The Wabamum Area Sequestration Project (WASP): Modeling CO_2 Injection into an H_2S Containing Saline Aquifer using Toughreact

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Introduction

CO_2 captured from point source emitters such as coal-burning power plants can be sequestered by injection into saline aquifers. This is considered a promising option for sequestering large amounts of CO_2. If the deep saline aquifers contain even minor amounts of anhydrite or other sulfate sources, H_2S may be present. If the unit in question has been buried to reach a temperature of 120°C, H_2S will almost certainly form via the process of thermochemical sulfate reduction (TSR) (Krouse et al. 1988; Hutcheon, 1999; Simpson, 1999). On a volume basis, the amount of anhydrite required to produce 50% H_2S in gas at 5% porosity is less than 1% of the rock. Typical anhydrite amounts e.g. in Devonian strata of the Western Canadian Sedimentary Basin, are much higher.

The Wabamun Area CO_2 Sequestration Project (WASP) investigates the feasibility of injecting one gigaton of CO_2 (20 Mt-CO_2 year^{-1} for 50 years) into a saline aquifer in the Western Canadian Sedimentary Basin. In the WASP study area in central Alberta, the Devonian Nisku formation was identified as a suitable aquifer for CO_2 injection due to its non-association with current oil and gas production, adequate depth, adequate containment, and good reservoir quality. Computer modeling was undertaken to determine what effects H_2S present in the reservoir would have on the injection of CO_2 into the Nisku formation.

TOUGHREACT Modeling Details

TOUGHREACT v. 1.2 (Xu and Pruess, 2001) was used to perform all of the simulations using the fluid property module ECO2N. A single layer uniform homogeneous carbonate formation with a thickness of 70 m which extended infinitely in the horizontal direction is considered in the present model. A one dimensional radial symmetrical geometry was used with non-uniform spacing. Injection of carbon dioxide was simulated at 31.69 kg/s (1 MT/year) for 50 years. The initial pressure was 16 MPa at the top of the formation. The measured water composition from brine obtained from a well located in the Nisku formation (Shevalier and Mayer, 2009) and an initial mineral composition from a representative sample of the Nisku formation (Nightingale et al., 2009) were used in the simulation.

The simulations conducted for this study considered the fate of injected CO_2 in the reservoir through geochemical interactions with the brine, with minerals present in the formation and residual trapping, i.e. how much CO_2 remained as a gas in the reservoir. Two sets of simulations were preformed, one with and one without dissolved H_2S present in the brine in order to evaluate the effect of ambient dissolved H_2S on the geochemistry of the reservoir when large amounts of CO_2 (1 MT/year for 50 years) are injected.

Results and Discussion

Initially, the pH of the brine was 6.10 across the entire reservoir. The pH distribution along the radial distance appeared to increase from values below 4.0 to 5.11 (see Figure 1). The region of pH < 4.0 is the region where there was no water present, i.e. the value of the gas saturation was ~1.0. This complete dehydration was probably due to the high rate of CO_2 injection and the region ranges from 19.7 m after one year to 136.1 m after 50 years (see Table 1). Beyond this region, the pH was initially at a value of 5.11 and remained constant, then increased over a very short distance from 5.11 to 6.44 and remained constant over the rest of the radial distance. This represents the region where CO_2 had diffused into the reservoir fluids and solubility trapping is occurring causing the pH to remain slightly acidic. This pattern was observed for both H_2S and non-H_2S aquifers.

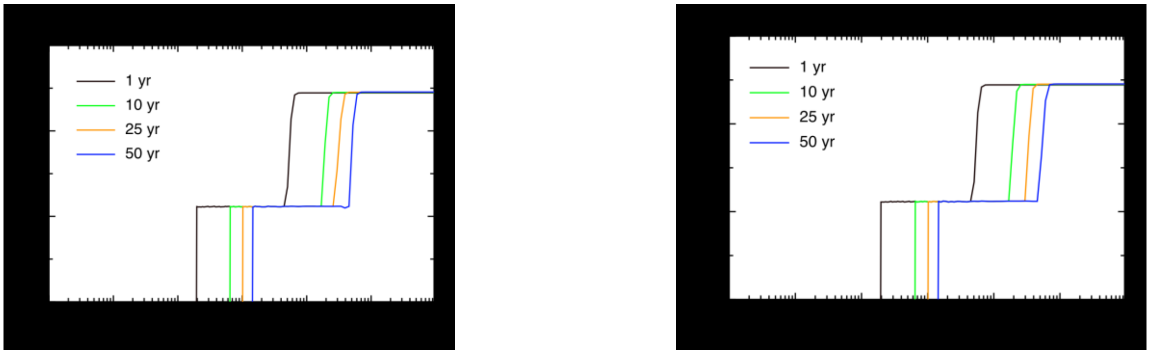

Figure 1. pH of aquifer as a function of radial distance after initiation of CO_2 injection for both non-H_2S and H_2S aquifers.

The initial concentration of bicarbonate in the brine was ~0.02 moles/kg across the entire modeling area. After one year of injection the concentration of bicarbonate in the brine was ~1.25 moles/kg at a distance of ~20 m from the injector (see Figure 2). At a distance of ~500 m the concentration decreased to the ambient value of ~0.02 moles/kg. A similar increase and decrease in bicarbonate concentration was evident for all times but at increasing distances from the injector (see Figure 2). The increase in bicarbonate concentrations along with the decrease in pH indicated that solubility trapping was occurring in this region. The gradual increase in sequestration of CO_2 over time was due to the larger fluid volumes available as the CO_2 travels radially outward into the reservoir. Further, as time progressed the amount of injected CO_2 sequestered by solubility trapping increased from 34% to 56% (see Table 1). Results for simulations with or without H_2S in the aquifer were similar.

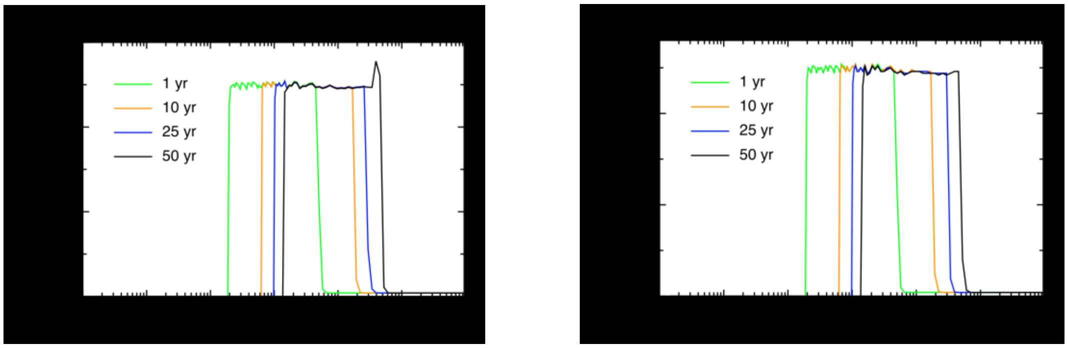

Figure 2. HCO_3 concentration as a function of radial distance after initiation of CO_2 injection for both non-H_2S and H_2S aquifers.

Time (years)	Amount of CO_2 stored in brine as HCO_3^- (MT)	Percentage of injected CO_2 stored as HCO_3^-
1.0	0.28	34%
5.0	1.66	33%
10.0	3.96	39%
12.5	5.50	44%
25.0	10.8	43%
37.5	17.8	48%
50.0	27.8	56%

Table 1: Injection time of CO_2 and amount of CO_2 stored as HCO_3 in the reservoir waters for both H_2S and non-H_2S aquifers.

There was a small decrease in dolomite present to ~100 m (see Figure 3). Thereafter the amount of dolomite present remained constant as the radial distance increased followed by a small increase. The radial distance of this volume change increased with time, from ~500 m after 1 year of injection to ~5000 m after 50 years. Calcite displayed an opposite trend, i.e. the volume fraction of calcite increased at similar radial distances then remained stable and then decreased slightly at similar distances to the dolomite change (see Figure 4). Mineral precipitation represents another method of CO_2 sequestration, but in this the case the net C sequestration via mineral trapping was negligible compared to the amount of CO_2 sequestered as HCO_3^-. The presence of H_2S did not significantly change the simulation results.

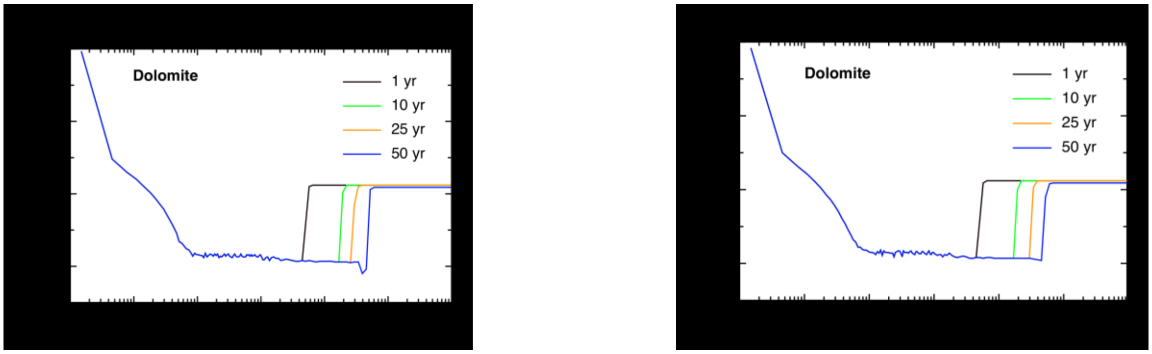

Figure 3. Dolomite mineral abundance as a function of radial distance after initiation of CO_2 injection for both non-H_2S and H_2S aquifers.

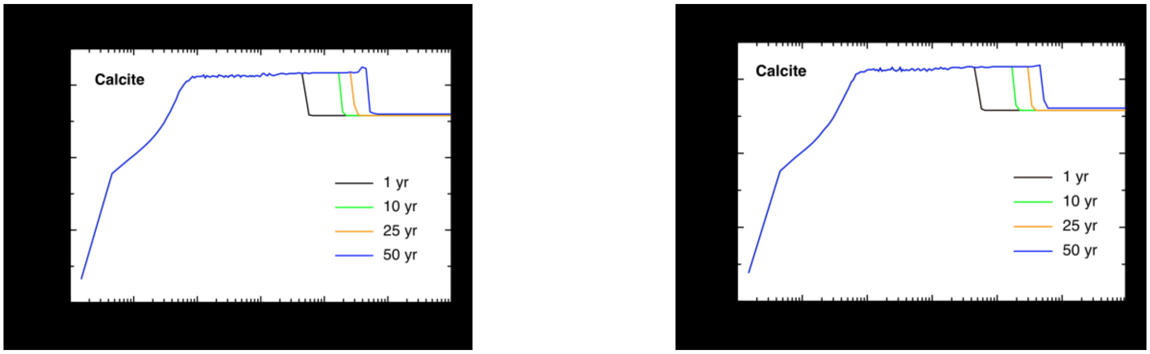

Figure 4. Calcite mineral abundance as a function of radial distance after initiation of CO_2 injection for both non-H_2S and H_2S aquifers.

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