The pressure impact of CO₂ storage on neighbouring sites

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Abstract

In this paper, we present a saline aquifer showcase model from the North German Basin, predicting the regional pressure impact of a small industrial scale CO₂ storage operation on its surroundings. The static model is based on real geology while the injection program is fictitious. We simulated a rate controlled injection of 2.5 Million tons CO₂ per year through a single vertical well into the structural top of a dome shaped anticline, over a period of 10 years. The target is a 20 m thick sandstone layer intercalated in low permeability claystone sequences. We used ECLIPSE300 with its CO₂ storage module and MUFTE-UG to predict pressure at the top of the target sandstone layer in 1, 5, 10, and roughly 31 km distance to the injection point. The farthest point represents the structural top of a neighbouring anticlinal dome, another favourable potential storage site. We varied the model’s boundary conditions, permeability, permeability anisotropy, rock compressibility, and injection temperature. A total of nine model scenarios were run, five with MUFTE-UG and another four with ECLIPSE. Comparison of reference scenarios showed that the results of both simulators match well.

In the open boundary model, pressure increase is lowest and dissipates back to the pre-injection state within 30 years after injection shutdown. In the fully closed models, pressure peaks are high, equilibrating to a remnant, model-wide overpressure several decades after the end of injection. In the distance, this equilibrated, model-wide overpressure is the actual maximum pressure. In the model scenarios which are laterally half open, half closed, pressure relief is seriously retarded in comparison to the fully open model. In all cases, the pressure maximum arrives at the neighbouring structure (31 km distance) years after the actual injection shutdown.

Rock compressibility impacts both the peak pressure and the speed of the pressure build-up and relief. High permeabilities are more important in the immediate injection area than for the regional footprint. In all of our fully closed (i.e. the most pressurized) models, the remnant regional overpressure amounted to about 9 bars. If 10 bars are taken as the maximum tolerable overpressure, then the volumetric storage capacity of the target structure itself is not affected. However, injection into the target structure does affect the storage capacity of the neighbouring site. While a purely volumetric approach yields a cumulative storage capacity of roughly 175 Mt for both structures, a tolerable regional overpressure of 10 bars lowers the joint storage capacity to about 32 Mt CO₂. Exactly what regional pressures are tolerable for a given aquifer, however, needs to be determined on a site specific base.

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Keywords: CO₂ storage; North German Basin; saline aquifer; pressure; numerical simulation

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1. Introduction and Model Setup

Numerical simulations of CO₂ storage are usually either generic, using simple brick or pie slice grids, or site specific, predicting CO₂ flow and pressure increase for a given storage site. Neither of the two can really predict the regional impact of a given storage operation on its surrounding basin. Birkholzer and Zhou [1] have systematically addressed this issue for the Illinois Basin, a large intracontinental sag basin. The geological situation in the North German Basin is structurally much more complex: numerous salt diapirs and fault systems dissect the basin and it is often not clear to which extent the aquifers are compartmentalized, or the faults sealing or leaking. Thus the pressure impact of CO₂ storage operations on neighbouring sites, where competing operational interests might exist, is still difficult to assess.

Here we present a saline aquifer showcase model from the North German Basin, predicting the regional pressure impact of a small industrial scale CO₂ storage operation on its surroundings [2]. We systematically vary the lateral boundary conditions to mimic a range of different tectonic settings. We emphasize, however, that we do not intend to predict safe operation pressures at or near the well as this would require a very different model setup regarding the grid resolution and injection schedule.

The static model is based on real geology while the injection program is fictitious. The geological model mimics the Buntsandstein Group of the North German Basin in a slightly simplified fashion. We simulated a rate controlled injection of 2.5 million tons CO₂ per year through a single vertical well (A in Figure 1) into the structural top of a dome shaped anticline (“Structure A”), over a period of 10 years. The target is a 20 m thick sandstone (thin red layer in Figure 1) which is intercalated in low permeability claystone sequences. The seal is an almost 60 m thick impermeable rock salt formation overlying the entire sequence (not shown in Figure 1), constituting a no-flow barrier. The bottom of the model has a no-flow boundary condition, too. Thickness, porosity and permeability for each model formation are given in Table 1. Other initial formation and fluid parameters are a hydrostatic pressure, a salinity of formation water of 334 g/l, and a geothermal gradient of 40°/km. Two different relative permeability curves were used for the sandstone and claystone formations, respectively.

Figure 1: Regional model setup. CO₂ is injected through well A. Pressure is recorded at three intermediate distances (1km, 5km, 10km) and at the structural top of a neighbouring structure (B), which is roughly 31 km away from the injection well A. The thin red layer is the target storage sandstone formation, while the light green and blue layers are claystone sequences. The top surface of the model corresponds to the base of the seal (the seal itself is not shown) and has been depth mapped (meters below mean sea level).
Table 1: Thickness, effective porosity and horizontal permeability of the model formations.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Thickness [m]</th>
<th>Effective porosity [%]</th>
<th>Horizontal permeability [mD]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rock Salt (barrier formation)</td>
<td>58</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Claystone Sequence 2</td>
<td>167</td>
<td>7</td>
<td>0.1</td>
</tr>
<tr>
<td>Sandstone (storage formation)</td>
<td>20</td>
<td>22</td>
<td>110</td>
</tr>
<tr>
<td>Claystone Sequence 1</td>
<td>350</td>
<td>5</td>
<td>0.01</td>
</tr>
</tbody>
</table>

We used MUFTE-UG [3] and Schlumberger’s ECLIPSE300 with its CO₂ storage module to predict pressure at the top of the sandstone layer in 1 km, 5 km, 10 km, and roughly 31 km distance to the injection point. The farthest point represents the structural top of a neighbouring anticlinal dome (B in Figure 1), another favourable potential storage site (“Structure B”). To test their impact on pressure build-up, we varied the model’s lateral boundary conditions, permeability, permeability anisotropy, rock compressibility, and injection temperature. A total of nine model scenarios were run, five with MUFTE-UG and another four with ECLIPSE (Table 2). The lateral boundary conditions are either fully closed (no flow or Neumann condition), fully open (constant flow or Dirichlet condition), or half open, which means Neumann conditions at one margin and Dirichlet conditions at the other. Pessimistic permeability scenarios (11 and 55 mD) have been assessed as well, but in these cases injectivity was so poor that the constant high injection rate of 2.5 Mt per year became entirely unrealistic. Injection temperature is either the minimum temperature to safely attain supercritical behaviour of the CO₂ (all MUFTE cases except Scenario 5), or a practical maximum temperature which is equal to the reservoir temperature (all ECLIPSE cases).

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Boundary Condition</th>
<th>Kx (mD)</th>
<th>Kv/Kx</th>
<th>Tinj (°C)</th>
<th>Rock Compressibility</th>
<th>Simulator</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>half open</td>
<td>110</td>
<td>0.1</td>
<td>35</td>
<td>4.5x10⁻⁵ bar⁻¹</td>
<td>MUFTE-UG</td>
</tr>
<tr>
<td>2</td>
<td>closed (Neumann)</td>
<td>110</td>
<td>0.1</td>
<td>35</td>
<td>4.5x10⁻⁵ bar⁻¹</td>
<td>MUFTE-UG</td>
</tr>
<tr>
<td>3</td>
<td>open (Dirichlet)</td>
<td>110</td>
<td>0.1</td>
<td>35</td>
<td>4.5x10⁻⁵ bar⁻¹</td>
<td>MUFTE-UG</td>
</tr>
<tr>
<td>4</td>
<td>half open</td>
<td>110</td>
<td>0.1</td>
<td>35</td>
<td>0</td>
<td>MUFTE-UG</td>
</tr>
<tr>
<td>5</td>
<td>half open</td>
<td>110</td>
<td>0.1</td>
<td>63</td>
<td>4.5x10⁻⁵ bar⁻¹</td>
<td>MUFTE-UG</td>
</tr>
<tr>
<td>6</td>
<td>closed (Neumann)</td>
<td>110</td>
<td>0.1</td>
<td>63</td>
<td>4.5x10⁻⁵ bar⁻¹</td>
<td>ECLIPSE</td>
</tr>
<tr>
<td>7</td>
<td>closed (Neumann)</td>
<td>110</td>
<td>1</td>
<td>63</td>
<td>4.5x10⁻⁵ bar⁻¹</td>
<td>ECLIPSE</td>
</tr>
<tr>
<td>8</td>
<td>closed (Neumann)</td>
<td>220</td>
<td>0.1</td>
<td>63</td>
<td>4.5x10⁻⁵ bar⁻¹</td>
<td>ECLIPSE</td>
</tr>
<tr>
<td>9</td>
<td>closed (Neumann)</td>
<td>550</td>
<td>0.1</td>
<td>63</td>
<td>4.5x10⁻⁵ bar⁻¹</td>
<td>ECLIPSE</td>
</tr>
</tbody>
</table>

Table 2: Parameters of the different model scenarios.

2. Simulation Results

The parameters that had the largest impact on regional (≥10 km distance) pressure development are the model’s boundary conditions and rock compressibility. Impact of the injection temperature on the far field pressure development, on the other hand, is minimal (Figures 2 and 3). Thus Scenarios 2 (MUFTE) and 6 (ECLIPSE) can serve as reference scenarios for direct comparison. Although initial and absolute pressures differ due to the different grid discretization of both simulators, the differential pressures are very similar (Figures 2-5).

In the fully open model scenario (Scenario 3), pressure increase is lowest and dissipates back to the pre-injection state within 30 years after injection shutdown (Figures 2 to 5). In the fully closed model scenarios (Scenarios 2, 6, 7, 8, and 9), pressure peaks are high, equilibrating to a remnant, model-wide overpressure several decades after the end of injection (Figures 2 to 5). At 31 km distance, this equilibrated, model-wide overpressure is the actual maximum pressure (Figure 2). In the model scenarios which are laterally closed on one side, but open on the other (Scenarios 1 and 5), pressure relief is seriously retarded in comparison to the fully open model (Figures 2 to 5). Neglecting rock compressibility (Scenario 4) leads to a substantial over-estimation of the amount and speed of pressure build-up and dissipation (Figures 2 to 5). Effects of permeability (Scenarios 7, 8, and 9) are much more relevant in the near injection area than for the pressure impact at neighbouring sites. They primarily impact the time of pressure dispersion throughout the model (or basin), but do not change the absolute overpressure in the far-field areas (Figures 2 to 5).
In all cases, the pressure maximum arrives at the neighbouring Structure B (ca. 31 km distance) years after the actual injection shutdown – at least 5 years in the open and half open models and up to several decades in the no flow boundary models (Figure 2).

![Figure 2: Pressure development at Structure B, in about 31 km distance to the injection point. Left, Scenarios 1-5 (MUFTE), right, Scenarios 6-9 (ECLIPSE).](image1)

![Figure 3: Pressure development at 10 km distance to the injection point. Left, Scenarios 1-5 (MUFTE), right, Scenarios 6-9 (ECLIPSE). Note the different vertical scales compared to Figure 2.](image2)
3. Impact of Regional Pressure Increase on Storage Capacity

In most regional or national storage capacity assessments, storage capacity is calculated on a purely volumetric base (e.g. [4] and references therein). This is a practical approach in regions where dynamic reservoir parameters such as permeability or compressibility are not available. However, CO₂ storage in any one site affects the storage capacity of hydraulically connected sites in the neighborhood, due to regional pressure increase [5].

In this study, volumetric storage capacity has not been calculated a priori. The total injection mass was 25 Mt CO₂, which implies that the storage efficiency of Structure A must be 28.6 % if the available storage area is assumed to be given by the lowest closed depth contour [4]. Using the same storage efficiency value for Structure B, this neighboring structural closure could accommodate up to 150 Mt CO₂.

If taking pressure into account, the storage capacity of the affected model aquifer additionally depends on compressibility and the maximum tolerable regional overpressure [5]:

\[
m_{\text{CO}_2} = A * D * \phi * \rho_{\text{CO}_2} * (k_f + k_r) * \Delta P
\]  

(1)
where $m_{CO2}$ is mass of CO$_2$ (storage capacity), $A$ is the area affected by the pressure increase, $D$ is the thickness of the aquifer, $\phi$ is porosity, $\rho_{CO2}$ is the density of CO$_2$ at reservoir conditions, $k_f$ is fluid compressibility, $k_r$ is rock compressibility, and $\Delta P$ the maximum tolerable regional overpressure. Note that this regional overpressure is much lower than the capillary entry pressure or fracture pressure of the barrier at the injection site. The ‘affected space’ ($A \times D$) needs to be delimited geologically, e.g. by lateral flow barriers such as storage formation pinch-out, sealing faults, or salt walls [5]. It should be noted that the affected space of the present model (and many natural examples) is not limited to the relatively thin target sandstone formation (red layer in Figure 1), but includes the overlying und underlying low permeability claystone sequences (green and blue layers in Figure 1). The simulation results showed that although the claystone sequences are sealing towards the migrating CO$_2$ for the period of the simulation time (40 years), they are no barrier to pressure propagation [2; cf. 6]. This does not apply to the actual seal (not shown in Figure 1), which has been assumed to be impermeable and incompressible. Thus the affected space has to be calculated on a formation by formation basis, and this means including each formation’s porosity. The total affected pore space $V_{por}$ can thus be defined as:

$$V_{por} = \sum_{i=1}^{n} A_i \times D_i \times \phi_i$$  (2)

where $n$ denotes the total number of defined formation layers and $i$ stands for each formation in turn. For the present model, this translates to:

$$V_{por} = (A \times D_{c1} \times \phi_{c1}) + (A \times D_s \times \phi_s) + (A \times D_{c2} \times \phi_{c2})$$  (3)

where subscript $c1$ stands for Claystone Sequence 1, subscript $s$ for the Sandstone (storage) formation, and subscript $c2$ for Claystone Sequence 2, as given in Table 1. Combining equations (1) and (3), storage capacity can then be calculated as follows:

$$m_{CO2} = V_{por} \times \rho_{CO2} \times (k_f + k_r) \times \Delta P$$  (4)

Note that in equation (4), the same compressibility is used for the entire affected pore space. Ideally, a formation specific rock compressibility should be used, similar to porosity, as shown in equation (5). Fluid compressibility, however, can safely be assumed to be constant throughout the aquifer, if salinity is constant (see Section 2) and no hydrocarbons are present.

$$m_{CO2} = \sum_{i=1}^{n} A_i \times D_i \times \phi_i \times \rho_{CO2} \times \Delta P \times (k_f + k_r)$$  (5)

Based on equation (4) and the values listed in Tables 1 and 3, storage capacities of the entire model aquifer are shown in Table 4, for different maximum tolerable overpressures.

<table>
<thead>
<tr>
<th>Description</th>
<th>Symbol</th>
<th>Value</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Affected area (=model area)</td>
<td>$A$</td>
<td>$2.45 \times 10^9$ m$^2$</td>
<td>--</td>
</tr>
<tr>
<td>Density of CO$_2$ at reservoir conditions</td>
<td>$\rho_{CO2}$</td>
<td>$630$ kg/m$^3$</td>
<td>--</td>
</tr>
<tr>
<td>Fluid compressibility</td>
<td>$k_f$</td>
<td>$3.3 \times 10^{-1}$ bar$^{-1}$</td>
<td>[7]</td>
</tr>
<tr>
<td>Rock compressibility</td>
<td>$k_r$</td>
<td>$4.5 \times 10^{-3}$ bar$^{-1}$</td>
<td>[6]</td>
</tr>
</tbody>
</table>

Table 3: Model values used for storage capacity calculation using equation (4). Where no source is given, the value is model intrinsic.
In all of our fully closed, i.e. the most pressurized model scenarios, the remnant regional overpressure amounted to about 9 bars. If 10 bars is taken as the maximum tolerable regional overpressure, then 25 Mt of CO₂ could easily be accommodated in Structure A, as the model aquifer’s maximum storage capacity would be about 32 Mt (Table 4). However, Structure B would lose most of its storage potential due to the regional pressure increase. If, on the other hand, 40 bars were taken as the maximum tolerable regional overpressure, then the joint storage capacity of the two structural closures would be about 129 million tons and both could be used for storage.

It has to be emphasized that these storage capacity numbers are synthetic and refer to no particular, existing site. Although the geometry and boundary conditions of the selected model area are meant to represent real geology, the rock and fluid parameters are by no means site specific. For real injection sites, all site specific parameters need to be diligently determined by the operator in the exploration phase. Also the maximum tolerable overpressures will have to be determined on a site specific base.

## 4. Discussion

We have presented a simplified geological model from the North German Basin which is representative of many areas of the basin, and have addressed typical structural settings (fault or diapir bounded sub-basins) with different model boundary scenarios. In addition, other relevant parameters such as permeability, compressibility, and injection temperature have been varied. The lateral boundary conditions proved to have the largest influence on regional pressure development, much more than for example the formation’s permeability. Defining a storage complex’s lateral boundaries, however, is a substantial challenge, especially as exploration would need to cover a much larger area than the actual CO₂ containment area.

The other important parameter in terms of regional pressure development and storage capacity is rock compressibility. Because pressure dissipation is not limited to the storage formation alone, but encompasses medium to low porosity rocks that can even be decent CO₂ seals [2, 6], it is important to obtain reliable porosity and rock compressibility values for all rocks of the storage complex during the exploration phase.

In terms of storage capacity, assessment in structurally complex areas has to consider sub-basins and compartments bounded by salt walls or sealing faults. When moving from national to regional to local storage capacity assessments, this translates to moving from the basin to the sub-basin to the compartment scale. If any hydraulic sub-unit of a basin has storage potential for more than a single storage site, then storage capacity should be assessed cumulatively per this hydraulic unit.

## References


