Security of Storage in Carbon Dioxide Enhanced Oil Recovery

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Preliminary studies from Carbon Dioxide Enhanced Oil Recovery (CO₂-EOR) in Canada have suggested that, in CO₂-EOR settings, solubility trapping takes place within both aqueous and hydrocarbon phases. As such it is postulated that CO₂-EOR may have the potential to securely store a greater quantity of CO₂ than a purely non-EOR storage operation. This study’s principal objective was to quantify how much solubility trapping takes place within both aqueous and hydrocarbon phases in CO₂-EOR settings.

The fate of CO₂ is an important consideration when injecting CO₂ into the geological subsurface. CO₂ can be trapped structurally and stratigraphically, by residual trapping, solubility trapping, and by mineral trapping (IPCC 2005). Although in a well selected storage complex a combination of each of these trapping mechanisms should lead to extremely high confidence in storage security, certain geological risks will always exist (Worden & Smith 2004). What is known however is that the highest geological storage risks exist when CO₂ is in free phase and is reliant on structural and stratigraphic trapping. Increased security of CO₂ storage will be achieved if the storage mechanism migrates from structural and stratigraphic trapping to solubility trapping in the time frame of the CO₂ storage operation.

The Pembina Cardium CO₂ Monitoring Pilot Project was used as a test site to determine the relative roles of solubility trapping. The Pembina Cardium CO₂ Monitoring Pilot site is located near the town of Drayton Valley, west of Edmonton (Alberta, Canada), in the Pembina Field (Fig. 1). The Pembina oilfield is the largest individual (Owen, 1975) and one of the oldest onshore oilfields in Canada. The pilot consisted of two five-spot injection patterns, with two of the production wells being shared by the two injector wells. This resulted in two CO₂ injectors with six surrounding producers (Fig. 1). These wells were completed in the middle of the Pembina field in an area that has been water flooded since 1962 (Dashtgard et al. 2008). CO₂ injection started in 2005 with approximately 75,000 tons of truck delivered liquid CO₂ being injected between March 2005 and March 2008. Between March 2005 and March 2007 CO₂ was continuously injected through the two injection wells. After this period the pilot switched to WAG injection with injected CO₂ being periodically alternated with water injection (Hitchon, 2009).
The lower map illustrates the location of the wells within the study area. Wells 10-11, 9-11, 7-11 and 8-11 are production wells in the classic 5 spot pattern with a CO$_2$ injector in the middle. Using wells 9-11 and 8-11, wells 12-12 and 5-12 form a second 5 spot pattern with another CO$_2$ injector in the middle. Wells 1-11 and 4-12 are also production wells, which sit further to the South.

Firstly two geochemical approaches, based on the work of Johnson et al. (2011), using empirical data from the site (gas geochemistry, production volumes and water isotope geochemistry) were used to determine the phase distribution of CO$_2$ (dissolved or free phase) at a number of production wells that were sampled monthly during the two-year CO$_2$ injection pilot. In addition a simplified reservoir simulation was performed to use as a test-bed to investigate various CO$_2$ injection scenarios with the model having some of the salient features of the pilot project. In particular the model was used to test the observations of the role of solubility trapping, both in oil and aqueous phases, versus free-phase CO$_2$ trapping.

The two geochemical methods show that the distribution of CO$_2$ in the reservoir, and hence the relative role of the trapping mechanisms, is closely matched where conditions permit both methods to work. The initial reservoir simulation model also closely matches the average CO$_2$ distribution and relative trapping contributions derived from the geochemical approaches giving extra confidence in both the methods using the empirical data and the reservoir model itself.
Subsequently the reservoir model was used to model a number of alternative scenarios including; continuous CO₂ injection, WAG, injection into a depleted oil field and injection into a saline aquifer. Results show that additional CO₂ storage by solubility trapping is achieved when an oil phase is present relative to a saline aquifer, hence increasing CO₂ security by reducing the proportion of injected CO₂ that remains as a buoyant free phase.

References


