Carbon Capture and Storage (CCS) is considered an essential mitigation strategy in order to reduce anthropogenic CO₂ emissions. To meet the 2°C target set in the Paris Agreement, decarbonization of the global power sector by the 2030s and the heavy industry sector beyond that is critical. CCS is currently the only option for decarbonizing the steel, chemical and cement industries.

CCS is a proven method (e.g. at Sleipner, Snøhvit, In Salah, Weyburn, Boundary Dam, Quest). There are remaining technical challenges related to upscaling, however, and cost is a critical factor in large-scale deployment of CCS.

In order to stimulate relevant research, the Norwegian Research Council has established a scheme of Centers for Environment-friendly Energy Research (FME) to develop expertise and promote innovation by focusing on long-term research in selected areas of environment-friendly energy, including CCS.

The FME SUCCESS center
The SUCCESS center for SUbsurface CO₂ storage was awarded FME status in 2009 and was formally inaugurated on 1 January 2010.

Key to public acceptance and successful deployment of CCS, the FME SUCCESS center focuses on effective and safe storage of CO₂. To meet the regulatory requirements for Measurement, Monitoring and Verification (MMV), the SUCCESS center seeks to provide a sound scientific base for CO₂ injection, storage and monitoring in order to fill gaps in strategic knowledge, and to provide a system for learning and development of new expertise. Such knowledge is vital in order to ensure conformance (concordance between observed and predicted behavior), containment (proving storage performance in terms of security of CO₂ retention) and contingency (leakage quantification and environmental impacts).

The following objectives were defined in the FME SUCCESS application:

- To improve our understanding and ability to quantify reactions and flow in carbon storage.
- To develop advanced modeling tools for multiphase flow and reaction.
- To investigate the integrity of sealing materials, and test their retention capacity.
- To improve our understanding and develop new models for the relationship between saturation, flow and geomechanical response.
- To improve our understanding and develop new models for geochemical and geomechanical interactions.
- To improve our understanding and modeling tools for flow and reaction in faults and fractures.
- To test, calibrate and develop new monitoring techniques and instrumentation.
- To improve the understanding of shallow marine processes and the ecological impact of CO₂ exposure, and develop marine monitoring methods.
- To reduce risk and uncertainties in sub-surface CO₂ storage.
- To facilitate extensive and high-quality education on CO₂ storage.

Field excursion Unis CO₂ lab workshop, Svalbard 2012
One of the strengths of the FME SUCCESS center is its expertise within fundamental, theoretical research, which is internationally recognized; the center hence focuses on basic research, interpreting the results of field and laboratory experiments in order to predict the long-term effects of CO$_2$ storage. In particular, the center has used the theoretical platform to address critical and relevant scientific issues related to CO$_2$ storage.

Upon inauguration, the SUCCESS center was organized into six scientific work packages and one educational work package.

**Mid-term evaluation**
In 2013, the Norwegian Research Council conducted a mid-term evaluation of the FME centers. The mid-term evaluation of the SUCCESS center concluded that the center needed to undertake major changes in the organization and operational structure to secure integration and industry relevance.

Following the recommendations of the mid-term evaluation, the SUCCESS center reorganized the scientific activities into three work packages:
- Work Package 1: Reservoir
- Work Package 2: Containment
- Work Package 3: Monitoring

An integration Work Package, WP0, was also established for the final two year-period of the center. WP0 aimed to test and verify new knowledge and methodology developed at the SUCCESS center in connection with two case studies. The Skade and Johansen formations were originally chosen as case studies. The Johansen Formation was later replaced by the Smeaheia project case, which is the selected reservoir candidate for Norwegian full-scale demo project.

**Final reports**
As part of the center’s scientific reporting, the center’s partners and board agreed that a set of reports would be written and...
summarize the major scientific findings and achievements. These reports have been referred to as Long-term Deliverables (LTD).

Knowledge and lessons from the two field pilots, Snøhvit and Sleipner, have been synthesized in separate summary reports (Volume 6 and 7). Lessons from the Longyearbreen CO$_2$ Lab, which has been an important test site for the SUCCESS center, have been and will be published in dedicated summary volumes of scientific journals.

The case studies on the Smeaheia fault block (deep, confined reservoir) and the Skade Formation (shallow, saline aquifer) in the North Sea are presented in separate reports in order to demonstrate the value of the results achieved at the SUCCESS center and associated projects, and determine how they can be applied to better quantify the storage feasibility of untested aquifers. They allow testing of the lessons and knowledge from the Snøhvit and Sleipner field pilots, and may constrain the range and use of the methods and models developed.

The LTD reports (5) include the SUCCESS center’s final reporting, and they aim at synthesizing results and findings of the SUCCESS center and relate directly to the objectives of the SUCCESS center (see the figure below).

The LTD reports cover the following topics:

- **Storage capability (Volume 1)**
  This report summarizes the SUCCESS center’s work on storage capability, which is the ability of a formation to safely store CO$_2$. An important objective of this center has been to identify geological factors and the hydro-geomechanical processes that are most important for determining storage capability. The most important factor is whether the storage reservoir is open or closed.

- **Injectivity (Volume 3)**
  Summarizing the results from field, experimental and theoretical studies of potential leakage mechanisms and their relevance to CO$_2$ storage site risk assessment, this report demonstrates that viscous deformation of the shales can play an important role in their ability to keep CO$_2$ contained and that material properties and their dynamic behavior in response to the stress introduced by CO$_2$ injection need to be evaluated in order to safeguard operations.

- **Containment (Volume 2)**
  This report presents experimental and computational results that have enhanced our understanding of reservoir injectivity, including a basic understanding of mechanisms, quantification of the expected impact, model calibration and case specific implications. A main outcome is a workflow that includes new computational tools, new geochemical and geomechanical experimental design/data and research-based advice.

- **Conformance (Volume 4)**
  The geophysical monitoring report summarizes the SUCCESS center’s work on rock physics related to pore pressure and saturation and estimating these two parameters via geophysical monitoring. By estimating their spatiotemporal distribution, we can monitor the migration of injected CO$_2$ and determine whether the containment of storage complex is secure.

- **Contingency (Volume 5)**
  This report synthesizes relevant knowledge and data regarding marine monitoring methods and strategies for inorganic carbon in the water column, based on modeling and observational work. A cost-effective strategy for a marine monitoring program should optimize the probability of detecting a leak.

**Christian Hermanrud (SUCCESS funded Prof II position, UiB) with some of his master students**
Relevance of work
The collective work of the SUCCESS center addresses various groups of stakeholders and the reporting structure is relevant to different communities. The report on storage capability is particularly relevant to storage site selection and Norwegian CO₂ storage capacity estimates, based on better constrained trapping efficiency and immobilization potential. The leakage risks report addresses important issues regarding safe operation of CO₂ storage and risk management. The report on injectivity provides valuable knowledge on the planning of CO₂ operations and reservoir utilization. Finally, there are two reports on monitoring: the report on geophysical monitoring addresses methods for measurement, monitoring and verification (MMV) of the subsurface; while the report on marine monitoring is particularly relevant to risk management and mitigation in the event of leakage to the water column.

Future work and recommendations
CO₂ storage has been successfully demonstrated at Million-tonne scale, but needs to be ramped up to Giga-tonne scale in order to achieve global emissions reductions targets. A shown in the report on Large-scale Storage of CO₂ on the Norwegian Shelf, there are no technical showstoppers for ramping up CO₂ storage (Tangen et al., 2014). However, ramping up to Giga-tonne scale requires 1) better estimate of storage capacity, 2) better pressure management strategies, and 3) smart methods for controlling and optimizing CO₂ injection (Nøttvedt, A., pers. comm. "Mission innovation workshop", 2017).

Better estimate of storage capacity requires more reliable forecasting of CO₂ migration and trapping processes, with range of uncertainties. This, in turn, requires improved physics and chemistry-based understanding of CO₂ flow and transport processes at multiple scales within heterogenous rock media.

Better pressure management strategies imply control on pressure limits at both near-well and reservoir scales and quantification of allowable pressurization. Consequently, better understanding of the effects of stress field, pressure history, reservoir/caprock heterogeneities, including faults and fractures, is needed.

Smart methods for controlling and optimizing CO₂ injection include effective control and handling of transmissivity, near-well geochemical processes, formation damage, etc. Well stimulation and next-generation well technologies need to be demonstrated to enable large-scale CO₂ injection. Future advances in CO₂ storage will likely occur at the interface between industry and academia and be coupled to the execution of ramp-up CO₂ storage projects.
Snøhvit: A SUCCESS Story

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# Table of contents

The FME SUCCESS center on CO₂ storage 2

Executive Summary 8

Introduction 9

Tubåen injection 10
  - Overview 10
  - Salt plugs 12
  - CO₂-hydrocarbon mixing 12
  - Intra-reservoir geometry 12
  - Geomechanical analysis 13

Ste injection 16
  - Background 16
  - Injection Temperature 17
  - Convective Mixing 18
  - Fault Transmissibility Impact on Pathways 18
  - Migration to Upper Layers 19
  - Risk of Contamination in Production 20
  - Model Comparison for Aquifer Injection 22

Summary and recommandations 24

References 27

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Executive Summary

Snohvit is a natural gas field, where CO$_2$ is separated from the gas produced in the Stø Formation. From 2008 until 2011, it was re-injected into the deeper Tubåen Formation. The injection experienced a persistent pressure increase, eventually reaching a level that was close to the estimated minimum fracture pressure. Injection at Tubåen was therefore halted and moved to the Stø Formation, located at a shallower elevation. This formation is also used for production, raising concerns that the CO$_2$ may interfere with the gas production.

Analysis of the Tubåen injection data indicated that the CO$_2$ was injected into a porous matrix without fracturing. However, extrapolations of the pressure trend predicted that the threshold for caprock integrity would eventually be exceeded. There is evidence of some injectivity loss from salt plug formation, but this alone cannot explain the entire increase in pressure. Pressure compartmentalization due to a complex geology with east–west trending sealing faults both north and south of the injection well, in addition to north–south trending sedimentary channels, limits communication within the reservoir. Improved detection of faults has been demonstrated using a combination of attribute studies and 4D seismics.

A reservoir modeling study of the Stø Formation suggests that the CO$_2$ plume may migrate into the brine in the layers above as well as into the adjacent oil leg. However, it is unlikely that the plume will reach the wells in the neighboring production segment within the lifetime of the license. Based on current data, the aquifer segment now replacing the original well appears to have sufficient injectivity and capacity to accommodate the separated CO$_2$.

"Based on current data, the aquifer segment now replacing the original well appears to have sufficient injectivity and capacity to accommodate the separated CO$_2."
Introduction

Snøhvit is a gas field that is located 140 km offshore, north-west of the city of Hammerfest in Finnmark county, Norway. It is not operated by platform, but by subsea templates at a depth of between 250 and 350 m. The gas is transported through a pipeline to shore for processing at the Melkøya facility, and is then shipped out on liquefied natural gas (LNG) tankers. The gas contains about 6% CO₂, which is separated from the hydrocarbons as part of the processing. Instead of venting this CO₂ into the atmosphere, it is transported back to the field and injected there for permanent storage.

The original plan was for the CO₂ to be stored in the Tubåen Formation, located below the gas field. However, this formation turned out to be pressure constrained and injection had to switch to the Stø Formation, which is also where the hydrocarbons are located. Even though this was not the ideal location, such a solution had been outlined as a backup in the field development plans. Even so, the Snøhvit field currently continues to store about as much CO₂ as that emitted by a large city in Norway! (Aasestad, et al., 2016).

This report will present the research conducted under the auspices of the SUCCESS center on both the Tubåen and Stø formations and will include an evaluation both of a satellite aquifer and of the use of a segment connected to a producing gas field as a storage site. These concepts are not limited to Snøhvit, but may also be used in other fields in order to reuse existing production facilities by connecting the injector to an existing template, reducing the cost of CO₂ storage. The key findings of these projects may thus provide guidance for future projects.

Figure 1: Gas from the subsea templates at Snøhvit is brought to shore by pipeline. (Illustration courtesy of Statoil).
Overview

The Snøhvit field is situated in an elongated east–west trending fault block system in the Hammerfest Basin in the western Barents Sea. The fault throw is more than 200 m, and is expected to serve as a good seal, which is confirmed by the pressure increases shown in seismic attribute interpretation. The present depth of the Tubåen Formation at Snøhvit is 2 670–2 780 m, and it is up to 110 m thick. The uplift of the area is in the range of 700–1 100 m, and open fractures observed in the reservoir are believed to have been caused by the late Cenozoic uplift (Wennberg, et al., 2008). Overlying the Tubåen Formation are the mud-rich deposits of the Nordmela Formation, which were deposited in a lower coastal plain environment.

The reservoir injection zone in Tubåen is described as a Jurassic lower delta plain depositional environment with a marine and tidal influence that leads to highly variable sandstone facies, interbedded with siltstones and mudstones. The formation can be subdivided into four sandstone units, Tubåen 1–4, separated by interbedded shale units. CO₂ was injected through three perforation intervals, covering the bottom Tubåen 1–3 sandstone units. Approximately 80% of the CO₂ has migrated into the Tubåen 1 sandstone unit, while the remaining 20% has migrated into the Tubåen 2 and 3 units (Hansen, et al., 2013). The analysis of pressure data and time-lapse seismic data indicates that the shale unit above Tubåen 1 restricts vertical migration of the CO₂ (Eiken, et al., 2011; Hansen, et al., 2013). The same conclusion was made by (Grude, et al., 2014), comparing the time-lapse data and the synthetic seismic data.

The initial reservoir pressure was around 290 bars and the initial reservoir temperature was around 99°C. The injection was made into an aquifer with formation water salinity of about 14% and permeability varying from a few milli-Darcy to one full Darcy. Permeability values larger than 500 milli-Darcy have been measured in the cores, but the lateral extent of such good sands is uncertain. The present stress field in the area is compressional, with a mainly north to south-oriented maximum horizontal stress direction, although considerable...
variations have been observed in the stress field orientations in the Hammerfest Basin (Chiaramonte, et al., 2015).

Figure 2 is a general depth map of the topography of Tubåen. The CO$_2$ injector (F-2 well) is marked with a gray, dotted cross-hair.

Vertical cut planes of the arms of this cross-hair are provided in Figure 3a and Figure 3b.

**Injection data and pressure**

A data set which included the injection pressure, rate and temperature of the injection through the F-2 well into Tubåen has been made available to the SUCCESS center. The pressure can be read at both the wellhead and from a gauge inside the well, while the temperature of CO$_2$ is only available from a gauge. The gauges are installed at 1 805 m true vertical depth (TVD).

An overview of the Snøhvit injection performance is shown in Figure 4. The injection rate shows a slightly increasing trend from the beginning of injection in April 2008 until March 2009. The rate then levels out towards 80 tonnes/hr while the injection pressure continues on a similar trajectory as before. This behavior indicates injection into the formation matrix and existing natural fractures without any indication of fracturing. Any fracturing of intact rock or opening up of existing fractures will result in an abrupt rate increase in the rate, something which does not happen in the F-2 well.

The injection data measured was analyzed using a pseudo step rate test (SRT), plotting the injection pressure against the flow rate. The assumption for the step rate test analysis is that there is a linear relationship between the injection pressure and the injection rate during both the matrix mode and fracture injection mode. If the fluid pressure is kept below the fracture pressure during the injection operation, the injection pressure will probably show a single data cluster following a linear trend. Such behavior was observed in the Snøhvit CO$_2$ injection project, where the fluid pressure never reached the fracture injection pressure, see Figure 5. Here the pressure versus rate plot shows a linear increase in the injection pressure with a rate with different slope functions for different periods, related to near-wellbore effects and pore clogging. The data from the early period (2008) show a steeper slope with a maximum injection rate of around 65 tonnes/hr. Higher injectivity was achieved following treatment of the injection limitations (using chemical treatments) (Hansen, et al., 2013), giving rates of up to 85 tonnes/hr and a corresponding lower slope pressure versus flow rate plot.

On the other hand, if the injection pressure exceeds the fracture pressure, the rate-pressure plot will show two distinct clusters. Intersection of the trend lines for the two data clusters in this case can be used to infer the fracture pressure.

Detailed interpretation, including a separate curve fit for the salt plugging phase, was not part of the study, but could have provided more details on the injectivity before and after chemical treatment and a better discussion of the local reservoir injectivity versus the general pressure increase in the reservoir. The effect of near-well thermal fracturing and the expected influence on injection have not been considered at this stage.
Salt plugs

The solubility of water in CO₂ varies according to the temperature and pressure, and injection of dry CO₂ into saline aquifers therefore leads to various degrees of evaporation of water and potentially to the formation of evaporate minerals (halite, gypsum, etc.) (Hellevang, 2015).

In affiliation with the SUCCESS center, the University of Oslo has developed an equation of state that can handle the thermodynamic equilibrium between CO₂ and high-salinity brines (Miri & Hellevang, 2014; Miri, et al., 2014; Miri, et al., 2016), as well as a new physical model and understanding of the process of salt formation (Miri, et al., 2015; Miri & Hellevang, 2016).

The new theory supports salt formation in most saline aquifers, also those at relatively low salinities, but injectivity challenges associated with clogging of the pore space only impact on tight high-salinity reservoirs where the CO₂ is channeled.*

"The new theory supports salt formation in most saline aquifers, also those at relatively low salinities, but injectivity challenges associated with clogging of the pore space only impact on tight high-salinity reservoirs where the CO₂ is channeled."

CO₂-hydrocarbon mixing

Residual hydrocarbons may mix with injected CO₂, changing the CO₂ stream properties. Such changes were modelled by Miri et al. (Miri, et al., 2014) using a Statistical Associating Fluid Theory (SAFT)-based equation of state. In this work, the phase equilibria and density of the binary, ternary and quaternary systems containing CO₂, CH₄, H₂O and NaCl were investigated at ambient temperature and pressure, with salt concentrations of up to 5 mol/kgw. The results of this work are generally applicable to fluid systems bearing those components, and may therefore be used in future projects as well.

Intra-reservoir geometry

One of the main challenges associated with estimating capacity, injectivity and evaluating risks for candidate reservoirs for CO₂ storage is the assessment of geological heterogeneities and, in particular, the presence of sub-seismic structural features such as faults and fractures.

The IMPACT project that was affiliated with the SUCCESS center studied the effect of structural heterogeneities on CO₂ storage, using seismic data from the Snøhvit CO₂ storage site (Hovland, 2013). Using a combination of seismic interpretation and attribute analysis, the study went beyond seismic resolution to further identify geological heterogeneities that may affect underground storage. Two 3D seismic surveys were used as a basis, each one covering an area that was 8 km wide and 8 km long around the injection well in the Tubåen Formation. The first pre-injection survey was carried out in 2003 and a new monitoring survey was conducted six years later, in 2009.

A variety of different integrated attributes were used to map the target reservoir, including variance, root mean square amplitude, superimposing, fault detection and...
figure 6: Fault detection attribute map of the base Tubåen Formation (at about 2 660 mbsl). Red means high confidence, green means medium confidence and blue means low confidence (Hovland, 2013)

figure 7: 4D anomalies detected in the Tubåen 1 perforation. The interpretation includes a north–west/south–east trending high amplitude anomaly and a detected ridge stopping the 4D anomalies to the west (Hovland, 2013)

Geomechanical analysis

The observed pressure increase and the uncertainty related to pressure barriers observed in the 4D seismics is characteristic of the Tubåen CO₂ injection (Hansen, et al., 2013; Hovland, 2013), as illustrated in Figure 7 and the interpretation of fracture attributes in Figure 6 (Hovland, 2013). One of the key issues associated with the sealing integrity of CO₂ storage sites is the risk of fault reactivation. Pressure build-up due to injection operation is likely to change the state of the in situ stresses and may destabilize faults.

Building on the probabilistic geomechanical analysis for Snøhvit (Chiaramonte, et al., 2015), the stability of faults near the injection well in Tubåen is addressed by a geomechanical numerical model in order to investigate the potential of injection-induced fault reactivation.

The model investigated stress paths with various drainage scenarios for the faults following the assumption of undrained and drained geomechanical behavior, as well as addressing stress path development within potential north–south trending faults related to the observed pressure barriers (Hansen, et al., 2013; Hovland, 2013).
The results show that most of the known bounding faults around the injector are unlikely to reactivate during pressure build-up. Reactivation also seems to be unlikely even for the sub-seismic faults (i.e. the north–south barrier identified in Figure 7), although closer to the failure line than the east–west bounding faults (see Figure 8). These observations are consistent with observations from a 4D seismic survey that indicated intact north–south trending barriers in the reservoir. In the long term, there will be pressure diffusion from the reservoir into the faults, and the faults around the well could become less stable, as the stress conditions approach the failure envelope. This is due to the decreased effective stress; see the stress path in . The study clearly demonstrated a significant difference in seal integrity when modelling the fault as drained versus undrained. In connection with injection, a drained condition might be more critical in most cases, compared to an undrained condition.

However, the assumption of a drained condition could be too conservative for sealing faults, which are often considered as impermeable and a flow barrier (Choi, et al., 2015). Further understanding of the drainage process of reservoir bounding faults during reservoir injection or depletion would be necessary in order to make a more detailed assessment of fault reactivation. A low permeable damage zone in the reservoir due to cataclastic deformation or clay smear might result in an undrained condition for reservoir bounding faults, while a fractured damage zone or very thin damage zone might be better represented as a drained condition. This highlights the need for detailed knowledge of fault rock properties as well as the damage zone. The uncertainty related to in situ stress conditions also needs to be addressed.

Further understanding of the drainage process of reservoir bounding faults during reservoir injection or depletion would be necessary in order to make a more detailed assessment of fault reactivation.

*Figure 8a: Undrained stress paths of surrounding faults during injection, Figure 8b: Drained stress paths of surrounding faults during and after injection.*
Stø injection

Background

The continued increase in pressure in Tubåen led to concern that the formation did not have enough capacity to hold all of the CO$_2$ that needed to be stored during the lifetime of the Snøhvit field. In 2011, after 1 Mt had been stored in Tubåen, a decision was made to switch to the backup solution outlined in the field development, namely to cement the bottom part of the F-2 well and perforate it in the lower region of the Stø Formation and store the CO$_2$ there instead. This formation is at 1 800 to 2 500 m below sea level. It is covered by the Fuglen Formation of the Middle to Late Jurassic age.

An overview of the Stø Formation is provided in Figure 9, showing four segments of interest. Production is predominantly done in the eastern part of the field in what is known as the E-segment. CO$_2$ is injected into the water-filled layers in the middle of the field, called the F-segment. These two segments, E and F, are connected by a small ramp in connection with the main production, there is enduring depletion of the field, because the amount of CO$_2$ injected is an order less than the amount of gas produced. The CO$_2$ originated from the gas produced at the very same formation, so there should obviously be enough capacity to store it back again. Nonetheless, storing the CO$_2$ in the F-segment is not straightforward, as it is possible that the CO$_2$ will be drawn towards the producing wells, and eventually find its way into the production.

One of the goals of the LCSANS project affiliated with the SUCCESS center was to investigate the extent of the CO$_2$ plume migration and the arrival times in order to assess the likelihood that it would interfere with production, and to see how this might be affected by the choice of modelling parameters (Kaufmann, 2016). A geological realization of the field, as well as of the fluid properties, was provided by industrial partner DEA.

Three fundamental pathways for the CO$_2$ migration were identified early on. The CO$_2$ could migrate straight up the ramp, already at the lower layer; it could migrate to an upper layer and pass through the fault; or it could migrate up-slope to the western part by gravitational forces, and then possibly...
be drawn back towards the production from there. Figure 10 illustrates these pathways.

A three-phase, compositional model was employed for sensitivity testing of various scenarios. The scenarios tested were continued injection in the F-segment, moving the injection to a new well in the G-segment, as well as split injection between these two wells. The base case contains very strong horizontal/vertical anisotropy to model less upward migration to the upper layers; the effect of the anisotropy is discussed in further detail in the section “Migration to Upper Layers”. Also a small production of about 3 000 tonnes/day is included in the F-segment, which helps to draw the injection away from the ramp, although this effect is not significant. Production in the F-segment shuts in before the lifespan of the field elapses, however, as there is a constraint on the well to avoid water coning.

Figure 11 shows the plumes at the reservoir life expectancy in 2056, run with the Eclipse simulator. What is notable here is that the production in the F-segment well drags the plume originating from the G-segment all the way out of that segment. However, once it enters Snøhvit Vest, it does not proceed to the producer but continues upwards Snøhvit Vest due to buoyancy, contaminating that segment.

A part of the plume from F-2 will migrate up the ramp, but most of it is still located up-slope in the F-segment, and continued production in that segment may experience contamination after some time.

We will now continue to review the factors behind the most interesting findings from the sensitivity analysis.

**Injection Temperature**

The temperature of the formation water in the reservoir is close to 91.8°C, with only very minor variations by depth. Based on readings from the wellhead, modelling of the well indicates that the temperature of the CO₂ injected should be between 21.6°C to 22.3°C. At this temperature, the density of the CO₂ is slightly less than 1 000 kg/m³, whereas at reservoir temperature the CO₂ has a density of around 600 kg/m³. With a density of 1 133 kg/m³ for the brine, the CO₂ has great buoyancy. From this, it might be reasonable to expect a thermal simulation to yield very different results than an isothermal one, but this turns out not to be the case. Figure 12 and Figure 13 show the situation in Sta 2 from a thermal run. Note that, compared to Figure 11, this run places all of the injection in the F-segment and thus models the entire G-segment as a numerical aquifer. It is also run for a shorter time; until the first license expiry date.

Figure 12 illustrates the mole fraction and shows that the plume has spread significantly; it has invaded the gas cloud and migrated up the ramp. This is not reflected in Figure 13, however, which shows the temperature. The well column has a lukewarm injection temperature, but the effect of this is only seen a couple of columns away. Hardly any temperature traces of the injection can be found 1 km from the well.

Although the injection starts out cold, compared to the formation water, the amount of
CO$_2$ injected is so minute that it is quickly warmed to ambient temperature, and does not have any influence on it. Although it would cause slightly greater buoyancy in the near-well area, running the simulation isothermally seems to yield an almost identical result, with around half the computation time. The latter part of the project therefore exclusively used isothermal runs.

**Convective Mixing**

Dissolution of CO$_2$ into brine generally has a positive impact on geological CO$_2$ storage. It slows the upward migration in the formation by removing CO$_2$ from the gaseous phase, where it is buoyant, and putting it into the aqueous phase, where it no longer is buoyant. As the total density of brine, now with dissolved CO$_2$, increases, the pressure build-up from injection also diminishes. Dissolution is facilitated when convective mixing occurs below the CO$_2$ plume (Riaz, et al., 2006; Elenius, et al., 2012).

However, in order for dissolution to have a practical impact on storage security, a substantial amount of CO$_2$ must dissolve in the brine, at a sufficiently fast rate. In a deep aquifer like the Ste Formation, the salinity is high, which reduces the solubility of CO$_2$. Low solubility requires a larger volume of brine to dissolve the CO$_2$ above and additionally yields a lower dissolution rate, slowing down the uptake of CO$_2$. Lower solubility also means less of an increase in density, further reducing the rate. Another factor that can reduce the dissolution rate in deep aquifers is that they are often less permeable, compared to more shallow formations.

The total mass of CO$_2$ dissolved in the brine is a product of many factors, summarized as

$$M = F K \frac{\Delta \rho g c A t}{\mu}$$  \hspace{1cm} (1)

with the various components detailed in Table 1 in natural units.

The values for parameters $F$ and $c$ are taken from Table 1 on page 428 in (Elenius, et al., 2014), selecting results that include effect of the capillary transition zone, giving the most favorable value. The value for parameter $\mu$ is taken from Table 4 on page 910 of (Elenius & Johannsen, 2012), while $\Delta \rho$ is calculated using the model in (Duan, et al., 2008). The values for remaining parameters $K$, $A$ and $t$ are taken from the simulations in the LCSANS project.

The resulting dissolved CO$_2$ mass given in M amounts to around 0.4% of the injection during the first five years, and an order less, around 0.4‰, of the injection during the expected life of the field. We have also neglected the finite aquifer depth, which limits the accessibility of brine under the plume, and any barriers from low-permeability zones, see (Elenius & Gasda, 2013), which would both further impede the dissolution.

In conclusion, dissolution is expected to have a negligible impact on plume migration and pressure development in this case.

### Fault Transmissibility Impact on Pathways

The ramp between the E- and F-segments is relatively narrow, but there is a much larger interface in the part of the fault that stretches between the ramp and the site where the two segments join Snøhvit Vest. Although there is no direct layer contact, there is sand-to-sand contact between the upper layers of the F-segment and the Ste 2 layer in the E-segment. If this fault is permeable, then the plume will be drawn towards this area from the pressure gradient of the producers. The transmissibility factor — ‘openness’ — of the fault does not need to be considerable before there is pressure contact. However, the influence of this factor can be observed through the injector well.

Figure 14 shows the development of the bottomhole pressure in F-2 for various transmissibilities.
transmissibility factors. The large drop in the middle is caused by a maintenance interval and is irrelevant to this discussion. What is interesting is the relative position of the curves. The largest drop comes from opening the fault slightly, going from completely impermeable to barely permeable with 5% transmissibility. The drop then continues with an increasing transmissibility factor, but with much less of a decline per factor unit than initially.

What is noticeable here, is that the scenario with a completely sealed fault leads to a higher pressure, and that a higher pressure may be incompatible with having the correct injectivity in the F-2 well. The historic bottomhole pressure, estimated from a gauge located in the well at about 1 760 mbssl and smoothed to remove non-streaming hours, is plotted in the graph for reference. Admittedly, the match between the simulation and the actual data is not very good. In particular, the simulations have a large fall-off in the start, indicating that the near-well zone may be inadequately modelled. The pressure trajectory of the green curve is actually a better match with the historical data at the end. The recommendation is therefore to keep monitoring the injection pressure in order to determine whether the presumption of a sealed fault is valid.

**Migration to Upper Layers**

The upward migration in the model is a feature of the base case setup, but data from the field are not consistent with this. It is therefore important to learn what controls this, so that we know which variable must be validated.

One hypothesis was that the original permeability map had unfortunate contrasts; that there were points at the top of Stø 2 where the neighboring column had lower permeability than the cell above in Stø 3. Switching to the new permeability map with lower contrasts did not alleviate the problem of extensive upward migration in the base case setup.

The map only shows the isotropic permeability with anisotropy between horizontal and vertical flow as a variable parameter imposed on top of it. It is useful to look at the combined effect of the permeability contrast, the difference in layer characteristics, and the direction of flow.

We can therefore define effective anisotropy as a measure of

\[ K_{\text{eff}} = \frac{K_z (\text{Stø 3})}{K_x (\text{Stø 2})} \]  

Here this role can be filled by other variables than permeability alone, such as the capillary entry pressure. Combining several of these, with values which are not drastic in themselves, can result in a strong ratio in total. For instance, having a one order permeability contrast between Stø 2 and Stø 3, two orders of anisotropy between horizontal and vertical flow and two orders of capillary entry pressure would lead to a whole five orders of ‘effective anisotropy’. In the simulations used in the following analysis, only the anisotropy parameter was changed in order to achieve this effect. The following results should therefore only be interpreted qualitatively.

In order to determine how much has migrated out of Stø 2, a calculation was performed of the mass of CO₂ still located in the Stø 2 layer in the F-segment, relative to the mass of CO₂ injected. As there is already CO₂ in the gas cloud and this gas cloud will migrate away due to draw from the production wells, this creates a book-keeping problem.

However, as the fraction of existing CO₂ in the gas is relatively low, at around 5%, and the fraction at the plume front is fairly high, this problem was bypassed by only counting cells whose CO₂ mass fraction was higher than 10%.

The simulations, on the other hand, yielded results that were indicative of an unstable numerical process, as at some points the CO₂ reappeared briefly in the Stø 2 layer after having left it, and there was no plausible explanation for this. These data points were ignored.

Figure 15 shows the resulting percentage over time for varying anisotropy rates. The graph runs to 2015 because full injection in the Stø 2 layer was only certain until then. The time of the last known seismics, where

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there is no observed upward migration, is drawn as a vertical dashed line, and assessing the validity of the various anisotropy values at this point is of interest. The graph shows that situations of relatively low effective anisotropy, of only two or three orders, have extensive migration of 30% and 15%, respectively. If any one of these was the actual level, a migration of this size would have showed up on the seismics. These levels can thus be classified as unrealistic.

This is probably true of the line for four orders of anisotropy as well, which has a migration rate of 10%. The top two lines, with only 3% and 1% migration are probably below seismic resolution, however, so effective anisotropy in the order of 1:105 or 1:106 is probable. It is worth note here that the lines diverge further with time; the amount ‘lost’ to other layers is not a constant percentage.

As for the tools available to detect and match such an effective anisotropy, this unfortunately is not observable through the bottomhole pressure of the injection well. Figure 16 shows the corresponding bottomhole pressure of the F-2 well. (The drop in the middle is again due to a period of maintenance). The development of the pressure only differs by a minute 4 bars at the end of the observation period, far less than the difference between the simulation pressure and the historic data.

(The simulations here are from a later stage of the study, using a model with updated properties compared to the one in Figure 14, offering a better trajectory but poorer level match).

Risk of Contamination in Production

There are no particular reservoir features that indicate otherwise, so the closest producer to the ramp will be the well a possible CO₂ plume would reach first. Figure 17 shows the CO₂ mole fraction of the production in this well over time for the three injection scenarios, assuming that the injection is moved from the F-segment in full, in part or not at all.

If the injection is moved in its entirety to the G-segment (the curve for 0% in Figure 17), the amount of CO₂ in production will remain at the background level for the full duration of the simulation. Although this curve seems to be completely horizontal, the underlaying figures shows that it actually increases throughout the time period, albeit very slowly, because of a change in the composition of the remainder of the existing E-segment gas.

Continuing to inject into the F-segment will lead to a much larger plume migrating up the ramp and diffusing into the existing gas in the E-segment. The bulk of the plume will not reach the production wells, but a diffusive front will, and the amount brought by this front depends on the amount injected. If the injection is split so that only 50% is injected into F-2, the plume will now reach the top of the ramp around 2030, and may be detected in the producer from 2037 onwards.

With full injection into F-2, the plume will reach the top of the ramp around 2025 and the fastest-moving portion of it will reach the producer in 2029. A gradually increasing portion will follow, but when the simulation ends in 2056, the fraction of CO₂ in the production will only have increased by 3.5 percentage points. A large part of this extra CO₂ appears to be due to numerical diffusion.

The advection-dispersion equation is expressed as:

$$\phi \frac{\partial c}{\partial t} + u \frac{\partial c}{\partial x} - ud \frac{\partial^2 c}{\partial x^2} = 0 \quad (3)$$

where \(c\) is the concentration, \(\phi\) is the porosity, \(u\) is the Darcy velocity and \(d\) is the longitudinal dispersion coefficient. A discretized
version of this equation is also an approximation to a similar equation, but where $d$ is now a numerical instead of a physical dispersion term, and is in fact half of the grid block width.

Assuming that the concentration starts out at 100% behind the initial front and 0% in front of it, the shape depicted in Figure 18 will show how the ‘smeared’ concentration will look after a certain period of time. This is the shape of the complementary error function of travel time.

By selecting a level where the concentration is so diluted that it is no longer considered part of the plume, for example a concentration below 10%, we get the relative front width from Figure 18 and can thus calculate the actual front width.

Doing this for both the physical and the numerical case gives us the following ratio for the widths $L$ of the dispersed fronts in these two cases at any given time:

$$\frac{L_{\text{numerical}}}{L_{\text{physical}}} = \sqrt{\frac{d}{2 \Delta x}}$$

where $d$ is the physical longitudinal dispersion, and $\Delta x$ is the grid block size. There are great uncertainties within the value of the longitudinal dispersion and the formulas here assume a one-dimensional flow in a homogeneous medium and a constant grid block size. They can thus only be used as qualitative guidance. Nonetheless, using values that are applicable to Snøhvit of 1 m and 250 m, respectively, we find that the numerical dispersion is an order of magnitude stronger than the physical dispersion. The latter may hence be disregarded.

If the grid resolution is increased to 120 m, we see that the end-time fraction of CO$_2$ falls from 8.25% to 6.8%. This is less than 60% of the extra fraction above the base level with the lower resolution of 240 m, which clearly indicates that a large portion of the CO$_2$ that arrives at the producer is caused by numerical dispersion. An attempt was made to run the scenario at an even higher resolution in order to see if this trend continues, but it was unfortunately unfeasible to complete it in a reasonable period of time with the computing resources available.

"There are great uncertainties within the value of the longitudinal dispersion and the formulas here assume a one-dimensional flow in a homogeneous medium and a constant grid block size. They can thus only be used as qualitative guidance."
Model Comparison for Aquifer Injection

Current implementations of the vertical equilibrium method are not yet suitable for tracking CO₂ plumes together with other gas, as the components will diffuse into each other with unclear separation.

Comparisons of the vertical equilibrium and the full-scale conventional simulators are therefore only presented for the G-segment, shown in Figure 19, where there are no hydrocarbons in the model. It is assumed here that the injection will be done in the middle of the eastern rim of the model, the boundary to Snøhvit Vest is open, and the sides to the south and the north are sealed. Injection is only done in the Stø 2 layer in this model run, as in the F-segment, in order to minimize the chance of migration of upper layers once the plume reaches the fault or Snøhvit Vest, see Figure 11.

The open boundary is modeled using a set of wells in each column, and the rate of these wells is set proportionally, so that the reservoir volume of the water produced is approximately the same as the reservoir volume of the CO₂ injected. This ignores the draw of the main field production on the G-segment, nonetheless, which is why, combined with the full field model, the plume will reach further than these simulations show. A slightly different relative permeability endpoint was also used, which is more common in CO₂-brine two-component systems, and may explain some of the differences.

Figure 20 shows how the upscaled results of the vertical equilibrium models and the full-scale models fare when compared with each other. What is of note here is that the full-scale simulators have a larger extent of the plume than the upscaled one. The main explanation for this is not that they are better at capturing the vertical dimension, but that the full-scale models do not fill the upper zone of the layer to more than around 80% saturation, while the vertical equilibrium model always fills the top layer to the maximum mobile saturation by construction, which is 85% for this run.

"The open boundary is modeled using a set of wells in each column, and the rate of these wells is set proportionally, so that the reservoir volume of the water produced is approximately the same as the reservoir volume of the CO₂ injected."
The Snøhvit CO₂ operation provides a unique data set and inspiration for research into CO₂ injection data analysis and coupling of injection pressure data with reservoir models. Key observations of CO₂ injection time series from Snøhvit have provided valuable insight into aquifer behavior.

The Snøhvit case also shows that aquifers and abandoned gas fields are not the only possible targets for CO₂ storage and sequestration, but that a satellite segment at an existing gas field with on-going production can also be a target. This section highlights the areas in which research at the SUCCESS center can be applied to modeling and investigations into future CO₂ storage projects, based on the experiences from the Snøhvit field.

Analysis of the wellhead pressure and rate data from Tubåen show that the pressure steadily increases during injection. The injection data is interpreted as porous matrix injection showing no indication of formation fracturing. Various research topics related to Tubåen have been addressed, trying to explain the unexpected increase in pressure during CO₂ injection.

Injection of CO₂ may dehydrate the aquifer, leaving salt precipitation with the potential to clog the pore space, and cause injectivity problems. The improved model for the geochemical effects supports salt formation in most saline aquifers, but injectivity challenges associated with clogging of the pore space are only important for tight high-salinity reservoirs, and where the CO₂ flows in channels.

Mixing of CO₂ and remaining hydrocarbon resources in the reservoir is a process that will alter the density and viscosity of the plume. A better equation of state for such a mixture will lead to improved modeling of the course of the sequestration. For Tubåen, the model suggests that the high salt concentrations will result in a mixture of CO₂ and methane with reduced densities and increased mobility, and the high pressure will ensure full miscibility of CO₂ and methane in a gaseous phase.

Reservoir complexity and possible sub-seismic scale faults are suggested as explanations for unexpected sealing or compartmentalization of the reservoir. Improved detection of faults is demonstrated using a combination of attribute studies and 4D seismics. Geomechanical models...
are used to demonstrate a significant difference in seal integrity when modelling the fault as drained versus undrained. The known bounding faults around the injector are found to be unlikely to reactivate during pressure build-up.

In Stø, layers containing oil and gas exist in the same field we are injecting into. CO₂ is injected below and to the side of these hydrocarbons in a brine-filled layer, but it rises due to buoyancy and migrates due the slope of the field. The migrating plume will eventually meet, and mix and diffuse interspersed with the existing hydrocarbons. This makes the case particularly challenging, as it necessitates a full three-phase, compositional run in order to keep track of the plume over time.

Simulations can illuminate phenomena that would otherwise remain obscure. However, the results of a simulation are no more reliable than the input data we supply, and in general we recommend that sensitivity studies be run to in order to identify the sizes that most influence the result. The Snøhvit simulations show large differences for some parameters, while others have virtually no effect.

The Stø study uses a model that was originally created to match production, with little emphasis on the properties around the injection site. The scope of the project limited the number of adaptations that could be made. Discrepancies between the historic data and the corresponding simulations indicate that there is a level of uncertainty that makes the results of more qualitative than quantitative use. Iterations using automated inverse modelling combined with model updating will likely improve this situation in future projects.

CO₂ that is injected into Stø is cooled in the pipeline along the seabed, and will have a significantly lower temperature than the surrounding formation water at the injection well bottomhole. The thermal effects are only applicable in a near-well region of a few hundred meters, however, and the simulations show that outside the nearest blocks, the CO₂ is already warmed by the formation brine and the model by and large acts isothermally.

Brine salinity and the short time before the plume meets a hydrocarbon leg makes convective mixing of CO₂ into the aqueous phase a negligible factor.

The sealing properties of the fault between the injection and the production segments create an effect akin to an internal boundary, and have a huge influence on the CO₂ migration pathways. Such boundaries must be surveyed even if they are far from the injector, as the pressure pulse moves more quickly than the saturation wave. A model of the entire reservoir should therefore be used.

Obstacles that are located between wells, such as the sealing properties of the faults, can be inverse modelled from the pressure response in the wells. At present, simulations based on available data do not provide a clear indication that the faults are sealing completely. Pressure development in the injection well should be continuously monitored in order to verify that the presumption of sealing faults is valid.

Conversely, the faults also provide a way for the CO₂ to migrate around this semi-impermeable zone, and in effect join the fairly permeable zones to another.
Lateral hindrances along the flow, on the other hand, cannot necessarily be detected by pressure changes. Upward migration into the upper zones is not extensive if there is a strong effective anisotropy ratio between horizontal flow in the injection zone and vertical flow through the semi-permeable zone above it, but it does not appear to be possible to use the bottomhole pressure of the injection well to determine this ratio. Current seismic images do not indicate any migration to the upper layers.

Well control and well scheduling are boundary conditions for simulations, and depend on the solution of saturation and pressure found in earlier time steps. Even though the simulation specification is set up to be the same, small differences in the solution procedure or in the default values of properties left unspecified may develop over time into deciding factors. Running the model in different simulators resulted in slightly different migration patterns, leading them in turn to begin operating the wells differently, again causing great differences. Both realizations were plausible. To avoid a narrow focus on one realization, the model should be investigated concurrently using different tools, and then compared.

Vertical equilibrium models are semi-analytical, in that they combine an upscaled, analytical model for the vertical dimension, while keeping a less expensive, full simulation for the two remaining horizontal dimensions. Such simulations are much quicker – at times in two to three orders – and can thus provide a more detailed sensitivity study with virtually identical accuracy. This approach should be used in situations where the underlying assumptions have been met; a longer time horizon and a relatively uninteresting near-well region. Simulations of injection into the G-segment using this technology produced results that match the difference between the conventional simulators.

Unfortunately, at present this approach cannot be used for the F-segment, where there is gas/oil/CO$_2$ interaction.

Although none of the scenarios tested indicated significant contamination of the main production in the E-segment, the current model data lead us to believe that there is enough injectivity in the G-segment to also move the injection there.

Based on the successful results using the current Snøhvit data set, we suggest further interdisciplinary work on the combination of detailed CO$_2$ injection time series analysis with CO$_2$ flow and pressure models on both the fault and reservoir scale in order to provide a better understanding of the wellhead pressure response to different fault properties and geological complexity scenarios.
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Snøhvit: A SUCCESS Story
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This work was funded by the FME SUCCESS center for CO₂ storage under grant no. 193825/S60 from the Research Council of Norway. The FME SUCCESS center is a consortium of partners from industry and science, hosted by Christian Michelsen Research AS.