anion concentration in the injected brine improves oil recovery, because the capillary pressure would decrease as the wettability is favorably modified to intermediate wetting conditions.

Conclusion

The simulator and recovery mechanisms presented by Aladasani et al. (2012) are used and their suitability and validity to low salinity waterflooding in carbonate reservoirs has been confirmed. This has been achieved by comparing simulated LSWF secondary and tertiary recoveries with published coreflooding experiments. Simulation and statistical analysis suggest that, under intermediate wetting conditions, the incremental recovery of LSWF is driven by low capillary pressures, and the primary LSWF recovery mechanism is the increase in oil relative permeability. Therefore, it is ideal to modify wettability by shifting and then maintaining the wetting state from oil-wet or water-wet to intermediate wetting conditions irrespective of the salinity dilution. Furthermore, if the wettability is shifted to a strong water-wet state, it becomes more favorable to use brine with added anions to shift the wettability back to an intermediate wetting state. IFT has a bigger impact on LSWF in carbonate reservoir; however, the contact angle is more significant to ultimate oil recovery.

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Appendix A



Figure 8. Correlation of Residual Oil Saturation and Salt Concentration

$$S_{or}(X_c) = S_{or1} + \frac{(0.6494)(X_c)^2 + (-0.02624)(X_c) + (7.486e - 10)}{(X_c)^2 + (-0.7334)(X_c) + (0.3566)} (S_{or1} - S_{or2})$$
(22)



Figure 9. Correlation of Contact Angle and Salt Concentration

$$\theta(X_c) = \theta_{or1} + \frac{(0.4106)(\theta)^2 + (0.8696)(\theta) + (-0.006548)}{(\theta) + 0.2763} (\theta_{or1} - \theta_{or2})$$
(23)



Figure 10. Correlation of IFT and Salt Concentration

$$IFT(X_{c}) = IFT_{or1} + \frac{(82.44)(IFT)^{2} + (738.4)(IFT) + (24.55)}{(IFT) + 843.8} (IFT_{or1} - IFT_{or2})$$
(24)



Figure 11. Prediction Profiler Acid Number & IFT



Figure 12. Prediction Profiler (2nd & 3rd Stages) Injected Brine Anions

Nomenclature

IFT	Interfacial Tension	\mathbf{B}_{w}	Water Formation Factor
σ Factor	Interfacial Tension	B_{β}	Phase β Formation
S_g at P_i^o	Gas Saturation	B_w^o	Water Formation Factor
S _o	Oil Saturation	Cw	Water Phase
Compressi	bility	- ••	
Sw	Water Saturation	μ	Viscosity
~ w		<i>μ</i> .	
S_{gr}	Residual Gas Saturation	μ_{B}	Phase B Viscosity
Sor	Residual Oil Saturation	μ_0	Oil Viscosity
Swe	Critical Water Saturation	L v	Water Viscosity
Sorg	Residual Gas Oil Saturation	M	Mobility Ratio
Saa	Critical Gas Saturation	λ	Mobility Ratio
Sai	Initial Oil Saturation	γ	Transmissivity
k k	Permeability	i W	Potential
k.	Phase & Relative Permeability	Ψ nnm	Parts Per Million
k	Gas Relative Permeability	\mathbf{PV}	Pore Volume
k k	Oil Relative Permeability	r v σ	Gas
k k	Water Relative Permeability	5 W	Water
r _{rw} lz*W0	Oil Palative Permaability at Critical Water Saturation	vv	Oil
Kro LWO	Oil Relative Fermeability in 2 Phase Oil Water System	0 *	Deregity
K_{r0}	O'I Relative Fermeability in 2-Flase Oil-water System	ψ V	
K _{ro}	Oil Relative Permeability in 2-Phase Oil-Gas System	X _c	Mass Fraction of Salt in
the Water	Phase	• •	
P _g	Gas Capillary Pressure	X_{w}	Mass Fraction of Water
in the Wat	er Phase		D
Po	Oil Capillary Pressure	ρ	Density
Pw	Water Capillary Pressure	$\rho_{\rm R}$	Rock Grain Density
\mathbf{P}_{B}	Phase Capillary Pressure	∇	Flux
P	Oil-Gas Capillary Pressure	ν	Darcy Velocity
- ego		·	
P_{cow}	Water-Oil Capillary Pressure	q	Flowrate
Pg	Bubble Point Pressure	K _d	Salt Distribution
Coefficien	t Between Water Phase and Reservoir Rock		
P_b^o	Initial Bubble Point Pressure	D_m	Molecular Diffusion
Coefficien	t		
θ	Theta (Contact Angle)	τ	Formation Tortuosity
B _o	Gas Formation Factor	Р	Pressure
Bo	Oil Formation Factor	g	Gravity Constant
D	Water Formation Factor	d	Surface Donth
\mathbf{D}_{W}	water Formation Factor	a	Surface Depui
\mathbf{B}_{β}	Phase β Formation Factor	t	Time
B_w^{o}	Water Formation Factor at P_b^o	Φ	Potential
Ċw	Water Phase Compressibility	STC	Standard Tank
Condition			
B_w	Water Formation Factor	R _s	Solution Gas-Oil Ratio
\mathbf{B}_{β}	Phase β Formation Factor	-	