Mathematical Modeling of Carbonated Water Injection for EOR and CO₂ Storage with a Focus on Mass Transfer Kinetics

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ABSTRACT

Mathematical modeling of carbonated water injection (CWI) as an EOR and CO₂ storage technique is studied in this paper. When carbonated water (CO₂ saturated water) contacts oil during injection into oil reservoirs, CO₂ will migrate from water into the oil phase as it has higher solubility in hydrocarbons. Consequently, oil mobility, and in turn oil recovery, will increase. In addition, CO₂ can also be stored securely in the reservoir during CWI. The simulation study of CWI coreflood experiments presented in the literature show that during CWI, the CO₂ transfer between water and oil phases is slow and equilibrium state is not reached instantaneously. Hence, in this paper, a new compositional simulator is developed by including the kinetics of CO₂ transfer and a set of CWI coreflood experiment from the literature is simulated and studied in detail. A genetic algorithm based optimizer is applied to obtain the unknown parameters during simulation through a history matching experiment. The performance of the developed simulator is also compared with ECLIPSE300 commercial compositional simulator. The CO₂ storage profile is also studied using the simulation results. Generally, the developed simulator can be used to better understand the physics of CWI process for practical field applications and also as a solid foundation for kinetic based study of transport phenomena in porous media where the mass transfer is important and not instantaneous.

Keywords: Carbonated water injection; EOR; Compositional simulation; Mass transfer kinetics.

List of symbols

ω_o^o = Mass fraction of the oil component in the oil-CO₂ mixture (i.e. oil phase)
 ω_o^{co2} = Mass fraction of the CO₂ component in the oil-CO₂ mixture (i.e. oil phase)
 ω_w^{co2} = Mass fraction of the CO₂ component in the water-CO₂ mixture (i.e. water phase)
 ω_w^w = Mass fraction of the water component in the water-CO₂ mixture (i.e. water phase)
 C_o^{co2} = CO₂ concentration in the oil-CO₂ mixture (g/cm³)
 C_w^{co2} = CO₂ concentration in the water-CO₂ mixture (g/cm³)
 k_{eq} = Distribution coefficient, here is 9.6.
 K = Mass transfer coefficient (MTC) (1/sec)
 p_α = Pressure of the phase α (atm) (α : oil-CO₂ or water-CO₂ mixture)
 p_c = Capillary pressure (atm)
 p_{ce} = Entry pressure (atm)
 s_α = Saturation of the phase α (α : oil-CO₂ or water-CO₂ mixture)
 k = Absolute permeability (mD)
 φ = Porosity
 μ_α = Viscosity of the phase α at the test conditions (cP)
 ρ_α = Density of the phase α at the test conditions (g/cm³)

1. Introduction

Carbonated water (CW) injection is an EOR method that is not studied widely. In carbonated water injection (CWI) technique, carbon dioxide (CO₂) is dissolved in the injected water before injection. During CWI, CO₂ is transferred from carbonated water (CW) into the oil phase improving the oil mobility. Oil swelling, viscosity and interfacial tension (IFT) reduction are amongst the possible mechanisms contributing towards enhanced oil recovery during CWI. During CWI, compared to typical CO₂ injection, the problems of poor sweep efficiency and gas fingering are mitigated as CO₂ is in dissolved state. Moreover, CWI can be applied particularly in offshore reservoirs, where the supply of CO₂ is limited. Moreover,

through CWI, some part of CO₂ is stored in the reservoir in the dissolved phase with less risk of CO₂ leakage [1-4]. CWI technique has not been studied extensively in the past. The first reported commercial application of CWI was in 1958 in United States called K&S project [5]. Additional oil recovery from watered-out area of the reservoir was obtained. CWI has been studied mainly experimentally aiming to better understand the involved mechanisms. Sohrabi et al.[1, 2] carried out a series of CW coreflood experiments at reservoir conditions. CWI, compared to WI, resulted in a higher oil recovery while some CO₂ was stored in the core. The effect of oil swelling, viscosity reduction and wettability of rock were discussed. Mosavat and Torabi [6] carried out CWI tests in a sand-packed setup for a light oil sample. Both additional oil recovery and CO₂ storage were observed. Tavakolian [7] investigated the potential of CO₂ storage during CWI compared to pure CO₂ injection through coreflood experiments. They observed a more stable storage of CO₂ during CWI compared to that during pure CO₂ injection. Riazi et al. [3, 4] studied CWI in a micro-model setup at reservoir conditions. Water was injected first chased by carbonated water. Significant oil swelling was observed during CWI (swelling stage). CWI was later chased with another WI (second WI) to strip dissolved CO₂ out of the swollen oil and obtain the volume of the remaining dead oil (shrinkage stage). They observed that the shrinkage rate was meaningfully quicker than the swelling rate as shown in Fig. 1 [4]. In the literature, modeling and simulation of the CWI process have not been given sufficient attentions and there is not any comprehensive mathematical study capturing the actual physics of the CWI process. Flow of fluids in the reservoir during the course of CWI is accompanied by CO₂ mass transfer across the phases which leads to the variations of the fluids properties (i.e. viscosity and density changes). Mass transfer controls the process of CO₂ distribution between water and oil during CWI and the displacement efficiency of CWI, is not dictated by the minimum miscibility pressure [8]. The literature data show that, both black-oil and compositional models have been used to

83 simulate CWI process. De Nevers [9] presented a calculation method based on the Buckley–
84 Leveret theory to predict the CWI performance. It was assumed that the equilibrium state is
85 reached instantaneously. The model could not match the experimental data. Ramesh and
86 Dixon [10] presented a three-phase black-oil simulator when CO₂ could be dissolved in oil
87 and water phases. Mansoori [11] developed a compositional simulator allowing CO₂
88 dissolution in water during CO₂ injection projects. CO₂ solubility in water was taken into
89 account using Henry's law. Phase equilibrium calculation was based on the instantaneous
90 equilibrium assumption. Chang et al. [12] presented a three-phase compositional model to
91 simulate CO₂ flooding processes when CO₂ is allowed to be also dissolved in water. It was
92 assumed that phases would reach thermodynamic equilibrium state instantaneously. Embid
93 and Rivas [13] developed a kinetic-based simulator for gas injection projects. They
94 mentioned that, the mass transfer kinetics is important when there are short contact times for
95 mass transfer process (laboratory displacement in cores) or when large diffusion patterns are
96 available for components to diffuse through (field scale) and moreover if there is slow
97 diffusion velocities due to large viscosity. Kechut et al. [14, 15] used ECLIPSE300 (E300)
98 compositional simulator to simulate a set of carbonated water coreflood experiments. E300
99 over predicted the oil recovery compared to experimental data for all coreflood tests. They
100 explained that this over prediction is due the inherent assumption of instantaneous
101 equilibrium made by available compositional simulators while in reality during CWI, CO₂ is
102 transferred gradually across the phases. To support their explanation, they mentioned the
103 micro-model observations reported by Riazi et al. [4] as shown in Fig. 1. They suggested that
104 a new simulation approach based on non-equilibrium assumption is required for simulation of
105 CWI coreflood experiments. Therefore, in this paper, a new compositional mathematical
106 model is developed to study CWI while the assumption of instantaneous equilibrium is
107 relaxed by introducing a mass transfer term. In the next sections, first, the structure of the

model is explained. Then the procedure followed to validate the model and simulate the coreflood experiments are discussed. Finally the results and conclusions of this study are presented.

2. Model Structure

2.1. Governing Equations

To develop the mathematical model, the governing equations based on the mass balance have been used. The mass balance equation for the component 'I' in the phase ' α ', which is displaced through a porous medium in 'x' direction by convection (i.e., velocity of fluids) and dispersion (or diffusion) mechanisms, is shown below [16-18]:

$$\phi \frac{\partial(\rho_{\alpha} s_{\alpha} \omega_{\alpha}^I)}{\partial t} = - \frac{\partial(\rho_{\alpha} u_{\alpha} \omega_{\alpha}^I)}{\partial x} + \frac{\partial}{\partial x} (\phi s_{\alpha} D_{I-\alpha} \frac{\partial(\rho_{\alpha} \omega_{\alpha}^I)}{\partial x}) + U \quad (1)$$

where, ω_{α}^I is the mass fraction of the component I in the phase α . ρ_{α} and s_{α} are the mass density and saturation of the phase α , respectively. u_{α} is the Darcy velocity of the phase α and $D_{I-\alpha}$ is the dispersion or diffusion coefficient. The last term on the right hand side, 'U', is the source or sink term, which describes the amount of the component I entering (source) or exiting (sink) the phase α . During simulation of CWI, the U term will capture the CO₂ transfer between the phases. The model is developed for a homogeneous and isotropic porous medium with the following assumptions:

- The model is one-dimensional in Cartesian coordinate.
- Not any chemical reaction is considered.
- The model is two-phase as CO₂ is in solution and not as a free gas.
- Oil is a dead oil sample so there is no free hydrocarbon gas in the system.
- Oil is a single component.
- The gravity effect is neglected. This is valid for a horizontal coreflood experiment.
- No dispersion is considered.
- Mixture densities and viscosities are a function of CO₂ concentration and pressure.

Considering the simulations of CWI, the equations are obtained for two phases of oil and water including three components of oil, water and CO₂. The mass balance equations for each component in each phase, assuming no dispersion, are as follows:

$$\phi \frac{\partial(\rho_o s_o \omega_o^o)}{\partial t} = - \frac{\partial(\rho_o u_o \omega_o^o)}{\partial x} \quad (2a)$$

$$\phi \frac{\partial(\rho_o s_o \omega_o^{CO_2})}{\partial t} = - \frac{\partial(\rho_o u_o \omega_o^{CO_2})}{\partial x} + U \quad (2b)$$

$$\phi \frac{\partial(\rho_w s_w \omega_w^w)}{\partial t} = - \frac{\partial(\rho_w u_w \omega_w^w)}{\partial x} \quad (2c)$$

$$\phi \frac{\partial(\rho_w s_w \omega_w^{CO_2})}{\partial t} = - \frac{\partial(\rho_w u_w \omega_w^{CO_2})}{\partial x} - U \quad (2d)$$

where ω_α^I is the mass fraction of the component I (i.e., oil, water or CO₂) in the phase α (water or oil phase). It should be noted that the phases are mixtures containing CO₂. ρ_α is the mass density (g/cm³) and s_α is the saturation of the phase α (i.e., mixture of oil-CO₂ or water-CO₂), respectively. u_α is the Darcy velocity of the phase α defined as follows:

$$u_\alpha = -\lambda_\alpha \frac{\partial p_\alpha}{\partial x} \quad \text{where} \quad \lambda_\alpha = \frac{k K r_\alpha}{\mu_\alpha} \quad \alpha = o, w \quad (2e)$$

where $K r_\alpha$ is the relative permeability of the phase α (oil or water) and p_α is the pressure of the phase α (atm). The ‘p’, ‘ ω ’ and ‘s’ parameters are bounded by the following auxiliary equations:

$$p_c = p_o - p_w = f(s_w) \quad (2f)$$

$$\sum s_\alpha = 1 \quad \alpha = o, w \quad (2g)$$

$$\sum \omega_o^I = 1 \quad I = o, CO_2 \quad \text{and} \quad \sum \omega_w^I = 1 \quad I = w, CO_2 \quad (2h)$$

where p_c is the capillary pressure. Eq. (2a) and (2b) are the mass balance equations for oil and CO₂ components in the predominantly oil phase. Eq. (2c) and (2d) are the corresponding mass balance equations for the water and CO₂ components in the predominantly water phase. The fully implicit technique combined with the Newton-Raphson iterative method has been

used to solve the equations [19-21]. Oil-water relative permeability ($K_{r_{o-w}}$) functions have been defined based on the Corey correlations as follows [22]:

$$K_{r_w} = k_{w_{\max}} s^{*n_w}, \quad K_{r_o} = k_{o_{\max}} (1-s^*)^{n_o}, \quad s^* = \frac{(s_w - s_{wc})}{(1 - s_{wc} - s_{or})} \quad (3)$$

where $k_{w_{\max}}$, n_w , $k_{o_{\max}}$ and n_o are maximum relative permeabilities and exponents of water and oil relative permeabilities, respectively. s_{wc} and s_{or} are saturation of connate water and residual oil, respectively. Capillary pressure curve (p_c curve) has been defined based on the Brooks-Corey correlation as follows [23]:

$$p_c = p_{ce} \left(\frac{s_w - s_{wc}}{1 - s_{wc} - s_{or}} \right)^{-\frac{1}{\lambda}} \quad (4)$$

where p_{ce} is the entry pressure and λ is the pore-size distribution index. K_r and p_c parameters have been obtained by history matching of the production data as described later on.

2.2. Mass Transfer Term

The kinetics of CO_2 distribution between the oil and water phases is included by introducing a mass transfer term to the governing equations. That is, a source term, U , has been added which is defined as follows [24]:

$$U = K \times (\rho_w \times \omega_w^{CO_2} \times k_{eq} - \rho_o \times \omega_o^{CO_2}) = K \times (C_w^{CO_2} - k_{eq} C_o^{CO_2}) \quad (5)$$

where, K (1/sec) is mass transfer coefficient (MTC). $C_o^{CO_2}$ and $C_w^{CO_2}$ are the CO_2 concentration in oil and water phases (g/cm^3), respectively. This equation implies that the driving force for the CO_2 transfer between the phases is the concentration gradient and the MTC controls how fast this transfer happens. It should be noted that the definition of mass transfer, Eq. 5, is based on macroscopic mass transfer. However, the effect of any factor or process which in microscopic view may influence the quantity of mass transfer between phases such as any resistance at the interface or any deformation of interface due to viscosity mismatch are captured inherently by the MTC. The MTC can be obtained by either history matching the coreflood production data or be estimated using some theoretical models [13,

16, 17]. In this study, MTC is obtained through history matching of core flood experiments as described later on. k_{eq} is the distribution or partition coefficient showing the CO_2 distribution between the phases at the equilibrium state defined as follows [25]:

$$k_{eq} = \frac{C_o^{CO_2}}{C_w^{CO_2}} = \frac{\rho_o \omega_o^{CO_2}}{\rho_w \omega_w^{CO_2}} \quad (6)$$

k_{eq} can be obtained experimentally using the solubility data or can be obtained using an EOS. In this study, measured data are used to estimate k_{eq} as described later on.

2.3. GA Program

A Genetic Algorithm (GA) based optimization [26] has been incorporated in a program developed to automatically find the unknown parameters by history matching of real production data. The unknown parameters were K_r , p_c and MTC. The GA program was used to optimise the objective function (also called cost or misfit function). In this study, a set of coreflood experiments have been selected from the literature [2]. The recorded core production data are differential pressure across the core (DP) and total (cumulative) oil production (TOP) and accordingly the objective function (OF) that needs to be minimised, is defined as follows:

$$OF = \sum_{i=1}^n \omega_{DP} \times \left| \frac{DP_{real} - DP_{predicted}}{DP_{real}} \right|_i + \sum_{i=1}^n \omega_{TOP} \times \left| \frac{TOP_{real} - TOP_{predicted}}{TOP_{real}} \right|_i \quad (7)$$

where the subscripts of ‘real’ and ‘predicted’ are presenting real and predicted values, respectively. $||$ is the absolute value function. ω_{DP} and ω_{TOP} show the weight of DP and TOP data during the matching process. That is, a higher weight value means finer match for that class of data (i.e. DP or TOP). In this work, an equal value of one has been selected (i.e. $\omega_{DP} = \omega_{TOP} = 1$) meaning both TOP and DP data have the same importance during matching process. It should be noted that Eq. 7 is the summation of absolute relative errors of ‘n’ data points of total TOP and DP data which needs to be minimised.

3. Coreflood Experiments

The simulator has been used to simulate a set of WI and CWI coreflood experiments from the literature [2] conducted on a water-wet sandstone core fully saturated by normal decane ($n\text{-C}_{10}\text{H}_{22}$) (with well-defined fluid properties). As explained by the authors [2], the reason of not having initial water saturation (S_{wi}) was to exclude the effect of any pre-existing water which could influence the flow of the injected carbonated water and the displacement of the dissolved CO_2 within the porous medium. The rock and fluid properties are given in Tables 1 and 2, respectively. Table 2 shows that the viscosities of water and decane are similar at the test conditions and therefore, viscous fingering is not an important process here. The brine with low salinity was used during these experiments and it was mentioned that, the properties of brine were similar to fresh water at test conditions. Therefore, in this study the term of water is used rather than brine. The WI coreflood experiment had been carried out first, followed by the corresponding CWI test. Both tests had been carried out as a secondary flood with similar test conditions. The operational conditions of both WI and CWI experiments were the same and given in Table 3. Fig. 2a and Fig. 2b show total oil production (TOP) data and corresponding recovery factor (RF) of the WI experiment compared to those of CWI plotted versus injected pore volume (PV), respectively. Fig. 2a and Fig. 2b show clearly that during CWI, oil recovery has improved and also the production of secondary WI and its corresponding CWI is the same until the breakthrough point. Fig. 3 compares DP values of WI and CWI experiments. Fig. 3 shows that CWI and WI have approximately the same and small differential pressure (DP) values across the core.

4. Results and Discussions

4.1. Simulation of the WI Coreflood Experiment

The WI experiment was simulated first. The unknown K_{rw-o} and p_c curves were obtained by history matching the production data of the WI experiment using the GA-based optimizer. The optimizer was linked to the developed simulator (model) in its black-oil mode (with zero

mass transfer). In this experiment, the core had been fully saturated with decane with no initial water saturation; therefore s_{wc} was set to zero and accordingly k_{omax} to one. Therefore the unknown parameters to be obtained by GA were s_{or} , k_{wmax} , n_w , n_o , p_{ce} and λ . The initial uncertainty range of each parameter used during optimization task was selected to be consistent with typical Corey parameters obtained for real oil reservoirs[22]. Moreover, GA optimization practice was repeated two times for each experiment to make sure that a reliable answer is obtained. Fig. 4 shows the improvement of minimum and mean (average) misfit during this optimization task. The best (minimum) misfit obtained was 0.62. The optimal values of the parameters obtained are summarised in Table 4. The same s_{or} was also obtained using the material balance calculation together with the core data. Moreover, the same k_{wmax} was also obtained using the Darcy equation together with the core data. Next, the simulation was repeated using the ECLIPSE100 (E100) black-oil commercial simulator with the same Kr_{w-o} to verify the performance of the developed simulator by comparing its prediction with that of E100. Fig. 5 and Fig. 6 compare respectively the experimental TOP and DP data with those by E100 and the developed simulator (model). The misfit value of the predicted results by E100 is 0.615. The close agreement between the data clearly verifies the reliability of the developed simulator (model) and the obtained Kr_{w-o} .

4.2. Simulation of the CWI Coreflood Experiment

Simulation of the CWI experiment was carried out using the developed simulator in its compositional mode. The oil phase density(decane-CO₂ mixture) was calculated using the Peng-Robinson (PR) equation of state (EOS) tuned for the decane-CO₂ system in the literature [27]. The oil phase viscosity was interpolated from some measured data available in the literature [28]. The water phase density (water-CO₂ mixture) was interpolated from some measured data in the literature [29, 30]. The water phase viscosity was calculated using a proposed correlation in the literature based on some measured data [31]. Moreover, at test

conditions (shown in Table 3) the water-CO₂ mixture density is 1.01 (g/cm³) (based on the
 measured data, presented above) and decane-CO₂ mixture density is 0.75 (g/cm³) (using
 tuned PR EOS, mentioned above). Moreover the measured CO₂ mass fraction in decane at
 test conditions is around 65% [28] and the measured CO₂ mass fraction in the water phase is
 5 % (mentioned in Table 3). Using these values, in Eq. 6, the k_{eq} value is approximately 9.6
 for the CWI test reported here. Here, MTC included in the mass transfer term (i.e. U term)
 and also the K_r and p_c curves were unknown. The K_r and p_c curves obtained during the
 simulation of WI experiment were used. To facilitate the determination of the MTC value, a
 sensitivity analysis was performed to understand the impact of MTC on the TOP and DP
 data. Fig. 7 and Fig. 8 demonstrate that by increasing the MTC value, mainly the post
 breakthrough part of TOP data will increase as predicted by the simulator. Accordingly, it
 was tried to history match the TOP and DP data of the CWI experiment by only tuning MTC
 when K_r and p_c curves of WI test was used. First, MTC was tuned manually and after a few
 trials, the MTC value of 5E-7 (1/sec) was chosen as the optimal value. Fig. 9 and Fig. 10
 compare the TOP and DP data of the CWI test obtained from the simulator with those of the
 experiment. The misfit value based on Eq. 7 is 0.52. Later, in another practice, the GA
 optimizer was used to obtain the K_r and p_c curves and MTC simultaneously by history
 matching the production data. One goal was to investigate the hypothesis proposed that the
 K_r and p_c curves for both WI and CWI are the same. Additionally, another goal was to check
 the accuracy and the uniqueness of the MTC value which was obtained manually. Table 5
 shows the optimal values obtained during this optimization experiment compared to those
 obtained by manual tuning. It shows that GA has resulted in a similar MTC value as that
 obtained manually and also has given a similar K_r and p_c curves as that obtained for the WI
 experiment. Next, the simulation results were analysed to better understand the mechanisms
 contributing to the additional oil recovery of CWI. As it was mentioned before, the main

mechanisms are possibly, oil swelling, viscosity and IFT reduction. Here the oil viscosity reduction cannot be a noticeable mechanism because the viscosity value of decane (oil sample) is already small and the resultant change is not significant. This was checked by comparing the TOP and DP data predicted by the developed simulator when the viscosity of decane-CO₂ mixture was set to be constant in the model and the same as pure decane viscosity, and when allowed to change based on the measured data (mentioned above). It was observed that the effect of reduction of decane viscosity by CO₂ is a marginal reduction in the DP after breakthrough point. It should be noted that for heavy and viscous oils, the viscosity reduction can be important as the level of viscosity reduction is high [8] but not here. Moreover, IFT reduction also cannot be a pronounced mechanism here. If a high level of change in IFT has occurred during this CWI, a different relative permeability curve compared to that obtained for WI is expected to be applied while the same K_r was used here. Therefore, it can be inferred that here, the swelling of oil as a result of CO₂ transfer is possibly the main mechanism resulting in additional oil recovery during CWI. It should be noted that using experimental data and the material balance calculation, the residual oil saturation at end of the CWI experiment is estimated as 27%. This value was not adjusted in the relative permeability curve during simulation of the CWI test. That is, $s_{or}=31\%$ from the WI test was not changed and the production data of CWI could be matched. Using a manual calculation, it can be estimated that the oil has around 15% swelling (i.e. $31/27=1.15$), which is captured by MTC. In another sensitivity, the developed simulator was used to estimate the amount of swelling in the residual oil. To do that, the value of the initial oil saturation in the simulator was set to the residual oil saturation value obtained at the end of the WI test, i.e., $s_{oi}=s_{or}=0.31$. Fig. 11 shows the RF profile as predicted by the developed simulator. It shows that at the end of this simulation a RF of around 17% has been obtained. This RF suggests a swelling factor

of around 1.17 (equivalent to 17% swelling), which is consistent with the 15% swelling presented above.

4.3. Compositional Simulation of the CWI Using ECLIPSE300 (E300)

E300 compositional commercial simulator was also used to simulate CWI. The goal was to compare the performance of the developed simulator with E300 simulator which works based on the instantaneous equilibrium assumption. The tuned PR EOS was also used here. Fig. 12,13 and 14 show respectively the RF, DP and total CO₂ production (TCO₂P) predicted by E300 compared to those obtained from the developed simulator. The misfit value of results predicted by the developed simulator is 0.52 whilst the misfit value of those predicted by E300 is 1.1. Fig. 12 shows a higher oil production predicted by E300 compared to that predicted by the developed simulator. Fig. 14 shows that the CO₂ production predicted by the developed simulator is quicker than that predicted by the E300. It worth mentioning that, no CO₂ production data were reported for this experiment, however for another similar experiment with quantitative CO₂ production data reported in the literature [2], the breakthrough time of CO₂ and water are very close. Comparing Fig. 14 and Fig. 13, it can be observed that the model has predicted that the breakthrough point of water and CO₂ are almost the same (it has happened approximately after 0.65 PV injection) however ECLIPSE has predicted a delayed CO₂ breakthrough. It can be explained that, in E300, CO₂ is allowed to be quickly transferred into the oil phase resulting in higher CO₂ concentration in the oil phase while the developed simulator assumes that the CO₂ transfer is a slow process. Therefore as predicted by the developed simulator, CO₂ can be produced quickly via water stream (the same breakthrough points of water and CO₂). To explain this, Fig. 15 shows the CO₂ concentration in the oil phase through the core after 0.5 injected pore volume predicted by the simulator compared to that predicted by the E300. A lower CO₂ concentration in the oil phase (consequently, a higher concentration in the water phase) is predicted by the

developed simulator. In another experiment, the MTC was increased during simulation to check if the predictions of the developed simulator and E300 can become closer as at high MTC values, the time needed to reach the equilibrium state will be reduced. Fig. 16 shows that the predictions of E300 and the developed simulators have overlapped when the MTC value is increased to $15\text{E-}7$ 1/sec, three times higher than the optimal value (i.e., $5\text{E-}7$, mentioned before). In other words, Fig. 16 shows that if mass transfer was faster, the system would have reached the equilibrium state and the prediction of model and ECLIPSE would be similar. However in the coreflood experiment studied here, this was not the case as the obtained MTC was three times smaller than of the MTC needed for the equilibrium state.

4.4. CO_2 Storage

During CWI, no free CO_2 is in the system, i.e. CO_2 is dissolved in water and oil phases. This will mitigate the risk of CO_2 leakage as CO_2 is more stable and less mobile when it is in the dissolved state. Fig. 17 shows the total CO_2 stored (TCO2S) as a percentage of total CO_2 injected (TCO2I) (i.e., $\frac{\text{TCO2S}}{\text{TCO2I}} \times 100$) as predicted by the simulator. It can be seen that before breakthrough of CO_2 at the core outlet, all amount of the injected CO_2 is stored (i.e. 100% storage). However, when the CO_2 production starts, the storage profile starts declining gradually. Moreover, at the end of the experiment, approximately 44% of injected CO_2 has been stored in the core as a dissolved fluid in the residual oil (trapped oil) and remaining water. This value is consistent with the values reported in the literature [2].

5. Summary and Conclusions

In this work, a kinetic based model was developed to study CWI coreflood experiments. The developed model was used to simulate a WI and the corresponding CWI coreflood experiment reported in the literature. WI was simulated first and next the CWI experiment was simulated. The same K_r and p_c curves were used for them. The CWI experiment was

history matched by tuning the mass transfer coefficient (MTC). It was discussed that the oil swelling is the main oil recovery mechanism in this experiment. The CWI experiment was also simulated using E300. E300 predicted higher oil recovery and lower and delayed CO₂ production compared to those predicted by the developed simulator. The simulator also predicted the CO₂ storage profile during the CWI experiment. The results presented here can be used to gain a better understanding of the mechanisms contributing during the CWI process.

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Fig. 1. Swelling rate during CWI compared to shrinkage rate during subsequent WI [4].

Fig. 2a. Comparison of total oil production (TOP) data of the WI and CWI experiments.

Fig. 2b. Comparison of recovery factor (RF) of the WI and CWI experiments.

Fig. 3. Comparison of differential pressure (DP) data of the WI and CWI experiments.

Fig. 4. Evolution of minimum and mean of misfits during the GA optimization.

Fig. 5. History matched TOP data by the developed simulator (model) compared to those predicted by E100 simulator and experimental values, WI experiment.

Fig. 6. History matched DP data by the developed simulator (model) compared to those predicted by E100 simulator and experimental values, WI experiment.

Fig. 7. Effect of MTC on TOP data.

Fig. 8. Effect of MTC on DP data.

Fig. 9. History matched TOP data by the developed simulator compared to experimental values, CWI experiment.

Fig. 10. History matched DP data by the developed simulator compared to experimental values, CWI experiment.

Fig. 11. RF when $s_{oi}=s_{or}=0.31$ as predicted by the developed simulator.

Fig. 12. RF predicted by E300 simulator compared to the experimental values and those predicted by the developed simulator, CWI experiment.

Fig. 13. DP data predicted by E300 simulator compared to the experimental values and those predicted by the developed simulator, CWI experiment.

Fig. 14. TCO2P data predicted by the developed simulator compared to those predicted by E300, CWI experiment.

Fig. 15. CO₂ concentration in oil phase through the core after 0.5 injected PV predicted by the developed simulator and E300.

Fig. 16. TOP data predicted by E300 simulator compared to the experimental values and those predicted by the developed simulator at large MTC value of 15E-7 1/sec, CWI experiment.

Fig. 17. $\left(\frac{TCO2S}{TCO2I} \times 100\right)$ versus injected PV of carbonated water predicted by the simulator, CWI experiment.

Table 1

Core properties [2].

Core	Length (cm)	Diameter (cm)	Porosity (fraction)	Pore Volume(cm ³)	Permeability (mD)
water-wet Clashach sandstone	33.2	4.986	0.19	123.16	1300

Table 2

Fluid properties [2, 32].

Fluid	Viscosity(cP) (Test conditions) (136.1 atm, 38 °C)	Density (g/cm ³) (Test conditions) (136.1 atm, 38 °C)	Density (g/cm ³) Standard conditions (1 atm, 20 °C)
decane	0.83	0.730	0.727
water	0.66	0.995	0.995
CO ₂	0.067	0.775	0.00184

Table 3

The operational conditions of the coreflood experiments [2].

Injection rate (cm ³ /hr)	20
CO ₂ mass fraction in injected CW	5 %
Salinity of injected CW (ppm)	10000
Outlet pressure (atm)	136.1
Initial pressure (atm)	136.1
Initial water saturation	0
Temperature (°C)	38

Table 4

Optimal Corey and Brooks-Corey coefficients of water-oil relative permeability and capillary pressure curves obtained by the GA optimizer linked to the developed simulator, WI experiment.

Parameters	n _w	n _o	k _{wmax}	s _{or}	p _{ce} (atm)	λ
Optimal values	2.5	2.25	0.14	0.31	0.04	7.7

Table 5

511 Optimal values of Corey parameters and MTC, obtained using developed simulator linked to the GA-
 512 based optimizer compared to manual tuning,CWI experiment.

	n_w	n_o	k_{wmax}	s_{or}	p_{ce}(atm)	λ	MTC (1/sec)
GA	2.35	2.25	0.14	0.3	0.03	7.5	4.9 E-7
Manual tuning	2.5	2.25	0.14	0.31	0.04	7.7	5E-7

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