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Control Of Pressure Propagation In A Heterogeneous CO2 Storage Reservoir Using Water Production

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Summary

Injection of CO2 into a reservoir increases the pressure above initial values, resulting in overpressure of a hydrostatically charged formation. Without careful monitoring and management, excessive pressure can lead to a number of serious complications for a CO2 storage operations. Using numerical simulations with four distinct porosity/permeability distributions to represent reservoirs with random and structured heterogeneity. We initially consider the impact heterogeneity has on pressure propagation from a CO2 injection well; in particular the effect of channels on the lateral extent of the region of increased pressure. Subsequently, we investigate how heterogeneity influences the efficacy of water production as a pressure management tool and the optimisation of well positioning. For a channelized reservoir the most effective production well, which reduces the area of high pressure by up to 88%. Even in a randomised reservoir with no structured distribution of porosity and permeability, water production can still reduce the high pressure footprint by 60-88%. The location of the production well relative to the heterogeneity has been shown have a significant effect. The most effective production well location may not always be close to the target, but should be connected to the target by relatively high permeability pathways.

Introduction

Heterogeneity is a pervasive property of many geological reservoirs and is a widely studied aspect for hydrogeology, hydrocarbon recovery, and CO_2 storage. As part of the ACT funded Pre-ACT project, this study investigates the impact of heterogeneity on pressure propagation in CO_2 storage reservoirs.

Injection of CO_2 into a reservoir necessarily increases the pressure above initial values, resulting in overpressure of a hydrostatically charged formation. Without careful monitoring and management, excessive pressure can lead to a number of serious complications for a CO_2 storage operation such as: reactivation of existing faults and fractures (Dockrill and Shipton, 2010); the creation of leakage pathways through historical wellbores (Cavanagh and Rostron, 2013); and geomechanical damage to the caprock and overlying strata in the overburden (Rutqvist, 2012). Issues with increasing pressure were observed in the Tubåen Formation at the Snøhvit site where injection was terminated due to concerns of approaching the fracture pressure (Grude *et al*., 2014; Hansen *et al*., 2013). In the first section of this study, we consider the impact heterogeneity has on pressure propagation from a CO_2 injection well; in particular the effect of channels on the lateral extent of the region of increased pressure.

For several years, water extraction from CO_2 storage reservoirs as a pressure management technique has been considered. The removal of resident water allows additional pore volume to be utilised for CO_2 storage, thereby increasing the capacity of a given site, and can be used to reduce the pressure near particularly high-risk localities, such as known fault zones and historical well bores. A number of studies use numerical simulations to determine the optimal positioning of production wells for pressure reduction at the injection point (Cameron and Durlofsky, 2012) and at a separate target zone (Birkholzer *et al*., 2012; Cihan *et al*., 2015). A five-spot pattern of production wells around a central injection point is the preferred geometry for limiting pressure at the injection point but this assumes a homogeneous reservoir (or the absence of distinct alignment in heterogeneity) and an axisymmetric influence from each well (Mathias *et al*., 2011). In the second section of this study, we investigate how heterogeneity influences the efficacy of water production as a pressure management tool and the optimisation of well positioning. We use numerical simulations with four distinct porosity/permeability distributions to represent reservoirs with random and structured heterogeneity.

Methods

The parameters in this study were chosen to be relevant to the proposed Smeaheia storage operation, Norway (Ministry of Petroleum and Energy, 2016) for the new full scale CCS value chain. This provides a realistic context for studying the effects of heterogeneity on pressure propagation and CO_2 migration.

A simple model was constructed, extending 20 km by 20 km laterally and 200 m thick. The top of the reservoir is flat and located at a depth of 1200 m. The lack of topography on the model or any dip is important as this study is focused primarily on the effects of heterogeneity. A statistical framework to generate appropriate variability in the models was adopted. Von-Kàrmàn autocorrelation functions were utilized, with appropriate orthogonal scale lengths, to derive the power spectra for the parameter variability. Pore volume multipliers were used on the lateral edges to represent an open aquifer. A range of porosity and permeability distributions were generated based on core plug data from nearby Norwegian wells with varying levels of correlation to represent different forms of heterogeneity from significantly channelized to small-scale random (Figure 1).

Numerical simulations of simultaneous CO_2 injection and water production were performed with a black-oil set-up using INTERSECT™ software (Schlumberger). A single well at the centre of the model, perforated through the entire thickness of the reservoir, was used to inject 1 Mt/a CO_2 for 50 years. Water production was also through a single vertical well, perforated through the entire reservoir interval located 5 km away. The rate was chosen such that an equivalent reservoir volume of water was produced to that of CO_2 injected. This volumetric 1:1 ratio has previously been used in other studies (e.g. Birkholzer *et al.*, 2012; Vosper *et al.*, 2018).

Results for CO_2 injection only

Heterogeneity in the permeability and porosity distribution has a significant effect on the flow path of a plume of CO_2. Preferentially, CO_2 will travel along the path of least resistance, i.e. the highest permeability. Where there are high permeability channels available, the CO_2 fills these first, avoiding low permeability channels wherever possible (Figure 1B, C). For cases with a very random permeability distribution, changing rapidly over short length scales, a CO_2 plume with a correspondingly random shape is observed from the modelling (Figure 1D).

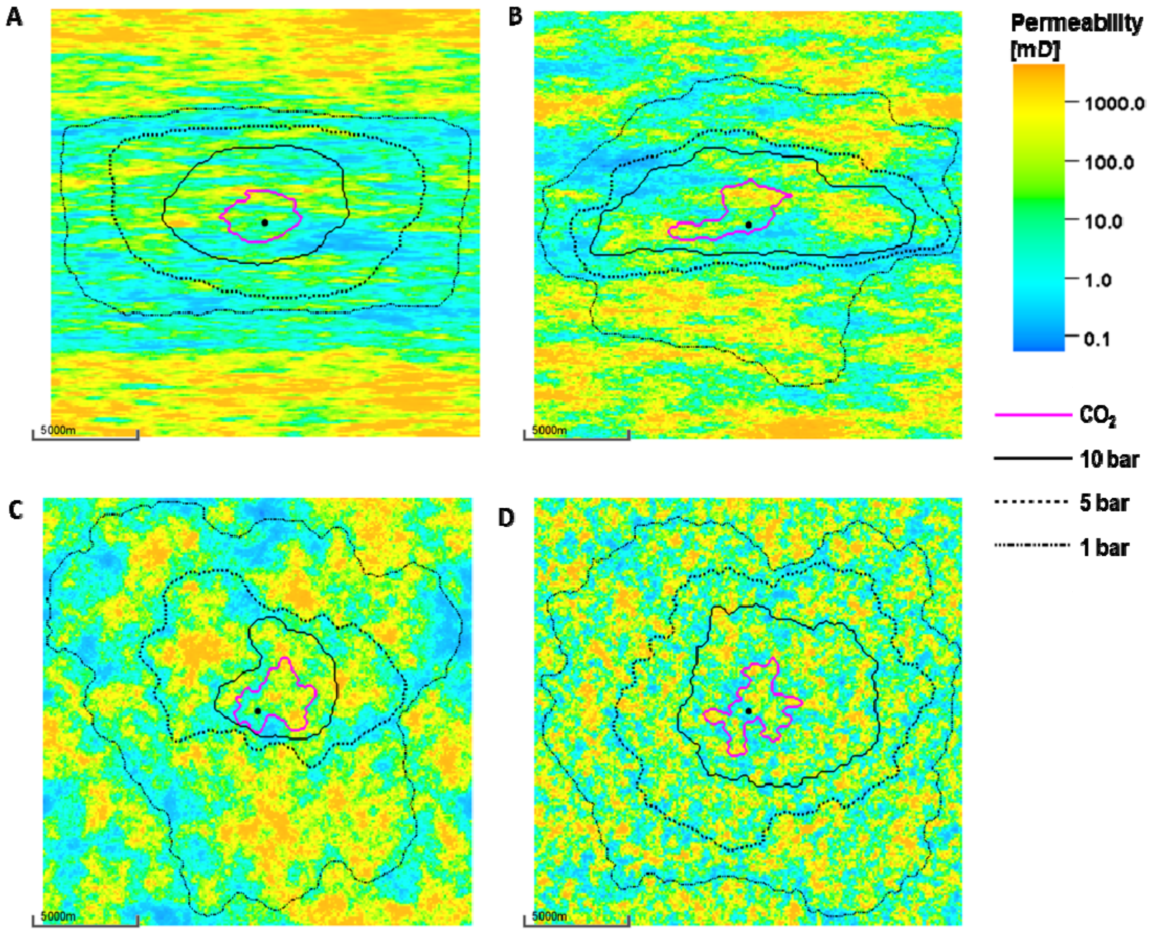

Figure 1 *Results showing the extent of the CO_2 saturation in all layers (pink) for four different permeability distributions (top layer only shown). Pressure increase contours displayed at 1, 5 and 10 bars.*

The extent and shape of the pressure increase due to CO_2 injection into a reservoir are directly influenced by the porosity, permeability, and any heterogeneity in these properties. Areas of low permeability intuitively give rise to higher pressures (Figure 1A). Distribution D gives the most radial pressure contours due to the small-scale variation in heterogeneity.

Results with water production

For permeability distribution A, the most effective production well location is in the West, which reduces the area of high pressure by 88%. This is because there is a relatively high permeability path between the production and injection wells (Figure 2A). Water production from the South is not effective (only 9% reduction in area) due to the area of low permeability between the production well and the area of high pressure. Although the southern production well for distribution B is placed in a high permeability channel it is not well-connected to the injection sire and only reduces the pressure in the South of the model, behind a low permeability channel (area reduction of 22%). This results in a depletion of part of the reservoir and only very limited reduction of the injection pressure. In case C, the production well in the North is not very effective because it is located in a patch of low permeability (5% reduction in area). In fact, production from the southern well is more effective at reducing the pressure north of the injection well than water production from the northern well. This result is not intuitive without consideration of the permeability distribution. Although case D has the most random distribution of permeability and no evident directional alignment, the impact of water production on the pressure is still very dependent on production well location and the area of high pressure is reduced by 60-88%.

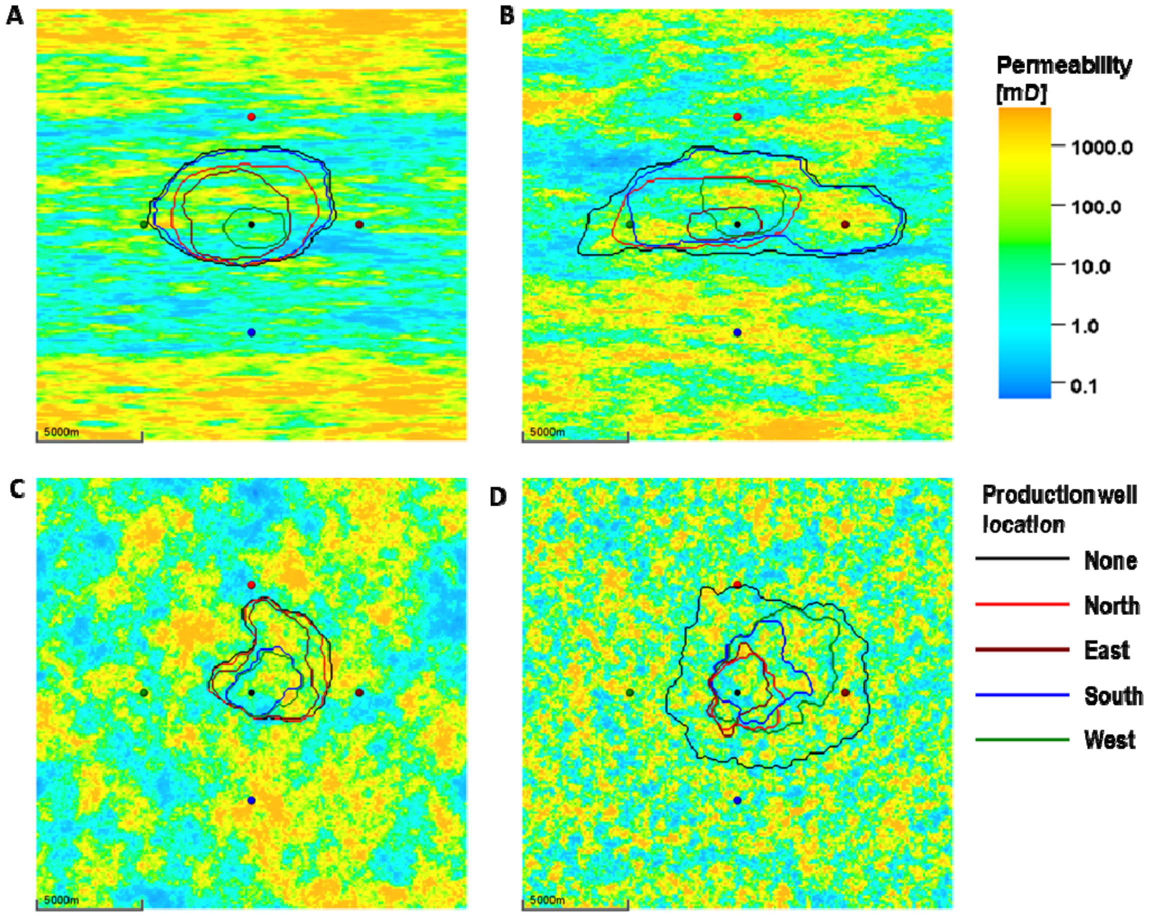

Figure 2 *Results showing the 10 bar pressure increase contour for four different production well locations. Black lines correspond to no water production, red indicates the 10 bar pressure increase contour with water production from the northern well (marked with a circle), brown from the East, blue South and green West. All production well locations are 5 km away from the injection well.*

Conclusions

Heterogeneity will determine the path of choice for CO_2 travel and any *a priori* knowledge of this heterogeneity (for example channels shown on seismic attributes) should be utilised for modelling and the positioning of injection wells as well as the design of monitoring systems.

This study has reiterated that water production does have an influence on the pressure in a CO_2 storage operation. The location of the production well relative to the heterogeneity has been shown have a significant effect. The most effective production well location may not always be close to the target, but should be connected to the target by relatively high permeability pathways. This work will be expanded as part of the Pre-ACT project with consideration of the environmental impact of disposal of produced saline water, including appropriate volumes and rates. The simulations are to be utilised in the creation of a conformance modelling tool.

Acknowledgements

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