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Public abstract

This report is part of the research project MiReCOL (Mitigation and Remediation of CO_2 leakage) funded by the EU FP7 program[1]. Research activities aim at developing a handbook of corrective measures that can be considered in the event of undesired migration of CO_2 in the deep subsurface reservoirs. MiReCOL results support CO_2 storage project operators in assessing the value of specific corrective measures if the CO_2 in the storage reservoir does not behave as expected. MiReCOL focuses on corrective measures that can be taken while the CO_2 is in the deep subsurface. The general scenarios considered in MiReCOL are 1) loss of conformance in the reservoir (undesired migration of CO_2 within the reservoir), 2) natural barrier breach (CO_2 migration through faults or fractures), and 3) well barrier breach (CO_2 migration along the well bore).

[1] More information on the MiReCOL project can be found at www.mirecol-co2.eu.

The aim of this report is to model the effects of different injection scenarios to control the CO_2 movement in the reservoir and to prevent CO_2 from arriving at and passing through pre-defined undesired migration paths, which may be faults, fracture zones or spill points. Based on the outcome of the different model scenarios, the response time of remediation, longevity of the remediation measure, spatial extension of the remediation and remediation costs are assessed.
Different reservoir management scenarios are carried out based on the Ketzin test site for geological storage and the Johansen geological model.
The most efficient management strategies are those that include a variation of the injection position. Lateral movements may induce minor variations that occur due to slight differences in the distance of the fracture zone and varying dip gradients. Alternation of the injection position is cost efficient, although local surface conditions might induce minor differences, the order of magnitude remains constant as long as the number of wells is not increased.
Reservoir management strategies that are based on temporal changes of the injection regime do not result in high costs, but the longevity of remediation is very low, there is no significant impact on the arrival time. The injection through multiple wells produces high costs of drilling and installation, but the longevity of this measure is also not significant.

Three different scenarios are found for the Johansen model which will serve as a base case for further work in the MiReCOL project, for which flow diversion can be a potential a diversion option.

TABLE OF CONTENTS

Page

1 INTRODUCTION

The selection of appropriate CO_2 injection strategies offers potential for increasing safety and longevity of the containment. An appropriate strategy can potentially prevent or at least retard CO2 from arriving at and passing through pre-defined undesired migration paths, which may be faults, fracture zones or spill points. By this it may decrease the risk that active remediation becomes necessary, such as gel and foam injection, brine injection or chemical immobilization of CO_2 itself at a later stage of the storage cycle. Therefore an appropriate injection strategy as proactive measure maybe quite cost efficient compared to active remediation.

The potentials and limitations of an adapted injection strategy are investigated at two sites. The impact of different management techniques such as variation of injection location and injection rate also considering different geological conditions are investigated at the Ketzin site for CO_2 storage, Germany. As a result, the choice of the injection location is probably the most effective management technique. This is investigated in the second part of the report. At the Johansen field site for CO_2 storage, Norway, a detailed case study is carried out to optimise the injection location.

This is the second report on CO_2 plume diversion by adapting the injection strategy in the MiReCOL project. Deliverable D 3.1 named “Current flow diversion techniques in the petroleum industry relevant to CO_2 leakage remediation” summarizes the state of the art for flow diversion with a wider scope; forming the base for work on flow diversion that includes injection of other fluids and materials into the reservoir.

2 MANGEMENT TECHNIQUES - KETZIN MODEL

2.1 Site description

The Ketzin site for CO_2 storage is located in the sedimentary Northeast German Basin about 25 km west of Berlin, Germany, at the south-eastern flank of the Roskow-Ketzin double anticline. The CO_2 is injected into the Upper Triassic Stuttgart Formation. The injection well Ktzi 201 is located at the southern flank of the anticline, penetrating the Stuttgart formation approximately between 630 and 710 m below ground level, with the main reservoir facies between 633 and 651 m below ground level. A total amount of about 67,000 tons of CO_2 have been injected between June 2008 and August 2013. All simulations are carried out with Eclipse 300. Dissolution of CO_2 in reservoir brine is included.

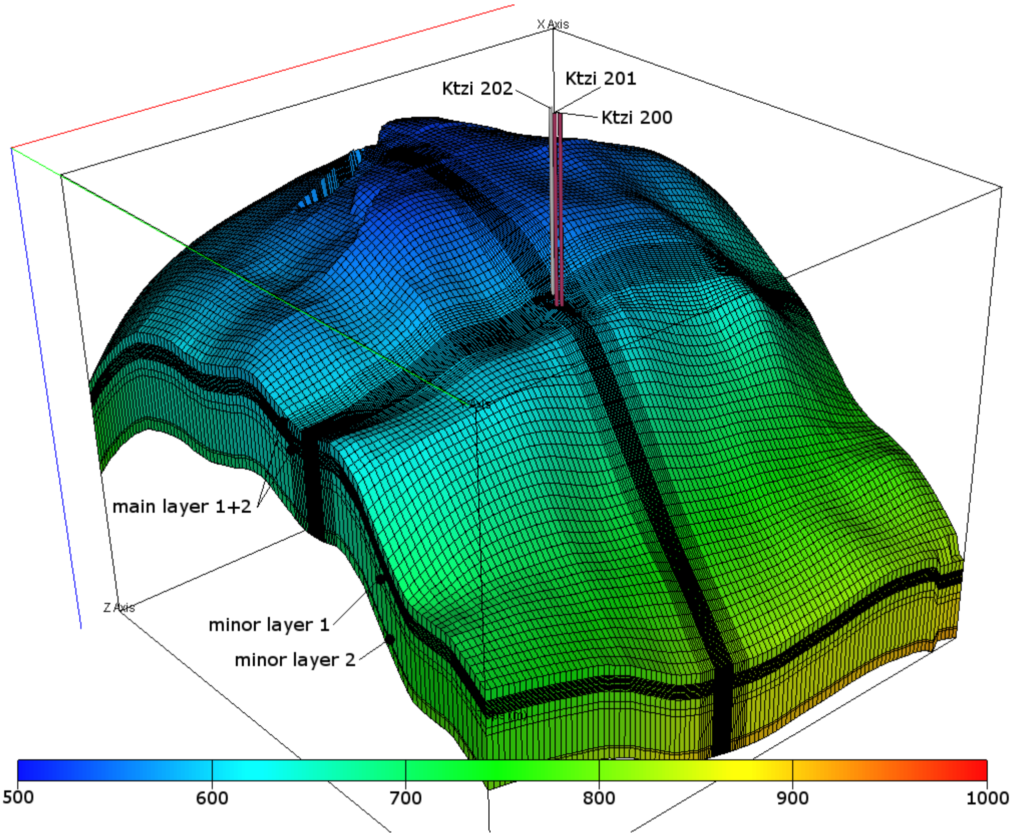

Figure 1: South West view of the Ketzin storage site geological model. The colours indicate the depth of the cells, the black lines indicate cell outlines. The model has an extent of 5x5 km. The three vertical lines indicate the injection well Ktzi 201 and the two observation wells Ktzi 200 and Ktzi202.The main layers in the upper part of the reservoir have a model thickness of 6 m each.

2.2 Method

2.2.1 Geology

The geological model is constructed based on the lithostratigraphy observed in the wells Ktzi 200, Ktzi 201 and Ktzi 202. The sandstone facies found in these wells is introduced to the entire model, with the layer structure following the topology of the anticline. The main reservoir horizons have a vertical discretization of 1 m, appearing as dark layer in Figure 1. The horizontal discretization is 10 m close to the wells, appearing as dark cross, and increases to 50 m for the far field.

Two minor reservoir layers below are represented with a single model layer each. The reservoir permeability follows single wellbore pumping tests (Wiese et al., 2010) in each of the three wells with a value of 100 mD. The main reservoir consists of two sandstone layers that are horizontally divided by an anhydrite layer. Upstream of the injection point, at observation well Ktzi 202 one of these sandstone layers disappears. Although it is not evident which of both sandstone layers is continuous, the upper layer is considered as continuous in this study while the permeability of the lower layer is reduced to 1 mD close to Ktzi 202.

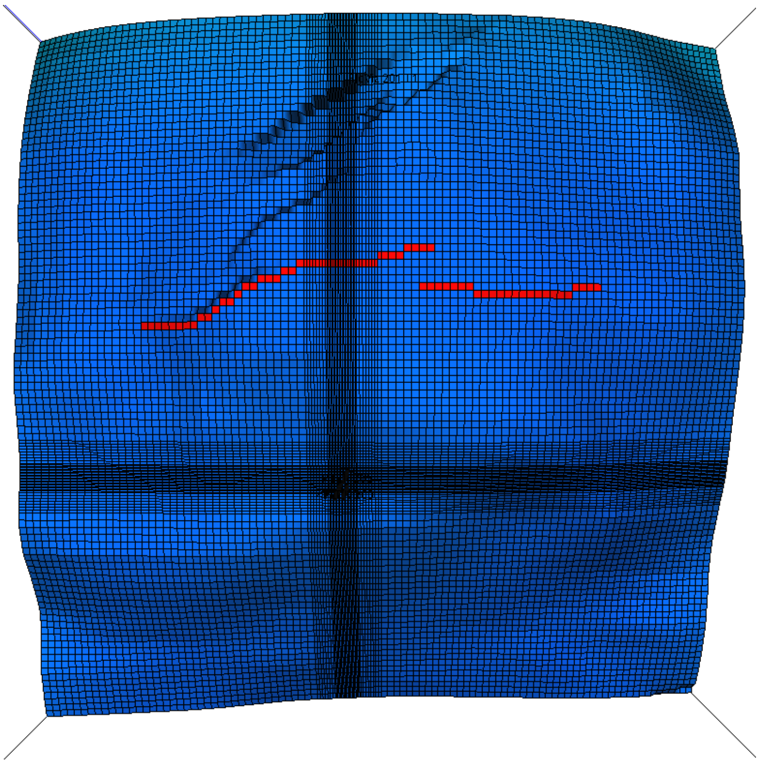

Figure 2: Top view on the Ketzin anticline model. The injection well Ktzi 201 is located in the lower part of the model. Faults exist in the upper part of the model, some of them show vertical displacements. The red lines indicate the southern faults. These represent the undesired migration paths that should not be reached by the CO_2 plume.

Several faults exist at the top of the anticline. These faults (Figure 2) represent the pre-defined undesired migration pathways because CO_2 might percolate to overlying strata. For practical reasons simulations are carried out such that these faults should not get in contact with CO_2 and the simulations are interrupted when CO_2 arrives at the faults. Arrival at the faults and arrival times are therefore prime criteria to assess effectiveness of the different model scenarios and reservoir managements studied. The faults are introduced as permeable.

2.2.2 Relative permeability

Relative permeability values follow core experiments (Scherpenisse and Maas, 2009, Figure 3). Hysteresis is not considered. For computational efficiency capillary pressure is not included in regular simulations. The outer boundary conditions mimic time constant hydraulic potential.

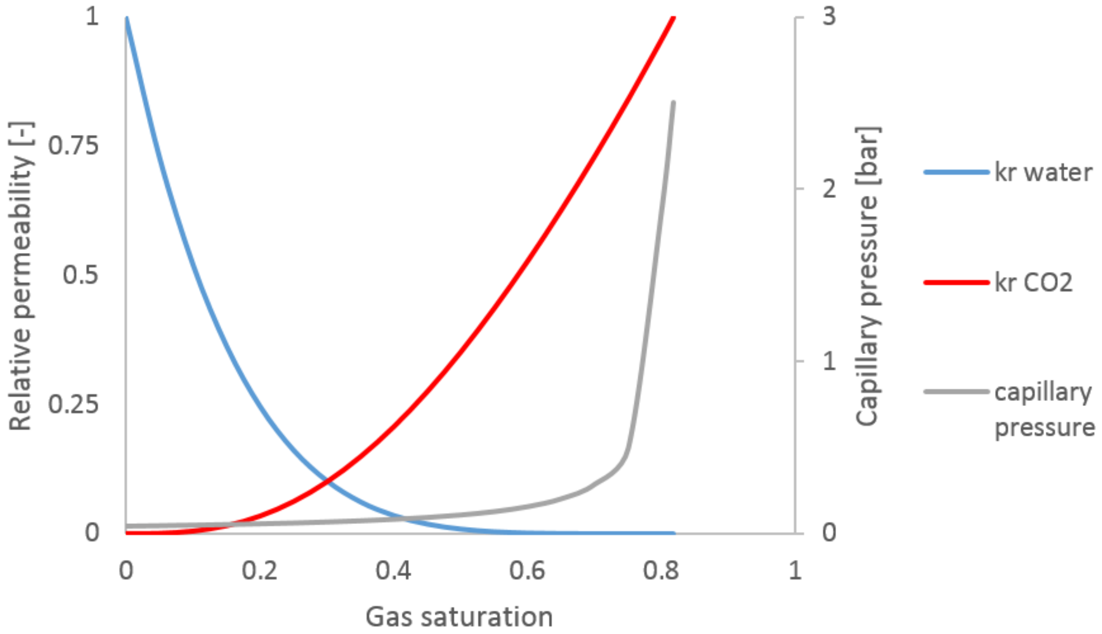

Figure 3: Relative permeability functions applied to the reservoir facies (following Scherpenisse and Maas 2009).

2.2.3 Temporal discretisation

The temporal discretisation follows changes in the injection rate. Changes of the injection rate are introduced with the real time and an average injection rate for the respective period. On average, the periods of constant injection rate have duration of three weeks.

2.2.4 Main reference Model

The above described model is set up with parameters similar to the Ketzin test site. It is the main reference model for the following investigation and therefore named “scenario 0”. In variations on scenario 0 different operational scenarios are simulated. These scenarios imply a modification of the Ketzin field conditions and evaluate the consequences with respect to the predefined undesired migration path represented by faults at the top of the anticline. Operational scenarios investigate the impact of different injection well positions and different temporal injection scenarios. Furthermore, geological scenarios are calculated to rank the potential impact of geological conditions with respect to operational potential.

2.3 Results

2.3.1 Variation of the injection location

A variation of the injection location is probably the most basic method to change the plume shape and spreading of CO_2. Eight scenarios of injection locations are simulated, with a shift of 400 and 800 m, respectively to each cardinal direction (Table 1). The west/east shifting follows approximately the iso-depth of the anticline, while the north/south shift follows the largest gradient (**Error! Reference source not found.**).

Table 1: Spatial variation of the injection positions and resulting arrival times at the critical faults zones.

	Direction	Distance [m]	Arrival time [years]	Difference to Case 0 [days]
Scenario 0	-	-	14	0
Scenario E400	East	400	13	-135
Scenario E800	East	800	16	554
Scenario W400	West	400	10	-1050
Scenario W800	West	800	8	-1591
Scenario N400	North	400	7	-1818
Scenario N800	North	800	3	-2867
Scenario S400	South	400	19	1350
Scenario S800	South	800	21	1859

In all simulated scenarios the CO_2 arrives at the fault. The most effective way of increasing the duration is to move the injection point further from the faults in southern direction. This increases the horizontal distance and also the difference in elevation. The arrival time is less affected by variation in east-west direction, and the duration decreases for most variations. These occur due to local depth gradients of the reservoir. For some injection points the plume can spread into two minor plumes, however with little impact on the arrival time (scenario W400, **Error! Reference source not found.**b).

2.3.2 Variation of injection rate

The variation of the injection rate is an inexpensive reservoir management option, albeit with large implications on site design or contractual implications. It is investigated whether a temporal change of the injection rate results in a different plume behavior. For comparison it is ensured that the injected mass is identical for all scenarios.

For a constant injection rate different durations are simulated. Scenario const has the duration of the real injection but applying constant rate, the scenarios const2 and const4 have a duration that is the fraction of the real injection with accordingly higher injection rate (Table 2, Figure 5).

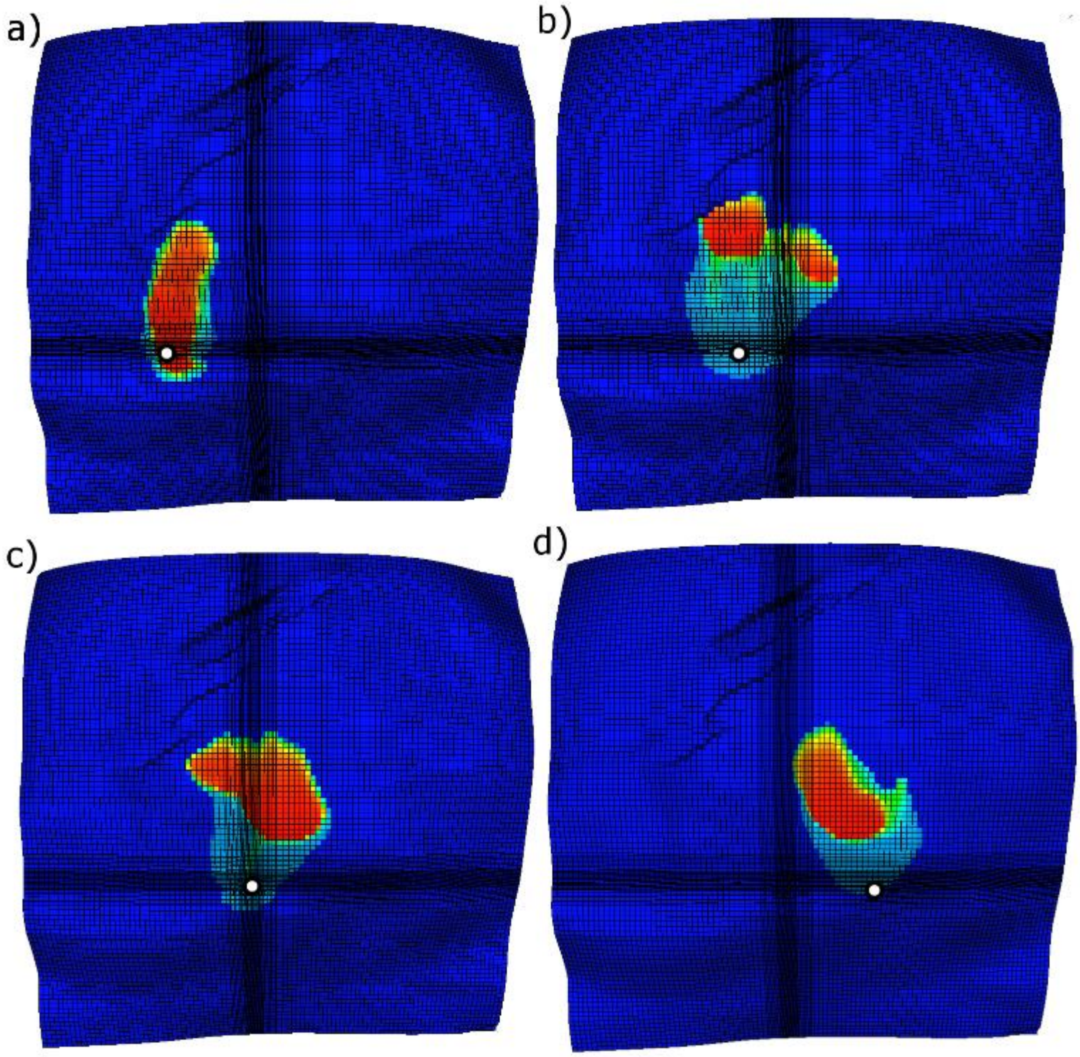

Figure 4: Plume shape at the time of arrival at the faults, with different well positions. a) Scenario W800, b) scenario W400, c) scenario 0, d) scenario E800. The plume shape differs due to the different anticline shape, in scenario W400 the plume splits up at a saddle point.

The impact of alternating injection is tested by three scenarios in which 50% of the time injection occurs and 50% is shut-in time. The duration of the intervals is 1, 10 and 100 days, indicated by the names scenario alt1, scenario alt10 and scenario alt100.

Table 2: Arrival times for the scenarios involving a modified injection rate. The number behind the constant scenarios refers to the ratio of injection duration. The number behind the alternation scenarios refers to the duration of each alternation cycle in days. The injected mass is identical for all scenarios.

	Type	Injection duration [days]	Arrival time [years]	Difference to Case 0 [days]
Scenario 0	Real injection rate and duration	1886	14	0
Scenario const	Constant rate	1886	13	-132
Scenario const2	Constant rate	943	14	126
Scenario const4	Constant rate	471.5	15	333
Scenario alt1	Alternation duration 1 day	1886	13	-103
Scenario alt10	Alternation duration 10 days	1886	13	-78
Scenario alt100	Alternation duration 100 days	1886	14	-11
Scenario 3w	Three injection wells with the positions of Case W400, Case 0, Case E400	1886	11	-581

The impact of multiple injection wells is tested by an additional scenario (scenario 3w). In this scenario the real injection rate is equally distributed to three wells. In addition to the injection well Ktzi 201 two hypothetical injection wells are introduced to the model with the position 400 m east and west of Ktzi 201, respectively (Figure 6).

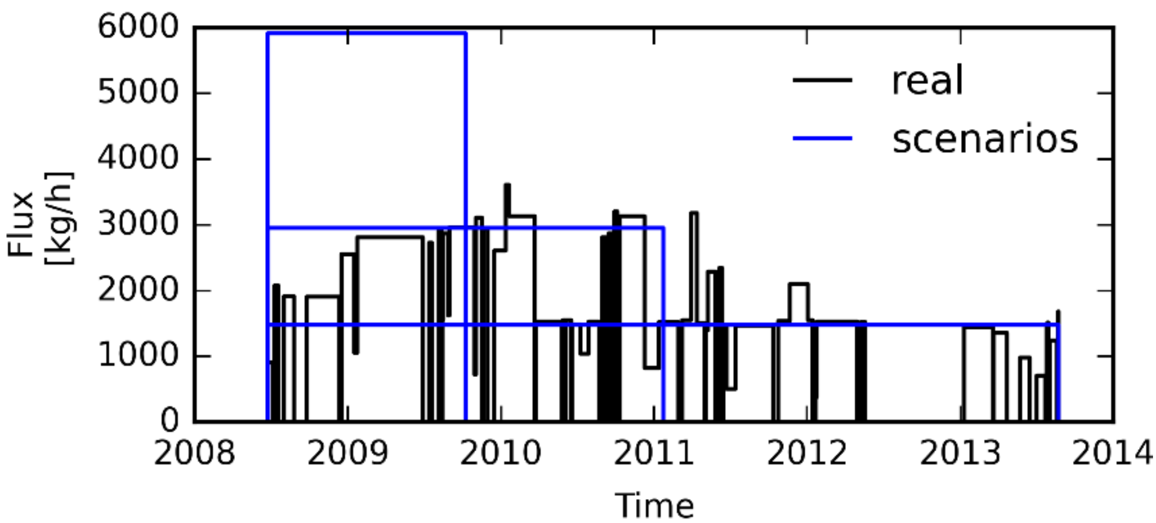

Figure 5: Injection rates for scenario 0 and the constant rate scenarios. The black curve represents the real injection rate of the Ketzin site, the blue curves represent constant injection rates with different duration. The injected mass is identical for all curves.

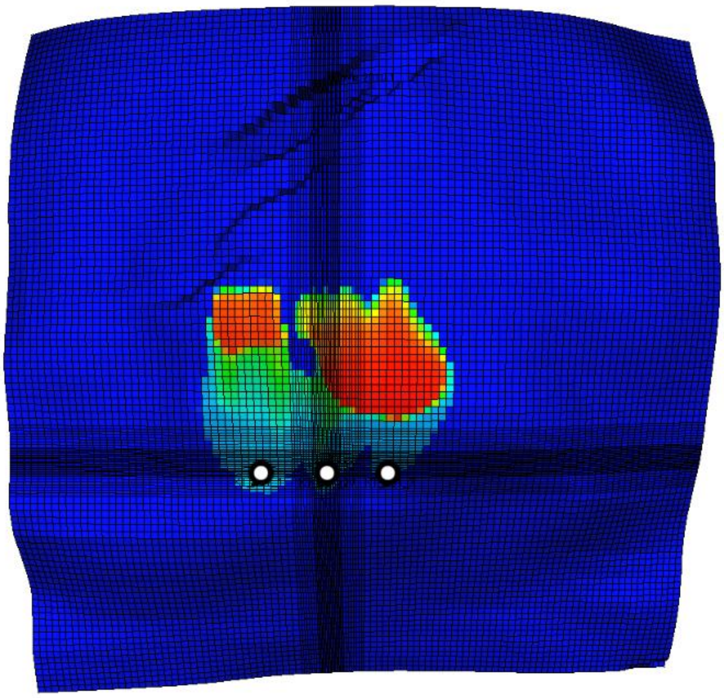

Figure 6: Gas saturation of scenario 3w. The dots indicate the well positions.

Generally, the arrival time of all scenarios does not show large differences. The largest difference occurs for the scenario with multiple injection wells, where the arrival time decreases by 581 days. The subplume generated by the eastern well reaches the fractures first. The arrival time of 11 years is comparable to scenario W400, which has the same well positions but only one third of the injection rate and leads to an arrival time of 10 years. This means that the impact of the injection rate is significantly lower compared to the impact of the well position. This is confirmed by the scenarios with constant injection rate and different duration. Constant rate injection shows a very similar arrival time of only 132 days earlier compared to real injection rate, which is characterized by interruptions and discontinuities. The arrival time does not show a substantial variation for the higher rate and shorter time rates (scenario const 2 and const 4). Nevertheless, the arrival time shows a slight increase of 126 and 333 days, respectively. This is surprising, since the CO_2 is injected effectively earlier compared to scenario const. The behaviour occurs because the Ketzin model is a multilayer system. Higher injection pressure has a larger gravity override effect and therefore causes a larger fraction of the CO_2 to be injected in the minor layers (Figure 7). Although some of the CO_2 from the lower layers flows through the open well after injection stop, there is a smaller amount of CO_2 present in the main layer 1 where the arrival at the faults occurs.

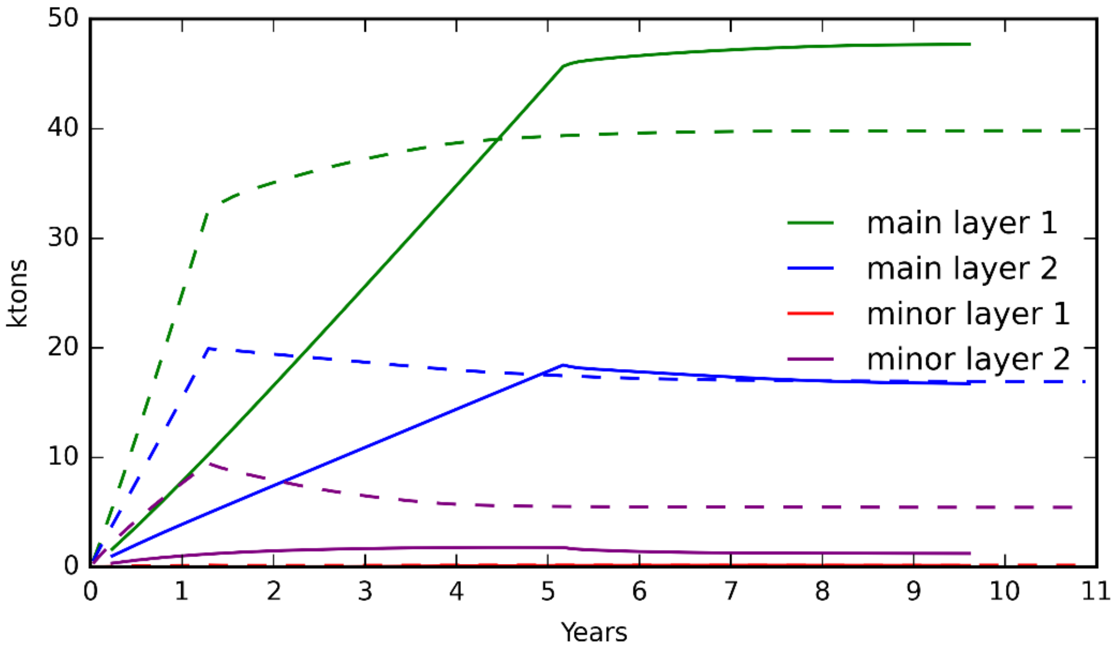

Figure 7: Distribution of CO_2 in the reservoir layers with different injection rate. The continuous lines show the base scenario (scenario 0), the dashed lines show scenario const4, where the fourfold rate is injected during a quarter of the injection time.

2.3.3 Variation of the geological model

The geologic setting of the reservoir itself may have a dominating impact on the arrival time. Although geology cannot be the subject of reservoir management, it determines the movement and spreading of the CO_2 plume. The shape of the anticline is well known from seismic surveys, wherefore the geologic structures follows Norden and Frykman (2013). The horizontal distribution of the reservoir facies is subject to higher uncertainty. This uncertainty of the reservoir characteristics is reflected in different scenarios (Table 3).

For scenario 0, the reservoir layers are generally assumed as homogenous (Figure 8). This is a reasonable approximation to unknown geology and represents an average permeability for the Ketzin reservoir. A heterogeneous field imposes strong prior constraints on the management scenarios e.g. since the permeability in the near wellbore area depends on the well position. This would induce discontinuities and secondary effects on the variation of single parameters. The vertical representation of well permeable reservoir facies follows the wellbore profiles in the three wells Ktzi 200, Ktzi 201, Ktzi 202. The main reservoir layers are represented with a thickness of 6 m each (discretisation 1m). To these layers generally a permeability of 100 mD is assigned, with exception for the northern part of the upper sandstone layer, since only one layer is present in the well Ktzi 202 (Figure 3).

Table 3: Arrival time for scenarios involving a modification of the geological model.

	Geology	Arrival time [years]	Difference to Case 0 [days]
Scenario 0	Mainly homogenous model, 100 mD	14	0
Scenario pcap	With capillary pressure	16	555
Scenario 50	Mainly homogenous model, 50 mD	28	3794
Scenario 200	Mainly homogenous model, 200 mD	7	-1822
Scenario swap	upper and lower sandstone layer swapped	15	480
Scenario invers	Permeability calibrated on pressure and arrival time	22	2219
Scenario stoch	Stochastic permeability and porosity	46	8565

The scenario pcap includes the capillary pressure function in multiphase simulation. Nevertheless, the impact of capillary pressure is similar for all scenarios, therefore this is neglected in the other simulations for computational efficiency. The capillary pressure function follows Lengler (2012). The application of capillary pressure increases the arrival time by 555 days. The shape of the plume is not significantly affected.

"Scenario 50" and "Scenario 200" have the same geologic structure with variation of the reservoir facies permeability by factor 2, to 50 and 200 mD, respectively. The arrival time follows proportionally to this property. Having in mind the permeability may vary over several orders of magnitude, it has a dominating impact on potential remediation.

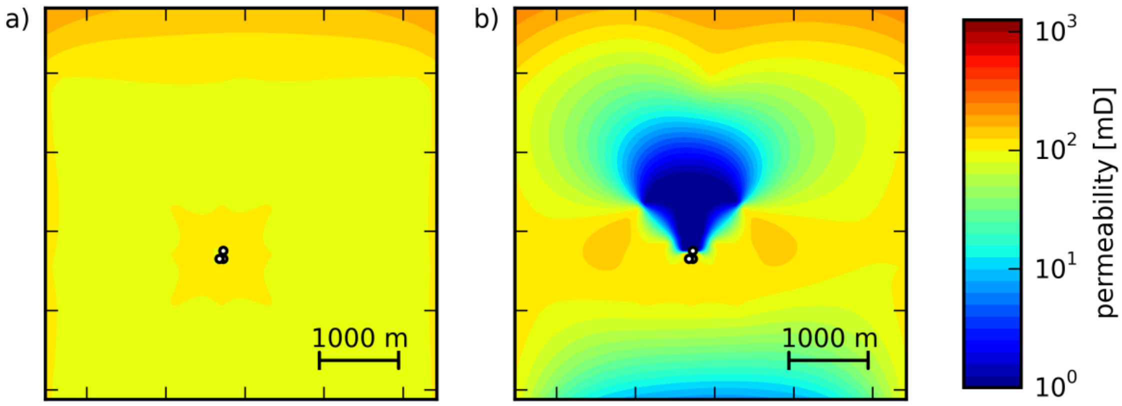

Figure 8: Hydraulic permeability for "Scenario 0", plot a) corresponds to the upper sandstone layer, plot b) corresponds to the lower sandstone layer. The wells are represented by points.

Further scenarios should provide an overview of the impact of horizontal variability. Considering the enormous bandwidth of potential geological structures, the approach intends to capture some realistic magnitude. However, the full range cannot be captured here.

The "Scenario swap" reflects that the reservoir layer found in Ktzi 202 may be part of the lower sandstone layer. The latter is continuous up to the fault region wherefore arrival occurs there. The arrival time is increased by 480 days. Gravity segregation between CO_2 and brine induces preferred flux in more shallow layers under otherwise identical geological conditions. Therefore the arrival is delayed when the lower reservoir layer is continuous.

The "Scenario invers" is based on a pressure data constrained permeability field. It is generated to match the pressure data of pre-injection hydraulic tests, pressure data of the first 30 days of injection, and the arrival time in observation well Ktzi 200 (Figure 9). Strong heterogeneities occur in the vicinity of the near wellbore area (Figure 9 c, d), while the far field is comparatively homogenous. The arrival time increases by 7 years since the permeability around the injection well screen reduced the flux into the upper layer, where the arrival occurs, is significantly reduced (Figure 9c) and therefore the injected amount of CO_2 is decreased. Furthermore, the permeability is slightly lower compared to "Scenario 0".

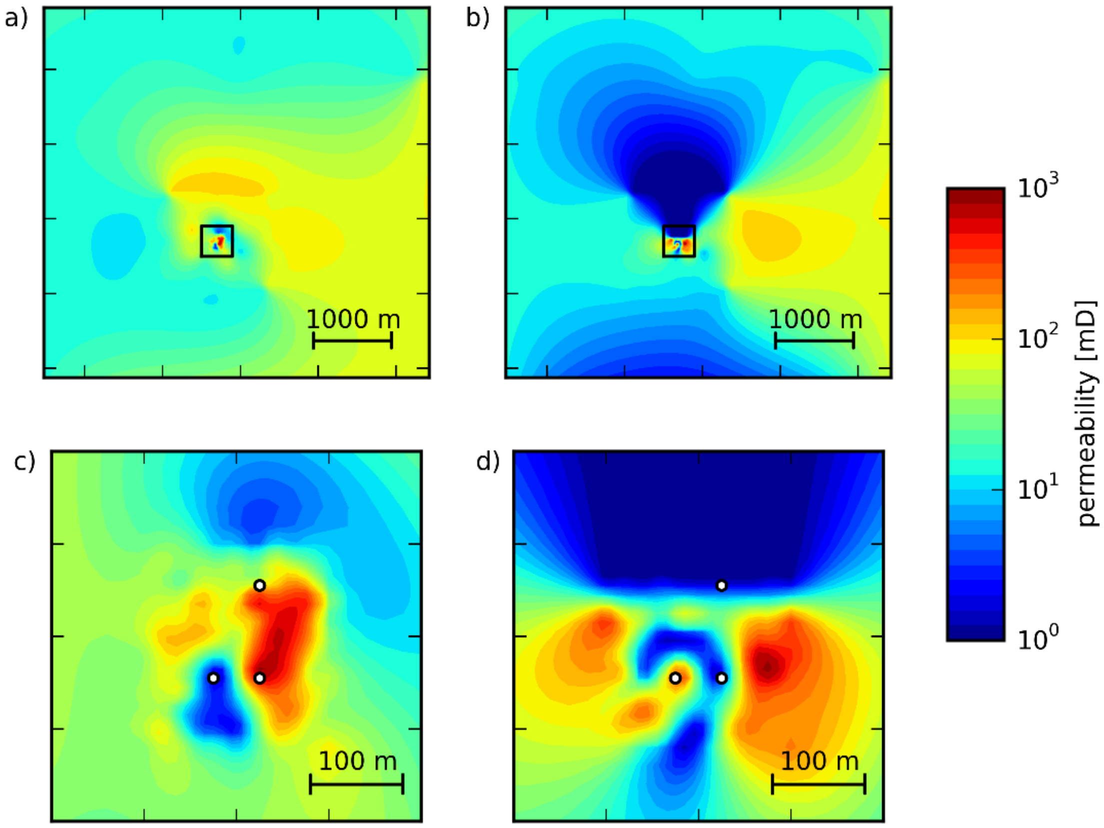

Figure 9: Calibrated permeability field matching hydraulic tests, CO_2 injection pressure and arrival time. Plots a) and b) show the main sandstone layers 1 and 2, the fault positon follows Figure 2, plots c) and d) show the insets from the above plots. The wells are represented by points.

The "Scenario stoch" is based on a stochastic permeability and porosity field (Norden and Frykman, 2013). The permeability varies over 6 orders of magnitude, with an arithmetic mean value of 100 mD and a geometric mean value of 4 mD. The high permeability structures do not form a continuous network, the CO_2 has to pass through several low permeable regions. As consequence the arrival time of 46 years is longest for all considered scenarios.

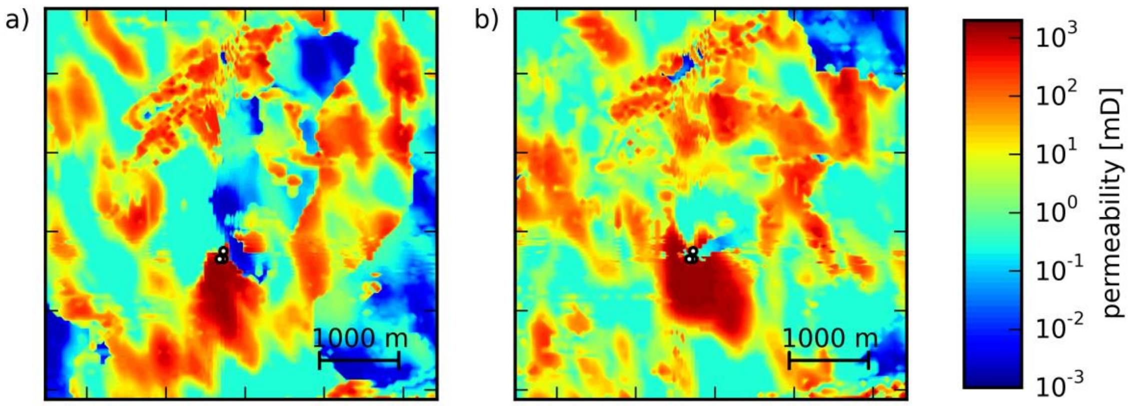

Figure 10: Stochastic permeability heterogeneity field following Norden and Frykman (2013). The plot a) shows a cross section of the upper sandstone layer, plot b) a cross section of the lower sandstone layer. The wells are represented by points.

2.4 Conclusions on Ketzin

Based on the Ketzin test site for geological storage, different reservoir management scenarios are carried out. In all scenarios the CO_2 reached the pre-defined undesired migration paths, represented by faults. An equilibrium state where the CO_2 does not reach the fault zone was not obtained. The most efficient management strategies are those that include a variation of the injection position. A downdip shift may increase the arrival time by 7 years, but an updip shift by the same distance can severely decrease the arrival time by 11 years. Lateral movements may induce minor variations that occur due to slight differences in the distance of the fracture zone and varying dip gradients. Reservoir management strategies that are based on temporal changes of the injection regime do not provide high cost, but the longevity of remediation is very low, there is no significant impact on the arrival time. The injection through multiple wells produces high costs of drilling and installation, but the longevity of this measure is also not significant.

Different geologic structures are simulated. Although geology cannot be subject of reservoir management, its variability should be considered for further management strategies. The effective permeability has a dominating impact on the plume behaviour and induces an arrival time variation proportional to the variation in permeability. This is generally also valid for heterogeneous permeability fields, the heterogeneity based on Ketzin data has been found to increase arrival time the most, by a time of 32 years since it implies a significant lower effective permeability on the reservoir scale. The distribution of the injected CO_2 to the different layers in a multilayer reservoir can induce significant variations in the arrival time. Due to gravity segregation CO_2 flows preferably into more shallow parts of the reservoir. For containment, however, it would be desirable to focus injection to layers where geologic structures reduce the connectivity to the fault region.

3 CASE STUDY - JOHANSEN MODEL

3.1 Site description

The field under consideration for this study is the Johansen formation, located off the coast of Norway (Figure 11). The aquifer is located at a depth of 2100-2400 m with an average thickness of roughly 100m (Eigestad et al, 2009, Christiansen et al, 2009). The lateral extent is about 100 km in the North-South direction and 60 km in the east-west direction. The average porosity is approximately 20-25 percent and permeability ranging from 64 to 1660 mDarcy. A theoretical storage capacity of >1Gton is estimated by Eigestad et al. (2009).
The area of most interest is around the Troll hydrocarbon field (red lines in Figure 11), which is located in the upper part of the aquifer. In this way the storage project can benefit the most of the existing infrastructure and is also close to the CO_2 source in Mongstad.

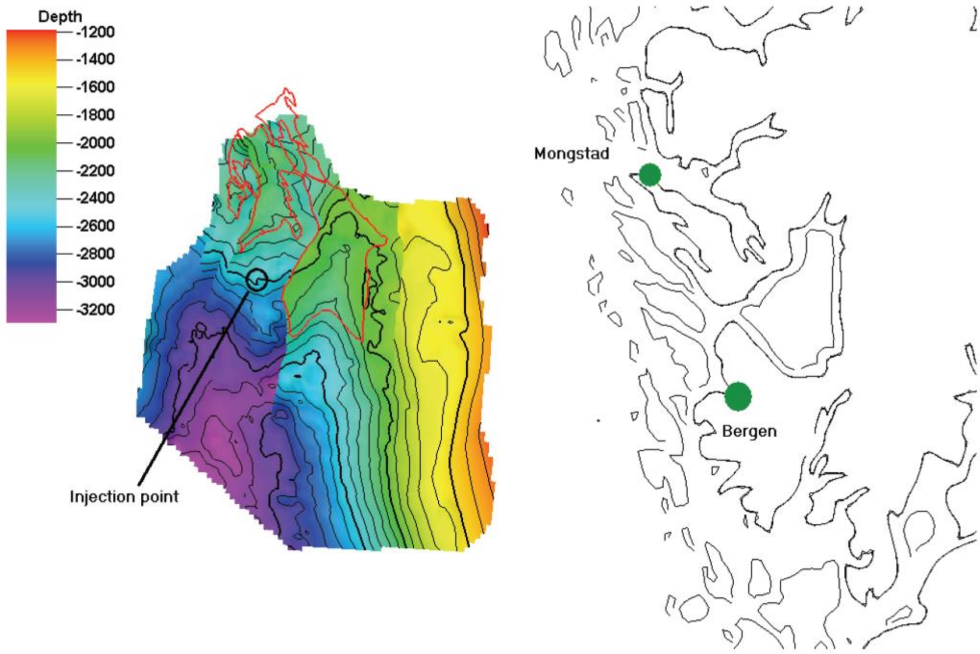

Figure 11: Depth map of the top of the Johansen formation and its location, with respect to the coast of Norway. Also indicated is a proposed injection site (from Bergmo et al, 2009).

This aquifer has been subject of a feasibility study into the possible underground storage of CO_2 coming from industrial companies on-shore Norway. The robust storage capacity was estimated to be 330 Mton of CO_2 (Bergmo et al, 2009), which takes into account the main uncertainties as the size of the communicating pore volume, fault properties and properties of the primary sealing formation. Reservoir simulations on this storage compartment were also reported by Wei and Saaf (2009).

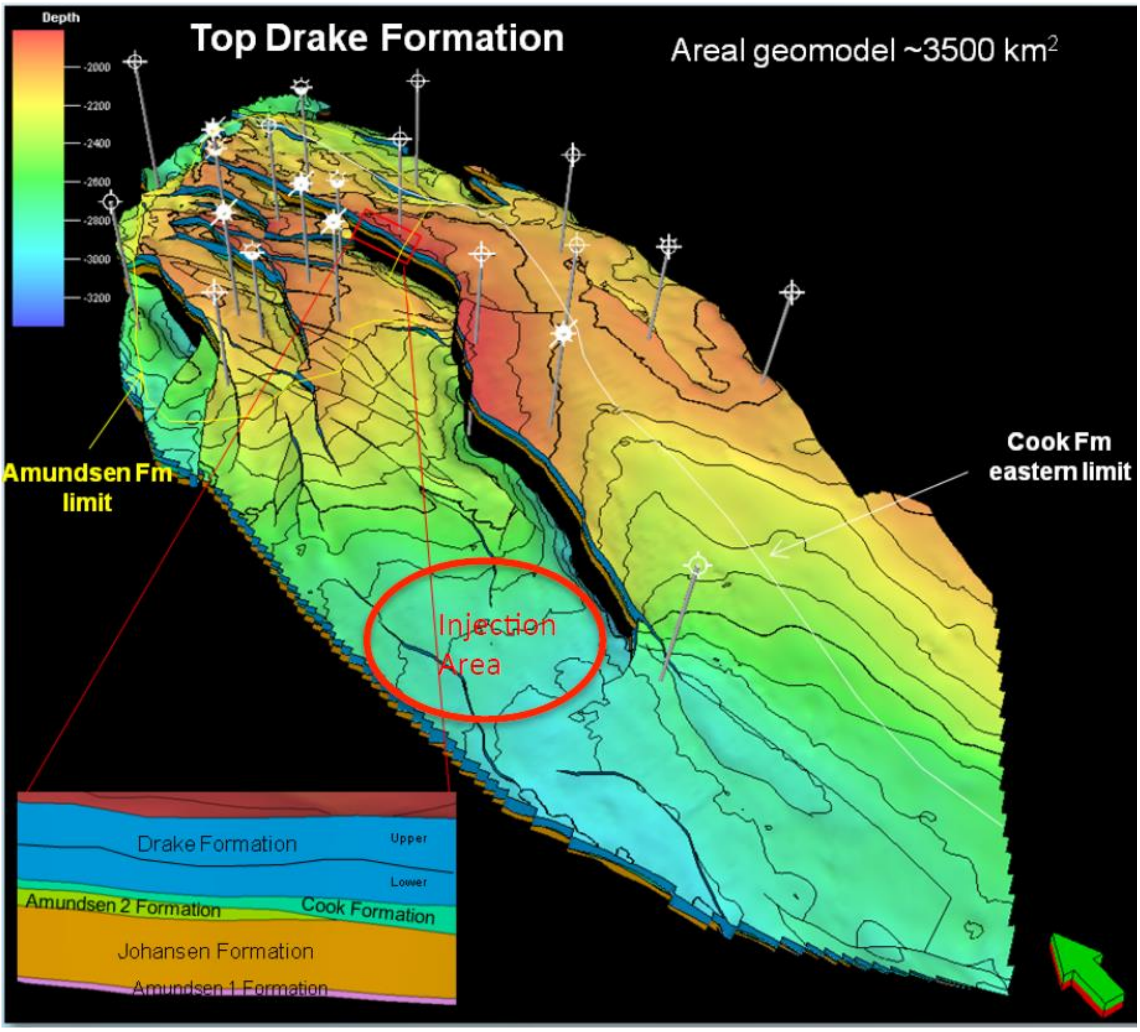

Figure 12: Overview of geological model with Drake formation (seal) and two aquifer formations (Johansen and Amundsen). The image is courtesy of Gassnova.

The Johansen formation is bounded by faults in the north and east. In the northern part of the Johansen formation many faults are identified with possible spill-points. The main seal of the aquifer is formed by the Drake formation (Figure 12).

3.2 Method

3.2.1 Simulator used Schlumberger's Eclipse 100 black-oil simulator

For the dynamic modeling of the Johansen field we have used Schlumberger's Eclipse black-oil simulator (also known as Eclipse 100). The Eclipse black-oil reservoir simulation software is a fully implicit, three-phase, three-dimensional, general purpose black-oil simulator. The black-oil model assumes that the reservoir fluids consist of three phases namely oil, water, and gas, with gas dissolving in oil. In our model we only enabled the water and the gas phases, representing water and CO_2 respectively. Dissolution of CO_2 is not considered.

The geological grid used in this study is described by Bergmo et al (2008) In this report we focus on a smaller area of the Johansen field and a section was made inactive, which can be seen in the number of grid blocks used in the final dynamic model

Table 3.1 Overview of grid dimensions in the simulation model.

	Number grid blocks x-direction NX	Number grid blocks y-direction NY	Number grid blocks z-direction NZ	Total number of grid blocks	Number of activegrid blocks
Dynamic grid	55	281	83	995,170	526,272

3.2.2 Pressure, Volume, Temperature (PVT) data

3.2.2.1 Gas PVT

For the Gas PVT we applied NIST data to generate tables based on an aquifer temperature of 94 ^oC (Bergmo et al, 2008).
The gas viscosity and the formation volume factor as function of pressure of the pure CO_2 are shown in Figure 13 and Figure 14, respectively.

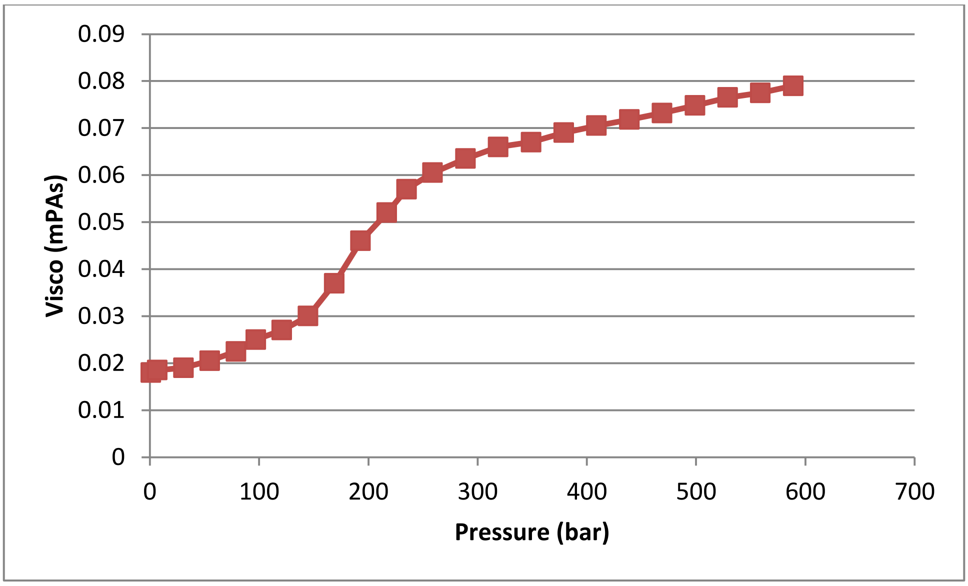

Figure 13: Viscosity of pure CO_2 as function of pressure, at a temperature of 94 °C.

3.2.2.2 Water PVT

The water formation volume factor is 1.0132 rm^3/sm^3 at reservoir conditions at a reference pressure of 215 bar. The water compressibility at reservoir conditions is 3.97954×10^{-5}/bar. The water viscosity is 0.39851 (mPas) at reservoir conditions at a reference pressure of 215 bar.

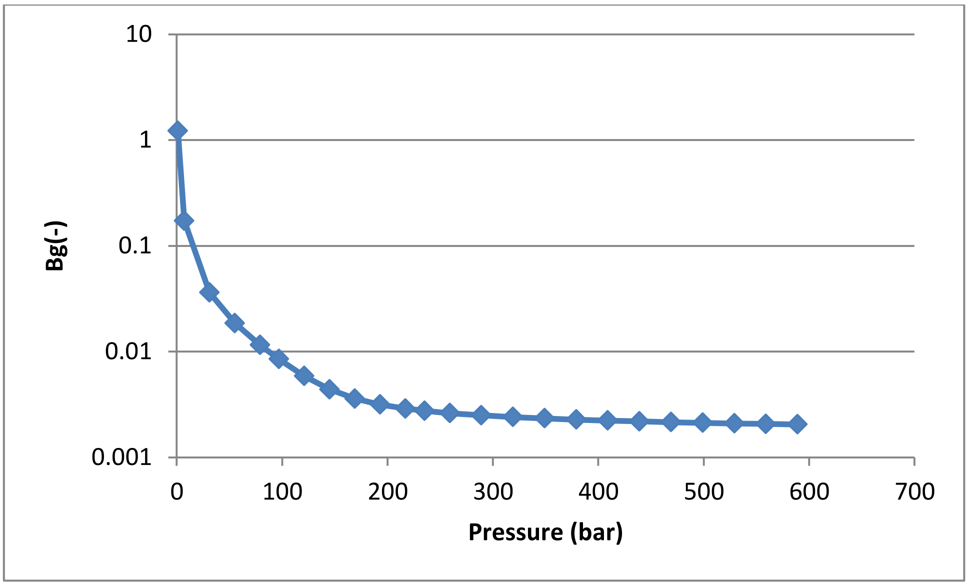

Figure 14: Reservoir volume factor (B_G) versus pressure, at a temperature of 94 °C.

3.2.3 Saturation functions and pressure dependent rock properties

3.2.3.1 Relative permeability

The relative permeability-saturation curves for the carbon dioxide were made hysteretic, while those of the wetting fluid (brine) were left non-hysteretic (see Figure 15).

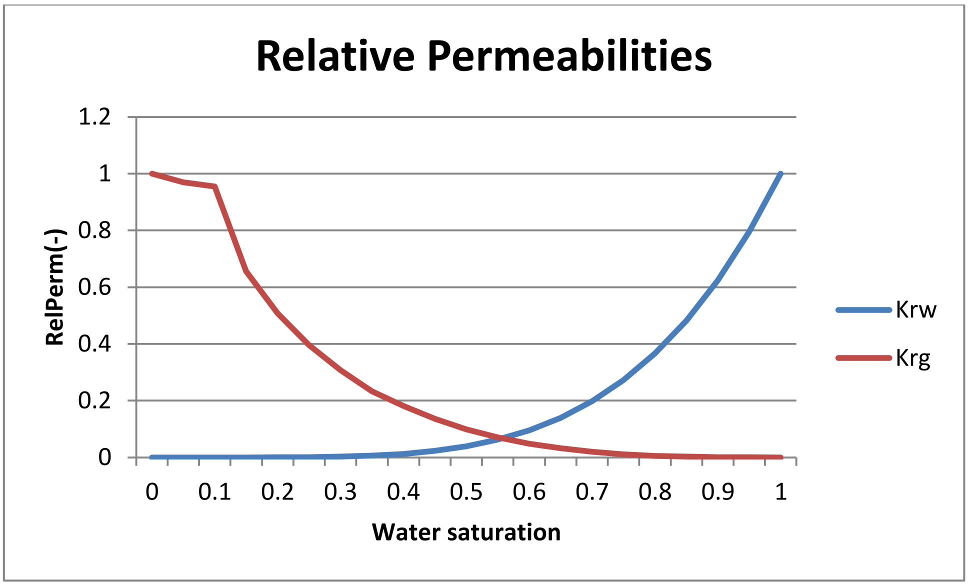

Figure 15: Relative permeability (based on a similar Dutch aquifer).

3.2.3.2 Capillary pressure

In our modelling we assumed the capillary pressure does not play an important role and was set to 0.

3.2.3.3 Rock Compressibility

The rock compressibility is set to standard value of 5.0e-5 1/bar at a reference pressure of 200 bar

3.2.4 Initial conditions

The starting point was a static geological model of the Johansen aquifer, as supplied by Bergmo et al, 2008). From the complete model the western section (63*183*36 grid cells, Figure 12) with most measured properties was selected for the reservoir modelling. The reservoir is initially assumed to be in hydrodynamic equilibrium with a reservoir pressure of 220 bar at a depth of 2200 m and a reservoir temperature of 94 degrees C. We used an isothermal model, hence all temperature dependent fluid and rock properties are specified at reservoir temperature.

3.2.5 Well Locations

For all simulations 1.1 Mton CO_2 per year were injected for 113 years in layer 15-18 (Johansen formation) of the model. Various injection locations were chosen and the resulting migration paths investigated for critical issues concerning the storage compartment integrity. To allow enough time for the migration the modelling was continued until the year 9000. The various injection locations are displayed in Figure 16.

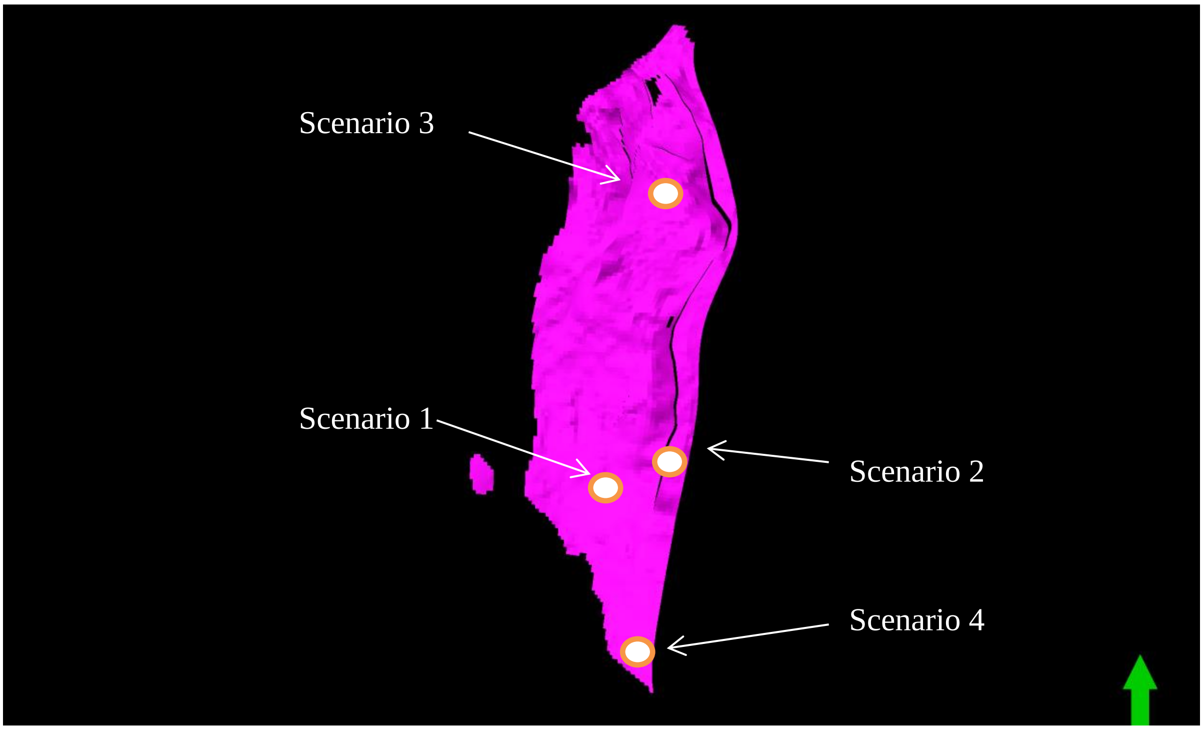

Figure 16: Plane view of layer 18 in the static model with the four hypothetical injector locations as used in this study.

3.3 Results

We present four scenarios in this report, from which one – Scenario 1 - appeared to be not critical (in the sense no diversion is needed) and three are critical and diversion is needed. These critical scenarios will serve as base cases for further work in this area, where brine/water injection will serve as CO_2 flow diversion option and can serve as a corrective measure.

3.3.1 Non-critical scenario

3.3.1.1 Scenario 1

In total 124.3 Mton of CO_2 were injected in the South West area of the Johansen formation. We observe that directly after injection and even after 9000 years the CO_2 is close to the well area and does not migrate to the fault area close to the injection site (see Figure 17) and no corrective measure are necessary in this scenario.

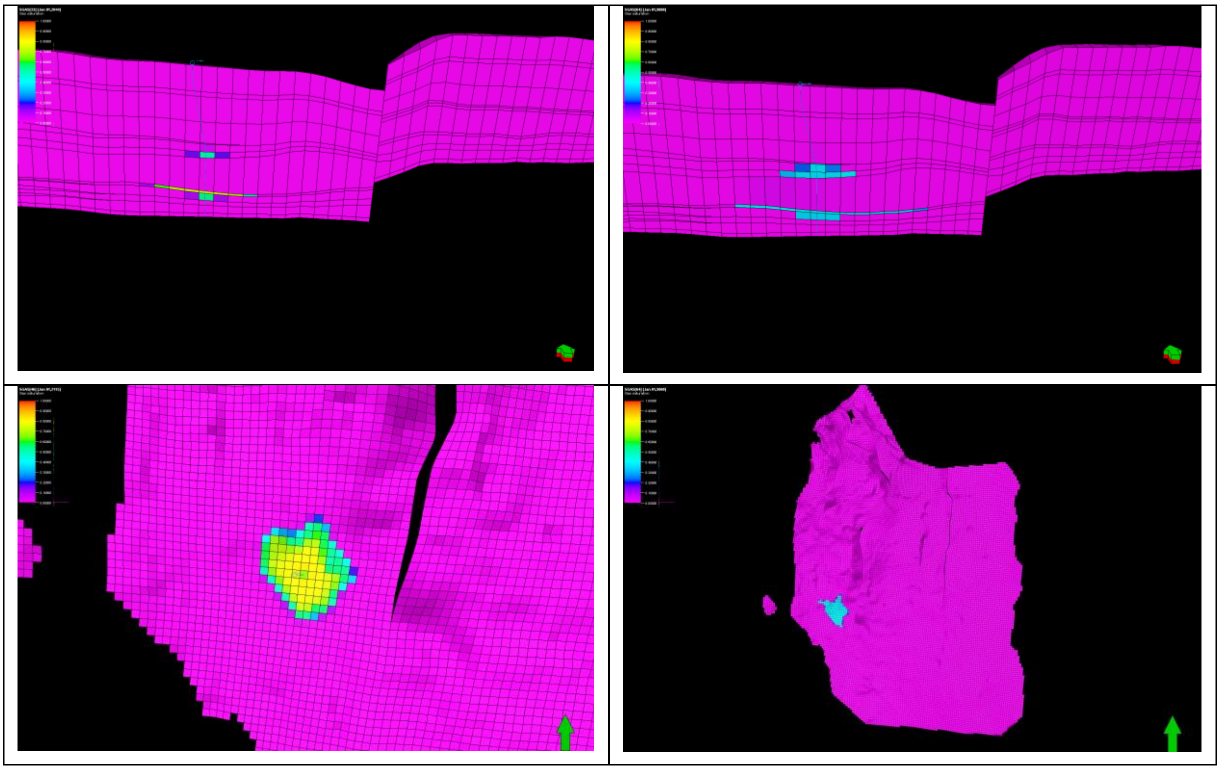

Figure 17: Gas saturation in scenario 1. Sideview directly after injection (top left) and after 9000 years (top right). Topview directly after injection (bottom left) and after 9000 years (bottom right).

3.3.2 Critical scenarios

3.3.2.1 Scenario 2

In the first critical scenario the injection well is placed in the eastern part of the model, close to a major fault. During injection the plume migrates from injector to the north along the fault with a large offset. These faults are usually sealing due to clay smearing. In our simulation we considered the migration along a fault not as a risk and no corrective measure is necessary. In Figure 18 we observed that the Johansen formation

varies in thickness laterally and becomes very thin just north of the injection well (Figure 18).
We identified this as a spillpoint and the anticipated storage location is before the thin zone, where a pinch out almost occurs.

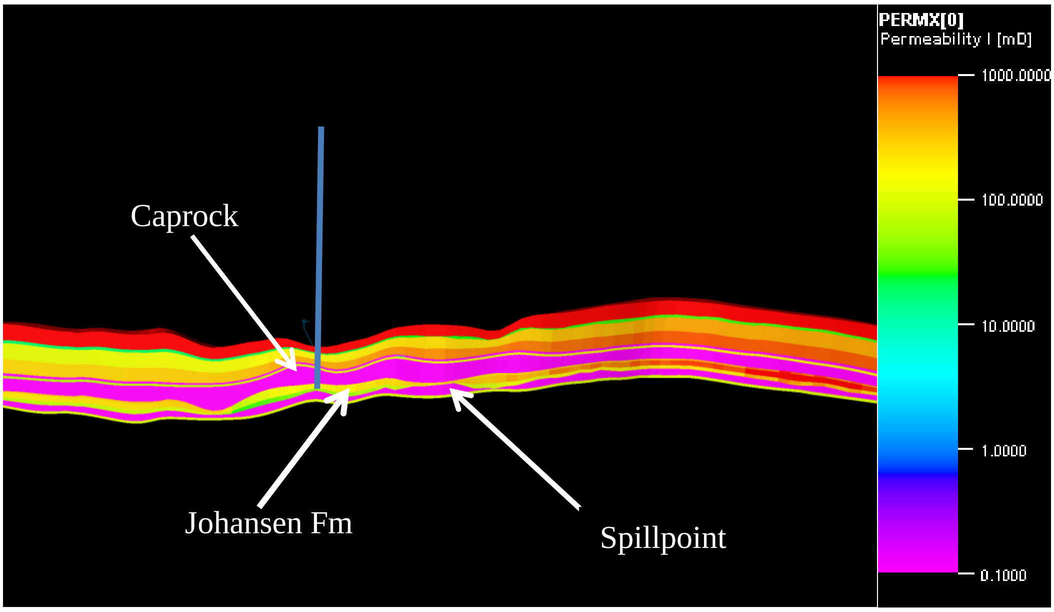

Figure 18: Permeability of scenario 2.

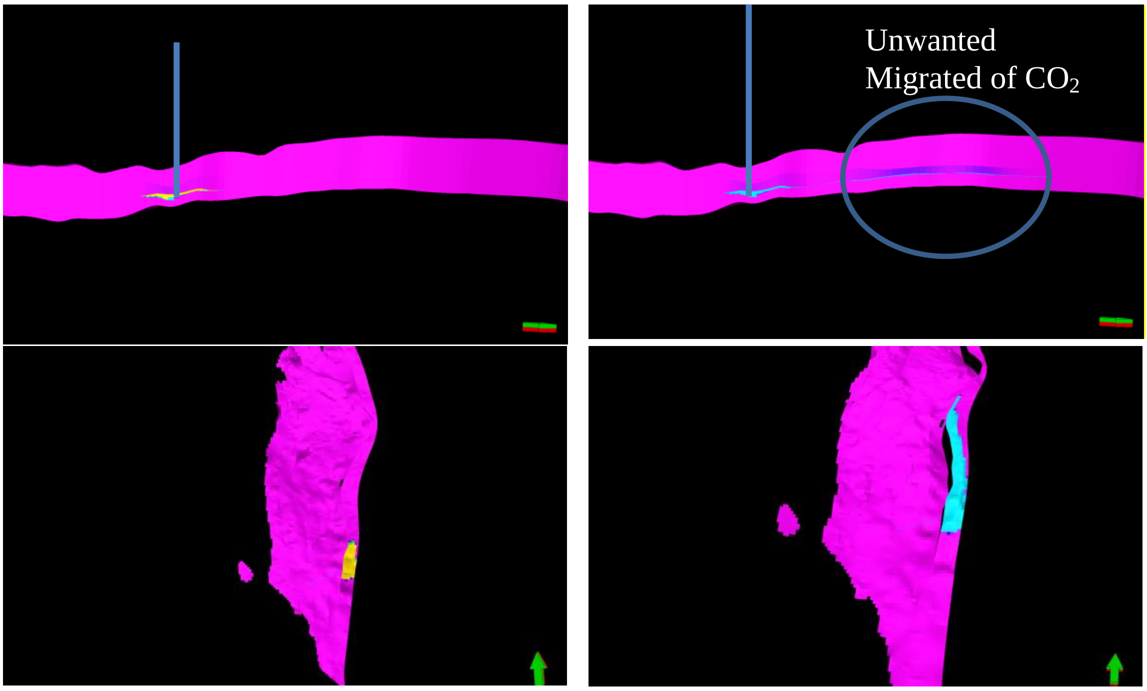

Figure 19: Gas saturation in scenario 2. Sideview directly after injection (top left) and after 9000 years (top right). Topview directly after injection (bottom left) and after 9000 years (bottom right).

Immediately after the injection period the CO_2 migrated within the intended storage zone (Figure 19). However after a longer period (now 9000 years is shown) the CO_2 migrated further to the north beyond the spill point. An unwanted migration and a corrective measure is needed here.

3.3.2.2 Scenario 3

In scenario 3 a well is placed down dip from a fault and the CO_2 starts migrating to the fault (Figure 20). We assume in this scenario the fault appears to be not sealing or safe and therefore corrective measures are needed.

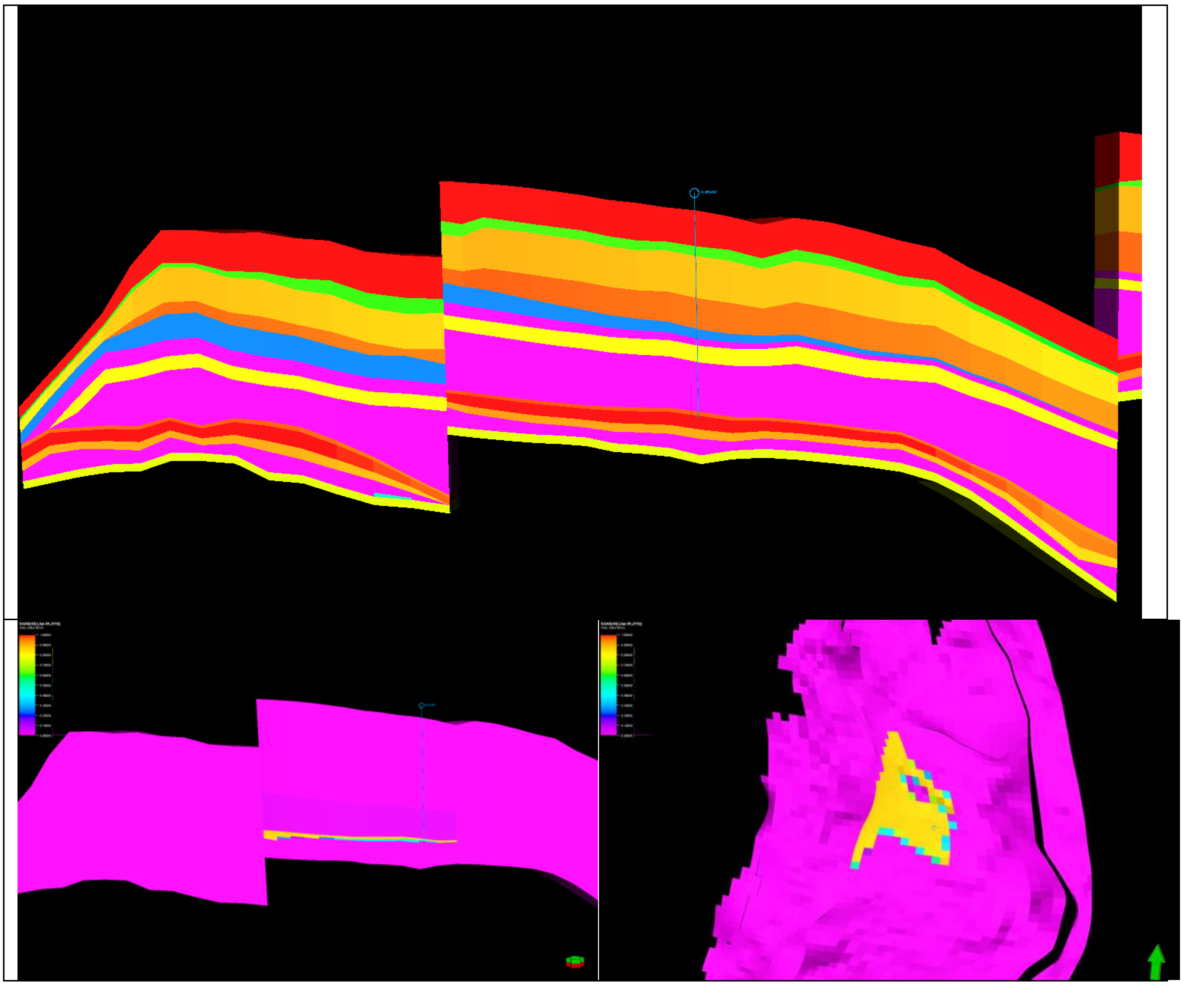

Figure 20: (top) Permeability (scale see Figure 18) (lower left) Sideview CO_2 migration after injection and (lower right) CO_2 migration topview after injection.

3.3.2.3 Scenario 4

In Scenario 4 the CO_2 is flowing towards a fault of the model, during the injection period. In this scenario the risk of fault reactivation and flow into fractures is increased.

Due to the CO_2 storage operations the pressure along the fault changed and the related stress changes around the fault as well. This is a potential leakage scenario and intervention is needed, which will be described in a future report.

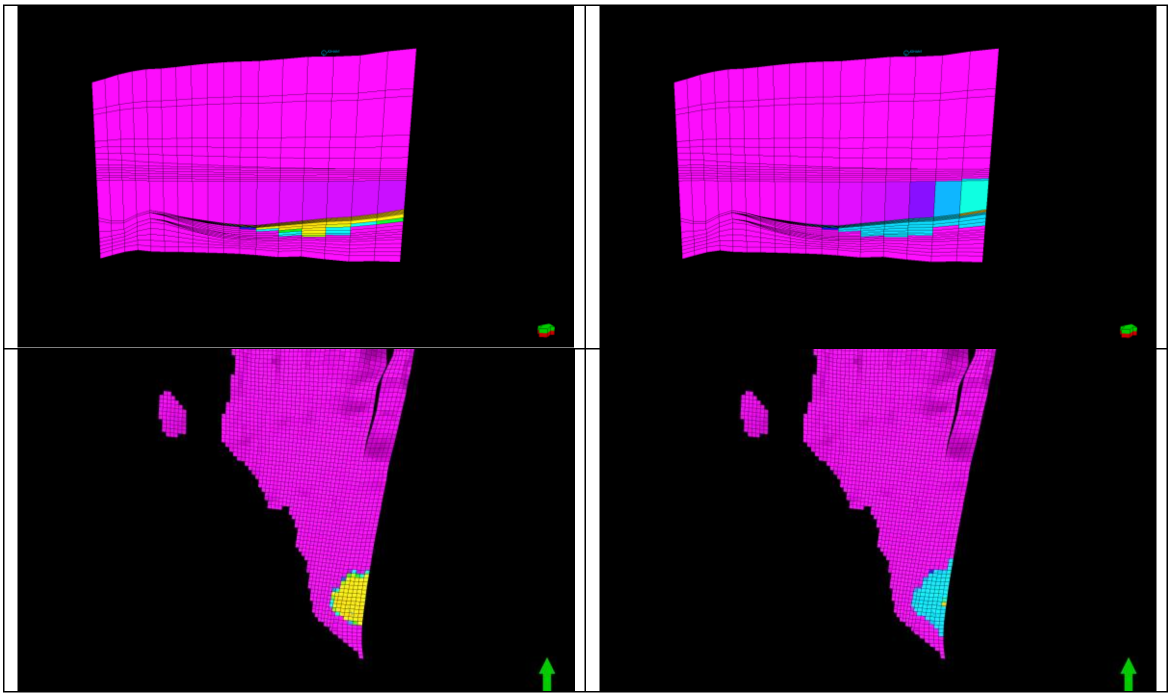

Figure 21: Gas saturation in scenario 4. Sideview directly after injection (top left) and after 9000 years (top right). Topview directly after injection (bottom left) and after 9000 years (bottom right).

3.4 Discussion on Johansen

- We defined 3 different scenarios which will serve as base cases for further work on flow diversion techniques, for which flow diversion can be a potential corrective measure.
- We defined 2 different type of scenarios:
  - Unwanted migration happens during the monitoring period (or after the injection period) to a spill point, and
  - Unwanted migration happens during the injection period itself to a fault.

4 FINAL CONCLUSIONS

Based on the Ketzin test site for geological storage and the Johansen geological model different reservoir management scenarios are carried out. All Ketzin scenarios imply the arrival of the CO_2 at the fracture zone. In most of the Johansen scenarios the CO_2 arrives at fault zones. In both cases, these structures were assumed to represent potential leakage paths.

The most efficient management strategies are those that include a variation of the injection position. Lateral movements may induce minor variations that occur due to slight differences in the distance of the fracture zone and varying dip gradients. Reservoir management strategies that are based on temporal changes of the injection regime do not incur high cost, but the longevity of remediation is very low and there is no significant impact on the arrival time at the location of potential leakage. The injection through multiple wells produces high costs of drilling and installation and the longevity of this measure is also not significant.

Three different scenarios are found for the Johansen model which will serve as a base case for further work on flow diversion techniques.

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