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Geochemical modeling of CO_2 storage in deep reservoirs: The Weyburn Project (Canada) case study

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ABSTRACT

Geological storage is presently one of the most promising options for reducing anthropogenic emissions of CO_2. Among the several projects investigating the fate of CO_2 stored at depth, the EnCana's CO_2 injection EOR (*Enhancing Oil Recovery*) project at Weyburn (Saskatchewan, Canada) is the most important oil production development that hosts an international monitoring project. In the Weyburn EOR Project CO_2 is used to increase recovery of heavy oil from the Midale Beds, a Mississippian reservoir consisting of shallow marine carbonate, where about 3 billions standard m^3 of supercritical CO_2 have been injected since 2000 with an injection rate of 5000 ton/day.

In this work the available dataset (bulk mineralogy of the reservoir, gas-cap composition and selected pre- and post-CO_2 injection water samples) provided by the *International Energy Agency Weyburn CO_2 Monitoring & Storage Project* has been used in order to:

i) reconstruct the pre-injection reservoir chemical composition (including pH and the boundary conditions at 62 °C and 15 MPa);
ii) assess the evolution of the reservoir subjected to CO_2 injection and predict dissolution/precipitation processes of the Weyburn brines over 100 years after injection;
iii) validate the short-term (September 2000–2003) evolution of the in situ reservoir fluids due to the CO_2 injection, by comparing the surface analytical data with the composition of the computed depressurized brines.

To achieve these goals the PRHEEQC (V2.14) Software Package was used with both modified thermodynamic database and correction for supercritical CO_2 fugacity. The oil–gas–water interaction and the non-ideality of the gas phase (with exception of CO_2) were not considered in the numerical simulations. Despite intrinsic limitations and uncertainties of geochemical modeling, the main results can be summarized, as follows: 1) the calculated pre-injection chemical composition of the Midale Beds brine is consistent with the analytical data of the waters collected in 2000 (baseline survey), 2) the main reservoir reactions (CO_2 and carbonate dissolution) take place within the first year of simulation, 3) the temporal evolution of the chemical features of the fluids in the Weyburn reservoir suggests that CO_2 can safely be stored by solubility (as $CO_{2(aq)}$) and mineral trapping (via dawsonite precipitation). The short-term validation performed by calculating chemical composition of the reservoir fluids (corrected for surface conditions) after the simulation of 3 years of CO_2 injection is consistent (error $\leq 5\%$) with the analytical data of the wellhead water samples collected in 2003, with the exception of Ca and Mg (error $>90\%$), likely due to complexation effect of carboxilic acid.

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1. Introduction

The discharge of anthropogenic CO_2 to the atmosphere is considered as a major concern in the control of the global warming (e.g., IPCC, 2005, 2007). A very promising approach to reduce the CO_2 emissions is to capture and dispose this green-house gas (GHG) in suitable deep geological formations (>800 m; e.g., Holloway, 1996; IEA, 2004, 2006), such as saline aquifers, depleted oil and gas fields or unexploited coal beds (e.g., Quattrocchi et al., 2006a). Once injected underground, CO_2 can be retained at depth (Gunter et al., 1993, 2000, 2004), as supercritical fluid (physical trapping), fluid migrating very slowly in an aquifer (hydrodynamic trapping), dissolved $CO_{2(aq)}$ into

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groundwater (solubility trapping), and newly-formed carbonates (mineral trapping). Among these sequestration processes, mineral trapping is likely the most stable (e.g., Gunter et al., 1993, 1997).

The appealing concept that CO_2 could permanently be sequestered underground has favored several experimental and modeling studies. Whatever the trapping process of CO_2, risks of reservoir to surface CO_2 leakage and seepage have to be carefully evaluated (e.g., Pruess and García, 2002; Rutqvist and Tsang, 2002; Damen et al., 2006; Jones et al., 2006; Voltattorni et al., 2006).

The geochemical monitoring of deep fluids is a routine procedure to investigate variations in the fluid composition caused by CO_2 injection and water–rock interactions, and to track the fate of the injected CO_2 plume. Furthermore, the geochemical results are used to develop numerical modeling of deep geochemical processes to: *i)* evaluate theoretical reservoir equilibrium conditions among the several phases (through thermodynamic database, saturation indexes, activities and speciation calculations of liquid phase) and *ii)* reconstruct physico-chemical variations of the different phases at non-equilibrium conditions on the basis of kinetically-controlled reactions (e.g., Marini, 2007).

Generally speaking, owing to the great depth (>800 m) at which the potential CO_2 storage reservoirs are located, the fluid sampling mostly takes place at the wellhead rather than at down-hole (e.g., "Schlumberger" and U-tube technology; Freifeld et al., 2005; Freifeld and Trautz, 2006). Unfortunately, the surface analytical data do not often reflect the reservoir conditions (temperature, pressure, pH and chemical–physical boundary conditions). As the fluid moves from the reservoir to the wellhead, both pressure and temperature decrease. Part of the fluid constituents is lost as gas phase, causing both disequilibrium among the present phases and changes in the fluid chemistry (e.g., Kharaka and Hanor, 2004; Quattrocchi et al., 2006b). Several procedures allow to reconstruct deep fluid composition (e.g., Bazin et al., 1997; Palandri and Reed, 2001; Marini et al., 2003), although their application is usually restricted to geothermal reservoirs (temperatures >100 °C). In these environments pressure can be parameterized as a function of temperature rather than an independent variable, being the pressure fixed at 0.1 MPa for 0–100 °C and following the steam/liquid water equilibrium curve at higher temperatures (100–300 °C; Wolery, 1992). The steam/liquid water curve can be reproduced at laboratory conditions and used to calculate the thermodynamic parameters. For example, Marini et al. (2003) reconstructed the reservoir composition (250 °C and 3 MPa) of geothermal fluids discharged at Miravalles volcano (Costa Rica) highlighting significant compositional variation (about 27%) between the fluids sampled at the wellhead and those computed from the fluids of the reservoir.

Conversely, sedimentary basins suitable for CO_2 geological storage (e.g., oil field pool, saline aquifers) are characterized by low temperature (30–70 °C) and relatively high pressure (>5 MPa). As a consequence, independent thermodynamic parameters cannot be calculated through steam/liquid water curve. Palandri and Reed (2001) approached the problem by assuming a thermodynamic equilibrium between formation waters and reservoir minerals, although their procedure did not take into account the influence of free and/or dissolved gas phases (with exception of CO_2) on chemical composition of the aqueous solution.

In this framework, the main goal of this work is to propose a geochemical model for the hosting aquifers of the Weyburn Oil Field (Canada), where anthropogenic CO_2 is injected since 2000, in order to: *i)* reconstruct the pre-injection reservoir chemical composition of the two reservoirs (Marly and Vuggy) where CO_2 is stored by using the geochemical data obtained at the wellhead and provided by the *International Energy Agency Weyburn CO2 Monitoring & Storage Project, ii)* assess the (kinetic) evolution of the system during the CO_2 injection and quantify the geochemical trapping mechanisms over 100 years after injection, *iii)* validate the simulated short-term (3 years) evolution of the reservoir during the CO_2 injection by comparison the simulated data with those measured at the wellhead.

2. The Weyburn Oil Field

The Weyburn Oil Field (hereafter WOF) is located in the Prairie Province of Saskatchewan (Western Canada) in the Midale Beds of the Mississippian Charles Formation. The latter is at the depth of 1300–1500 m (El Sayed et al., 1993) and is divided in the Frobisher Evaporite and the Midale Carbonate. Shallow marine carbonate-evaporitic rocks

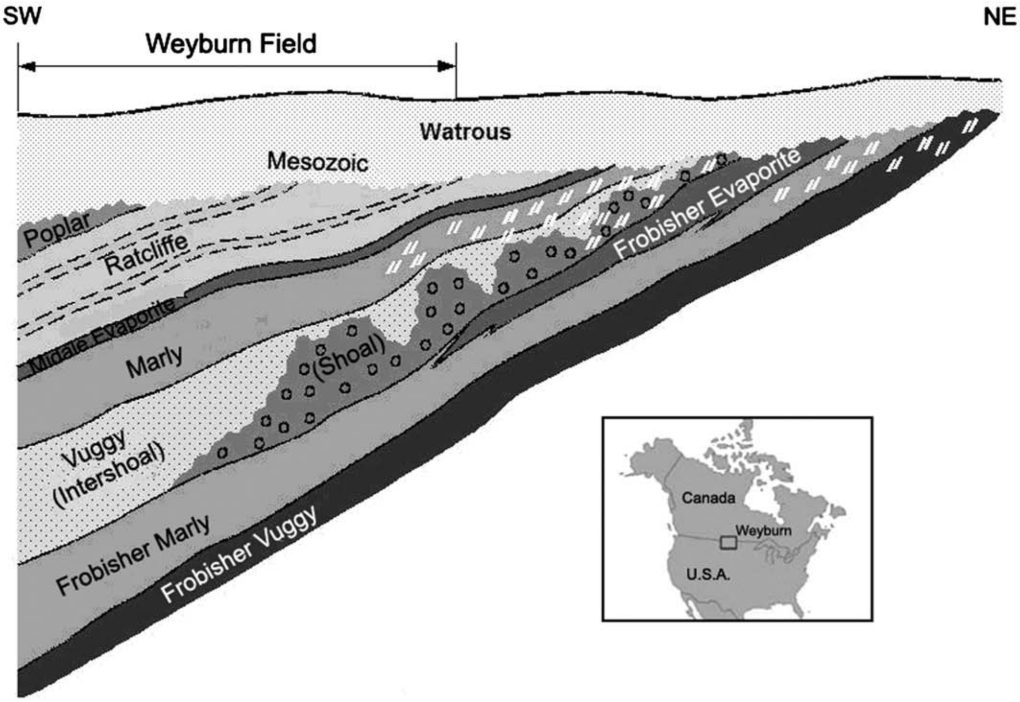

Fig. 1. Location and schematic SW–NE geological cross-section of Midale Beds. The carbonate strata of the oil reservoir are sealed by evaporite beds (Midale Evaporite) and by the Mesozoic Watrous Formation. Modified after Wilson and Monea (2004).

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