



Brine Salinity: A Deciding Factor for Carbon dioxide Dissolution and Trapping during Geological Sequestration

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Abstract

Adequate geological storage of carbon dioxide in saline aquifers is a function of several factors that requires understanding and examination. Previous works have argue that solubility of carbon dioxide in brine decreases as the salinity of the brine increases, but it is unclear in the literature the impact of salinity on carbon dioxide (CO₂) trapping during sequestration. This work adopt a simulation based approach to determine CO₂ dissolution and trapping at different salinities. A dataset was written and validated with CMG's greenhouse gases simulator and the thermodynamics properties calculation carried out with Peng-Robinson equation of state. Four sensitivity analyses was conducted with brines of no salinity (pure water), salinity of 100000ppm, 200000ppm and 300000ppm and model outputs compared for CO₂ sequestration. The result shows that CO₂ solubilised in water with zero level salinity, and a lower gas cap size was formed at the top of the structure. Later, gas cap size increases as the salinity level increases at the top of the structure. Also, the moles soluble in water decreases as the salinity level increases with the least moles for zero water salinity. Alternatively to the moles solubilised, the number of moles of CO₂ trapped increases with the salinity level. CO₂ storage in deep saline aquifers is the best storage techniques but its injection into aquifer of high salinity reduced its solubility.

Keywords: Brine Salinity, CO₂ Dissolved, CO₂ Trapped, Sequestration, Solubilized.

INTRODUCTION

Carbon dioxide (CO₂) having its main source from burning of fossil fuels has continuously increase concentration of greenhouse gas in the atmosphere and require control to reduce global warming and environmental issues (Xie and Economides, 2009; Ahmadi *et al.*, 2016). So many approach have been studied and investigated to reduce the emission of CO₂ to the atmosphere so as to control global warming to an extent (Mathieu, 2006). Among these notable approach and measures, CO₂ sequestration has prove to be a promising strategy to reduce carbon emissions. CO₂ sequestration is the only storage method that reduces the concentration of CO₂ in the atmosphere without affecting the fossil fuels consumption level, and it is becoming popular and the most recommended for safety of the environment (Leung *et al.*, 2014). Geological sequestration entails storing captured CO₂ in deep geologic formations such as saline aquifers, and basalt formations (Shukla *et al.*, 2010; Otheim *et al.*, 2011).

CO₂ sequestration has been quantified as dependent on the rate of CO₂ dissolution into brines and their migration dynamics. The accumulation of CO₂ is a function of molecular diffusion before it dissolves in to formation brine. Consequently, the density of the brine increases with CO₂ dissolution, resulting to a phase segregation of the denser brine, and eventually leads to natural convective mixing driven by the density distinction from formation brines (Nordbotten *et al.*, 2005).

Previous works have shown that convective mixing is affected not only by a porous medium's porosity, permeability, and thickness, but also by mineralization of brine and its initial density (Agartan *et al.*, 2015; Taheri *et al.*, 2021; Amarasinghe *et al.*, 2021; Faisal *et al.*, 2003).

The underlying factors that influenced carbon dioxide trapping and dissolution is still controversial and not fully explored even with few experimental and numerically analysis on injection and transport of CO₂ in saline aquifers conditions (Chalraud *et al.*, 2009, Alkan *et al.*, 2010, Al-Khdheawi *et al.*, 2018;). Another study shows that increase in relative permeability hysteresis increases the CO₂ trapped (Amadichuku *et al.*, 2023). Past works have opined that solubility of CO₂ in brine decreases as the salinity of the brine increases (Yan *et al.*, 2011; De Silva *et al.*, 2015; Zhao *et al.*, 2015; Ahmadi and Chapoy, 2018). However, it is not yet clear how salinity increases or decreases carbon dioxide trapping and dissolution during sequestration.

Therefore, this work investigates the influenced of brine salinity on carbon dioxide trapping and dissolution during saline aquifer storage.

METHODOLOGY

Computer Modelling Group (CMG) simulator and Grid properties, fluid model creation, brine properties, water and gas relative permeability, and model initiation data presented in Table 1 to Table 6 were used in this work.

Table 1. Grid properties data

Properties	Value
Grid Top	1200m
Grid thickness	5m
Permeability (I, J and K)	100 millidarcies
Porosity	0.12
Rock compressibility	5.5e-7 per kPa
Reference pressure for rock compressibility	11800 kPa

Table 2. Data for GEM fluid model creation

Component	Mole fraction
CH ₄	0.999
CO ₂	0.001
Reservoir temperature for GEM fluid model	50°C

Table 3. Brine properties

Property	Value
Water density	1020kg/m ³
Water compressibility	4.35e-7 per psi
Reference pressure	11800kPa

Table 4. Water relative permeability data

Sw	krw	krow
0.2	0	1
0.2899	0.0022	0.6769
0.3778	0.018	0.4153
0.4667	0.0607	0.2178
0.5558	0.1438	0.0835
0.6444	0.2809	0.0123
0.7	0.4089	0
0.7333	0.4855	0
0.8222	0.7709	0
0.9111	0.95	0
1	0.9999	0

Table 5. Gas relative permeability data

Sg	kr _g	kro _g
0.0006	0	1
0.05	0	0.88
0.0889	0.001	0.7023
0.1778	0.01	0.4705
0.2667	0.03	0.2963
0.3556	0.05	0.1715
0.4444	0.1	0.0878
0.5333	0.2	0.037
0.6222	0.35	0.011
0.65	0.39	0
0.7111	0.56	0
0.8	0.9999	0

Table 6. Model initialization data

Properties	Value
Temperature	50°C
Reference pressure	11800 kPa
Datum depth	1200m
Water gas contact	1150m
CO ₂ fraction	0.001
CH ₄	0.999

Builder was used in writing the dataset and validated with GEM. A two-dimensional (2D) homogeneous aquifer model of dimensions 100x1x20 (2000 grid blocks) was built with the data and the model was populated with petrophysical, grid and rock properties using the data in Table 1 and Table 2. Peng-Robinson 1978 equation of state was selected as for thermodynamic properties calculation. The CH₄ component was treated as the trace component. Li-Nghiem’s model was used for the calculation of Henry’s constant for gas solubility in brine. The created fluid model was imported into the component section of GEM data file. Data in Table 3 were used in defining the brine properties. Relative permeability data in Table 4 and Table 5 were used to define the relative

permeability curves and the model was initialized using the data in Table 6. Water-Gas contact was set at 1150m above the reference depth which gave a model fully saturated with brine. Gas cap was initialized with supercritical CO₂ fraction of 0.001 and CH₄ fraction of 0.999 respectively. An injector well ‘CO₂-INJECTOR’ was completed in three layers at the bottom of the model at 1298m, 1299m and 1300m. The injector was shut-in after 5years of CO₂ injection, with only natural gradient driving the flow for 195years. After the base model (zero salinity level), three models with similar rock and fluid characteristics were simulated for different salinity of 100000ppm, 200000ppm, and 300000ppm. The simulation workflow is shown in Figure 1.

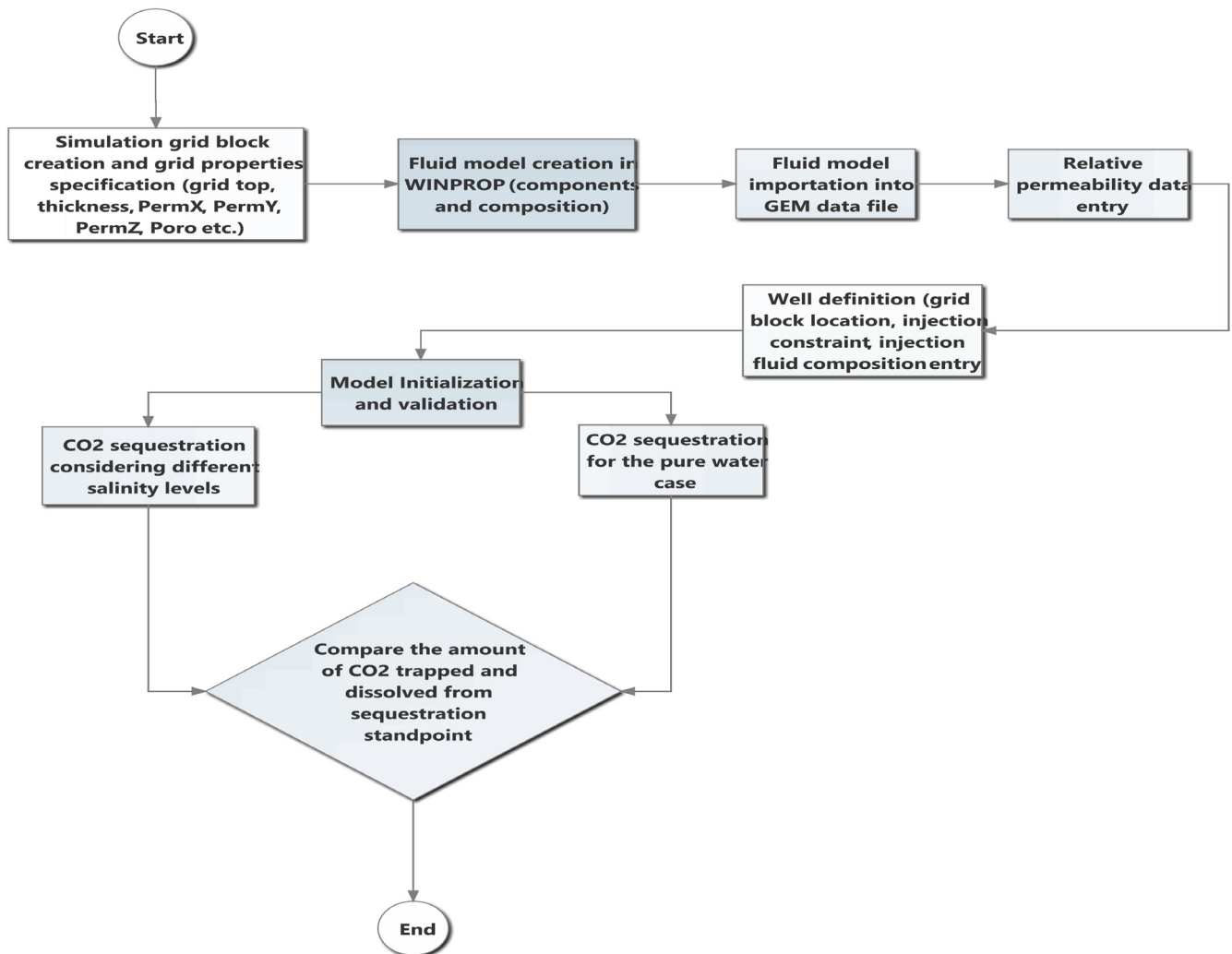


Figure 1. Simulation workflow

RESULTS AND DISCUSSION

CO₂ Dissolved and Trapped in Zero Salinity Level

The spatial distribution of CO₂ plume in saline aquifer for the base model is shown in figure 2. The base model shows the injection of CO₂ for 5years and the migration of the CO₂ plume during the next 195 years in aquifer with zero water salinity. The injected CO₂ migrated laterally during injection under the influence of pressure provided by the injection well. Post-injection, the lateral expansion of the plume ceased and CO₂ migrate upward due to its lighter density compare to formation water. There was a greater amount of CO₂ at the bottom of the structure due to the onset of solubility trapping mechanism. A gas cap of size 294.945m was formed at the top of the structure with CO2 soluble in zero salinity level



Figure 2. CO₂ spatial distribution for zero water salinity (pure water)

The amount of CO₂ trapped structurally and dissolved in brine during the injection period and post-injection period for zero water salinity level is presented in figure 3. During the injection period, 17631590moles of CO₂ were trapped structurally. For the Post-injection phase, the amount of CO₂ trapped structurally increases slightly and later decline after which it was constant at 16853558moles due to the onset of CO₂ solubility trapping. During the injection phase, 17991720moles of CO₂ was soluble in water while during the post-injection period, CO₂ solubility trapping gave 38286492moles of CO₂ in water.

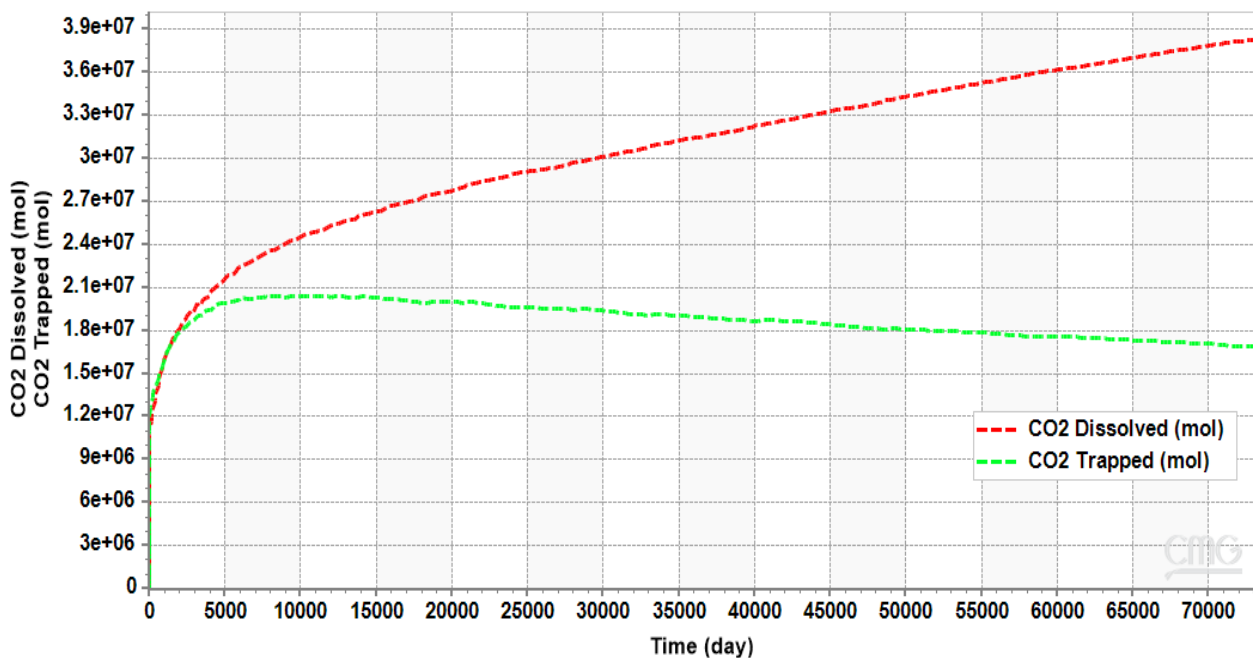


Figure 3. CO₂ trapped and dissolved for zero water salinity level (pure water)

CO₂ Dissolved and Trapped in 100000ppm Water

The 2D visualization of CO₂ plume migration in saline aquifer of water salinity 100000ppm is shown in figure 4. The model simulates the injection of CO₂ for 5years and its migration under natural buoyancy during the next 195years. The injected CO₂ migrate laterally during the injection phase under the influence of pressure provided by the injection well. After 195years, there was formation of gas cap of size 384.4325m in length and mobile supercritical CO₂ at the top of the formation with a saturation of 0.99.

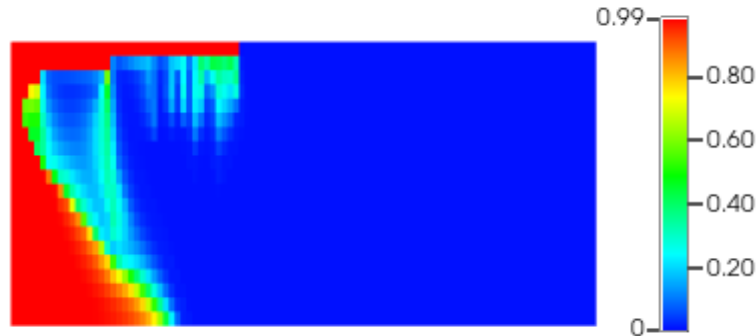


Figure 4. CO₂ spatial distribution for water salinity of 100000ppm

The amount of CO₂ trapped structurally during the injection period and post-injection period for 100000ppm water salinity level is presented in figure 5. During the injection period, 11132027 moles of CO₂ were trapped structurally while for the Post-injection phase, the amount of CO₂ trapped structurally increase slightly before maintaining 10693296 moles due to the onset of CO₂ solubility trapping. During the injection phase, 7566161.5 moles of CO₂ was soluble in water and 16974034 moles of CO₂ during the post-injection period.

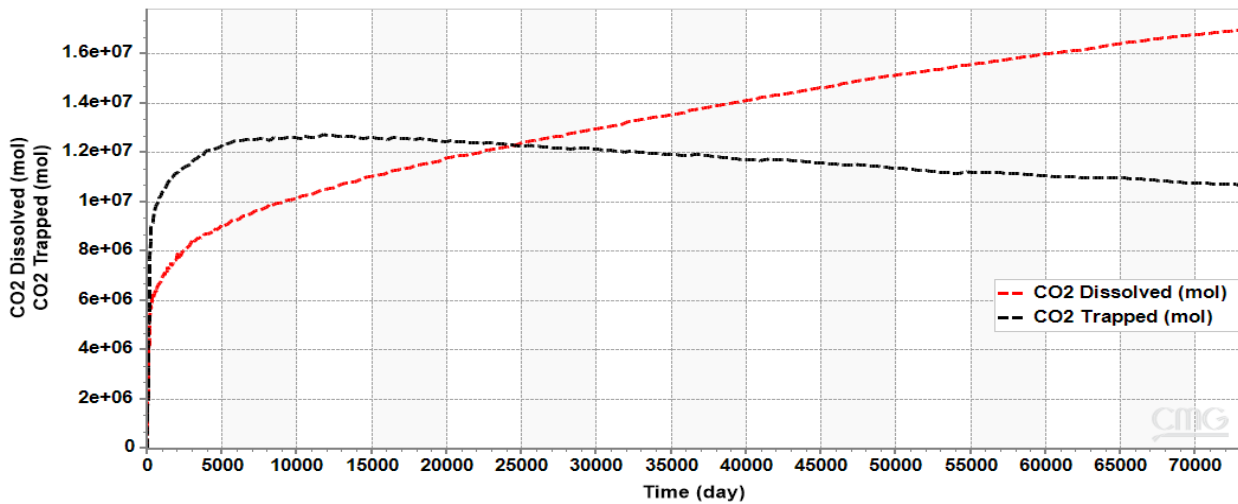


Figure 5. CO₂ trapped and dissolved for 100000ppm water salinity level

CO₂ Dissolved and Trapped in 200000ppm Water

Figure 6 shows the 2D visualization of CO₂ plume migration in saline aquifer of water salinity 200000ppm. After 195 years, there was a formation of gas cap of mobile supercritical CO₂ at the top of the formation with a saturation of 0.99. With the CO₂ injector shut-in after 5 years and CO₂ plume migration occurring under natural buoyancy during 195 years, a gas cap of size 455.5605m was formed at the top of the structure.

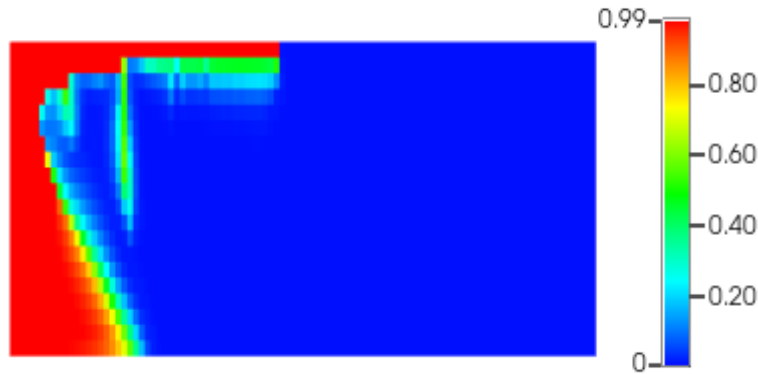


Figure 6. CO₂ spatial distribution for 200000ppm water salinity

The amount of CO₂ trapped for 200000ppm water salinity level is shown in figure 7. There was an increase in the amount of CO₂ trapped because of the influence of pressure provided by the injection well. For the Post-injection period, the amount of CO₂ trapped structurally reduced followed by the onset of solubility. For the injection period, 11587398 moles of CO₂ were trapped structurally. The amount of CO₂ trapped structurally increases before maintaining 13000772 moles due to the

onset of CO₂ solubility for post injection phase. During the injection phase, 4560236moles of CO₂ was soluble in brine and 9807470moles of CO₂ in water for the post injection period.

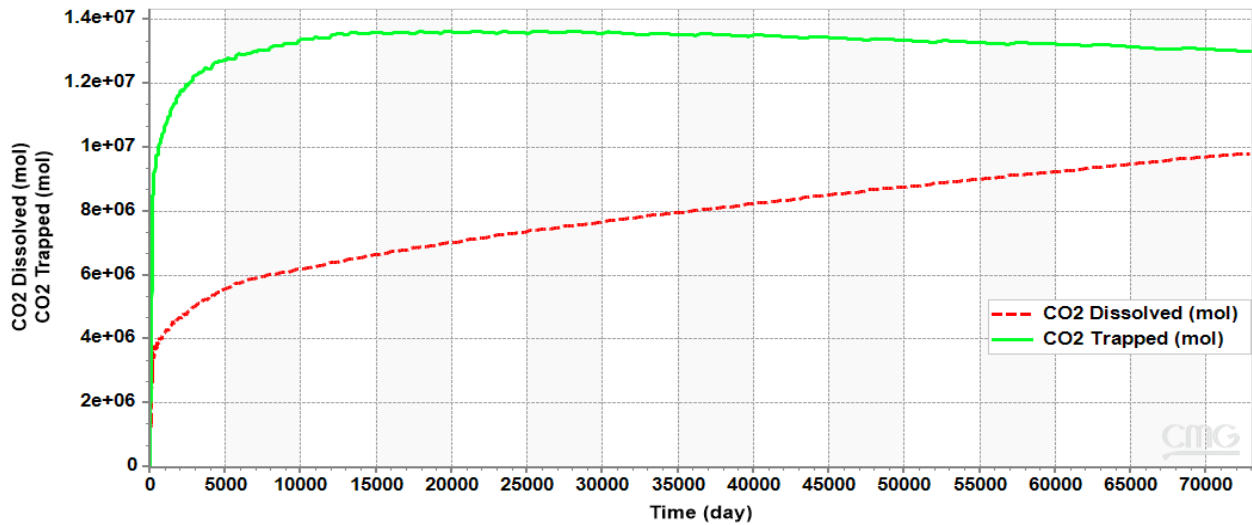


Figure 7. CO₂ dissolved and trapped for 200000ppm water salinity

CO₂ Dissolved and Trapped in 300000ppm Water

Figure 8 shows the CO₂ plume migration in saline aquifer of water salinity 300000ppm. With the CO₂ injector shut-in after 5years and CO₂ plume migration occurring under natural buoyancy during the next 195years, a gas cap of mobile supercritical CO₂ of size 482.2156m was formed at the top of the structure.



Figure 8. CO₂ spatial distribution for 300000ppm water salinity level

The amount of CO₂ trapped structurally during the injection period and post-injection period for 300000ppm water salinity level is presented in figure 9. 11855227moles of CO₂ was trapped structurally in the injection phase and 15193304 moles for the post injection phase due to the onset of CO₂ solubility trapping. During the injection phase, 2364830.5moles of CO₂ was soluble in water while in the post-injection period, 4788070.5moles of CO₂ was soluble in water.

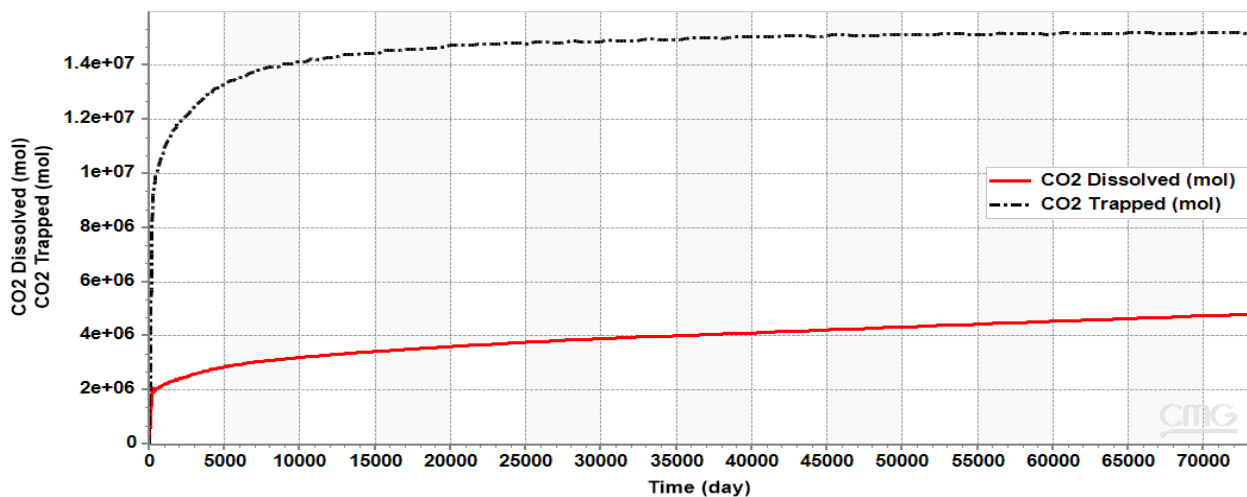


Figure 9. CO₂ trapped and dissolved in water for 300000ppm water salinity level

Comparison of CO₂ Dissolved in Brine and Pure Water

The amount of CO₂ dissolved in brine of different salinities with respect to time is presented in figure 10. The amount of CO₂ dissolved decreases as the brine salinity increases.

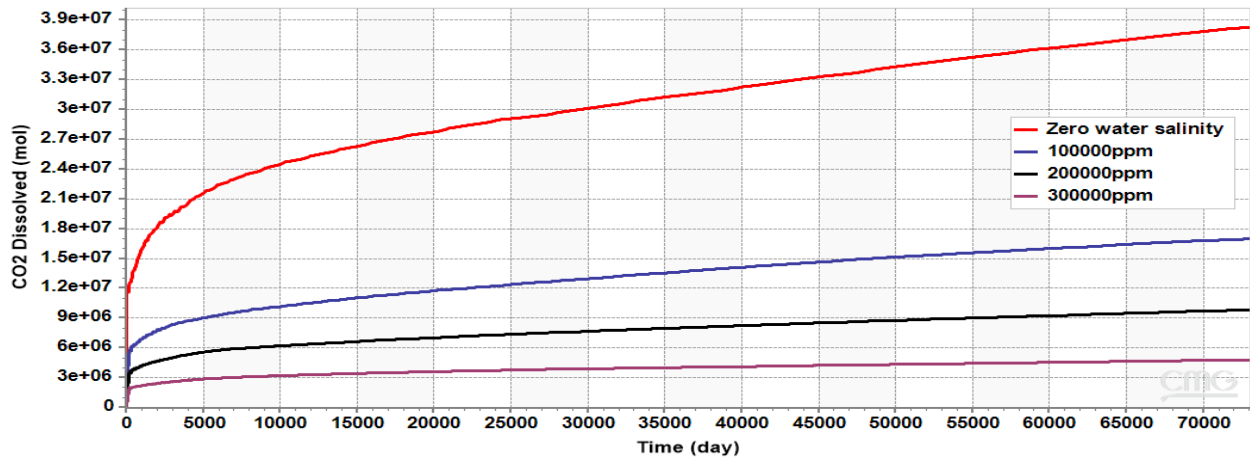


Figure 10. Comparison of the amount of CO₂ dissolved for all water salinity levels

Figure 11 shows a direct comparison of the amount of CO₂ dissolved in pure water and brines of different salinities. There was a decrease in the amount of dissolved CO₂ from 38286492 moles to 16974034 moles when the water salinity was increased from zero to 100000ppm. For water salinity of 100000ppm, 200000ppm and 300000ppm, the amount of CO₂ dissolved decreases as the water salinity increases. This occurs due to the reduction in gas solubility as the water salinity increases and the formation of a high saturation of mobile CO₂ at the top of the formation. For water salinity levels of 100000ppm, 200000ppm and 300000ppm, result shows that 16974034 moles, 9807470 moles and 4788070.5 moles were solubilised in water.

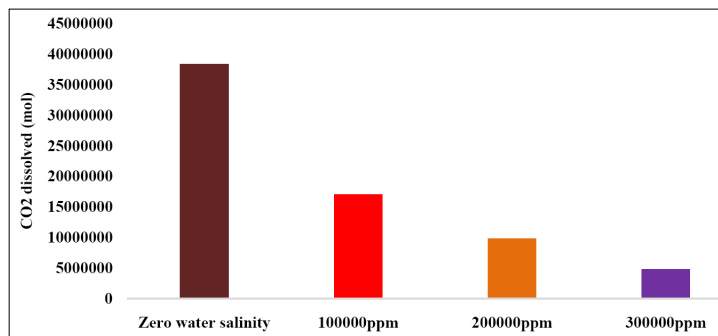


Figure 11. Comparison of CO₂ dissolution for different water salinity levels

Comparison of CO₂ Trapped in Brine and Pure Water

The amount of CO₂ trapped in formation with brine of different salinities with respect to time is shown in figure 12. The results obtained indicated that the amount of CO₂ trapped structurally increases as the water salinity increases because of the reduced CO₂ solubility as a result of high-water salinities.

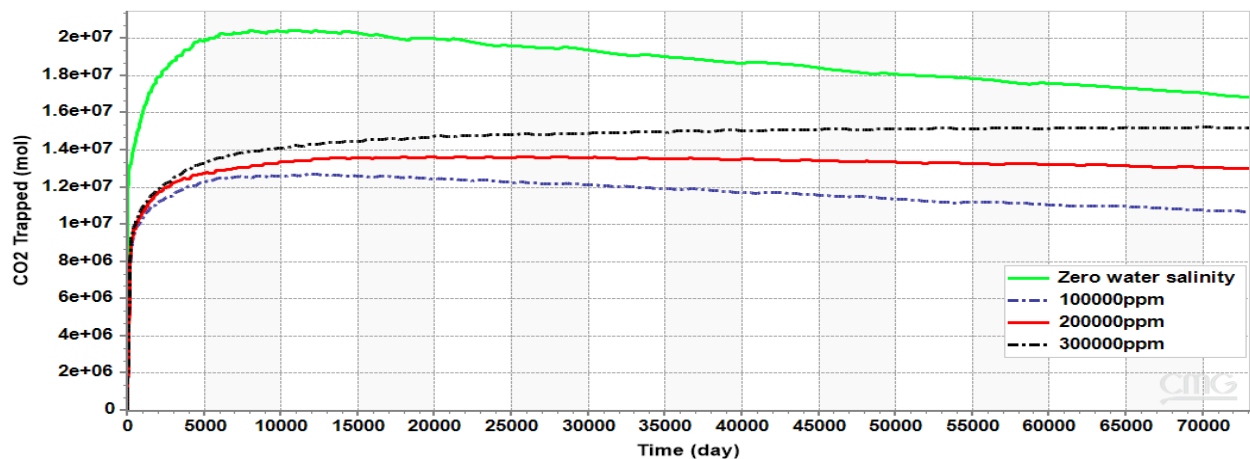


Figure 12. Comparison of the amount of CO₂ trapped for all water salinity levels

Figure 13 shows the amount of CO₂ trapped for zero water salinity level, 100000ppm, 200000ppm and 300000ppm respectively. The results obtained shows an initial decrease in the amount of CO₂ trapped from 16853558moles to 10693296moles when the water salinity was increased from zero to 100000ppm. For water salinity of 100000ppm, 200000ppm and 300000ppm, the amount of CO₂ trapped increases as the water salinity increases. This occurs due to the reduction in gas solubility as the water salinity increases and the formation of a high saturation of mobile CO₂ at the top of the formation. For water salinity levels of 100000ppm, 200000ppm and 300000ppm respectively, result shows that 10693296moles, 13000772moles and 15193304moles were respectively trapped.

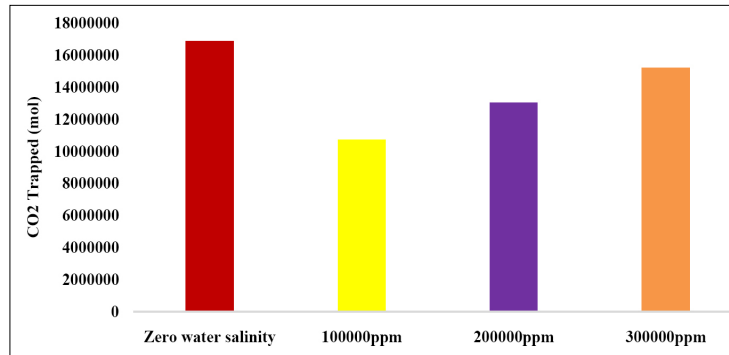


Figure 13. Comparison of CO₂ trapped for different water salinity levels

CONCLUSION

This work evaluates the influence of brine salinity at different concentration on CO₂ dissolution and trapping during sequestration. A simulation based approach was used and sensitivity done for different salinity level and outputs compared with the following conclusions drawn:

- The amount of CO₂ dissolved decreases with increase in brine salinity concentration.
- The amount of CO₂ trapped structurally increases with brine salinity increase.
- The gas cap size (length) increases with increase in water salinity concentration

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