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Heterogeneous saline formations for carbon dioxide disposal: Impact of varying heterogeneity on containment and trapping

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Abstract

Natural gas fields often contain carbon dioxide in their reservoir fluids. Exploitation of these resources requires the removal of carbon dioxide from produced fluids to meet quality standards for sale into a domestic market or for the processing of the gas into LNG. To limit the atmospheric emissions of carbon dioxide, a major greenhouse gas, it has been proposed that one method of abatement could be to inject the CO_2 into deep saline formations. This study shows that the selection process for identifying appropriate saline formations should not only consider their size and permeability but should also consider their degree of heterogeneity. To this end, notional yet realistic geological marine sand models were constructed, on an areal scale of 50 km^2, to examine the effects of reservoir heterogeneity on the migration and storage of a 50 million tonne plume over a time scale of 1000 yrs. The models were identical in geometry and in their distribution of porosity and permeability but were individually populated with facies realisations for different net-to-gross ratios. Standard geostatistical techniques were used to generate the various distributions. With regard to the shale content, the ratio of sand to shale was varied from 100:0 (i.e. homogeneous) to 40:60. A radial shale variogram, with a length of 300 m, was used. The models were up-scaled, using flow-based methods, to make the computation feasible. A set of metrics were developed and used to compare plume migration (both vertically and laterally) and containment (through dissolution and residual phase trapping) between the various scenarios. The study showed that heterogeneity had a significant impact on the subsurface behaviour of the carbon dioxide. Increasing the shale content, corresponding to a gradual decrease in reservoir quality, progressively inhibited vertical flow of the plume whilst promoting its lateral flow. This increase in the tortuosity of the carbon dioxide migration pathways resulted in a reduction in the rate of residual gas trapping through hysteresis effects. Ultimately, however, less carbon dioxide is likely to collect under the seal, thereby reducing the risk of seepage to overlying formations. It is evident that for the time scales of containment being considered here simulation periods of the order of tens of thousands of years, or even longer, will be required to demonstrate the onset of an equilibrium state.
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1. Introduction

The emission of greenhouse gases such as carbon dioxide (CO_2) into the atmosphere has been associated with alterations in the Earth's climate (Houghton, 2001). The injection of CO_2 into subsurface saline formations for the purpose of greenhouse gas control has been proposed

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as means of responsibly reducing anthropogenic CO_2 emissions (Hitchon, 1996; Cook et al., 2000). There are several natural gas production projects currently operating that dispose of associated reservoir CO_2 into subsurface formations for greenhouse gas emission avoidance, including projects at Sleipner in the North Sea and In Salah in Algeria. Notable future natural gas production projects which plan to dispose produced reservoir CO_2 in the subsurface include the Gorgon LNG Project in North-Western Australia and Snohvit LNG Project in Norway. Natural gas projects with reservoir CO_2 are natural candidates for CO_2 disposal as CO_2 and other acid gases must be removed from reservoir gas prior to liquefaction process of LNG manufacturing or to meet quality standards required for domestic gas sales. There are also some small scale disposal projects such as the Frio Brine project, recently conducted in Texas, that act as pilot projects to demonstrate to government and stakeholders the effectiveness of current technology with regards to the safe injection of CO_2 into saline formations (Hovorka et al., 2004). In the case of the Sleipner gas project in Norway, this full field scale natural gas production project has been injecting CO_2 into the Utsira Sand saline formation for nearly a decade, while supplying Europe domestic market with natural gas (Korbol and Kaddour, 1995; Baklid et al., 1996).

Recent studies are helping to develop selection criteria for potential geological storage sites to be used to sequester CO_2 from industrial sources. The research carried out by the Australian GEODISC consortium in determining ESSCI (Environmentally Sustainable Sites for CO_2 Injection) locations are an example of this type of study (Bradshaw et al., 2002). Bachu, working for the Alberta Research Council in Canada, has developed a set of selection criteria for formations for CO_2 disposal and a general road map for site selection activities for industry and government (Bachu, 2000, 2002).

The selection of a potential geological target for the sequestration of CO_2 must meet strict technical criteria to ensure, as far as is reasonably possible, the high probability of success of any sequestration project that might be undertaken. These criteria must address the issues of containment, capacity, injectivity, and reservoir surveillance.

The basis for demonstrating sufficient containment for injected CO_2 in a selected formation has usually focused on the presence of a geological seal and trap capable holding a column of CO_2 (Bradshaw et al., 2002). However, the containment of CO_2 in a saline formation can be achieved through three additional permanent storage mechanisms without relying entirely on an overlying seal.

Firstly, containment may occur through the dissolution of CO_2 in the formation water. The solubility of CO_2 in water is dependent on the salinity, pressure and temperature of the formation water (Chang et al., 1996). As CO_2 is injected into the formation it contacts virgin formation water and mass transfer occurs, with CO_2 dissolving into the water until an equilibrium state is reached. At any given time the system will contain a mixture of virgin water, a plume of injected CO_2 and water that has, to some degree, CO_2 dissolved in it. The literature offers some information regarding the solubility of CO_2 in hydrocarbons and water contained in subsurface formations (e.g. Enick and Klara, 1990). Ennis-King and Paterson (2003) have investigated the mass transfer at the interface of a plume of CO_2 and the formation water as it migrates upwards. Under typical reservoir conditions, water that has CO_2 dissolved in it is denser than virgin formation water. This contrast in density ultimately leads to instabilities in the water column, which create convection currents. These currents bring water with a relatively lower saturation of dissolved CO_2 into contact with the plume, promoting further dissolution. As a method of increasing storage this convection mechanism is far more efficient in transporting CO_2 than diffusion but, nevertheless, is still an effect that only manifests itself over long periods of time.

A second method of containment is through the CO_2 being trapped as a residual phase. This happens when water is imbibed behind the migrating CO_2 plume, and is caused by what is known as the gas–water relative permeability hysteresis effect (Flett et al., 2004a,b). As CO_2 is injected into the saline formation, a drainage process occurs as water (the formation wetting phase) recedes from the advancing non-wetting CO_2. After injection ceases, movement is driven by the buoyancy (density) contrast between the lighter CO_2 plume and the denser aquifer water. As the CO_2 plume migrates upwards after injection ceases, water imbibes behind the plume. This process traps, through the action of capillary forces, CO_2 in the form of bubbles, in pore throats, thereby developing an immobile residual phase. Previous reservoir simulation studies have outlined that residual phase gas trapping could be significant in storing CO_2 (Flett et al., 2004a,b; Kumar et al., 2004). It should be noted that this storage mechanism is a post injection process whereas dissolution takes place both during and after injection.

A third storage mechanism is mineralisation. This mechanism can permanently store injected CO_2 as part of the formation matrix. The process of CO_2 dissolving in formation water can lead to the formation of carbonic acid, which can then react with susceptible minerals in the formation rock. This will result in certain minerals being dissolved and others being precipitated. The mineralisation process is slow and complex, and the

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