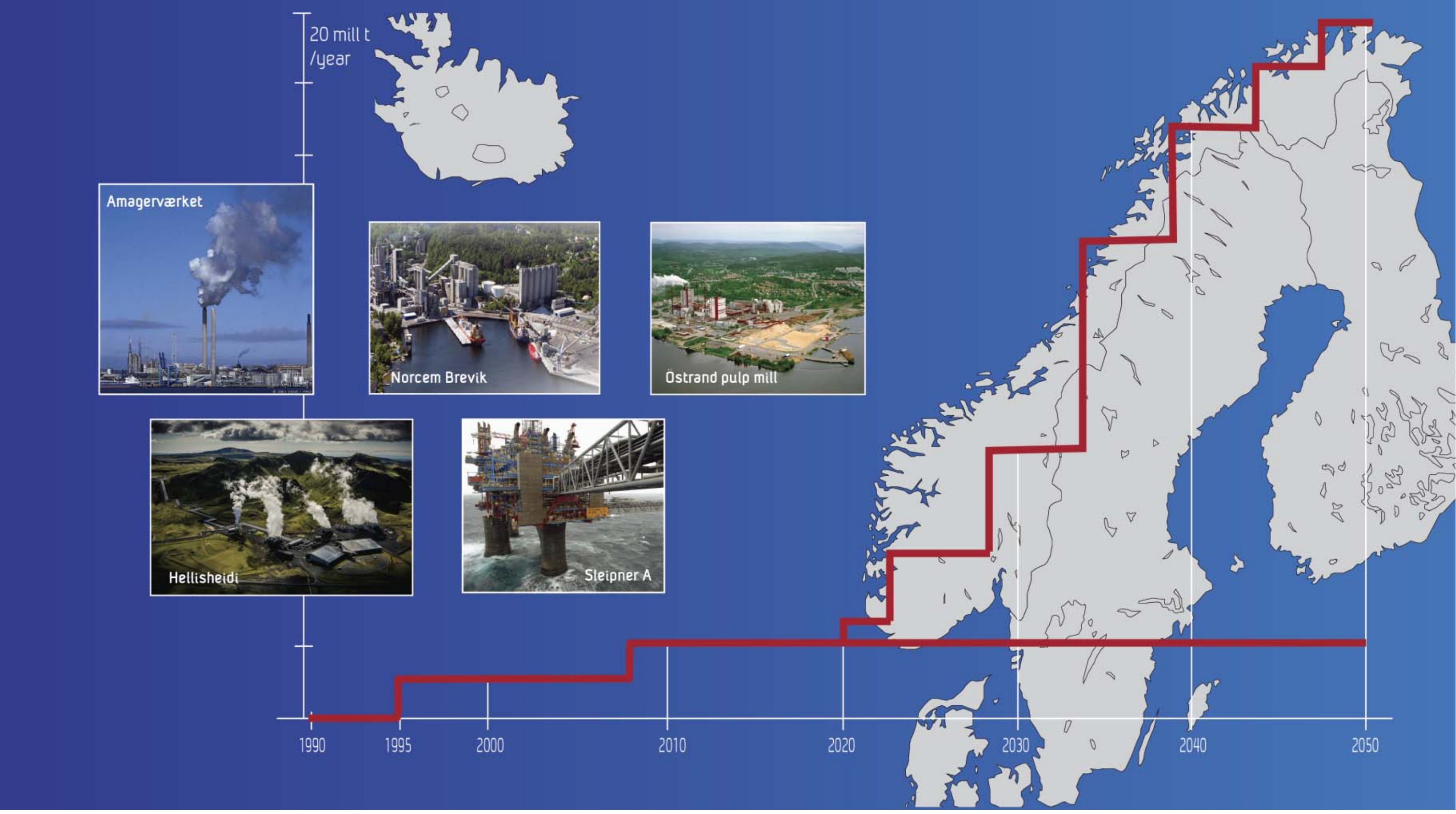

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NORDICCS Conference contribution D 6.3.1203

November 2012

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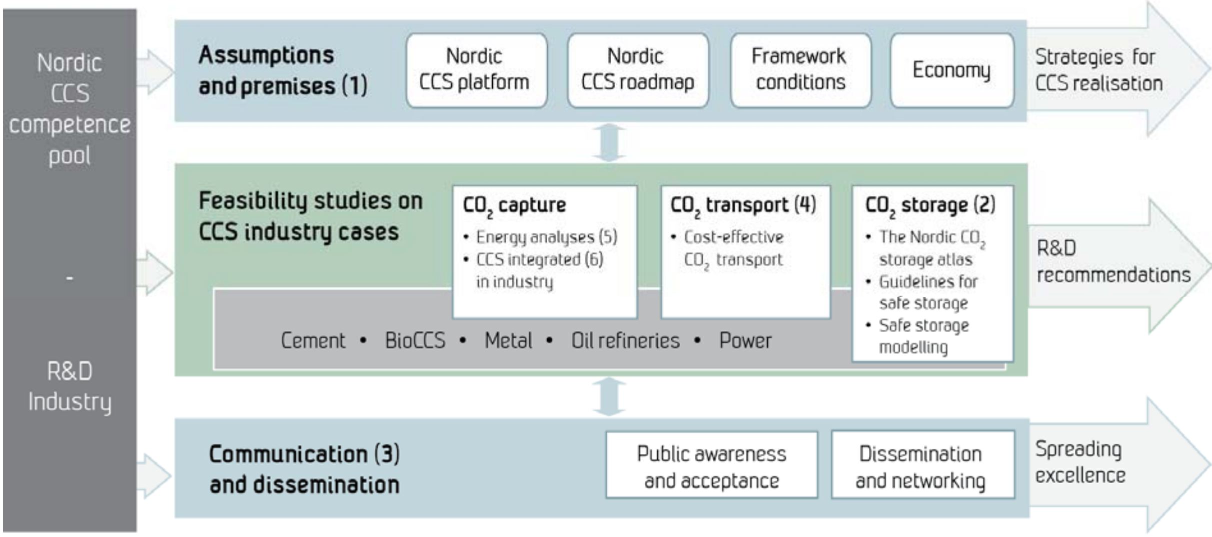

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Summary

Within the Skagerrak-Kattegat region up to 14 Mt of CO_2 can annually be captured from power and industry sources. To establish a CCS infrastructure in the region it is necessary to identify and characterize potential CO_2 storage sites. Initial screening of the region has revealed large aquifers in the Upper Triassic Gassum Formation. In dynamic simulation studies 250 Mt of CO_2 were injected into the Gassum Formation over a period of 25 years. Identification and analysis of parameters that affect CO_2 storage capacity were performed. Parameters important for the migration speed and the dissolution rate of CO_2 in open dipping aquifers were investigated by a series of simulations on generic tilted reservoir models.

Keywords CO_2 storage; CO_2 storage capacity; Skagerrak; Gassum Formation; Hanstholm structure; open dipping traps

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Nordic CCS Competence Centre, NORDICCS, is a networking platform for increased CCS deployment in the Nordic countries. NORDICCS has 10 research partners and six industry partners, is led by SINTEF Energy Research, and is supported by Nordic Innovation through the Top-level Research Initiative.

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Evaluation of CO_2 storage potential in the Skagerrak/Kattegat area

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Abstract

Within the Skagerrak-Kattegat region up to 14 million tonnes CO_2 can annually be captured from power and industry sources. To establish a CCS infrastructure in the region it is necessary to identify and characterize potential CO_2 storage sites within reasonable distance to the sources in order to keep transport costs low. The Skagerrak-Kattegat area on the Norwegian side has no previous record of oil exploration or other activities which could have resulted in extensive mapping of the sub-surface. The data coverage is therefore scarce compared to regions in the North Sea and the density of data is decreasing as one moves eastward in Skagerrak.

Initial screening of possible CO_2 storage sites in the region has been performed [1] based on published work, new interpretations of seismic lines and interpretation of available well logs. The screening has revealed large open and semi-closed aquifers in the Upper Triassic Gassum Formation and three locations in the Skagerrak region were chosen for further investigation. Two open dipping aquifer models were constructed; one on the Norwegian side and one on the Danish side. In addition a model of the Hanstholm structure offshore Denmark was constructed and simulations for estimating storage capacity were performed. Reservoir properties in the Gassum formation are based on petrophysical logs from 12 Danish onshore and offshore wells. None of these wells penetrate the target locations and average properties from the well logs were used in the construction of reservoir models. In simulation studies performed on each of the three models, a total of 250 million tonnes of CO_2 is injected down-flank using three horizontal injection wells over a period of 25 years. Total simulated time was 4000 years.

Identification and analysis of important parameters for CO_2 storage capacity were performed on the constructed models to compensate for the scarcity of data. Pressure increase and early distribution of CO_2 are sensitive to location and number of injection/production wells in addition to the general properties of the reservoir. Increasing number of injection wells and/or introducing water production wells will reduce the increase in pressure for a given model and injection rate. The final distribution of CO_2 in the simulations is sensitive not only to geological input parameters such as permeability, porosity and structural topography but also to temperature, salinity, flow parameters and grid resolution. Important parameters for the migration speed and the dissolution rate of CO_2 in open dipping aquifer traps were investigated by a series of simulations on a generic tilted reservoir model.

Simulations indicate that the Late Triassic Gassum Formation has the capacity for storing at least the 250 million tonnes CO_2 from the mapped industrial sources in the Skagerrak-Kattegat area but it must be emphasized that there are large uncertainties in the constructed models due to scarcity of data. The most critical factors for safe storage are the fracturation pressure of the sealing cap rock and the parameters controlling lateral migration of the injected CO_2. The induced pressure increase

in the Hanstholm model is higher than the estimated safe pressure increase for the cap rock integrity but the formation may still be suitable for storage by increasing the number of injection and water production wells. Further characterization of the cap rock and overburden is required to give a better estimate of fracturation pressure in all three target areas. Sea bottom depth may be a limiting factor for the open dipping traps since a thinner overburden will reduce the fracturation pressure of the cap rock.

The main results indicate that the north-eastern part of the Gassum formation on the Danish side is the most promising target for injection of 250 Mt CO_2. This is based on the observation that all the injected CO_2 is capillary trapped or dissolved within the model boundaries, the injection pressure is thought to be in the safe pressure range and the option of injecting part of the CO_2 into the shallower Haldager formation is available. This option is also possible for the model on the Norwegian side but simulations indicate that the injected CO_2 can migrate to the northern boundary of the formation where further migration is uncertain. The location is still worth investigating further since small changes in flow parameters can change the maximum plume size of the injected CO_2. These parameters are at the present uncertain and more data is needed for better characterization of the target formation.

The Hanstholm structure has a domal closure that can hold the injected amount of CO_2 but simulation results from the current model indicate injectivity problems with the applied high injection rates. Introducing a larger number of injection wells and/or production wells could change this and if it is possible to build confidence in the sealing properties of the cap rock, Hanstholm could be the preferred target. Further characterisation of the target formations and the overburden could also change the ranking of the models (cap rock integrity and safe pressure increase).

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GHGT-11

Evaluation of CO_2 storage potential in Skagerrak

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Abstract

Within the Skagerrak-Kattegat region up to 14 Mt of CO_2 can annually be captured from power and industry sources. To establish a CCS infrastructure in the region it is necessary to identify and characterize potential CO_2 storage sites. Initial screening of the region has revealed large aquifers in the Upper Triassic Gassum Formation. In dynamic simulation studies 250 Mt of CO_2 were injected into the Gassum Formation over a period of 25 years. Identification and analysis of parameters that affect CO_2 storage capacity were performed. Parameters important for the migration speed and the dissolution rate of CO_2 in open dipping aquifers were investigated by a series of simulations on generic tilted reservoir models.

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CO_2 storage; CO_2 storage capacity; Skagerrak; Gassum Formation; Hanstholm structure; open dipping traps;

1. Introduction

The Skagerrak-Kattegat area between Denmark, Sweden and Norway has no previous record of oil exploration or other activities which could have resulted in extensive mapping of the sub-surface. The data coverage is therefore scarce compared to regions in the North Sea and the density of data is decreasing as one moves eastward in Skagerrak. Initial screening of possible CO_2 storage sites in the region has been performed based on published work, new interpretations of seismic lines and interpretation of available well logs.

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The screening has revealed large open/semi-closed dipping aquifers in the Upper Triassic Gassum and Haldager Formations [1], which is evaluated for CO_2 storage. The present contribution presents reservoir simulations of CO_2 injection into the Gassum and Haldager Formations in the area north and north-east of the Fjerritslev Trough [2]. In addition a model of the Hanstholm structure offshore Denmark has been constructed on which initial simulations have been performed for estimating storage capacity. The reservoir simulations are part of an interdisciplinary project with the overall goal to establish a basis for large-scale handling of CO_2 in this area, including regional CO_2 sources and capture possibilities, transportation and infrastructure, possible storage sites as well as legal aspects related to the whole CCS chain [3].

The Gassum Formation is overlain by thick marine mudstones of the Fjerritslev Formation, which is characterized by large lateral continuity, forming a highly competent cap rock unit probably making the Gassum Formation one of the most promising reservoirs for CO_2 storage in the study area. The sandstone of the Haldager Formation consists of fluvial and shallow marine sandstones interbedded with thin mudstones. The thickness of Haldager Formation sandstone towards northwest under the Norwegian channel as taken from one well drilled in the Norwegian sector (IKU well 13/1-U-1) in the study area is 32 m and the net/gross ratio of 0.5. The average thickness of Haldager Formation sandstone in the offshore Danish wells is about 25 m, with an average porosity of more than 26 % and a net/gross ratio of 0.5 – 0.8. The Haldager Formation sandstone is overlain by the marine mudstones of the Børglum Formation. Regional distribution of the mudstones with good sealing capacity above makes also the Haldager Sand Formation a good potential reservoir for CO_2 storage in the area. Here we only present results from simulations of CO_2 injection into the Gassum formation and it is assumed that the Fjerritslev Formation is sealing.

2. Models

Three locations in the Skagerrak region have been investigated for CO_2 injection in this study. Two open dipping aquifer models in the Gassum Formation (Model1, Model2) with homogenous net thickness were made. In addition a model of the Hanstholm structure just south of Model1 has been constructed on which initial simulations were performed for estimating storage capacity.

Outline of the model areas for Model1, Model2 and Hanstholm on a top Gassum Fm. surface is shown in Figure 1. Location of Model1 and Model2 was decided based on the concept of storing CO_2 in an open dipping trap. The injection points should therefore be located down flank of a gentle dipping formation. The main short term mechanism for trapping CO_2 is assumed to be capillary trapping of CO_2 as residual phase. In addition, the long migration distance of the injected CO_2 will enhance the dissolution of CO_2 into the formation water. The Hanstholm structure is assumed to be a closed structure and was chosen for its size. The main short term trapping mechanism is assumed to be capillary trapping by the assumed sealing cap rock.

Reservoir properties are based on petrophysical logs from 12 Danish wells (including 6 offshore wells). No wells penetrate the model areas and average properties of the wells have been used. No thickness maps of formations were available when the reservoir models were built and a constant effective thickness was assumed. The model thicknesses are equal to the average net thickness in the well logs (not weighted) giving 50 and 20 meter thickness for Gassum and Haldager respectively. The basic assumption then is that the injected CO_2 will mainly migrate along and below the sealing cap rock at the top of the formations.

Average effective porosity from the well logs is 22.5 % but a linear correlation to depth was applied based on average porosity and depth points in the wells. The range of porosity in the two models is between 21.3 % and 28.5 %. Permeability was correlated to porosity by a relationship developed by GEUS for this study based on their regional database. Permeability varies between 200 and 650 mD. Average net permeability from wells is 210 mD.

The open dipping trap models (Model1 and Model2) cover a large depth range and hence one can expect a relatively large variation in temperature and salinity of the formation water. A salinity gradient of 75.6 ppm NaCl per meter and a temperature gradient of 31 °C/m were assumed based on regional models and well data. In order to model the effect of this on density and viscosity of the formation water and solubility of the injected CO_2, 6 pVT regions (having constant temperature and salinity) were generated for Model1 and Model2.

Viscosity and density of the formation water was calculated for each region based on [4] and [5]. The solubility of CO_2 in brine is calculated from a correlation by Spycher et al. [6]. The density of CO_2 is based on an equation of state for CO_2 developed by Span and Wagner [7]. The viscosity of CO_2 was calculated from a correlation by Fenghour et al. [8].

Due to the relatively large grid block sizes linear relative permeability curves for brine and CO_2 phases were used. Residual CO_2 was set to 20 % and residual brine was set to 7 %. Measurement on cores from the Utsira Sand at the Sleipner CO_2 injection site (unconsolidated sand stone) indicates residual CO_2 saturation of 25% [9]. Assuming 20% might be on the low side (i.e. will underestimate trapped CO_2) but no measurements were available for the Gassum sandstone.

Initial hydrostatic conditions were assumed, with open/semi-closed boundaries up-dip towards north (Model1) and northwest (Model2). The open boundaries to the north were modeled by production wells producing at constant pressure giving amount of CO_2 migrating out of the model as produced CO_2.

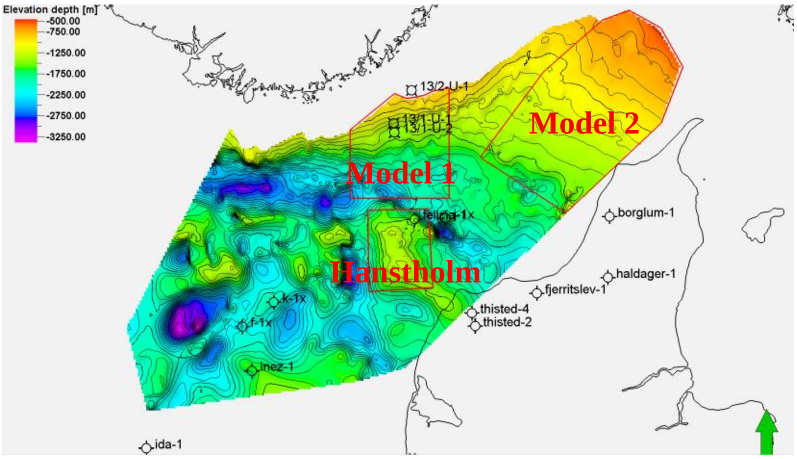


Figure 1. Outline of the model areas for Model1, Model2 and Hanstholm shown on a top Gassum Fm. surface.

3. Results, base case

In all three models, a total of 250 million tonnes of CO_2 is injected down-flank using three horizontal injection wells over a period of 25 years. Total simulated time is 4000 years.

3.1. Model1 and Model2

Injection took place by 3 horizontal injection wells perforated in the bottom layer with distance between injection wells 8 – 10 km. The wells have perforation intervals of 800-1000 meters. Injection depth was approximately 2410 m (Model1) and 1708 m (Model2). The well injection rate was 3.33 Mt/year = $4.88 \cdot 10^6$ Sm^3/day/well giving a total of 10 Mt/year.

The results of the simulations on the open dipping traps are shown in Figure 2 and Figure 3 as distribution of CO_2 saturation. For Model1, CO_2 reaches the northern border after 400 years, and after 4000 years 7.5 % has escaped. The rest is capillary trapped (~74.5%) or dissolved (~18%). Figure 2 shows CO_2 saturation in Model1 after 25 years (stop of injection), after 400 years when the first CO_2 has reached the open boundary to the North and after 4000 years. The open boundary is modeled with constant hydrostatic pressure.

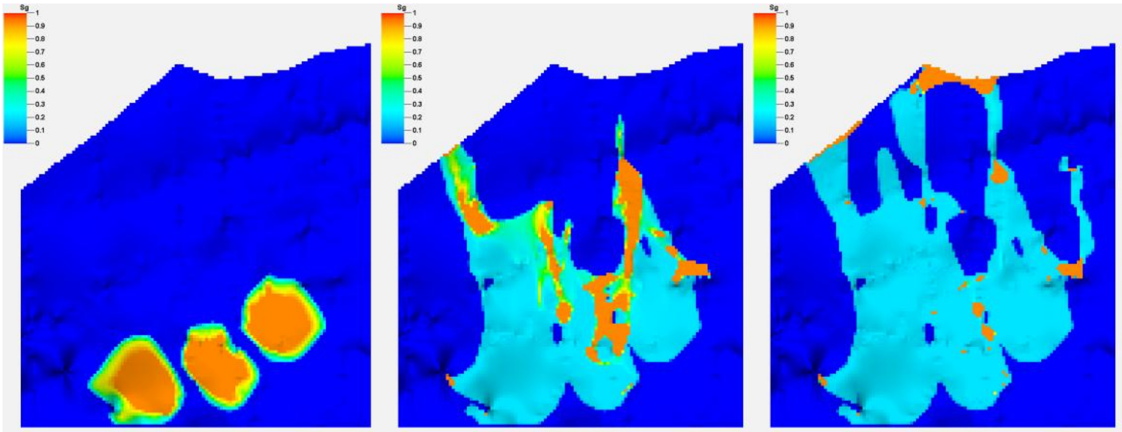


Figure 2. Plume development, shown as CO_2 saturation, for Model1 after 25, 400, and 4000 years after injection stop.

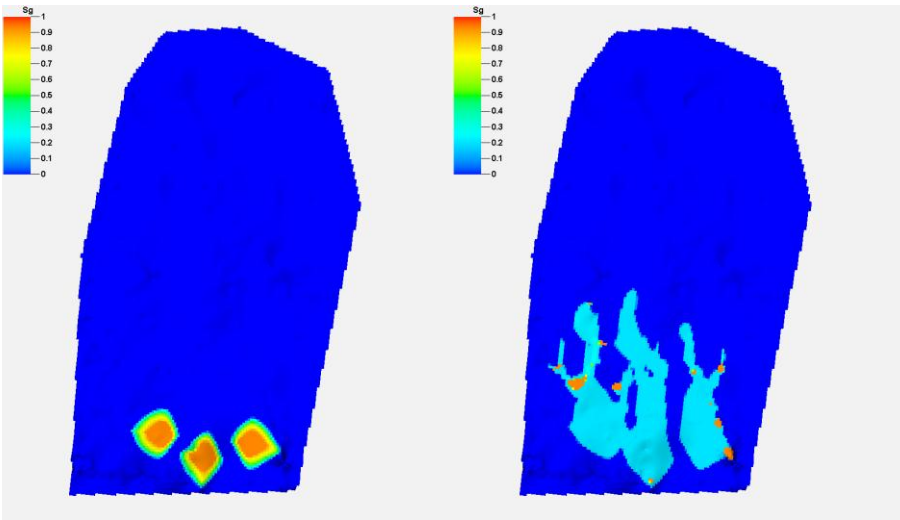


Figure 3. Plume development, shown as CO_2 saturation, for Model2 after 25 and 4000 years after injection stop.

For Model2, even after 4000 years, all the CO_2 stays within the model boundaries. A total of ~24% is dissolved after 4000 years, while the rest is capillary trapped (residual). Figure 3 shows distribution of injected CO_2 after 25 and 4000 years.

3.2. Hanstholm

The results of simulation of CO_2 injection in the Hanstholm structure is shown in Figure 4. Three horizontal injection wells were located down flank on the western and north-western side of the structure. The injected CO_2 migrates towards the top of the structure and 12.5% is dissolved into the formation water after 4000 years. Figure 4 shows CO_2 distribution after 25, 400 and 4000 years.

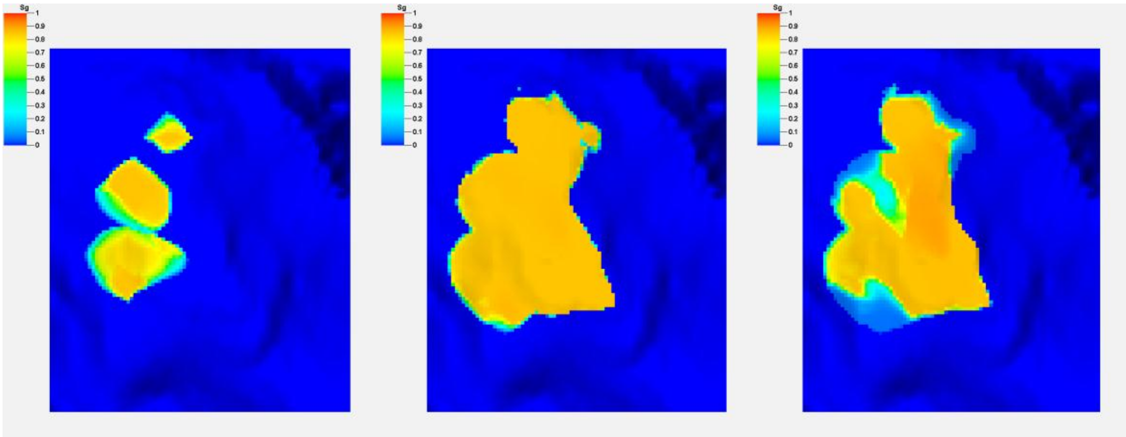


Figure 4. Distribution of injected CO_2 in the Hanstholm structure after 25, 400, and 4000 years (from left to right).

3.3. Evaluation of injectivity and storage potential

The injectivity is mainly a function of the permeability in the regions close to the injection wells. If the injectivity is low the bottom hole pressure (BHP) of the injection well will be high since a higher pressure is needed to push the injection phase at a given rate into the reservoir. Typical parameters affecting permeability for sand stone reservoirs are burial history and depth (diagenesis), shale content and porosity. A general observation is that the injectivity reduces with increasing depth and increasing shale content.

The increase in BHP for the three horizontal injection wells for Model1 and Model2 is around 90 bar in both cases. A safe pressure with respect to fracturing of the cap rock is assumed to be around 75 % of the lithostatic pressure but a detailed characterisation of the overburden is needed to estimate this. Estimating a safe pressure increase has not been performed at this stage but the difference between hydrostatic and lithostatic pressure increase with depth enabling a higher safe pressure increase with depth. A first estimate of safe pressure below the cap rock can be calculated by assuming an average density of the overlying formations. An estimate for Model1 and Model2 gives safe pressure increases of approximately 108 and 76 bars respectively if assumed sea depth is 100 meter and overburden density is 2000 kg/m^3. No maps of sea depth in the injection areas were available but increasing sea depth to 400 meter gives corresponding safe pressure increases of 86 and 54 bars.

If the pressure increase is too high several options exists to reduce it. Increase number of injection wells, produce formation water (will need production wells) and in the case of Model1 and Model2, inject part of the CO_2 into the shallower Haldager formation. A simulation where 1/3 of the CO_2 is injected into the Haldager formation in Model2 has been set up and the results indicate that the injected CO_2 stays just inside the model area in Haldager after 4000 years and the maximum BHP increase in Haldager is approximately 65 bar and the BHP increase in Gassum is reduced from 90 to 80 bar.

The present simulations indicate that the open dipping traps in the Gassum formation can permanently store 250 Mt CO_2 by residual trapping. More detailed mapping of reservoir and overburden is required for better estimate of safe pressure, required number of injection (and production) wells and better estimates of CO_2 migration in the trap.

The bottom hole pressure increase in the Hanstholm structure when using 3 horizontal injection wells are approximately 140 bar. This is too high although the pressure increase below the cap rock (some distance away from the well perforations) will be lower. The option of increasing the number of injection wells and/or introduce water production wells down flank should therefore be considered. As for the other models a more detailed characterization of the cap rock and overburden is required to determine the safe pressure increase. The structure is however large enough to contain 250 Mt CO_2 assuming the cap rock is sealing.

4. Parameter sensitivities

In the open dipping traps of Model1 and Model2 the lateral migration speed of CO_2 is important for estimating capacity and safety of the storage site. A series of simulations on a synthetic tilted model were performed to investigate migration speed and dissolution rate as function of grid block resolution and capillary pressure. The synthetic model is 1500 by 10 000 meters and has a thickness of 50 m. The tilt of the model is 2° and the top of the model is at 1000 meter depth (shallow part). Porosity and horizontal permeability is 22.5 % and 210 mD respectively. Vertical to horizontal permeability ratio is 0.1 and the injection is down flank in one vertical well perforating the bottom layers. Injection rate was 100 000 tonnes of CO_2 per year for three years, total pore volume of the model is around $1.7 \cdot 10^6$ m^3. Grid resolution and capillary pressure were varied in the sensitivity simulations.

Capillary pressure will affect the migration speed and thickness of the CO_2 front. No capillary pressure measurements were available and capillary pressure measured on Utsira sand was used as basis for sensitivity simulations. The Utsira capillary entrance pressure (no gas saturation) equals to 0.01 bars. Simulations were performed with varying capillary pressure by multiplying the measured capillary pressure curve by factors 2, 4, 8, 16, and 32. It is assumed that the capillary pressure in Gassum will be higher than the capillary pressure in Utsira due to the reservoir's grain-size, sorting and assumed cementation (smaller pore throats).

The effect of increasing the capillary pressure on CO_2 distribution is shown in Figure 5a for the model with a grid block size of 100 by 100 meters and layer thickness below the top equal to 0.5 meter. It can be seen that an increase in the capillary entry pressure will reduce the total migration distance of the injected CO_2. This is because the migrating CO_2 has to overcome the capillary entry pressure before it can flow into a neighbouring grid block. Thickness of the migrating CO_2 front will thus be larger if the grid layering is fine enough to capture this. Capillary effects are a pore scale phenomenon and since large scale models have to be coarsely gridded the effect of the capillary pressure is scaled into the grid block size and the critical gas saturation (i.e. the minimum gas saturation necessary for the gas to be mobile). No simulation tests have been performed on how the distribution of CO_2 will depend on critical and residual gas saturation.

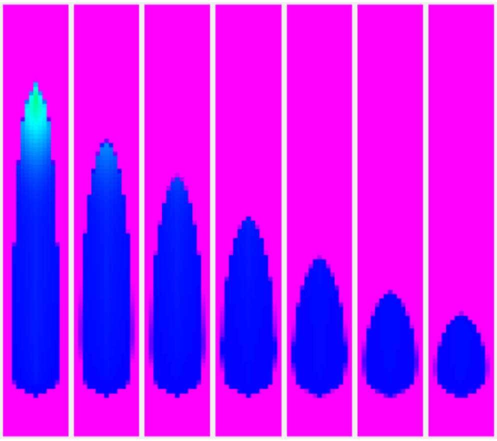
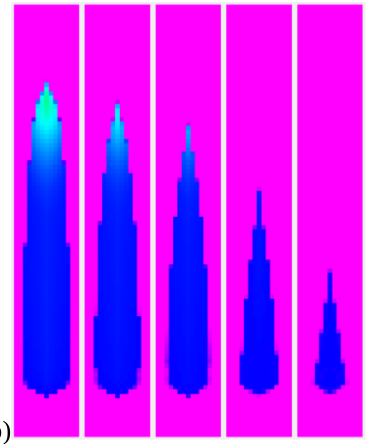
(a)  (b) 

Figure 5. (a) Effect of capillary pressure on migration distance. Capillary entrance pressure in the different simulations was (from left to right): 0 (no capillary pressure), 0.01, 0.02, 0.04, 0.08, 0.16 and 0.32 bar. Plots show CO_2 distribution after migration has stopped (capillary trapped as residual CO_2); (b) Effect of layer thickness below the top, from left; 0.5 m, 0.75 m, 1 m, 2 m, 5 m layer thickness. Areal grid block size is 100 by 100 m simulated with no capillary pressure.

The injected CO_2 will due to buoyancy forces migrate along the top of the model. The thickness of the migrating front will in the simulations depend on grid layer thickness and critical gas saturation. These should be balanced to represent the effect of capillary pressure. However, both of these parameters are unknown. Figure 5b displays the effect of refining the layers below the top of the model from 5 to 0.5 meter layer thickness. Increasing the layer thickness will reduce the plume length. This is due to increased thickness of the front (one layer in the grid) and because the increased size of the grid blocks will require a larger volume of CO_2 in each grid block to overcome the critical gas saturation. This will slow down the speed of the migrating front. No sensitivity on the gas distribution by refining the areal grid block size has been investigated. Having smaller grid blocks will reduce the gas volume required to overcome the critical gas saturation but this effect will be minor if the coarsest grid resolution is sufficient to resolve the shape of the migrating CO_2.

Dissolution of CO_2 into the formation water is a function of the contact area between the CO_2 phase and under-saturated formation water. In practice this will depend on how large volume CO_2 has swept because almost all the dissolved CO_2 is present in the residual non-mobile water. An increase in migration distance will result in an increase in dissolved CO_2.

Simulations with refined layer thickness below the top were performed for Model2. Base case simulations which had 5 meter layer thickness would correspond to a very high capillary entry pressure. Results of refining the layers at the top to 1 and 2 meters are shown in Figure 6. The migration distance for the refined models is increased but the injected CO_2 is still within the boundaries of the model. Similar increase in migration distance should be expected for Model1 with the consequence that more CO_2 migrates out of the boundaries of the model.

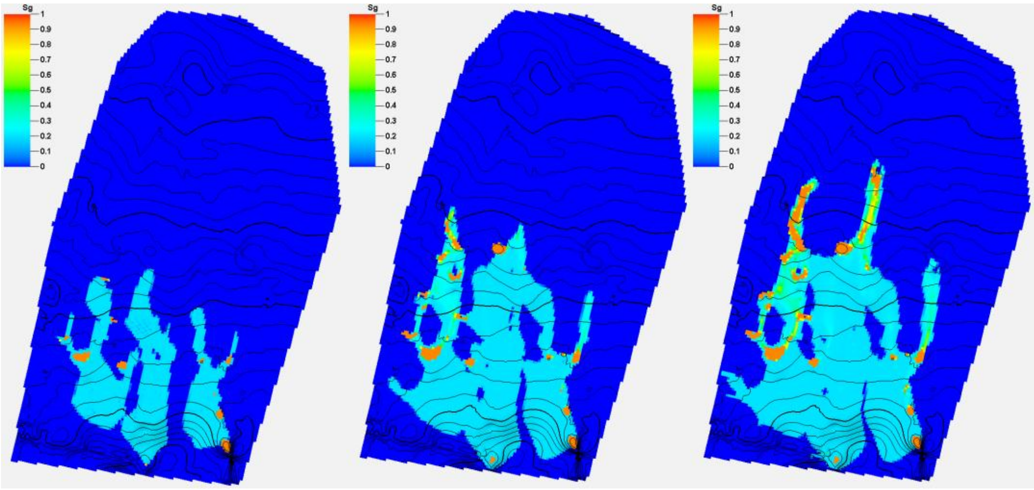


Figure 6. Distribution of injected CO_2 after 4000 years for the base case model with uniform layer thickness of 5 m in the whole model (left) and for refined layer thickness below the top equal to 2 m (middle) and 1 m (right).

5. Conclusions

Simulations indicate that the Late Triassic Gassum Formation has the capacity for storing at least the 250 million tonnes of CO_2 from the mapped industrial sources in the Skagerrak-Kattegat area but it must be emphasized that there are large uncertainties in the constructed models due to scarcity of data. The most critical factors for safe storage are the fracturation pressure of the sealing cap rock and the parameters controlling lateral migration of the injected CO_2. The induced pressure increase in the Hanstholm model is higher than the estimated safe pressure increase for the cap rock integrity but the formation may still be suitable for storage by increasing the number of injection and water production wells. Further characterization of the cap rock and overburden is required to give a better estimate of fracturation pressure in all three target areas. Sea bottom depth may be a limiting factor for the open dipping traps since a thinner overburden will reduce the fracturation pressure of the cap rock.

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Acknowledgements

The work presented in this paper received financial support from industry and Gassnova under the Climit programme (Project number 194492). The publication has been produced with support from the NORDICCS Centre, performed under the Top-level Research Initiative CO_2 Capture and Storage program, and Nordic Innovation. The authors acknowledge the following partners for their contributions: Statoil, Gassco, Norcem, Reykjavik Energy, and the Top-level Research Initiative (Project number 11029).

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GHGT-11

Evaluation of CO_2 storage potential in Skagerrak

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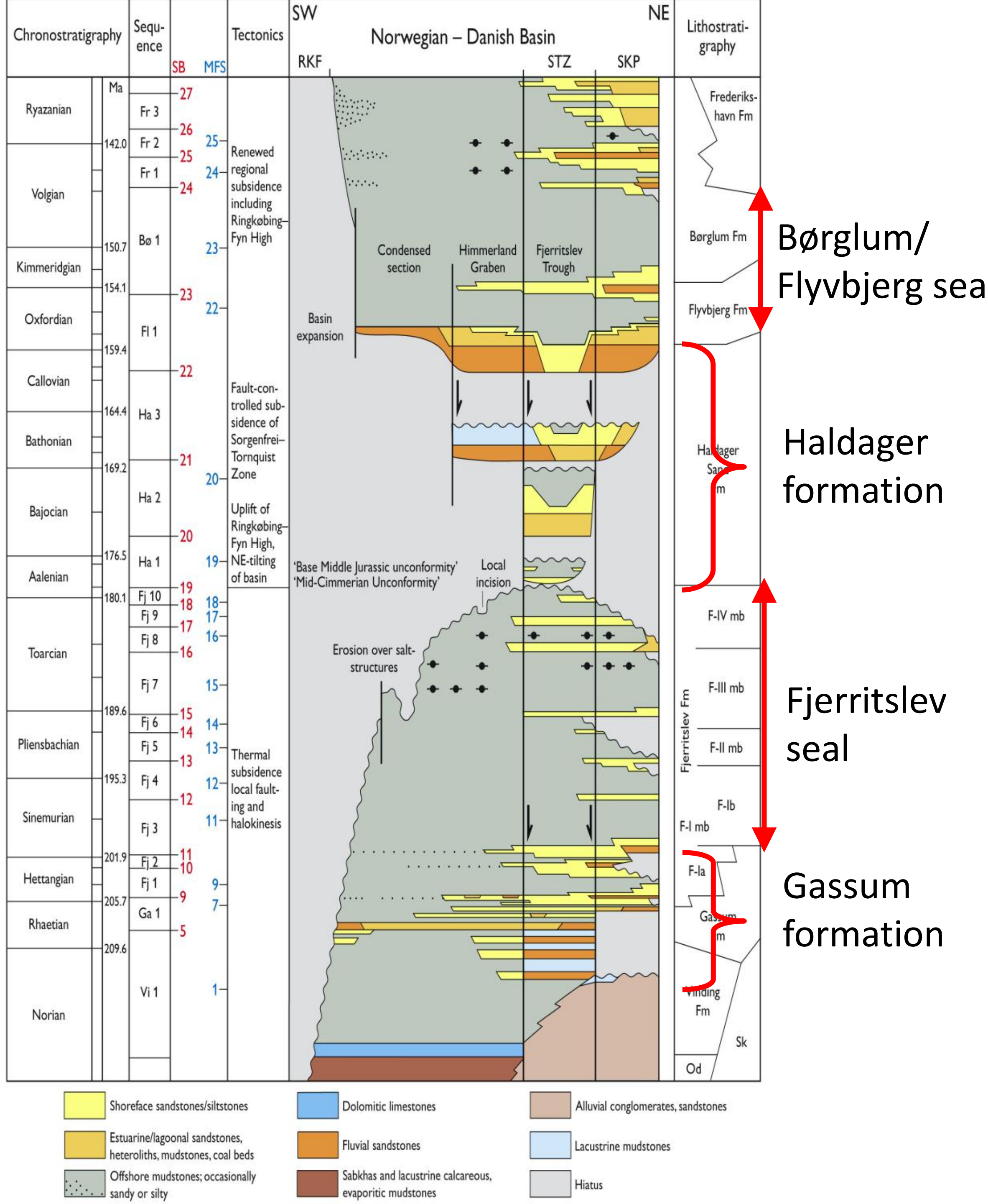
In the Skagerrak region

- Up to 14 Mt CO_2 can annually be captured from industry
- No previous of oil production
- Large regional sand stone aquifers identified with potential for CO_2 storage
  - Open dipping aquifers
  - Closed domal structures
- Gassum Formation is main target
  - Offshore between Denmark and Norway

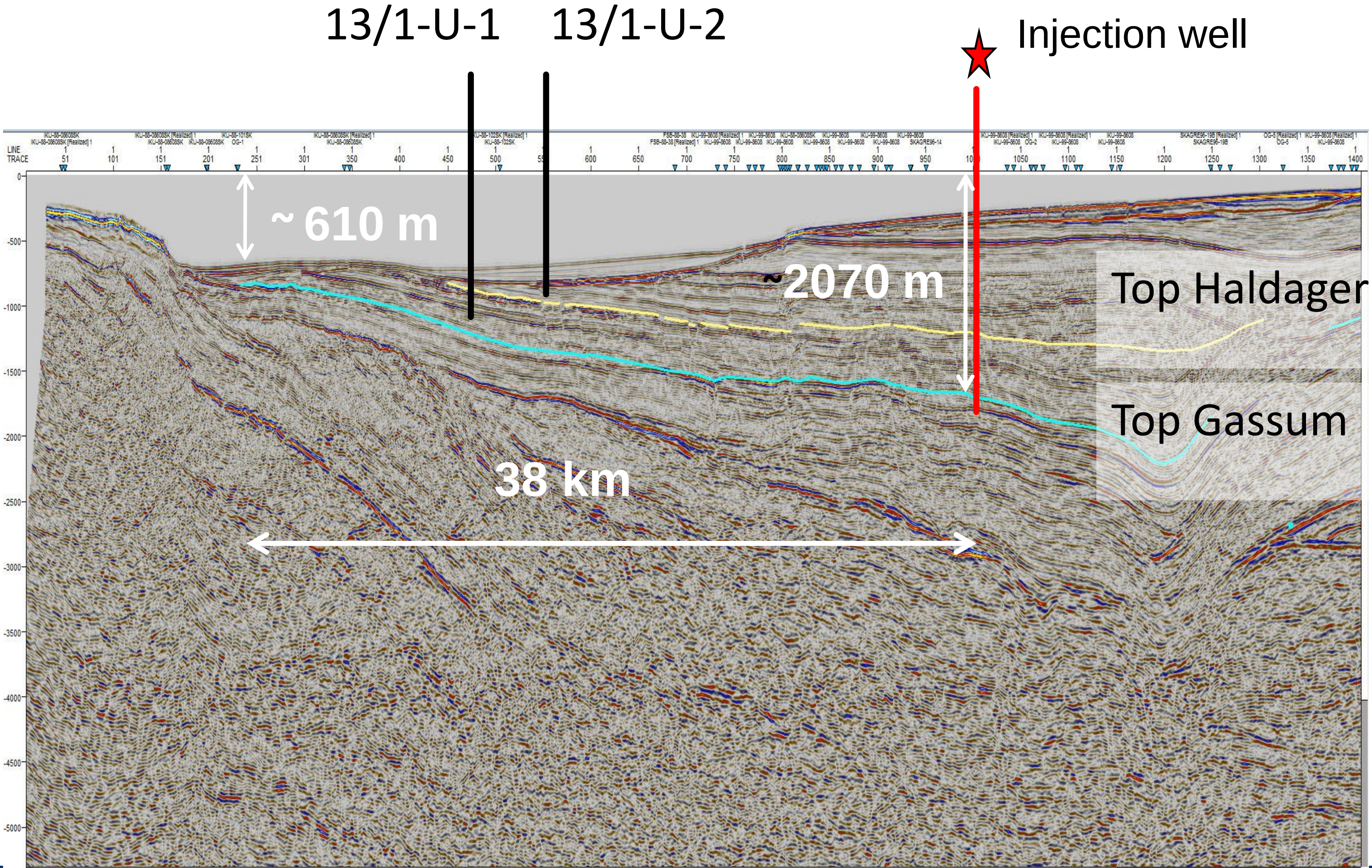
Geology

- Large dipping Trias to early Cretaceous sands formations:
  - Skagerrak (deep)
  - **Gassum**
  - Haldager
- Sealing formations
  - Fjerritslev
  - Bjørglum
  - Flyvbjerg
- Age:



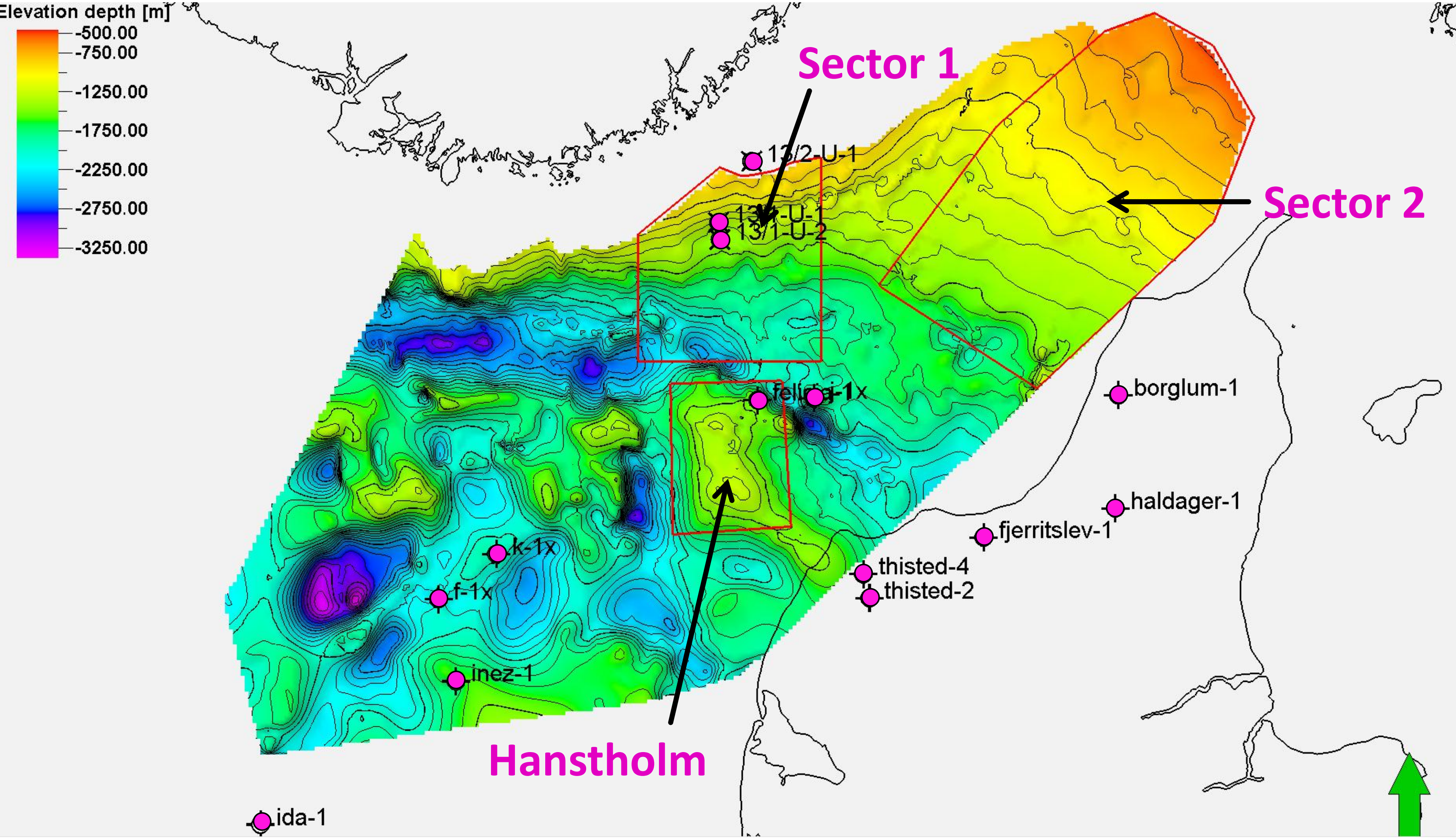
SINTEF

Large dipping formations

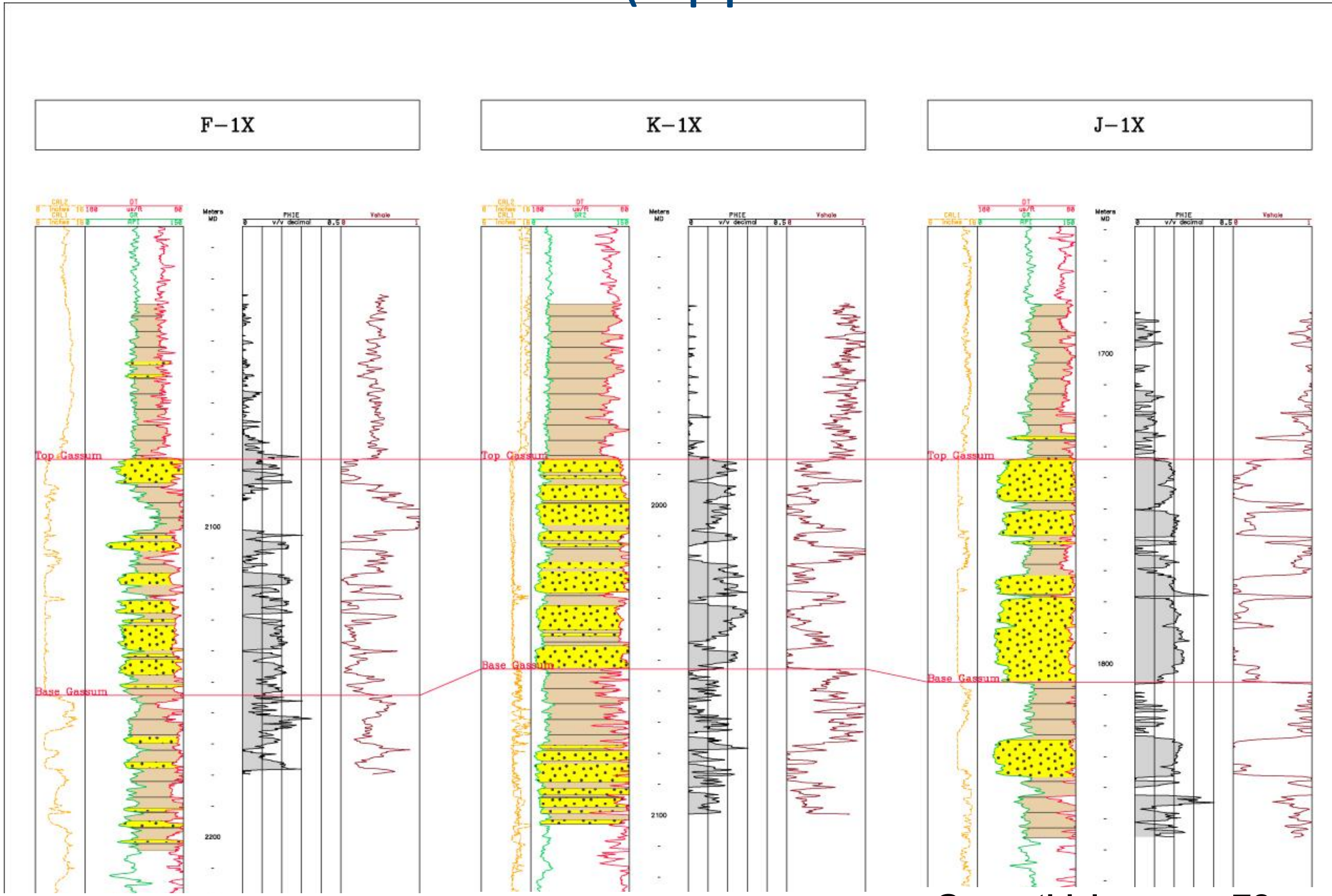


CO_2 storage in the Gassum Formation at three sites

Two open dipping aquifers: (Sector 1 and 2) and one structural closure (Hanstholm)



Gassum Fm reservoir (Upper Triassic - Lowermost Jurassic)



Fjerritslev Fm.

Gassum Fm.

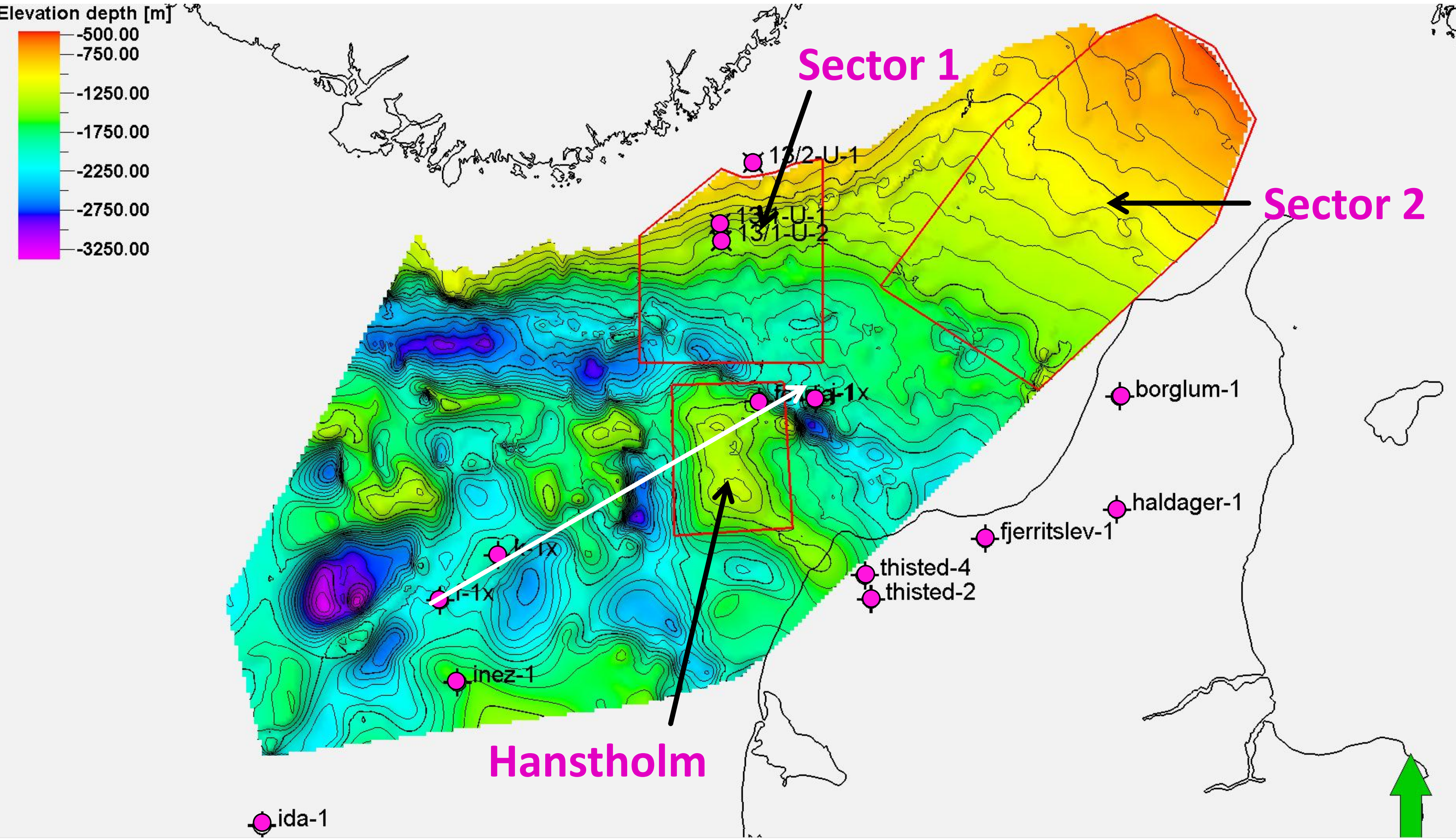
Skagerrak Fm.

Gross thick.:	76 m	Gross thick.:	67 m	Gross thick.:	72 m
Net sst thick.:	36 m	Net sst thick.:	46 m	Net sst thick.:	56 m
Net / gross:	0.47	Net / gross:	0.69	Net / gross:	0.78
Porosity:	17-23 %	Porosity:	20-28 %	Porosity:	18-25 %

(GEUS, 2011)

CO_2 storage in the Gassum Formation at three sites

Two open dipping aquifers: (Sector 1 and 2) and one structural closure (Hanstholm)



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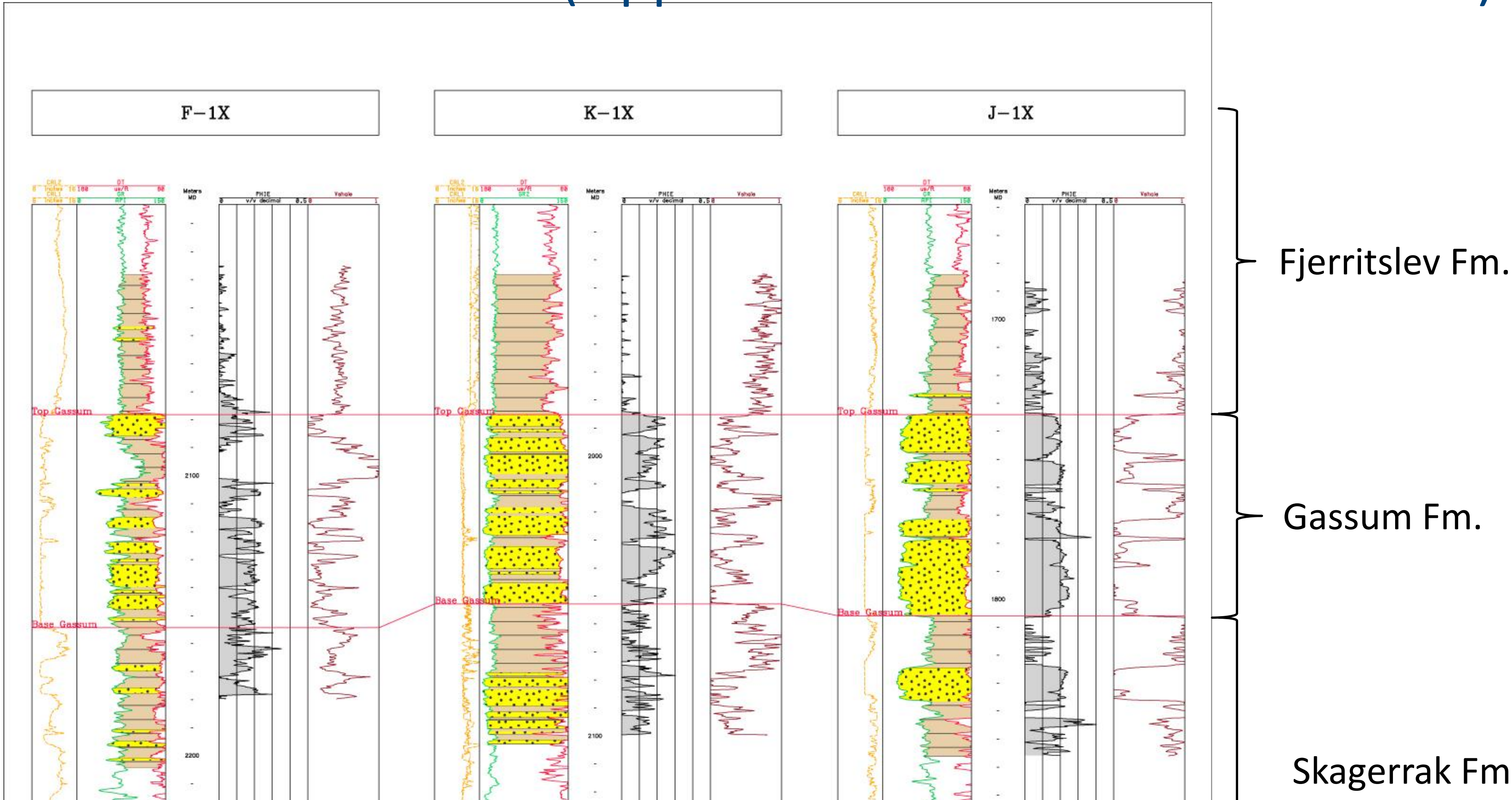


	F-1X	K-1X	J-1X
Gross thick.:	76 m	67 m	72 m
Net sst thick.:	36 m	46 m	56 m
Net / gross:	0.47	0.69	0.78
Porosity:	17-23 %	20-28 %	18-25 %

(GEUS, 2011)

Reservoir models

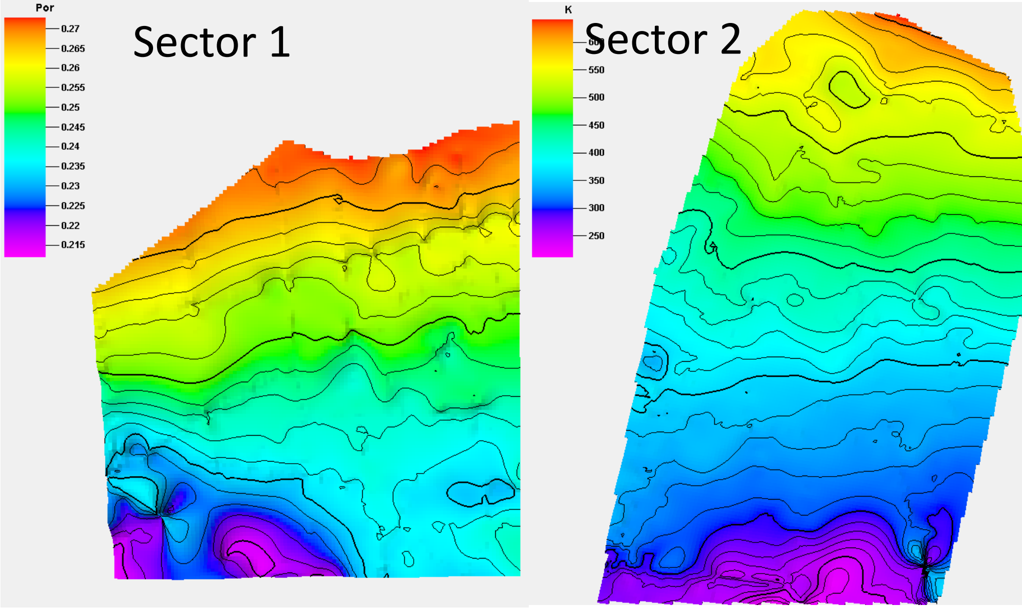
Sector 1 and Sector 2

Average reservoir properties from wells correlated to depth

- Net formation thickness: 50 meter
- Porosity: 21 – 29 %
- Permeability: 200 – 650 mD
- Temperature and salinity gradients: 75.6 ppm NaCl/m and 31 °C/km
- Injection depth at 2400 and 1700 meter
- Uniform layer thickness: 5 meter

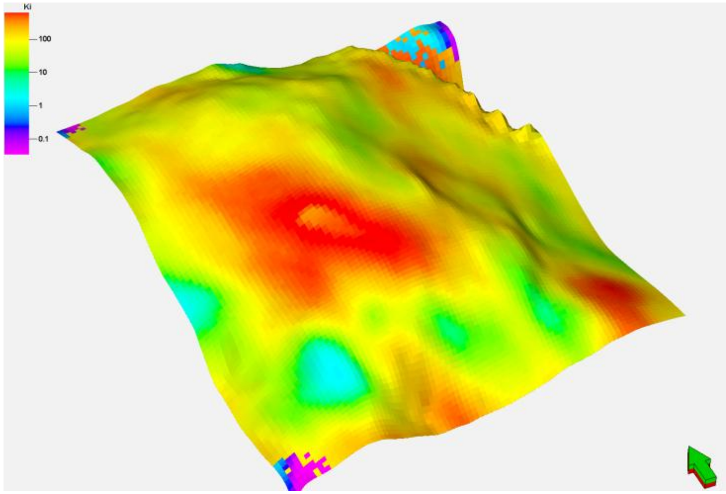
Hanstholm

- Structural closure (top at 910 m)
- Heterogeneous model (based on well logs)
- Injection down-flank at 1100 -1250 m
- Constant salinity and temperature



Porosity plots at top of formation

Hanstholm



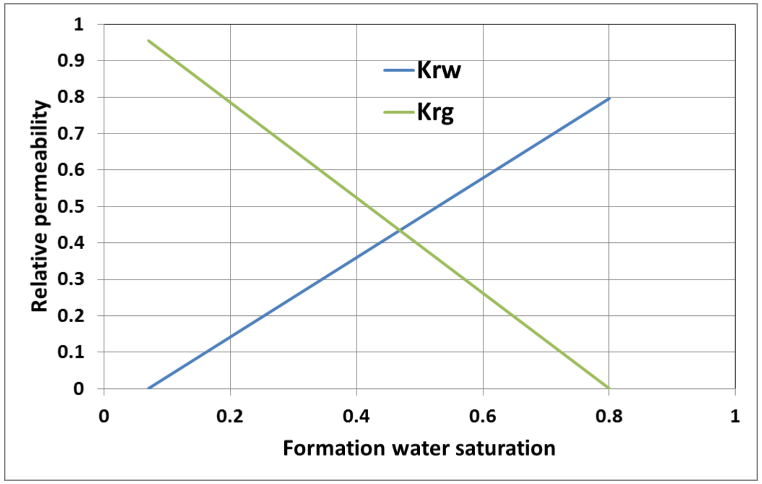
Permeability in top sand layer

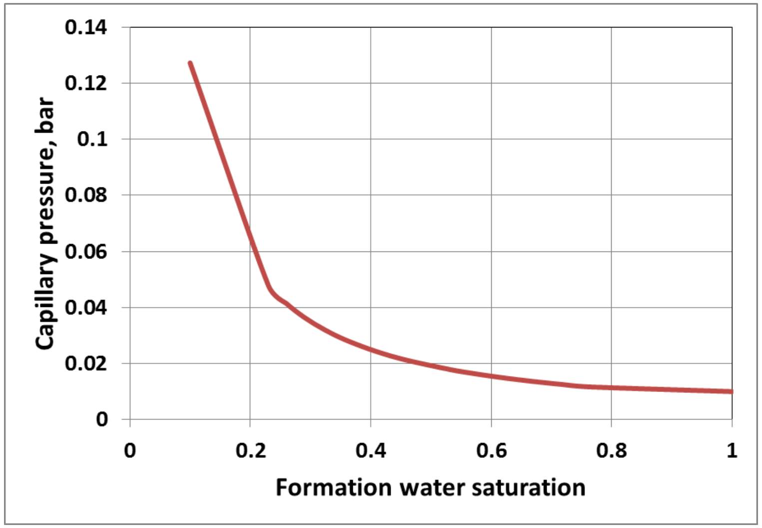
CO_2 Injection scheme

- 10 Mtonne CO_2/year injection rate for 25 years (250 Mtonne)
- 3 horizontal injection wells
- Injection down-flank
- 4000 years time period simulated

Flow parameters

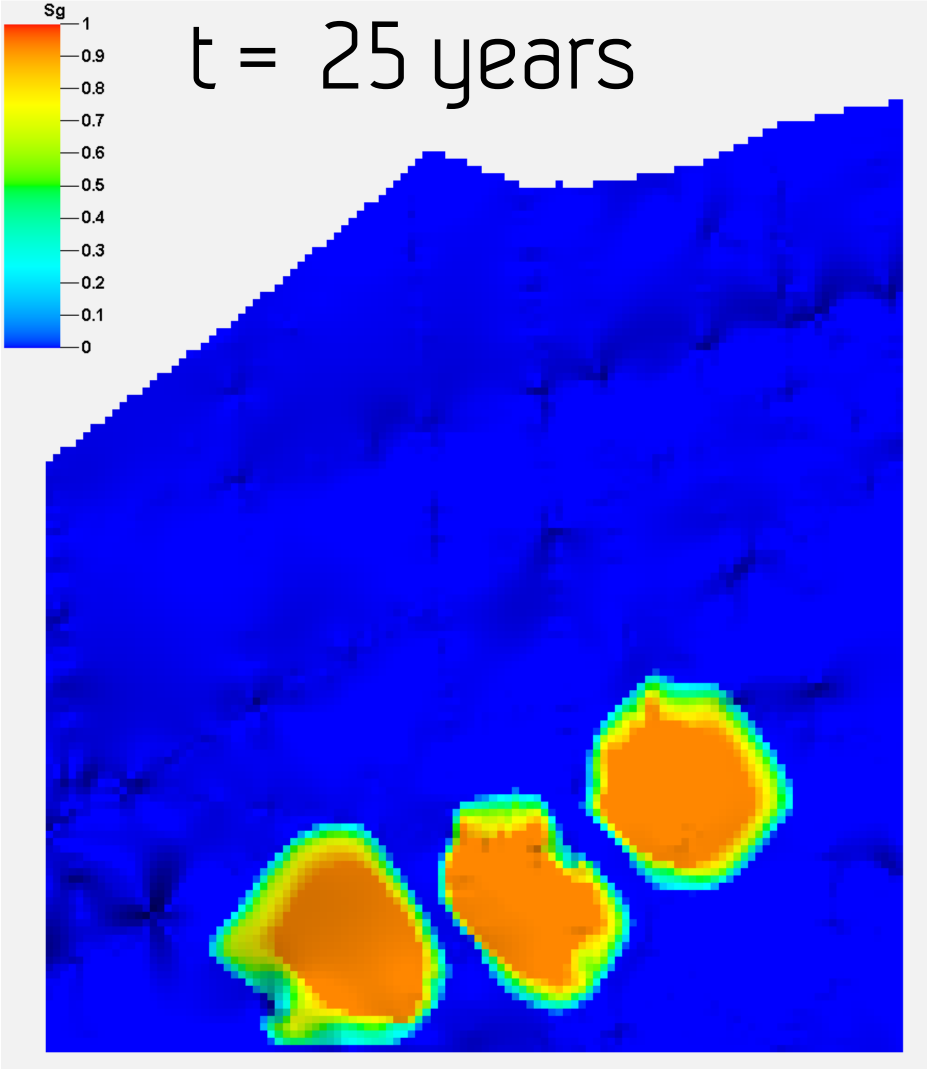
- No capillary pressure in the field scale simulations
  - Capillary effect usually scaled into relative permeability end points
- Relative permeability end-points:
  - Irreducible water saturation $S_{wirr} = 0.07$
  - Critical gas saturation $S_{gc} = 0.2$
- Linear relative permeability functions
- No hysteresis
- Capillary pressure curves used in sensitivity runs
  - Based on capillary pressure measured at
  - Utsira core (no data for Gassum sandstone formation)





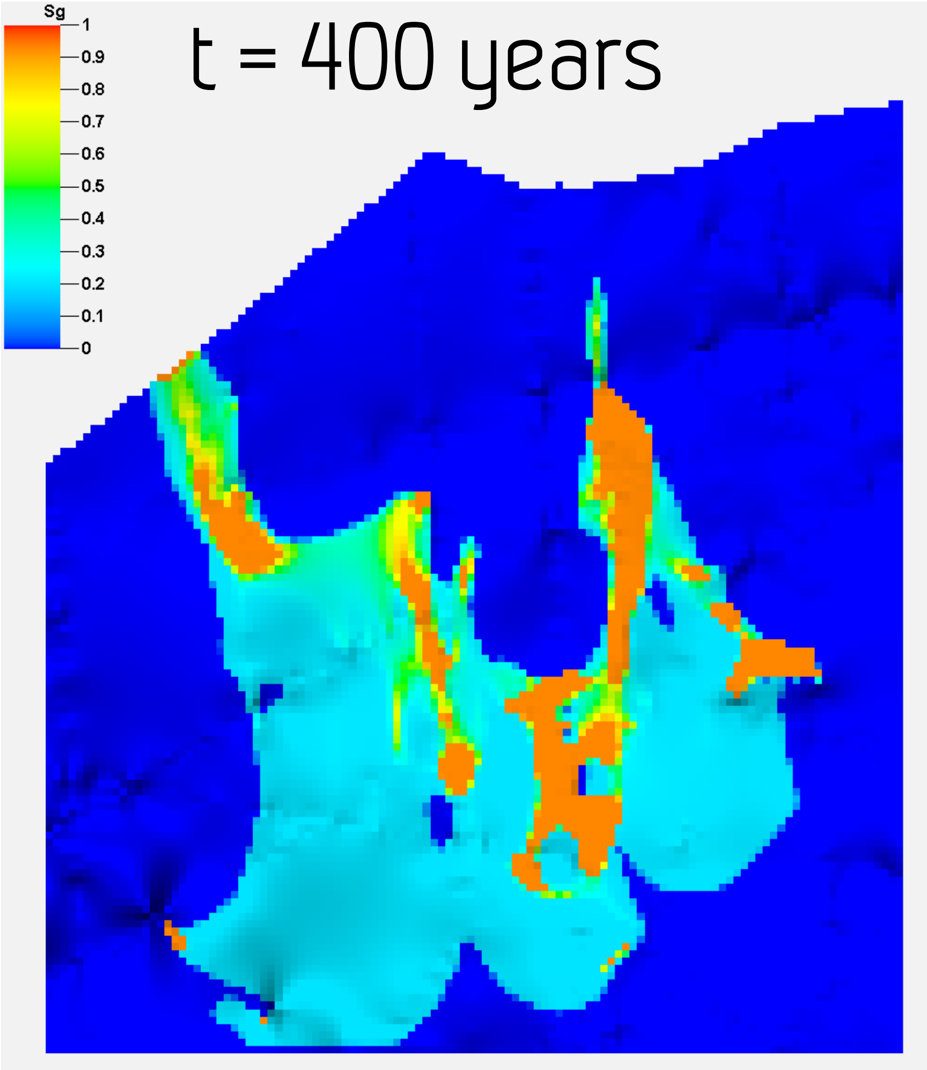
Open dipping formations: Sector 1

- CO_2 distribution at time t



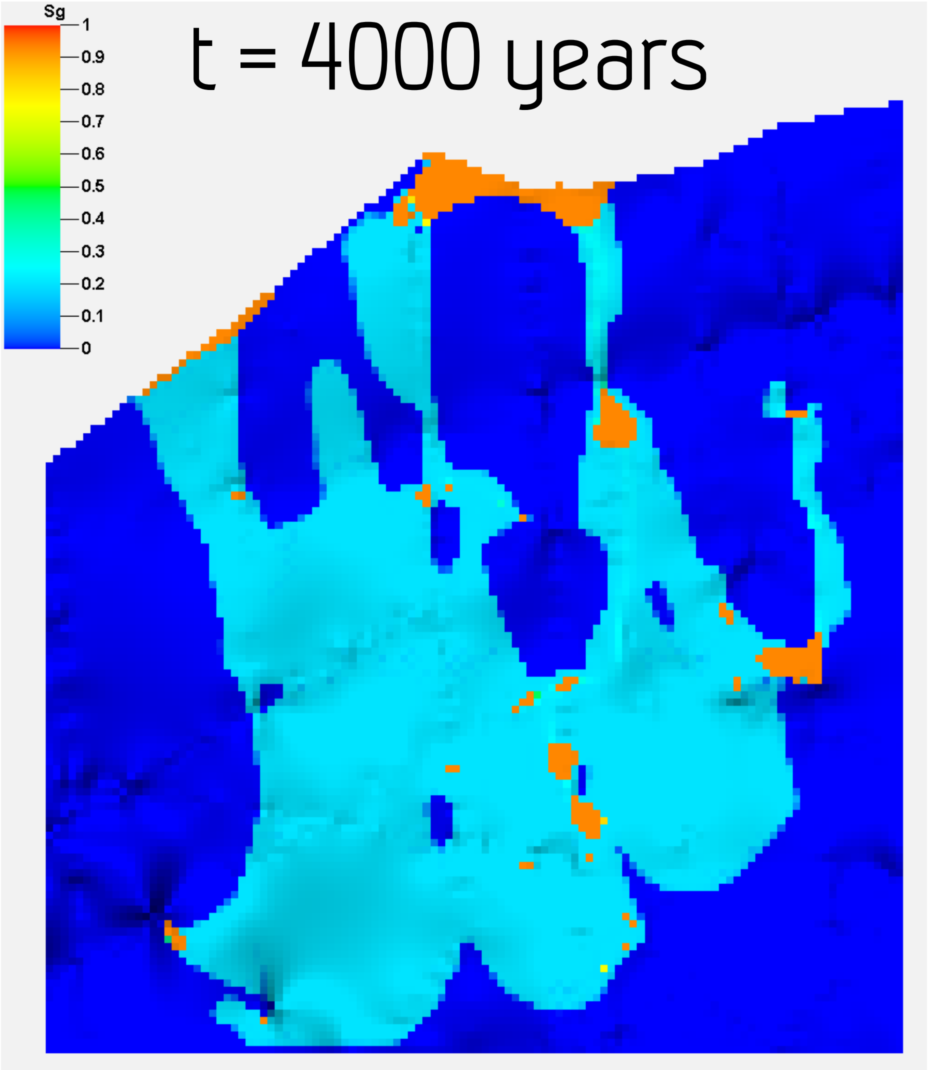
Open dipping formations: Sector 1

- CO_2 distribution at time t
- CO_2 reaches the boundary after 400 years
- Further migration is unknown
- Amount of CO_2 migrating out of the model is monitored (open boundary)



Open dipping formations: Sector 1

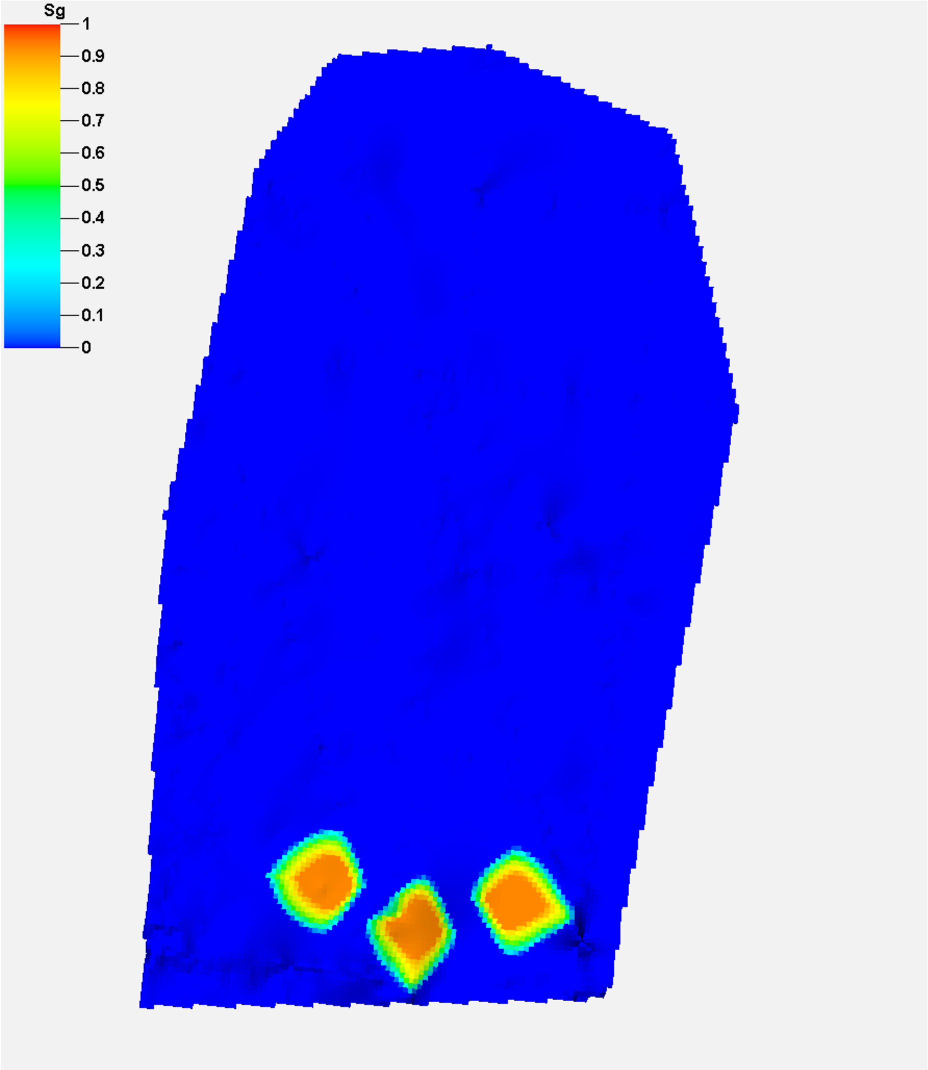
- CO_2 distribution at time t
- CO_2 reaches the boundary after 400 years
- Further migration is unknown
- Amount of CO_2 migrating out of the model is monitored (open boundary)
- After 4000 years:
  - 7.5 % has migrated out of the model
  - 74.5 % capillary trapped (residual gas)
    or trapped in small structural domes
  - 18 % dissolved into the formation water



Open dipping formations: Sector 2

- CO_2 distribution at time t

t = 25 years

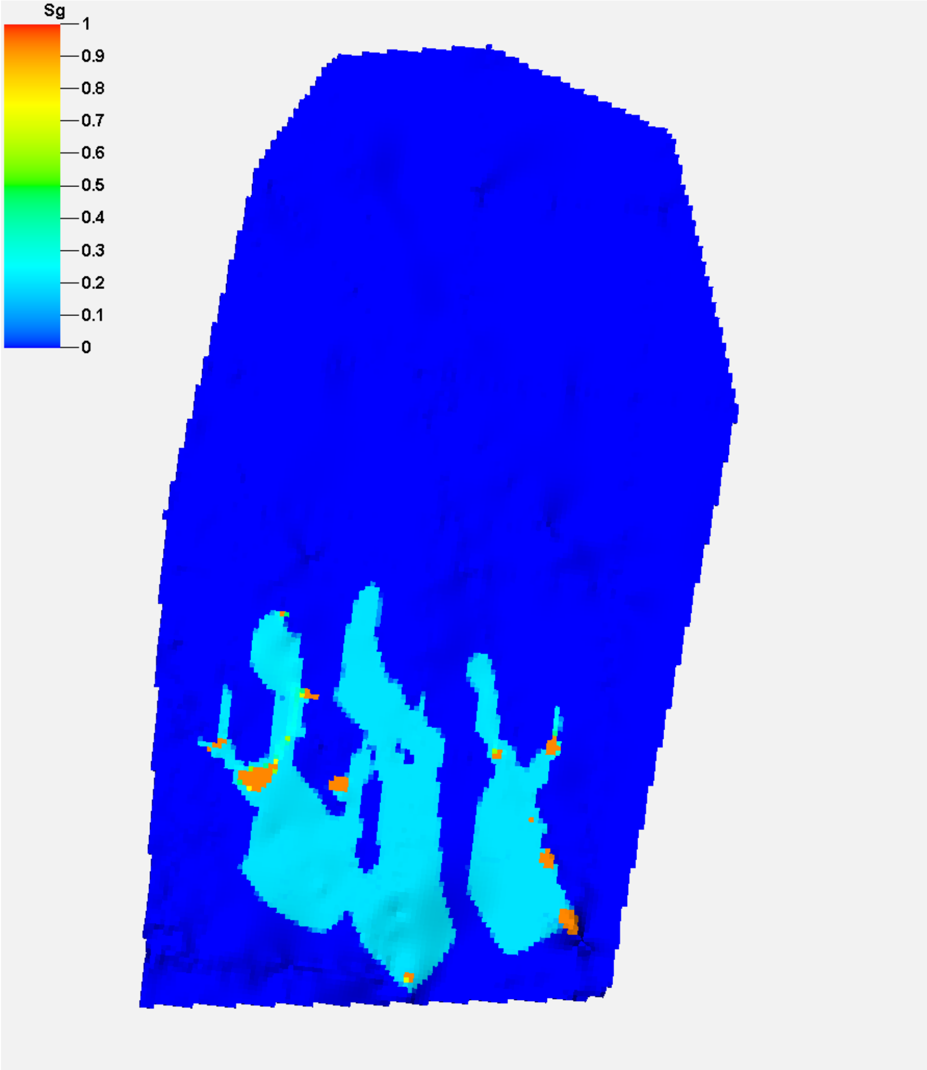


Open dipping formations: Sector 2

t = 4000 years

- CO_2 distribution at time t

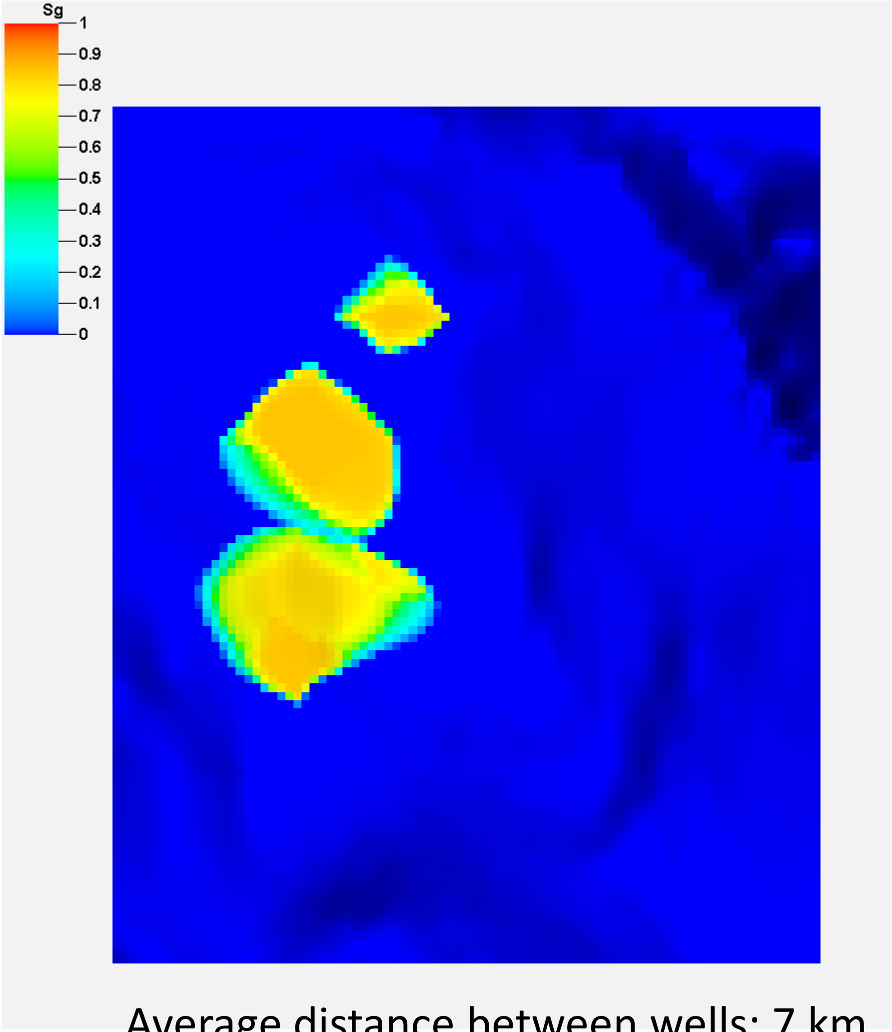
- After 4000 years all the injected CO_2 stays within the model boundaries:
    - Dissolved in the formation water
    - Capillary trapped as residual phase and structurally trapped in small domes



Structural closure: Hanstholm

t = 25 years

- CO_2 distribution at time t

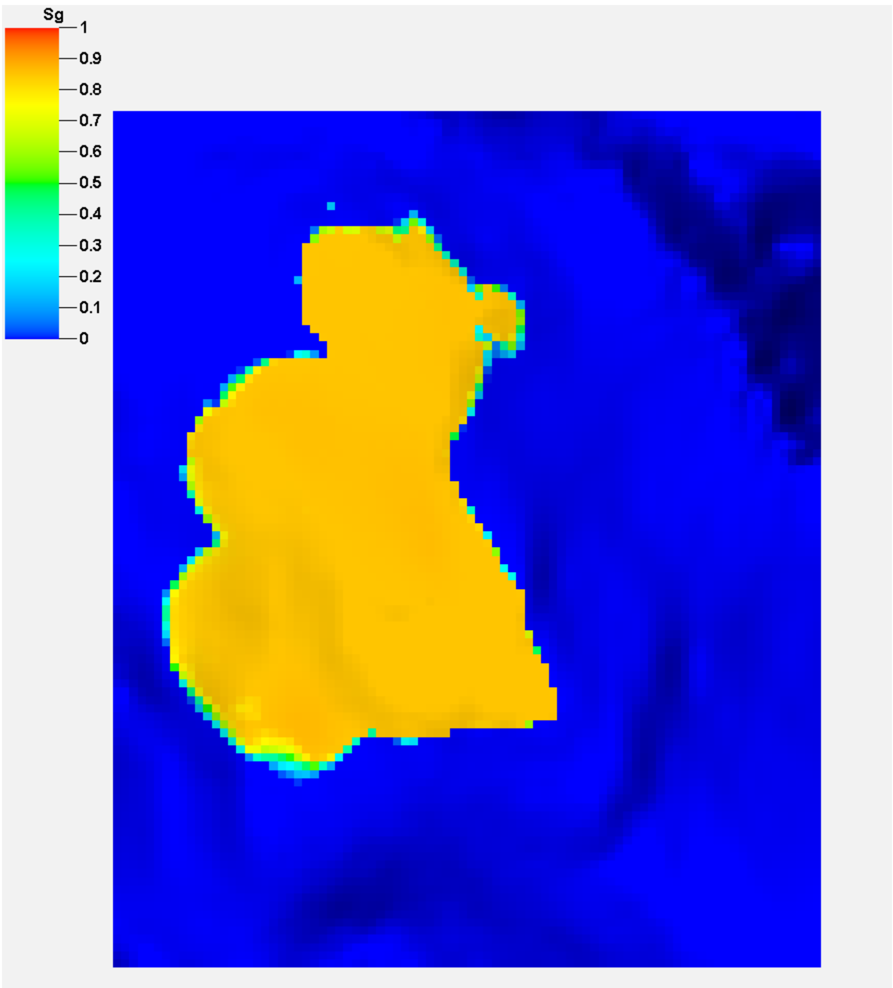


Average distance between wells: 7 km

Structural closure: Hanstholm

t = 400 years

- CO_2 distribution at time t
- Injected CO_2 migrates towards the top of the structure



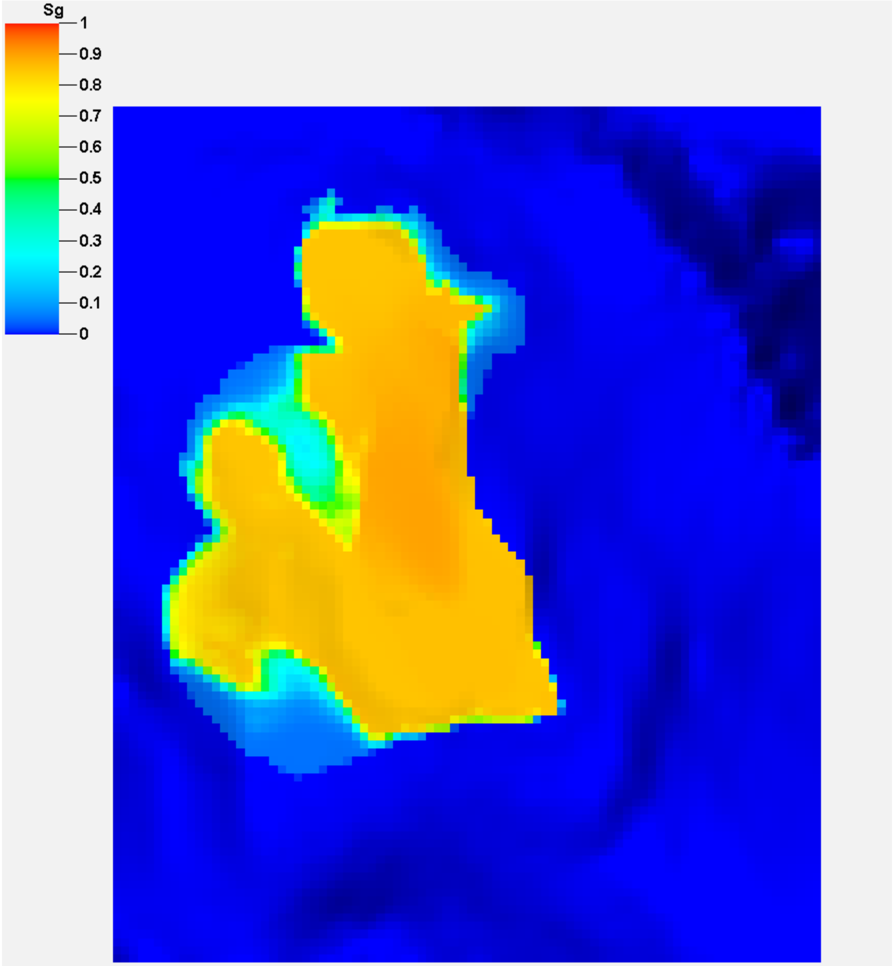
Average distance between wells: 7 km

Structural closure: Hanstholm

t = 4000 years

- CO_2 distribution at time t
- Injected CO_2 migrates towards the top of the structure
- After 4000 years the injected CO_2 is trapped as:
  - Residual phase (capillary trapped)
  - Capillary trapped below the cap rock
  - Dissolved in the formation water

- With three injection wells, the induced pressure increase will be too high
  - Safe pressure below the cap rock is assumed to be 75 % of lithostatic pressure

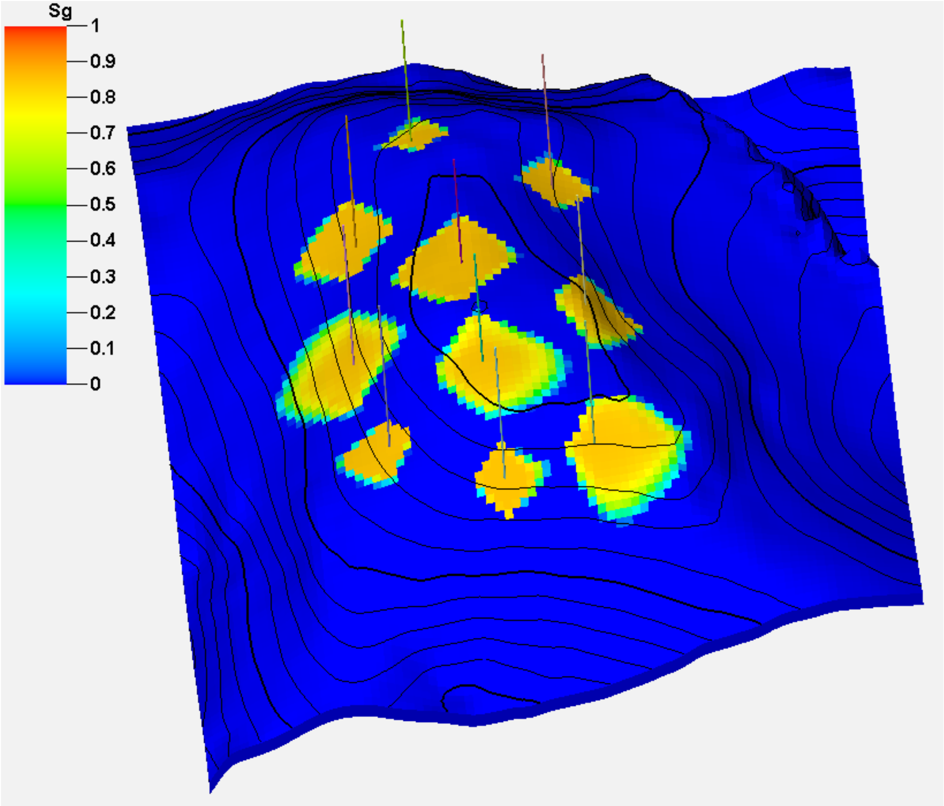


Average distance between wells: 7 km

Structural closure: Hanstholm

t = 25 years

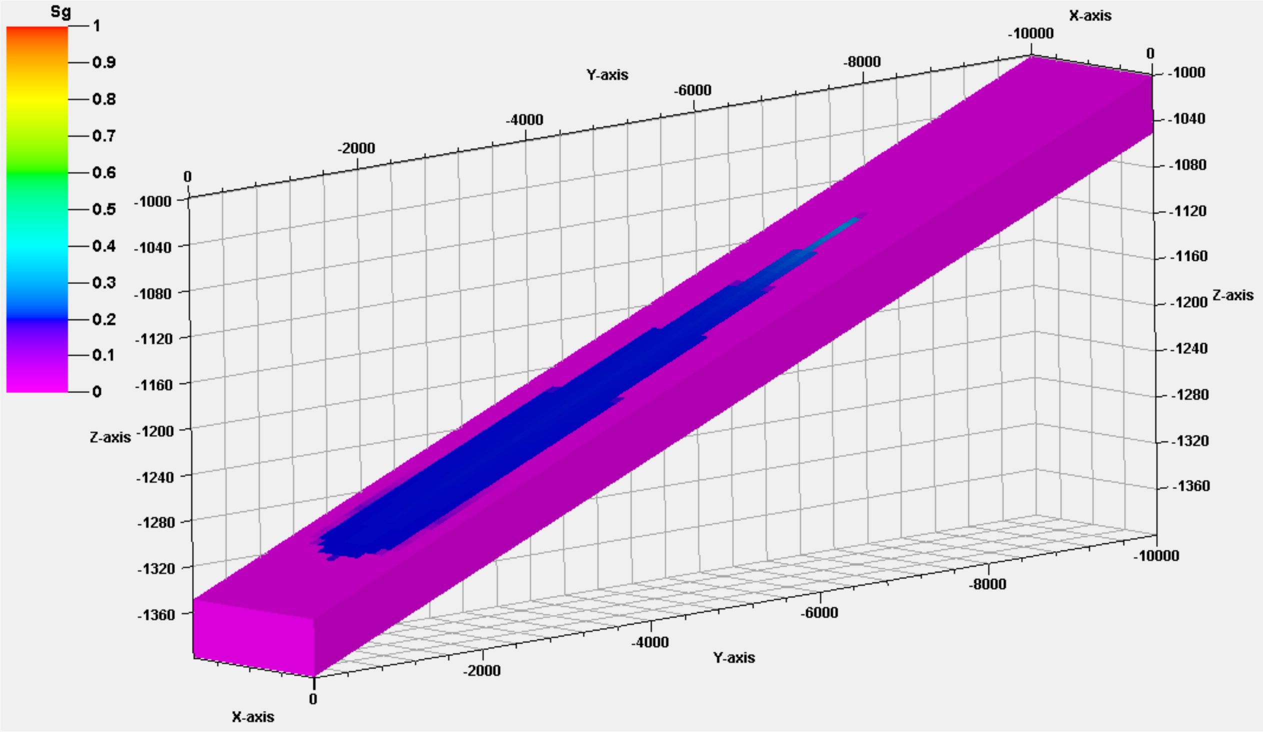
- Safe pressure below cap rock 130 bar (75% of lithostatic pressure)
  - Initial pressure 90 bar
  - 40 bar pressure increase allowed
- With three injection wells, the bottom hole pressure increase is 140 bar
- 10 injection wells gives 90 bar pressure increase
- Pressure increase below the top of the structure is 90 bar.
- Introducing three water production wells reduce the pressure increase below the top to 60 bar
- More production wells required for pressure control (10?)



10 horizontal injection wells
Distance between neighboring wells: 5 to 8 km

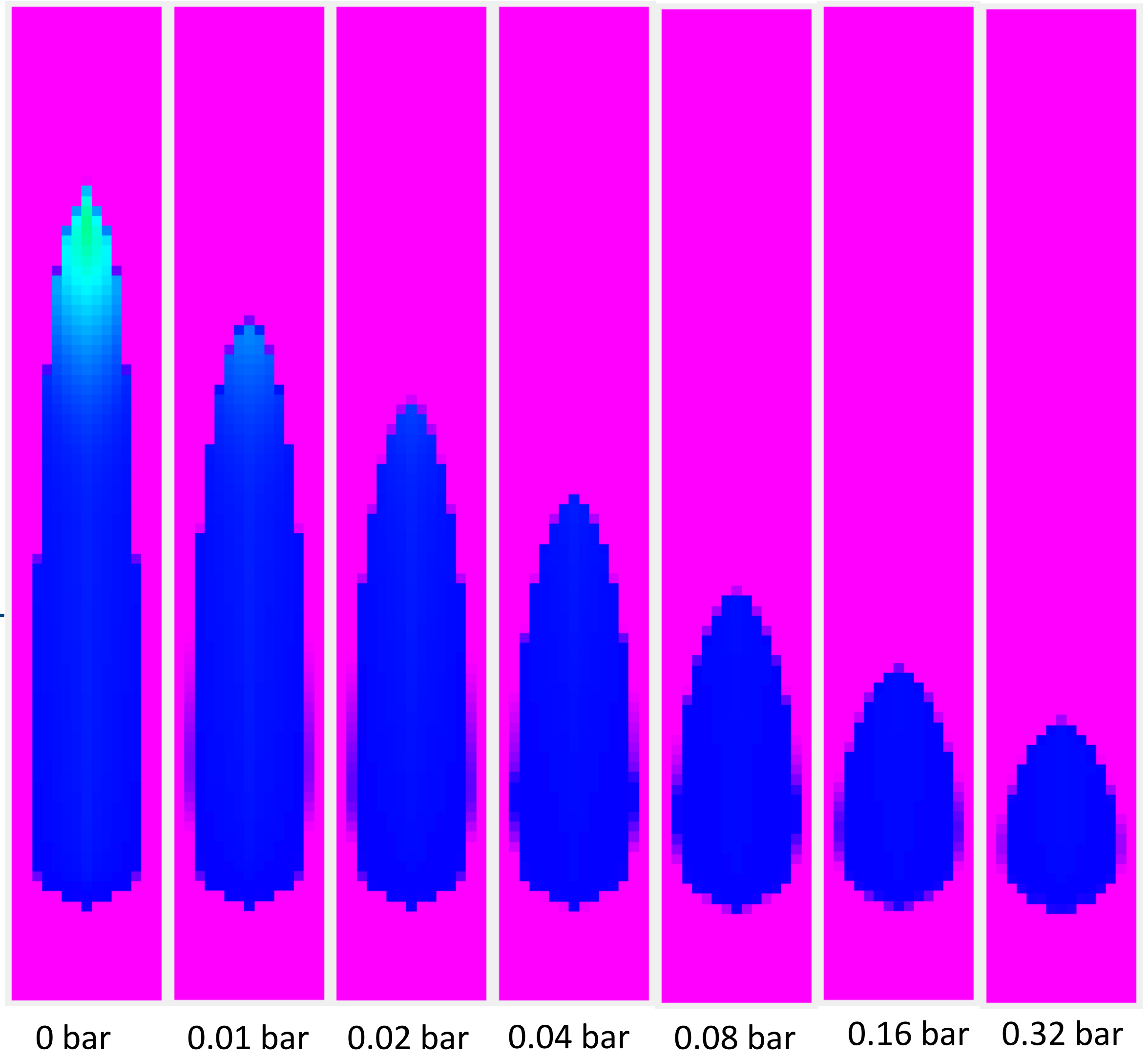
Parameter sensitivities influencing migration distance

- Lateral migration rate in open dipping traps important for estimating capacity and storage safety
- Parameters affecting lateral migration investigated on a synthetic model
  - Homogenous
  - Size: 3 000 by 10 000 meter
  - Thickness: 50 meter
  - Porosity: 22 %
  - Permeability 200 mD
  - Tilt: 2°
  - One injection well
  - 300 000 tonnes CO_2 injected
  - Simulated until stop
- Parameters investigated:
  - p_c and grid resolution



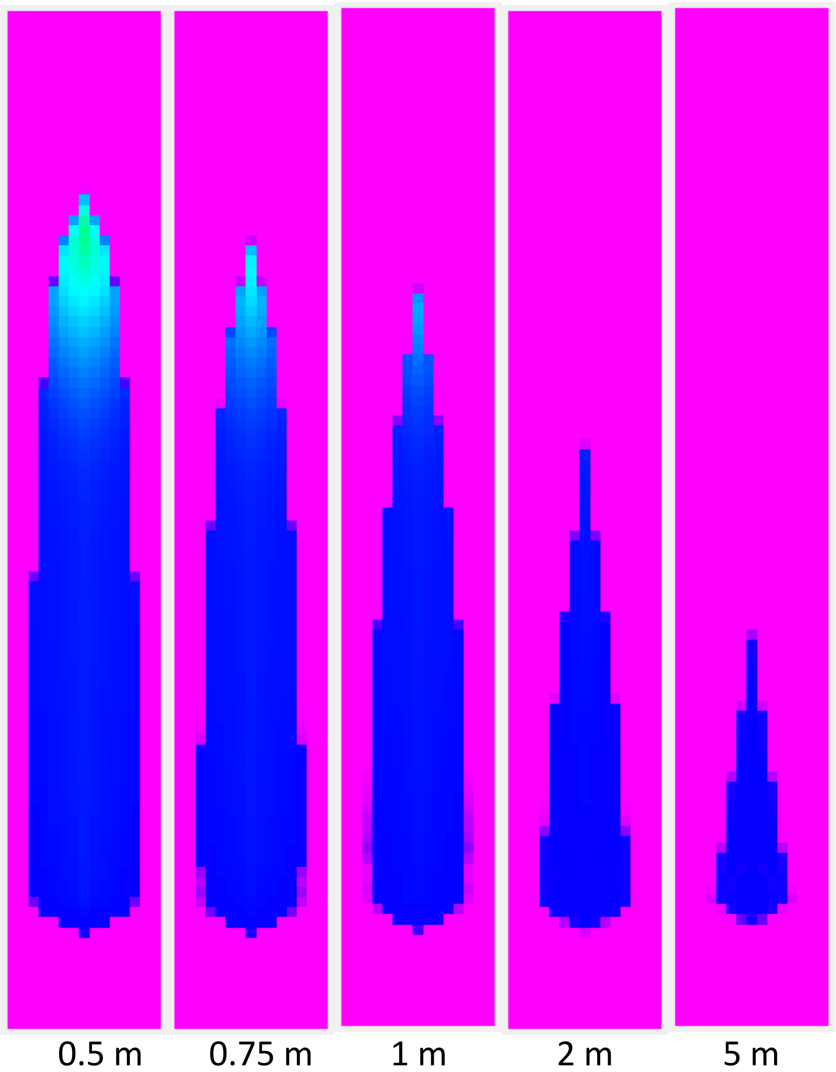
Sensitivity of capillary pressure

- Effect of capillary pressure on migration distance.
- Capillary entrance pressure in the simulations were (from left to right): 0, 0.01, 0.02, 0.04, 0.08, 0.16 and 0.32 bar.
- Plots show CO_2 distribution after migration has stopped (capillary trapped as residual CO_2).
- Measured p_c at Utsira Sand is 0.01 bar
- Layer thickness is 0.5 m



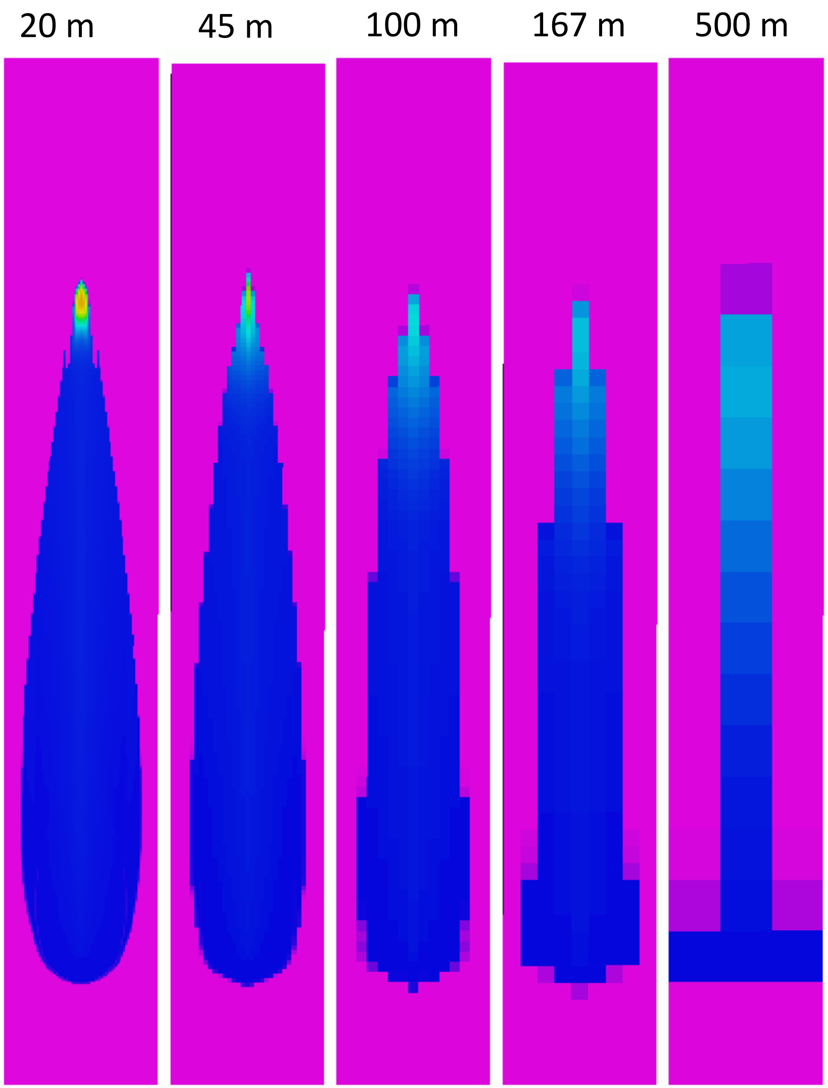
Sensitivity of grid block layer thickness

- Effect of varying layer thickness below the top
- Grid layer thickness from left; 0.5 m, 0.75 m, 1 m, 2 m, 5 m
- Areal grid block size is 100 by 100 m
- No capillary pressure.



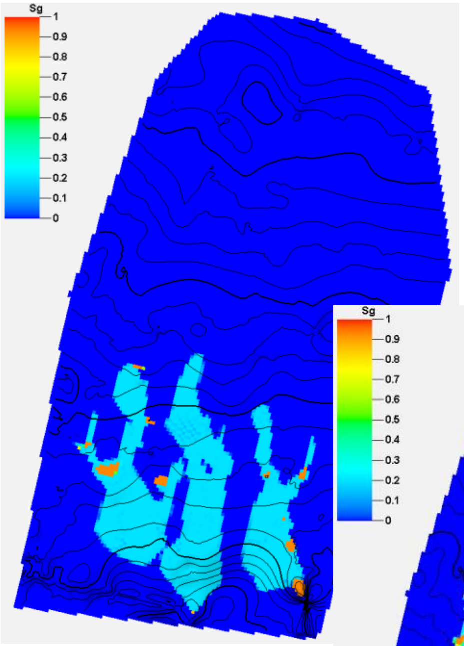
Sensitivity of horizontal grid resolution

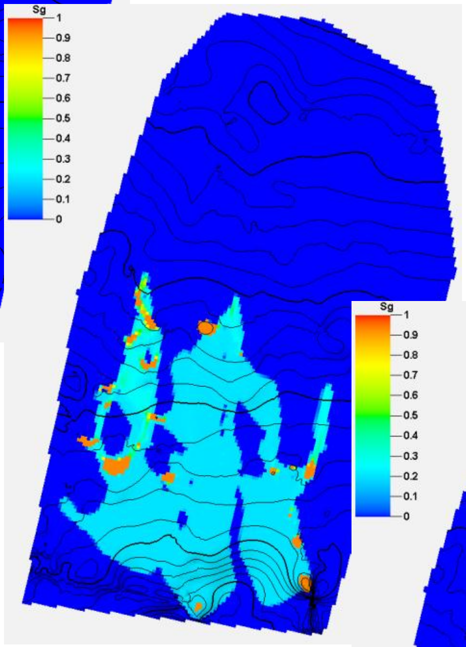
- Varying horizontal grid resolution.
- Grid block length (quadratic blocks) from left; 20 m, 40 m, 100 m, 167 m, 500 m.
- Layer thickness of the upper layers are 0.75 m
- No capillary pressure.
- Migration distance not very sensitive to horizontal grid resolution if grid block size resolves the shape of the plume

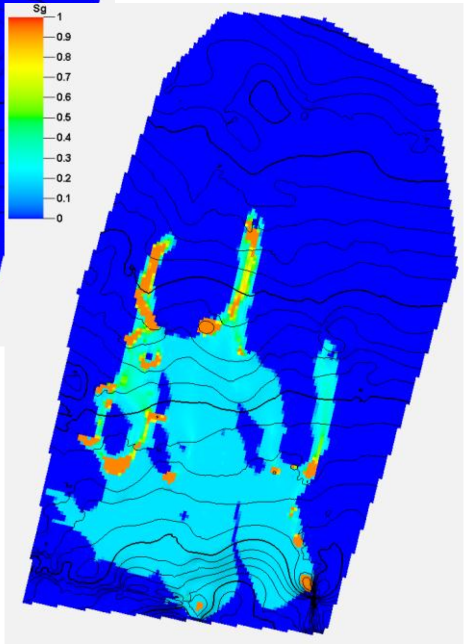


Sensitivity with respect to grid effects

- Distribution of injected CO_2 after 4000 years in Sector 2
- with uniform layer thickness of 5 meter in the whole model (left)
- with refined layer thickness in the upper 4 layers equal to 2 meter (middle)
- with 1 meter layer thickness in the upper 4 layers (right)







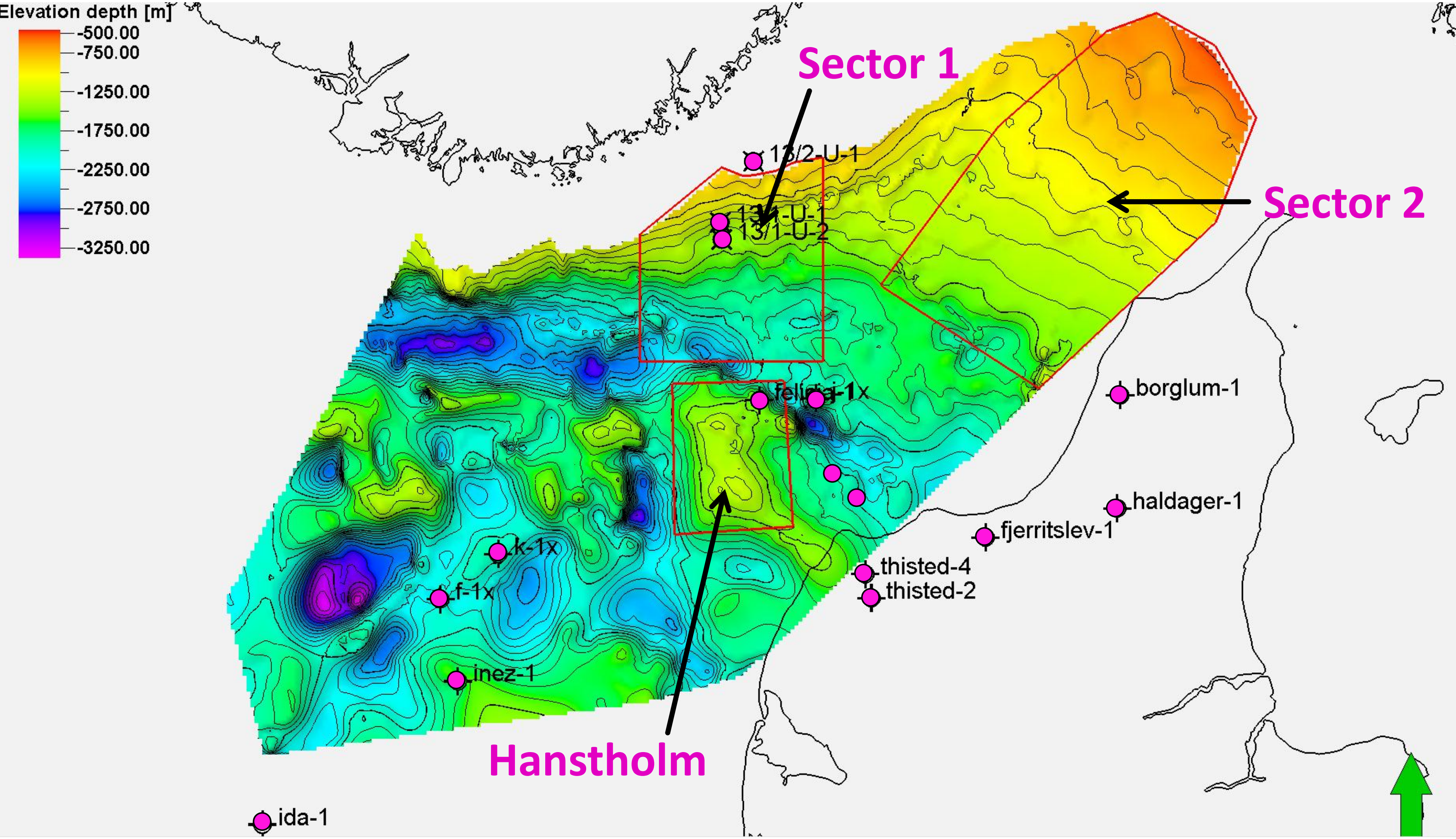
Parameters affecting migration distance not investigated:

- Interface between target formation and cap rock
- Heterogeneities in the formation

Conclusions

- Simulations indicate that The Gassum Formation has the capacity to store at least 250 Mtonne CO_2
- Large uncertainties in formation and fluid flow properties due to scarcity of data
- Pressure increase from CO_2 injection is in the range of safe pressure increase:
  - Better characterisation of the target formation and overburden required
  - More injection wells (and production wells) may be required for pressure control
- North eastern part of the Gassum formation is the most promising target for injecting 250 Mtonne CO_2
  - All injected CO_2 is contained within the model boundaries (cap rock assumed sealing)

CO_2 storage in the "open" parts of Gassum represents safe storage on the same scale as other structural closures in the North Sea



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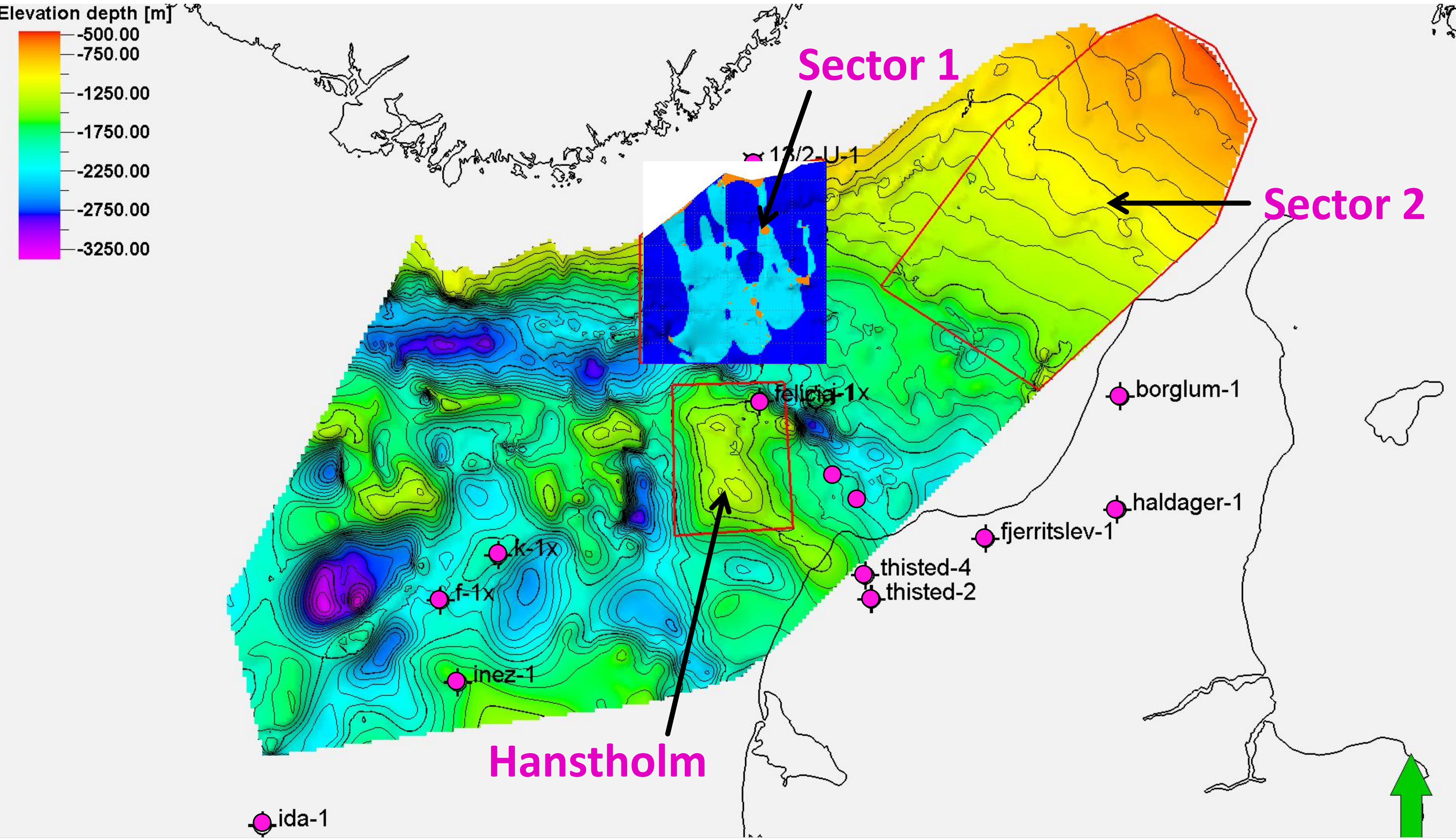

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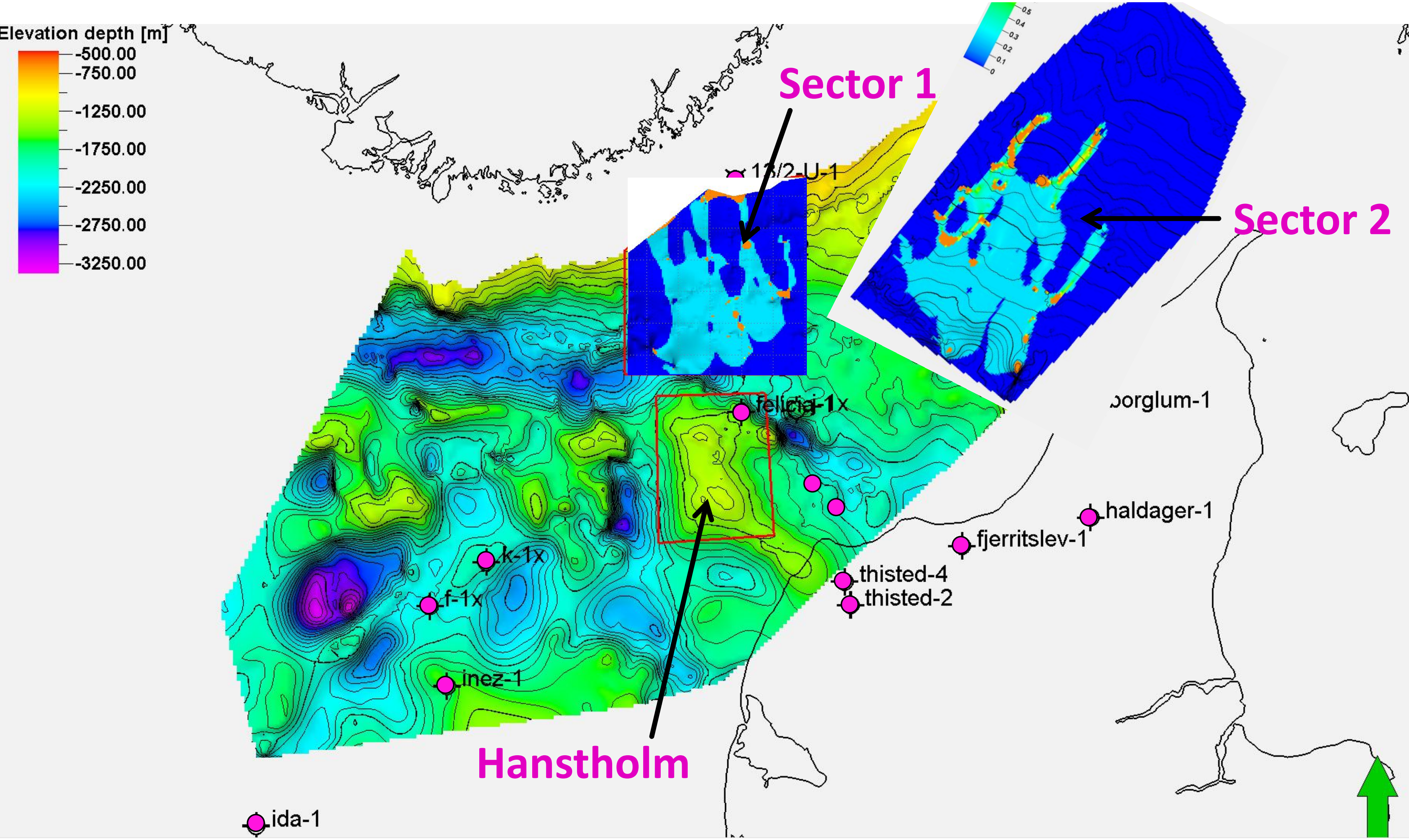

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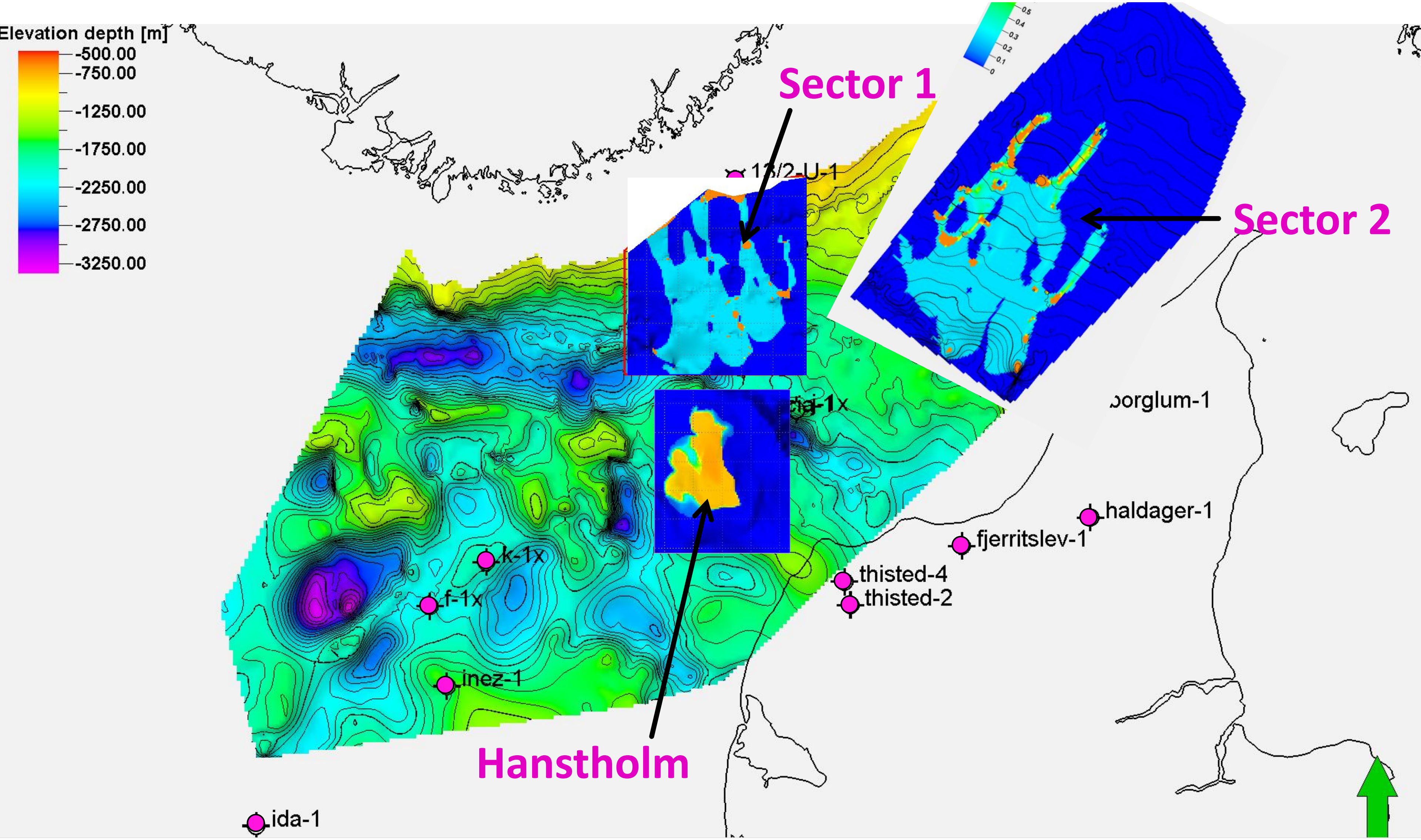

Acknowledgements

- The presented work received financial support from industry and Gassnova under the Climit programme (Project number 194492).

- The publication and presentation has been produced with support from the NORDICCS Centre, performed under the Top-level Research Initiative CO_2 Capture and Storage program, and Nordic Innovation. (Project number 11029).

Top-level Research Initiative