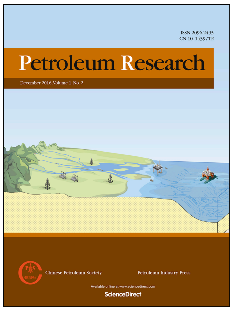
Evaluation of enhancing CO2 sequestration by post-brine injection under different scenarios using the E300 compositional simulator

Mohajeri, M. & Shariatipour, S. M.

DOI 10.1016/j.ptlrs.2019.08.001
ISSN 2096-2495

Publisher: Elsevier

Journal Pre-proof



Evaluation of enhancing CO_2 sequestration by post-brine injection under different scenarios using the E300 compositional simulator

Mahdi Mohajeri, Seyed Shariatipour

PII: S2096-2495(19)30031-6

DOI: https://doi.org/10.1016/j.ptlrs.2019.08.001

Reference: PTLRS 92

To appear in: *Petroleum Research*

Received Date: 4 May 2019

Revised Date: 26 August 2019

Accepted Date: 27 August 2019

Please cite this article as: Mohajeri, M., Shariatipour, S., Evaluation of enhancing CO_2 sequestration by post-brine injection under different scenarios using the E300 compositional simulator, *Petroleum Research* (2019), doi: https://doi.org/10.1016/j.ptlrs.2019.08.001.

Evaluation of Enhancing CO_2 Sequestration by Brine Injection under Different Scenarios Using the E300 Compositional Simulator

Mahdi Mohajeri [a], **Seyed Shariatipour** [a]

[a] **School of Energy, Construction and Environment, Coventry University, United Kingdom**

Evaluation of Enhancing CO_2 Sequestration by Post-Brine Injection under Different Scenarios Using the E300 Compositional Simulator

ABSTRACT

To accelerate the CO_2 trapping in geological storage sites, several injection strategies have been proposed by researchers yet. However, the question remains unanswered as to which one of these injection strategies is the most efficient in terms of immobilizing CO_2 and most importantly, how these strategies might be improved. In this paper, we attempt to simulate a typical geological CO_2 storage scheme in an aquifer using an E300 compositional reservoir simulator and subsequently investigate and compare the impact of various injection strategies on CO_2 immobilizing efficiency. Secondly, the impact of adding a short period of post-brine injection on various strategies is newly investigated.

Our results reveal that using a relatively short period of post-brine injection can significantly improve total CO_2 trapping efficiency in all the strategies. In general, by using post injection of brine, more CO_2 is spread out through the aquifer and ,as a consequence, by increasing the interfacial area of the CO_2 plume, the amount of dissolution as a result of mass transfer increases significantly. Moreover, the effect of convection can become stronger in the case of post-brine injection creating a stronger density instability and thus a more rapid initiation of convection. Furthermore, when brine is injected into the system, CO_2 is displaced laterally away from the well which results in a forced imbibition process by injected brine and thereby enhancing the capillary trapping efficiency. In particular, the post-injection of brine has other effects in horizontal injection and simultaneous CO_2/brine injection using different intervals. In this regard, post-brine injection creates a stronger downward pressure gradient that counters the tendency of the CO_2 plume to rise and therefore retards the CO_2 in reaching the top of the aquifer and increases the time that the CO_2 can be in contact with the fresh formation brine accordingly.

We envisage that the method could enhance the total trapping efficiency of CO_2 from 26%, 30.8%, 39.8% and 59.1% to 47.7 %, 44.2 %, 62% and 63.9%, when post-brine injection was added into

different strategies of CO_2 continuous injection, simultaneous injection of CO_2 / brine in the same and different intervals and a horizontal system, respectively. However, our findings show that the effectiveness of post-brine injection may be reduced in high vertical permeability values and in this respect, capillary trapping can be more affected by vertical permeability variation. Furthermore, the results show that selection of the rate and duration of post-brine injection can have considerable effects on total CO_2 trapping efficiency.

Key words: CO_2 Storage, Brine Injection, Injection Strategies, Capillary Trapping, Dissolution Trapping, CO_2 Trapping, CO_2 Sequestration

1. Introduction

Global warming is considered as one of the most significant environmental issues facing society (*IPCC, 2005*). The temperature rise is mainly as a result of the 'greenhouse' effect in which CO_2 plays an important role. There are some novel technologies promoted to help in reducing the effect of CO_2 emission on the environment. The most radical is a complete ban on fossil fuel combustion. One more palatable option is carbon capture and storage (CCS) which is best utilized in major stationary sources such as utility boilers for power production or industrial plants. In the CCS process, CO_2, along with some potential impurities such as acidic gas, is separated from the exhaust gases of a plant. The CO_2 is then compressed to a liquid and transported via tankers or a pipeline to the field in which it is meant to be injected in an underground geological storage (*IPCC, 2005*). The geological CO_2 storage was first proposed in 1970 (*Halloway and Davage, 1993*). Nonetheless, extended research into CCS started in early 1990's.

Promising potential geological storage sites for CO_2 include depleted oil or gas reservoirs, deep saline aquifers and coal beds. Among these, deep saline aquifers have been mainly considered as a primary geological solution for CO_2 storage. These geological storage formations consist of a permeable porous media under high temperature and pressure. Generally, the CO_2 is injected as a supercritical fluid (Ennis-King and Paterson, 2002). However, the injected CO_2 is less dense than the formation brine leading to the gas migrating to the top of the site as a result of buoyancy forces where it eventually accumulates. Given the life span of a CCS initiative is hundreds of thousands of years, it is essential that the selected location has the necessary morphology to prevent the CO_2 from escaping. Therefore, a geological storage site must contain a sealing cap rock that is capable of providing a vertical barrier through a geological seal.

Four trapping mechanisms have been identified in the underground storage of CO_2 that can prevent the gas from escaping and secure its long-term storage. These mechanism are as follows: structural trapping (Sealing Cap Rock), capillary trapping, dissolution (including diffusion and convective mixing) and mineral trapping.

It is believed that unlike mineral trapping, which occurs very slowly, capillary trapping and dissolution are the most significant and fastest means for long duration CO_2 sequestration. In the following, these two mechanisms are briefly explained.

Capillary or residual trapping is an important mechanism for trapping CO_2. The idea is to take advantage of the capillary effects to trap CO_2 as an immobile phase. In other words, this trapping mechanism is induced when CO_2 is injected near the bottom of the aquifer and the CO_2 bubble rises to the top of the aquifer due to buoyancy. Once CO_2 injection ends, the fluid displacement leading to residual saturations depends on the absolute and relative permeabilities, hysteresis, buoyancy forces, the dip of the aquifer, the natural background flow gradient, and the magnitude of the residual saturation (*Kumar et al., 2005*). Spiteri *et al.* (2005) provided a comprehensive summary of several capillary gas trapping models. The classical Land's model (Land, 1968), however, is widely used in simulation processes. This trapping mechanism has been recognized as the most rapid method to trap CO_2 with time scales in the order of years to decades (*Ennis-King and Paterson,2002; Kumar et. al., 2005; Obi and Blunt, 2006; Juanes et al., 2007; Qi et al., 2007*).

On the other hand, CO_2 dissolution is defined as dissolution of CO_2 into brine as a result of convective mixing and molecular diffusion (*Riaz et al., 2006*). Dissolution of CO_2 into brine is rapid, but the overall rate of mass transfer depends on contact between the phases. This is a complicated function of time, especially after injection stops, controlled by the same parameters as the post injection fluid displacement (*Kumar et al. 2005*). In this respect, the model presented by Spycher *et al.* (2003) is widely used to calculate the CO_2 dissolution in brine. They studied the behaviour of a mixture of H_2O-CO_2 at the temperatures between 12–100 °C and pressures up to 600 bar.

However, one of the main concerns in any CO_2 storage process is the potential risk of CO_2 leakage through sealing cap rock. Any cap rock has a sealing capacity making it able to resist the short-term excess injection pressure, and the long-term buoyancy pressure. However, this sealing capacity may degrade in time for several reasons (*Espinoza and Santamarina, 2017*). Therefore, in any storage process, the main objective is to immobilize the CO_2 as soon as applicable.

Most of the previous simulation studies in the literature are based on injection strategies where a continuous CO_2 stream is injected into the aquifer for a defined period of time. Subsequently, the injection wells are shut-in for different periods of time and then the effects of different parameters on CO_2 sequestration performance are evaluated. In this process, the amount of CO_2 trapped and dissolved in the brine can be determined using commercial mathematical models (*Kumar et al., 2005; Juanes et al. 2006; Ide et al., 2007*). However, to accelerate the CO_2 trapping process and minimise the amount of mobile CO_2 beneath the cap rock, the concept of brine injection has recently gained a great deal of attention (*Juanes et al., 2006; Leonenko et al. 2006; Anchliya et al., 2012; Nghiem et al., 2009; Qi et al., 2008; Burton and Bryant 2009; Eke et al., 2011; Zirrahi et al., 2013; Shariatipour et al., 2016*). This referenced work has demonstrated that brine injection in an aquifer can not only considerably accelerate the dissolution of CO_2 in an aquifer, but also enhance the CO_2 capillary trapping efficiency. Therefore, the time-scale of CO_2 immobilisation within the aquifer can decrease significantly and, as a consequence, the risk of potential leakage through cap rock can be reduced. In this regard, several injection strategies have been proposed such as simultaneous CO_2 /brine injection as a mixture (*Burton and Bryant 2009; Eke et al., 2011; Kumar et al. 2005; Shariatipour et al., 2016; Zirrahi et al., 2013, Qi et al., 2008*), simultaneous injection of CO_2 /brine in different completion intervals (*Nghiem et al., 2009*), horizontal injection strategy (*Anchliya et al., 2012*), CO_2/brine alternating injection (*Juanes et al., 2006*).

When designing a sequestration project in a saline aquifer, however, it is necessary to predict the distribution and long-term behaviour of CO_2. In this regard, some subsurface interactions occur within the system, such as chemical reactions, dissolution and capillary trapping, which control the CO_2 distribution, migration and immobilisation within the storage site (*Yang et al., 2010*) and therefore they must be considered within the CO_2 storage programme

In addition, in order to predict the behaviour of CO_2 during sequestration and monitoring the aquifer to avoid any potential leakage of CO_2 through the cap rock, it is essential to model and simulate the movement and behaviour of the injected CO_2 during and after the injection periods. This includes the CO_2 distribution and a quantification of the total amount of mobile and immobilised CO_2 within the aquifer. As such, numerical simulation is necessary to optimize CO_2 sequestration design in order to make decisions in regard to the optimum operating conditions, including the number of injection wells, well completion, well placement and injection rates, which leads to the optimum CO_2 immobilization and reduction of the upwards migration of CO_2 (*Delshad et al., 2010*).

The present study discusses simulation results for various injection strategies with and without post-brine injection in a 2D homogenous aquifer, and tries to identify the best injection strategy leading to the trapping of the most CO_2 in for a given time period. This could serve as the basis for determining whether or not further work should be conducted on the discussed strategies in conditions closer to real condition.

2. Materials and Methods

2.1 Project design

A series of simulations were carried out for different injection scenarios to assess their impact on the distribution of injected CO_2 and the amount of CO_2 dissolved and trapped in a storage concept. This was undertaken using a commercial compositional reservoir simulator, Eclipse 300 with CO2STORE option.

The amount of CO_2 dissolved in the formation water can be explicitly put into the simulation model by using realistic fluid properties model based on pressure, volume and temperature (PVT) data obtained from the laboratory. This data needs to be recorded at different temperatures and pressures, including viscosity and density of both brine and CO_2 (*Qi et al., 2008*). Alternatively, in compositional simulators, such as E300, the CO_2 solubility in the aqueous phase can be calculated using EOS models as a function of temperature, salinity and pressure.

In this study, only dissolution and capillary trapping have been considered and since the timescale of simulation is not long, the mineral trapping is expected to be negligible. In the following, the reservoir description and different injection scenarios are presented, initially with the trapping indicators subsequently being defined on which the different scenarios have been assessed.

2.2 Reservoir description

A 2D homogenous fine grid geological model with 10,400 (120 × 1 × 90) grid blocks with a size of (15m × 15m × 2m) was used in this study. The deep saline aquifer was 2100 m deep with a thickness and lateral extent of 180 m and 1,800 m, respectively. The aquifer is closed with no-flow boundaries i.e. an isolated reef surrounded by tight rocks in real condition (Bachu, 2015; Smith *et al*., 2001). Other parameters used in the simulation are shown in Table 1. The properties used are typical characteristics of a deep saline aquifer and are, in particular, very similar to those used by Nghiem *et al*. (2009).

Table 1 Reservoir parameters used in the model

Properties	**Values**	**Units**
Porosity	0.2	--
Permeability	100	mD
Kv/Kh *	0.1	--
Rock compressibility	5e-05	1/bar

*Vertical to horizontal permeability ratio

The aquifer was initially fully saturated with brine with an initial pressure of 190 bar and a temperature of 40°C. These conditions met the requirement for having supercritical CO_2 within the reservoir (31.04°C and a pressure of 73.82 bar). The concentration of NaCl is 32,000 ppm at a depth of 2100 m and is assumed to be constant throughout the entire aquifer. The density of gas was calculated using a cubic equation of state and tuned to obtain an accurate density of the compressed supercritical CO_2 (Schlumberger, 2015). Except for two strategies of horizontal injection and simultaneous CO_2/brine injection in different intervals, all other strategies had an injection well perforated in an interval of 60 – 90. The relative permeability of water and gas for water-wet Berea sandstone and gas-water system were used in the simulation. The relative permeability and capillary curves are shown in Fig 1 and Fig. 2.

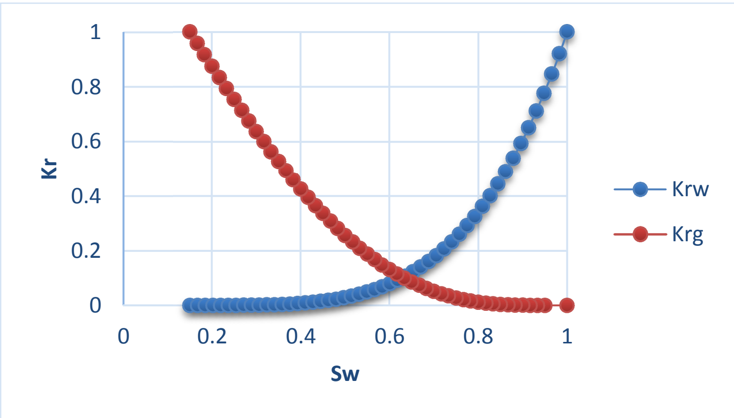


Fig. 1 Relative permeability curves for gas-water system

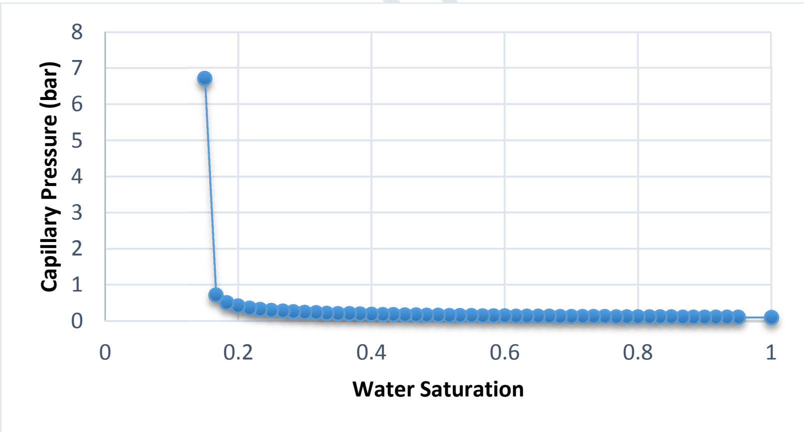


Fig. 2 Capillary curve

2.3 Injection strategies

As mentioned above, different strategies for brine injection have recently been the focus of interest. In this study, first, a continuous CO_2 injection for 15 years plus 100 years shut-in-well was run as the base case. Junes *et al*. (2006) showed that higher injections rates lead to more efficient macroscopic trapping and lateral movement of CO_2 as a result of the higher gas pressure in the vicinity of the wells and also the occurrence of the 'snap-off' phenomenon. Therefore, the selected injection rate needed to be as high as possible. However, higher injection rates lead to higher bottom hole pressures (BHP). Therefore, a BHP limit must be taken into account when an injection rate is selected. In our study, injection rate of 20 rm^3/day was chosen (equivalent to roughly 11,909 kg/day).

In contrast, some researchers have identified the risk of over pressurization of the finite Saline Aquifers as a result of CO_2 injection (*Ennis-King and Paterson, 2002; van der Meer and van Wees, 2006*). The effect can be exacerbated when brine and CO_2 are injected simultaneously. Obviously, as the pressure of the aquifer increases, the risk of CO_2 leakage through the sealing cap rock is enhanced. One way to maintain aquifer pressure in a favourable range is to place some extra wells to produce brine. Even though this may increase the costs of a CO_2 sequestration project and also increase the risk of CO_2 or carbonated water breakthrough, as the outcomes of over pressurization of the aquifer might be worst, placing of production wells in order to balance the aquifer pressure may be the only solution. This is not only reduces the risk of over pressurization and potential CO_2 leakage, but also can increase the CO_2 storage capacity. As such, in all the scenarios evaluated, a production well is present at the right corner of the model, which is far enough from the injection well and also is completed in the last 20 m intervals to avoid of any potential CO_2 or carbonated water breakthrough.

Once CO_2 is injected, the trapping in the aquifer depends on three factors, namely pressure, temperature and the salinity (*Duan and Sun, 2003; Spycher at al., 2003*). The last two are constant during a CO_2 sequestration project (unless in some certain conditions, such as brine injection with different composition into the reservoir). The aquifer pressure, however, varies with the amount of injected CO_2 and therefore increases with CO_2 injection. On the other hand, the same conditions in terms of aquifer pressure for all different injection scenarios need to be maintained in order to make a valid comparison. Hence, in the present study, following the first pressure build-up to around 305 bar, the pressure, which is high enough to yield optimum trapping efficiency, was maintained.

Therefore, for the first three years of CO_2 injection, the production well was shut-in to let the reservoir pressurize to around 305 bars. Then, the production well started to produce with the same rate as the injection rate (both in the reservoir control mode) until the end of the injection period.

After performing the base case simulation for continuous CO_2 injection, other strategies were simulated, and the results subsequently compared to each other in terms of their capability to immobilise CO_2. The injection scenarios are shown in Table 2**.** The simulation time step for all the scenarios is 115 years in total.

Table 2 Injection strategies

NO.	Scenario	Description
1	Continuous CO_2 injection 1 (Base Case)	15 years CO_2 injection, followed by 100 years shut-in-well.
2	Continuous CO_2 injection 2	15 years CO_2 injection, followed by 2 years post-brine injection and 98 years shut-in-well.
3	Simultaneous injection of CO_2 /Brine in the same interval 1	15 years of simultaneous brine and CO_2 injection using a same well, followed by 100 years shut-in-well.
4	Simultaneous injection of CO_2 /Brine in the same interval 2	15 years of simultaneous brine and CO_2 injection using a same well, followed by 2 years post-brine injection and finally 98 years shut-in-well.
5	Simultaneous injection of CO_2 /Brine in different intervals 1	15 years of simultaneous brine and CO_2 injection using two different wells, followed by 100 years shut-in-well.
6	Simultaneous injection of CO_2 /Brine in different intervals 2	15 years of simultaneous brine and CO_2 injection using two different wells, followed by 2 years post-brine injection and finally 98 years shut-in-well.

7	Horizontal CO_2 and Brine injection 1	15 years simultaneous brine and CO_2 injection using two horizontal wells, followed by 100 years shut-in-well
8	Horizontal CO_2 and Brine injection 2	15 years simultaneous brine and CO_2 injection using two horizontal wells, followed by 1 year post-brine injection and finally 99 years shut-in-well
9	CO_2/Brine Alternating Injection	2 years Gas injection followed by 1-year brine Injection for 5 Cycles (15 years total) and finally 100 years shut-in-well

2.4 Trapping index

In each scenario, the amount of injected CO_2 can be different and therefore no direct comparison can be valid. Therefore, it is essential to define some indices to normalise the trapping efficiency. In this study, the following trapping indices are presented.

$$Dissolved\ CO2\ Index, DCI(t) = \frac{Overall\ molar\ mass\ of\ dissolved\ CO2\ in\ brine\ at\ any\ \ t}{Overall\ molar\ mass\ of\ injected\ CO2\ at\ any\ \ t}$$

$$Trapped\ CO2\ Index, TCI\ (t) = \frac{Overall\ molar\ mass\ of\ trapped\ CO2\ at\ any\ \ t}{Overall\ molar\ mass\ of\ injected\ CO2\ at\ any\ \ t}$$

$$Trapping\ Efficiency\ Index, TEI(t) = \ DCI\ (t) + TCI\ (t)$$

3. Results and discussion

3.1 Continuous CO_2 injection

For the base case, CO_2 was continuously injected into the aquifer for 15 years, at a rate of 20 rm^3 /day for the first three years. The production well then started to produce formation water at the same rate as the CO_2 injection. This not only allows more CO_2 to be injected as a result of the relatively constant pressure (our simulations showed that without designing a production well, no more than nine years CO_2 injection was allowed as the reservoir pressure builds up to the fracture pressure limit), but also maintain the pressure in a favourable range that maximises the trapping efficiency while minimising the leakage potential through the sealing cap rock. After 15 years injection, the well was shut-in for 100 years and the trapping efficiency was subsequently determined.

As our results showed, 9.8 % of the injected CO_2 was dissolved into the brine. Furthermore, the amount of CO_2 capillary trapped almost doubled to 16.4%. This means that 26.2 % of the entire injected CO_2 was dissolved or trapped within the aquifer during a total of 115 years of CO_2 sequestration. However, a considerable percentage of CO_2 (73.7 %) remained mobile.

As shown in Fig. 3, in terms of CO_2 distribution, the injected CO_2 expanded laterally and simultaneously migrated upward during the injection period. When injection stopped, the lateral expansion also stopped and all the CO_2 migrated gradually towards the top of the aquifer. Finally, at the end of the simulation, all of the CO_2 remaining accumulated at the top of the aquifer.

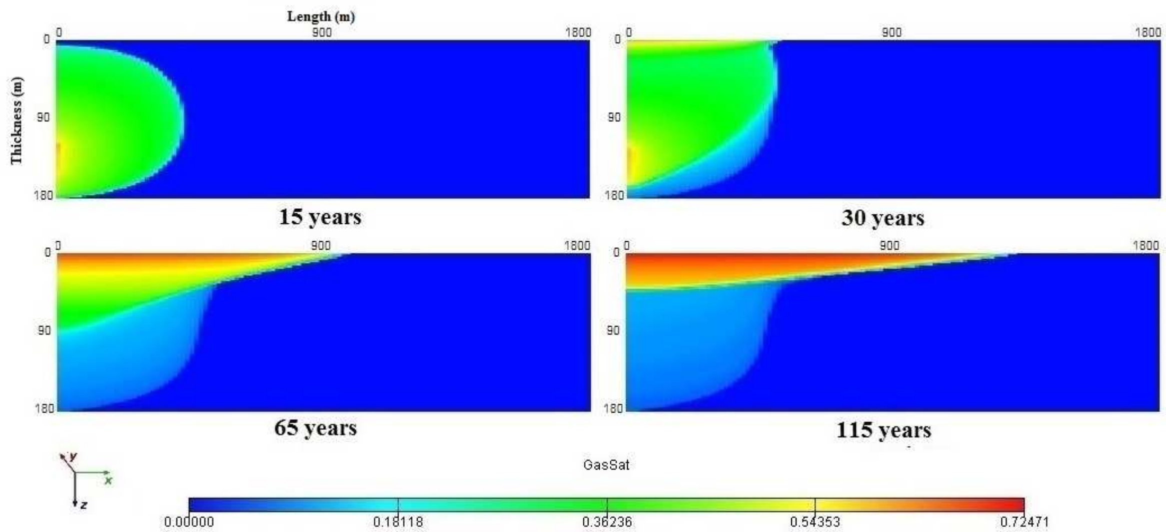


Fig. 3 CO_2 distribution through the aquifer over simulation period of continuous CO_2 injection

As shown in Fig. 4, our results showed that capillary trapping was not limited to the post-injection stage and started from the beginning of CO_2 injection into the aquifer. More importantly, the rate of CO_2 trapping was greater than it was in the post-injection period.

Similarly, the rate of dissolution was also higher in the first 15 years than when the well was shut-in.

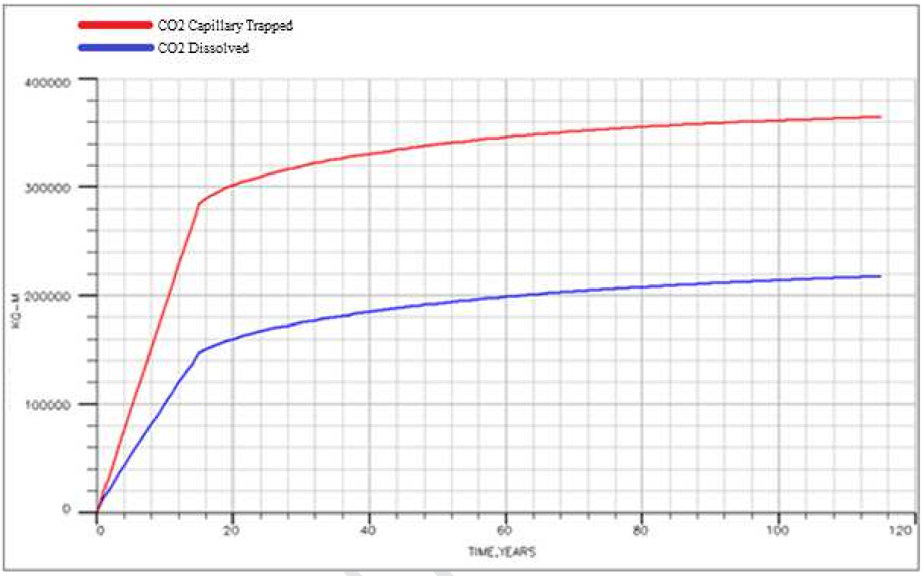


Fig. 4 Comparison of CO_2 dissolved and capillary trapped over simulation period of continuous CO_2 injection

3.2 CO_2 continuous injection followed by post-brine injection

Leonenko *et al*. (2006) suggest brine injection to accelerate dissolution by pumping the brines from under-saturated regions to regions occupied by CO_2. Nevertheless, their proposed time frame of brine injection is 200 years meaning that the operational cost for this duration could be prohibitive. As such, a relatively short period of post-brine injection may be considered as an alternative of the long-term brine injection.

Therefore, two years of post-brine injection with the same composition as the initial brine was injected into the aquifer in order to investigate its effect on trapping efficiency. This duration of brine injection was the longest timeframe where no breakthrough occurred. After that, the CO_2 reached to the producer.

As seen in Fig. 5, both the trapping and dissolution efficiency increased dramatically by adding the post-brine injection into the system. In this respect, the amount of CO_2 dissolved experienced a considerable increase of 22 % when the brine was injected into the aquifer. However, this increase was just about 10% for the trapping efficiency. Seemingly, the brine injection made more of an impact on the dissolution rate of CO_2 than on capillary trapping. In this case, the amount of mobile gas demonstrated a 21 % decrease during the sequestration process, reducing from 73 % to 52 %.

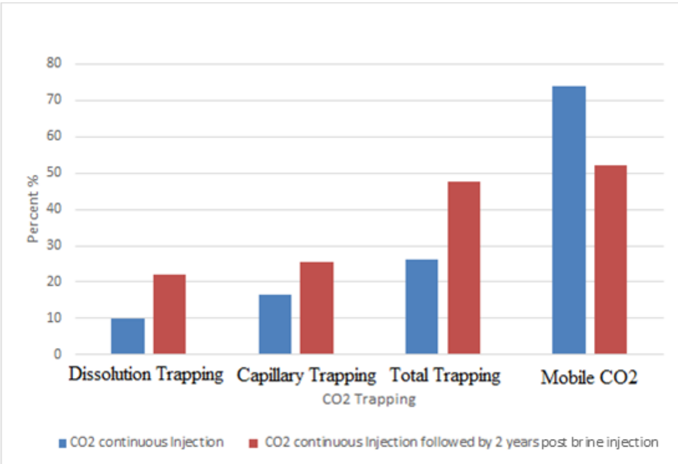


Fig. 5 Comparison of the amount of CO_2 immobilised in two cases of continuous CO_2 injection with and without post-brine injection

This increase in dissolution can be explained by the fact that when brine was injected into the system, more CO_2 spread out through the aquifer, and as a consequence, by increasing the interfacial area of existing CO_2 , the amount of dissolution as a result of mass transfer increased significantly. Furthermore, the effect of convection can be stronger in the case of brine injection creating a stronger density instability and thus a more rapid initiation of convection.

The CO_2 distribution during and after injection is shown in Fig. 6. It is seen that during brine injection, most of CO_2 was affected by injected brine enhancing the effectiveness of the sequestration process. Clearly, brine displaced CO_2 laterally away from the wells resulting in a forced imbibition process and therefore improving capillary trapping.

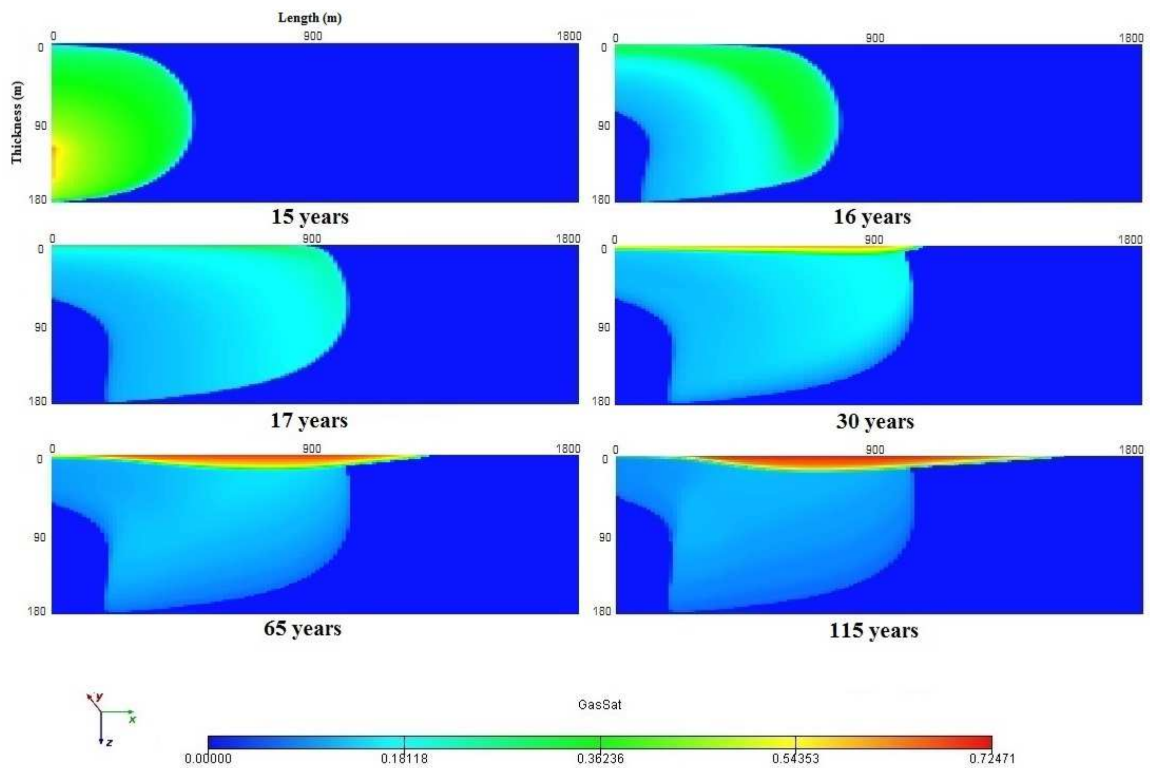


Fig. 6 CO_2 distribution through the aquifer over simulation period of continuous CO_2 injection followed by post-brine injection

In the following, the impact of a number of variables on post-brine injection efficiency are evaluated.

3.2.1 Impact of Kv/Kh ratio on post-brine injection efficiency

In the previous section, a *Kv*/*Kh* ratio of 0.1 was used. This means that vertical permeability is only 10 mD which is considered to be low. Therefore, this may delay the upwards migration of the CO_2 due to buoyancy forces and, as a consequence, a major proportion of it could be exposed to the injected brine within the same completion interval. However, this may be different for various vertical permeability values. To make this scenario clear and to investigate the effect of vertical permeability on the effectiveness of post-brine injection, a sensitivity analysis on different *Kv/Kh* ratios and horizontal permeabilities was carried out and the results were compared. The different *Kv/Kh* ratios chosen are shown in Table 3.

Table 3 Sensitivity analysis on different *Kv/Kh* ratios

NO.	*Kv/Kh*	Vertical Permeability (mD)
1	0.1	10
2	0.5	50
3	1	100

As shown in Fig. 7, as the vertical permeability increased, the amount of both capillary and dissolution trapping decreased, resulting in a reduction in the effectiveness of the post-brine injection. As such, dissolution trapping decreased from 22% to 19% and 16.9%, when the *Kv/Kh* ratio increased from 0.1 to 0.5 and 1, respectively. Furthermore, the capillary trapping index fell by about 7% and 10% when *Kv/Kh* ratio increased from 0.1 to 0.5 and 1, respectively. Seemingly, the results suggest that capillary trapping was more affected by the vertical permeability variation than the dissolution of CO_2.

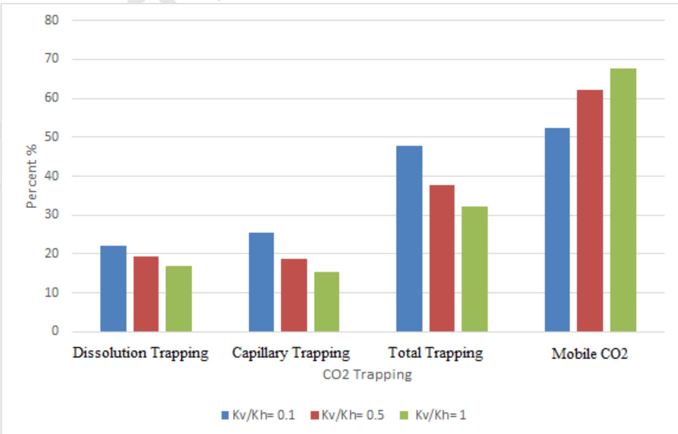


Fig. 7 Amount of CO_2 immobilised in different *Kv/kh* ratios

In terms of CO_2 distribution as shown in Fig. 8, the tendency of CO_2 to migrate upwards increased clearly as the vertical permeability enhanced, and therefore when the brine was injected, less CO_2 was available to come in contact with it. Accordingly, there was a decrease in the total amount of CO_2 trapping and a higher proportion of the mobile CO_2 accumulated at the top of the aquifer.

In a study, Kumar *et al.* (2005) stated that at small values of *Kv*/*Kh*, there is more horizontal movement of the CO_2 in the layers into which injection occurred. At larger values, there is more vertical migration followed by movement along the top seal, which is in agreement with our findings.

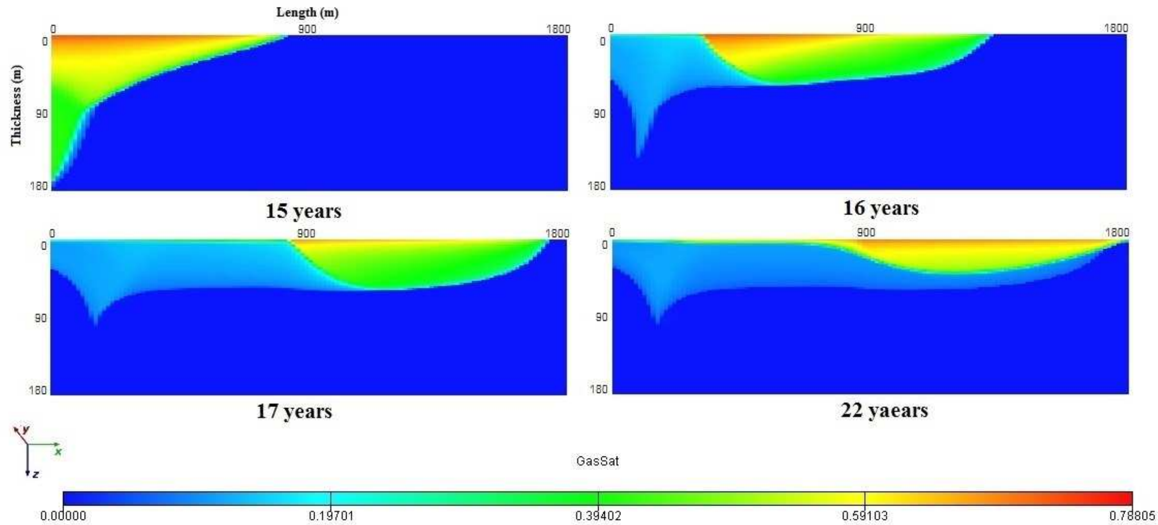


Fig. 8 CO_2 distribution through the aquifer over simulation of continuous CO_2 injection followed by post-brine injection with *Kv/Kh* =1

Nonetheless, as shown in Fig. 8, after only 22 years, the CO_2 plume reached the boundary where the simulation was stopped in order to avoid producing CO_2. It seems that the presented strategy of post-brine injection in aquifers with high vertical permeability may not be very effective.

3.2.2 Impact of brine injection rate on trapping efficiency

To investigate the effect of post-brine injection rate on the overall performance of the trapping efficiency, the same volume of brine for two cases of 250 (rm^3/day) over two years and 50 (rm^3/day) over 10 years was injected into the aquifer.

As shown in Fig. 9, as the rate of post-brine injection increased, the final amount of both trapped and dissolved CO_2 was enhanced. As such, both the dissolved and trapping efficiency experienced about a 2% enhancement when the rate of the brine injection increased from 50 (over ten years) to 250 (over two years).

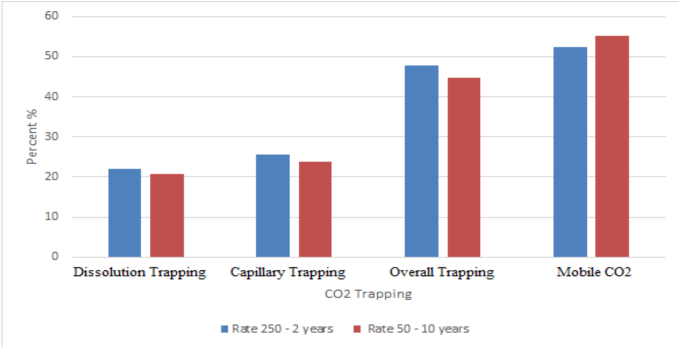


Fig. 9 Amount of CO_2 immobilised in simulation of two different injection rates

This difference may be explained by the fact that at the same time of the brine injection, the injected CO_2 was gradually migrating to the top of the aquifer. In other words, injected CO_2 was getting away from the injection well due the fact that the completion interval was at layers 60 – 90. This means that proportions of CO_2, which had already reached to the top of the aquifer, were no longer in contact with the injected brine. However, for lower brine injection rates, a reduced fraction of the CO_2 came into contact with the injected brine. This clearly led to a reduction in the overall amount of trapped CO_2.

3.2.3 Impact of duration of post-brine injection

Another important question is whether or not the extension of the brine injection has any effect on the overall trapping efficiency. To investigate this, we continued the brine injection with a rate of 250 rm^3/day over a period longer than two years. The results are shown in Table 4.

Table 4 Brine injection in various durations

NO.	Rate of injection (Res M^3/day)	Duration of injection (Years)
1	250	2
2	250	3
3	250	4
4	250	5
5	250	5 (+250 days)

It should be mentioned that the injection continued just before the production well started to produce CO_2. Therefore, in the last case, the simulation was run for five years and 250 days, since after that the well would have gone to CO_2 breakthrough.

As shown in Table 5, as the duration of brine injection increased, the overall trapping efficiency was enhanced. For instance, the total amount of total trapping increased from 47.71 % to 60.76 % after the five years and 250 days injection period. Another interesting point was the considerable difference between capillary and dissolution trapping. Obviously, the amount of capillary trapping experienced a small surge of about 1% when the duration of injection increased from two to three years. After third year, no change could be seen in the capillary trapping. This means that brine injection could not affect the capillary trapping afterwards.

On the other hand, dissolution trapping demonstrated a continual dramatic enhancement as the duration of brine injection increased. As shown in Fig. 10, the enhancement trend steadily increased until the end of the brine injection period.

Table 5 Amount of CO_2 immobilized over the simulation period with five different durations of brine injection

Scenario	**Dissolution Trapping (%)**	**Capillary Trapping (%)**	**Total Trapping (%)**	**Mobile CO_2 (%)**
Two years post-brine injection	22.13	25.58	47.71	52.29
Three years post-brine injection	25.69	26.45	52.14	47.86
Four years post-brine injection	28.90	26.54	55.44	44.56
Five years post-brine injection	32.08	26.56	58.65	41.35

Five years and 250 days post-brine injection (Before breakthrough)	34.18	26.58	60.76	39.24

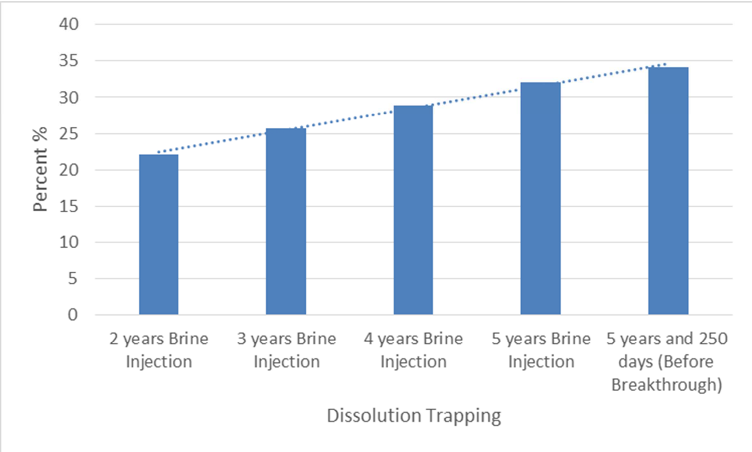


Fig. 10 Dissolution trapping over simulation period with five different duration of post-brine injection

3.3 Simultaneous injection of CO_2/brine in same interval

In a study conducted by Burton and Bryant (2009), a process in which CO_2 was dissolved in brine before injection into deep subsurface formations, was examined. They stated that since the CO_2-laden brine dissolved at surface facilities is slightly denser than brine containing no CO_2, the complete dissolution of all CO_2 has zero risk of leaking from the target aquifer. They also mentioned that although this results in higher costs, surface dissolution may be attractive when the costs of monitoring or ensuring against buoyancy-driven CO_2 leakage exceed these additional costs.

In another research programme (*Eke et al., 2011*), a scenario of CO_2/brine surface mixing has been simulated. Their findings showed that dissolving CO_2 into brine at the surface facilities before injection into geologic formations produces a CO_2-saturated-brine stream with a density slightly higher than the original brine in the formation. This is capable of eliminating the buoyancy force which is a strong driving force to bring CO_2 to the surface. They also claimed that immobilized CO_2

will remain in place indefinitely, even if the integrity of the seal is suspect and no additional time is required for immobilization after injection ends.

Furthermore, in a study conducted by Shariatipour *et al*. (2016), the advantages of the concept of the down-hole mixing (DHM) method of brine with CO_2 have been shown. They noted that by applying this strategy, there is little overall pressure increase, because CO_2 is mixed with brine extracted from the formation, and also the extracted brine is already at high pressure when it is mixed with the CO_2, greatly increasing the solubility of CO_2 and reducing the volume of brine required. Their findings showed that the upward migration of CO_2 in the reservoir can be limited to viscous effects during the injection period, and that during the subsequent shut-in period gravity segregation displaces the CO_2 saturated brine downwards, thereby increasing the storage safety.

As such, a co-injection of CO_2 and brine was designed in order to investigate the effect of the simultaneous injection of brine and CO_2 in a same interval. For the first three years, both CO_2 and brine with the same rate of 20 (Res M3/day) (1:1 ratio) were injected into the aquifer. Then, when the pressure of the aquifer built up to around 305 bar, the production well started to produce with the same rate as overall injection rate. This process continued for 15 years overall, and the well was subsequently shut-in for 100 years.

The main advantage of this scenario compared to the base case was in the higher amount of dissolved CO_2, which is in agreement with previous studies where improvements in CO_2 dissolution were reported. As such, the dissolution efficiency increased by about 4.2 % from 9.8 % to 14 %. However, the trapping efficiency showed a slight increase of only 0.4 % compared to the base case.

This dramatic rise in dissolution may be qualified by a number of hypotheses. First, by simultaneously injecting CO_2/brine into the system, leading to a wider spreading of the CO_2 plume, the interfacial area of CO_2 in contact with the formation brine increases significantly. This means that the mass transfer between the CO_2 and the formation brine is enhanced and, as a consequence, the CO_2 dissolution is also enhanced (*Juanes et al., 2006*).

In addition, Qi *et al*. (2008) showed that simultaneously the injection of CO_2 and water mitigates the mobility contrast between injected and displaced fluids, leading to a more stable and uniform sweep and higher storage efficiencies than injecting CO_2 alone. Moreover, by adding brine into the injection stream, it mixes with supercritical CO_2 leading to an increase in the mixture's density and viscosity. This means that the density difference between the injected stream and native formation brine increases. Consequently, the Rayleigh number increases leading to a decrease in the onset time of convective mixing and increase in the convective mixing efficiency.

As shown in Fig. 11, simultaneous brine injection resulted in a higher amount of lateral spreading of the CO_2 through the aquifer. However, a great disadvantage of this strategy is that simultaneous brine injection results in faster upwards migration as the injection rate is doubled (CO_2 plus brine). This results in the injected brine pushing the CO_2 upwards and therefore it takes less time for the mobile CO_2 to reach the top of the aquifer, where it accumulates.

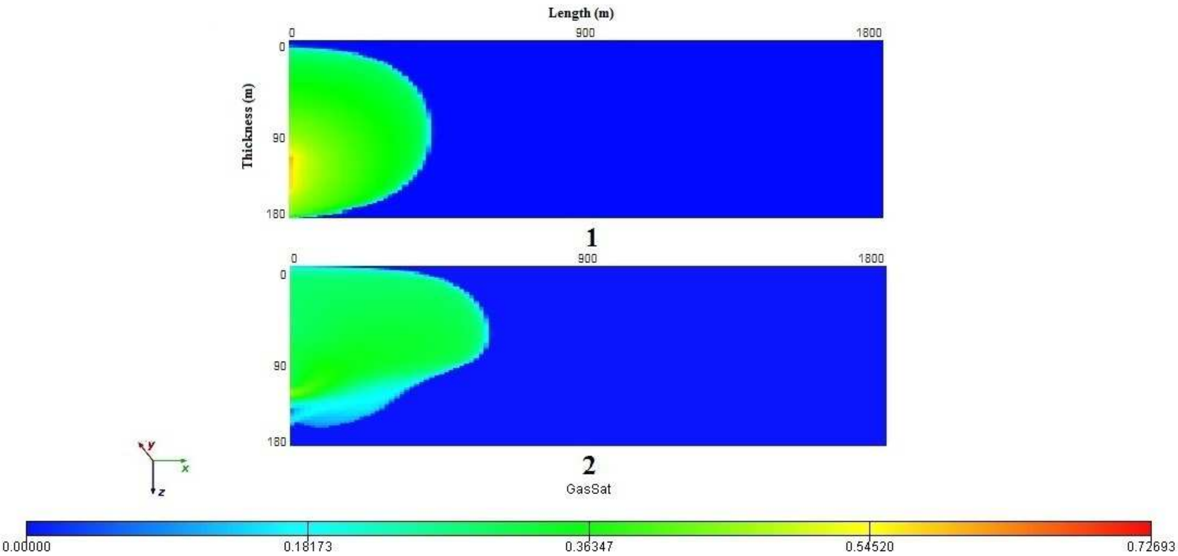


Fig. 11 Lateral expansion of CO_2 through the aquifer after 15 years in two cases: 1-continuous CO_2 injection and 2-simultaneous CO_2/brine injection

3.4 Simultaneous injection of CO_2/brine in same interval followed by post-brine injection

The effect of a short period of post-brine injection after the end of the main CO_2 injection was newly investigated. Therefore, a two-year brine injection scenario was carried out at the end of the 15 years of simultaneous injection of CO_2/brine. In this injection strategy, the total trapping efficiency experienced a dramatic increase of 14%, compared to the same strategy without post-brine injection, reaching 44% of CO_2 trapping, including an 8% increase in solubility efficiency and about 5% in capillary trapping efficiency. Even though the strategy of simultaneous CO_2/brine injection without post-brine injection could barely affect the capillary trapping by just 0.4 % enhancement compared to the base case, adding post-brine injection significantly improved the figure to about 5% increase. As mentioned earlier, this enhancement may be explained by a stronger lateral spreading of CO_2 as a consequence of post-brine injection which results in a forced imbibition and thereby enhancing the capillary trapping efficiency.

Nevertheless, the results showed that this post-brine injection scenario was less efficient than the strategy of two years post-brine injection following 15 years continuous CO_2 injection. As shown in Fig. 12, despite the fact that the dissolved CO_2 remained at 22 %, trapped CO_2 showed a considerable difference, where the figure was lower in the scenario of simultaneous CO_2 /brine followed by two years of brine injection. Obviously, the CO_2 distribution in these two cases was totally different and as shown in Fig. 13, when CO_2/brine was injected simultaneously into the reservoir, the CO_2 spread further out through the aquifer than when CO_2 was injected in the reservoir alone. Therefore, when additional brine was post-injected through the aquifer, less CO_2 was available to come into contact with the injected brine and consequently the CO_2 trapping was not as effective.

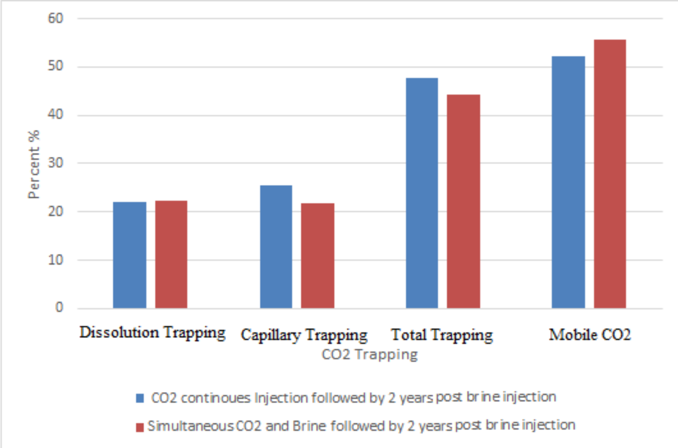


Fig. 12 Comparison of the amount of CO_2 immobilized in two cases of continuous CO_2 injection and simultaneous CO_2 and brine injection, both followed by 2 years post-brine injection

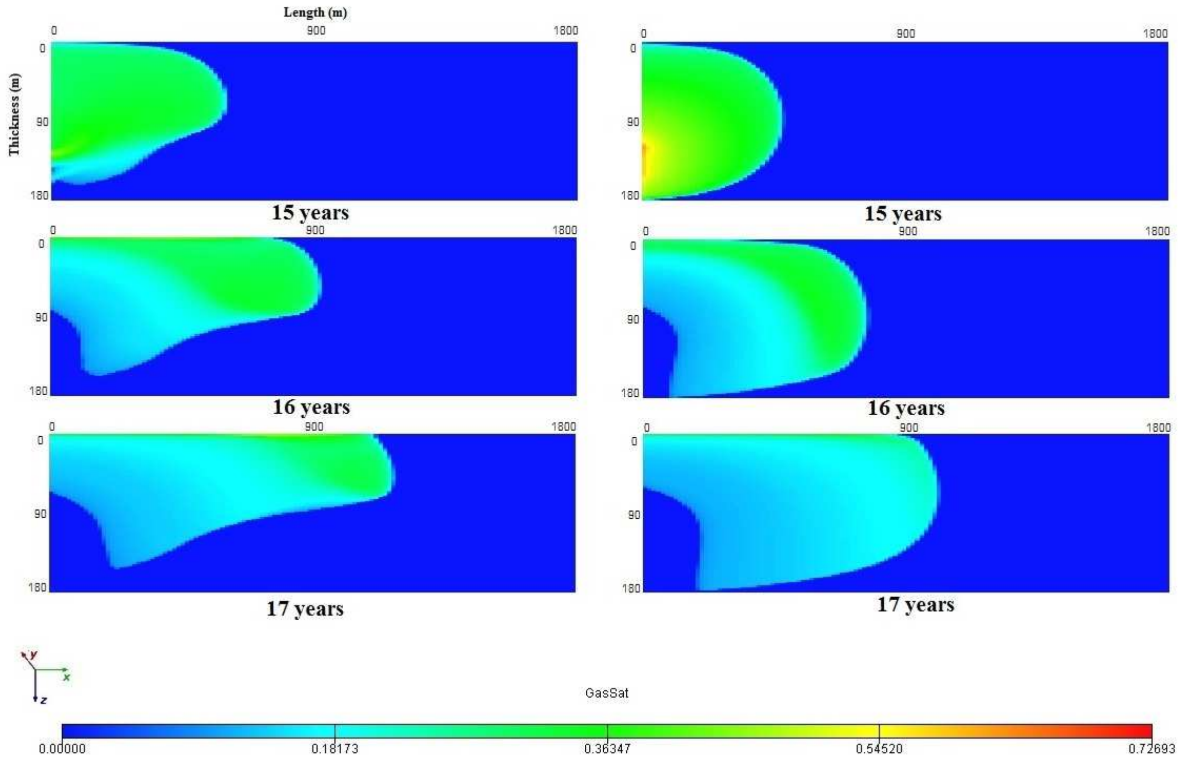


Fig. 13 Comparison of CO_2 distribution through the aquifer in two cases of continuous CO_2 injection followed by two years post-brine injection (right) and simultaneous CO_2/ brine injection followed by two years post-brine injection (left)

3.5 Simultaneous injection of CO_2/brine in different intervals

In this scenario, two different intervals in same injection well were considered. As such, the upper interval completed in 20-35, was used to inject brine, and the lower one completed in 60 – 90, was used to inject CO_2.

Similar to other scenarios, the brine and CO_2 were simultaneously injected for the first three years with a same rate of 40 (Res. m^3/day). Subsequently, when the pressure increased to around 305 bar, the production well started to produce brine with the same rate as the total injection rate (40 rm^3/day). The injection process was then continued for another 12 years and finally the wells were shut-in for 100 years and eventually the trapping efficiency was determined.

As shown in Fig. 14, this scenario for CO_2 sequestration showed great promise since a total of 39.7% of the injected CO_2 into the aquifer was trapped during the sequestration process. This indicated a dramatic increase compared to the base case reaching of 26 % to 39.7 %. In addition, this strategy showed a 9 % increase compared to when the CO_2/brine were injected simultaneously in same interval. Furthermore, the amount of dissolved CO_2 almost doubled in comparison to the base case. Another interesting point was that, even though the previous injection strategy (simultaneous CO_2/brine injection in the same interval) did not enhance the capillary trapping compared to the base case, the injection in different intervals saw it increase from 16 % to 22 %.

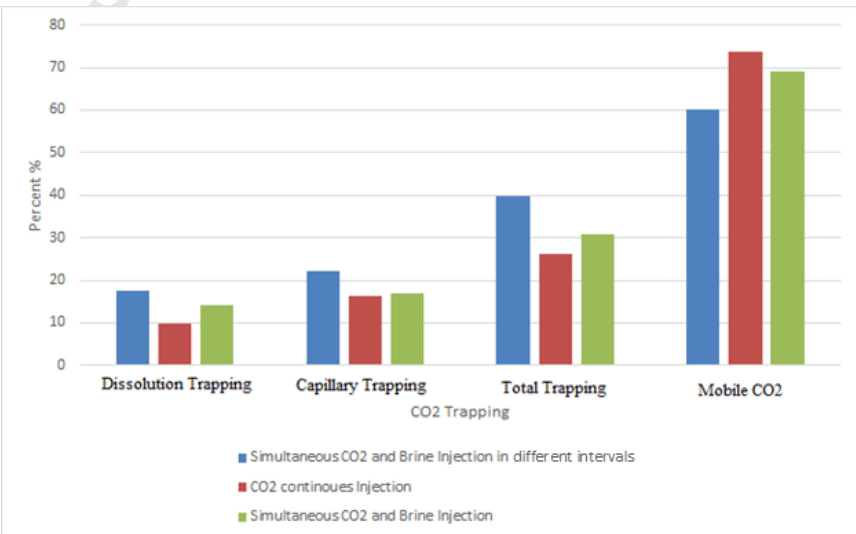


Fig. 14 Comparison of the amount of CO_2 immobilized in three cases of continuous CO_2 injection, simultaneous CO_2/brine injection in same and different intervals

In this respect, a similar simulation study was conducted by Nghiem *et al*. (2009) using two different intervals of a single well for CO_2 and brine injection. They noted that capillary gas trapping was promoted through injecting CO_2 near the bottom of the aquifer by the downer interval with brine injection by the upper one. This is a result of the imbibition when CO_2 rises to the top of the aquifer due to buoyancy.

In fact, in this injection design, as a result of buoyancy and gravity forces causing the CO_2 to migrate upwards and the brine to move downwards, a counter-current flow is formed. This counter-current flow of CO_2 and brine meets each other in the space between two injectors. As such, the counter-current flow induces imbibition and enhances capillary trapping during and after the brine injection stage (*Nghiem et al., 2009*).

Our results shows that this counter-current flow also leads to enhance the spreading of the CO_2 to out wider through the aquifer leading to an increase surface area and therefore extra contact of the CO_2 with the under-saturated brine in the aquifer. Consequently, the amount of dissolution may increases as a result of mass transfer.

Another interesting point was that brine injection in the upper intervals delayed the CO_2 in reaching the top of the aquifer, resulting in more effective trapping. As shown in Fig. 15, it took 53 years for the CO_2 to reach the top of the aquifer when brine and CO_2 were injected into the aquifer within different completion intervals. However, this time span reduced to just 15 years when CO_2 alone was injected continuously. In addition, when CO_2/brine was injected simultaneously in the same interval, it took just 12 years for the CO_2 to reach the top of the aquifer, which could be considered as a disadvantage for that strategy.

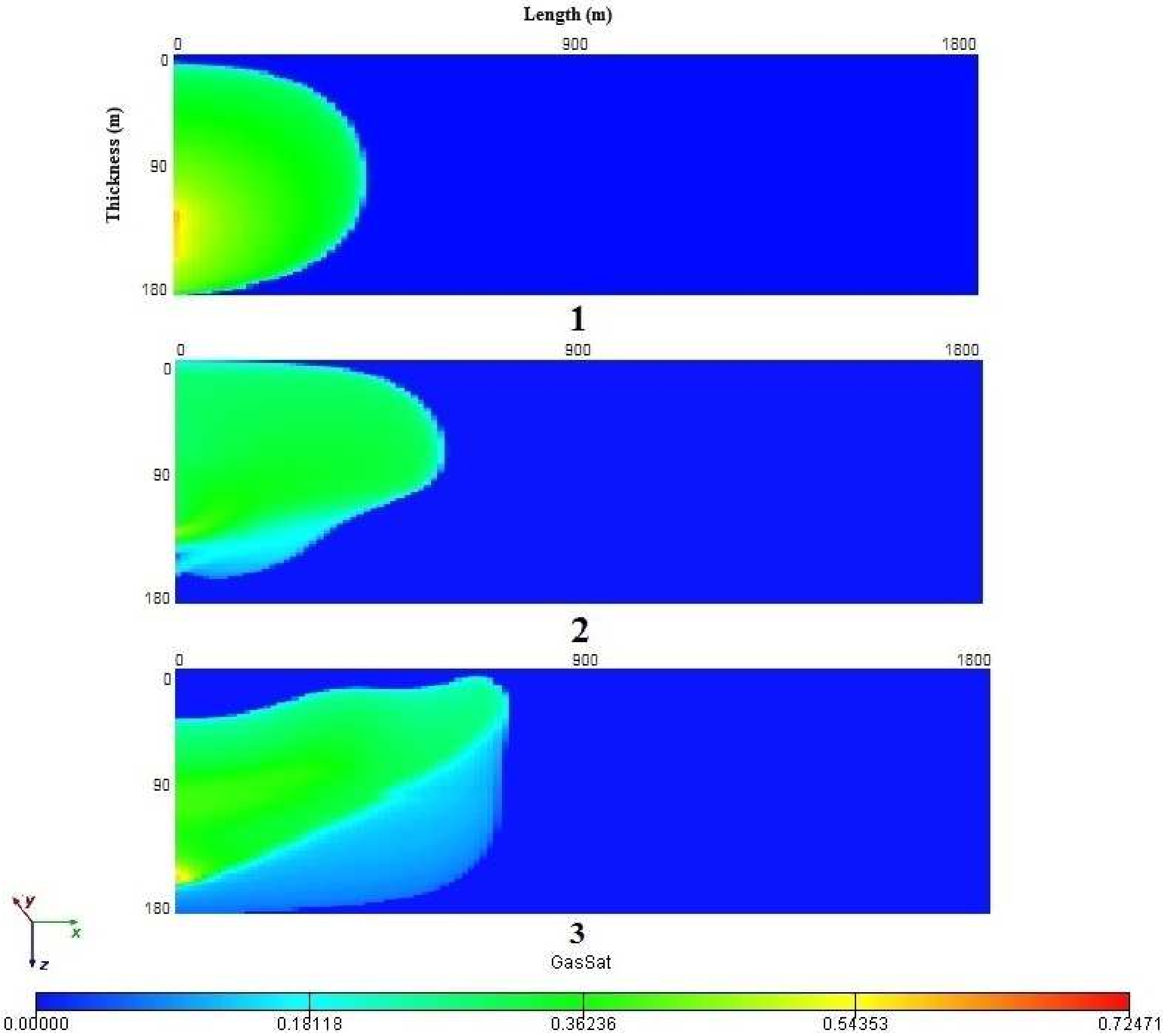


Fig. 15 Injected CO_2 reaching to the top of the aquifer in different periods of time in three cases: 1-continuous CO_2 injection after 15 years; 2-simultaneous CO_2 /brine injection in same intervals and; 3- simultaneous CO_2 / brine injection in different intervals after 53 years

The CO_2 distribution of this strategy is shown in Fig. 16.

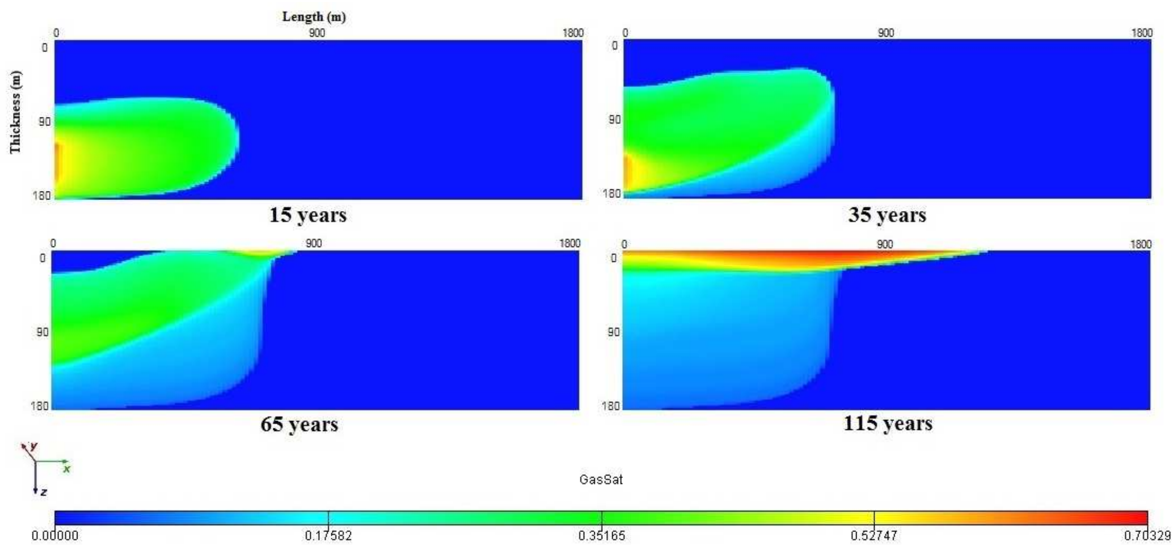


Fig. 16 CO_2 distribution through the aquifer over simulation period for the simultaneous injection of CO_2 / brine in different intervals

As shown in Fig. 17 and Fig. 18, the initial rates of both trapping and dissolution were higher when CO_2/brine was injected in the same interval. However, when the well was shut-in after 15 years, both rates of dissolution and trapping experienced a very slight increase. On the other hand, when the injection intervals were different, although the initial rate of dissolution and trapping were less, the final amount was higher and following the shut-in-well, the CO_2 trapping continued to increase. This may be explained by the fact that after shut-in-well of the brine injector, since the counter-current flow accelerated, the trapping efficiency improved leading to more CO_2 becoming trapped.

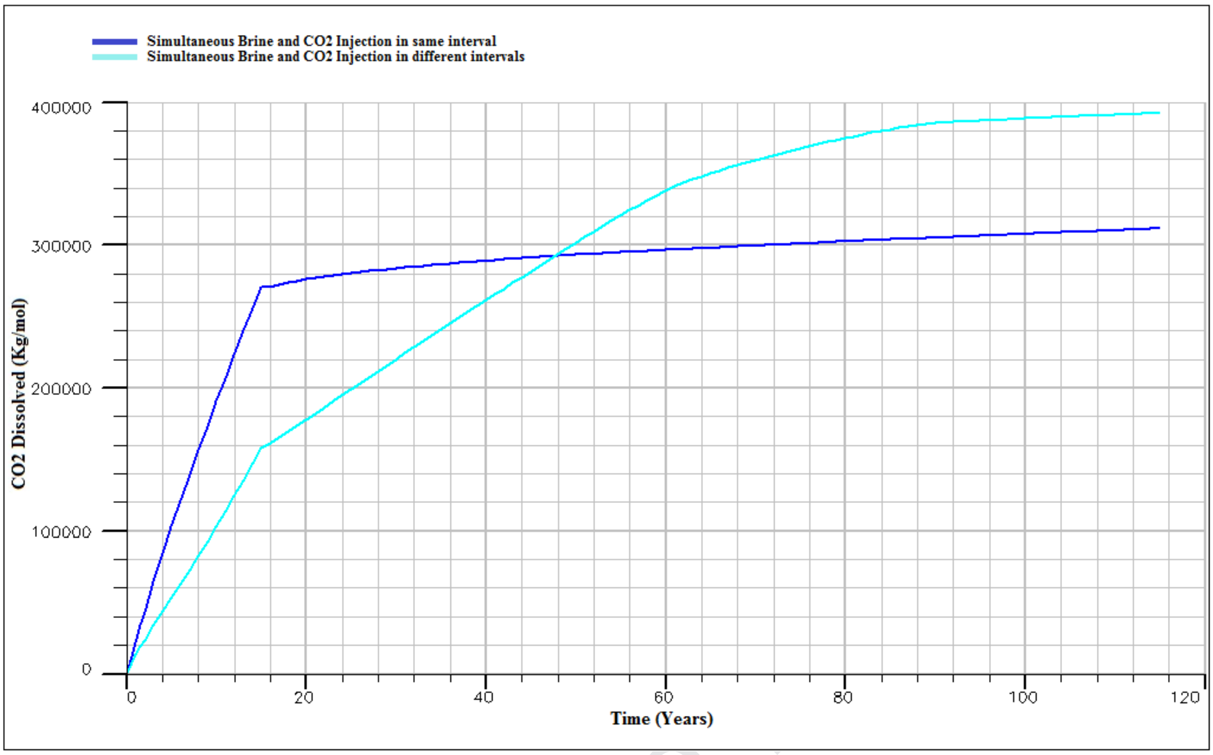


Fig. 17 Comparison of dissolved CO_2 over simulation period in two cases of simultaneous injection of CO_2/brine in same and different intervals

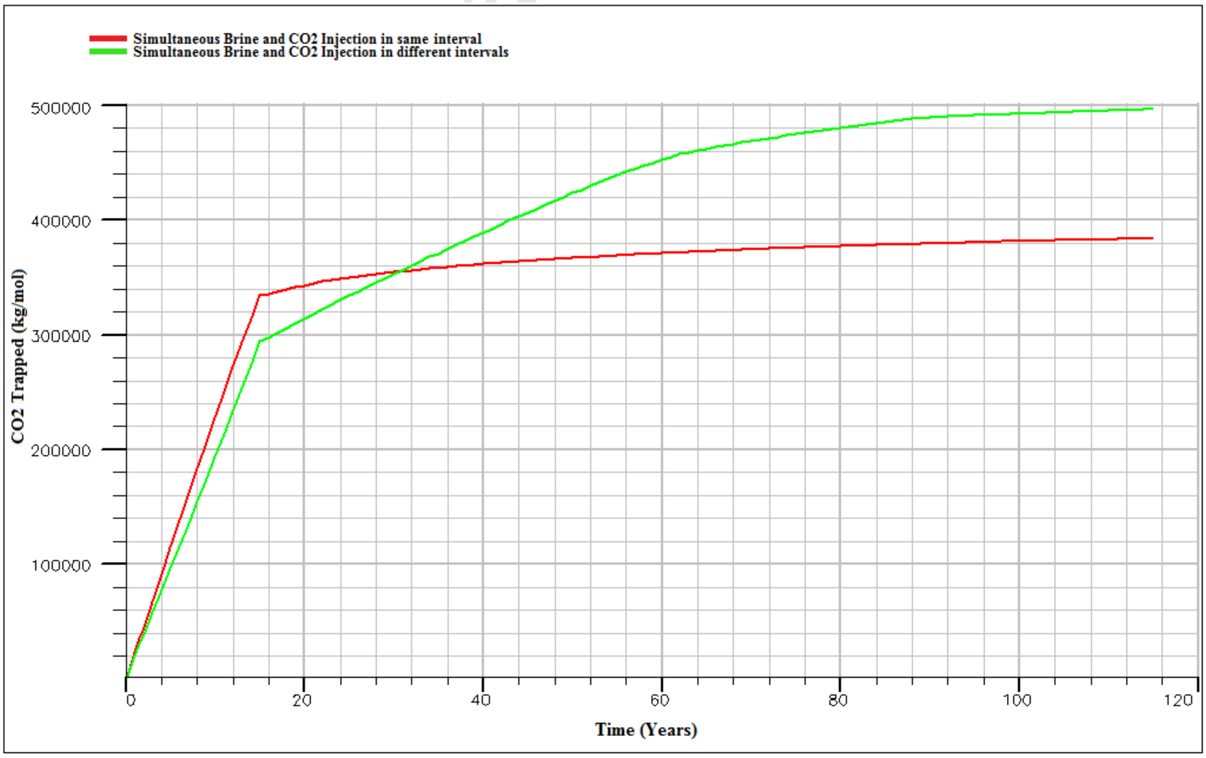


Fig. 18 Comparison of capillary trapped CO_2 over simulation period in two cases of simultaneous injection of CO_2/brine in same and different intervals

To examine the effect of the location of the CO_2 and brine injector, a number of additional intervals were selected for further investigation. Furthermore, as the vertical permeability may also have an effect on the trapping performance, the analysis was coupled with different vertical permeabilites. As such, the interval of the CO_2 injector remained unchanged (60-90), while the intervals of the brine injector were chosen as shown in Table 6.

Table 6 Sensitivity analysis on different *Kv/Kh* ratios and brine injector intervals

Kv/Kh ratio	Vertical Permeability (mD)	Interval of brine injector
0.1	10	5 - 20
		20 - 35
		35- 50
0.5	50	5 - 20
		20 - 35
		35 - 50
1	100	5 - 20
		20 - 35
		35 - 50

As shown in Table 7, as a result of increasing the vertical permeability, both the capillary and dissolution trapping decreased. As discussed earlier, the higher vertical permeability resulted in a higher upward migration of CO_2 and therefore less became available for trapping.

On the other hand, as the displacement of the brine and CO_2 injector decreased, the total amount of trapped CO_2 increased. Another important thing was that the same behaviour of total trapping enhancement was seen when the two injectors were closer in three different vertical permeabilties. This means that this behaviour can be experienced whatever the vertical permeability might be.

Table 7 Amount of CO_2 immobilised over simulation period in different *Kv/Kh* ratios and brine injector intervals

Kv/Kh ratio	Injector intervals	Dissolution trapping (%)	Capillary trapping (%)	Total trapping (%)	Mobile CO_2 (%)
0.1	5 - 20	17.55	22.21	39.77	60.23
	20 -35	17.55	22.21	39.77	60.23
	35 - 50	18.61	23.72	42.33	57.67
0.5	5 - 20	16.26	20.18	36.45	63.55
	20 -35	16.26	20.18	36.45	63.55
	35 - 50	16.87	20.97	37.84	62.16
1	5 - 20	14.3	17.13	31.43	68.57
	20 -35	14.31	17.13	31.44	68.56
	35 - 50	14.63	17.48	32.11	67.89

3.6 Simultaneous injection of CO_2/brine in different intervals followed by post-brine injection

In this part, the effect of the short period of post-brine injection on simultaneous CO_2/brine injection in different intervals was newly investigated. Therefore, two years of post-brine injection with a rate of 250 (Res m^3/day) was added into the system. As shown in Fig. 19, the results were very promising. In this regard, the total amount of trapped CO_2 showed a significant increase of 23% compared to the same scenario without a post-brine injection.

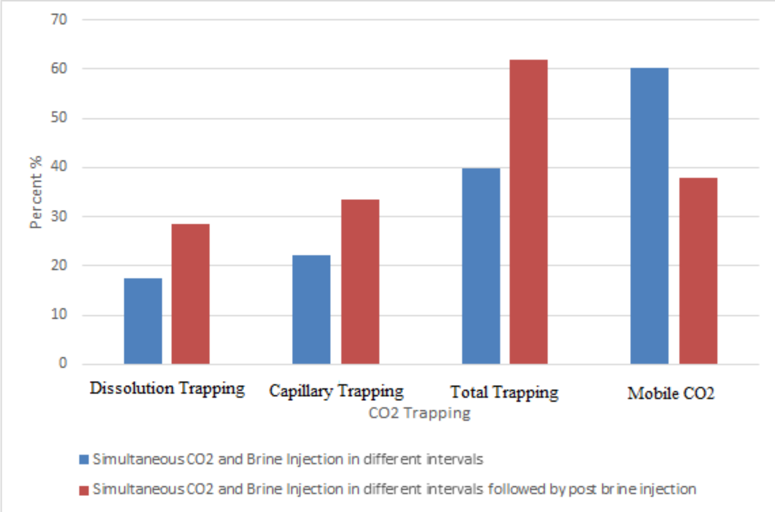
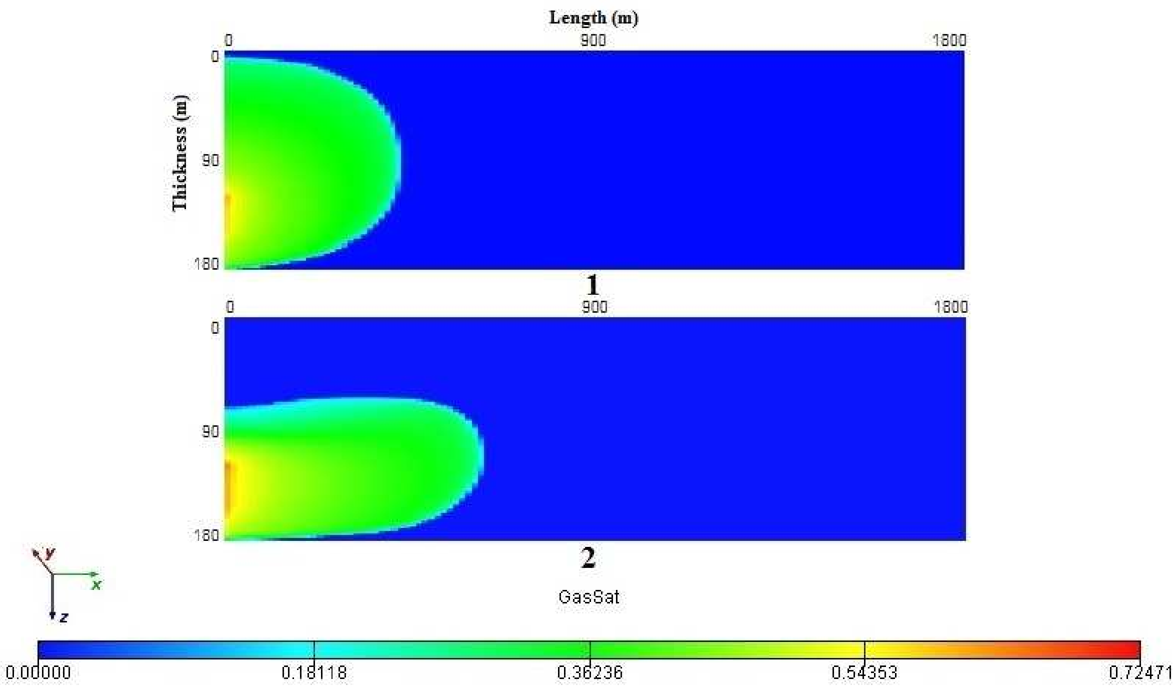


Fig. 19 Comparison of the amount of CO_2 immobilized in two cases of simultaneous CO_2/brine injection in different intervals with and without post-brine injection

In this injection design, the addition of 2 years post-brine injection improves the counter-current flow formed as a result of buoyancy and gravity forces which causes the CO_2 migrates upward and the brine move downward. In addition, post-brine injection can help the CO_2 to spread out much wider through the aquifer than the same strategy without post-brine injection. This leads to enhancing contact of the CO_2 with the under-saturated brine in aquifer. This wider spreading of the CO_2 compared to the base case of continuous CO_2 injection can be seen in Fig. 20.

531 

532 Fig. 20 Lateral expansion of CO_2 through the aquifer after 15 years in two cases of 1-
533 continuous CO_2 injection and 2-simultaneous CO_2/brine injection in different intervals

534 The CO_2 distribution of the process is seen in Fig. 21. Clearly, when the post-brine was injected into
535 the aquifer, the CO_2 was seen to spread further. This also delayed the CO_2 in reaching the top of the
536 aquifer and therefore the total amount of trapped CO_2 became considerably enhanced.

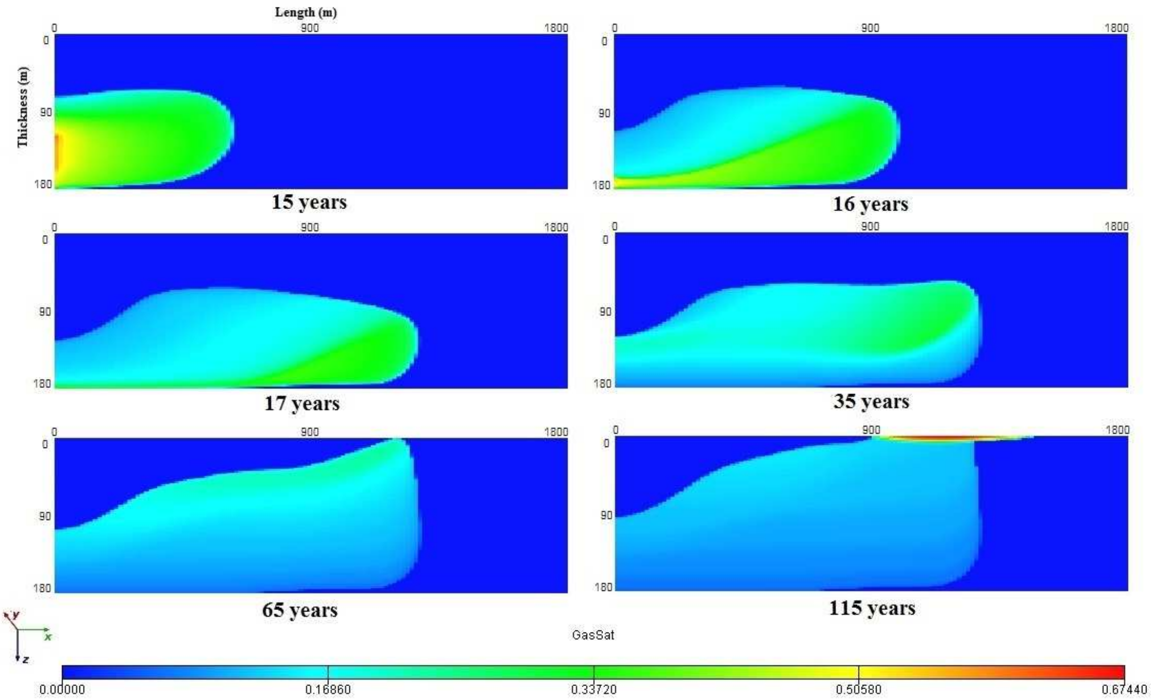


Fig. 21 CO_2 distribution through the aquifer over simulation period of simultaneous injection of CO_2 /brine in different intervals followed by 2 years post-brine injection

3.7 Horizontal well injection

One of the reasons for the low overall trapping efficiency is the accumulation of CO_2 around the well bore which prevents it from being exposed to a fresh brine and therefore maintaining an efficient trapping and dissolving reaction. Anchliya *et al.* (2012) initially proposed an effective way to reduce the CO_2 concentration around the wellbore through brine injection above the perforation using a horizontal well. They used two horizontal wells for CO_2 and brine injection and also two production wells next to the injectors. They noted that locating two production wells around the injectors impedes the upward movement of CO_2 more than when there is no horizontal production well. Nevertheless, this design may be prohibitive as some additional long distance horizontal wells need to be drilled. This will be more important in a real field when it may need more than one set of injections and productions wells.

Therefore, in this study, no horizontal production well was put in and as with the previous scenarios, there was just one vertical brine producer at the right corner of the model used just for maintaining the pressure in a favourable range. The second difference between our model and the one proposed by

Anchliya *et al.* (2012) was that unlike their work, our strategy was based on stopping the injection before the CO_2 went into breakthrough in the production well.

Accordingly, two horizontal injection wells were designed and perforated in the model. The upper injection well, perforated in layer 50 with a length of 900 (m) used for brine injection and the downer well completed in the lowest layer with the length of 750 (m) used for the CO_2 injection. The length of brine injector needs to be higher than the gas one. This is as a result of the shape of the gas following expansion. The CO_2 and brine injection rates were the same for the previous scenarios.

As shown in Fig. 22, the overall trapping efficiency demonstrated a dramatic increase of 33%, 29% and 20% compared to the base case, the simultaneous injection of CO_2/brine in the same and different intervals, respectively.

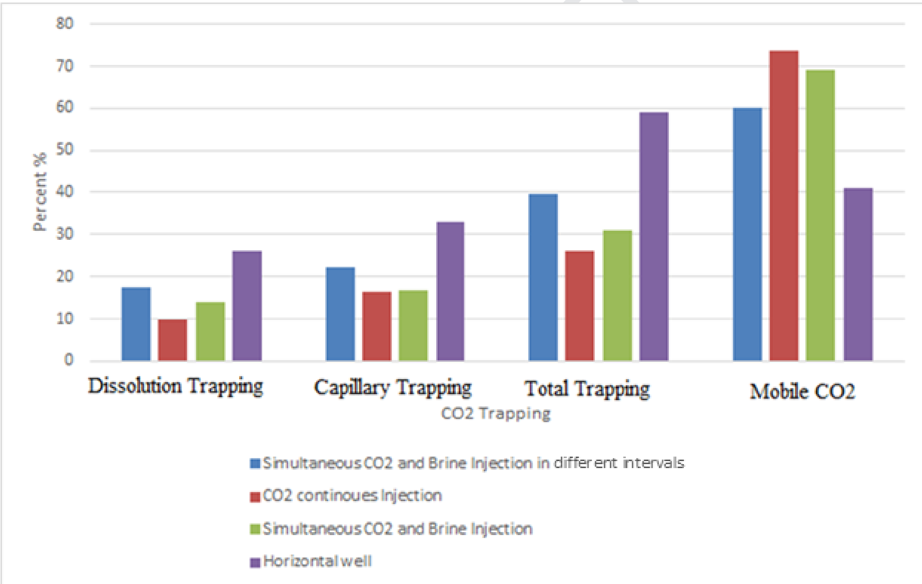


Fig. 22 Comparison of the amount of CO_2 immobilised over simulation period of 4 different cases of continuous CO_2 injection, horizontal well injection and simultaneous CO_2/brine injection in same and different intervals

In this respect, a 17%, 12% and 9% enhancement was achieved for the dissolution trapping compared to the base case and the simultaneous injection of CO_2/brine injection in same and different intervals, respectively. For capillary trapping efficiency, the figure doubled in comparison to the base case with the simultaneous injection of CO_2/brine in same interval reaching 33%. Furthermore, an 11%

enhancement was experienced for the capillary trapping compared to the simultaneous CO_2/brine injection in different intervals. This showed that implementing horizontal wells could enhance both the capillary and dissolution efficiency significantly.

In the research conducted by Anchliya *et al.* (2012), they suggested that the brine injection over the CO_2-injection well reduced the velocity of the rising plume three-fold and finally that almost 90% of the CO_2 can be immobilized as early as early as 50 years after the start of injection. They also stated that the amount of capillary trapped CO_2 far exceeds the amount of dissolved CO_2 which is in not quite in agreement with our findings as both dissolution and capillary trapping showed a significant increase compared to the base case.

Another important point in the horizontal systems is that the effective placement of horizontal injectors leads to the lateral spreading of the CO_2. This means that in addition to its upward movement due to buoyance forces, as a result of spreading the injection well within the aquifer horizontally, which in our case is about ½ of reservoir length, the CO_2 will spread more effectively. As a consequence of its wider spread, the CO_2 plume is exposed to more fresh brine accelerating the dissolution and trapping efficiency. This clearly can be seen in Fig. 23.

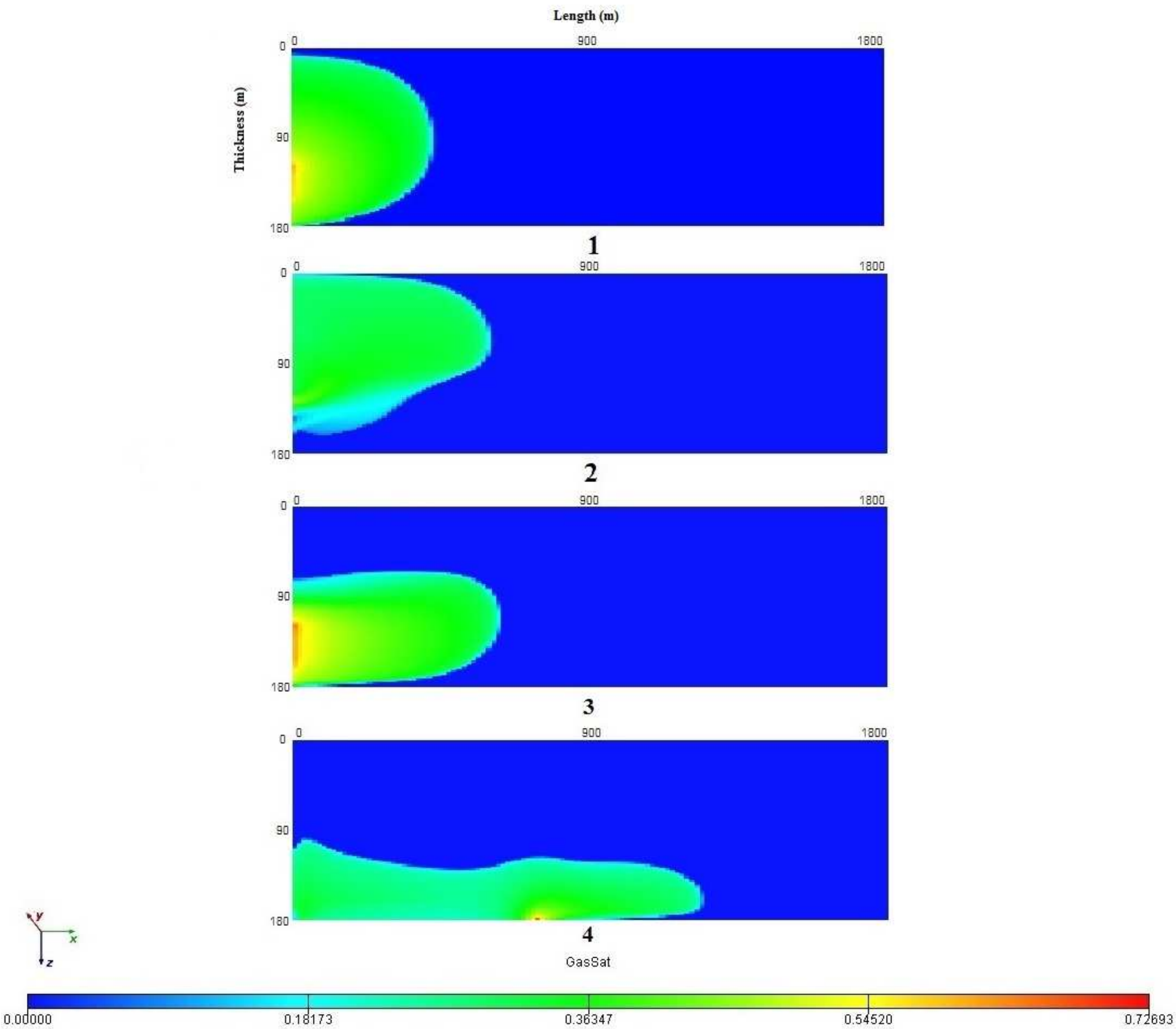


Fig. 23 Comparison of CO_2 distribution through the aquifer after 15 years in 4 different cases: 1-continuous CO_2 injection; 2-simultaneous CO_2/brine injection in same intervals; 3-simultaneous CO_2/brine injection in different intervals and; 4- horizontal design

Furthermore, this design of a top brine injector creates a downward pressure gradient that counters the tendency of the CO_2 plume to rise. As shown in Fig. 24, this retarded the CO_2 in reaching the top of the aquifer and increased the time that the CO_2 is in contact with the fresh formation brine.

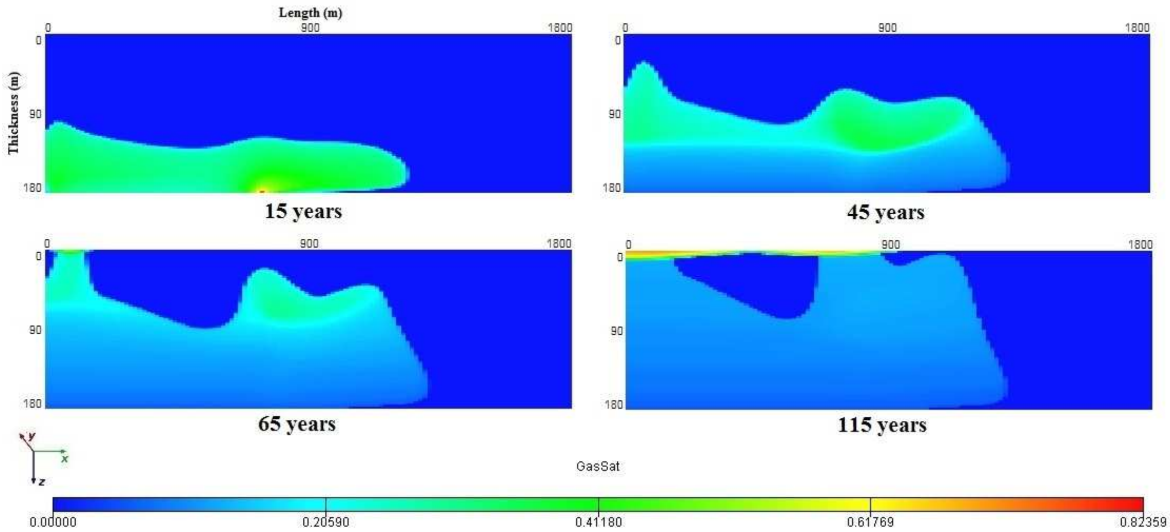


Fig. 24 CO_2 distribution through the aquifer over simulation period of horizontal injection

As mentioned earlier, one of the main reasons for the low overall trapping efficiency is the accumulation of CO_2 around the well bore which prevents it from encountering fresh brine and continuing to be immobilised efficiently. In the horizontal system, the CO_2 continuously comes across fresh brine within the aquifer.

However, in ordinary CO_2 injection systems, the injected CO_2 creates a dense inverted funnel-shaped plume around the wellbore, preventing the CO_2 coming into contact with fresh brine. Therefore, the horizontal design not only delays the CO_2 in reaching the top of the aquifer and reducing the accumulation of CO_2 at the top, but also provides an increased interfacial area for the ongoing trapping and dissolution of the CO_2 (*Anchliya et al., 2012*).

3. 8 Horizontal design followed by post-brine injection

In this part, the effect of the short period of post-brine injection in the horizontal design was newly investigated. As such, a brine injection was added into the system to investigate whether the strategy of a horizontal design can be improved in terms of CO_2 trapping efficiency.

Unlike the other scenarios where two year’s brine was injected into the model, after about 370 days, the production well started to produce CO_2, which was normal as the injection well was much closer to the producer than the vertical injector. Therefore, to avoid breakthrough, only 365 days of brine injection was applied to the simulation.

As shown in Fig. 25, adding post-brine injection enhanced the performance of horizontal system. The overall trapping efficiency demonstrated an increase of about 4 %, achieving 63% in total. This is the highest amount of total trapping obtained for all the scenarios, even though unlike the other strategies, brine was injected for only one year at the end of the 15-year injection period.

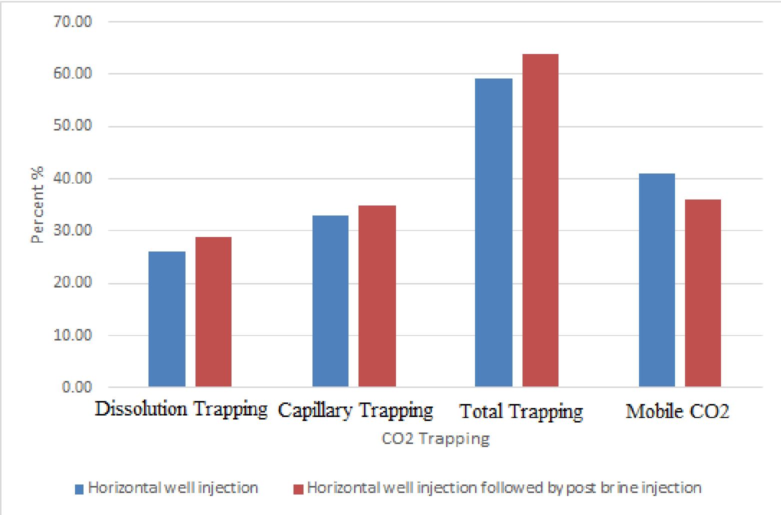


Fig. 25 Comparison of the amount of immobilised CO_2 over simulation period in two cases of horizontal injection with and without post-brine injection

Moreover, as shown in Fig. 26, this design creates a stronger downward pressure gradient that counters the tendency of the CO_2 plume to rise and therefore this retards the CO_2 in reaching the top of the aquifer and increases the time that the CO_2 is in contact with the fresh formation brine accordingly. Another important point in this design is the more effective lateral spreading of CO_2 by adding the post injection of brine into the system which enhances the dissolution trapping efficiency significantly.

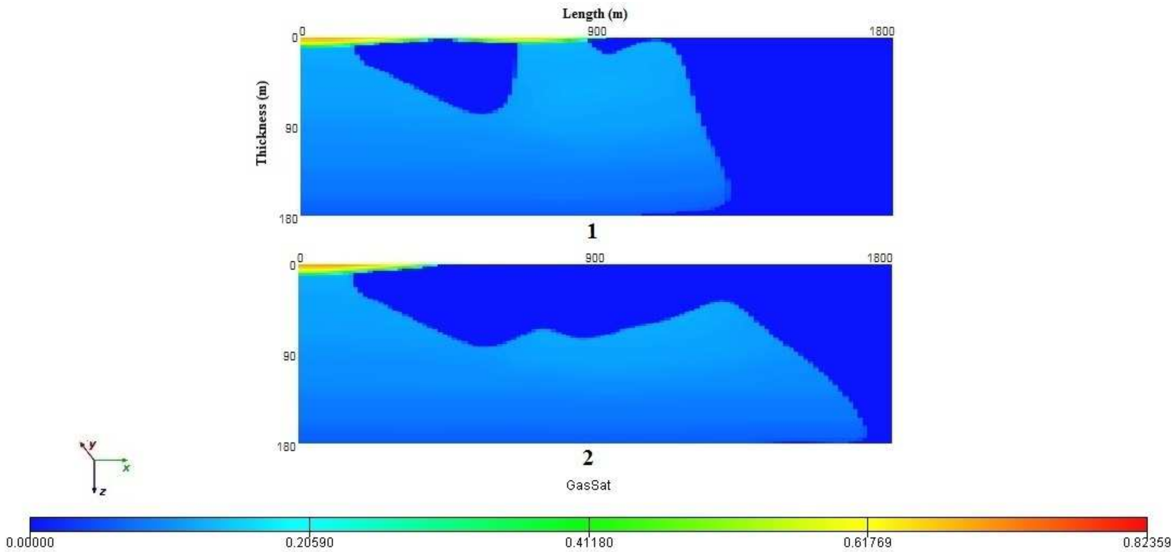


Fig. 26 CO_2 distribution through the aquifer at the end of the simulation in two cases: 1- horizontal injection with post-brine injection and; 2- horizontal injection without post-brine injection

Another important factor is the distance between the two injection wells. The importance of the perforation interval in the horizontal design has been mentioned in the research conducted by Anchliya et al. (2012). However, no further explanation has been reported. Therefore, in order to investigate the possible effects of perforation intervals, a sensitivity analysis, including various distances, was newly conducted. The design details are shown in Table 8.

Table 8 Sensitivity analysis on location of brine injector in horizontal injection scenario

NO.	**Layer completed of brine injector**	**Distance with CO_2 injector (m)**
1	80	20
2	70	40
3	60	60
4	55	70
5	50	80
6	45	90

7	40	100
8	30	120
9	20	140
10	10	160

As shown in Table 9**,** despite the fact that the changes were not that considerable, as the brine injector became further removed from the CO_2 injector, the trapping efficiency increased. However, this continued until an optimum distance and after that the behaviour was reversed. In this regard, the best results were obtained when the distance was 80 (m) between two injectors (brine injector was placed in layer 50). From this layer, as the distance moved either farther or closer to the CO_2 injector, the trapping efficiency decreased.

Table 9 Comparison of the amount of immobilised CO_2 over simulation period with different intervals of brine injector

Brine injector interval	Dissolution trapping (%)	Capillary trapping (%)	Total trapping (%)	Mobile CO_2 (%)
80	24.87	31.66	56.53	43.47
70	25.89	32.98	58.87	41.13
60	26.02	33.08	59.1	40.90
55	26.03	33.14	59.18	40.82
50	26.06	33.04	59.3	40.8
45	26.18	33.17	59.24	41.2
40	25.85	32.79	58.63	41.37
30	24.37	31.36	55.73	44.27
20	24.31	31.23	55.53	44.47
10	23.17	30.85	54.56	45.44

We hypothesise two possible reasons for this behaviour. When the brine injector is too far from the CO_2 injector, the advantage of the downward pressure gradient can be eliminated since the CO_2 is no longer exposed efficiently by the pressure waves. However, as this space between the two injectors is too wide, the greater volume of CO_2 can take advantage of a counter-current brine flow leading to more efficient trapping. Accordingly, the distance between the two injectors must be an optimum- neither too far resulting in the elimination of the downward pressure gradient, nor too close leading to a limiting of the space where the injected CO_2 and brine can interact.

3.9 CO_2/brine alternating injection

An alternating CO_2 and brine injection, inspired by the water alternating gas injection (WAG) process was carried out. In this process, five cycles of brine and CO_2 injection was conducted. For the first two years, CO_2 with the rate of 20 (Res m^3/day) was injected into the reservoir. This was followed by a one-year brine injection at the same rate. These three-year periods were repeated for 5 cycles. After 3 years, the production well started to produce brine for pressure maintenance purposes as discussed earlier. After a total of five cycles of injection, the well was shut in and simulation advanced for 100 years.

In this regard, the overall trapping efficiency experienced an enhancement of 26% to 35% compared to the base case. In this regard, dissolution trapping efficiency demonstrated about 5% and capillary trapping about 4% increase.

As shown in Fig. 27, at the end of the simulation, the extent of CO_2 at the top of the aquifer was less compared to the base case. This means that alternating the brine injection leads to more CO_2 being trapped and, as a consequence, the amount of CO_2 accumulation at the top of the aquifer being reduced.

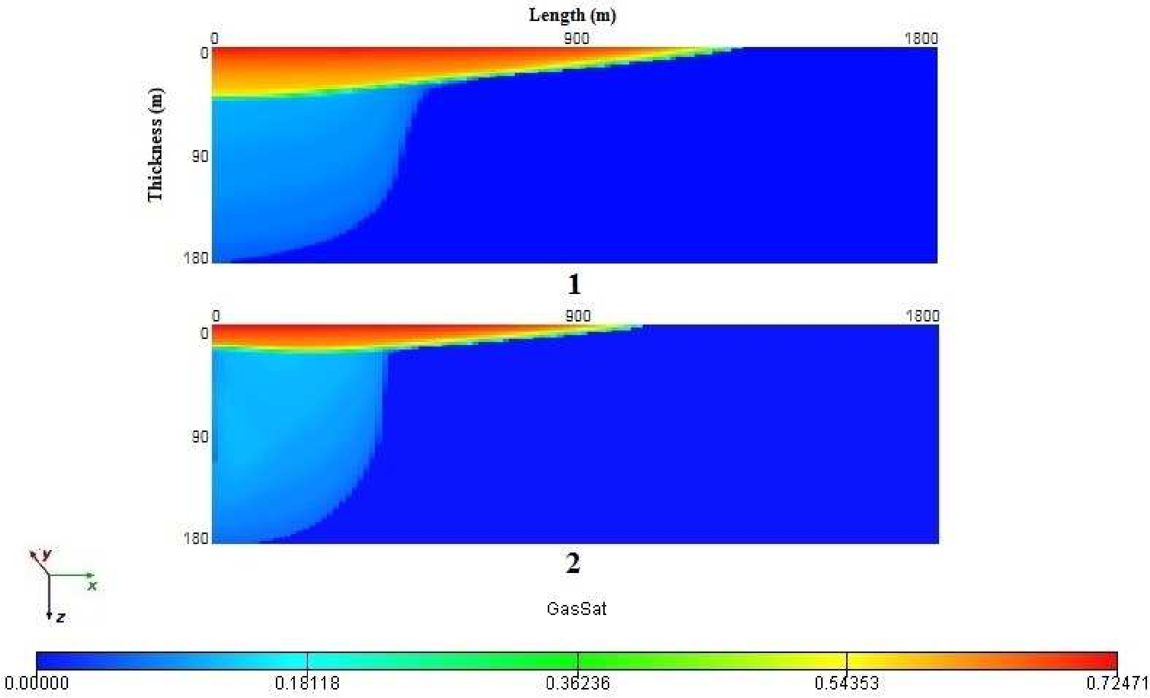


Fig. 27 Comparison of CO_2 distribution within the aquifer at the end of the simulation in two cases of 1-continuous CO_2 injection and 2-WAG

As Juanes *et al.* (2006) stated, the injection of water slugs alternating with CO_2 injection increases the effectiveness of the sequestration project. The injected water forces the breakup of large connected CO_2 plumes, enhancing the trapping and immobilization of the CO_2.

In the following, the CO_2 distribution process in the whole simulation is shown in Fig. 28.

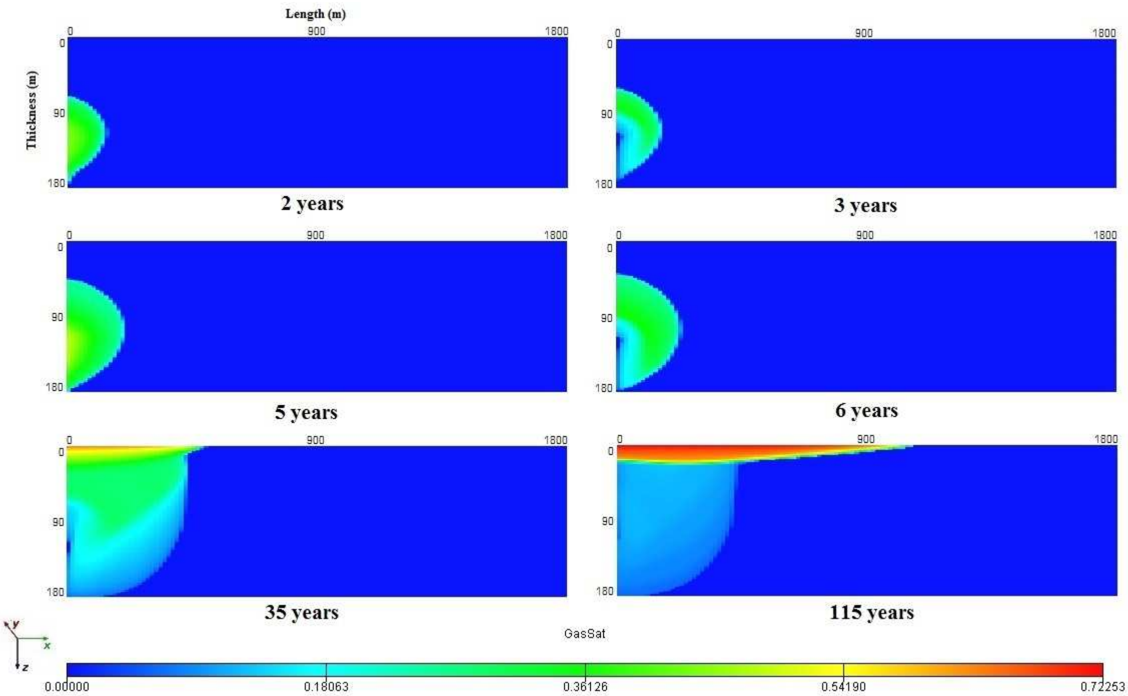


Fig. 28 CO_2 distribution through the aquifer over simulation period of WAG

3.10 Overall CO_2 trapping results

The overall results of CO_2 trapping are shown in Table 10. Obviously, our presented strategy of using a short period of post-brine injection can significantly improve the total trapping efficiency and all the strategies including this brine injection show a high amount of CO_2 immobilisation. In this regard, both horizontal well design followed by one year brine injection and simultaneous CO_2/brine injection in different intervals followed by two years brine injection experienced the two highest amounts of CO_2 trapping with 63.87% and 62%, respectively. Nonetheless, horizontal well injection without any brine injection was also one of the effective strategies showing 59% of CO_2 being trapped over 115 years. Meanwhile, continuous CO_2 injection as a base case experienced the least amount of CO_2 trapping with only 26.21% after a 115-year simulation period. Last but not least, CO_2/brine alternating injection also enhanced the trapping efficiency, 35% in total. This was a better efficiency than both the base case and simultaneous CO_2/brine injection without post-brine injection.

Table 10 Overall simulation results of immobilised CO_2 in different injection scenarios

Injection strategies	**Dissolution trapping (%)**	**Capillary trapping (%)**	**Total trapping (%)**	**Mobile CO_2 (%)**
CO_2 continuous Injection (Base case)	9.8	16.4	26.2	73.8
CO_2 continuous injection followed by 2 years post-brine injection	22.1	25.6	47.7	52.3
Simultaneous CO_2/brine Injection	14.0	16.8	30.8	69.2
Simultaneous CO_2 /brine injection followed by 2 years brine injection	22.4	21.8	44.2	55.8
Simultaneous CO_2/brine injection in different intervals	17.6	22.2	39.8	60.2
Simultaneous CO_2/brine injection in different intervals followed by 2 years post-brine injection	28.6	33.5	62.0	38.0
Horizontal well injection	26.1	33.0	59.1	40.9
Horizontal well injection followed by 1-year brine injection	29.0	34.9	63.9	36.1
CO_2/brine alternating injection	15	20	35	75

As shown in Fig. 29, the strategies used in this study are ranked based on their performance to trap CO_2 most efficiently.

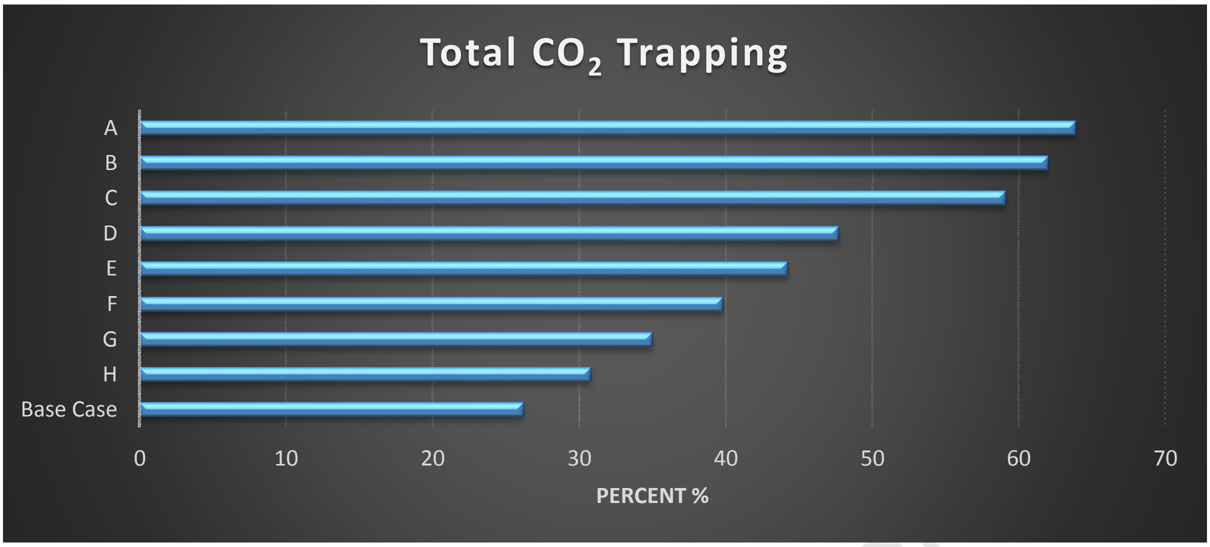


Fig. 29 The ranking of strategies used based on their performance to trap CO_2 the most. A: Horizontal well design followed by post-brine injection; B: Simultaneous CO_2/Brine Injection in different intervals followed by post-brine injection; C: Horizontal well design; D: CO_2 continuous injection followed by post-brine injection; E: Simultaneous CO_2/brine injection in same interval followed by post-brine injection; F: Simultaneous CO_2/brine injection in different intervals; G: CO_2/brine alternating injection; H: Simultaneous CO_2/brine injection,

4. Conclusions

Our simulation results show that using a short period of post-brine injection just after the end of CO_2 injection could significantly improve the total trapping efficiency and all the strategies including a short period of post-brine injection showed the highest amounts of CO_2 immobilisation.

In general, by using post injection of brine into the system, more CO_2 was spread out through the aquifer, and as a consequence, by increasing the interfacial area of the CO_2 plume, the amount of dissolution as a result of mass transfer increased significantly. Moreover, the effect of convection could be stronger in the case of brine injection creating a stronger density instability and thus a more rapid initiation of convection. On the other side, when brine was injected into the system, CO_2 was displaced laterally away from the wells which resulted in a forced imbibition process by injected brine and thereby enhancing the capillary trapping efficiency.

In addition, by increasing the rate of post-brine injection, the final amount of both trapped and dissolved CO_2 enhanced. However, in lower brine injection rates, a lesser fraction of CO_2 came into contact with the injected brine. This clearly reduced the overall amount of trapped CO_2.

In addition, by increasing the duration of the post-brine injection, the overall trapping efficiency enhanced. As such, the amount of capillary trapping experienced a slight surge when the duration of injection increased. After the third year; however, no change could be seen in the capillary trapping. In contrast, the dissolution rate showed a dramatic continual enhancement as the duration of brine injection increased.

However, having said that, our findings showed that the effectiveness of post-brine injection may reduce in high vertical permeability values. As such, as the vertical permeability of the aquifer increased, the amount of both capillary and dissolution trapping reduced, resulting in the decreased effectiveness of the post-brine injection. This can be the result of the tendency of the CO_2 to migrate upward increasingly as the vertical permeability increases. Meanwhile, the capillary trapping was more affected by the vertical permeability variation than the dissolution.

Moreover, using post-brine injection had significant effect on the efficiency of all other strategies presented in this study. In this respect, adding post-brine injection improved the effectiveness of the strategy of simultaneous CO_2/brine injection in same interval and therefore the total CO_2 trapping efficiency enhanced by 14 % in total. In addition to a considerable enhancement in dissolution trapping efficiency, even though the strategy of simultaneous CO_2/brine injection without post-brine injection could barely affect the capillary trapping by just 0.4 % enhancement compared to the base case, adding post-brine injection into the system significantly improved the figure to about 5% increase. As mentioned earlier, this enhancement may be explained by a stronger lateral spreading of CO_2 as a consequence of post-brine injection which results in a forced imbibition process and thereby enhancing the capillary trapping efficiency.

Nonetheless, our results showed that the post-brine injection strategy after simultaneous CO_2/brine injection was less efficient than the strategy of two years post-brine injection following 15 years continuous CO_2 injection. Despite the fact that the dissolved CO2 remained at 22 %, trapped CO2 showed a considerable difference, where the figure was lower in the scenario of simultaneous CO2 /brine followed by two years of brine injection. Our explanation is that when CO_2/brine is simultaneously injected into the reservoir, the CO_2 spread further outwards through the aquifer than when the CO_2 is injected in the reservoir alone. Therefore, when additional brine is post injected through the aquifer less CO_2 is available to come into contact with the injected brine and consequently the CO_2 trapping is not as effective.

The effect of the post-brine injection in the simultaneous CO_2/brine injection in different intervals was also very promising. As such, the total amount of trapped CO_2 showed a significant increase compared to the same scenario without post-brine injection. In this injection design, the addition of two years post-brine injection may improve the counter-current flow formed as a result of buoyancy and gravity forces causing the CO_2 to migrate upward and the brine move downward. Furthermore, post-brine injection could help the CO_2 to spread out much wider through the aquifer than the same strategy without post-brine injection. This leads to an enhancement of the contact between the CO_2 and the under-saturated brine in aquifer. This also delays significantly the CO_2 in reaching the top of the aquifer

Moreover, adding post-brine injection enhanced the performance of horizontal system and showed the highest amount of CO_2 trapping efficiency. As such, this design created a stronger downward pressure gradient that countered the tendency of the CO_2 plume to rise. Consequently, this retarded the CO_2 in reaching the top of the aquifer and increased the time that the CO_2 could be in contact with the fresh formation brine accordingly. Another important point in this design was a more effective lateral spreading of CO_2 by adding the post injection of brine into the system which enhanced the dissolution trapping efficiency significantly.

Last but not least, the sensitivity analysis on the distance between the two injection wells in horizontal design showed that as the brine injector became further removed from the CO_2 injector, the trapping efficiency increased. However, this continued until an optimum distance and after that the behaviour was reversed. We hypothesise two possible reasons for this behaviour. When the brine injector is too far from the CO_2 injector, the advantage of the downward pressure gradient can be eliminated since the CO_2 is no longer exposed efficiently by the pressure waves. However, as this space between the two injectors is too wide, the greater volume of CO_2 can take advantage of a counter-current brine flow leading to more efficient trapping. Accordingly, the distance between the two injectors must be an optimum-neither too far resulting in the elimination of the downward pressure gradient, nor too close leading to a limiting of the space where the injected CO_2 and brine can interact.

Acknowledgements

The authors would like to acknowledge Chevening FCO as the sponsorship for the present study. We also would like to acknowledge Schlumberger for the use of ECLIPSE.

References

Anchliya, A., Ehlig-Economides, C., Jafarpour, B., 2012. Aquifer management to accelerate CO_2 dissolution and trapping, SPE Journal. 17 (3), 805-816.

Bachu, S., 2015. Review of CO_2 storage efficiency in deep saline aquifers. International Journal of Greenhouse Gas Control. 40, 188-202.

Burton, M., Bryant, S. L., 2009. Eliminating buoyant migration of sequestered CO_2 through surface dissolution: implementation costs and technical challenges. Society of Petroleum Engineers, Calgary.

Duan, Z., Sun, R., 2003. An improved model calculating CO_2 solubility in pure water and aqueous NaCl solutions from 273 to 533 K and from 0 to 2000 bar. Chemical Geology. *193*(3-4), 257-271.

Delshad, M., Wheeler, M.F., Kong, X., 2010. A critical assessment of CO_2 injection strategies in saline aquifers, Society of Petroleum Engineers, Tulsa.

Eke, P. E., Naylor, M., Haszeldine, S., Curtis, A., 2011. CO_2/brine surface dissolution and injection: CO_2 storage enhancement. SPE Projects, Facilities & Construction. 6(1), 41-53.

Ennis-King, J., Paterson, L., 2002. Engineering aspects of geological sequestration of carbon dioxide. Society of Petroleum Engineers, Melbourne.

Espinoza, D.N., Santamarina, J.C., 2017. CO_2 breakthrough—Caprock sealing efficiency and integrity for carbon geological storage. International Journal of Greenhouse Gas Control. 66, 218-229.

Holloway, S., Davage, D., 1993. The potential for aquifer disposal of carbon dioxide in the UK. Energy Conversion and Management. 34, 925-932.

Ide, S., Jessen, K., Orr Jr, F.M., 2007. Storage of CO_2 in saline aquifers: Effects of gravity, viscous, and capillary forces on amount and timing of trapping. International Journal of Greenhouse Gas Control. 4, 481-491.

IPCC, 2005. IPCC special report on carbon dioxide capture and storage, in: Mete, B., Davidson, O., De Coninck, H.C., Loos, M., Meyer, L.A. (Eds.), Prepared by orking Group III of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, pp. 442 pp.

Juanes, R., Spiteri, E.J., Orr, F.M., Bunt, M. J., 2006. Impact of relative permeability hysteresis on geological CO_2 storage. Water Resources Research. 42, W12418.

Kumar, A., Ozah, R., Noh, M., Pope, G.A., Bryant, S., Sepehrnoori, K., Lake, L.W., 2005. Reservoir simulation of CO_2 storage in deep saline aquifers. SPE Journal. 10(3), 336-348.

Land, C.S., 1968. Calculation of imbibition relative permeability for two- and three-phase flow from rock properties. Society of Petroleum Engineers Journal. 8(2), 149-156.

Leonenko, Y., Keith, D.W., Pooladi-Darvish, M., Hassanzadeh, H., 2006. Accelerating the dissolution of CO_2 in aquifers. 8th International Conference on Greenhouse Gas Control Technologies, Trondheim, pp. 19−22.

Nghiem, L., Yang, C., Shrivastava, V., Kohse, B., Hassam, M., Card, C., 2009. Risk mitigation through the optimization of residual gas and solubility trapping for CO_2 storage in saline aquifers. Energy Procedia. 1, 3015–3022.

Obi, E.O.I., Blunt, M.J., 2006. Streamline-based simulation of carbon dioxide storage in a North Sea aquifer. Water Resour. Res., 42, W03414, doi:10.1029/2004WR003347.

Qi, R., Laforce, T., Blunt, M.J., 2008. Design of carbon dioxide storage in aquifers. International Journal of Greenhouse Gas Control. 3, 195–205.

Schlumberger, 2015. ECLIPSE reservoir simulation software, technical description. Schlumberger, Paris.

Shariatipour, S.M., Mackay, E.J., Pickup, G.E., 2016. An engineering solution for CO_2 injection in saline aquifers. International Journal of Greenhouse Gas Control. 53, 98-105.

Smith, D.J., Noy, D.J., Holloway, S., Chadwick, R.A., 2011. The impact of boundary conditions on CO_2 storage capacity estimation in aquifers. Energy Procedia. 4, 4828–4834.

Spiteri, E.J., Juanes, R., Blunt, M.J., Orr, F.M. Jr., 2005. Relative permeability hysteresis: Trapping models and application to geological CO_2 sequestration. Society of Petroleum Engineers, Dallas..

Spycher, N., Pruess, K., Ennis-King, J., 2003. CO_2-H_2O mixtures in the geological sequestration of CO_2. I. Assessment and calculation of mutual solubilities from 12 to 100 C and up to 600 bar. Geochimica et Cosmochimica Acta. 67(16), 3015-3031.

Van der Meer, L., van Wees, J.D., 2006. Limitations to storage pressure in finite saline aquifers and the effect of CO_2 solubility on storage pressure. Society of Petroleum Engineers, Tulsa.

Yang, F., Bai, B.J., Tang. D.Z., Shari, D-N., David,W., 2010. Characteristics of CO_2 sequestration in saline aquifers Petroleum Science. 7, 83-92.

Riaz, A., Hesse, M., Tchelepi, H.A., Orr, F.M., 2006. Onset of convection in a gravitationally unstable diffusive boundary layer in porous media. Journal of Fluid Mechanics. 548, 87-111.

Zirrahi, M., Hassanzadeh, H., Abedi, J., 2013. The laboratory testing and scale-up of a downhole device for CO_2 dissolution acceleration. International Journal of Greenhouse Gas Control. 16, 41-49.