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## Numerical modeling including hysteresis properties for CO<sub>2</sub> storage in Tubåen formation, Snøhvit field, Barents Sea.

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### Abstract

In April 2008 the first injection of supercritical CO<sub>2</sub> started into the Tubåen Formation from the Snøhvit field, Barents Sea. At full capacity, the plan is to inject approximately 23 Mtons of CO<sub>2</sub> via one well during a 30 year period. The aim of this study was to simulation the 30 years of injection of supercritical CO<sub>2</sub> and the following long term (5000 years) storage of CO<sub>2</sub> in the Tubåen formation. The formation is at approximately 2600 meters depth and is at 98°C and 265 bars. The simulations suggested that, because of limited lateral permeability, the bottom hole pressure increases rapidly to more than 800 bars if an annual injection rate of 766000 tons is used. This is significantly higher than the fracture pressures for the formation, and it is therefore suggested that the aim to inject 23 Mtons over the planed 30 years may be unrealistic. To prevent fracturing due to increasing pressure, the bottom hole pressure constraint is applied that leads to significant decrease in the amount of CO<sub>2</sub> injected. With the hysteresis property applied, reservoir pressure behavior is the same in the base case (no hysteresis); however, the CO<sub>2</sub> plume is distributed over a smaller area than in the base case. Similar to the case of hysteresis, the diffusion flow case shows the CO<sub>2</sub> plume to be distributed over a smaller area than in the base case, but reservoir pressure decreases more than in the other two cases.

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*Keywords:* CO<sub>2</sub> storage; compositional simulation; residual trapping; solution trapping; hysteresis.

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### 1. Introduction

Underground sequestration of carbon dioxide is a viable greenhouse gas mitigation option by reducing the release rate of CO<sub>2</sub> to the atmosphere [1]. CO<sub>2</sub> injected underground can be trapped in reservoirs by four storage mechanisms: (1) structural and stratigraphic trapping; (2) residual CO<sub>2</sub> trapping; (3) solubility trapping; and (4) mineral trapping [2]. In the shorter time frame, the three mechanisms: structural, residual and dissolution trapping, dominates the CO<sub>2</sub> storage. These mechanisms are therefore very important and must be represented correctly in numerical simulations. In April 2008 Statoil started injecting CO<sub>2</sub> into the

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Tubåen Formation at a depth of approximately 2600 meters. The gas was captured from the Snøhvit gas field in the Barents Sea. Previously, the long term behavior and distribution pattern of CO<sub>2</sub> in the reservoir has been investigated by geological modeling with a maximum time frame of 1000 year [5, 6]. Several experiments were performed to investigate surface tension, capillary force and relative permeability relationships for supercritical CO<sub>2</sub> and brine [7]. The effects of hysteresis in relative permeability functions were investigated and residual trapping was shown to significantly prevent movement of CO<sub>2</sub> upward [8, 9]. One long term simulation in Snøhvit was performed to investigate the CO<sub>2</sub> migration pathways and sealing capacity of main faults in the time frame of 1000 years [10].

In this work, the numerical model of the Tubåen and Nordmela formations in the Snøhvit field with heterogeneous porosity and permeability has been developed based on 3D seismic, core and log data. The period of injection of CO<sub>2</sub> is 30 years, with approximate 23 million tons of CO<sub>2</sub> injected in one well into the Tubåen formation. The numerical model was run with several scenarios simulating CO<sub>2</sub> injection and predicting the behavior of CO<sub>2</sub> in the reservoir in 5000 years by applying hysteresis properties of relative permeability. The overall aim of the study was to investigate and evaluate more accurately CO<sub>2</sub> behaviour during long-term storage and storage capacity in the Tubåen formation, in the Snøhvit field, with special focus on the long-term potential for residual trapping. An earlier study from the Sleipner field has given the result that two thirds of the CO<sub>2</sub> has not reached the top of the formation and 40% of CO<sub>2</sub> was estimated to be trapped residually [11]. CO<sub>2</sub>-enriched water-phase convection (due to density differences) was also considered in the model. The diffusion coefficient of CO<sub>2</sub> in formation water has been determined to be in the range from  $4.5 \times 10^{-4}$  to  $4.7 \times 10^{-4}$  cm<sup>2</sup>/s in reservoir condition of 83°C and 178 bars [12]. When it comes to the slow mineral trapping, the Tubåen formation is dominated by quartz with minor reactive minerals such as feldspars. This mineralogy provides little potential for long-term trapping [3, 4] and has therefore not been considered in this paper.

## 2. Overview of the Tubåen formation & Snøhvit field

### 2.1 Overview

The Snøhvit field, discovered in 1984, is located in the southwestern Barents Sea, about 130 km off the Norwegian coast, northeast of Tromsø in northern Norway (figure 1).

The Tubåen formation is in the lower part of the Lower to Middle Jurassic strata that consists mainly of sandstones interbedded with thin shale layers deposited in a shallow marine to coastal plain environment with fluctuating coastlines [3]. The target for CO<sub>2</sub> storage is the thick sandstone bodies within the Tubåen Formation (figure 2). These sediments are interpreted as representing estuarine deposits.

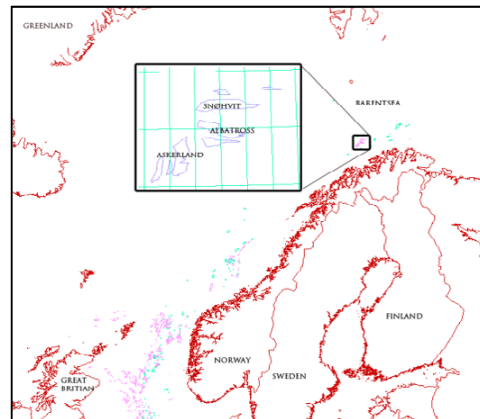


Figure 1 Snøhvit location [13].

A small gas accumulation is found in the upper part, at the crest of the Snøhvit structure. The conformably overlying Nordmela Formation has silty shale and very fine grained sandstones in the lower part, overlain by fine-grained sandstones [3] and is considered as a cap rock preventing CO<sub>2</sub> from moving upward. The overlying Stø formation is gas reservoir is currently being produced.

Tubåen formation has porosity in the range around 15%. Formation water has salinity of 168g/l calculated from [14]. The reservoir temperature is 98 °C and the formation pressure prior to injection was about 265Bar at the target segment. In Snøhvit the reservoir is laterally restricted by faults orienting in the east-west direction. The sealing of the main faults is an uncertainty factor investigated in a previous study [10]. This model studies the pressure build up in the Tubåen formation assuming non-conductive faults.

### 2.2 Fracture pressure

The reservoir fracture pressure is a key value to estimate the feasibility to inject CO<sub>2</sub> into a formation. Fracture pressure data is available for the Snøhvit field down to approximately 2500 meters (Figure 3), and fracture pressures for deeper units is therefore uncertain. Additional complications rise from the fact that fracture pressures are different from different rock types even at the same depth.

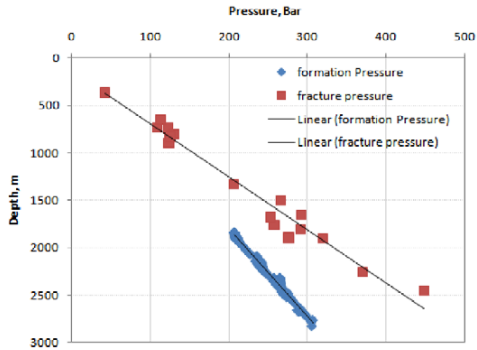


Figure 3. Fracture pressure in Snøhvit field

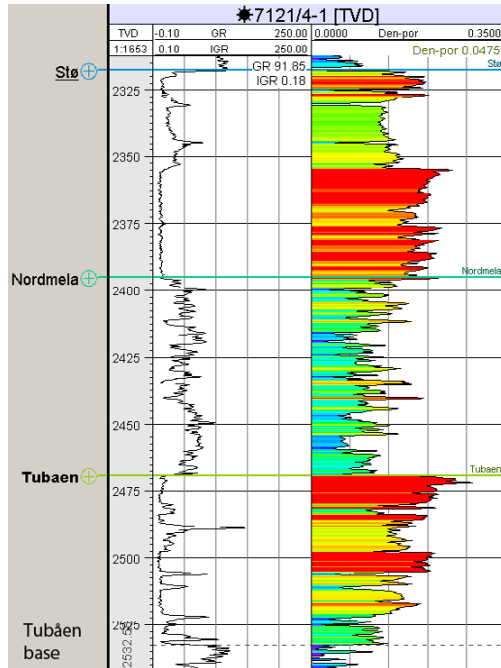


Figure 2. Log data of the well 7121/4-1: red color indicates good porosity, green and blue is low porosity (data from NPD: [http://www.npd.no/engelsk/cwi/pbl/wellbore\\_documents/135\\_02\\_Completion\\_log.pdf](http://www.npd.no/engelsk/cwi/pbl/wellbore_documents/135_02_Completion_log.pdf))

### 3. Numerical model

The model consist of 73920 cells (120×44×14) with the cells dimensions: 300m×300m×variation in the Z-direction. The simulations were run using the ECLIPSE 300 simulator. The injection well was based on the real location defined to inject CO<sub>2</sub>, the vertical perforation is opened nearly vertical injection into the Tubåen formation. The simulation rate was according to the planed 23 Mtons CO<sub>2</sub> over 30 years.

The numerical model with heterogeneous porosity was developed based on 3D seismic and log data. Permeability was calculated from the porosity-permeability relationship of core plugs in the two wells 7121/4-1 and 7121/4-2 (figure 4).

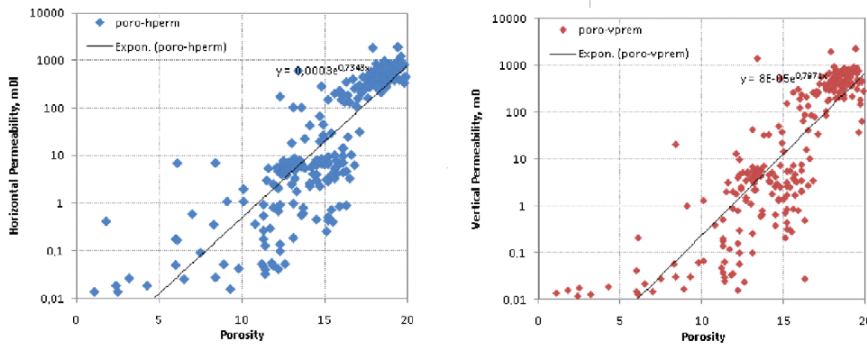


Figure 4. Porosity-permeability relationship in horizontal and vertical direction (data from the report of Statoil: Routine core analysis well 7121/4-1, 7121/4-2, NPD)

### 3.1 Fluid properties, PVT

The fluid model is compositional and run as follows:

The reservoir has been defined to consist of saline water (168g/l Nail) and a small gas cap at the crest of the structure. Components of the gas are taken from sample 2 at the depth 2470m in the well 7121/4-1 (Table 1). The gas water contact reported is 2473m in the Tubåen formation at the same well.

Calculation of CO<sub>2</sub> solubility and density of the aqueous phase were based on the Pang Robinson Equation Of State (EOS) [15] and modified following the suggestions of Storewide and Whitson to obtain accurate gas solubility [16].

Table 1. Gas cap components, sample in the well 7121/4-1 at 2470 m (data from NPD website: [http://www.npd.no/engelsk/cwi/pbl/geochemical\\_pdfs/135\\_1.pdf](http://www.npd.no/engelsk/cwi/pbl/geochemical_pdfs/135_1.pdf))

Component	Mol
CO <sub>2</sub>	4.97
N <sub>2</sub>	2.74
C <sub>1</sub>	82.14
C <sub>2</sub>	5.07
C <sub>3</sub>	2.51
i-C <sub>4</sub>	0.41
n-C <sub>4</sub>	0.84
i-C <sub>5</sub>	0.28
n-C <sub>5</sub>	0.29
C <sub>6</sub>	0.51
C <sub>7+</sub>	0.24
Total	100.00

### 3.2 Relative permeability and hysteresis

Relative permeability and capillary properties of two phase brine and supercritical CO<sub>2</sub> in the Tubåen formation were adopted from a series of experiments for CO<sub>2</sub>-brine systems under the conditions that are correlative with the in-situ conditions, i.e. temperature of 98 °C, initial pressure of 265 bars, and salinity of 168g/l [14]. The relative permeability curve of sample Cardium 1 [17] could be applied for Tubåen formation with correlative conditions (figure 5) due to the lack of data. Hysteresis property of permeability was applied for the model to see the effect on the residual trapping.

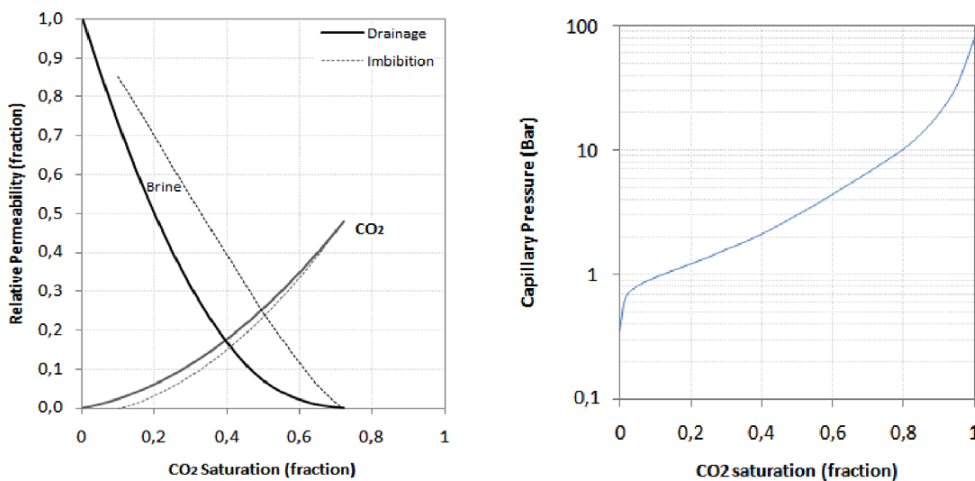


Figure 5. Relative permeability and capillary curve [17]

## 4. Results

### 4.1 No pressure constraint

At the end of the 5000 years simulation, the pressure had reached to about 543 Bar (figure 6a). The bottom hole pressure, however, had increased to very high levels and reach up to 815 Bar at the end of the injection. The planned 23 Mtons injection of CO<sub>2</sub> during 30 years is equivalent to approximate  $1.2 \times 10^{10}$  m<sup>3</sup> at standard condition (figure 6b). In that case, reservoir pressure increased up to 560 Bar after 30 years injection. After the injection stop, the reservoir pressure decreased a bit due to CO<sub>2</sub> dissolving into the aquifer. This injection rate was therefore not feasible because the pressure increased to levels significantly higher than the fracture pressure.

Because the problem is the increasing pressure, water alternative gas injection (WAG) to prevent the CO<sub>2</sub> plume from moving upward or fingering may not be feasible in this reservoir.

### 4.2 Fracture pressure constraint

The fracture pressure of each rock formation is different, and fracture pressures of a rock formation are different at different depths. Due to poor data in fracture pressure at the injection depth of the Tubåen formation and from the data of fracture pressure of formations in Snøhvit field (figure 3), constraint for bottom hole pressure applied at the injection depth in average was about 440 Bar. If this value is applied as a maximum allowed bottom hole pressure, i.e. the injection rate is reduced as this value is reached, the amount that can be injected over the 30 years period is significantly reduced. This is seen in figure 6 as the BHP constraint case, and it is evident that the volume of CO<sub>2</sub> injected decreases significantly to about one thirds of the planned volume.

The distribution of the CO<sub>2</sub> plume, seen as moles of CO<sub>2</sub> per rock unit after 30 years injection and 5000 years of storage, is shown in figure 7. After 5000 years, a part of the CO<sub>2</sub> has reached the cap rock and may potentially penetrate through the cap rock (figure 7d)

### 4.3 Hysteresis effect

With hysteresis applied for the model, the reservoir pressure behavior differs minor. However, the distribution of the CO<sub>2</sub> plume observed is less spread out (figure 8a) and concentration of CO<sub>2</sub> in the area near by the injection well is higher due to small CO<sub>2</sub> bubbles strapped in the pore space.

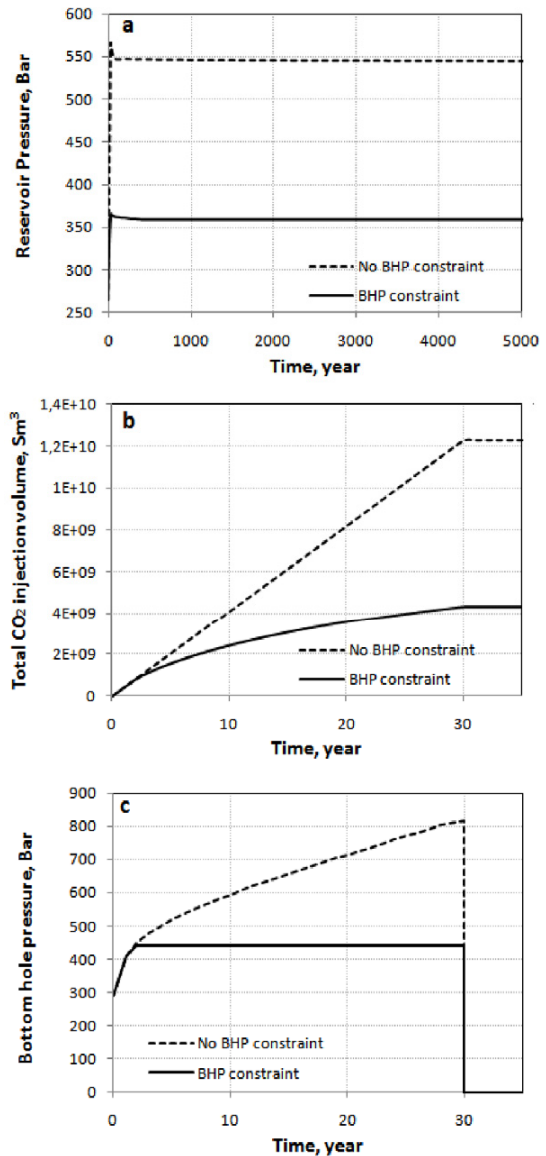


Figure 6. Reservoir pressure profile in 5000 years CO<sub>2</sub> storage (a), total CO<sub>2</sub> injected volume (b) and bottom hole pressure (c) in 30 years – injection period, BHP constraint is the base case.

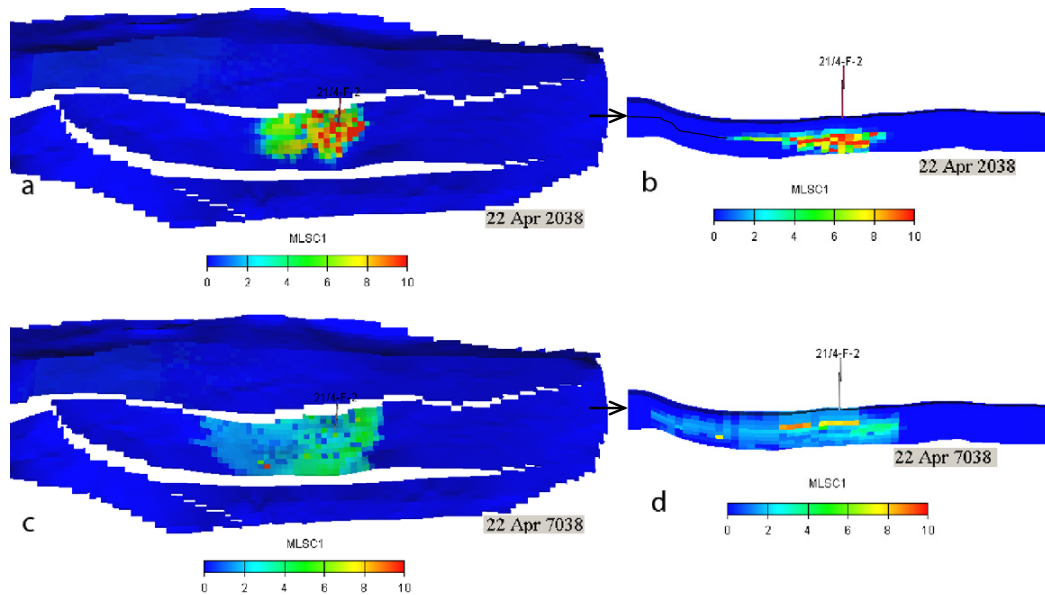


Figure 7. MLSC1: mol of CO<sub>2</sub> per unit rock; CO<sub>2</sub> plume after 30 years injection (a) and after 5000 years storage (c) observed at the top layer of Tubåen formation (layer 4), cross-section (east-west) cut through injection well (east-west) after 30 years injection period (b) and 5000 years (d), with the permeability property and diffusion of CO<sub>2</sub> in to the caprock, after 5000years CO<sub>2</sub> can penetrate through the cap rock-Normela formation (d).

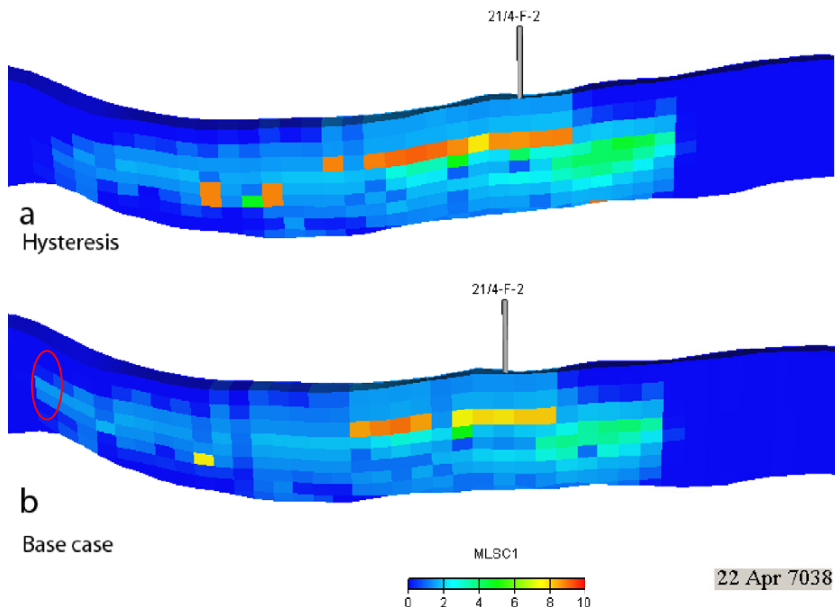


Figure 8. MLSC1: mol of CO<sub>2</sub> per unit rock; CO<sub>2</sub> plume after 5000 years storage observed in the cross-section (east-west) cut through injection well; (a) Hysteresis property applied (b) No hysteresis property, CO<sub>2</sub> plume is more spread out.

#### 4.4 Diffusion

When taking into account diffusion, the simulation shows that CO<sub>2</sub> dissolution and diffusion into water that results in a downwards migration of the water because of the increased aqueous phase density. Therefore, that leads CO<sub>2</sub> plume to spread out less. At the top of Tubåen formation, the area spread out of CO<sub>2</sub> plume is smaller in the case of diffusion calculated than the case no diffusion, figure 9. In the diffusion case, reservoir pressure decreases more, after 5000 years, than the base case (no diffusion) and the hysteresis case due to diffusion triggering a larger CO<sub>2</sub> volume dissolution. And with long period such 5000 years, diffusion transport could be considerable and CO<sub>2</sub> penetrated through caprock (fig 7)

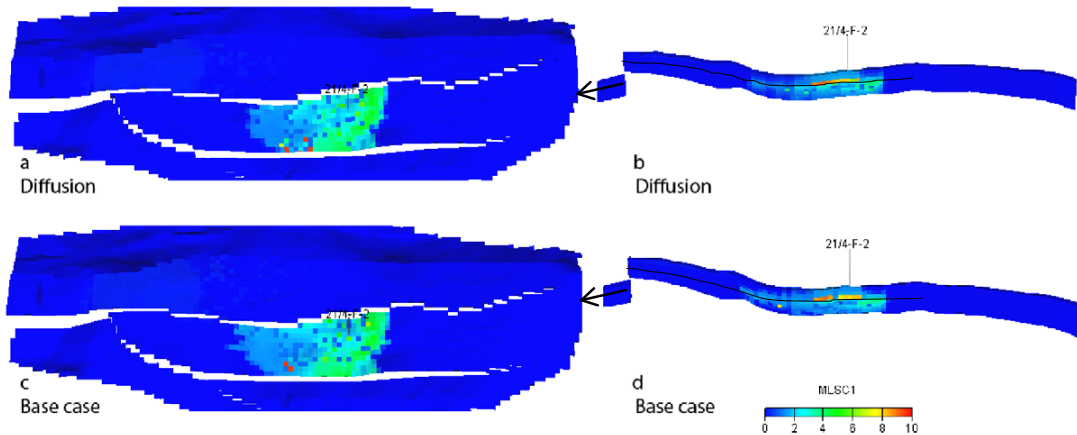


Figure 9. MLSC1: mol of CO<sub>2</sub> per unit rock; CO<sub>2</sub> plume after 5000 years storage observed in the top layer of Tubåen formation and the cross-section (east-west) cut through injection well; (a, b) Diffusion calculated (c, d) No diffusion, CO<sub>2</sub> plume is more spread out.

#### 5. Discussion and conclusion

To prevent fracturing due to increasing pressure, the bottom hole pressure constraint was applied. This leads to a considerable decrease in the amount of CO<sub>2</sub> injected over the 30 years of injection, or alternatively a longer period of injection at lower rates. With hysteresis properties applied, reservoir pressure behavior was the same as the base case (no hysteresis); however, the CO<sub>2</sub> plume was distributed over smaller area than in the base case. Similarly to the case of hysteresis, the diffusion flow case showed that the CO<sub>2</sub> plume distributed over a smaller area than in the base case, but reservoir pressure decreased more than the other two cases.

The sealing capacity of the main faults is one of the uncertainties [10]. In this model, faults are assumed to be closed, because the production of gas from the reservoir in the Stø formation is not connected with the small gas accumulation in the Tubåen formation. During CO<sub>2</sub> injection, pressure increase may activate the main faults. However, the pressure threshold to activate the faults is unknown and this scenario is not included in this study.

The application of relative permeability curves and hysteresis properties of the fluids which is not from the reservoir could result in errors in the forecasting results. Experiments to investigate the behavior of supercritical CO<sub>2</sub> in the reservoir rock at reservoir conditions are necessary to perform, and the experiment results may lead better estimates of the CO<sub>2</sub> and pressure migration. Critical gas saturation is a parameter affecting to the amount of CO<sub>2</sub> trapped by residual trapping mechanism. Another source for uncertainties and errors is the petrophysical properties and the discretization of these properties.



Finally, to test if the geological model and the numerical simulations can predict the short and long-term behavior of the CO<sub>2</sub> injection, the results should be compared to historical data obtained after the 2008 Snøhvit injection started.

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