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Near wellbore processes and water-rock reactions driven by the geologic sequestration of dry CO_2 in a natural gas layer.

M. Marcolini (1), C. Geloni (1), A. Battistelli (1), F. Gherardi (2) and S. Biagi (2)

(1) Snamprogetti SpA, Fano, Italy, (2) Institute of Geosciences and Earth Resources (IGG), National Research Council of Italy, (CNR), Pisa, Italy (marica.marcolini@snamprogetti.eni.it / Fax: +39 0721-881984 / Phone: +39 0721-881739)

Within the studies performed to evaluate the feasibility of CO_2 geologic sequestration in an exploited natural gas reservoir, the near wellbore flow and reactive transport coupled processes driven by the injection of dry CO_2 were investigated by means of numerical simulation. The focus of this study is on the physical and geochemical processes affecting the mineralogical composition and petrophysical properties of the reservoir formations, and their possible relevant consequences on injection performances.

To obtain a reliable description of these processes, the non-isothermal, multicomponent reactive geochemical transport simulator TOUGHREACT (Xu et al., 2004), coupled to the equation of state (EOS) module TMGAS (Snamprogetti, 2006; 2007), was employed. TMGAS was developed in the framework of the TOUGH2 V.2 reservoir simulator (Pruess et al., 1999). The new EOS module can simulate two-phase equilibrium of sodium chloride-dominated brines with non aqueous (NA) phase made up of hydrocarbons (alkanes up to C10, BTEX and pseudo-components) and inorganic gases, such as CO_2, H_2S and N_2. The NA phase can be either in gas, liquid or supercritical conditions, with the limitation that a full three-phase equilibrium cannot be handled by the present code version. The Peng Robinson EOS is used with the modifications suggested by Soreide and Whitson (1992) to compute the phase equilibrium between the brine and the NA phase, using binary interaction coefficients for

the aqueous phase calibrated against recently published data of gas solubility in brines as a function of temperature, pressure and salinity.

Simulations of the non-isothermal injection of dry CO_2 under both supercritical liquid-like and liquid conditions were performed to study the short-to-medium term evolution of an exploited sand layer containing natural gas. Field and laboratory data are available for i) the petrophysical properties and mineralogical composition of the rocks, ii) the initial composition of formation water, iii) initial temperature (T=45˚C) and pressure (P=140 bar) in the reservoir. Porosity, permeability and liquid saturation are assumed uniformly distributed into the domain with an initial mean values of 0.32 (volume fraction), 400 mD and 0.15, respectively. The modelled domain consists of an horizontal 1D-radial grid, with the injection well located on the symmetry axis and with a large external radius to minimize boundary effects. The simulations of constant rate injection of dry CO_2 are performed for a period of 100 years.

Two different scenarios are presented:

case (A) - injection of supercritical liquid-like CO_2, downhole temperature of about 37˚C

case (B) - injection of liquid CO_2, downhole temperature of about 25˚C.

The non-isothermal injection of dry CO_2 determines the development of three different fronts moving from the injection well with different speeds: i) a displacement front separating the natural gas from the injected CO_2; ii) a thermal front between the CO_2 warmed up to reservoir temperature and that still at the injection temperature; iii) an evaporation front at which the salts dissolved in the brine are concentrated in the residual brine to ultimately precipitate.

The fluid flow pattern is very similar for both cases: the natural gas displacement front reaches a distance of about 1000 m after 100 years. The injection of dry CO_2, moreover, promotes the advancement of an evaporation front, located at about 50 m from the injection well at the end of injection. In the short term, only negligible amounts of minerals are predicted to precipitate/dissolve within the injection layer. CO_2 dissolution in the immobile brine reduces the pH of the aqueous phase in the region delimited by the evaporation and displacement fronts, driving a slight dissolution of dolomite and a moderate precipitation of calcite. This effect is more evident in the lower temperature case. However, in both cases no significant CO_2 mineral trapping is predicted to occur by the code. The very low system reactivity determines undetectable porosity variations and, consequently, does not affect the injectivity of reservoir formation during CO_2 storage operations.

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