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Effects of geological heterogeneity on CO_2 distribution and migration - A case study from the Johansen Formation, Norway

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Abstract

In characterizing subsurface reservoirs for CO_2 storage, the geological heterogeneity distribution is of importance with respect to the injectivity and migration paths. The object of this study is a saline aquifer of Jurassic age; the Johansen Formation of the Northern North Sea. Through scenario modeling the effect of site-typical geological heterogeneities of depositional origin have been tested. The existence of laterally continuous calcite cemented layers and draping mud layers of low permeability in association with flooding events, could compartmentalize the reservoir. This is not necessarily a disadvantage; however, as the sweep efficiency becomes higher when the plume is spread out, potentially increasing the effect of trapping mechanisms.

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Keywords: CO_2 storage; reservoir characterization; Johansen Formation; North Sea; fluid flow modeling; geological heterogeneities

1 Introduction

The aim of the study is to investigate the reservoir properties and the effect of site-typical depositional geological heterogeneities with respect to CO_2 storage in the Johansen Formation (Northern North Sea, Norway). This deep, saline aquifer is a candidate for large scale CO_2 storage from an onshore gas power plant situated on the west coast of western Norway, which is proposed by Norwegian authorities to operate with full scale CO_2 handling. The storage capacity needed is in the order of 2 Mt CO_2/year.

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A major challenge with respect to prediction of injectivity and storage capacity for CO_2 in subsurface saline aquifers is how to utilize sparse subsurface data to establish a robust reservoir model. The Norwegian continental shelf is well covered by seismic surveys and penetrated by more than 5051 wells (of which 1366 are exploration wells) since the late 1960's in search for hydrocarbons or for production development. The Johansen Formation, however, contains no proven hydrocarbon resources, explaining why direct lithological data are scarce.

2 Geological Setting

Three large scale depositional units displaying regressive to transgressive sequences, or mega sequences, are observed within the Dunlin Group in the eastern part of northern North Sea. The sequences are interpreted as three major clastic wedges built out from the hinterland. The Johansen mega sequence is one, and comprises the formations Johansen, Amundsen and the lower part of Burton [1]. The Johansen Formation is a sandstone body of early Jurassic age (Sinemurian to Pliensbachian) [2] (Figure 1). The sand deposits display westerly progradational features from the central Troll Field, including some large clinoform geometries. The vertical grain size trend, electric log pattern and depositional geometry revealed from seismic data have been interpreted to correspond to a progradational to retrogradational delta outbuilding. The Johansen Formation was mainly deposited during low stand. Initial deltaic growth was interrupted several times by incidents of sea level rise, before deposition during a longer period of dominantly uninterrupted basinward progradation [3]. The average formation thickness is around 100 m. Large scale reservoir geometries within a sequence stratigraphic framework have been interpreted from 2D and 3D seismic data and wire line logs from 25 penetrating wells. The burial depths in the study area vary from approximately 2000 m to 4000 m. The large variation in depth reflects displacement along large faults during extensive rifting in late Jurassic – early Cretaceous, in combination with late Cenozoic uplift [4]

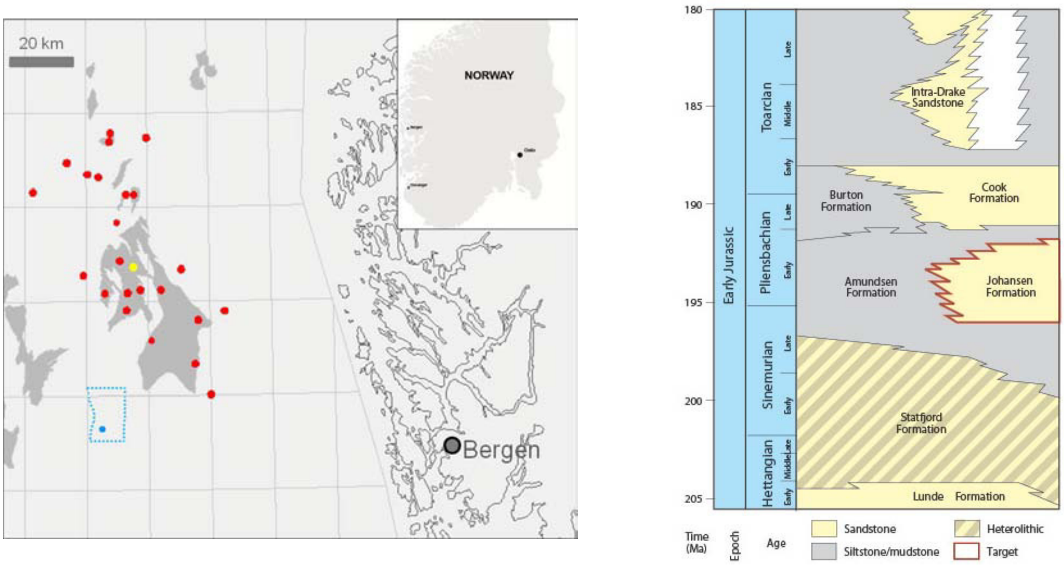

Figure 1: (a) Map of study area offshore Norway, displaying wells penetrating the Johansen Formation (red dots), cored well 31/2-3 (yellow dot), oil/gas fields including Troll (grey), the modelled area (blue square) and injection well (blue dot) (b) Stratigraphy of the Dunlin Group (modified from [5])

The Johansen Formation may be described as a micaceous, feldspathic arenite, and comprises relatively thick successions of porous sand and poorly consolidated sandstone in the central parts, with the formation top at burial depths of around 2000 m, while more distal, less sandy facies are representative of the wells towards the north, west and south. The well log signatures typically display a progradational to retrogradational pattern, with some internal flooding surfaces. A middle aggradational phase is particularly well developed in the more proximal parts. The rather narrow and southwestward elongation of the sand-dominated lithology of the Johansen Formation is in favour of a river-dominated delta, with delta slope and prodelta facies represented by the lower fine-grained, progradational part, delta top with fluvial plain by the middle aggrading part, and back stepping facies belts by the upper retrogradational part. Intermittent events of marine flooding may have given rise to mud drapes and accumulations of marine shell beds of various lateral extents. Potential injection points for CO_2, however, are likely be located further south (Figure 1a) and at larger depths (~3000 m) in order to prevent interference with the operating gas field. Apparent sand-dominated facies developments in this area are outside well control, in a position further basinward where higher wave dominance is probable.

3 Reservoir Properties

Detailed mineralogical information (microscopy, XRD) has been obtained from eighteen meters of core in one well (Figure 1), and from some side wall cores and cuttings from additional six wells. These wells were drilled in connection with exploration and development of the Troll gas field, in an area where top Johansen is at burial depths around 2000m. In the following, geological observations of particular importance with respect to reservoir porosity and permeability distribution are described.

3.1. Pore filling Kaolinite

Kaolinite is a common alteration product from feldspar dissolution and mica alteration and occurs both as grain replacing and pore filling. Muscovite altered to kaolinite reveals a splaying effect of grain expansion into the pore space, reducing permeability. Despite relatively high feldspar contents (in the order of 15 vol %), it is evident that a significant amount of original feldspar has been leached. Obvious secondary porosity in the form of grain molds is small (0-2 vol %). Partly dissolved feldspar grains with internal secondary porosity, however, are common.

Approximate volume estimates of kaolinite from SEM (Figure 2a) (including both pore filling and pseudomorph clay) commonly reach 15 % in the sampled shoreface facies. Kaolinitization is dependent on water through flow to remove potassium and excess silica and is therefore often more extensive in highly permeable zones [6]. It is also likely that more proximal areas experiences higher meteoric water fluxes compared to more distal parts. With increasing burial and decreasing pore water flux kaolinitization is expected to cease, and not to cause further permeability decrease.

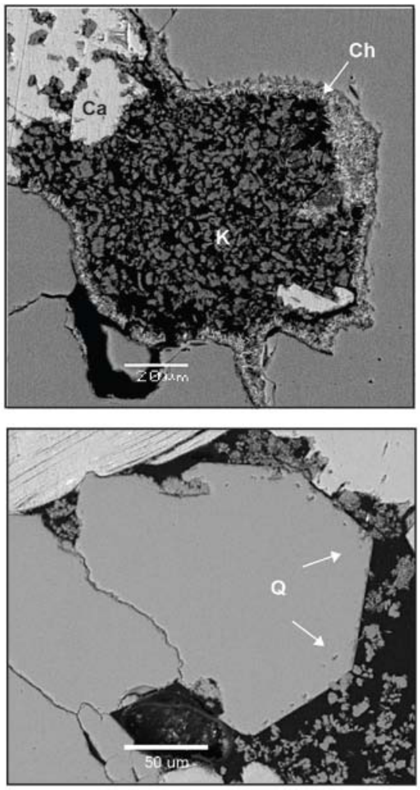

Figure 2: SEM images from well 31-2-3 (a) Pore filling kaolinite (K) , grain coating chlorite (Ch) and calcite cement (Ca) (b) Autigenic quartz (Q) overgrowth

3.2. Chlorite Coating

Chlorite coating on detrital quartz grains prevents the quartz surface from contact with the pore water, and has proved to be efficient with respect to preservation of porosity during deep burial by inhibiting quartz overgrowths [7]. Chlorite coated quartz grains are common in the samples from the Johansen Formation (Figure 2a), but the coating is patchy and of variable thickness. The current reservoir conditions in the study area, with temperatures around 70°C and pressures at about 200 bar, coincides with the onset of early quartz cementation [8]. Quartz overgrowths are observed (Figure 2b), implying that the porosity in the sandy facies of the Johansen formation will be slightly lower at 3 km. Deltaic and fluvial environments are the most common depositional environment for chlorite coated quartz grains, and abundant chlorite coating is observed in thoroughly studied sandstones above and below the Johansen Formation, also in sandstones deposited further basinward compared to the study area [7] [9]. Chlorite coats on smaller grain sizes might lower permeability [10]. Chlorite may also appear as pore-filling, or –lining. This effect would be accounted for in plug permeability measurements, and is also likely to be minor relative to the effect of kaolinite in this case.

3.4 Calcite Cemented Layers

Petrophysical well data, cores and cuttings samples show the presence of calcite cemented layers within the sandy facies of the Johansen Formation (Figure 3a). Prosser et al. [11] correlated calcite cemented layers between eleven closely spaced wells in delta front and shoreline deposits of the Rannoch and Etive formations and found that some layers within the Rannoch Formation were laterally extensive (> 8 km). The most likely source of the calcite cement in the Johansen Formation could be local accumulations of biogenic aragonitic skeletal particles (*e.g.* mussels) dissolving and re-precipitating as calcite. Shell banks may accumulate during periods of low clastic sediment input. The biogenic carbonate may dissolve and re-precipitate *in situ* or within transported and re-deposited storm- or channel lags [12]. Continuous layers are formed when strata bound concretions growing from separate nuclei merge, and are ultimately controlled by the depositional conditions and amount of carbonate available. The rate will be controlled by diffusion at low flow rates during burial [12] [13] [14]. Well established models for prediction of the areal extent and thickness of calcite cemented layers in deltaic sequences does not exist, and there is not necessarily a positive correlation between the bed thickness recorded in cores and/or petrophysical logs and the areal extent of the cemented horizon [12].

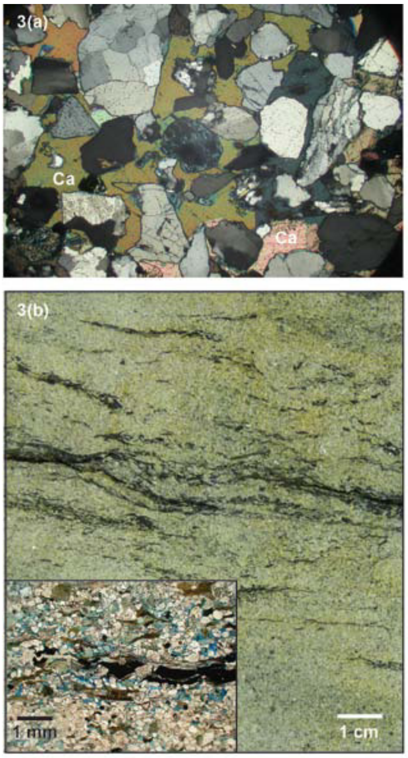

Figure 3: Photos from core and thin section in well 31-2-3 in the Johansen Formation (a) 2118.4m Calcite cemented sandstone, porespace completely filled. (b) 2129.8.m Draping layers of coal and mica.

3.3. Preferred Orientation of Mica

In core sections mica flakes and elongated, light carbonaceous fragments display preferred orientation and draping layers (Figure 3b). The depositional setting is interpreted to reflect lower energy settings in the delta front, which also coincides with a finer grain size. On a micro-scale such layers are likely to reduce the vertical permeability.

4 Scenario Modeling

The uncertainty introduced due to data scarcity makes scenario modeling useful in evaluating risk and reservoir suitability. Eclipse 300 (Schlumberger software) was applied to perform multiphase fluid flow simulations on some different scenarios based on interpretation of controlling factors, as described in the above. Clinoform geometries in a natural depositional system are complex and difficult to model. The models presented here are intended to be conceptual with respect to the near well- and early phase migration-effects of the observed and interpreted reservoir properties, with main emphasis on depositional geological heterogeneities on a meso and micro scale. Tectonic elements (sub-seismic faults, cracks etc.) are not included, except for the local structural dip at the injection site.

4.1. Input

Formation thickness and structural dip at the injection site was interpreted from 3D seismic data, as well as apparent sedimentological strike and azimuth. A depth map of the reservoir top and model area is given in Figure 4. Clinoform geometries, including number of extensive flooding surfaces and progradational, aggradational and retrogradational signatures, were conceptualized with respect to relative thicknesses based on observations in more proximal wells. Because the injection area is located quite far basinward it is assumed that foreshore facies represents the shallowest depositional setting. Facies specific reservoir properties and trends were interpreted mainly from the only cored well (Figure 1).

In the proposed injection area at ~3km burial depth (Figure 4), the estimated reservoir temperature is set to 90^{o}C concurrent with a typical local geothermal gradient of 30^{o}C/km. Porosity reduction due to chemical compaction and quartz overgrowths, considering chlorite coating on quartz grains and a relatively high feldspar content [15], was assumed to be moderate and set to 5% reduction relative to observations from ~2km. Horizontal permeability as a function of porosity was inferred from core measurements (by Shell). Vertical permeability has not been measured. Presence of oriented mica and elongated coal fragments in draping layers associated with lower energy settings are thought to affect the effective vertical permeability on a micro scale (mm). Data from well 31/2-3 (Figure 1) in the Sognefjord Formation (comprising both horizontal and vertical permeability measurements) were used for comparison. On a meso scale (m) calcite cemented layers and flooding surfaces are considered the main controlling factors. Draping layers of silt/clay are interpreted to be laterally continuous and with low permeability. In a wave dominated setting, however, these may be absent due to erosion. The effect of different scenarios related to the continuity of calcite layers and presence/absence of draping layers is tested in the following (model scenarios described in Table 1).

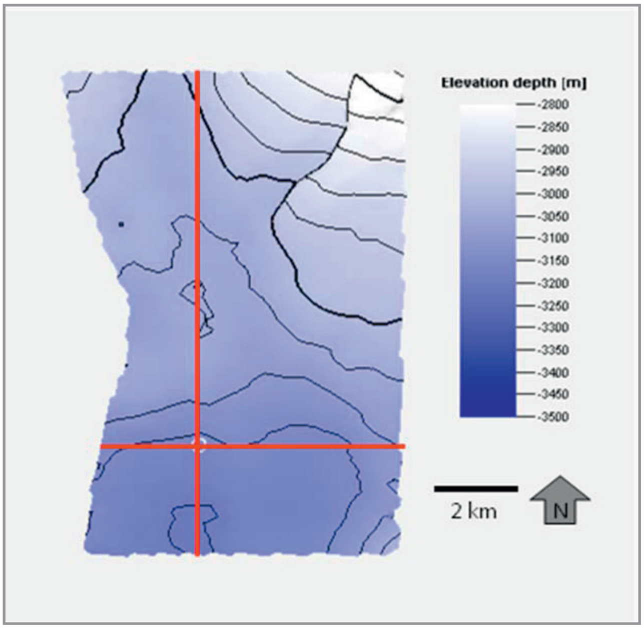

Figure 4: Depth map of top Johansen Formation inside Modeled area (outline on map displayed in Figure 1). Model results discussed in section 4.2. will be displayed along the EW and NS cross sections (red). The injection well is located in the intersection.

Table 1: Model scenarios 1-5

	Description
1	2 main sandstone units separated by 1 low permeability mud layer. No calcite cemented layers.
2	5 main sandstone units separated by 4 low permeability mud layers. 6 extensive calcite layers (>7km) of 30cm thickness
3	2 main sandstone units separated by 1 low permeability mud layer. 8 extensive calcite layers of 30cm thickness (3km along depositional dip, throughout model along depositional strike)
4	2 main sandstone units separated by 1 low permeability mud layer. Calcite cementation in 8 zones intra sandstone units, represented as randomly distributed 1x1.5km ellipsoid shapes of 30cm thickness, with the major axis parallel to depositional strike. 20% calcite (zero permeability) in each zone.
5	2 main sandstone units separated by 1 low permeability mud layer. Calcite cementation in 8 zones intra sandstone units, represented as randomly distributed 300x400m ellipsoid shapes of 30cm thickness, with the major axis parallel to depositional strike. 20% calcite (zero permeability) in each zone.

Facies associations, their relative thicknesses and associated reservoir properties (Table 2) were interpreted from two proximal wells, and the interrelations transferred and adjusted according to depth, formation thickness and structural setting at the injection site. Intra clinothem trends of porosity and permeability (horizontal and vertical) were linearly interpolated within layers along depositional dip (1^{o}), in accordance with a basinwards fining trend. An example of model geometry and porosity distribution is shown below (Figure 5). Calcite cemented layers are assumed to have zero porosity.

Table 2: End member values in property model. Facies related permeability (K) in milli Darcy, and porosity in percent (%)

Zone	Porosity (%)	Kx=Ky (mD)	Kz (mD)	Kz/Kx,y
Foreshore	31	1544.7	1390.2	0,90
Upper delta front	28	485.2	339.6	0.70
Lower delta front	25	152.4	22.9	0.15
Delta toe and drapes	16	4.7	0.5	0.10

No flow-boundaries are assumed east and west of the injection site, since the corresponding facies are interpreted as relatively tight marine clays, and there are bounding faults. Further, the aquifer is assumed to be at hydrostatic pressure of 300 bars. It is probably open towards the North and up structural and stratigraphic dip, but the simulations were run with no flow boundaries in this case in order to shorten simulation time. No bottom hole constraints were made. Simulations were run for 30 years (injection phase) with an injection rate of 1.6E06 Sm^3/day. Saturation curves were given according to[16].

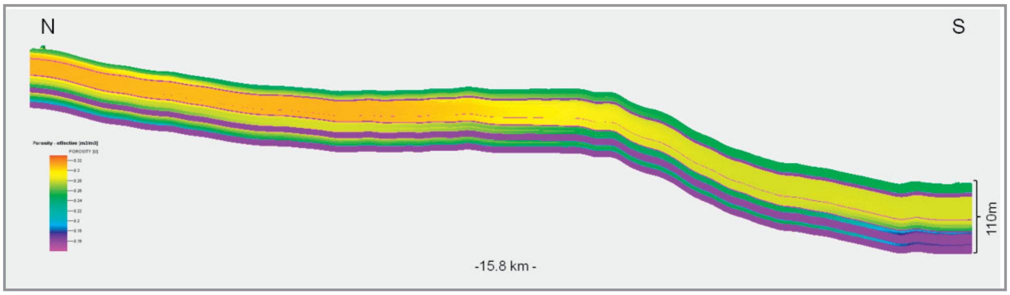

Figure 5: North-South cross section (15.8km) through property model, displaying the porosity distribution in Scenario 2 (thin calcite layers not visible at this scale). The vertical exaggeration is 10.

4.2. Results

In all runs the injection rate was constant until the end of simulation time. The average field pressure and the bottom hole pressure increased steadily as expected due to closed boundary conditions. There were not large variations in the bottom hole pressure build-up for the different runs (134-139 bar relative to initial reservoir pressure), with the highest in the continuous layer case (Scenario 2). The simulations show that in high permeability reservoirs extensive flow baffles will not necessarily deteriorate the reservoir (Figure 6) (as in Scenarios 2, 3), but will contribute to spreading of the CO_2 plume and increase the sweep during migration. After the initial stage of injection, this effect is not as pronounced (Scenario 4) or close to negligible (Scenario 5) for the cases with less extensive flow baffles. The effect may be enhanced, however, by adapting the injection strategy (*e.g.* perforating vertical injection wells only in the lower half of the reservoir, use of horizontal injection wells etc.)

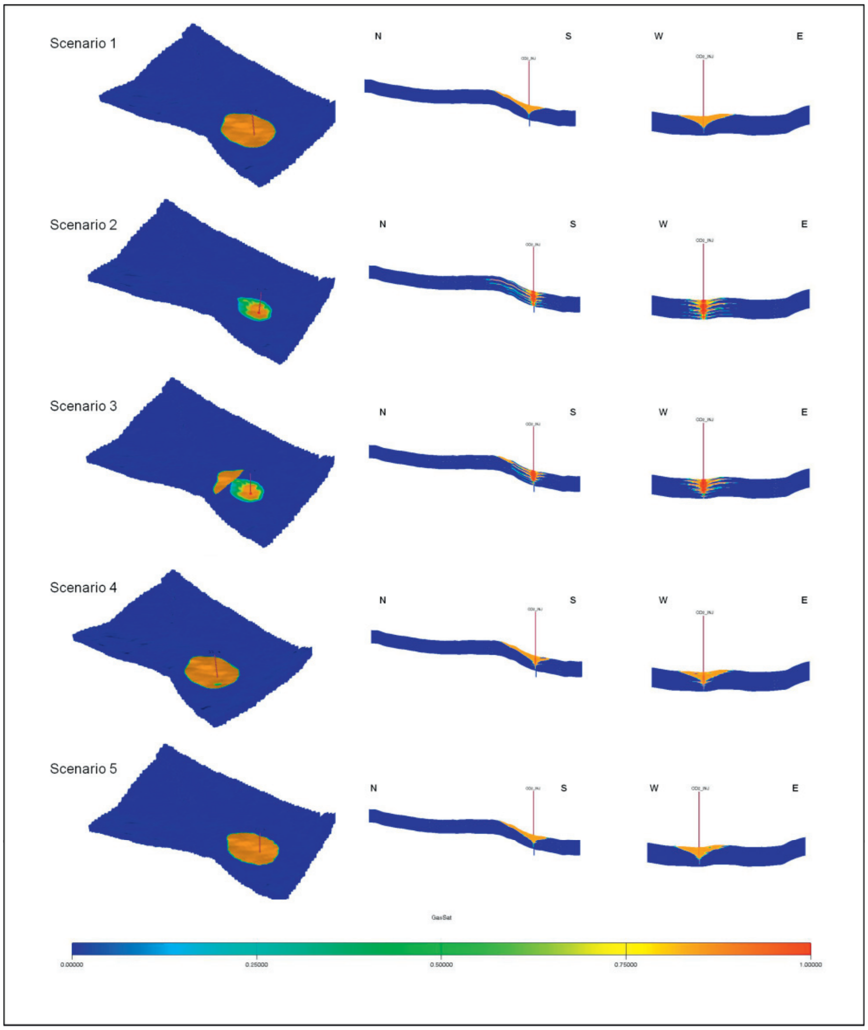

Figure 6: Model results from scenarios 1-6 (in accordance with table 1). Gas saturations after 30 years of injection. Views of top layer (left row) with z axis exaggeration of six. Cross sections through the injection well: 15.8km North-South, (middle row) and West to East cross sections, 9.7km Z axis exaggeration is ten. Model thickness is varying, but 110m thick in the injection point.

5 Discussion

Depositional environment and related facies distribution, together with burial compaction and diagenesis are important with regards to formation of site specific heterogeneities, and hence, reservoir performance. In the Johansen Formation, reservoir connectivity in the injection area and along the migration path will depend largely on the scale and connectivity of sandstone bodies and there-under the dominating mode of deposition and energy regime in the injection area. In a more wave dominated setting, the sediments are likely to have a more uniform distribution, and draping mud layers separating clinothems and potentially forming flow compartments, might have been completely eroded. Calcite cemented horizons are a common phenomenon in the area, and their lateral extent may vary from metres to several kilometres.

In the present study the models are conceptual. By drilling an injection well (and eventually an upstream monitoring well), one would immediately obtain input for a high resolution model for the injection and early migration area. During injection, based on observations of saturation and pressure distribution between the two points, one would be able to resolve to some degree the nature of calcite layers (if present) as well as the overall porosity and permeability distribution. Evenly spaced samples from calcite in core and detailed analysis might also aid in predicting the extent of the layers [12]. With respect to averaging methods for porosity and permeability, the presence of concretions rather than layers may seriously alter simulation results, as they are often present within otherwise permeable zones [10]. With more data deterministic modeling of strata-bound calcite and low-permeability draping layers would be possible. In the case of scattered concretions stochastic modeling would probably be more useful.

The simulations illustrate that averaging of the reservoir properties within each sand body might yield oversimplified plume geometries (*i.e.* funnel shaped - due to unhindered upwards flow towards sealing unit). Within the investigated deltaic sandstone, the location of the injection well relative to facies settings shows that the fluid distribution varies despite comparable properties (*i.e.* porosity, permeability, Net/Gross, formation thickness), mainly due to number and extent of cemented layers delimiting gravity driven flow, causing separation and lateral spreading of the plume. With highly permeable sands in between, the presence of flow baffles is an advantage with respect to sweep and volume utilization. The plume geometry is also important with regards to estimating the volume potential and relative effect of the various trapping mechanisms for CO_2 (*i.e.* stratigraphic-, dissolution-, residual- and mineral trapping).

6 Conclusion

When the data base is scarce – as is often the case with potential CO_2 reservoirs in saline aquifers - it is important to stress that a full scale reservoir model cannot be very accurate with respect to geological heterogeneities and fluid flow due to the uncertainties in the initial input. Therefore, scenario models taking expected site specific geological heterogeneities on micro- and meso-scale into account, are useful as part of the reservoir characterization and in planning suitable injection and monitoring schemes.

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