Carbon Capture and Storage in the Skagerrak/Kattegat region

Final report

February 2012

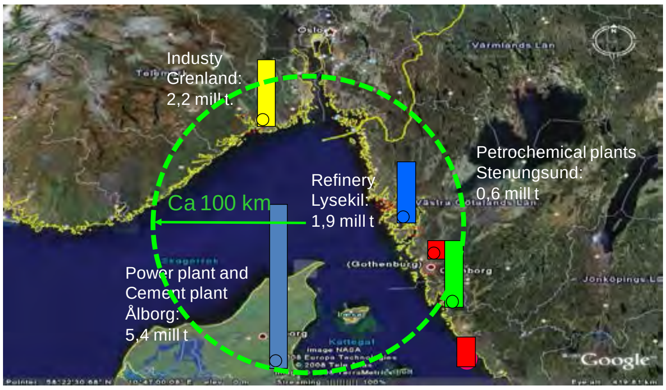
EXECUTIVE SUMMARY

Introduction

This project explored the feasibility of establishing a Carbon Capture and Storage (CCS) infrastructure in the Skagerrak/Kattegat region of southern Scandinavia. This involves assessment of the technical and economic parameters of the complete CCS chain and, in particular, identification of possible storage locations. In addition, the legal and regulatory requirements and political framework needed to establish a possible CCS solution were reviewed and evaluated. In addition to this report, extended versions of Chapters 2-5 can be retrieved from http://www.ccs-skagerrakkattegat.eu/.

This project, which received support from local industries, regional and national authorities, and the EU INTERREG IVA programme, ran from June 2009 to December 2011. During this period, close contacts between the project participants were established through partnership meetings and conferences.

Three major industrial clusters in Gothenburg (Sweden), Grenland (Telemark County, southern Norway) and Aalborg (Denmark) were targeted in this study. The potential capture from seven different plants of the targeted industries is estimated at 6 million tonnes (Mt) of CO_2 annually. If all the large industrial and power-generating emission sources (> 0.3 Mt CO_2) within the Skagerrak/Kattegat region are included the total comes to approximately 14 Mt of CO_2 per year. Therefore, a s cenario for this level of CO_2 was also investigated regarding transport and storage options. Establishing a CCS system within the Skagerrak/Kattegat region and increasing handling capacity to 14 MtCO_2/yr would account for approximately 25% of the reduction in CO_2 emissions from fossil fuels targeted for 2020 for the three Nordic countries combined.



Identification of potential CO_2 storage reservoirs in the Gassum formation within the Skagerrak-Kattegat region

This study consists of an initial screening of the main CO_2 storage sites in the area based on published work that is supplemented by new seismic mapping and interpretations of available well-logs and cores. This material was used to select the optimal traps/structures for CO_2 storage. The geological formations that were selected for more detailed studies were the Skagerrak formation, Gassum formation, and Haldager Sand/Bryne formation. Petrophysical analyses and estimations of reservoir properties were performed for the Gassum and Haldager Sand formations.

Two types of reservoir structures were identified and studied in detail: 1) large, gently dipping reservoirs in the northern Skagerrak area; and 2) closed dome structures above salt pillows in the Norwegian Danish basin.

Three aquifer models with homogenous properties and thicknesses have been developed for the most promising Gassum formation. Model 1 describes the large dipping aquifer located just south of Kristiansand with proposed injection occurring 60 km offshore and approximately 2000 m below the seabed. Model 2 describes the same dipping aquifer but at a location northwest of Jutland in the Danish sector, while Model 3 describes the Hanstholm structure.

The modelling simulates the injection of a total of 250 MtCO_2 down-flank using three injection wells over a period of 25 years. For Model 1, the CO_2 reaches the northern border after 400 years, and 7.5% of the deposited CO_2 escapes the formation after 4000 years. The remainder of the CO_2 is capillary trapped (~75%) or dissolved (~18%). In Model 2, even after 4000 years, all the CO_2 is retained within the reservoir boundaries. A total of ~25% is dissolved after 4000 years, while the remainder is capillary trapped (residual). In Model 3 (Hanstholm), a major proportion of the injected CO_2 is stored as separate-phase CO_2 and about 12% is stored dissolved in formation water. Although the Hanstholm simulation indicates that the structure can accommodate 250 MtCO_2 injected over a period of 25 years, the resulting formation pressure is rather high, making seal leakage a risk.

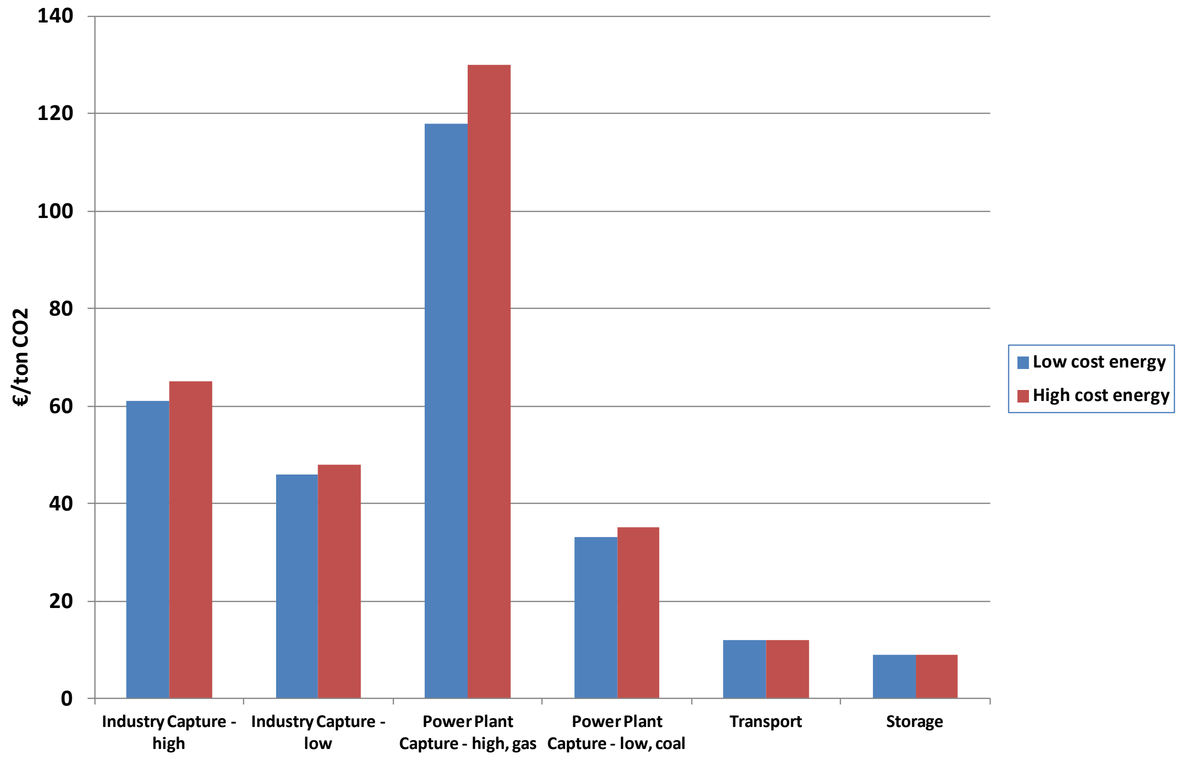
The results of the simulations for the selected storage sites are promising, although additional detailed work needs to be carried out to validate and develop these alternative geological structures into safe and reliable CO_2 storage sites. The reservoir south of Kristiansand (Model 1) is used as the primary potential storage site for the CCS evaluation described in this project.

Total chain costs for a possible CCS network

The total CCS costs per ton of CO_2 for the industrial plants are estimated as: 67–82 €/tCO_2 in a low-energy-cost regime; and 69–86 €/tCO_2 in a high-energy-cost regime. The listed variability within the same energy cost regime reflects the different capture costs at the industrial plants, whereas for transport and storage, single-cost values have been calculated assuming that the total amount going through the network is 14 MtCO_2/yr. Assuming a level of 6 MtCO_2/yr, which is the amount of industrial CO_2 available from the partners in this study, the transport and storage costs would increase by approximately 20%.

For the two power plants included in the study, the total CCS costs are 54–56 €/tCO_2 for the coal plant for low and high energy costs respectively while the corresponding cost for the gas plant are 139-151 €/tCO_2. The considerable difference in cost for the two power plants is due to the lower CO_2 content in the flue gas of the gas plant in combination with a lower annual load factor.

The figure below shows the range in capture cost for the plants investigated in this study along with transport and storage cost assuming low and high energy cost, i.e. for the fuel used in the capture plant.



The most significant capture cost parameter is the energy cost. In this study, post-combustion CO_2 capture technologies are assumed to be implemented using state-of-the-art MEA technologies for the industrial plants and chilled ammonia technology for the power plants. This implies a demand for a low-quality steam supply to the stripping part of the capture plants.

In particular, various options for using in-house waste heat recovery as part of the energy supply to the capture plant have been investigated. In some of the plants, there is sufficient heat available to provide the stripper energy through direct heat exchange, whereas in other plants, a combination with suitable heat pump concepts could be used. Using natural gas or other fossil fuels to fire the boilers would significantly increase the avoided CO_2 costs.

The CO_2 transport costs are calculated to be in the range of 12 to 14 €/tCO_2 for the different cases studied, i.e., ship, ship/pipeline, and pipeline network. These cost figures reflect the situation when the full capacity (14 MtCO_2/yr) of the chain is utilised. Under the assumptions used, ship transport from the sources to a hub in Grenland, Norway with subsequent transport by pipeline to the injection wells in the Gassum formation represents the most cost-efficient solution. However, the uncertainties in the cost estimates for the alternatives studied are all in the same order as the difference in cost estimates between the transportation options.

A major challenge when evaluating the transport part of the CCS chain is the ramping up of CO_2 flows to the full capacity of the network. A sensitivity calculation shows that the transport cost would increase up to three-fold depending of the strategy chosen for handling the various load situations.

The cost of CO_2 storage is estimated based on the available (albeit limited) information as approximately 9 €/tCO_2, assuming that 14 MtCO_2 is injected annually. The main cost-driving parameter is the number of injection wells, which in the economic assessment is assumed to be five.

Overall, the techno-economic analysis shows a significant gap between the estimated CCS costs and the current cost of emitting CO_2 to the atmosphere. Even assuming a future scenario in which the cost of emitting CO_2 is 45 €/tCO_2, there is a lack of economic incentive for implementing CCS in the region investigated.

Main legal challenges facing CCS identified in the present study

The review and evaluation of the regulatory framework related to CCS identified the following key challenge areas:

Prohibition of the export of CO_2 under the London dumping protocol

The London dumping protocol is an international agreement for the protection of the seas against the dumping of waste. An amendment to the protocol was made in October 2009 to facilitate the export of CO_2 streams for disposal, provided that an agreement or arrangement could be entered into by the countries concerned. It is difficult to predict when this amendment will take effect. Until such time, the export of captured CO_2 from Sweden or Denmark to Norway for the purpose of under-seabed storage remains prohibited under international law.

Nature protection areas and pipeline routing

The existence of protected marine areas, particularly those designated as *Natura 2000* areas according to the EU's habitat directive, may have a significant effect on the laying of pipelines from some of the major CO_2 point sources in the region. This has been identified as a potential problem for Nord-Jyllandsverket in Aalborg, Preem in Lysekil, and Borealis in Stenungsund.

Current non-viability of ship transportation of captured CO_2 under the EU Emissions Trading Scheme

The EU Emissions Trading Scheme (EU ETS) does not currently allow for captured CO_2 to be transported by ship as part of a CCS operation. Although this type of transport is not prohibited, using ships in a CCS chain will have consequences in terms of eligibility for relief from the obligation to surrender allowances for captured CO_2. This problem has been acknowledged by the EU Commission. However, any solution is likely to require cumbersome and time-consuming amendments to the complex legislation.

Uncertainties regarding financial securities required from storage operators

The EU CCS directive requires the operator of a storage site to provide evidence of financial security, in order to ensure that all obligations arising under the storage permit will be met. These include closure and post-closure requirements and obligations arising from the inclusion of the storage site under the EU ETS. It remains unclear what level of financial security will be required until a significant amount of information regarding a particular storage site has been collected and a dialogue has been initiated with the competent national authorities.

Vague rules on third-party access to the CCS infrastructure

The ability of third parties to access the CCS infrastructure, including storage sites and pipelines, would ensure competition and effective utilisation of the infrastructure. Whether or not the rules to be established in Denmark, Norway, and Sweden will be sufficiently clear and precise to promote investor confidence remains to be seen.

Coordination across the region – different procedures and different timelines

The building of the CCS infrastructure, including the land- and sea-based pipelines, possibly ports, and storage sites will entail the procurement of several permits. The assessment of permits for individual parts of the project (e.g., a particular pipeline stretch) may also include assessments of the overall environmental and health impacts of the entire CCS infrastructure. Ten years is not an overly pessimistic estimate of the time required to obtain all the necessary permits, allowing for several appeals.

Issues of importance to potential stakeholders

This study reveals a number of critical issues that need to be resolved before CCS can be implemented in the region.

One of the main problems relates to the time-consuming procedures required to implement appropriate legal frameworks and to obtain permits to establish a CCS network, as well as agreements for the transportation of CO_2 across national borders. Furthermore, differences exist between the countries involved with respect to policies to address the climate challenge, which increase the urgency for finding CCS solutions. A coordinated action for climate issues is required to avoid uncertainties and to create a predictable operating environment for the industries in the region.

Qualification of the Gassum formation as a candidate CO_2 storage site in the Skagerrak/Kattegat region requires further investigation. The responsible national authority should initiate the relevant work and include this site as part of the mapping of CO_2 storage sites on the Norwegian continental shelf. Until this is accomplished, there will be little motivation for industries to proceed with work on the upstream part of the CO_2 chain.

There is a lack of economic incentives for building the CCS network. Even with a future CO_2 emission cost of 45 €/tCO_2 there is a gap of 10–20 €/tCO_2 to be covered to meet the cost of the least expensive capture system described in the present study. This gap is even larger if the transport and storage infrastructure is constructed and operated for a network of less than full capacity, as will undoubtedly be the case for the establishment of the transport and storage infrastructure over time. The national governments have a responsibility to develop and establish adequate financial and funding mechanisms to facilitate CCS implementation.

CONTENTS

1 INTRODUCTION

1.1 Project background and scope

The Scandinavian countries intend to reduce considerably their CO_2 emissions.

Within the Skagerrak/Kattegat region, there are several industrial and energy-related clusters. Within a radius of approximately 100 km 14 $MtCO_2$ are emitted to the atmosphere from large point sources, each with an annual emission level of 0.3 $MtCO_2$ or greater.

The industrial clusters typically constitute a significant part of the value creation in the local communities, in terms of long-term employment, business for local sub-suppliers, and tax and fiscal incomes to the community, and contribute to export values and the Gross Domestic Product.

Faced with a demanding future, dictated in part by the necessity for a low-carbon regime, industries need to adopt a common approach to developing sustainable ways to handle carbon and minimise costs. By taking a proactive role in these matters, one may reduce the threat of whole industrial sectors being transferred to other countries with less stringent regulations regarding climate gas emissions.

Moreover, establishing a well-functioning infrastructure for addressing the CO_2 challenge may attract new industry to the region.

Before companies can start to budget the costs for the installations needed for CO_2 capture, there is an urgent need for technical and economical information about the future transportation and storage infrastructure.

This project addresses the entire CO_2 value chain, including CO_2 capture at industrial sites, finding an optimal CO_2 transport infrastructure, and the use of available geological and seismic data to identify a possible storage site.

Furthermore, the regulatory framework that must be in place to implement CCS in this region is examined. As is typical for regional projects across national borders, several trans-boundary issues and legal matters need to be resolved.

The project was developed together with regional industry, central and regional public authorities, and the R&D centres of Tel-Tek (infrastructure of CCS) and the University of Oslo (Geosciences) in Norway, and Chalmers University of Technology (carbon capture) and the University of Gothenburg in Gothenburg, Sweden (legal framework).The project was initiated in June 2009 and concluded in December 2011.

This report also covers an associated project, which was funded by Gassnova/Climit (Norwegian Governmental agencies supporting research and development in CCS) and the main actors in industry and part of the energy sector in the region. The aim of this project is to map possible locations for CO_2 storage.

The participants in this part of the overall project were Gassnova, Tel-Tek, Statoil ASA, Skagerak Kraft AS, Yara Norge AS, Esso Norge AS, Preem AB, Vattenfall AB, Borealis AB, Göteborg Energi, University of Oslo (Department of Geosciences) and SINTEF Petroleumforskning.

The INTERREG/Swedish Energy Agency-sponsored part of the project had a total funding of 11 million NOK, and the Gassnova/Climit sponsored (associated) project had 8 million NOK.

In a recent IEA CCS Roadmap report, the present project, together with two other CCS projects, the Rotterdam initiative (NL) and the Yorkshire and Humber Initiative (UK), both of which are briefly described later, was described as an example of how one may achieve economies of scale by setting up a common infrastructure for the transport and storage of CO_2 from clusters of possible sources.

The present project differs from the abovementioned projects in two major aspects: 1) a relatively large share of the CO_2 is derived from industry (not only the energy sector); and 2) it is a multinational project.

1.1.1 The Skagerrak/Kattegat region

Industrial CO_2 sources contribute approximately 25% of the total Scandinavian (NO, DK, SE) greenhouse gas emissions. The industrial sources cover several branches, from petrochemicals, fertilisers, refineries, and cement, to the pulp and paper industry. All of these industries are facing different situations regarding competition and business challenges (Skagerrak/Kattegat, 2011). The carbon emissions in this region are related to both energy demand and specific industrial process sources. In addition, potential sources located not far from the core area could be linked to a future common CO_2 transport system. Therefore, there is a platform for investigating viable and cost-effective transport systems, provided that a safe CO_2 storage site that has sufficient storage capacity and is located near the sources can be validated.

1.1.2 Industry-related sources

The industrial CO_2-containing emissions vary with respect to concentration and total pressure, and are often distributed among several local point sources within a particular industrial site. In some cases, there are business-related drivers for separating the CO_2 from the main product, e.g., in ammonia and fertiliser production and natural gas processing and conditioning, which generate concentrated CO_2 emissions.

State-of-the-art carbon capture requires large quantities of energy, typically low-quality steam for stripping CO_2 from amine-based solvents, which represents one of the possible post-combustion technologies. Within large industrial sites there may be considerable potential for waste heat recovery, which may be utilised as an energy source for the CO_2 capture plant.

1.1.3 Multinational project

The project has a number of industrial and energy-related partners and is linked with another CCS project (Gassnova Project, 2011), which is aimed at looking more closely into storage alternatives within the Skagerrak/Kattegat region.

These projects acknowledge the financial support from the EU INTERREG programme and the Gassnova Project, in addition to funding by industrial partners and local communities.

One of the main objectives of the present project is to estimate the access costs for the industries in this area for using a common CO_2 transport and storage infrastructure, <u>independent</u> of any limitations set by national borders. As is typical for projects across national borders, several cross-border issues and legal matters need to be tackled, and these are properly addressed within the current project.

1.2 Other relevant CCS projects

Worldwide, a limited number of full-scale integrated CCS projects are in the process of execution or operation. Typically, these projects have relatively strong economic incentives, such as the utilisation of CO_2 in EOR projects or are tax-motivated in combination with a necessity to remove CO_2 so as to meet sales-gas specifications.

Man other CCS projects are at the planning or visionary stage at different locations worldwide. A substantial proportion of all the CCS projects worldwide involves so-called large-scale integrated projects, in which the complete value chain, from capture to storage, is addressed.

This short overview is restricted to a few projects in northern Europe that are regarded as relevant to our project. These projects are all integrated projects in which a number of emission sources are connected within an integrated infrastructure for transport and storage. All projects reviewed are at the planning or visionary stage.

1.2.1 One North Sea

The One North Sea study, which concluded with a final report titled “A study into North Sea CO_2 cross-border transport and storage” (One North Sea, 2010), was carried out for the Norwegian and UK governments on behalf of the North Sea Basin Task Force. This task force includes the Netherlands and Germany in addition to the two aforementioned countries.

A main driver for the One North Sea study was the fact that there is both an abundant storage capacity and a large cluster of CO_2 sources in and around the North Sea basin. Combined with the presence of world-class research institutes and commercial stakeholders, this suggested that the North Sea countries could be natural leaders of the development and deployment of CCS technology in Europe.

About 50% of the European storage potential for CO_2 is located under the North Sea. The clustering of sources and possible storage sites provides opportunities to develop efficient transportation and storage networks. By 2030, CO_2 volumes of up to 270 Mt/year could be captured and stored in this region. It is concluded in the One North Sea study that in the initial period no cross-border transport is necessary. Several countries are possibly involved, and at a later stage, i.e., beyond 2020, cross-border transportation of CO_2 could become increasingly important, and eventually account for up to 25% of the CO_2 stored. Based on these conclusions, the One North Sea study contains an extended treatment of the legal and regulatory issues connected with bringing captured CO_2 between countries.

1.2.2 The Yorkshire and Humber Initiative

The Yorkshire and Humber Initiative was commissioned under the auspices of the Carbon Capture and Storage Partnership for Yorkshire and Humber, a stakeholder group convened by “Yorkshire Forward” to stimulate the development of a CCS network in the region. This summary is based on the report “A carbon capture and storage network for Yorkshire and Humber” (Yorkshire Forward, 2010).

This region of the UK emits around 60 M tCO_2/year from large single-point sources. The region is relatively close to saline aquifers and near-depleted oil or gas reservoirs in the southern part of the North Sea, which might be exploited as future storage sites.

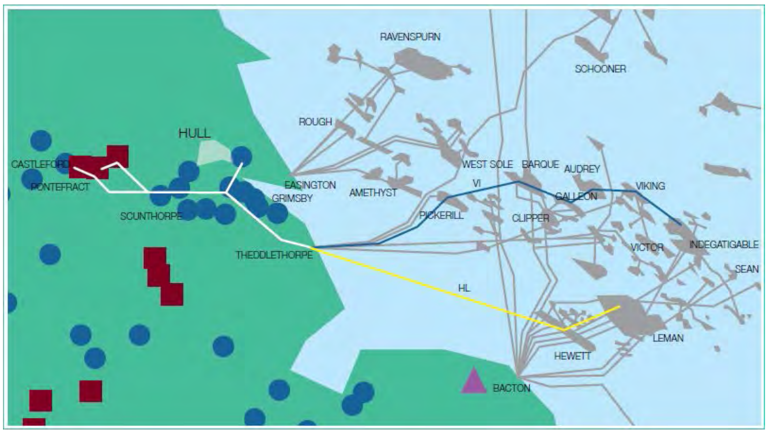


Figure 1.1. Overview of the proposed structure of the Yorkshire and Humber CCS system

CCS in this region could be very cost-effective, as the transport distances are short, and the development of storage sites could be realised at moderate cost. Figure 1.1 illustrates the region and a possible CO_2 pipeline network. As the main sources are all located along a corridor that points towards possible storage sites offshore, the design of a cost-efficient transport network seems relatively straightforward.

A major conclusion from the Yorkshire and Humber Initiative is that linking all large sources into a common network is much more cost-effective than the alternative stand-alone solutions.

1.2.3 The Rotterdam Climate Initiative (RCI)

The relatively high concentration of large-scale CO_2 emitters, such as refineries and energy-related operations, and the short distance to significant storage capacity, makes the Rotterdam region highly suitable for an early demonstration of CCS (RCI, 2009).

The Rotterdam region has a number of relatively pure CO_2 sources, totalling about 2 Mt/year, which are easily accessible. Some of this CO_2 is already used commercially, e.g., in greenhouses connected by a pipeline system. Part of this CO_2 volume could also be used in early CO_2 transportation and storage demonstration projects.

Through CO_2 capture projects connected to new power plants and the production of hydrogen, the amount of CO_2 could eventually be increased to approximately 5 Mt/year.

In the longer term, this early demonstration network could be expanded to handle up to 20 $MtCO_2$ annually. Included in this volume are future plans for retrofitting CO_2 capture to existing industrial emitters. These measures are expected to incur the highest single cost for system development. The plan is to use depleted gas and oil reservoirs as storage sites.
The use of ships for transport has been studied, with the conclusion that the cost would be comparable to that that of pipeline transport. In the shipping solution, a concept whereby the cooling of CO_2 is achieved through evaporation of LNG has been looked into as an option.

Original plans in the RCI were for an early user network to enter operation by 2015. The long-term transport network of the RCI is shown in Figure 1.2, where the offshore part is planned as the last part of the development. The early phase of CO_2 transport could be based on utilising the existing oil and/or gas pipeline infrastructure. At a later stage, new pipelines would have to be built.

Figure 1.2. Final pipeline infrastructure for the CCS system proposed by RCI.

The estimated cost for utilisation of the transportation and storage network (included compression) is 25 €/tCO_2.

The connection to Barendrecht, with local on-shore CO_2 storage in a depleted gas field, was planned as an initial phase. After strong opposition from the local community, this has been put on hold.

1.3 Nordic CCS projects

1.3.1 Top-Level Research Initiative

This brief summary of the Top-Level Research Initiative is based on the report "Potential for carbon capture and storage (CCS) in the Nordic region", which is a research project initiated and funded by the Nordic Innovation Centre. Several research institutions in the Nordic countries were involved, and the work was coordinated by the VTT Technical Research Centre in Finland. The objective of the study was to create an overview of the potential application of CCS in the Nordic countries.

The mapping of CO_2 emissions from major sources and the mapping of storage possibilities constituted important parts of this study. The study provides an overview of relevant CCS technology development in the Nordic countries. Public awareness of CCS and the political issues relevant to the deployment of CCS are also addressed.

Altogether, 277 emissions sources, each with annual CO_2 emissions exceeding 0.1 Mt/year, were mapped. Of these, 31 sources had CO_2 emissions exceeding 1.0 Mt/year, accounting for a fossil CO_2 volume of 57 Mt/year. This represents about 26% of all fossil CO_2 emissions from the Nordic countries. About 45% of these large sources were energy-related (power or/and heat). The cement and steel industries, together with oil refineries and petrochemical plants, constitute a substantial part of the remaining emissions.

A map indicating the main CO_2 sources and the proposed clustering of these sources is shown in Figure 1.3.

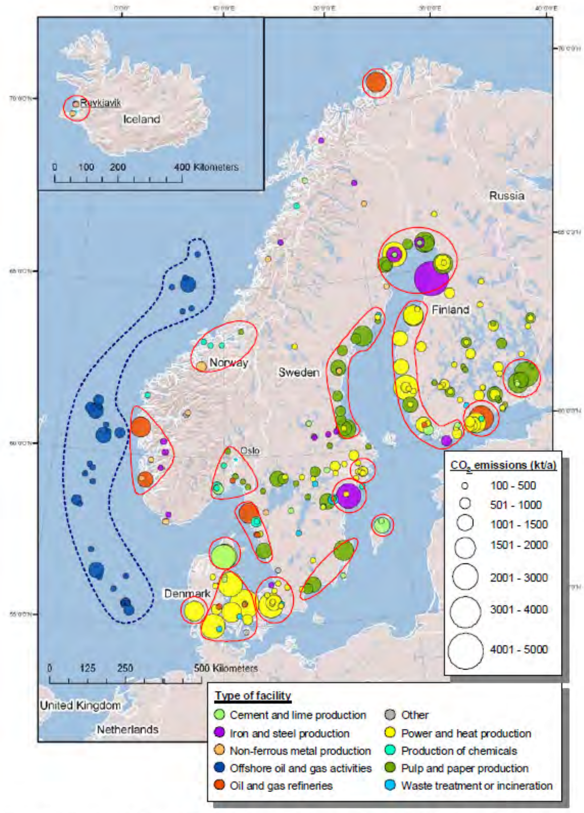


Figure 1.3. ***Clustering of large CO_2 emitters in the Nordic region***

Most noteworthy are the clusters around south-eastern Norway, the Gothenburg region of Sweden, and northern Jutland. These CO_2 clusters are mentioned as possible early candidates for CCS, as they contain a number of large point sources, and possible storage sites not too far away could be available.

Identifying potential storage sites in the Nordic region was also part of the study, and the main locations identified were in the west of Norway (The Utsira aquifer is included) and on-shore and offshore sites in Denmark, which are partially relevant to our present study. The storage potential for Norway was estimated at 84.6 $GtCO_2$ and that for Denmark at 1.7 $GtCO_2$. The potential storage capacity in Sweden was regarded as modest, and in the case of Finland, limited to chemical binding to minerals.

The report for the Top-Level Research Initiative contains no specific proposal for a transport and storage network, and cost estimates for CO_2 capture, transport, and storage are only referred to in general terms.

1.3.2 The Baltic Sea – project

The Baltic Sea – project, which was initiated by the Swedish industry and the Governments Energy Agency, focuses on CO_2 emissions, and possible CCS projects, in the Baltic region.

This summary of the Baltic Sea – project, based on r eports emanating from the study, is limited to those areas and projects that are of special interest to our project.

One of the reports (Swedish energy agency, 2010) is highly relevant to our project, in that it concentrates on a possible infrastructure for CCS, based on connecting (Swedish and possibly Danish) clusters of large CO_2 sources in the Baltic region and possible storage sites located in the Baltic or offshore Norway. Clusters of emitters and possible storage sites have been mapped.

The Baltic Sea – project concludes by identifying two main potential storage sites in Sweden, one south of Gotland, and one south of Skåne. The theoretical, and apparently optimistic, storage potentials of these sites are estimated at 1.6 and 20 billion tonnes CO_2, respectively.

Storage potentials for onshore and offshore sites in Denmark, of which the Thisted formation (up to 11 billion tonnes CO_2) is by far the largest, are also mentioned.

The uncertainty related to these estimated storage potentials is in the range of a factor of 10, which indicates that further studies are necessary to allow better estimations.

The Baltic Sea project includes a number of initial ideas concerning possible transportation systems for connecting CO_2 emission clusters with possible storage sites. Some of these concepts are based on cross-border transportation, which is highly relevant to the Skagerrak/Kattegat project.

For the most relevant volumes and distances, pipelines seem to be the most cost-effective transport option, with the cost estimated at 4–8 €/tCO_2. The large gap between the upper and lower estimates is due to uncertainties linked to various conditions, such as unit cost for piping, CO_2 volumes, and time-scales. The cost of initial compression of the CO_2 to approximately 100 bars is not included.

The cost of ship transportation was also estimated, and was found to be of the same order of magnitude as the cost of pipeline transport.

Due to the significant economy of scale, it is generally concluded that collecting larger volumes of CO_2 (where possible) into larger pipelines is much more cost-effective than establishing a system with many small and (partly) parallel pipelines.

1.4 References

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2 CO_2 CAPTURE IN THE SKAGERRAK/KATTEGAT REGION

In 2008, Denmark, Norway and Sweden combined emitted around 180 Mt GHG (CO_2e), which included 145 MtCO_2, not including LULUCF (Land Use, Land Use Change, Forestry). Table 2.1 shows the number of installations that emitted more than 100 ktCO_2 in Denmark, Norway and Sweden in 2007 (VTT, 2010).

Table 2.1. ***Number of installations in Denmark, Norway and Sweden emitting more than 100 ktCO_2 per year in 2007***

	No. of installations emitting >100 ktCO_2 in 2007	Biogenic emissions (2007) MtCO_2	Fossil emissions (2007) MtCO_2
Denmark	47	2.1	29.1
Norway	57	1.3	23.7
Sweden	88	29.1	19.0

Source: VTT (2010)

Expanding the Skagerrak/Kattegat region southwards to comprise Copenhagen and Malmö, there are at least 27 installations that each emit more than 100 ktCO_2 annually, with combined CO_2 emissions exceeding 30 Mt. Figure 2.1 shows all the sources in the region that emit at least 100 ktCO_2 (biogenic or fossil. Individual plants are indicated in the figure with differently coloured dots as follows: coal power, black; gas (and waste)-fuelled, red; cement, purple; refineries, yellow; chemical, blue; pulp and paper, green; and steel, grey.

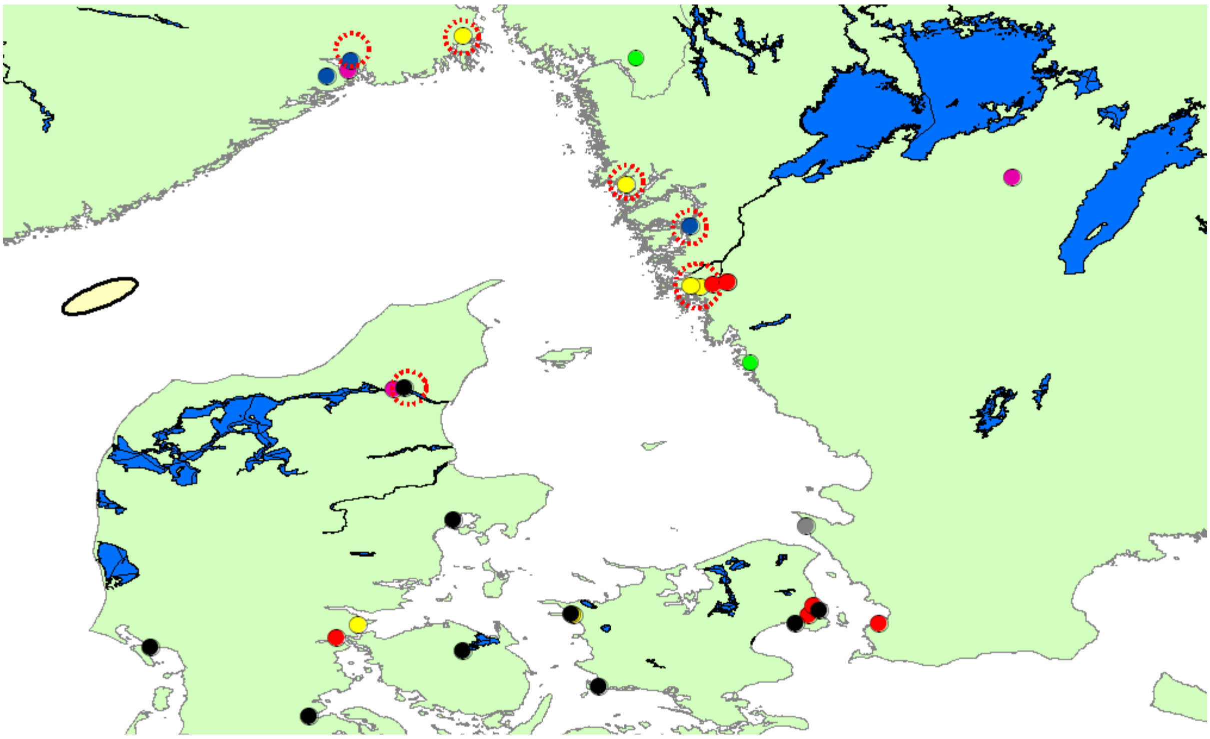


Figure 2.1. ***CO_2 sources in the region with annual CO_2 emissions exceeding 100 kt.***

In this study, capture has been assessed in detail for seven of the plants, while transportation schemes have been investigated for all the plants. The seven plants investigated in this study are marked with a red dotted circle (see also Table 2.2). It should be noted that for Gothenburg only the plants farthest to the east and west within the circle have been investigated (the Ryaverket power plant and the Preemraff refinery). Also shown is the potential storage site investigated in the present study (light yellow ellipse; see Chapter 3). The indicated size and area of the storage site are for illustrative purposes only.

Sources that easily could be added to the analysis (i.e., for which CCS could be an option) beyond the seven described below, include ten power plants, two refineries, and a cement plant in Denmark, with combined emissions of approximately 17 $MtCO_2$, plus a gas-fuelled power plant, a steel mill, and a paper mill on the west coast of Sweden, with combined annual emissions of approximately 2 $MtCO_2$.

2.1 CO_2 sources analysed in this project

The study includes three refineries, two chemical plants, and two power plants (Figure 2.1). In contrast to power plants, CO_2 emissions from industrial sources often originate from several sources within each facility, which of course complicates the process and increases the cost for capture. It is also important to note that the sources within a specific plant may differ in terms of the quantity and quality of the CO_2 and, thus, also in terms of capture cost. This work investigates each plant on an aggregated level. Table 2.2 lists the industries and power plants that are investigated along with their approximate annual CO_2 emissions and the number of relevant sources at each facility. The specific cost of CO_2 capture is likely to increase with lower total emissions and increasing number of emission sources.

Table 2.2. ***Plants analysed in the present project, showing their annual CO_2 emissions and the numbers of CO_2 sources at each facility***

Industry	**Country**	**Installation name**	**CO_2 emissions kt**	**No. of relevant CO_2 sources**
Refinery	Sweden	Preemraff Lysekil	1,800	4
Refinery	Sweden	Preemraff Gothenburg	544	2
Refinery	Norway	Esso Slagentangen	365	9
Chemicals	Norway	Yara Porsgrunn	726	3
Chemicals	Sweden	Borealis Cracker	730	9
Power station	Denmark	Nordjyllandsverket	2,000	1
Power station	Sweden	Ryaverket	400	1

2.2 CO_2 Capture Technologies

Currently, no commercial technologies for large-scale CO_2 capture are available. The technologies that are closest to application for CO_2 capture can be divided into three groups: 1) pre-combustion (Figure 2.2a); oxy-fuel combustion (Figure 2.2b); and post-combustion (Figure 2.2c). The latter technology is the main focus of the present work; its general features are described in the following chapter. Another promising CO_2 capture technology, not included in Figure 2.2, is chemical looping combustion, which has the potential to reduce the costs for the separation of the CO_2. However, at present, this process seems to be further from commercialisation than the alternatives listed above.

Pre-combustion removal is based on g as production (H_2, CO, CO_2 etc.) from an oxygen-blown gasifier (Figure 2.2a). The gas is shifted to H_2, during which the CO is transformed into CO_2, which enables removal of the CO_2. The remaining hydrogen-rich gas is then used instead of the carbon-rich fossil fuel. This technology still requires the development of a gas turbine that uses hydrogen as fuel or a competitive fuel cell technology.

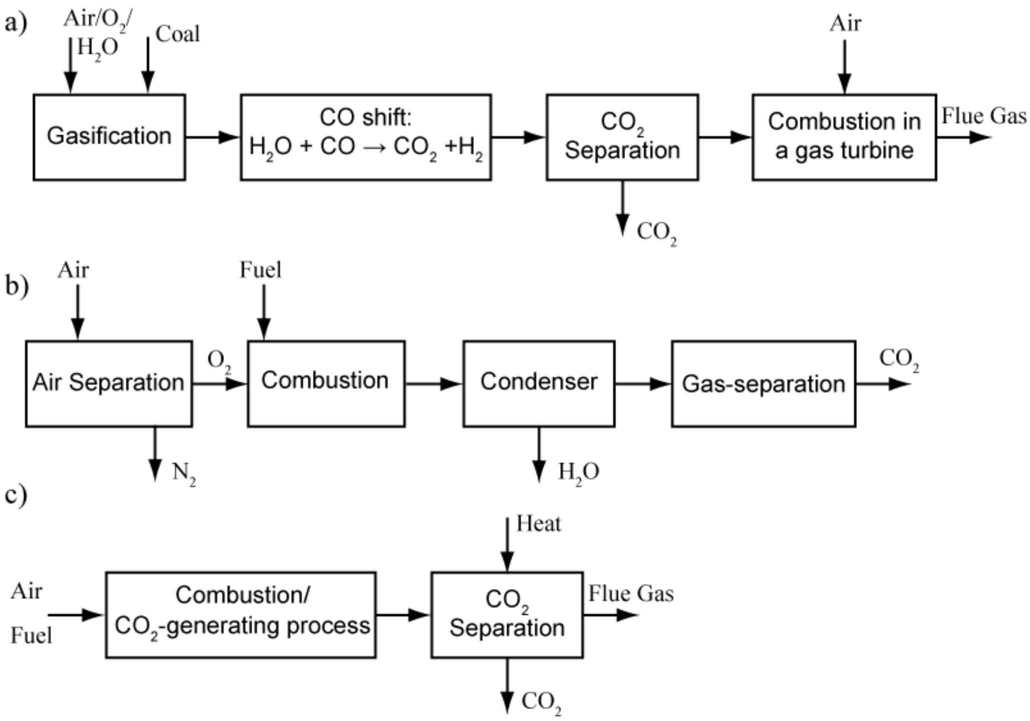


Figure 2.2. ***Alternative processes for CO_2 separation in connection with power production: (a) Pre-combustion; (b) Oxy-fuel combustion; and (c) Post-combustion.***

During oxy-fuel combustion (Figure 2.2b), the fuel is converted with oxygen of high purity to obtain a CO_2-rich flue gas (i.e., without the presence of air-borne nitrogen). Typically, a large fraction of the flue gas is recycled externally to the combustion chamber to achieve conditions similar to air-firing. Oxygen is produced in cryogenic air separation, and the development of oxygen production alternatives with lower energy requirement is an important area of research. Together with post-combustion, oxy-fuel combustion is the main candidate for the near-term demonstration of CO_2 capture, although most research projects are devoted to power plants.

In the post-combustion process (Figure 2.2c) the fuel is converted in a traditional way. The CO_2 is then removed from the flue gases by chemical absorption. Post-combustion capture has the advantage that there is no requirement to integrate the capture process with the fuel conversion, which makes it suitable for the retrofitting of CO_2 capture to existing plants as well as for industrial application of CO_2 capture. Therefore, this technology is the main focus of the present work and is discussed in further detail below.

2.2.1 Post-Combustion Capture

The basic principles of the post-combustion capture process are illustrated in Figure 2.3. The flue gas enters at the bottom of the absorption column. The liquid absorbent (CO_2 lean) is introduced at the top of the absorption column. When the absorbent meets the flue gas, the CO_2 is absorbed into the liquid, while the remaining gases exit at the top and are emitted. The CO_2-rich solution exits the bottom of the column and is transferred to a second column, the desorber. In the desorber, the temperature is raised until the CO_2 is released from the liquid. The pure gaseous CO_2 exits the top of the desorption column and is compressed before transport. The energy required for desorption is supplied to the reboiler. The CO_2 lean stream is recycled back to the absorber.

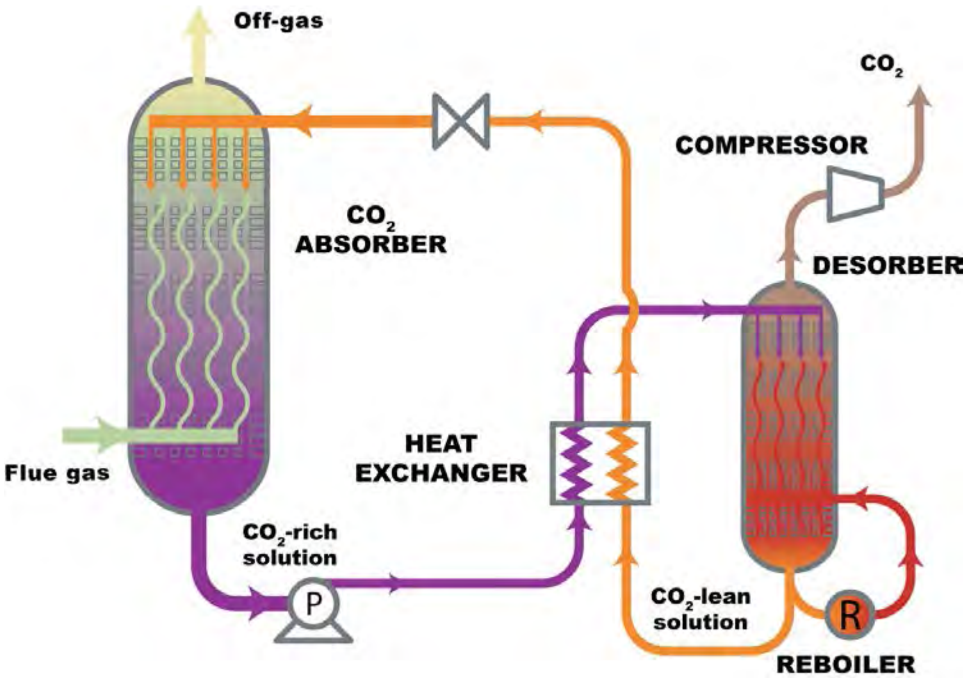
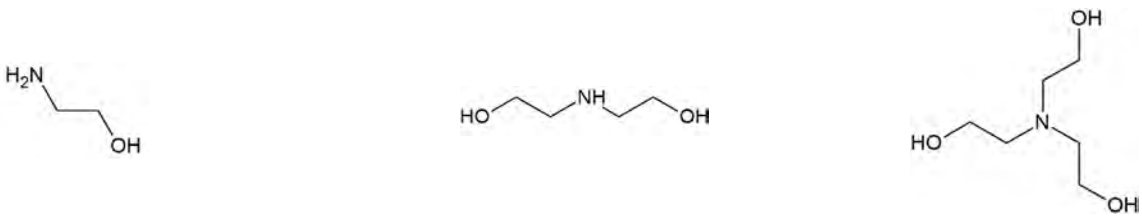


Figure 2.3. Schematic of the CO_2 absorption process. Source: Björk and Aronsson (2011).

Several different solvents can be used to absorb CO_2. The solvent is crucial for process performance parameters, including heat demand, capture ratio, and size of the absorption/desorption columns. Amines are commonly used, and monoethanolamine (MEA) is the most commonly used CO_2 absorbent. However, the possibility of using aqueous ammonia to absorb CO_2 has recently received attention due to its promising performance. The process described in Figure 2.3 is rather independent of the absorbent; the operating temperature and pressure of the units might vary to some extent, and extra units to treat the off-gases might be required depending on the volatility of the solvent.

Amines

Alkanolamine-based solvents are well known for their ability to absorb CO_2 (the name "alkanolamine" is commonly shortened to "amine"). Amines can be classified as primary, secondary or tertiary, based on the degree of substitution of the nitrogen atom. The difference depends on the molecular and structure formula, as illustrated in Figure 2.4 by monoethanolamine (MEA) (Figure 2.4a), diethanolamine (DEA) (Figure 2.4b), and triethanolamine (TEA) (Figure 2.4c). The reactivity of the solvent with CO_2 and the heat of reaction decrease with increasing degree of substitution. Therefore, primary or secondary amines are often blended with a tertiary amine to reduce the cost of solvent regeneration. Another method to reduce the cost of solvent regeneration is to produce sterically hindered amines (Vaidya and Kenig, 2007), which also are more resistant to degradation. MEA is the most commonly used solvent.



a) Monoethanolamine (MEA) b) Diethanolamine (DEA) c) Triethanolamine (TEA)

Figure 2.4. Molecular structures of different types of amines

MEA is relatively cheap owing to its commercial use and availability. Furthermore, MEA has high-level reactivity and facilitates high-volume acid gas removal at a high absorption rate. The major drawback of MEA is the high heat of reaction between MEA and CO_2, which entails high energy requirements for solvent regeneration. Typically, MEA is reported to have a regeneration requirement of 3,700 kJ/kg. Furthermore, the degradation of MEA is an issue. Most of the degradation is due to reactions with oxygen, although MEA may also be subject to carbamate polymerisation (at temperatures above 100°C) and thermal degradation (at temperatures above 200°C) [Davidson, 2007]. MEA is also sensitive to the presence of SO_x, which must be removed before the absorption step. Degradation of the solvent has a negative effect on plant economics, as the solvent needs to be replaced and it may also lead to the emission of harmful degradation products. F inally, MEA is corrosive and may damage process equipment.

The post-combustion processes based on MEA follow the schematic shown in Figure 2.3. The absorption takes place at atmospheric pressure and in the temperature range of 40–60°C. The regeneration of solvent and release of CO_2 occur at slightly elevated pressure (1.5-2.0 bar) and in the temperature range of 100–120°C.

Ammonia

Ammonia is a compound of nitrogen and hydrogen, with the formula NH_3. Owing to its low cost and commercial availability, it is a possible alternative agent for CO_2 capture. Currently, the largest ammonia pilot plants are almost at a scale of 100 ktCO_2 captured per year. The energy requirement for regeneration is low compared to amines. This is due to the lower heat of absorption of $CO_2$by ammonia than by amines (2,500 kJ/kg CO_2) (Darde *et al*., 2010). Other positive aspects are that ammonia is less corrosive and undergoes less degradation compared to MEA (Wang *et al*., 2011). Furthermore, ammonia is not sensitive to sulphur and may instead be used to capture SO_2 and NO_x (Gal, 2004b).

The use of ammonia as an absorber also has some disadvantages. The reaction of CO_2 with ammonia generates solid ammonium carbonate and bicarbonate, which impose special requirements on the equipment used. Although it is possible to operate the process to avoid the formation of solid products, this will have negative consequences for plant performance. Furthermore, initial studies have shown that ammonia has a lower reaction rate than MEA and as a consequence, requires larger absorption columns. Ammonia is also highly volatile and the amount of unreacted ammonia (slip) is high compared to the use of amines.

There are two proposed alternatives for the ammonia process, which differ mainly with respect to the temperature of absorption. The most commonly discussed option is the so-called “chilled ammonia process” (CAP), which is also discussed in the present work. In CAP, the absorption takes place in the temperature range or0–10°C. This lowers the amount of ammonia slip, although it places high demands regarding the level and quality of cooling in the absorber. To be competitive, the precondition for the chilled ammonia process is access to large volumes of cooling water at a low temperature (Jilvero *et al*., 2011). The desorption step takes place in the temperature range of 100–150°C and at operating pressures ranging from 2 bar to >100 bar. The possibility to regenerate at elevated pressures is beneficial for the CO_2 absorption process, as it requires much less energy to compress the liquid solvent than the gaseous CO_2.

2.2.2 Safety considerations related to CO_2 Capture

Most capture plants will be subject to a compulsory Environmental Impact Assessment under EU law (see Chapter 5 for details).

Discussions and concerns about the safety related to the capture process itself have mainly focused on the health effects of amines and their derivatives (see Section 2.2.2). During the capture process, some of the amines that escape from the recycling process will be emitted into the air and form compounds, such as various nitrosamines and nitramines, some of which are highly carcinogenic. According to the Norwegian Institute of Public Health (NIPH), the cancer risk will depend on how much of the compound is formed, released, and decomposed in the atmosphere by light, and how carcinogenic the substances are. Therefore, NIPH has recommended very strict emission limits for the total concentrations of nitrosamines and nitramines in air and water (0.3 ng/m^3 air). This recommendation has led in turn to the Norwegian Government postponing the final investment decision on a full-scale carbon capture plant at Mongstad. However, in late August 2011, t he Norwegian Climate and Pollution Agency (KLIF) stated that new research results on the emissions of amines and their degradation products showed far lower concentrations of nitrosamines and nitramines than were previously assumed. However, KLIF emphasises that the findings are only valid for the capture plant at Mongstad and cannot be extrapolated to capture plants at other geographical locations.

2.3 Applied Methodology

In this section, the methodologies used to evaluate the feasibility and eventual benefit of installing post-combustion CO_2 capture with MEA or ammonia to five large industrial plants and two power stations are described. Different methods for supplying the extra heat demand are assessed, and the thermal performance of the plant, including CO_2 capture, is simulated (power plants only). Furthermore, the total cost for capturing CO_2 is estimated. The target is to capture 85% of the generated CO_2.

2.3.1 Capture from industrial sources in the region

To supply the necessary heat in the desorption reboiler, different options are proposed. One option is to use the excess heat in the existing process, possibly by using heat pumps to achieve the necessary temperature levels. Other options are to invest in an external unit (e.g., a boiler) that would produce the necessary steam and also co-generate electricity. The costs associated with these alternatives are identified for each industrial plant.

The methodology used combines knowledge of the capture process with knowledge obtained from process integration studies.

The methodology applied in the analysis can be divided into the following steps:

- Identify the available excess heat from the industrial plant using pinch analysis;
- Identify the CO_2 emission sources at each industrial plant site;
- Determine the energy demands for the different heat supply options, with the assumption that CO_2 emissions from fossil fuel-fired heat supply plants are also captured;
- Determine the investment cost for the heat supply, as well as for the capture process;
- Evaluate the operating costs using two levels of energy costs.

The pinch analyses for each of the industrial plants include only heat sources that are not integrated, i.e., heat sources that are cooled by a utility (e.g., water and air). The cooling demand identified in this way thus represents the present excess heat from the process at various temperature levels. Although thorough analyses at the plants followed by adequate measures would probably lead to lower levels of excess heat at other temperatures, this is not taken into account in the present study. The excess heat identified is used as the heat supply to the CCS desorber either directly or via a heat pump at 129°C.

The different heat supply options used are:

- Natural gas combined cycle (NGCC)

The NGCC alternative is designed with a heat recovery steam generator (HRSG) that produces high-pressure (HP) steam (80 bar), which is expanded in a back-pressure turbine to low-pressure (LP) steam (2.3 bar). The NGCC provides sufficient LP steam for capturing the CO_2 generated from both the process plant and the NGCC. The electrical efficiency of the gas turbine is 0.375, the electrical efficiency for the whole cycle is 0.45, and the heat to electricity factor is 1.23.

- Natural gas boiler (NB) and Biomass boiler (BB)

The NG boiler alternative has a total efficiency of 0.91. The boiler produces HP steam (80 bar), which is expanded in a back-pressure steam turbine to produce LP steam (2.3 bar) and electricity; the electrical efficiency is 0.22. The boiler capacity is adjusted to produce enough LP steam to cover the heat demand for CO_2 capture from both the current process plant and the boiler. The BB follows the design of the NB, except that it has a total efficiency of 0.87 and an electrical efficiency of 0.21. In the BB case, the CO_2 from the boiler is not captured, since it is assumed to be climate-neutral.

- Excess heat, delivered directly or *via* an electricity-driven heat pump (EH+HP)
  In this alternative, the available excess heat (>129°C) is used to produce steam for the desorption unit. If this heat is not sufficient to cover the heat demand, a heat pump must be used to supply additional heat. If additional heat is still needed, this heat is supplied by an NGCC, BB or NB.

The heat pump uses available heat above 70°C in the process plant to produce the necessary amount of LP steam. It is assumed that the drop in temperature of the available heat, related to its collection from process streams, is 5°C. The heat pump is a closed cycle compression unit that uses n-butane as the working medium. The heat pump is assumed to work with a Carnot efficiency of 0.64.

2.3.2 Capture from power plants in the region

In this case, two different absorbents are considered: aqueous ammonia and MEA. The processes for capturing $CO_2$with MEA are well known, and the performances of these processes have been evaluated in several studies and pilot plants. The ammonia process is less mature, which means that its performance status remains uncertain. Thus, for MEA, performance is evaluated based on previous results described in the open literature, whilst a rigorous process model is set up in Aspen Plus to evaluate the ammonia process. In this project, the optimal use of energy for integrating the CO_2 capture process is evaluated through process simulations. The power plants are simulated using the Ebsilon Professional tool.

2.3.3 Cost calculation principles

To evaluate the feasibility of CO_2 capture, the cost of installing capture units should be compared to the cost of emitting CO_2 (e.g., the expected EU-ETS price). The cost for capturing CO_2 can be defined in two ways: 1) the cost of CO_2 captured (€/tCO_2 captured); and 2) the cost of CO_2 avoided (€/tCO_2 avoided). The difference between the two costs is that the cost of CO_2 avoided has a constant production and includes the emissions and costs of the additional units required to capture the CO_2. In contrast, the cost of CO_2 captured includes the cost for the loss of production. For CO_2 capture from industrial sources, the cost of avoided CO_2 is applicable, as the product cannot be used to power the capture process and thus, additional units are needed. For CO_2 capture from existing power plants, the cost for CO_2

captured is applicable, as these plants exploit the existing production of heat and electricity rather than installing new units to cover the extra demand.

Thus, for industry, the cost of avoided CO_2 is calculated as the capital and operating costs for the heat supply plant and capture plant divided by the avoided amount of CO_2 emitted, which is calculated as the difference between the emissions from a plant without capture and one with capture (including the heat supply plant).

To calculate the cost of CO_2 captured, the capital and operating cost is divided by the sum of the captured CO_2 from the industry plant and the heat supply plant. In the power plant case, the cost of CO_2 captured is calculated as the capital and operating costs for the capture plant reduced by the cost for loss in electricity and heat divided by the captured CO_2 amount.
The cost for installing CO_2 capture consists of the following parts:

- The investment cost for the capture unit, including gas ducts and compressor. The investment and operation cost include the absorption system, with the most expensive items being the absorption and desorption columns, the chiller of incoming flue gases, and the heat exchanger between the absorber and the desorber;
- The operational cost of the capture unit;
- The cost related to the loss of electricity and heat production is derived from the process simulations (applicable for power stations);
- The investment cost for the heat supply plant, including a collection system for the excess heat and a heat pump or boiler (applicable for industry);
- The running costs of the heat supply system (electricity to the heat pump and fuel to the boilers and gas turbine). The electricity produced in the heat supply plant is treated as an income, taking into account certificates issued when the electricity is produced from biomass (applicable for industry).

Table 2.3 lists the assumed fuel costs in the economic calculations. All investment costs have been calculated using annuities, applying an annuity factor of 0.084 for the power plants and 0.13 for the industrial sources in the region, based on recommendations from the participating industries/power plant owners. The year 2011 has been used as the basis for all the economic calculations. The annual operation time for the industrial plants is assumed to be 8,760 hours.

Table 2.3. Assumed fuel costs for the economic calculations in the present study

Fuel	Unit	Price	
		Low	High
EO1[a]	€/MWh_{fuel}	64	87
EO5[a]	€/MWh_{fuel}	41	59
Natural gas[a]	€/MWh_{fuel}	35	44
Coal[a]	€/MWh_{fuel}	8.2	13
Cost of emitting CO_2[b]	€/tCO_2	45	45
Biomass[c]	€/MWh_{fuel}	35	40
Electricity[c]	€/$MWh_{electricity}$	67	77
Heat[d]	€/MWh_{heat}	34	39
Green certificate	€/$MWh_{electricity}$	25	25

[a] Based on the World Energy Outlook 2010 [IEA 2010a] "450-ppm scenario" (Low) and "current policies scenario" (High). The 450-ppm scenario assumes that the CO_2 concentration in the atmosphere must not exceed 450ppm. The current policies scenario includes approved targets until 2010.
[b] Taken as a representative value from the World Energy Outlook 2010 [IEA 2010a] "450-ppm scenario" and "current policies scenario".
[c] Estimated based on the ENPAC tool described in Axelsson *et al*., 2010.
[d] Assumed as 50% of the electricity price (valid for power plants).

2.4 Results

In this section, the costs for capturing CO_2 from five industrial plants and two power plants are calculated. Section 2.1 gives a brief description of each industrial plant. The results and cost of capture from industry are given in Section 2.4.1, while Section 2.4.2 describes the results for the two power plants examined in the study.

2.4.1 Results for industrial plants

Preem, Lysekil - Refinery
The Preem refinery in Lysekil is a complex refinery with a crude oil capacity of 11.4 Mt/yr. The refinery converts crude oil from Russia, the North Sea, and the Middle East to gasoline, diesel, propane, propylene, and heavy fuel oils. The refinery has a catalytic cracker and a hydro cracker to improve the yield of lighter products. The refinery has the possibility to process crude oil with high-sulphur content.

CO_2 emissions from the oil refining process originate from several sources. Four sources represent 97% of the total emissions, and the emissions from these during a typical year are listed in Table 2.4. It is assumed that it is realistic to capture CO_2 from these sources.

Table 2.4. CO_2 emission sources; Preem Lysekil

	Chimney 1	Chimney 2	Chimney 3	Chimney 4
Temperature	160˚C	180˚C	270°C	170°C
Flow	450,000 Nm^3/h	270,000 Nm^3/h	90,000 Nm^3/h	150,000 Nm^3/h
CO_2 concentration	6.7 vol-%	9.1 vol-%	14.0 vol-%	24.0 vol-%
CO_2 emissions	500 kt/yr	400 kt/yr	240 kt/yr	600 kt/yr

In a plant audit, available and practically utilisable excess heat sources were identified in the flue gases and in 55 process streams. The corresponding loads are shown in Figure 2.5. Above 150°C, this corresponds to approximately 40 MW. The curve is fairly linear between 150°C and 50°C, and above 129°C there is about 80 MW available. The total amount of heat available above 90°C is approximately 225 MW.

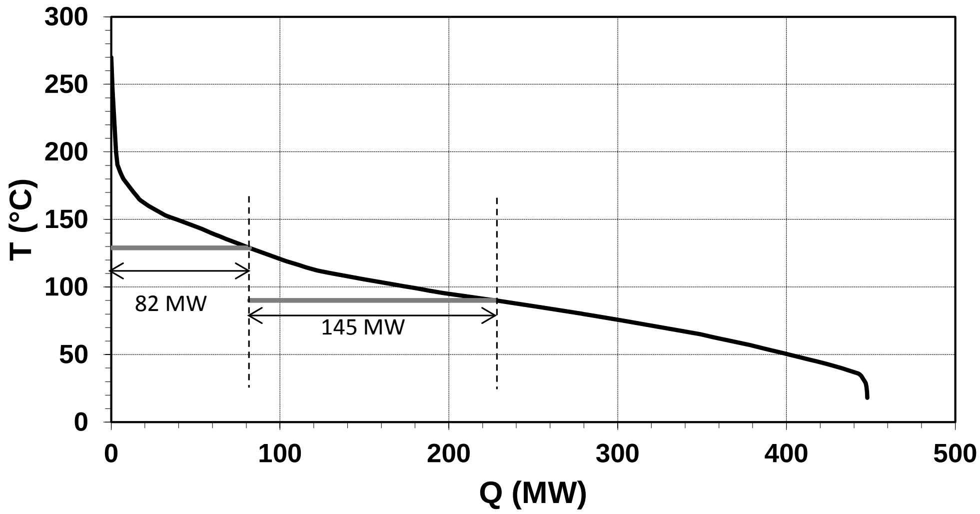


Figure 2.5. Excess heat at various temperatures; Preem, Lysekil

Preem, Gothenburg - Refinery

The refinery in Gothenburg is a so-called 'hydro skimming' refinery, and the main products are propane, butane, gasoline, diesel, aviation and gas turbine fuel, kerosene, domestic heating oil, and heavy fuel oil. The crude oil capacity is 6 Mt/yr.

The CO_2 emissions originate from several sources, with two chimneys accounting for 89% of the emissions. Due to the costs associated with collecting the CO_2, it is assumed that it is realistic to limit CO_2 capture to these two sources (see Table 2.5).

Table 2.5. CO_2 emission sources; Preem Gothenburg

	Chimney 1	Chimney 2
Temperature	150°C	180°C
Flow	128,000 Nm^3/h	189,000 Nm^3/h
CO_2 concentration	8.70 vol-%	9 vol-%
CO_2 emissions	192 kt/yr	292 kt/yr

The identified available, and practically utilisable, excess heat sources are found in the flue gases and in 65 process streams. The respective loads are shown in Figure 2.6. The refining capacity of the Preem, Gothenburg refinery is about half that of the Lysekil refinery, and the total load is also about half that of the Lysekil refinery. However, the share of high temperature heat is higher at Preem, Gothenburg. Above 129°C, this corresponds to 54 MW, and the total amount of heat available above 90°C is roughly 107 MW.

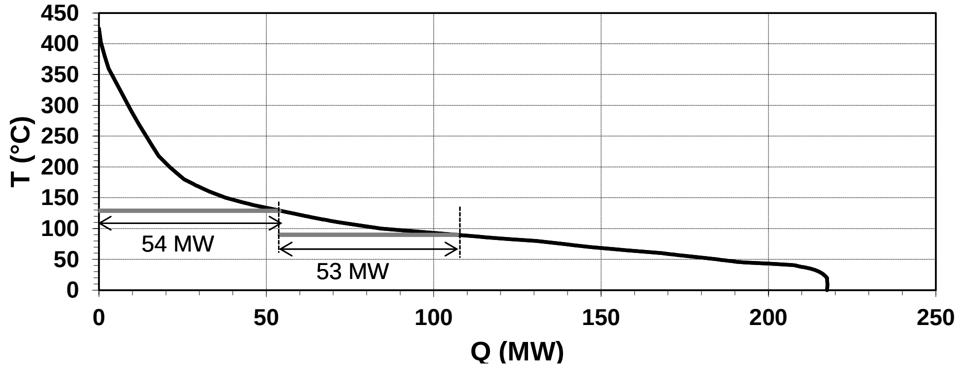


Figure 2.6. Excess heat at various temperatures; Preem, Gothenburg

Esso, Slagentangen - Refinery

The Esso refinery at Slagentangen is Norway´s oldest crude oil refinery. The refinery has a crude oil capacity of 6 Mt/yr. The refinery converts crude oil, mainly taken from the North Sea, into a variety of petroleum products. The main products from the refinery are propane/butane, gasoline, jet fuel, kerosene, diesel (less than 10 ppm sulphur), and light and heavy fuel oils.

The CO_2emissions originate from nine chimneys (furnaces in crude distillation plant, gasoline plant, thermal cracker plant and hydrofiner plants boilers) located in the same area. Given the locations of the sources it is assumed that it is possible to capture CO_2 emissions from all of them (Table 2.6), although in a first stage it should be considered to use only the gas from the crude distillation plant.

Table 2.6. CO_2 emission sources; Esso Slagentangen

	Total flue gases
Temperature	160˚C
Flow	183,333 Nm^3/h
CO_2 concentration	10 vol-%
CO_2 emissions	365 kt/yr

In the Esso refinery, available and practically utilisable excess heat is found in the flue gases and in 10 process streams, as shown in Figure 2.7. Compared to the Gothenburg refinery, with roughly the same refining capacity, the amount of utilisable excess is half. The share of high-temperature excess heat (above 129°C) lies between the shares observed for the Lysekil and Gothenburg refineries. Almost 18 MW is available above 129°C, and the total amount of heat available to 90°C is about 56 MW.

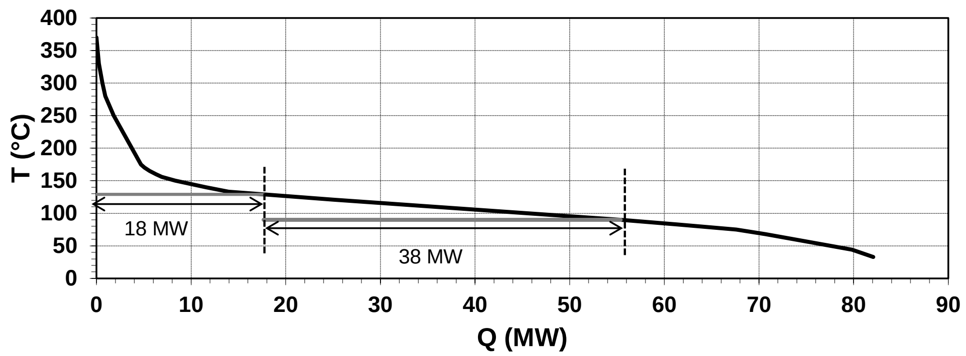


Figure 2.7. Excess heat at various temperatures; Esso Slagentangen

Borealis, Stenungsund – Ethylene cracker

The Borealis cracker plant is part of the chemical complex in Stenungsund. In Stenungsund, Borealis has two sites; a cracker plant and a polyethylene plant. The cracker plant has a capacity of 0.62 M t/yr of ethylene products from naphtha, ethane, propane, and LPG feedstocks. The cracker plant delivers its products to a wide range of industries both in Stenungsund and around Europe. One of its main consumers is the polyethylene plant, where the ethylene is used to produce plastics that are used for products ranging from medical devices to power cable insulation.

The ethylene is produced by cracking the feedstock in high-temperature furnaces. After the cracker furnaces, the product stream goes through several reaction, dryer, and distillation steps to produce the ethylene fraction. The cracker process generates large amounts of CO_2 emissions, mainly from the furnaces.

The CO_2 emissions from the nine cracker furnaces correspond to 78% of the total CO_2 emissions (Table 2.7). The remaining CO_2 emissions originate from three boilers, a hot oil furnace, and from flaring. Only the CO_2 emissions from the cracker furnaces were included for plant layout reasons.

Table 2.7. CO_2 emission sources; Borealis Stenungsund

	Total flue gases
Temperature	144˚C
Flow	28,544 Nm^3/h
CO_2 concentration	5 vol-%
CO_2 emissions	566.2 kt/yr

In the plant audit, available and practically utilisable excess heat was found in the flue gases and 32 process streams (Figure 2.8). The graph resembles the graphs for the refineries, except in the temperature range of 150–90°C. For the cracker plant, the amount of excess heat above 129°C is about 23 MW. There is a lack of excess heat between 150°C and 110°C, and the amount of excess heat above 90°C is relatively small (an additional 7 MW), i.e., 30 MW in total. The amount of excess heat above 70°C is approximately 90 MW.

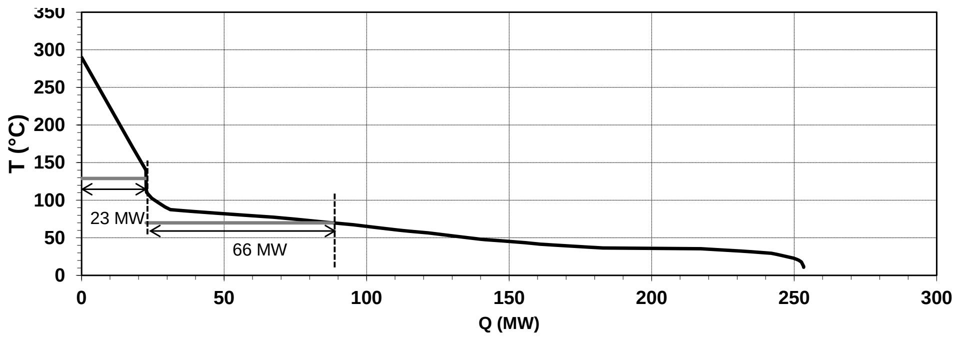


Figure 2.8. Excess heat at various temperatures; Borealis Stenungsund

Yara, Porsgrunn - Ammonia plant

The Yara ammonia plant is part of an industrial consortium site in Porsgrunn, which also comprises nitric acid plants and fertiliser plants. The facilities produce a w ide range of product grades, as well as a range of gases and chemicals for industrial applications. The ammonia production capacity is 510 kt/yr.

Ammonia is produced by reacting nitrogen from the air with hydrogen, at high pressure and temperature, in the presence of a catalyst. The hydrogen is produced in a catalytic steam reforming unit. A mixture of ethane, propane, and butane gases reacts with steam at high temperature and pressure in the presence of a catalyst. Ethane, propane, butane and a coke oven gas are used as energy sources to generate the heat required in the ammonia production process. One of the gases produced (and sold) for industrial applications is CO_2. However, at Yara, not all of the produced CO_2 can be commercialised and part of it is therefore emitted.

The CO_2emissions during a typical year are listed in Table 2.8. The flue gases and the flow from the air tower are used in the capture plant. The concentration of the excess CO_2 in the stream is increased in the capture plant and the gas is subsequently compressed.

Table 2.8. CO_2 emission sources; Yara Porsgrunn

	Flue gases	Air tower	Excess CO_2
Temperature	220˚C	15˚C	
Flow	208,900 Nm^3/h	220,000 Nm^3/h	20 t/h
CO_2 concentration	13.4 vol-%	8.0 vol-%	96.0 vol-%
CO_2 emissions	356.9 kt/yr	224.0 kt/yr	144.0 kt/yr

In the plant audit, only relatively small amounts of available, and practically utilisable, excess heat were identified (Figure 2.9). The sources are the flue gases and two process streams. Approximately 48 MW is available above 129°C, and the total excess heat above 70°C amounts to about 25 MW.

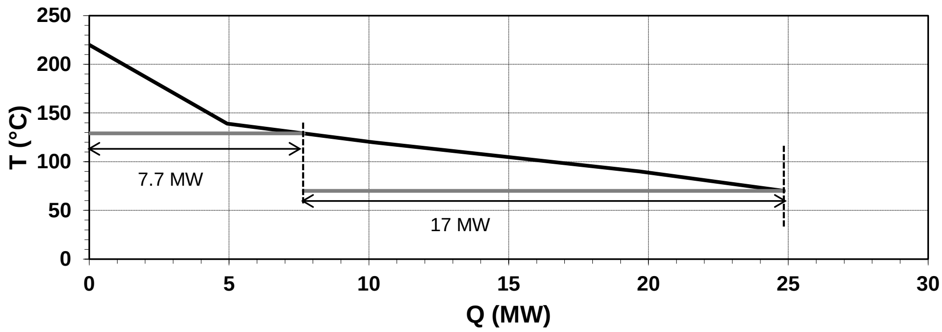


Figure 2.9. Excess heat at various temperatures; Yara Porsgrunn

Costs for industrial plants

In Table 2.9, the key values for capturing the identified CO_2 emissions are presented for the five industrial plants according to the principles outlined in Sections 2.3.1 and 2.3.3. Results are presented for the alternative strategy to supply the heat demand to the desorbers in the capture plants that have the lowest specific capture cost.

The use of fossil fuels in the heat supply plant increases the amount of CO_2 that has to be captured, and thus the size of the equipment, as compared to the use of excess heat, an electricity-driven heat pump or a biomass boiler. In the future, from the systems perspective, consideration ought to be given to CO_2 capture from biomass-based systems, since capture of biogenic emissions will correspond to negative emissions (assuming no indirect emissions associated with the biomass). However, to get capture from biomass in place will require that biomass based capture is recognized and incentivized by the European Union Emission Trading Scheme.

Even if the fossil fuel-based systems are larger, and thus more expensive, than the excess heat-based systems, they have the advantage of producing electricity, which has a high value. Electricity from biomass-based systems has an even higher value, since bio-based electricity provides extra income through Green certificates (25 €/$MWh_{electricity}$).

In the Preem Lysekil, Esso, Borealis, and Yara plants, the amount of available excess heat above 129°C is not sufficient to meet the entire heat demand of the desorber *via* direct heat exchange, which makes it necessary to combine the use of excess heat with a heat pump. At Yara, the relatively low levels of available heat are not suitable for use directly in the desorber *via* a steam system. Instead, the excess heat is first utilised by a heat pump and thereafter, to meet the overall heat demand, a BB, NB or NGCC must be used.

At Preem, Gothenburg the large amount of excess heat above 129°C is sufficient to cover the energy demand of the desorber in the capture plant *via* direct heat exchange, without the aid of a heat pump.

In all the plants, the lowest specific cost for CO_2 capture is found for an alternative that utilises excess heat. The lowest specific cost is found at Preem, Gothenburg (46–48 €/tCO_2, depending on assumed energy costs) due to the large amount of excess heat that can be used to meet the heat demand *via* direct heat exchange without the aid of a heat pump. At Preem, Lysekil, Esso, and Borealis, excess heat in combination with a heat pump gives the lowest specific capture cost (50–59 €/tCO_2).

At Yara, the three alternatives (NGCC, NB and BB) in combination with a heat pump have nearly the same specific capture cost, 60–68 €/tCO_2, depending on a ssumed energy costs. This level is higher than those of the other industrial plants due to the need for supplementary heat in addition to the heat produced in the heat pump. The advantage of the BB alternative is the lower level of capture, since emissions from the BB are not captured. This alternative is the one shown in Table 2.9.

The avoidance cost should be lower than the cost for emitting the CO_2 gas, which is assumed to be 45€/tCO_2 (note that the avoidance cost calculated here refers only to the cost at the plant, which means that cost of CO_2 transport and storage should be added). For those cases in which no fossil fuel is used, the specific capture and avoidance costs are the same. Thus, the systems with the lowest specific capture and avoidance costs coincide, giving an avoidance cost for the five plants of between 46 €/tCO_2 and 65 €/ tCO_2, depending on the assumed energy costs. The lowest cost is found at Preem, Gothenburg where the avoidance cost is about the same (46–48 €/tCO_2) as the cost for emitting the gas. The alternatives of using an NGCC or an NB have in all five plants much higher avoidance costs due to the use of fossil fuels which leads to less avoided CO_2-emissions.

At Yara, the alternative of using a heat pump and a BB results in the lowest specific avoidance costs (61–65 €/tCO_2). Although the NGCC and NB alternatives have the same specific capture costs, they have higher avoidance costs due to the use of fossil fuels. The specific avoidance cost for the BB alternative is somewhat higher than those for the other investigated plants due to a lower level of available excess heat, which necessitates the use of a complementary heat supply source.

In summary, the lowest specific capture costs are achieved when excess heat is utilised. For those plants in which the amount of available excess heat is not sufficiently large to meet the entire heat demand of the capture plant, *via* direct heat exchange, the lowest specific capture cost is obtained when a heat pump also is used. Specific capture costs of 45 €/tCO_2 to

60 €/tCO_2 can be achieved in such systems using excess heat alone or in combination with a heat pump. The specific avoidance costs are the same for these systems, since no fossil fuel is used. Higher specific costs are incurred if the heat from the heat pump is not sufficient to cover the heat demand of the capture plant so that supplementary heat *via* a heat supply plant is needed.

Table 2.9. Key values and costs for the five industrial plants

	Preem, Lysekil		**Preem, Gothenburg**		**Esso, Slagentangen**		**Borealis, Stenungsund**		**Yara, Porsgrunn**	
Heat supply plant	EH + HP		EH		EH + HP		EH + HP		HP+BB	
Total CO_2 from process (kt/yr)	1,740		484		365		566		726	
CO_2 from heat supply plant (kt/yr)	0		0		0		0		111	
CO_2 captured (kt/yr)	1,479		411		310		481		638	
CO_2 avoided (kt/yr)	1,479		411		310		481		638	
Power to heat supply plant (MW)	18		0		4.5		7.7		1.5	
Energy costs	**Low cost**	**High cost**	**Low cost**	**High cost**	**Low cost**	**High cost**	**Low cost**	**High cost**	**Low cost**	**High cost**
Capture cost (€/t CO_2)	50	53	46	48	56	59	54	58	61	65
Avoidance cost (€/t CO_2)	50	53	46	48	56	59	54	58	61	65
Share CAPEX (%)	44	41	50	48	45	42	41	38	35	33
Share OPEX (%)	56	59	50	52	55	58	59	62	65	67

2.4.2 Results for power plants

In this Section, the two power plants that are included in the study are described along with the results of the analysis of CO_2 capture.

Nordjyllandsverket, Aalborg – Coal-fired power plant

Nordjyllandsverket is a state-of-the art pulverised coal-fired, combined heat and power (CHP) plant. The power plant is owned by Vattenfall. The plant is located close to the Danish city of Aalborg. Nordjyllandsverket consist of two units; Units 2 and 3. Unit 3 is in focus in the modelling work. However, the flue gas streams of both units are assumed to be available for capture. The total electrical power output of Nordjyllandsverket is 660 MWe. In condensing mode, the electrical capacity of Unit 3 is 380 MWe. When steam is extracted for district heating purposes, the electrical capacity is reduced to 340 MWe, while the district heating capacity is increased to 420 MWth. In condensing mode, the power plant can operate at an electrical efficiency of 47%, which is high for a coal-fired power plant. The reasons for the high efficiency are the high steam data, advanced feed water heating, double reheat cycles, and the possibility to use low-temperature cooling water from the adjacent Limfjord (as opposed to cooling towers). In this project, a case is chosen in which no district heating is produced and the power plant is run at full electrical capacity. Only the newest unit (Unit 3) is assumed to be equipped with CO_2 capture. The older unit (Unit 2) is only used during high-load periods. Unit 2 operates in a load-following mode and thus, it is unlikely that it would be profitable to implement CCS at the older unit. Figure 2.10 shows the annual load factors for Nordjyllandsverket in the period from 2006 and 2010 versus an average load factor of 89% (set by Vattenfall). All information regarding Nordjyllandsverket is taken from Nordjyllandsværket - Grøn Regnskab 2010.

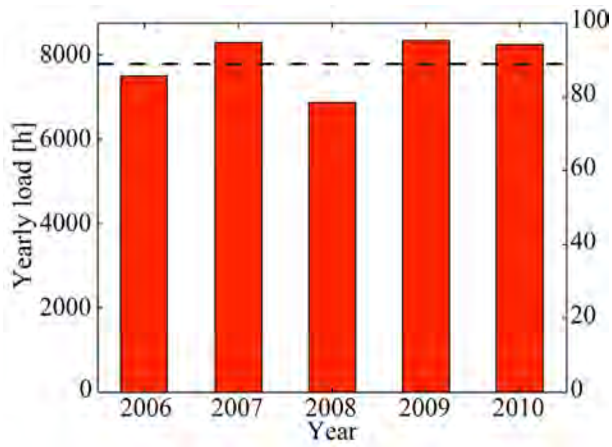


Figure 2.10. ***Yearly load factors for Nordjyllandsverket in the interval 2006-2010. The striped line denotes an average load factor of 89% (Vattenfall, 2010).***

The annual flow rate of CO_2 is based on a capture rate of 85% and the average CO_2 emissions over the last 5 years. The load factor is also based on the average value for the last 5 years. The properties and purity of the CO_2 stream are in accordance with the specifications described in Chapter 4 for transport. Table 2.10 summarises the results for power plant performance and the economic analysis, which is based on t he procedure explained in Sections 2.3.2 and 2.3.3. The cost for capture is given in €/tCO_2 captured. The capture cost is divided into the capital cost (CAPEX) and the operating cost (OPEX). In a coal-fired power plant running in condensing mode, no excess heat is available. Thus, heat for regeneration is extracted from the steam cycle. Low-pressure steam is extracted before entry into the low-pressure turbines. As a consequence of the extraction of steam from the power plant steam cycle, the electric efficiency decreases. The heat supplied to the desorber column and the temperature of the accessible cooling water are the main determinants of the efficiency drop of the power plant.

Table 2.10. ***Costs of capture associated with the use of ammonia or MEA; Nordjyllandsverket***

Total CO_2 from process (kt/yr)	2,000			
Captured amount (kt/yr)	1,700			
Load factor (h/yr)	7,704 (89%)			
	Ammonia		**MEA**	
	Low	**High**	**Low**	**High**
Total capture cost (€/tCO_2)	33	35	42	46
- Share CAPEX (%)	35	33	17	16
- Share OPEX (%)	65	67	83	84
Power plant efficiency drop (%-points)	8.0		10.3	

The results of the economic analyses of the costs of CO_2 capture for Nordjyllandsverket are in agreement with the results for coal-fired power plants presented in the report by ZEP (2011). Considering the project-specific estimated carbon price of 45 €/t, the MEA option appears to be as profitable as that with no CCS installed. Considering the case of using ammonia, there is in fact a possibility for increased profitability. However, the uncertainties related to the use of ammonia as the absorption medium are far greater than those linked to the MEA process, and the technology for ammonia is far from mature.

Ryaverket, Gothenburg – Gas-fired combined heat and power plant

This section presents details on CO_2 capture for the largest CHP plant in Gothenburg: the RyaCHP. This is a 600-MWth combined cycle gas turbine (CCGT) plant firing Danish natural gas. It is owned and operated by Göteborg Energi, a company fully owned by the municipality of Gothenburg. At full load, the plant outputs approximately 295 MW of heat and 250 MW of electricity. The Rya CHP was built with a high degree of flexibility, to allow responses to changes in the demands for heat and power over the year. Therefore, the levels of CO_2 emissions vary considerably between years, within a specific year, and even from hour to hour. The operational profiles of the plant for different years, since its inauguration in 2006, are compared in Figure 2.11a. A load curve for a "typical year" (without CCS) is shown in Figure 2.11b. For long periods in the summer, the plant is shut down completely.

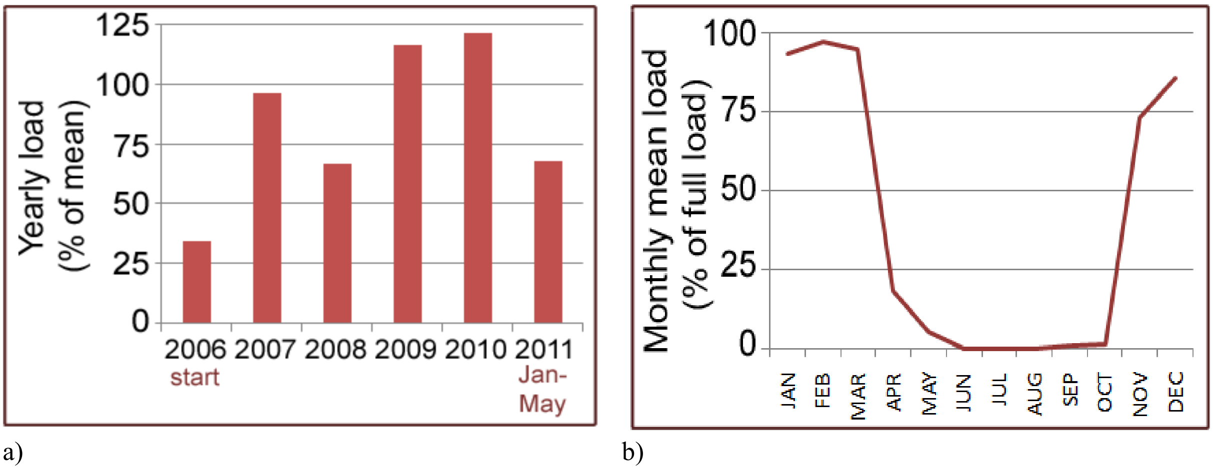


Figure 2.11. a) Rya CHP loads (fuel use), indexed for each year since inauguration. b) Predicted typical load curve (heat) for the Rya CHP plant.

The Rya CHP plant was commissioned in 2006 and will most likely be part of the Gothenburg energy system for several decades; the technical life-time of the plant is estimated at 40–50 years. The district heating system to which the plant delivers heat is to a large degree saturated, i.e., with little potential for expansion. Considering the fact that the heating demand is expected to decrease by 10–15%, mainly due to efficiency measures (and possibly also due to climate change), the district heating demand of Gothenburg is likely to decrease.

The Rya CHP plant is part of a complex system, for which the effect of changes to the plant must be evaluated. The application of CO_2 capture means losses of district heating (and power) and the net total CO_2 effect depends on how these losses are compensated. One possible consequence of the losses in the Rya plant from CO_2 capture is that marginal peaking heat boilers are run to a greater extent. Since many of these are carbon-intensive (oil-fired), the ensuing increased emissions may offset much of the benefit of CCS in the Rya plant. The total effect will depend on several parameters, of which CO_2, fuel, and energy prices are of great importance.

A projected load demand curve for Rya CHP (without CCS), with CO_2, energy, and fuel costs taken from the '450-ppm scenario', has been provided by Göteborg Energi. The results show that the plant would run at fewer full-load hours per year than at present, supplying only 24% of the heat compared to the current market conditions. One reason is the high CO_2 prices. This projection shows that the system is highly dependent upon assumed outside parameters, such as fuel, energy, and CO_2 prices (Sfiris, 2011).

The capture options for the Rya CHP plant have been assessed with respect to various modes of operation and integration possibilities. Both chilled ammonia and MEA have been studied as absorption media. The heat for the ammonia process is assumed to be supplied 100% by primary steam, while for the MEA process 40% of the heat is assumed to come from primary steam and 60% from back-pressure steam.

The effect of applying recycling of gas turbine flue gases has also been studied. It is found to give up to a 43% mass decrease in flue gas flow and an increase in CO_2 concentration from 8.6% to ≤14.8%, at full load, as compared to a case with no flue gas recycling. Carbon capture with flue gas recycling is estimated to increase power production by 0.6–0.7%-points and decrease heat production by 3.1–3.4%-points, as compared to carbon capture without flue gas recycling.

Applying carbon capture to the Rya CHP plant would give a 13.4% loss in electricity production and 18.2% loss in heat production, based on an annual operation of approximately 3,600 relative full-load hours. Details as to costs and performance are given in Table 2.11.

The large losses in heat production for carbon capture do not necessarily imply economic losses, if electricity production can be maintained at a high level. With carbon capture that mainly consumes heat, the power plant's power/heat ratio will increase. This means that it could be run during periods of lower heating demand. The increase in income from electricity for the extra operating hours, with economic benefit from the low requirement for CO_2 allowances, could to some degree compensate for the losses of heat. This is particularly true for MEA absorption and for a system with overall decreasing heat demand, e.g., the Gothenburg system (Sfiris, 2011).

Table 2.11. Flow values, efficiencies, and costs of carbon capture, using ammonia or MEA as the absorption medium.

Exhaust flow, max (t/h)	1,450			
Separated CO_2, max flow (t/h)	124			
Total CO_2 from process, NH_3/MEA (kt/yr)	444 / 453			
Captured amount CO_2 , NH_3/MEA (kt/yr)	377 / 385			
Load factor, heat[1] , NH_3/MEA (h/yr)	3,621 / 3,699			
	Ammonia		**MEA**	
	Low	High	Low	High
Cost of capture (€/tCO_2)	118	130	154	174
- Share CAPEX (%)	26	24	16	14
- Share OPEX (%)	74	76	84	86
Heat requirement[2] (MW_{th})	85		125.8	
Total power requirement[2] (MW_e)	3.2		5	
Power loss CHP plant[2] (MW_e)	34.1		26.8	
Heat loss CHP plant[2] (MW_{heat})	50.6		109.4	
Plant power loss[2] (%-points)	5.8		4.5	
Plant heat loss[2] (%-points)	8.6		18.6	

[1] In carbon capture mode with ammonia

[2] For Rya CHP at full load

In conclusion, there are possibilities for carbon capture at the Rya CHP plant. Given the low CO_2 concentrations in the flue gas, large load variations, and few load hours per year (as compared to other plants and industries in the project), the costs would be relatively high (>100 €/tCO_2) and the process operation would be more complex. Carbon capture at the plant would entail losses in electricity and heat production, both annually and in terms of maximum output, which would affect the system in which the plant operates. The total effect on carbon emissions would depend on how the load changes in the plant and on how the loss of heat and power production is compensated for within the system.

2.5 Summary and Conclusions

The key parameters for evaluating the feasibility of implementing carbon capture to the CO_2 sources investigated in this project are summarised in Figure 2.12. Of course, low capture and avoided costs are desirable. However, a substantial captured mass is also important for an efficient and cost-effective infrastructure for transportation and storage. For the industrial sources, the heat required to power the capture process is supplied by excess heat from the process *via* direct heat exchange, either alone or in combination with a heat pump. This is true for all cases, with the exception of the Yara plant, in which a heat pump in combination with a biomass-fired boiler is the most cost-efficient choice. The heat pump and the biomass boiler are not powered by fossil fuels and the avoided cost therefore becomes equal to the capture cost. The capture from power plants is powered by extracting steam from the steam cycle, which means that an external heat supply is not required. Therefore, the cost for CO_2 avoided is not applicable to the power plants. For the industrial processes, post-combustion capture with MEA is the technology of choice, while post-combustion with chilled ammonia is considered to be most cost-efficient for the investigated power plants. Ammonia is less mature than MEA as a CO_2 absorbent, but has a higher potential for reducing the energy penalty.

In the applied scenario, the cost for emitting CO_2 is assumed to be 45 €/t. According to our results, the cost for capturing CO_2 from industrial processes will be between 45 €/tCO_2 and 65 €/tCO_2 (excluding transport and storage costs). Thus, CO_2 capture will not be implemented in industrial processes in the absence of technical developments that lower the cost of capturing CO_2 or increase in the costs of emitting CO_2. It is also important to note that there are large differences in capture costs between sources. Thus, carbon capture may not be implemented at the same time at all locations, which will have consequences for the development of the required infrastructure for transportation and storage. For example, coal-fired power plants, exemplified by Nordjyllandsverket in the present investigation, have a considerably lower CO_2 capture cost than industrial sources. Thus, the implementation of carbon capture at coal-fired power plants will be cost-efficient and implemented at an earlier stage. On the other hand, substantial reductions in the cost of capture will be required for CCS to become feasible in gas-fired power plants. Gas-fired power plants are represented by Ryaverket in the present investigation, where the capture cost is very high, mainly due to low utilisation (41% compared to 89% for Nordjyllandsverket) and the low CO_2 concentration in the flue gases.

The capture cost account for approximately 75% of the total cost and holds the largest potential for reducing the total cost. For example, the implementation of new absorbents, such as ammonia or advanced amines, or process integration and optimisation are possible strategies to reduce the cost of capture. However, it is important to note that such developments will require substantial efforts in research and development and large investments. Thus, the efforts of all stakeholders, public and private, need to be intensified to gain practical experience and to explore options for limiting the associated costs. To explore the potential for commercial deployment, multiple capture technologies need to be tested in all relevant sectors. This will require significant investment in several pilot-scale capture plants over the coming decade. In addition to this report an extended version of Chapter 2 can be retrieved from http://www.ccs-skagerrakkattegat.eu/.

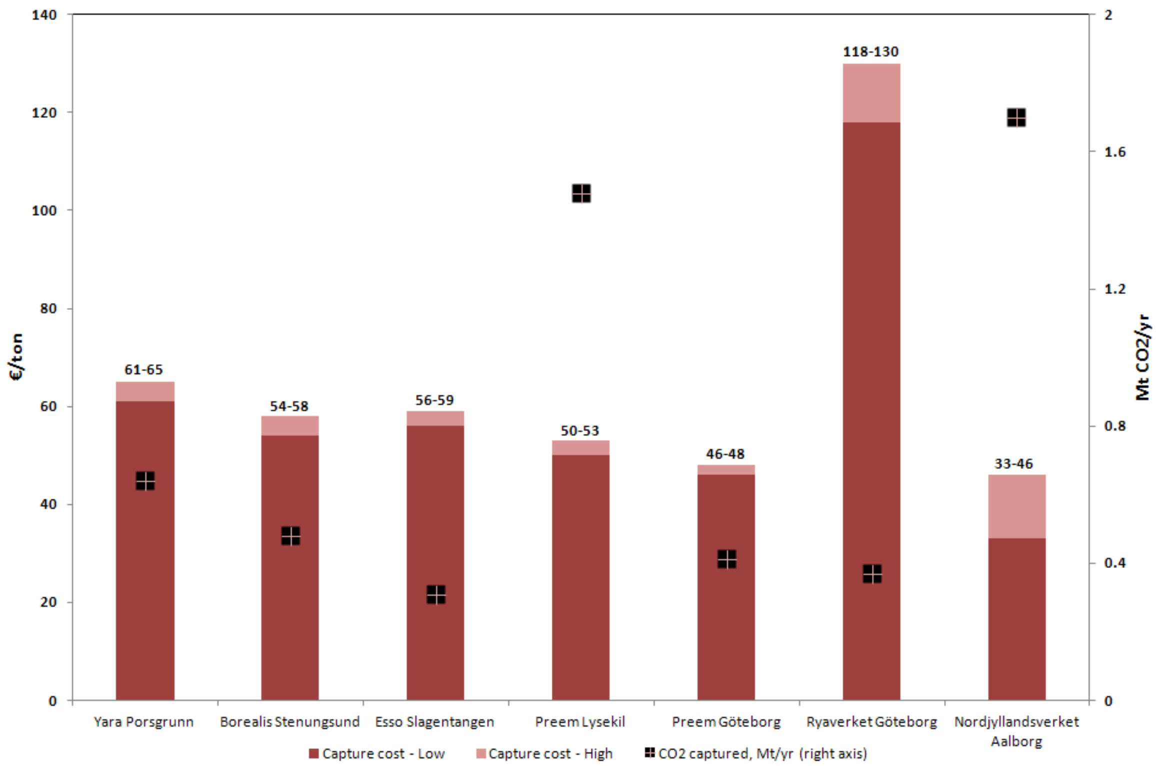


Figure 2.12. Summary and basis for ranking the CO_2 sources investigated. The CO_2 capture cost is indicated by the bars (see left axis). The span in cost is given by the two cost scenarios. As no fossil fuels are used to power the capture process at the industrial sources, the avoidance cost equals the capture cost. For power plants, the avoidance cost is not applicable. The black squares (right axis) indicate the amount of CO_2 captured at each site, assuming a capture ratio of 85%.

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3 CO_2 STORAGE

3.1 Introduction

To establish a CCS infrastructure in the Skagerrak/Kattegat region it is necessary to identify and characterise potential CO_2 storage sites within reasonable distances of the major sources of CO_2 so as to minimise transport costs. Although the geology of the North Sea has been explored extensively over the past 40 years of oil and gas exploration, the Skagerrak/Kattegat region has not been opened for such exploration, with the result that its geology and reservoir characteristics are far less known. Therefore the aim here was to study the Kattegat, Skagerrak, and Eastern North Sea as well as on-shore parts of Denmark, to identify and characterise potential subsurface reservoirs for storing CO_2.

The main criteria for selecting a site for geological storage of CO_2 (IPCC, 2005) are: adequate CO_2 storage capacity and injectivity; safety and security of storage (i.e., minimisation of leakage); and minimal environmental impact. The rock of a potential reservoir must be porous, in order to store large quantities of fluids (CO_2), and sufficiently permeable to allow a high injection rate of CO_2. The reservoir also needs to have a seal or cap rock above the reservoir, i.e., physical and/or hydrodynamic barriers that will confine the CO_2 within the reservoir. Typical rocks that form seals or cap rocks in offshore Norway are sediments, such as mudstones, shales or fine-grained chalks. An additional requirement is that the overall geometry and the structures constitute a trap that confines the injected CO_2 to the reservoir. This is analogous to oil/gas traps, which are familiar from the petroleum industry. Therefore, a suitable CO_2 storage play requires that all the reservoir, seal, and trap conditions are fulfilled.

This study consisted of an initial screening of potential CO_2 plays based on published work, followed by new seismic mapping and the interpretation of available well-logs and cores, with the aims of selecting the optimal traps/structures for CO_2 storage, performing petrophysical analyses, and estimating reservoir properties. Finally, reservoir simulation was performed for a few selected sites. GEUS has contributed to the study with their knowledge of the subsurface geology in the Danish area, and Sintef Petroleum carried out the reservoir simulations. In addition to this report an extended version of Chapter 3 can be retrieved from http://www.ccs-skagerrakkattegat.eu/.

3.2 Screening of CO_2 storage plays

The adjoining onshore areas of southern Norway and western Sweden consist of old crystalline basement rocks without storage potential (Figure 3.1). Therefore, the only place to look for storage is within the sediments located offshore. The main study area of this project is restricted to 2–9° East and 56–62° North, which encompasses several major structural elements (Figure 3.1). The North Sea Basin, including the Skagerrak/Kattegat, has experienced a complex geological history, resulting in the sedimentary basins we find there today. The area has been subjected to a minimum of two rift events in the post-Caledonian eras: (1) the Late Carboniferous - Early Permian; and (2) the Late Jurassic - Early Cretaceous (e.g., Faleide *et al*., 2002, and references therein; Nielsen, 2003). The late Jurassic rift event was followed by post-rift subsidence caused by cooling during the Cretaceous period when the area became a passive margin basin.

During the first rift event, in the Late Carboniferous – Early Permian, two basins developed in the North Sea area; the east-west-oriented northern and southern Permian Basins (e.g., Heeremans and Faleide, 2004). The northern Permian Basin, the Norwegian-Danish Basin, is NW-SE striking, and contains Paleozoic, Mesozoic, and Cenozoic sedimentary sequences

(Heeremans and Faleide, 2004; Figure 3.1). The eastern part of the Norwegian-Danish Basin is characterised by movements of the Zechstein salt (Hospers *et al*., 1988). Sedimentary salt layers have been mobilised as viscous fluid, which tends to rise because it has a lower density than the overlaying sediments. Salt pillows and salt diapirs may create structures that give rise to dome-shaped traps, although they may also cause erosion. During the second rift event (Late Jurassic – Early Cretaceous), several basins developed with a NW-SE orientation in the Central North Sea (e.g., the Central Graben) and the NS-oriented Viking Graben in the northern North Sea (e.g., Viking Graben; Gabrielsen *et al*., 2001).

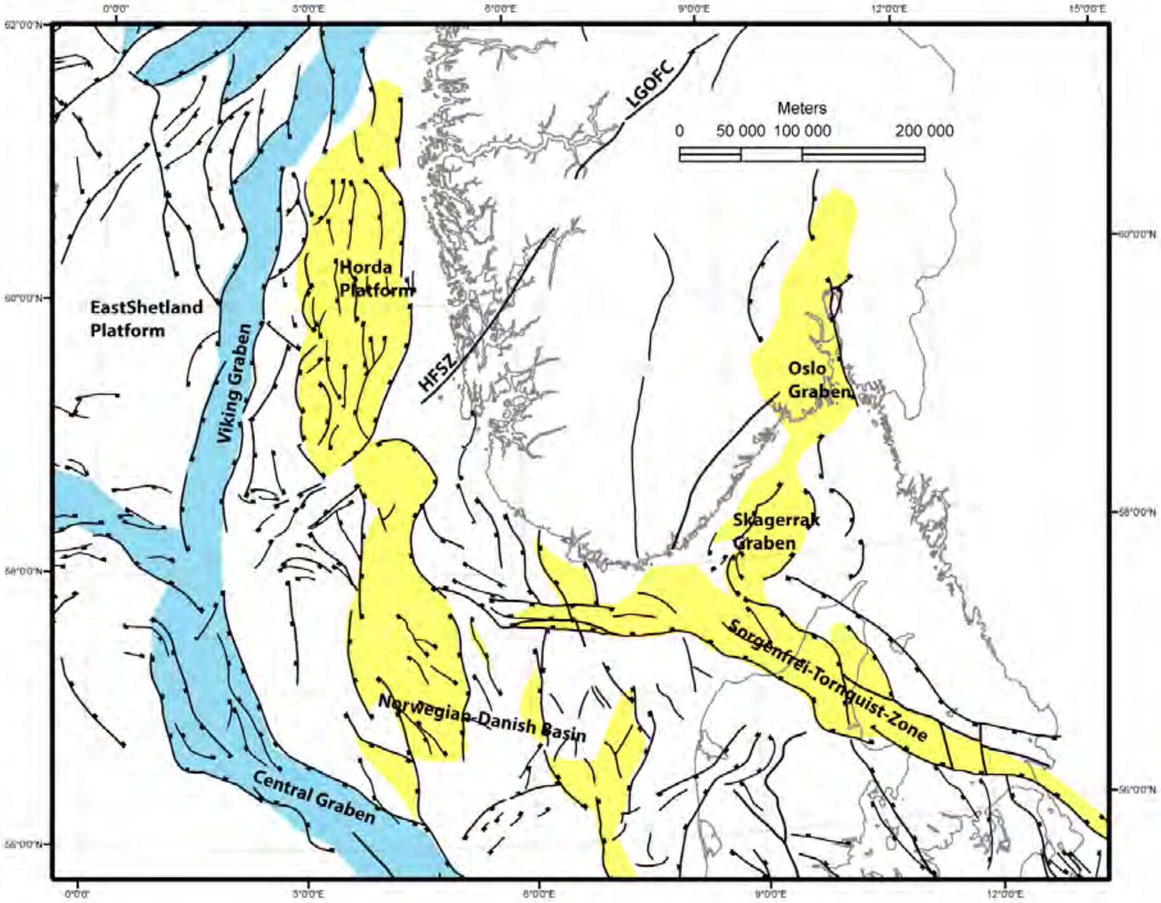


Figure 3.1. ***The main geological structures of southern Scandinavia, including the Danish Basin (i.e., the eastern part of the Norwegian-Danish Basin), the Sorgenfrei-Tornquist Zone, the Skagerrak/Kattegat Platform, Skagen Graben, and the Ringkøbing-Fyn High. The other elements shown are the East Shetland Platform, Horda Platform, and Oslo Graben.***

During the Cenozoic, the North Sea Basin developed as an epeiric sea centred above the Jurassic to early Cretaceous Central Graben (Faleide *et al*., 2002). The basin is bordered to the east and northeast by the Fennoscandian landmass, to the south by Central Europe, and to the west by the British Isles (Figure 3.1). The eastern part of the Cenozoic North Sea Basin is located above a number of late Paleozoic and Mesozoic structures: the Ringkøbing-Fyn High, the Central Graben, the Horn Graben, the North German Basin, and the Norwegian-Danish Basin (Huuse, 2002; Michelsen *et al*., 1998). The Sorgenfrei-Tornquist Zone to the northeast underwent uplift in response to Alpine compression in the Late Cretaceous-Paleocene, and may have constituted a topographic barrier for any sediments coming from southern Scandinavia (Michelsen *et al*., 1998; Faleide *et al*., 2002; Huuse, 2002). Thus, Paleogenic uplift of source areas occurred in at least two separate regions: along the Sorgenfrei-Tornquist Zone and along the Atlantic margin of northwest Europe (Faleide *et al*., 2002, and references therein; Huuse, 2002, and references therein). Magmatic activities in the Late Paleocene-Early Eocene related to the opening of the North Atlantic caused uplift of the land surface in Norway and Scotland (Riis and Fjeldskaar, 1992; Jensen and Schmidt, 1993).

During the Oligocene to middle Pleistocene period, the eastern and central North Sea was filled with pro-deltaic and deltaic sediments supplied from the N (Oligocene), NE (Early Miocene), E (Late Miocene-Early Pliocene) SE (late Pliocene), and SSE (Pleistocene) (Huuse, 2002, and references therein). In the Early Neogene, sediments were transported from the NE, with a marked shift in the Middle Miocene with subsequent deposition *via* the Baltic River system into the southern North Sea. During the Late Neogene (Pliocene and Pleistocene), the northern hemisphere was glaciated, with subsequent glacial deposits in the central and eastern North Sea. As a consequence of isostatic rebound related to this glaciation, together with tectonic uplift, the Cenozoic sedimentary record is tilted upwards towards the NE.

Data analysis

Large amounts of seismic data are available for the studied area (Figure 3.2). Information on wells, including drill cuttings and well logs, has been integrated with the seismic interpretation. The ongoing PhD project of Erlend Morisbak Jarsve includes a study of regional high-quality 2D seismic reflection profiles tied to key wells, providing the best data coverage (Figure 3.2). The Cenozoic seismic stratigraphic framework is based on the work of Jordt *et al*. (1995), which subdivided the Cenozoic succession into ten seismic sequences (CSS-1 to CSS-10). The study of the Mesozoic has been carried out in close co-operation with GEUS, which interpreted the Triassic-Jurassic succession in the Danish part of the Skagerrak and the eastern North Sea. Erlend Morisbak Jarsve has re-interpreted the corresponding succession in the Norwegian sector based on the new seismic data coverage presented in Figure 3.2.

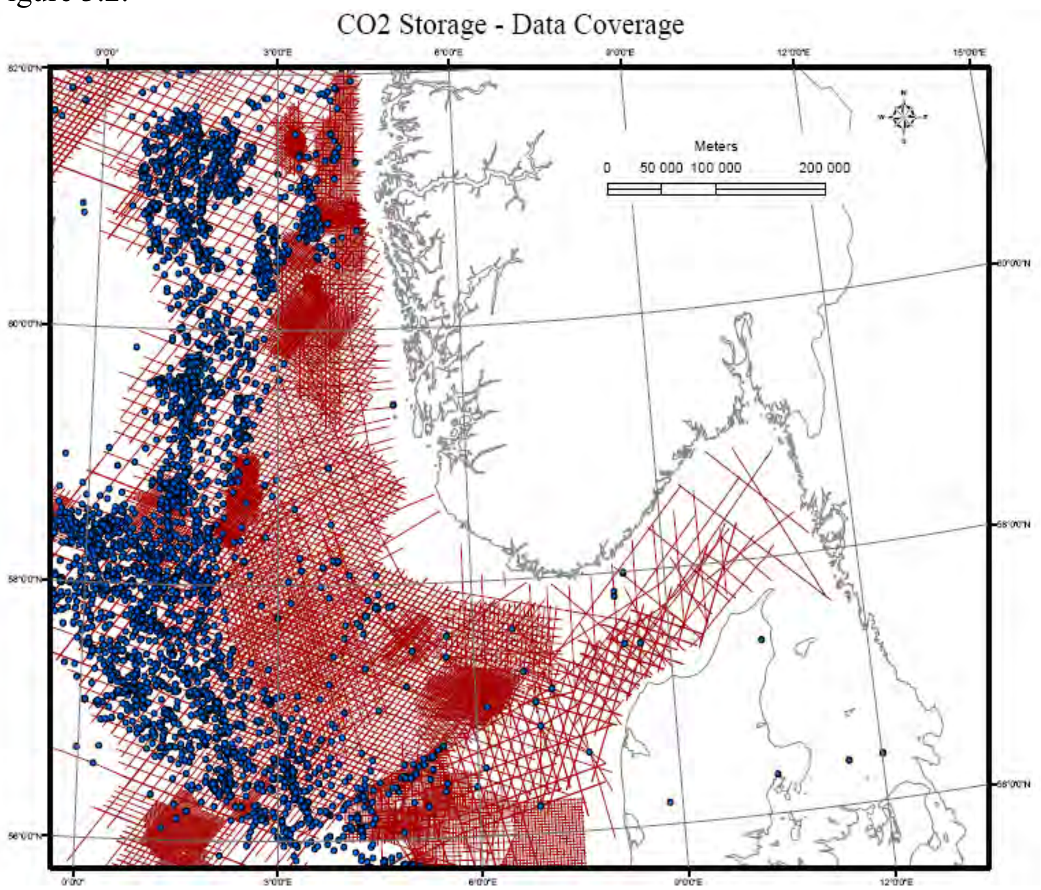


Figure 3.2. ***Overview map of the study area with the "new" seismic dataset coverage from Fugro and the locations of the wells. The new seismic data is the basis for elucidating the potential for CO_2 storage systems in the eastern North Sea, Skagerrak, and Kattegat areas.***

Some of the wells selected are the principal sources for analysis on the bases of location and geological succession. Some of the key wells were selected and analysed further to obtain information about the age and lithological/mineralogical composition (reservoir characterisation and cap rock integrity) of the main CO_2 plays.

3.2.1 Potential for CO_2 storage in the Upper Paleozoic, Mesozoic, and Cenozoic sedimentary rocks

The concept of CO_2 storage plays includes reservoir-seal pairs located in suitable structural and/or stratigraphic traps. We have subdivided the potential systems for CO_2 storage into Upper Paleozoic, Mesozoic, and Cenozoic plays. The screening of the potential Upper Paleozoic and Mesozoic and Cenozoic plays is based on existing data and published work, as well as ongoing Cenozoic work based on the new seismic data set from Fugro. Selected regional seismic profiles of the Paleozoic, Mesozoic, and Cenozoic sedimentary sequences linked to key wells were used in the mapping. Stratigraphic and lithological data for some of the selected Danish wells have proven essential for both the screening work and the subsequent detailed selected site studies. A wide range of selection criteria is applied with respect to temperature, pressure, and burial depth, with consideration of reservoirs to a depth of about 3 km. Reservoir quality normally decreases with burial depth, while drilling and operational costs increase. Thus, 3 km is a useful cut-off depth (Faleide *et al.*, 2011).

Upper Paleozoic plays

The potential reservoir rocks in this region are the Permian sandstones (Rotliegend) found along the Sorgenfrei-Tornquist Zone, in the Permian Basin and in the eastern part of the Norwegian-Danish Basin. There are potential structural traps related to Permian rifting and stratigraphic traps related to erosional truncation of Upper Paleozoic strata, with Permian (Zeichstein) salt and Mesozoic shales as potential seals.

Mesozoic plays

There are abundant potential Triassic and Jurassic sandstones (Skagerrak Fm, Gassum Fm, Haldager Sand Fm/Bryne Fm) and several Upper Jurassic/Lower Cretaceous sands in the following areas: Skagerrak Graben, Sorgenfrei-Tornquist Zone (Aalborg Trough, Fjerritslev Trough), Norwegian-Danish Basin, Farsund Basin, Egersund Basin, Åsta Graben, and Stord Basin. In this region, there are several types of reservoirs with trapping and sealing mechanisms, i.e., stratigraphic ones related to Jurassic prograding systems (Figure 3.3; B - Stord Basin, Åsta Graben; E - Egersund Basin) or erosional truncation (A - Skagerrak), and structural ones related to salt diapirism (D - Norwegian-Danish Basin), and faulting and inversion (Sorgenfrei-Tornquist Zone extending into the Farsund Basin). Jurassic-Cretaceous shales (Fjerritslev Fm, Børglum Fm/Lola, and Farsund Fm) have been shown to be excellent seals in Denmark, and Plio-Pleistocene glacial sediments above the erosional unconformity in Norwegian Channel may constitute the uppermost seal. Similar sediments form an effective seal in the Peon gas field.

Although the chalk may function both as reservoir and seal, it is not considered further in this study.

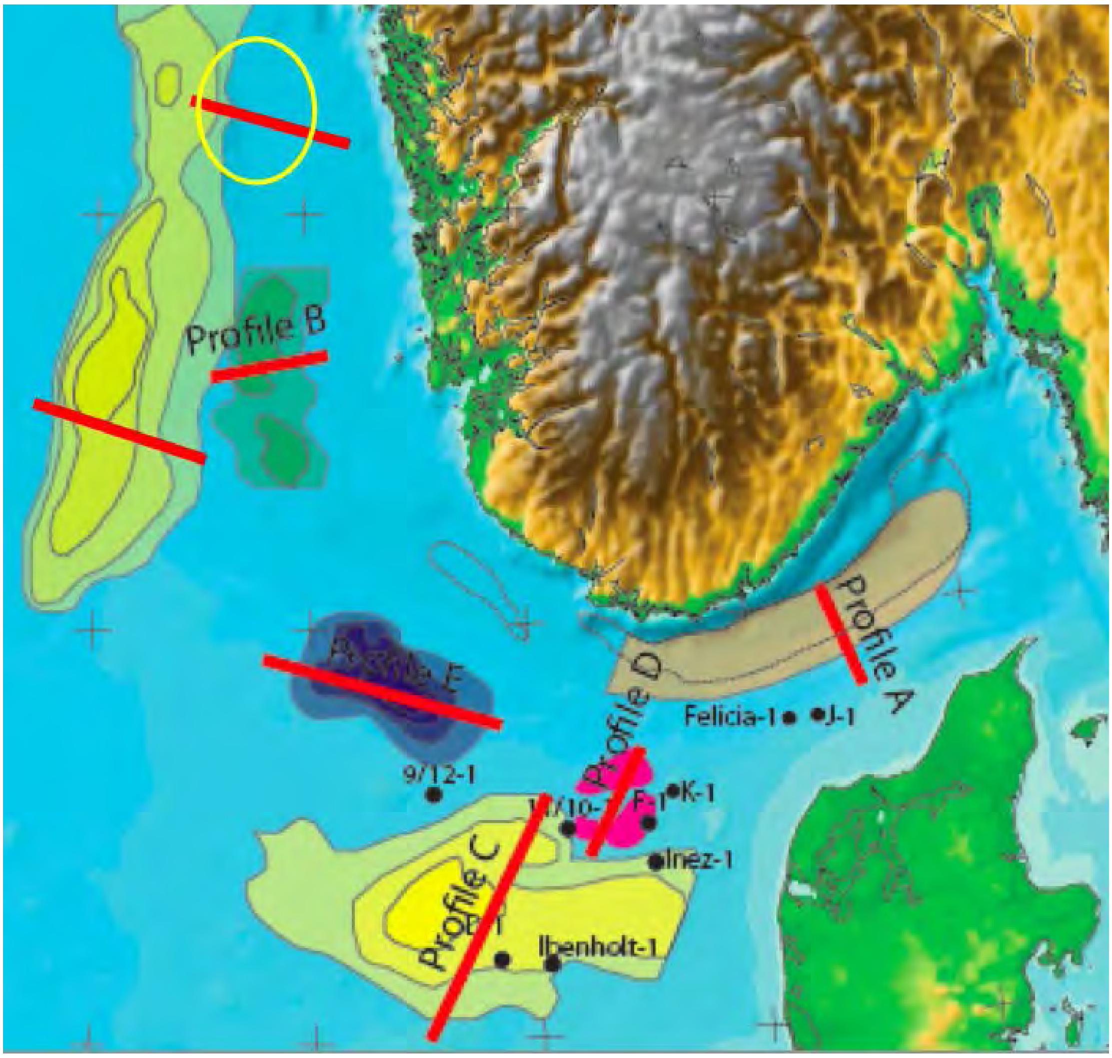


Figure 3.3. ***Overview map of the study area with mapped CO_2 storage plays. The Troll sands (circle) and the Utsira Fm are shown to the northwest. A) Gassum/Haldager Sand reservoirs in the Skagerrak Graben. B) Upper Jurassic play in the Stord Basin. C) Oligocene sands in the Norwegian-Danish Basin; D) Triassic/Jurassic plays in the Norwegian-Danish Basin (salt pillow structures); E) Upper Jurassic play in the Egersund Basin.***

Cenozoic plays

Several sands, especially those from the Oligocene-Miocene, in the Norwegian-Danish Basin (Profile C in Figure 3.3), are located in stratigraphic traps related to a sedimentary outbuilding, which in turn is related to regional subsidence of the North Sea Basin and uplift of the surrounding land areas. In addition, some of the Paleocene sandstones in the Siri Fairway are potential reservoirs. The potential seals are Oligocene to Pliocene mudstones, and there may also be sealing faults.

3.2.2 Ranking of storage plays

The main uncertainty associated with the Late Paleozoic plays is poor reservoir quality. There are several reasons for this: 1) large content of volcanoclastic material in the sandstones; 2) excess heating by volcanic activity; and 3) deeper burial. All of these factors result in cementation and reduced permeability. Permian sandstones are uncommon in the area and are too deeply buried to be of use.

There are several Mesozoic sandstone reservoirs of good quality in the area, although there are uncertainties related to traps or seals. Facies changes could occur within the seals and inversion could cause uplift/erosion and fault reactivation. The Mesozoic strata are regionally tilted in relation to onshore uplift and offshore subsidence. For the Cenozoic plays, there are uncertainties as to sand distribution and quality, and in some areas the regional tilt may have caused uplift and erosion. There could be facies changes within the seals (i.e., a mudstone might grade into a more sandy sediment with poorer sealing capability), making these seals less effective.

The Permian (Rotliegend) sandstones may be the prime reservoir of the Paleozoic plays, with Permian (Zechstein) salts or Mesozoic shales as potential cap-rocks. However, given the uncertainties associated with reservoir quality (porosity and permeability) and limited occurrences above a depth of 3 km, we rank the Paleozoic plays lowest in priority. The main Mesozoic plays are systems with Triassic-Jurassic sands (Skagerrak Fm, Gassum Fm, and Haldager Sand Fm) and with potential Jurassic-Cretaceous shales or Plio-Pleistocene sediments seals and potential structural and stratigraphic traps. Similar systems are well-known from Denmark. There are also additional smaller sands of the Upper Jurassic/Lower Cretaceous, but we recommend focusing on the major sandy units. The chalk has not been considered due to their low matrix porosity and lower expected injectivity. There are both structural and stratigraphic traps for the Triassic-Jurassic sandstones, and these Jurassic-Triassic plays rank at the top of our list. There are several potential Cenozoic plays in the Norwegian-Danish Basin that are connected with Paleocene and Oligocene-Miocene sands. These sands are of different ages but represent similar plays in the Utsira formation. These newly discovered systems in the Norwegian-Danish Basin are quite interesting. The reservoir quality of the sands and their distribution are presently uncertain, and regional tilt and facies changes within seals and reservoirs (sandstone may lose its reservoir qualities if the proportion of mud increases) represent added uncertainty. Therefore, we rank these plays below the most interesting Mesozoic prospects.

3.3 Selection and characterisation of geological sites

Based on the ranking of the CO_2 plays described above, the Skagerrak Graben and the adjoining Farsund/Norwegian Danish Basin were selected for closer examination (Figure 3.4). The potential formations are: Skagerrak Fm; Gassum Fm; and Haldager Sand Fm/Bryne Fm. The Gassum Fm is overlaid by the thick mudstone sequences of the Fjerritslev Fm, providing an excellent seal. Similarly, the Haldager Sand Fm is well sealed by the mudstones of both the Flyvbjerg and Børglum formations (Figure 3.5). In addition, there is an upper seal toward the sea formed by the Quaternary mudstones. In general, thicker mudstone/shale formations make better seals, although even rather thin young sediments have been shown to be effective cap rocks. The shallow Peon gas field has a seal of Quaternary mud that is less than 200 m in thickness. Figure 3.6 shows that there is generally 100 - 200 meter thick Quaternary seal in the area.

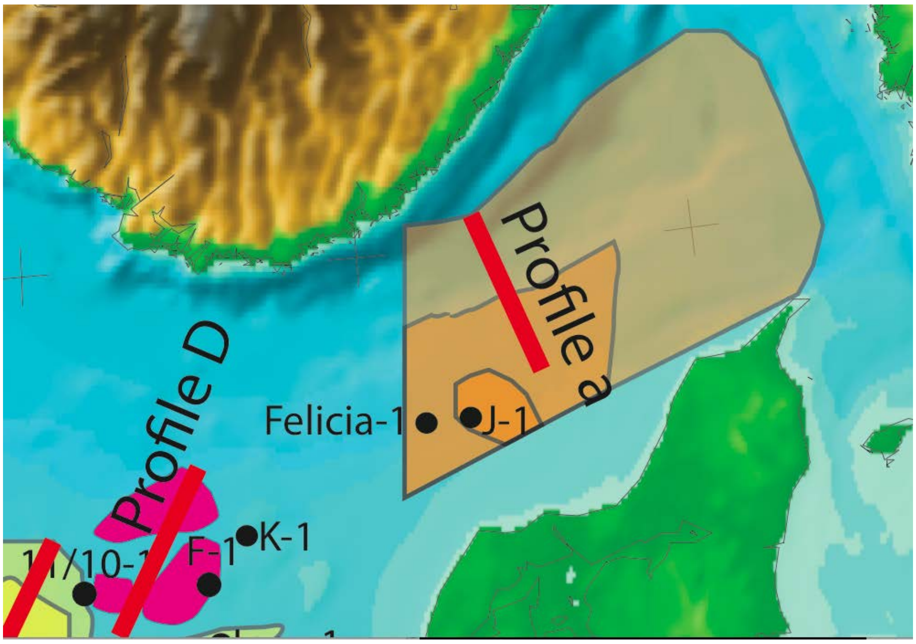


Figure 3.4. ***Map of the area selected for closer characterisation of Triassic - Jurassic sandstones that are potentially suitable for CO_2 storage. The NE area has large reservoirs that are gently sloping upwards towards the NNW and NE, while the eastern and southern areas are dominated by halokinesis and several potential structural traps.***

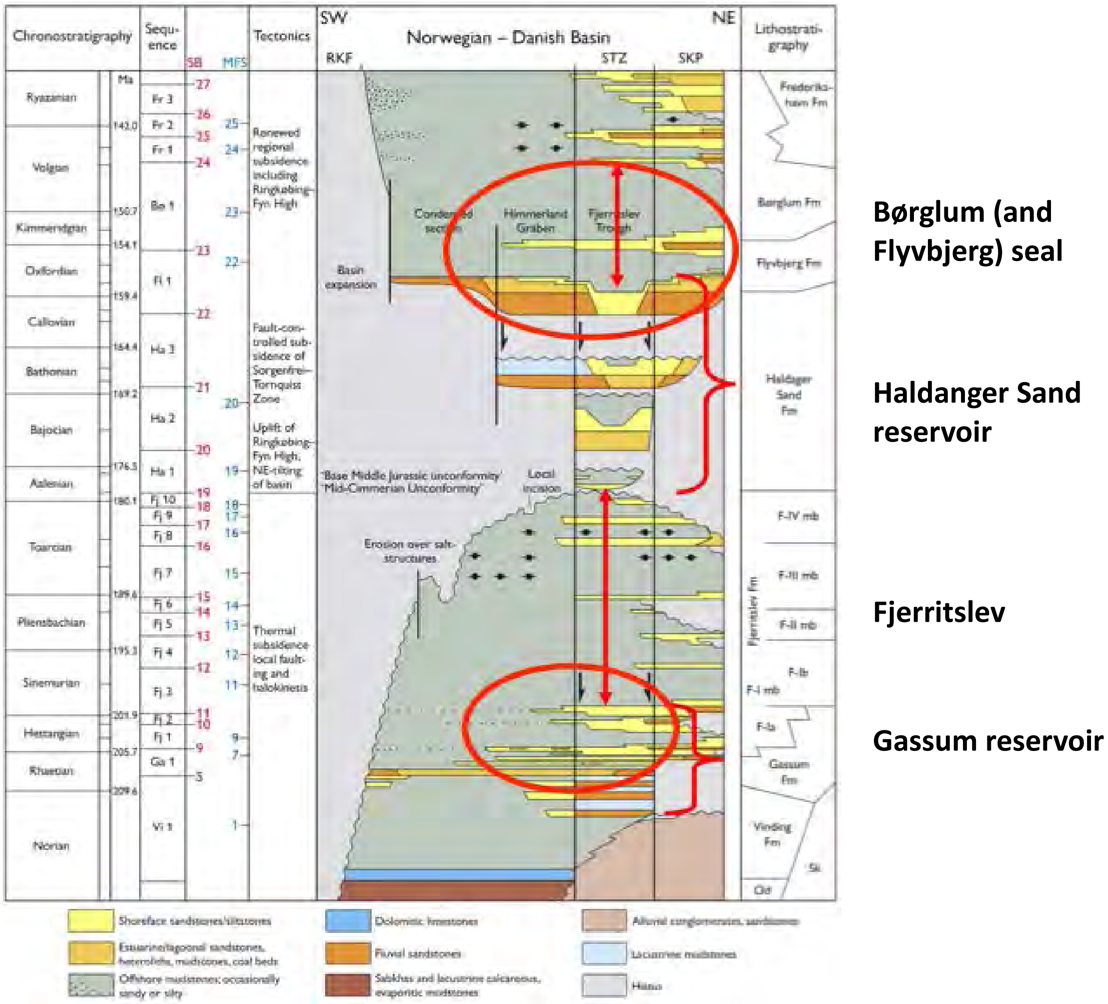


Figure 3.5. ***Sequence stratigraphy and sequence boundary surfaces from Nielsen (2003) used to correlate the seismostratigraphic surfaces. The reservoirs and seals of special importance are highlighted.***

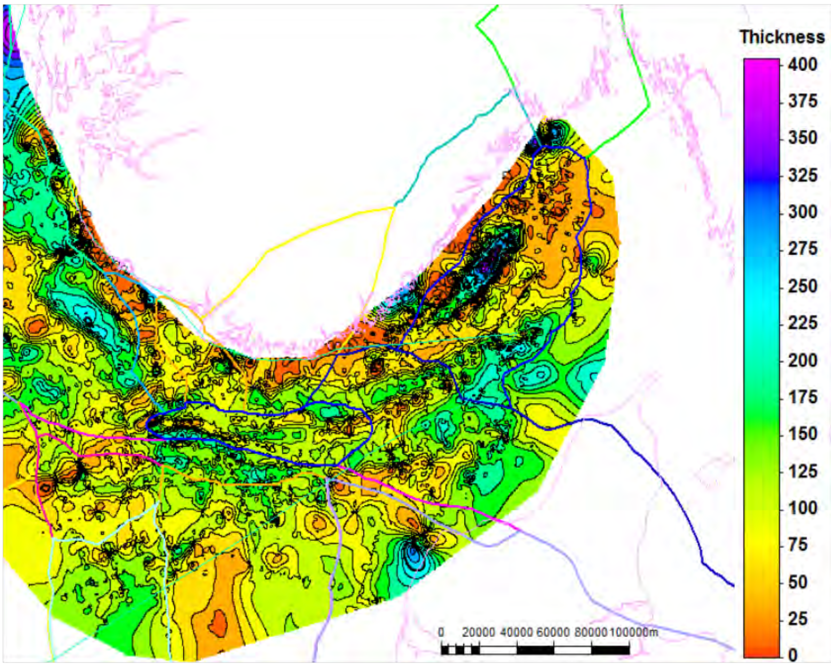


Figure 3.6. Thickness map of the Quaternary sediments.

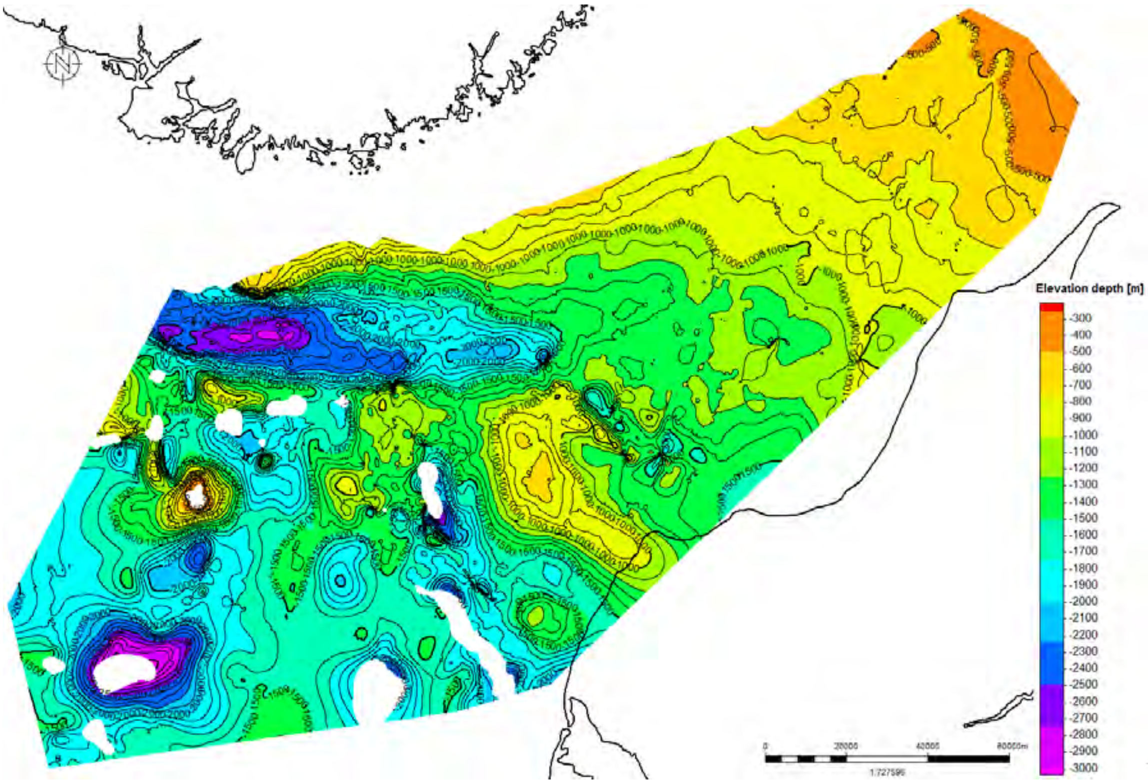
3.3.1 3D delineation of structures using seismic data, well logs, and sequence stratigraphy

The major seismostratigraphic Triassic and Jurassic surfaces in the area were mapped based on the available 2D seismic lines and sequence boundaries from Nielsen (2003), as shown schematically in Figure 3.5. The burial depths of the top Haldager Sand and Gassum formations are quite similar, as shown in Figure 3.7. The main difference between these two formations is that the lower Gassum formation in the southern part is somewhat more affected by halokinesis, see Figure 3.8. Thus, we have two distinct types of reservoirs for the sands in the Haldager Sand and the Gassum formations.

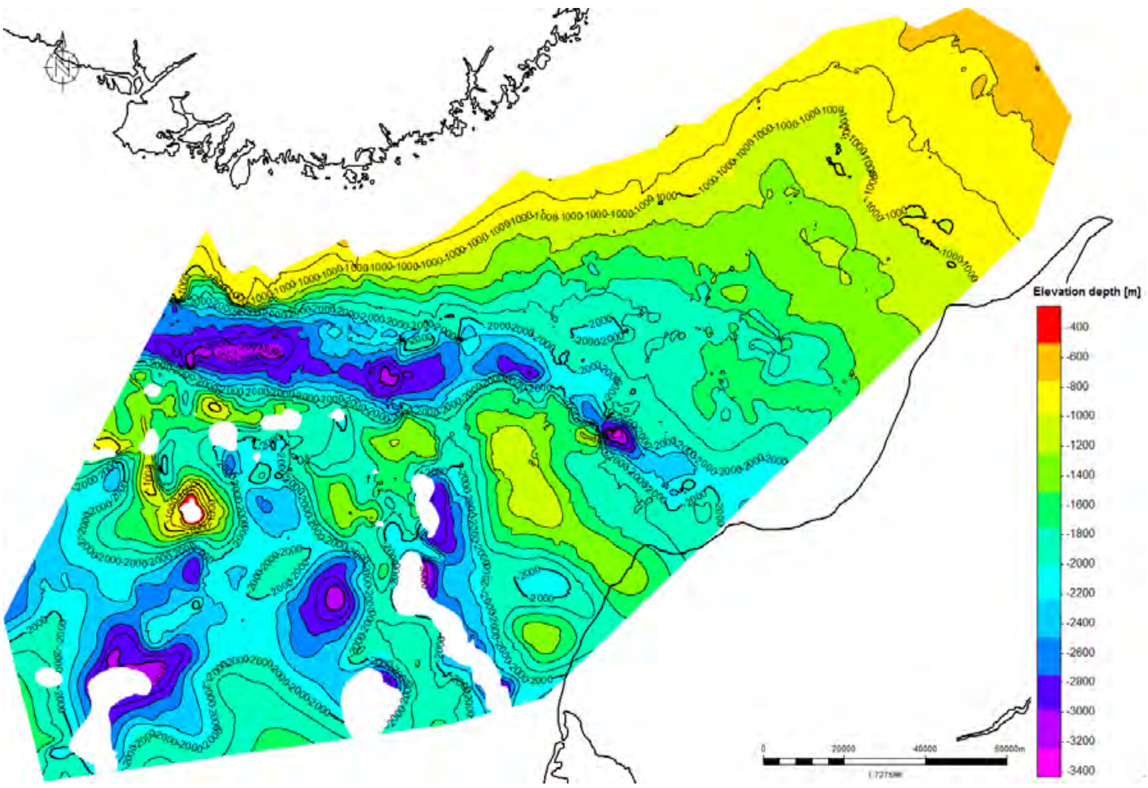
3.3.2 Geological reservoir model

Geological reservoir models are normally based on volumetric information for the formation (i.e., lateral thickness variations, see Figure 3.9), the fraction that is sandstone (i.e., net sand thickness), and the extent to which this fraction has sufficient reservoir porosity (i.e., net reservoir thickness). In the present study, the net sand is based on a cut-off value of 30% volume of shale/mudstone (Vshale), while the net reservoir uses a 15% porosity cut-off value. Porosity is either determined from core samples or derived from well logs. Log-derived porosity should be calibrated to core analysis. In this study, log-derived porosities are used and other reservoir parameters are provided by GEUS (Nielsen *et al*., 2011).

Top surface of the Haldager Sand formation



Top surface of the Gassum formation



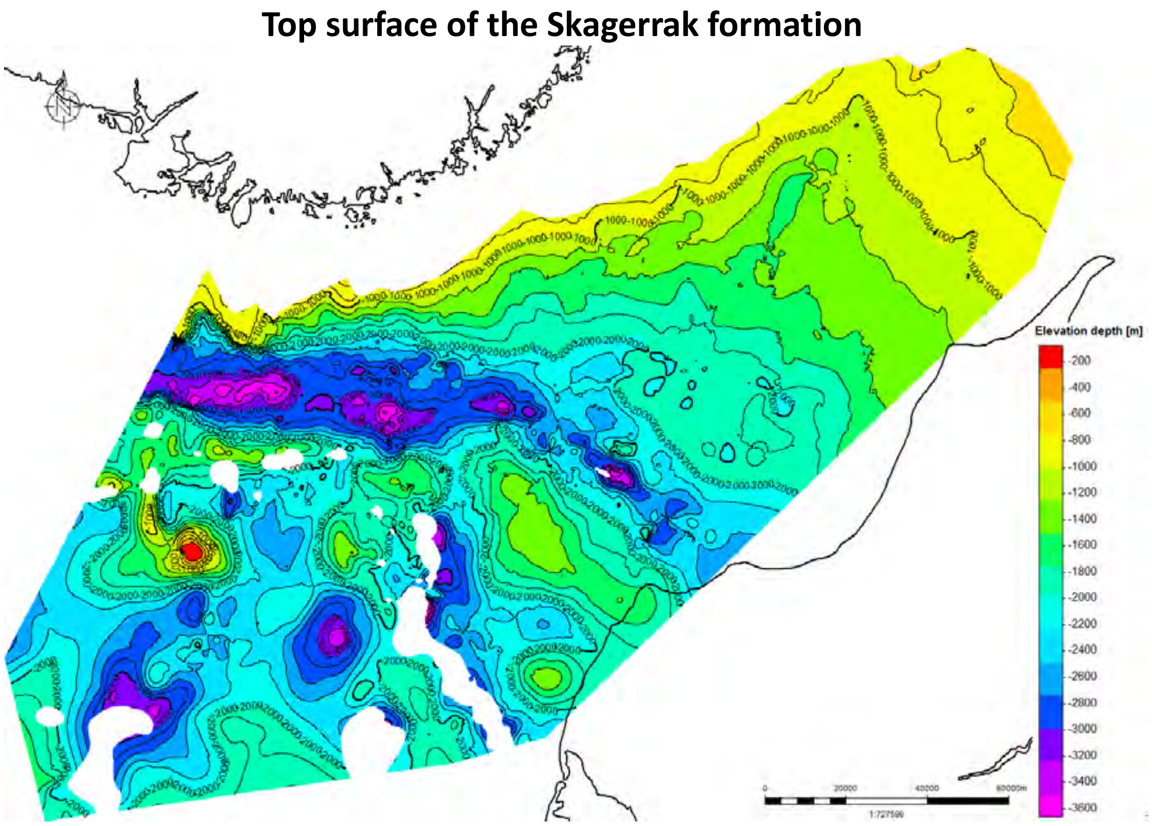


Figure 3.7. *Top surfaces of the Haldager Sand Formation, Gassum Formation, and Skagerrak formation. Note the differences in deformation style north and south of the Sorgenfrei-Tornquist Zone. The southern part is strongly influenced by halokinesis, with several salt-pillow and salt diapir structures (white).*

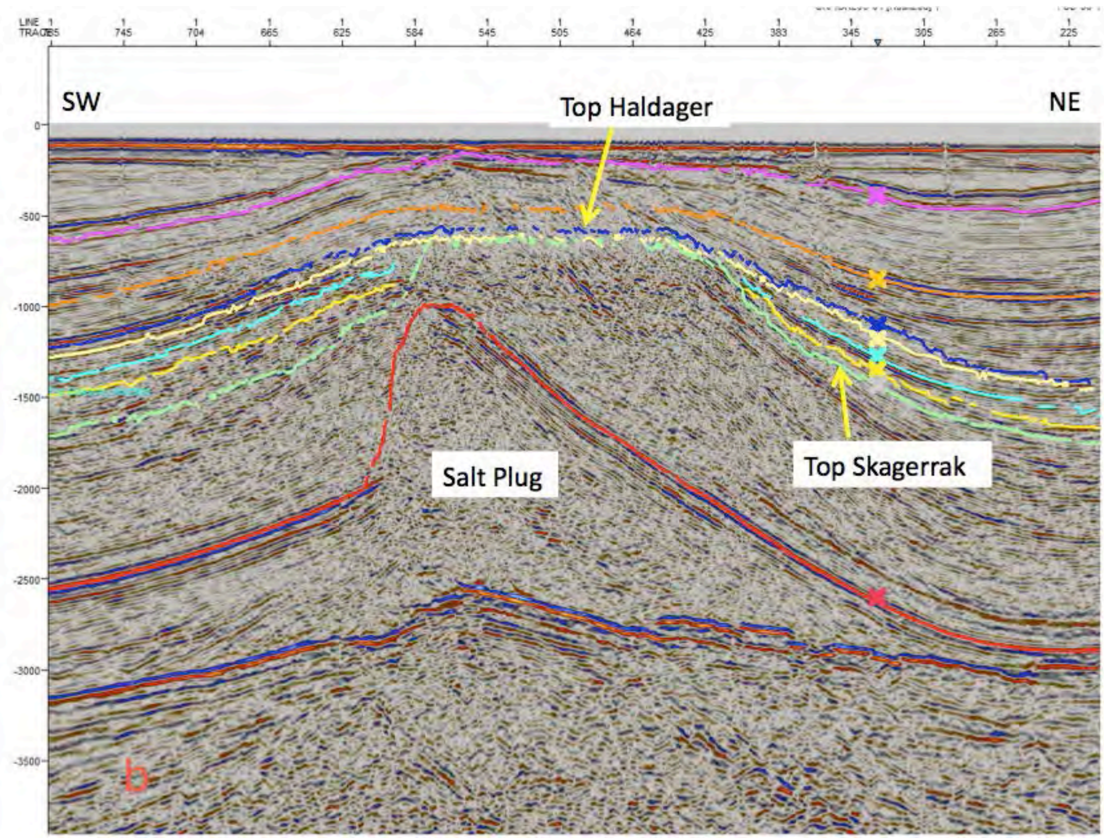
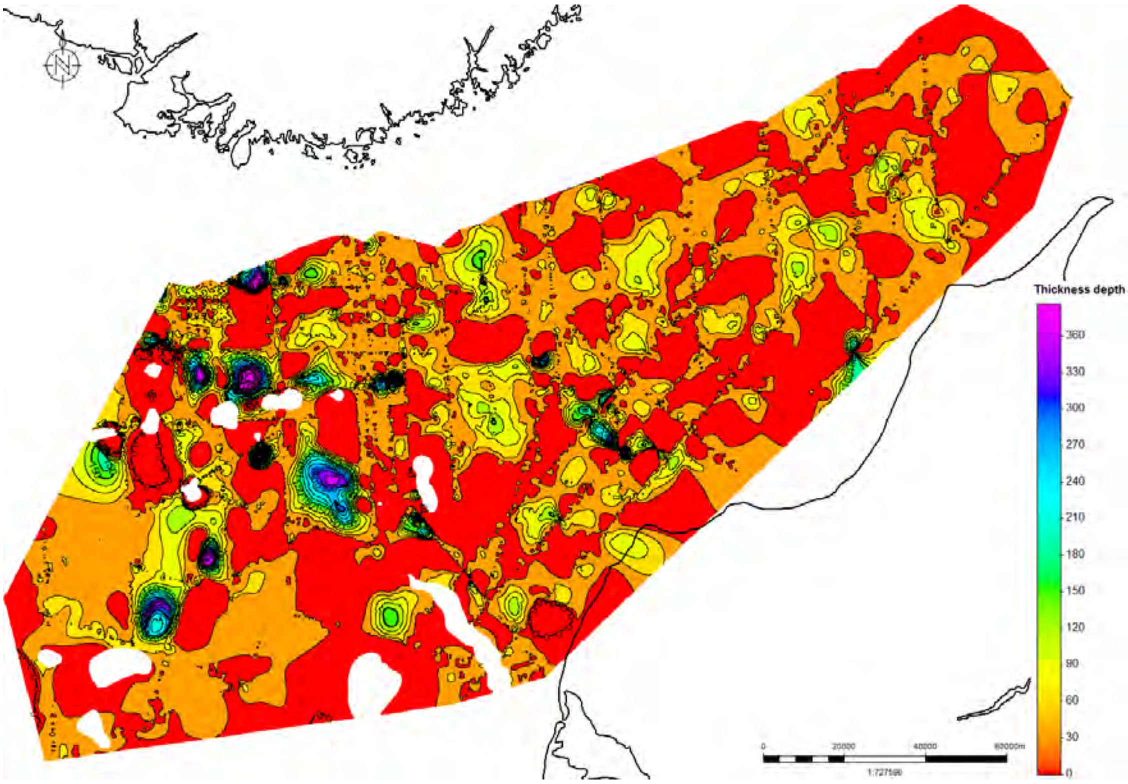


Figure 3.8. *Example of a seismic cross-section across the salt plug. Note the erosion of the Triassic and Jurassic sediments and/or contemporaneous sedimentation on the flanks.*

Thickness map of the Haldager Sand



Thickness map of the Gassum formation

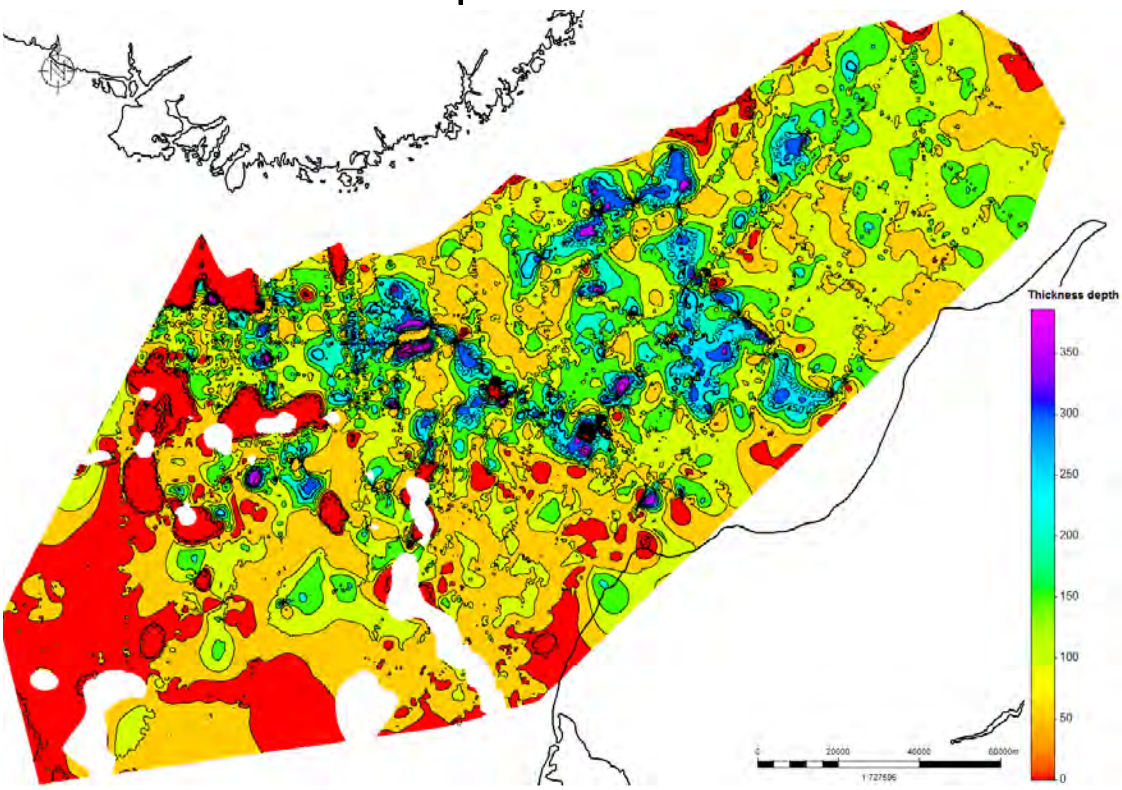


Figure 3.9. Thickness map of the Haldager Sand and Gassum formations.

Permeability is normally estimated from porosity, using empirical porosity-permeability relations obtained for the formation in question. Thus, permeability is heavily dependent upon the depositional environment and later diagenetic changes, which take place during burial (conditions of higher pressure and temperature). To date, no porosity-permeability model has been published for the Triassic-Jurassic area, which we are studying. However, GEUS has compiled a large dataset of porosity-permeability data for the eastern North Sea, Skagerrak, Kattegat, and northern Jutland (see Figure 3.10). Using the data from the Skagerrak Fm, Gassum Fm, Haldager Sand Fm, and Sandnes Fm, GEUS has derived the following relationship to estimate permeability:

$$\text{Permeability} = 10^{6} * \text{Porosity}^{5.8577}$$

where permeability is given in mD and porosity in fraction.

The temperature model is based on an average surface temperature of 8°C and a temperature gradient of 30°C/km. GEUS has also provided a salinity model, based on the salinity depth trends from Laier (1989) for Danish onshore areas, which is adopted here.

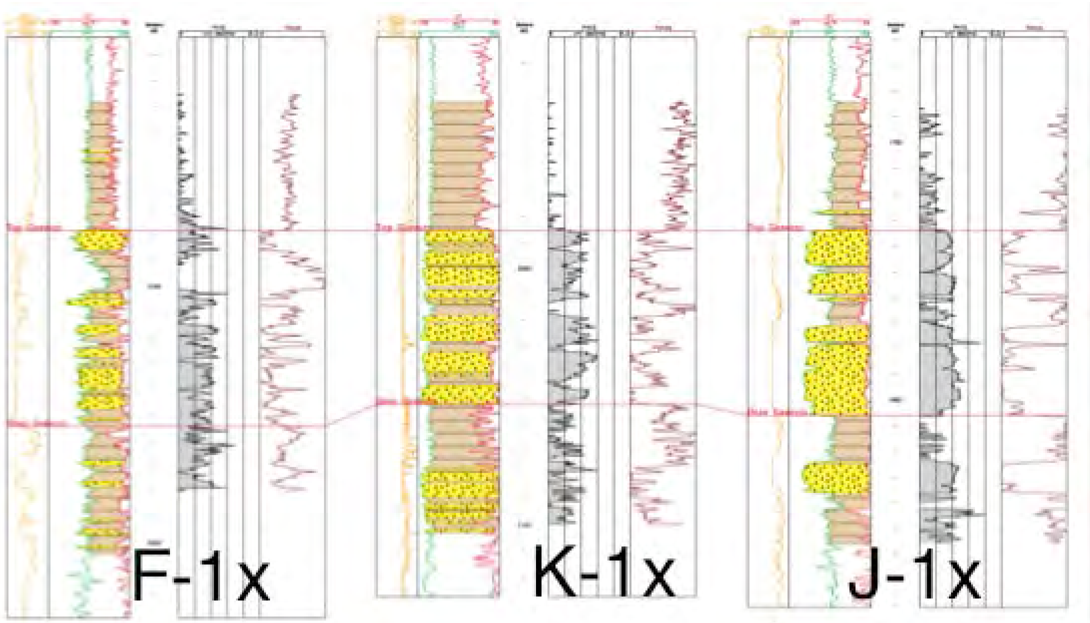


Figure 3.10. ***Gassum formation log panel for the F-1x, K-1x, and J-1x wells (GEUS, 2011).***

3.4 Reservoir simulations with CO_2 injection modelling

A reservoir simulation of CO_2 injection into the Gassum formation in the area north and north-east of the Fjerritslev Trough (Fawad *et al.*, 2011) was performed by SINTEF Petroleum Research (Bergmo *et al.*, 2011). Two open dipping aquifer models (Model 1, Model 2) with homogenous properties and homogenous thickness were made (Figure 3.11). In addition, a model of the Hanstholm structure just south of Model 1 was constructed in which initial simulations have been performed for estimating storage capacity. Details of the reservoir models, sensitivities and simulation results are given in a separate technical report.

3.4.1 Description of reservoir models

The locations of Model 1 and Model 2 were decided based on the concept of storing CO_2 in an open dipping trap. Thus, the injection points should be located down-flank of a gentle dipping formation. The main short-term mechanism for trapping CO_2 would then be capillary trapping the CO_2 as a residual phase. In addition, the long migration distance of the injected CO_2 would enhance the dissolution of CO_2 into the formation water. The Hanstholm structure, which is assumed to be a closed structure, was chosen for its size. The main short-term trapping mechanism in Hanstholm would be capillary trapping by the assumed sealing cap rock.

Reservoir properties are based on the petrophysical logs from 12 Danish wells. No wells penetrate the model areas, and the average properties of the wells have been used in Model 1 and Model 2 shows the average values for the wells that penetrate the Gassum formation with a 30% volume shale cut-off and a 15% porosity cut-off. The well data were received from GEUS.

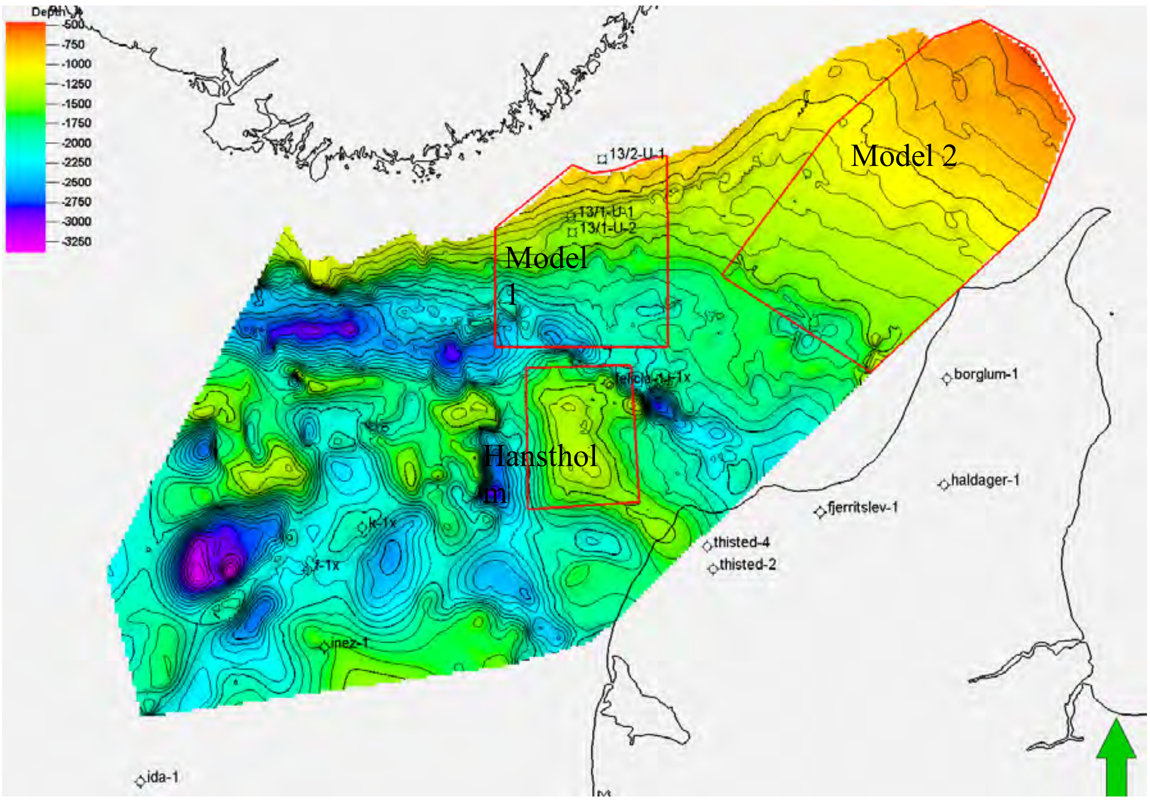


Figure 3.11. ***Outline of the areas for Model 1, Model 2 and Hanstholm shown on a top Gassum Fm. surface.***

Table 3.1. ***Temperature, salinity, and average porosity and permeability of the Gassum Formation based on data from 12 wells.***

Well	**Depth [m]**	**Porosity [%]**	**Permeability [mD]**	**Temperature [°C]**	**Salinity [ppm NaCl]**
F-1x	2,100	20.4	90	71	175,000
K-1x	2,000	23.7	220	68	175,000
J-1x	1,800	20.1	85	62	160,000
Felicia-1	1,600	-	-	56	150,000
Børglum-1	1,450	28.6	650	51	140,000
Thisted-1	800	27	470	32	90,000
Mors-1	2,800	21.8	130	92	240,000
Inez-1	1,700	22.7	170	60	150,000
Sæby-1	1,100	23.4	200	41	110,000
Terne-1	1,200	17.7	40	44	120,000
Rønde-1	2,700	15.1	15	90	160,000
Vedsted-1	1,900	24.1	240	65	170,000

The average porosity of the Gassum fm in the wells is 22.5 %, although a small correlation to depth has been applied in Model 1 and Model 2. Permeability is correlated to porosity by a relationship derived by GEUS based on empirical data (see Section 3.3.2).

For the Hanstholm model, the Felicia-1 well, which is located at the edge of the structure, had very poor log data, therefore a synthetic well log was created from neighbouring wells and a facies model was built in which the reservoir properties were conditioned. The current Hanstholm model is an update of the model used for CO_2 storage capacity estimates in the Dynamis project (EU-funded project). Figure 3.12 shows the permeability distribution of the top-most sand layer in the Hanstholm model.

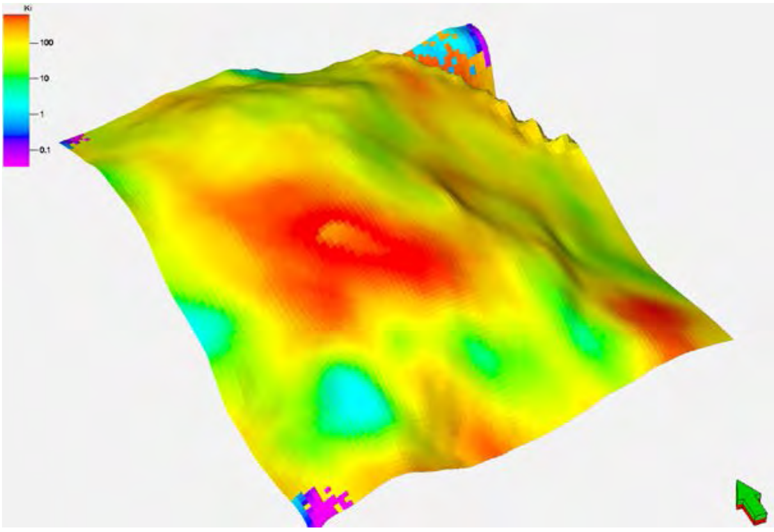


Figure 3.12. ***Permeability distribution of top-most sand facies in the Hanstholm structure.***

The open dipping trap models (Model 1 and Model 2) cover a wide depth range and therefore one can expect relatively large variabilities in the temperature and salinity of the formation water. A salinity gradient of 75.6 ppm NaCl per meter and a temperature gradient of 31°C/km were assumed. To model the effect of these parameters on the density, viscosity, and solubility of the injected CO_2, six pVT regions (having constant temperature and salinity) were generated for Model 1 and Model 2. Figure 3.13 shows the different pVT regions for

Model 2. The grid block sizes for the models are between 400 m and 500 m. In the Hanstholm model, constant temperature and salinity levels are assumed.

Initial hydrostatic conditions are assumed, with open/semi-closed boundaries up-dip towards the north (Model 1) and northwest (Model 2). All three models have boundary conditions representing the total mapped pore volume of the formation, i.e., a communicating pore volume of approximately $3 \cdot 10^{11}$ m^3 is assumed. The actual pore volumes for the three models without modified boundaries are: Model 1, $2.3 \cdot 10^{10}$ m^3; Model 2, $5.4 \cdot 10^{10}$ m^3; and Hanstholm, $1.9 \cdot 10^{10}$ m^3.

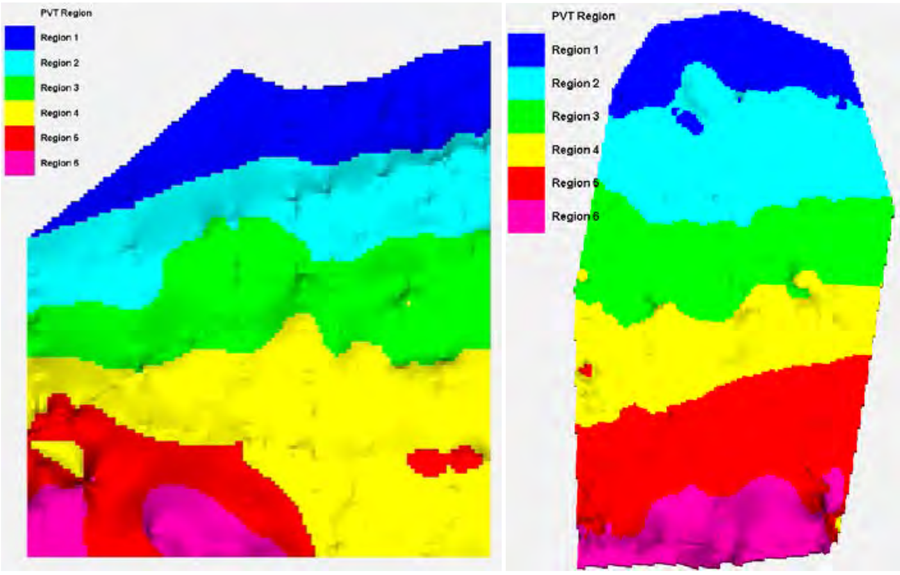


Figure 3.13. ***Depth regions with constant temperature and salinity levels in Model 1 (left) and Model 2 (right). The size of Model 1 is exaggerated compared to that of Model 2.***

3.4.2 Base case simulation results

In all three models, a total of 250 M tCO_2 is injected down-flank using three horizontal injection wells over a period of 25 years (base case). The total simulated time is 4000 years.

Model 1 and Model 2

Injection is performed through three horizontal injection wells that perforate the bottom layer, with a distance of 8–10 km between the wells. The wells have a perforation interval of 800–1000 meters. Injection depth is approximately 2410 m (Model 1) or 1708 m (Model 2). The well-injection rate is 3.33 $MtCO_2$/yr, which is equivalent to $4.88 \cdot 10^6$ Sm^3/day/well and a total of 10 $MtCO_2$/yr.

The results of the simulations on the open dipping traps are shown in Figure 3.14 and Figure 3.15 as distribution of CO_2. For Model 1 (Figure 3.14), the CO_2 reaches the northern border after 400 years, and after 4000 years 7.5% of the CO_2 has escaped. The remainder is capillary-trapped (~74.5%) or dissolved (~18%). For Model 2 (Figure 3.15), even after 4000 years, all the CO_2 is retained within the model boundaries. Overall, ~24% of the CO_2 is dissolved after 4000 years, while the remainder is capillary-trapped (residual).

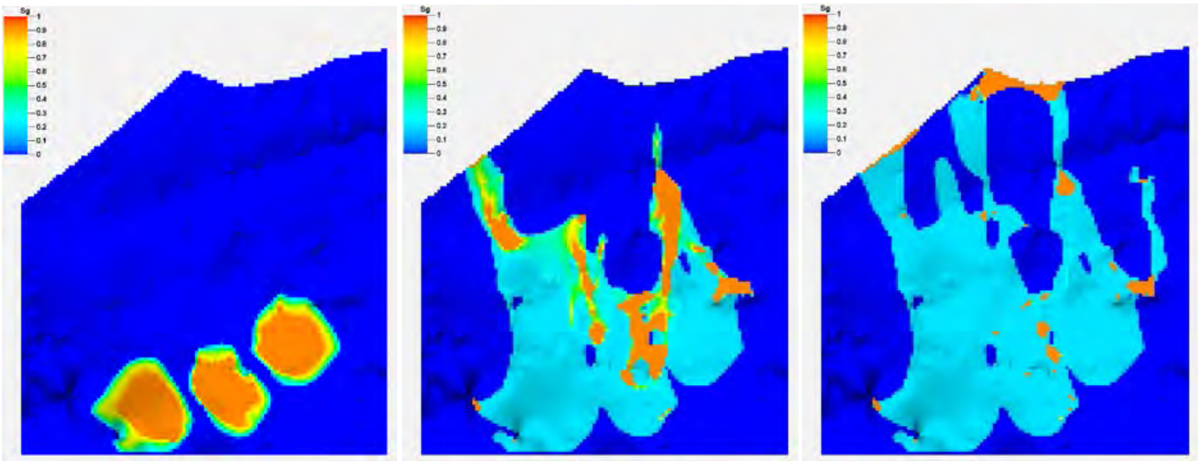


Figure 3.14. ***Plume development, shown as CO_2 saturation, for Model 1 at 25, 400, and 4000 years after end of injection phase.***

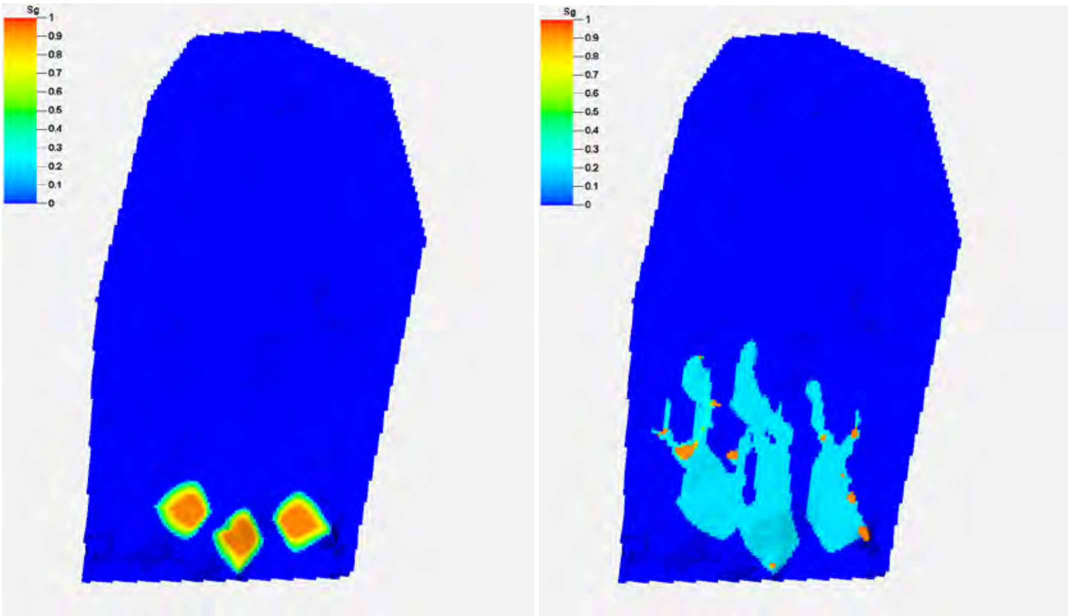


Figure 3.15. ***Plume development, shown as CO_2 saturation, for Model 2 at 25 years and 4000 years after end of injection phase.***

Hanstholm

The initial simulation of CO_2 injection in the Hanstholm structure is shown below. Three horizontal injection wells are located down-flank, at depths ranging from 1000 m to 1200 m, on the western and north-western sides 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 3.16 shows the CO_2 distribution after 25, 400, and 4000 years.

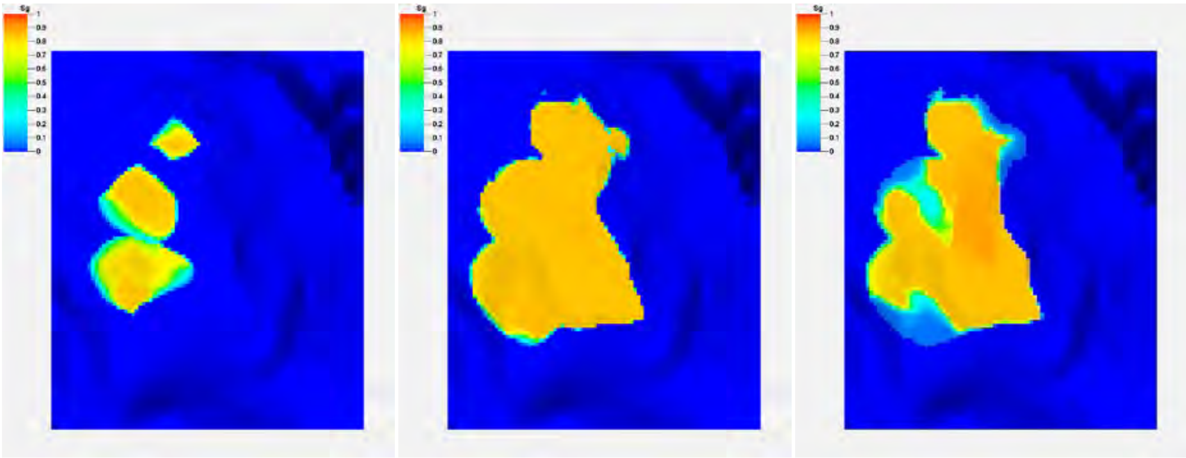


Figure 3.16. ***Distribution patterns of injected CO_2 in the Hanstholm structure after 25, 400, and 4000 years (from left to right).***

3.5 Evaluation of injectivity and storage potential

Injectivity is mainly a function of the permeability of 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 that affect the permeability of sandstone reservoirs include burial history and depth (diagenesis), shale content, and porosity. In general, injectivity decreases with increasing depth and increasing shale content.

Figure 3.17 shows the pressure increases for the three horizontal injection wells (increase in BHP) for Model 1 and Model 2. The BHP increase is approximately 90 bar in both cases. A safe pressure increase is assumed to be around 75% of the lithostatic pressure, although a detailed characterisation of the overburden is needed to verify this value. Even though estimates of safe pressure increases have not been performed at this stage, the difference between the hydrostatic and lithostatic pressure, increases with depth, enabling a higher safe pressure with depth.

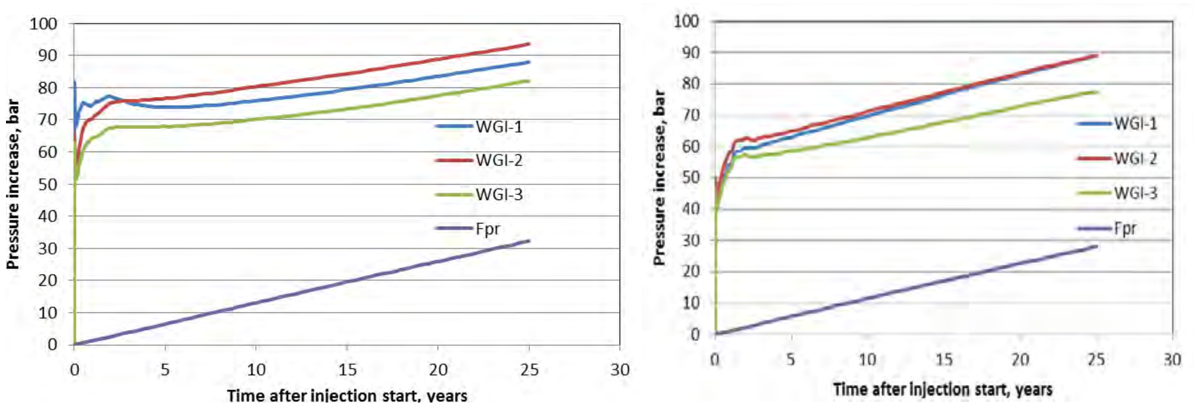


Figure 3.17. ***Pressure increases in the horizontal injection wells during injection, and average pressure increases in the formations for Model 1 (left) and Model 2 (right).***

If the pressure increase is too great, several options exists to reduce it, such as increasing the number of injection wells, producing formation water (requires production wells), and in the case of Model 1 and Model 2, injection of part of the CO_2 into the shallower Haldager formation. A simulation in which one-third of the CO_2 is injected into the Haldager formation in Model 2 has been set up, and the results are shown below. The injected CO_2 stays just inside the modelled area after 4000 years, the maximum BHP increase in Haldager is approximately 65 bar, and the BHP increase in Model 2 is reduced to 80 bar. Figure 3.18 displays the CO_2 distributions in the two formations.

The present simulations indicate that the open dipping traps in the Gassum formation can be used to store permanently 250 M tCO_2 by residual trapping. More detailed mapping of the reservoirs and overburden is required for better estimates of safe pressures and the required number of injection (and production) wells, as well as better estimates of CO_2 migration in the trap.

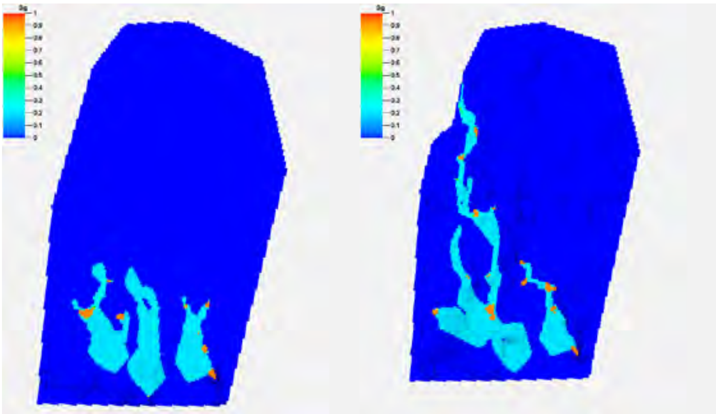


Figure 3.18. ***Distributions of CO_2 after 4000 years in the Gassum Formation (left) and the Haldager Formation (right).***

When three horizontal injection wells are used, the pressure increase in the Hanstholm structure is approximately 160 bar (Figure 3.19). This seems to be too high and the option of increasing the number of injection wells and/or introducing water production wells down-flank should be considered. As for the other models, a more detailed characterisation of the cap rock and overburden is required. However, the Hanstholm structure is large enough to contain 250 MtCO_2, assuming cap rock sealing.

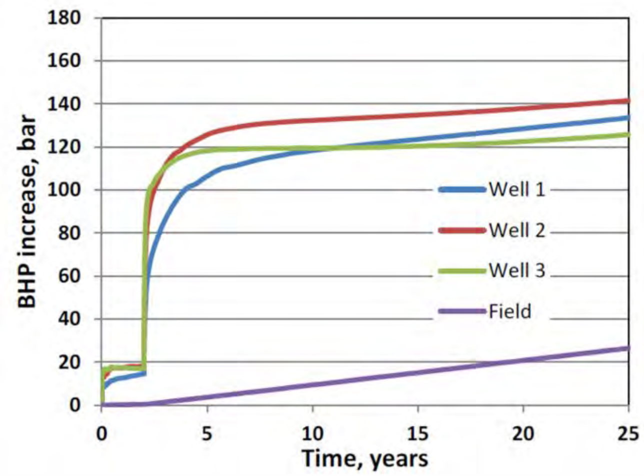


Figure 3.19. ***Pressure increase in the Hanstholm model shown by BHP in the wells and average formation pressure (field).***

A sensitivity study to identify important parameters for storage capacity and safety is on-going and will be presented in the technical report.

3.6 Safety aspects related to the storage of CO_2 offshore and onshore

With respect to the mechanisms involved in CO_2 storage, uncertainties related to the physical, geomechanical, and geochemical processes must be considered. The exact geometries of the target formations and the sealing formations, and the interface between the two affect the lateral migration of CO_2. The uncertainty in defining this interface has a significant effect on the accuracy of predictions of CO_2 spread and safety of storage. Some of the uncertainties associated with safe CO_2 storage raised in the current project are:

- Leakage through undetected fractures and faults in the cap rock and further to the sea floor.
- Substantial increases in reservoir pressure towards the cap rock capillary entry pressure or fracture pressure.
- Failure to determine CO_2 migration paths and locations. Uncertainties related to the location of the CO_2 gas.
- CO_2 reaches a well and leaks outside the casing to the surface. CO_2 migrates to the surface and further into the atmosphere. Since the number of wells in the area is low, this will apply to injection (and possibly water production) wells.

Better characterisations of the target and the sealing formations and the overburden are required to assess the associated risks. If injection is chosen, a monitoring program is required to monitor CO_2 behaviour and to detect risks at an early stage. The connecting pore volume will determine the average pressure build-up in the formation, and this can only be assessed accurately at some time after injection. The integrity of any injection (and/or production) wells should be considered with regards to reactivity with dissolved CO_2.

3.7 Ranking of possible storage sites (excluding transport cost)

There are significant uncertainties in the simulations presented here owing to data scarcity and the need to make several assumptions. However, the results indicate that Model 2 is the most promising target for the injection of 250 $MtCO_2$. This is mainly based on the observations that all the injected CO_2 is retained within the model boundaries, the injection pressure is considered to be below the safe pressure, and the option of injecting part of the CO_2 into the shallower Haldager formation is available. Although this is also an option for Model 1, the simulations indicate that the injected CO_2 can migrate to the northern border of the formation, at which point further migration is uncertain. Nevertheless, Model 1 is worth investigating further, since small changes in flow parameters can change the migration distance of the injected CO_2. Currently, these parameters are uncertain.

The Hanstholm structure seems to have a closure that can hold the injected CO_2. However, the current model properties indicate injectivity problems with the applied high injection rates. Introducing additional injection wells and/or production wells could change this picture totally, and if the assumption that the cap rock is sealing Hanstholm is correct, this could be the preferred target. Further characterisation of the target formations and the overburden could also change the ranking of the models (in terms of cap rock integrity and safe pressure increases).

3.8 Cost of CO_2 storage

Currently, there are great uncertainties regarding storage costs. To our knowledge, the best available cost data for storage have been reported by ZEP (2011). The data from this report are applied to estimate the cost of CO_2 storage in the Skagerrak/Kattegat region. It is clear that the cost will vary from case to case, since the type and conditions of the reservoir will influence the capacity, both in terms of the injection rate of CO_2 and the total storage volume.

While onshore storage is generally less expensive than offshore storage, in this report only offshore storage is considered, since a potential reservoir is identified in the Skagerrak basin.

The identified storage site must undergo a rigorous investigation of its suitability. Qualifying a storage site involves gathering detailed information about the site through interpretation of seismic data, drilling exploration wells, and modelling the structure. Thereafter, injection testing is performed and finally, the site may be qualified for CO_2 storage. This whole investigative process will take several years. In this report, a timeframe of 3 years is assumed to be appropriate to complete the investigation of the reservoir and to secure permission for storing CO_2.

The number of injection wells will vary depending on the conditions in the reservoir. The injection well will have a specified injection rate, and the number of wells depends on the total amount of CO_2 to be stored each year. In this report, an injection rate is suggested, although at this early stage this number is only a best guess. The total injection period is set at 40 years. The site is continuously monitored throughout the injection period. After the injection period, the site is closed down and secured. Thereafter, a monitoring period of 20 years is foreseen.

The main cost element of CO_2 storage is the drilling of wells. In order to qualify the storage site, one or more exploration wells are needed. The number of injection wells will vary as stated above based on the capacity of the reservoir. In addition, observation wells are needed. In some cases, it is possible that the exploration wells could be reused as monitoring or injections wells. The depth of the well will also most likely affect the drilling cost. For the sake of simplicity, in this report, all wells have the same drilling cost.

3.9 Assumptions

The cost estimation for storage performed here is an early phase estimate and will have an accuracy of ±40%. The following main parameters are the basis of the storage cost estimate:

Project lifetime

- Investigation period is set at 3 years
- Injection period is assumed to be 40 years
- Post-injection monitoring period is set at 20 years

Injection of CO_2

- Injection rate per year is 3.3 $MtCO_2$/well.
- Total amounts of CO_2 injected per year are ~ 14 Mt and ~ 6 Mt.

Wells

- Number of injection wells is five (based on injection rate and amount of CO_2 to be stored annually)
- Number of exploration wells is two
- Number of observation wells is one
- Depth of well is 2700 m

Cost data

- Rate of return: 8%
- Modelling: 5 M€
- Injection testing: 5 M€
- Permitting process: 10 M€
- Cost of well: 62.5 M€ (based on oil production well cost)

- Maintenance and operations: 6 % of Capex
- Liability transfer: 1 €/tCO_2
- Decommission: 10% of Capex
- Offshore structure, subsea installation: 30 M€

Significant investment is needed during the period before injection and during decommissioning of the well(s). The cost of maintenance after decommissioning is relatively low.

3.10 Storage cost estimations

Table 3.2 summarise the results of the storage cost estimations.

Table 3.2. Estimation of cost of CO_2 storage

Amount of CO_2 (Mt/yr)	Capex (M€)	Opex (M€)	Cost (€/tCO_2)
~ 14	755	57	8.9
~ 6	450	31	11.4

3.10.1 Sensitivity analysis

Sensitivity analysis shows that the cost of the wells, injection rate, and rate of return have the greatest impacts on the total costs for storage. Both the cost of well and the injection rate will differ significantly from site to site, according to the special conditions pertaining to that site. The effects of changes in well cost are presented in Figure 3.20.

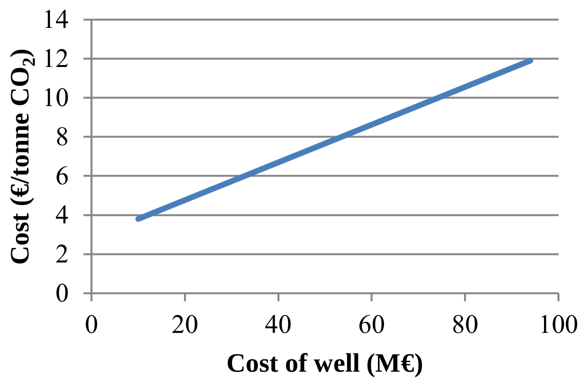


Figure 3.20. The effect of well cost on the overall cost of CO_2 storage.

Figure 3.20 shows that the specific costs are largely dependent upon the cost of the wells. A decrease in well cost of 20 M€ will lead to a reduction in overall cost of 3 €/ tCO_2. In this example, the cost for wells is taken from the oil industry. This number may be too high, and drilling in a “non–profitable” region can reduce the costs.

Reservoir thickness and permeability are two key factors that determine the cost of storage. These two geological properties strongly influence the number of wells required and the amount of CO_2 that it is possible to store. This means high variability in the cost estimates for storage. The values given in this example are based on assumptions from the ZEP report (2011), although the injection rate is higher and the number of wells is lower in the current report.

3.11 Summary

Several geological formations have been identified as potential reservoirs within the region. In particular, the Gassum and Haldager Sand formations have considerable potential. Two types of reservoir structures should be followed up with more detailed studies: 1) large, gently dipping reservoirs in the northern Skagerrak area; and 2) closed dome structures above salt pillows in the Norwegian Danish basin.

Reservoir simulations have been made for two open dipping aquifers and one dome structure (Hanstholm). One open dipping aquifer is located south of Kristiansand, with injection 60-km offshore and approximately 2000 m below the seabed, while the other lies northwest of Jutland in the Danish sector. Simulation results for both these storage sites are promising, although additional detailed studies are needed to qualify and develop this geological structure into a safe and reliable CO_2 storage site.

Simulation of CO_2 injection into the Hanstholm structure has shown that the structure can accommodate 250 $MtCO_2$ injected down-flank using three horizontal injection wells over a period of 25 years. However, the resulting formation pressure is rather high, which means that seal leakage is a risk. The Hanstholm structure requires additional detailed studies to qualify as a safe and reliable storage site. The aquifer south of Kristiansand has been used as the basis for evaluations of the costs of CO_2 storage and transport.

Storage costs, based on five injection wells, are estimated at 8.9 €/tCO_2. The largest uncertainties lie in the drilling costs and the number of injection wells, so the estimate is considered an upper boundary.

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4 CO_2 TRANSPORT

After the CO_2 has been captured, the next step in CCS is transport of the CO_2 to a suitable permanent storage site. Possible methods for transportation include pipelines, both onshore and offshore, and ships. In this chapter, several transportation and infrastructure options are evaluated, and solutions are proposed for the transport of CO_2 in the Skagerrak/Kattegat region. The optimal solution may vary depending on the assumptions made.

The technical basis for the transportation, receiving, and intermediate storage of CO_2 is established and a cost estimation is performed. The cost of accessing a future infrastructure in the Skagerrak/Kattegat region is also estimated. A comprehensive description of the transport cost estimations is given in the report "CO_2 Transport Solutions in the Skagerrak/Kattegat region", which can be downloaded from http://www.ccs-skagerrakkattegat.eu/.

4.1 Transportation methods

A technical description of the different segments of CO_2 transport is presented in this section. The transportation methods investigated are ships and pipelines.

4.1.1 Ship transportation of CO_2

Currently, CO_2 is transported in partially pressurised tankers at 14–16 barg. To be economically viable, large-scale CO_2 transportation by ship should occur at pressures near the triple point, for example at 7 barg and -50°C (Aspelund *et al.*, 2006; Hegerland *et al.*, 2004). In an extensive report titled "Preliminary Feasibility Study on CO_2 Carrier for Ship-based CCS" (Chiyoda Corporation for the Global CCS Institute, 2011), the CO_2 is transported at 10°C and 26.5 bar. The ship size is 3000 m^3. In the current report, the assumption is made that ship transportation of CO_2 takes place at 7 barg and -50°C. This is not necessarily the optimal condition for CO_2 transport and this issue should be revisited in the future.

The key elements in CO_2 transportation by ship are included in Figure 4.1: liquefaction, intermediate storage, loading, CO_2 ship, unloading (onshore or offshore), and heating.

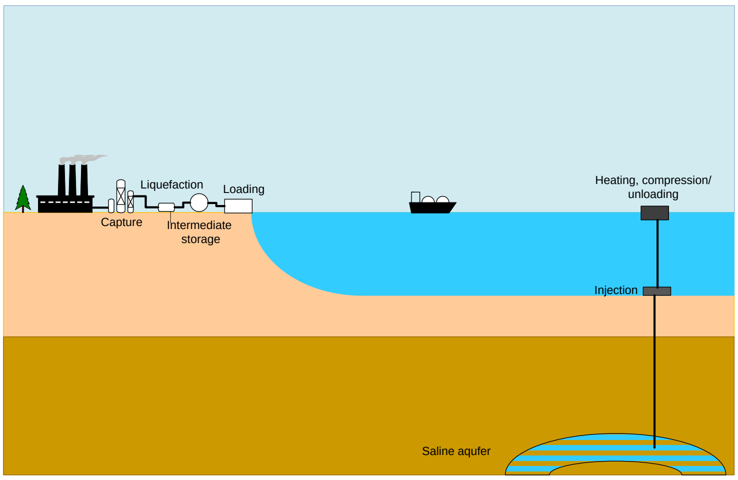


Figure 4.1. Schematic of CO_2 transportation by ship with key elements

For unloading offshore, a pumping station is needed. Here, the liquid is pumped to injection pressure and heated to ambient temperature (at least 15°C), to avoid hydrate formation before injection. Offshore processing is considered costly and can be avoided by unloading the CO_2 from the ship to an onshore hub located close to the offshore storage site. This alternative necessitates an additional onshore intermediate storage tank, compression, and an offshore pipeline.

CO_2 is stored at the bubble point in semi-pressurised intermediate storage tanks until the ship arrives. In the semi-pressurised vessels, the CO_2 is maintained in the liquid phase at the saturation line, with a pressure higher than atmospheric pressure and a temperature lower than the surroundings. The intermediate storage capacity should match the amount of CO_2 produced between the ship calls. Transportation of CO_2 by ship requires intermediate storage, since CO_2 is in most cases captured continuously. A loading system on the quay transfers the liquid CO_2 to the ship. CO_2 arrives at the storage site or at an onshore hub in a ship at around 7-9 barg and -50°C. The slight increase in pressure is because the tanks holding the liquid CO_2 will heat up slightly during transport, the increase being dependent upon the length of transport.

A hub is defined as an intermediate storage site. Such storage can play different roles depending on its place in the infrastructure. It can involve intermediate storage in a ship transportation solution, where CO_2 that is continuously captured is stored until the next ship call. A hub can also be a collection point for CO_2 from different sources, either *via* ship transportation to a hub or permanent storage *via* pipelines.

4.1.2 Pipeline transportation of CO_2

The transportation of CO_2 in a pipeline is most effective when the CO_2 is in a liquid or supercritical state (dense phase). The reason for this is that the friction loss along the pipeline per mass unit of CO_2 is lower that it is for the transport of CO_2 as a gas or in two-phase, liquid and gas. The pressure in the pipeline decreases due to friction and the temperature decreases due to heat transfer with the outside medium along the length of the pipeline. The CO_2 will gradually transform from a supercritical fluid into a liquid, but will still be in single phase. The pressure at the end of the pipeline must be above ~ 74 barg (critical pressure of CO_2), to ensure that the CO_2 is kept in the liquid dense phase.

The initial pressure at the beginning of the pipeline depends on the associated pressure drop over the pipeline length. The pressure drop in the pipeline depends on the flow rate, pipe geometry, pipeline route, etc. Pipeline transportation of CO_2 is illustrated in Figure 4.2.

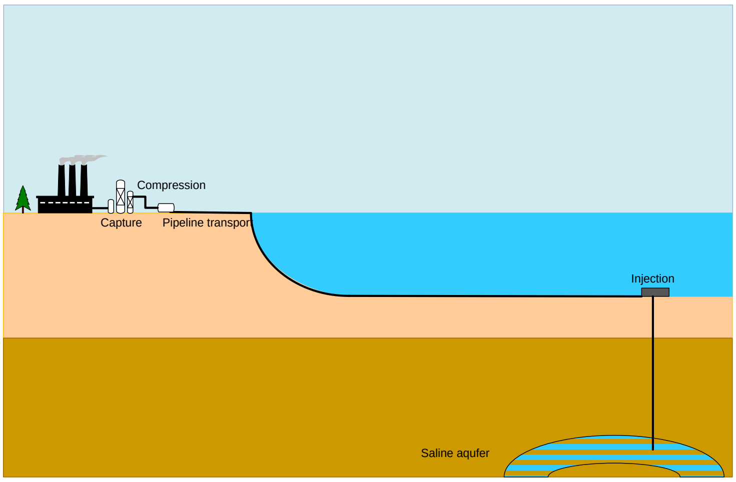


Figure 4.2. Illustration of pipeline transportation of CO_2

4.2 Boundary conditions

4.2.1 Capture – transport – storage

The interfaces between capture, transport and storage are presented below. Detailed information about the technical elements included in the transport part of the project is given in Section 4.3, *Transport cost estimates*.

- **Capture**
  - The CO_2 is delivered for transport at 75 bar and 20ºC and with a water content of <500 ppm (vol%). Additional conditioning, which will depend on the transportation method, is included in the transport cost.
- **Transport**
  - For ship transportation of CO_2: 7-9 barg, -50°C and <50 ppm (vol%) water.
  - For pipeline transportation of CO_2: initial pressure depends on the length of the pipeline. The CO_2 will be delivered at the injection site at a pressure of 75 bar. The water content should be <500 ppm (vol%) water (de Visser *et al*. 2008)
- **Storage**
  - The CO_2 is delivered for injection at 75 bar and ambient temperature. The injection pressure will depend on the conditions in the reservoir and injection depth. Simulations performed by Sintef indicate that an injection pressure of 124–158 bar could be needed due to overpressure in the reservoir. The effect of this pressure is included only for selected cases, to illustrate how this will affect the cost. An injection pressure of 158 bar is used in these calculations.

4.2.2 Location of sources and potential storage site

In Figure 4.3, the locations of the emission sources and the potential storage site are shown. Grenland, Gothenburg, and Aalborg have more than one emission source (industry and/or power plants), with three, four, and two, respectively. A more detailed description of the emission sources is found under the capture chapter of this report (Section 2.1). In addition to the sources described therein, which represent the contributing partners in this project, there are a few other point sources that are deemed appropriate to include in a transport network in the Skagerrak/Kattegat region. Emission data from the additional point sources have been gathered from the public domain, i.e., company websites. As the emissions vary from year to year depending on the production level, a representative emission level is sought. It is assumed that CO_2 capture will give a 30% increase in CO_2 due to the energy needed for capture (possible excess energy available at the plants has not been taken into account), and a capture rate of 85% is assumed. Emission levels for the additional point sources included in the transport network are given below. Full utilisation during the year is assumed, i.e., a production year of 8760 hours.

- For Keely Oy, a refinery located in Gothenburg, the estimated CO_2 for transport is 460 ktCO_2/yr
- For Södra Cell Värö, a paper mill located at Värö, the estimated amount of CO_2 for transport is 1120 ktCO_2/yr
- For, Sävenäsverket HP & CHP, a waste handling plant located in Gothenburg, the estimated amount of CO_2 for transport is 690 ktCO_2/yr
- For Aalborg Portland AS, a cement plant located in Aalborg, the estimated amount of CO_2 for transport is 2980 ktCO_2/yr
- For Norcem AS, a cement plant located in Brevik, Grenland, the estimated amount of CO_2 for transport is 990 ktCO_2/yr

- For Noretyl AS (Ineos), a chemical plant located in Porsgrunn, Grenland, the estimated amount of CO_2 for transport is 700 ktCO_2/yr
- For Norske Skog Saugbrugs, a paper mill located in Halden, the estimated amount of CO_2 for transport is 640 ktCO_2/yr

Not all of the point sources in the present investigation have continuous operation the whole year round. Power plants can have reduced operation during periods of the year when electricity consumption and/or the price is low. This has consequences for the transportation network. For simplicity, it is assumed that all point sources have continuous operation, although the transportation network will be designed based on the maximum CO_2 output from the sources. While several point sources utilise biomass as an energy source, no distinction is made between biogenic and fossil-derived CO_2 in this project.

The coordinates for the storage site proposed by UiO in the Skagerrak/Kattegat region are: 57° 37′ 30″ N 8° 8′ 40″ E. The storage is located outside the coast of Kristiansand in the southern part of Norway.

Figure 4.3. The Skagerrak/Kattegat region with CO_2 emission sources and storage locations

4.3 CO_2 transport cost estimations

A few studies on CO_2 transportation have been performed over the years. The most recent and comprehensive study is the ZEP report (2011). Several of the assumptions made in that report are adopted in the current report.

4.3.1 Methodology for cost estimations

The cost estimations for ship and pipeline transportation are performed using the factor estimation method and are based on data from Eurostat (the European statistical organisation linked to the EU). The data are based on ge neral process equipment and generic cost (Rotterdam location). Equipment cost is calculated using the Aspen Icarus Project Manager. A complex model is built-up using the Microsoft Office program Excel. The model is flexible and the input parameters, which include CO_2 amount, transport length, degree of pipe utilisation, rate of return on investment, number of years, electricity cost, and number of hours per year, can be varied. The model handles both ship and pipeline transport cost calculations. The factor estimation method gives an accuracy of ±30%. Given the flexibility of the model, several sensitivity analyses are performed. The effects of different parameters can be investigated and the most cost-intensive items can be identified.

4.3.2 Assumptions

A more detailed description of the assumptions made is included in the report "CO_2 Transport Solutions in the Skagerrak/Kattegat region".

The main assumptions made for the cost estimations are CO_2 amount and transport length. It is assumed that the CO_2 from all point sources in the Skagerrak/Kattegat region is captured and available for transport to permanent storage from Day 1 of operation. Production at the point sources is assumed to be continuous, which means that a production year is set at 8760 hours.

For all cases, the proposed pipeline network and ship route are not final, and an as close to optimal solution as possible will be recommended. The exact placement will not be provided, as there are already networks of cables and pipes on the seabed in the region and it is outside the scope of this study to present a full overview.

The costs refer to the cost level in Q2 of 2011. The rate of return on investment for both the pipeline and ship is set to 8% and the project lifetime is 25 years, i.e., 1 year of construction and 24 years of operation. These assumptions are adopted for both pipeline and ship transportation.

Pipelines
The operating pressure of the offshore pipeline depends on the length of transport and the injection pressure needed to overcome the pressure in the reservoir. The pipeline inlet pressure is compressed from 75 bar to a pressure that ensures that the CO_2 is kept in a dense phase during pipeline transport. The operating pressure of the pipeline will also depend on the reservoir conditions. Pressures of up to 158 bar have been reported based on reservoir simulations for injection into reservoirs at a depth of 2,400 m. The onshore transport pressure is not limited in this project.

The following elements are included in the cost: preparation for construction (permits, rights of way, survey etc.); project management; conditioning for transport (compression); line-pipe (prefabricated onshore/offshore pipes, transport, preparation and installation); templates/control cables at injection site; costs for civil work; contractor for detailed engineering; RFO (ready for operation) costs; commissioning; insurance; operational cost (energy consumption and maintenance); and a 20% contingency.

Ship
The following elements are included in the estimation of ship transportation costs: liquefaction plant; intermediate storage tank at loading site (100% of ship size); port terminal cost (including loading arm); ship; conditioning of CO_2 during unloading (heating and compression); offshore terminal (only for offshore unloading); intermediate storage tank at onshore hub (100% of ship size); and operational costs (crew costs, maintenance, fuel cost and port fees).

The ship size is limited to 40,000 m^3. If the amount of CO_2 and length of transport dictate a size close to this limit, then the calculations will automatically increase the number of ships to two. The two ships are assumed to be equal in size.

4.4 Description of transport cases

A storage location offshore of Kristiansand in Southern Norway has been identified (Section 4.2.2). This location will be implemented as the location for storage for all the cases proposed below, with the exception of the Reference case, in which the CO_2 is transported to a hub at Mongstad for storage in the Utsira formation off the west coast of Norway.

Approximately 14 MtCO_2 from 15 point sources have been identified in this project and are included in the proposed transport cases presented below.
Cases involving a pipeline network have countless possibilities with regard to the design of the pipeline routes. The effects of relatively small changes in the routes have been investigated. This work was very time-consuming and the limited investigation yielded only small differences in transport cost. A best guess is proposed, but it is important to understand that this is in no way grounded upon an in-depth investigation of the areas where the pipelines are drawn. Straight lines are drawn, and the different pipeline segments are connected in a pipeline network. The same approach is used for the ship routes. The measured distances are only indicative, as ship routes are flexible.

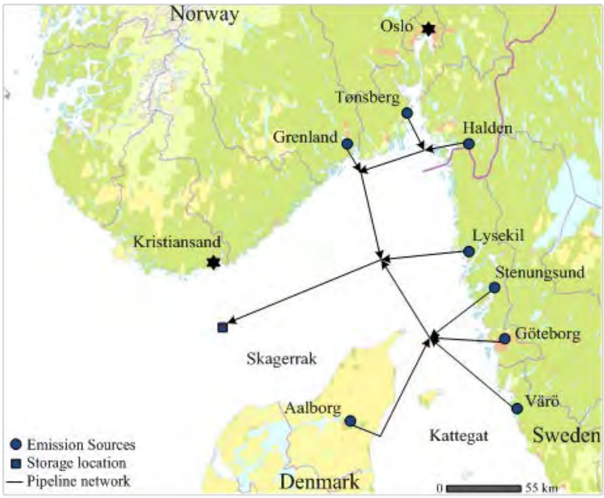
Case 1
The pipeline network is designed to transport CO_2 from all of the point sources in the region. A central pipeline in the Skagerrak/Kattegat is suggested, to which individual pipelines from the emission sources can be connected. One common pipeline is foreseen from regions with more than one emission source, although a number of smaller pipelines will be needed to collect the CO_2 in the cluster of Grenland, Gothenburg, and Aalborg. An important assumption for this case is that the pipeline network operates at 100% utilisation. An illustration of Case 1 is given in Figure 4.4a. The focus is on connecting all of the point sources in a transport network, since the main objective of the present project is to look at the Skagerrak/Kattegat region as a whole. Nonetheless, other solutions should be investigated, since some regions (e.g., Grenland and Aalborg) might benefit from having a separate pipeline directly connected to the storage site.

Case 2
The basis of Case 2 is ship transport, and one ship is foreseen from each location. This means that some emission sources share one ship with other sources located in the cluster (Grenland, Gothenburg, and Aalborg), while all the others have their own ship. All of the ships in this scenario transport the CO_2 to a central hub, from where the CO_2 is transported to permanent storage through a pipeline or to offshore unloading at the storage site. While there are several possible locations for a hub, in this project the following are considered: Grenland (Brevik); Kristiansand; and Stenungsund. Full (100%) utilisation of the pipeline is foreseen. Case 2 is illustrated in Figure 4.4b. The locations of the hubs are shown, but only the pipeline from Grenland is included in the illustration.

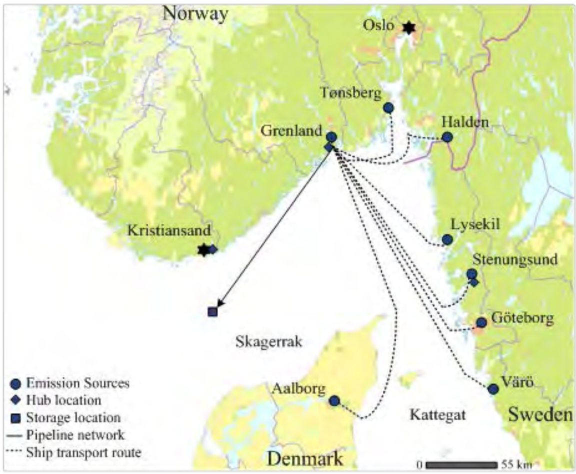
Case 3
This case combines ship and pipeline transportation to a greater extent than in Case 2. Direct pipelines from Grenland, Gothenburg, and Aalborg to a permanent storage site are included. CO_2 from the other sources is collected by a single ship on a roundtrip. The CO_2 is unloaded either at a hub location for further transport by pipeline to the storage site or directly at the storage site. The locations considered are: Grenland (Brevik); Kristiansand; and Stenungsund. Full (100%) utilisation of the pipeline is foreseen. An illustration of Case 3 is given in Figure 4.4c.

Reference case

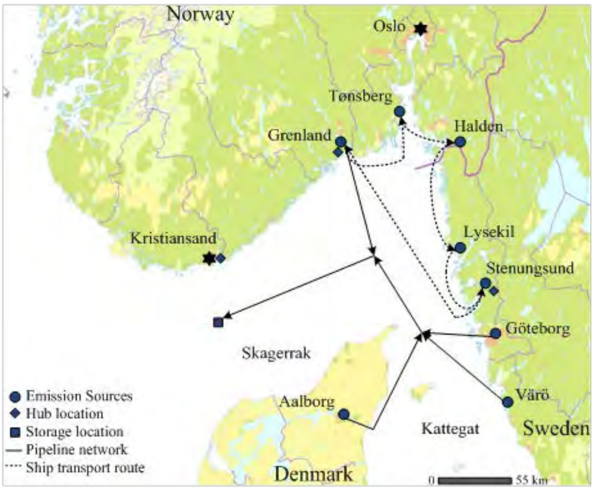
The Reference case is included to illustrate the importance of utilising storage sites near the emission source. An increased transport distance will affect the cost of transport. The Utsira formation off the west coast of Norway is considered to be a possible storage site for some of the CO_2 emissions from Europe. The Utsira formation is already in use as a storage depot for CO_2 from offshore gas processing. The Reference case considers pipeline transportation of CO_2 to a hub at Mongstad; further transportation to permanent storage is not included. It is assumed that the CO_2 from the Skagerrak/Kattegat region will join a common pipeline from Mongstad to the storage site. The network is utilised 100%.



a) Case 1; pipeline network



b) Case 2; ship transport



c) Case 3; combination of ship and pipeline transport

Figure 4.4. ***Illustration of the three main proposed transportation systems for CO_2 (©Mareano)***

4.5 Cost estimations for CO_2 transportation options

The CO_2 transportation solutions described in Section 4.4 are cost estimated in order to find the optimal socio-economic solution. Capital expenditure (Capex) and operational expenditure (Opex) are estimated using the method described in Section 4.3. From this, the cost for transport per tCO_2 is estimated. The different solutions are discussed and evaluated.

4.5.1 Case 1

In this case, it is assumed that all point sources have fully integrated capture of CO_2 and that this is ready for transport from Day 1 of operation of the pipeline network. As stated in

Section 4.4, there are many possible pipeline routes, and the following two are investigated here;

1.1 A fully integrated pipeline network
1.2 An alternative pipeline network for Grenland and Aalborg

The results of the cost estimations for Case 1 are found in Table 4.1.

Table 4.1. Results of the cost estimations for Case 1

Case	Capex	Opex	Cost (€/tCO_2)
1.1	2,142	11	14.3
1.2	2,042	11	13.7

Comparison of Cases 1.1 and 1.2 reveals that removing Grenland and Aalborg from a central pipeline network could reduce the cost.

4.5.2 Case 2

In Case 2, the main transport of CO_2 takes place *via* ships, although pipeline transport is foreseen between point sources in clustered areas, such as Grenland, Gothenburg, and Aalborg. CO_2 emissions from one cluster are combined and transported on one ship, while the other point sources are served by one ship each. All of the ships transport the CO_2 to a central hub for pipeline transportation to a permanent storage site or directly to storage using offshore unloading. An onshore hub consists of unloading equipment, intermediate storage and conditioning of CO_2 for further transportation by pipeline to permanent storage. Hub locations in Grenland, Stenungsund, and Kristiansand are investigated. Offshore unloading from ships includes an installation at the storage injection site where the CO_2 is prepared for injection. It is generally accepted that offshore installations are costly. However, in the end, this expense must be weighed against the increased cost of the pipelines and intermediate storage needed for onshore unloading. There is little knowledge about quay access for the point sources but, the information that is available suggests that all do have access. Information about maximum ship size and available area for intermediate storage is not available, and is therefore assumed not to be limiting. The variations of Case 2 which are explored further are:

2.1 Onshore unloading, hub at Grenland
2.2 Onshore unloading, hub at Stenungsund
2.3 Onshore unloading, hub at Kristiansand
2.4 Offshore unloading at storage location

Table 4.2 gives the results of the cost estimations for Case 2.

Table 4.2. Results of the cost estimations for Case 2

Case	Capex (M€)	Opex (M€)	Cost (€/tCO_2)
2.1 (Hub Grenland)	867	88	11.9
2.2 (Hub Stenungsund)	1,063	102	14.1
2.3 (Hub Kristiansand)	882	103	13
2.4 (Offshore unloading)	969	137	16

Generally, a ship has a lower Capex than a pipeline, but it has a higher Opex cost. All of the cases include collection pipelines in Grenland, Gothenburg, and Aalborg (the pipeline network in each region is assumed to be built using the same mobilised equipment, which reduces the Capex). Cases 2.1 and 2.2 both have seven ships, intermediate storage tanks at emission site and at hub, and a large pipeline to storage. Case 2.3 has eight ships, intermediate storage tanks at emission site and at hub, and a large pipeline to storage. Case 2.4 has eight ships, intermediate storage tanks at emission sites, and four installations for unloading offshore.

The results show that Case 2.1 gives the lowest overall cost of the proposed Case 2 transport solutions. The main reasons for this are that compared to Case 2.2, the distance to storage is shorter for a hub located in Grenland than for a hub in Stenungsund, which reduce the Capex, and that the amount of CO_2 transported on the ship is greater for Case 2.2, which increases both the Capex and Opex. Compared to Case 2.1, Case 2.3 has an extra ship and a shorter pipeline. This gives a Capex that is close to that of Case 2.1, albeit with a higher Opex cost and overall transport cost. The most cost-intensive case under the current assumptions is Case 2.4, due to the relative expense (Capex and Opex) of offshore unloading.

Capital cost can be reduced somewhat by optimising the size of the intermediate storage tanks associated with ship transport. Certain pipeline sections are assumed to be built at the same time, so as to reduce the start-up cost of construction. This approach could also be used with other pipeline segments to reduce further the Capex.

Other alternatives are looked into with respect to the effect of the number of ships utilised in the transport network. Reducing the number of ships by combining transport from several emission sources increases the cost. The main reason for this is the negative effect that the longer round-trip has on the cost. In general, the cost of transport increases with decreasing number of ships. Increasing the number of ships by one from Aalborg, compared to the seven ships used in Cases 2.1 and 2.2 and the eight ships used in Case 2.4, results in decreased cost.

4.5.3 Case 3

In Case 3, ship and pipeline transportation systems are combined. The most promising strategy in a start-up phase of CCS is to use a combination of ship and pipeline transportation. In Case 3, CO_2 pipelines are in place from the clusters Gothenburg, Grenland, and Aalborg, and from Värö to permanent storage in the Skagerrak basin. The CO_2 from sources located in the inner part of the Skagerrak, Tønsberg, Halden, Lysekil, and Stenungsund, is transported by ship. Both onshore and offshore unloading from the ship are investigated. Four variations of Case 3 are cost-estimated:

3.1 Onshore unloading, hub at Grenland
3.2 Onshore unloading, hub at Stenungsund
3.3 Onshore unloading, hub at Kristiansand
3.4 Offshore unloading at storage location

The results of the cost estimations are shown in Table 4.3.

Table 4.3. Summary of the estimated costs for Case 3

Case	Capex (M€)	Opex (M€)	Cost (€/tCO_2)
3.1 (Hub Grenland)	1,517	35	12.1
3.2 (Hub Stenungsund)	1,625	29	12.4
3.3 (Hub Kristiansand)	1,626	35	12.8
3.4 (Offshore unloading)	1,525	40	12.6

Small differences are noted between the different alternatives investigated. Case 3.1 gives the lowest cost because it utilises the pipeline from Grenland, which means that under the assumptions made this is the most economic alternative. Cases 3.2 and 3.3 have an additional pipeline from Stenungsund and Kristiansand, respectively. The reduced operational cost for Case 3.2 is due to the smaller ship used, since the CO_2 from Stenungsund is not transported on the ship. The most expensive alternative is Case 3.3 owing to full utilisation of the ship, as compared to Case 3.2, and the extra pipeline. Offshore unloading, as in Case 3.4, is also a reasonable solution.

Increasing the number of ships to four, one from each emission site (Tønsberg, Halden, Lysekil, and Stenungsund), is more economical than having just one ship collecting CO_2 from each source in a round-trip. This is due to the length of the round-trip and the need for larger and relatively expensive intermediate storage tanks. Optimisation of the round-trip and the size of the intermediate storage tanks could reduce the cost. It is also clear from additional calculations that replacing one large ship with several smaller ones would reduce the costs, in similarity to the conclusion drawn for Case 2.

It is clear from the results that there are only small differences in overall costs between the suggested cases.

4.5.4 Reference case: Transportation of CO_2 to the Utsira formation

This case is chosen as a Reference case because this storage site has a high probability of coming into full-scale operation. A well-known storage location is the Utsira formation off the west coast of Norway. Even though this sink is located outside the Skagerrak/Kattegat region, it will be used as a reference case and compared to the other proposed infrastructure solutions. This case illustrates the cost for transporting all the CO_2 from the sources in the Skagerrak/Kattegat region to a hub at Mongstad. The results are presented in Table 4.4.

4.5.5 Cost estimations

The costs of the main transportation options are summarised and compared to the Reference case in Table 4.4. The results are also presented graphically in Figure 4.5, where the transport costs are divided into Capex and Opex costs.

Table 4.4. Comparison of Cases 1, 2, 3 and the Reference case

Case	**Capex (M€)**	**Opex (M€)**	**Cost (€/tCO_2)**
Case 1	2,142	11	14.3
2.1 (Hub Grenland)	867	88	11.9
3.1 (Hub Grenland)	1,517	35	12.1
Reference case	2,846	17	19.2

Figure 4.5. Comparisons of Cases 1.1, 2.1, 3.1 and the Reference case with respect to cost.

A general comparison of Cases 1, 2 and 3 shows that the pipeline-based transport (Cases 1 and 3) solutions have higher Capex costs than the ship-based systems, while a ship-based system has a higher Opex, as in Case 2. In Case 3, which is a combination of ship and pipeline networks, it can be seen that the Capex is decreased compared to Case 1 and that the Opex is decreased compared to Case 2. Case 2.1 is the least cost-intensive solution, closely followed by Case 3.1, although the differences are within the accuracy of the estimation method. Other factors, such as the limitations related to protected areas, quay access etc., will therefore be of importance when planning a transport infrastructure.

In the Reference case, CO_2 is transported to an assumed hub at Mongstad. There are several possible storage sites outside Mongstad, e.g., the Johansen formation and several locations in the Utsira formation. If there is no hub at Mongstad, an alternative ‘reference case’ would be to transport directly to storage in the Johansen or the Utsira formation. The distance to the Johansen formation is approximately the same as to Mongstad, whereas for the southern parts of Utsira the distance is 100–200 km shorter, thus reducing the transport cost by 1-2 €/tCO_2.

It is clear that finding a storage site in close vicinity to the point sources is favourable. Longer pipelines are costly, while long transport distances favour ships. For the overall volumes considered in this study (~14 MtCO_2) and a transport distance to Mongstad of approximately 1500 km, the costs of CO_2 transportation by ship and pipelines are of the same magnitude.

4.5.6 Cost of CO_2 transport with a capacity of 6 Mt/yr

The basis for the transport cost estimates is that all the emission sources identified in the region (Section 2.1 and Section 4.2.2) are included. As all of these sources are not a part of the current project, in the current section the cost estimates for Cases 1.1, 2.1 and 3.1 are recalculated to include only those sources specified in Section 2.1. Here, approximately 6 MtCO_2 is stored annually. The results are given in Table 4.5.

Table 4.5. ***Cost of a transportation network for 6 MtCO_2 annually in the Skagerrak/Kattegat region***

Case	Capex (M€)	Opex (M€)	Cost (€/tCO_2)
1.1	1,394	8	20.9
2.1 (Hub Grenland)	493	44	14.1
3.1 (Hub Grenland)	1,071	26	19.2

The results from Table 4.4 are compared to the 14 MtCO_2 estimations from Table 4.5 and the results are presented graphically in Figure 4.6. From the figure, it can be seen that the transport costs increase for all cases when the amount of transported CO_2 is reduced from 14 Mt to 6 Mt. This increase in costs is more pronounced for pipeline-based transport networks, as in Cases 1.1 and 3.1. The reason for this is that laying pipelines offshore is expensive, regardless of size or capacity, which means that smaller pipelines transporting smaller amounts of CO_2 will be more costly per ton CO_2.

Figure 4.6. Comparison of costs of transporting 6 MtCO$_2$ and 14 MtCO$_2$

4.5.7 Effect on cost of increasing the injection pressure for CO_2

To illustrate the effects of injection of CO_2 into a reservoir with a depth of 2,400 m with an overpressure of 110 bar in the reservoir, the costs of Cases 1.1, 2.1, and 3.1 have been re-calculated. Compared to the cost calculation in Section 4.4, the pressure at injection point is here set to 158 bar. In Figure 4.7, the effect of the higher pressure is indicated as the additional cost compared to the 75 bar cases (75 bar is the minimum pressure needed to ensure single dense phase CO_2, which is assumed in all the other calculations).

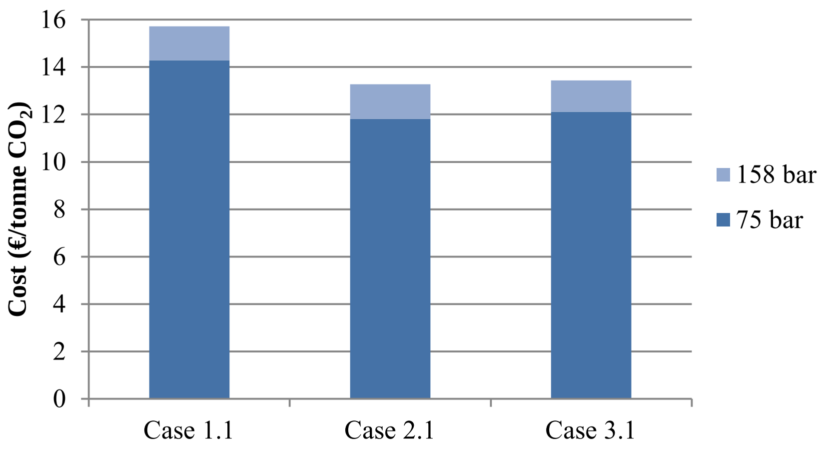


Figure 4.7. Comparison of costs for the different cases with pressures at injection site of 75 bar and 158 bar

The results show that increasing the injection pressure from 75 bar to 158 bar gives a moderate increase in cost, which is due to the increased pumping cost (pumping station and operational cost due to higher electricity consumption) and increased material cost for pipelines.

4.6 Establishing a transport network

4.6.1 Description of ramp-up

In Section 4.5.5, different transport options were compared assuming 100% utilisation from Day 1, i .e., all the point sources are equipped with capture plants at the same time, for example in 2020. However, there will most probably be a step-wise ramp-up stage before the identified full potential for carbon capture is reached. Here, we have investigated the effect of gradual increases in the amount of CO_2 to be transported in the pipelines. The effects of increasing the pipeline grid over time as demand increases is compared with the building of an oversized system to take into account the complete potential identified in the region at the beginning. In the region, there are 15 point sources with CO_2 volumes ranging from 172 to 2,984 kt/yr. To investigate ramp-up, it is possible to analyse, for example by sector, which industries are most likely to introduce capture first. Based on this analysis, a timeline with the possible amounts of CO_2 and the locations could be established. Here, we have chosen not to do such an analysis, since such a list would have very large uncertainties; therefore, the added value of a detailed investigation of a ramp-up scenario was considered to be low.

A generic approach is applied in which the amounts of CO_2 for transportation are increased by 25%, 50%, and 75% before reaching 100% utilisation.

4.6.2 Cost of ramp-up cases

The costs of construction of the pipeline grid (Case 1.1) are calculated for a step-wise increase in the pipe size to fit the demand at the time and for increased utilisation of a system constructed to cover the complete demand, thus increasing utilisation over time. The costs of the two cases, as compared with that of Case 1.1 (full utilisation), are shown in Figure 4.8. From the figure, it can be seen that the cost of the pipeline structure increases from around €14 per tonne CO_2 to €26 per tonne CO_2 with increased utilisation, and €46 per tonne CO_2 with increased pipe size.

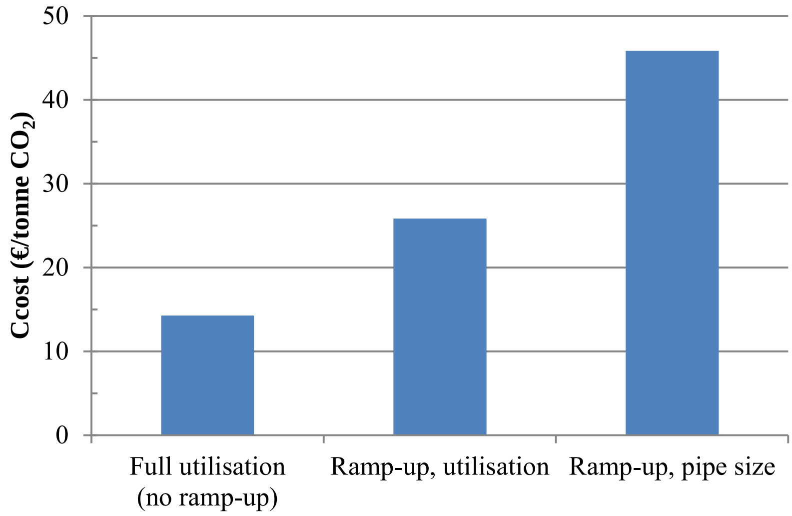


Figure 4.8. Cost of pipeline transportation for the ramp-up cases

The effects of timing have been analysed by investigating the effects of increasing the amounts of CO_2 over 10, 25 and 50 years, respectively. Increased pipe size is very expensive for the 10-year period, and the costs decrease when the time period is increased to 25 years and 50 years. For a ramp-up period of 50 years, the cost of ramp-up differs by approximately 10% for the two ramp-up cases.

4.7 Sensitivity analysis

Sensitivity analysis was performed for Cases 1.1, 2.1, and 3.1, with the parameters varied being the rate of return, number of years (lifetime), Capex, and Opex. All parameters were varied by ±50%. A sensitivity analysis of the amount of CO_2 transported and the length of transportation has not been included, since Cases 2.1 and 3.1 combine ship and pipeline transport. Ships and pipelines will react differently to changes in these parameters.

The results of the sensitivity analysis show that the effect of a ±50% change in rate and number of years has the greatest effect on Case 1.1, followed by Case 3.1, due to the higher share of Capex costs. A decrease in the number of years generally has little effect on the total costs. The sensitivity analysis for Capex and Opex show that changes in Capex have the greatest effect on cases based on pipeline transport (Case 1.1 and to some extent Case 3.1), while changes in Opex have the greatest effect on Case 2.1, in which transportation by ship predominates.

4.8 Summary

The overall transport cost is estimated to lie in the region of 12–14 €/tCO_2 when approximately 14 Mt of CO_2 are transported annually. The cost increases to 14–21 €/tCO_2 when approximately 6 Mt of CO_2 are transported annually. Under current assumptions, transportation of CO_2 by ship is the most cost-effective solution, although the costs differences among the various options lie well within the accuracy of the estimations. Other factors, such as limitations related to protected areas and quay access will therefore be of importance when planning the transportation infrastructure.

The estimated transport costs are comparable to those reported in similar studies. The RCI (Section 1.2.3) calculated a cost of 25 €/ tCO_2 for transport (including compression) and storage, while the Baltic Sea – project (Section 1.3.2) estimated the cost to be 4–8 €/tCO_2 for transport (excluding compression) only.

4.9 References

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5 LEGAL ISSUES CONCERNING CCS

5.1 Introduction

This section aims to identify potential legal obstacles or uncertainties that may affect the safe deployment of CCS in the region. Where possible, appropriate remedies are discussed. In addition to this report an extended version of Chapter 5 can be retrieved from http://www.ccs-skagerrakkattegat.eu/.

CCS activities in the Skagerrak/Kattegat region will be subject to international, EU, and domestic laws, and to some extents regional or local rules and regulations. The focus here is mainly on EU and domestic laws in the three countries concerned, since these will be most influential in shaping the conditions for CCS. Nonetheless, some remarks will be made on aspects of international law that may have significance for CCS.

5.1.1 International framework

On the international level, extensive assessments of existing rules have been made, mainly aimed at identifying potential obstacles to the deployment of CCS. Some obstacles to sub-seabed storage of CO_2 have been removed by amendments to existing agreements, such as the London Dumping Protocol and the OSPAR Convention, both of which considered most cases of storage of CO_2 in the sub-seabed as dumping, which is prohibited.

A problem of particular relevance to the establishment of a CCS structure in the Skagerrak/Kattegat region is that the London Dumping Protocol prohibits the export of wastes or other materials from Parties signatories to the Protocol to other countries for dumping at sea. In October 2009, the Parties adopted an amendment to the pertinent article that enables the export of CO_2 streams for geological storage, provided that an agreement or arrangement has been entered into by the countries concerned. To enter into force, the amendment requires formal acceptance by 27 of the 40 Parties to the Protocol. As of May 2011, only Norway had submitted its acceptance. According to the IEA, only about half of the Parties are engaged in CCS development through international forums, and even among those that take an active interest in the promotion of CCS technologies not all have an interest in offshore CO_2 storage or transboundary movement of CO_2 for such storage. Thus, ratification of the amendment may have a low priority for many of the Parties to the convention. This makes it difficult to predict if and when the amendment will take effect. In the meantime, the export of captured CO_2 from Sweden or Denmark to Norway for sub-seabed storage remains prohibited under international law.

The resolution of this issue requires intensified efforts on the part of those supportive of regional CCS solutions, to highlight the problem on the international political agenda and to engage constructively with those that have expressed concerns regarding negative impacts of this liberalisation of international dumping regulations. Norway already has a high profile in this matter, and engagement by other States, which are less likely to be viewed as pursuing an immediate self-interest, is desirable.

Overall, the approach of international law to CCS is patchy and far from comprehensive. The ensuing legal uncertainties may hamper the safe deployment of CCS technology internationally. However, in the regional context, the implications of this are limited due to the common standards adopted by the EU.

5.1.2 The CCS Directive and other EU laws regarding CCS

In April 2009, a major piece of EU legislation on CCS, the CCS Directive on the geological storage of CO_2 (2009/31/EC), was adopted. As discussed below, the Directive should eventually come to apply also to EFTA States, such as Norway.

The Directive establishes a legal framework for the environmentally safe geological storage of CO_2, so as to contribute to the fight against climate change. The purpose of such storage is defined as 'permanent containment of CO_2 in such a way as to prevent and, where this is not possible, eliminate as far as possible negative effects and any risk to the environment and human health.'

The Directive applies to the geological storage of CO_2 in the territories of the States concerned, their exclusive economic zones, and on their continental shelves. This covers areas within 200 nautical miles, i.e., approximately 370 km, of the coast (when geography so allows). CO_2 may not be stored in a storage site with a storage complex, i.e., the storage site itself and any secondary containment formations, extending beyond this area. Storage of CO_2 with a total intended storage capacity of less than 100 kt, undertaken for research, development or the testing of new products and processes, is not covered by the Directive.

The CCS Directive deals mainly with the storage phase of CCS. However, the adoption of the Directive also entailed amendments to a number of other EU legal acts so as to make them apply to, and accommodate, various aspects of CCS. These include Directive 85/337/EEC on environmental impact assessment (EIA), Directive 2008/1/EC on integrated pollution prevention and control (IPPC), Directive 2006/12/EC on waste (subsequently replaced by 2008/98/EC), and Directive 2004/35/EC on environmental liability. In a separate but coordinated process, amendments were made to the Emissions Trading Directive 2003/87/EC (ETS Directive) to the effect that CO_2 captured for geological storage in accordance with the CCS Directive is not to be considered as emitted under the cap and trade system. Any subsequent emissions from any part of the CCS chain must instead be covered by emission allowances. This is further discussed below in Section 5.6.

The Directive on EIA has been amended so that an impact assessment is required for a number of CCS-related activities, regardless of transboundary effects. The EU legislation on waste and shipments of waste does not apply to CO_2 captured and transported for the purpose of storage according to the CCS Directive.

The CCS Directive, as well as the IPPC, Waste, EIA, and Environmental Liability Directives, are based on EU environmental policy and only establish minimum harmonisation. The directives leave individual States free to impose more stringent protective measure on operators under their jurisdiction, as long as those measures pursue the same objectives as the pertinent EU Directive(s).

The Marine Strategy Framework Directive (2008/56/EC) from 2008 requires EU Member States to carry out a series of measures, including the adoption of environmental targets, monitoring programmes, and programmes of measures, aimed at achieving 'good environmental status' by 2020. National measures that will be taken to comply with the directive may affect marine CCS activities. Since the directive grants Member States considerable discretion in devising appropriate measures, it is difficult to predict their specific impacts. Programmes of measures are only required to be developed by 2015.

5.1.3 Implementation of the CCS Directive in domestic law

The fact that the CCS Directive is a directive – as opposed to a regulation – means that it has to be implemented in the national legal framework. While directives are binding upon the Member State as to the result to be achieved, they leave to each State the choice of form and methods. The implementation of a directive into domestic law does not require that its provisions be incorporated formally and verbatim into specific legislation; a general legal context may be adequate provided that it guarantees the full application of the directive in a sufficiently clear and precise manner.

Implementation of the CCS Directive in the legal orders of the EU Member States was to be completed no later than 25 June 2011. However, unlike Denmark, Sweden had still to adopt any substantive implementation measures in September 2011.

In late 2010, the Swedish government presented draft implementation measures, which can be described as minimalistic, i.e., they reveal little intention at this stage to take any measures that are not required by EU law. The proposal describes the CCS Directive as partly a framework that will have to be gradually filled, e.g., by judicial decisions and national rules. However, by including the authorisation procedure for storage sites in the Environmental Code, the Swedish legislator will make applicable a number of general requirements, e.g., regarding siting.

The Danish implementation procedure reveals a somewhat more proactive attitude towards CCS. In May 2011, it resulted in the adoption of an amendment to the Subsoil Act (Undergrundsloven). These (proposed) national rules will be further discussed below in relation to particular CCS activities.

For members of the European Free Trade Association (EFTA), such as Norway, the CCS Directive may become binding by its inclusion in the European Economic Area (EEA) Agreement between the EFTA States and the EU. Although the CCS Directive has yet to be added to the EEA agreement, it has been identified as EEA-relevant and Norway is in the process of implementing it. The intention is to present draft implementation measures before the end of 2011. The measures are expected to include a new regulation on the transport and storage of CO_2 in sub-seabed reservoirs on the continental shelf. Regulations are also expected with respect to health and safety in relation to this type of transport and storage.

The current Norwegian CCS activities at Sleipner and Snøhvit are subject to authorisation and oversight in accordance with the Oil Law (Petroleumsloven) and the Pollution Control Act (Forurensningsloven). These are expected to form the basis for the new regulations. The implementation deadline of June 2011 does not apply to Norway. EFTA States typically get one to two additional years for implementing directives.

The problems that may follow from differences in regulatory approaches and political commitments to CCS are discussed further below.

5.1.4 Pertinent issues not covered by the Directive

Although the CCS Directive and the amendments to other pieces of legislation, which it stipulates, establish a legal framework for CCS activities in the States concerned, significant issues remain outside the purview of EU law. This goes for many aspects of liability. Under the Environmental Liability Directive, operators of storage sites are required to take, and bear the costs of, preventive and remedial actions with respect to environmental damage caused or threatened by a CO_2 storage site. However, liability for harm to humans or property, as well as for the damage caused by CCS activities other than storage, such as transport or injection, is a matter for the individual States. Access to land for transport infrastructure and storage sites is also not covered by EU law. The same goes for spatial planning. In these cases, national rules and principles will continue to apply.

5.2 Regulation of CO_2 capture

The capture phase of CCS has been deemed by the EU Commission not to include any element that cannot be managed within the frame of existing EU law. Most importantly, the IPPC and EIA Directives were found to be adequate to regulate CO_2 capture, with minor adjustments. Only a few remarks will therefore be made on the regulation of capture.

Directive 2001/80/EC on Emissions from Large Combustion Plants requires operators of new combustion plants (i.e., plants for which a construction license was granted after May 2009) with a rated electrical output of ≥300 MW to assess whether: a) suitable storage sites are available; b) transport facilities are technically and economically feasible; and c) it is technically and economically feasible to retrofit for CO_2 capture. If these conditions are met, the competent national authority must ensure that suitable space is set aside on the installation site for the equipment needed to capture and compress CO_2. Currently, there is no requirement that such equipment actually be installed. However, the inclusion of such a requirement remains an option. If the safety and economical feasibility of geological CO_2 storage is deemed to have been demonstrated, the EU Commission shall examine and report in March 2015 on w hether it is needed and practicable to establish mandatory emission performance standards for new large electricity-generating combustion installations. Such performance standards could in effect make CCS compulsory for some of these installations.

As an example, the proposed Swedish implementation measures do not impose any additional obligations in this respect and adhere to the 300-MW threshold.

When CO_2 is captured from an installation that in itself is subject to compulsory EIA under EU law, e.g., thermal power stations and other combustion installations with a heat output of ≥300 MW, the capture installations will also require an EIA. The same applies to other capture installations if the total yearly capture is ≥1.5 Mt. Regarding the capture of CO_2 from installations that do not by themselves require an EIA, and where the total yearly capture is <1.5 Mt, States must themselves determine whether an EIA is necessary, based either on a case-by-case examination or the thresholds or criteria that they set.

When capture is made from an installation that falls under the IPPC Directive – *inter alia* combustion installations with a rated thermal input exceeding 50 M W and oil and gas refineries – the capture will itself be subject to that directive. This entails requirements that, among other things, the best available techniques (BAT) be used to prevent pollution, that no significant pollution must be caused, and that energy must be used efficiently. The carrying out of an EIA as a prerequisite for obtaining a permit is an ordinary procedure for large industrial operations but may obviously add to the time needed to get a capture process up and running. However, compared to the time that is likely to be needed for obtaining authorisation for transport and storage operations, this should be a minor issue.

5.3 Regulation of CO_2 storage sites

The pertinent EU guidelines stress that geological storage is where most of the uncertainty and risk lie in any integrated CCS project, due *inter alia* to uncertainty regarding geological processes and current day conditions in the subsurface. The key to safe and efficient regulation and supervision of storage operations is likely to be continuous and open dialogue between operators and regulators, as well as extensive knowledge sharing among all stakeholders. Responsible authorities must be cautious not to be, or to be perceived as being – too closely involved with operators, while acknowledging that data produced and experiences gained by the operators will be of fundamental importance to their regulatory and supervisory activities. It must also be recognized that while the quality of the supervision and decision making by responsible authorities to a large extent is dependent upon careful monitoring and diligent reporting by the operator, that same operator has a significant economic incentive not to register and report leakage of CO_2, since such an eventuality would entail costly remedial measures under the ETS.

The CCS Directive recognizes the unconditional right of each Member State to decide whether it accepts the siting of any CO_2 storage within its territory. In practice, the same principle should apply to storage within a Member State's exclusive economic zone at sea, although the situation there is slightly more complex. For any State that accepts in principle such storage within its territory or under its jurisdiction at sea, there are EU law requirements, e.g. regarding the siting and the permit that will be required.

5.3.1 Substantive requirements

A fundamental obligation of the CCS Directive is that a geological formation may only be selected as a storage site "if under the proposed conditions of use there is no significant risk of leakage, and if no significant environmental or health risks exist". Although the Directive provides a definition of "significant risk", it is too opaque to provide much useful guidance. There are, however, certain criteria for assessing the suitability of geological formations for use as storage sites. The way in which the fundamental requirement of "no significant risk" will be interpreted is unclear. Since CCS, like most large-scale industrial operations, is inevitably associated with certain risks, it comes down to how "significant" is to be understood. In addition, it will be crucial for the responsible authorities to settle on a sufficient yet not excessive amount of data to be requested from the operator. With complex systems, there always tend to be further measurements or assessments that could be made, whereas the value of the data produced will have to be weighed against the costs and time associated with the preparation and acquisition of such data. This situation, of course, is not unique to CO_2 storage, although the novelty of the activity may make it particularly difficult to identify what constitutes an appropriate amount of data on which to base vital decisions.

The operation of a geological storage site normally requires a permit from a national authority. To qualify for a permit, the prospective operator must, *inter alia*, be technically competent and must provide evidence of financial security. The requirement for financial security is discussed further in Section 5.7.

If a permit is granted, it should define, *inter alia*, the total quantity of CO_2 that may be stored, the limits set for reservoir pressure, and the maximum injection rates and pressures. It must also contain an approved monitoring plan, an approved plan for corrective measures, conditions for closure, and an approved provisional post-closure plan.

The CO_2 stream to be injected must consist "overwhelmingly" of CO_2. The concentrations of all incidental substances from the source, capture or injection process, as well as of any trace substances that may have been added to assist in monitoring must meet certain requirements. These substances should not adversely affect the integrity of the storage site or the relevant transport infrastructure, and they should not pose significant risks to the environment or human health. Moreover, they should not breach the requirements of applicable EU legislation, such as the Directive on Emissions from Large Combustion Plants or the Directive on Industrial Emissions. Only streams that have been analysed as to their composition and for which a risk assessment has been carried out may be injected.

The operator of the storage site must monitor the injection facilities, the storage complex (including where possible the CO_2 plume), and where appropriate the surrounding environment. The monitoring, which is to be carried out in accordance with the monitoring plan, has several purposes: comparison of the actual and modelled behaviours of the CO_2 and formation water; detection of significant irregularities; detection of CO_2 migration or leakage; detection of significant adverse effects for the surrounding environment; and updating the assessment of the safety and integrity of the storage complex in both the short and long terms. Since monitoring requirements should in principle be risk-based, they will vary depending on the risk profile for each storage complex. This makes it difficult to make general conclusions regarding the extent and nature of the monitoring required. In addition to the CCS Directive, the monitoring activities must meet the requirements of the ETS and its monitoring and reporting guidelines (MRG), as discussed in Section 5.7. The specific nonbinding CCS guidelines on monitoring emphasise that the choice of monitoring technology should be based on the best available practice at the time the monitoring plans are formulated or updated, and that the cost effectiveness of specific technologies may be considered in that context.

In case of leakage or any irregularity, which implies the risk of a leakage or risk to the environment or human health, the operator must immediately notify the competent authority and take any necessary measures to correct significant irregularities or to stop leakages.

'Leakage' occurs not only when CO_2 escapes into the atmosphere, the ocean or groundwater; any release of CO_2 from the storage complex (the storage site and any secondary containment formations) identified in the permit is considered as leakage. Therefore, the manner in which the storage complex is defined in the permit is very important. However, under the EU-ETS, the practical definition of leakage is slightly narrower.

Once the storage site has been closed – something that normally requires that all the relevant conditions stated in the permit have been met – the operator is responsible for sealing the storage site and removing the injection facilities. The operator also remains responsible for monitoring, reporting, and dealing with irregularities or leakage, as well as for obligations under the EU-ETS. If closure occurs because the competent authority has withdrawn the storage permit, which it may do for example if the operator has failed to meet the permit conditions, the aforementioned responsibilities will instead rest with the authority. The costs, however, are to be recovered from the operator, including by drawing on t he financial security.

In the normal situation in which closure occurs at the operator's initiative, all legal obligations for the site should eventually be transferred from the operator to the State. Such transfer of responsibility requires that the site has been sealed, the injection facilities removed, and that all available evidence indicates that the stored CO_2 will be completely and permanently contained. With regard to the latter requirement, the operator must demonstrate: conformity between the actual behaviour of the injected CO_2 and the modelled behaviour; the absence of any detectable leakage; and that the storage site is evolving towards a situation of long-term stability.

Transfer of the responsibility to the State should normally not occur until 20 years after closure of the site. However, if the responsible authority is already confident that all available evidence indicates that the stored CO_2 will be completely and permanently contained, the transfer may be brought forward. In addition, after the transfer of responsibility, the authority shall recover from the former operator any costs incurred if there has been fault on the part of the operator, including deficient data, concealment of relevant information, and negligence.

Before the transfer of responsibility, the operator must make a "financial contribution" available to the national authority. This is to cover at least the anticipated cost of monitoring the site for a period of 30 years after the transfer. This is further discussed in Section 5.7.

After the transfer of responsibility, monitoring may be reduced to a level that allows for the detection of leakages or significant irregularities. If any leakages or significant irregularities are detected, monitoring must be intensified, as required. This monitoring, in the particular case of the identified potential storage site on the Norwegian continental shelf, will be the responsibility of the Norwegian state.

5.3.2 Permit procedures

Under EU law, a storage site may not operate without a permit issued by the Member State under whose jurisdiction the storage is to be located. This requires a permit procedure to be established in each State that accepts, in principle, the establishment of CO_2 storage sites within its territory. Furthermore, the permit procedure should reasonably apply to storage under the seabed when conducted under the Member State's jurisdiction.

If, before a permit for storage is applied for, there is a need to assess potential storage complexes by means of activities that intrude into the subsurface, such as drilling and injection tests, this should not be allowed without a specific exploration permit. In case of competing applications for a storage permit for the same site, an exploration permit for the site in question shall normally give the holder priority, provided that the application is made while the exploration permit is still valid.

Before a permit application can be submitted, an EIA must be carried out in accordance with the EIA Directive and any additional national requirements. Permits are to be granted on the basis of objective, published, and transparent criteria. An application for storage permit must, *inter alia*, contain: proof of the technical competence of the potential operator; a characterisation of the storage site and storage complex and an assessment of the expected security of the storage; a proposed monitoring plan; and a proposed plan for measures that are to be taken to correct significant irregularities or to close leakages in order to prevent or stop the release of CO_2 from the storage complex (a so-called 'corrective measures plan').

The required characterisation and assessment of the potential storage complex and surrounding area are to be carried out in three steps: 1) data collection; 2) the building of a three-dimensional static geological earth model; and 3) characterisation of the storage dynamic behaviour, sensitivity profile, and risk assessment. Each step is described in detail in Annex I of the CCS Directive.

The static geological earth model (or models) should characterise the complex in terms of: the geological structure of the physical trap; geomechanical, geochemical and flow properties of the reservoir overburden (cap rock, seals, porous and permeable horizons) and surrounding formations; fracture system characterisation and the presence of human-made pathways, including wells and boreholes; and pore space volume.

Storage permits are to be reviewed 5 years after issue and every 10 years thereafter.

In Norway, under whose jurisdiction the potential storage site identified in the project is located, the permit procedure for sub seabed storage is likely to be based on the Oil Law (Petroleumsloven) and the Pollution Control Act (Forurensningsloven).

Considering the novelty of CCS technology and the absence of well-established permit procedures, it is very difficult to indicate a timeframe for the exploration activities, environmental impact assessment, and permit procedures required for the establishment of a storage site. The applicable EU guidelines indicate a period of between 2 and 11 years from the award of an exploration permit (presuming that such is needed) to the award of a storage permit. For saline reservoirs, an exploration program is also likely to be required. The shorter end of this time range would only apply to storage in existing oil and gas fields without the need for exploration and provided that a smooth approval system is already in operation. Preparing an application for the required exploration permit could require an additional 1 to 2 years. This timeline is generally supported by the CO_2 Capture Project; which however is overly optimistic in claiming that the actual permit procedure will require only 6–8 months. Consultations with neighbouring countries will likely be required, and the EU Commission may require 4 months for reviewing the draft storage permit before issuing a non-binding opinion. If the permit decision is then appealed, the process is more likely to take 1.5 to 3 years.

Considering the Norwegian government's general attitude towards CCS, it is assumed that it would be supportive of the establishment of storage sites. However, there may be competing domestic interests in relation to different storage options. It is also likely that the legal framework will suffer from teething problems (e.g., in the form of inconsistencies or lack of clarity), which initially at least could make the process more cumbersome and time-consuming than expected.

5.4 Regulation of CO_2 transportation

Although transportation of CO_2 by ship and/or by pipeline is in itself not new, it has strong similarities with familiar systems for transporting natural gas. From a legal perspective, analogies with the regulation of natural gas can therefore be informative. However, the general lack of pre-existing CO_2 infrastructures raises specific challenges. The need for an integrated transportation system means that the commencement of operation may require all parts of the transportation and storage infrastructure to be in place. The most time-consuming procedures could thus determine the start of operation for the system as a whole. This may be problematic if, as will be discussed below, the time needed for obtaining permits varies considerably between the States concerned. This may be partly remedied by allowing the commencement of some transport and injection operations before all the major CO_2 sources are connected.

5.4.1 Substantive requirements

Shipments of CO_2 are not covered by the EU regulations on shipments of waste as long as they are carried out for the purposes of geological storage in accordance with the CCS Directive. Such shipments are also not covered by the Seveso II Directive on the control of major accident hazards involving dangerous substances.

Safety issues pertaining to CO_2 transport by ship are covered by international agreements and some EU rules. Ship transportation of CO_2 is not a novel activity in the region, although to date it has only taken place on a small scale.

Protected areas, particularly those designated as Natura 2000 areas according to the EU's Habitat Directive, may significantly affect the laying of pipelines from some major CO_2 point sources in the region. This could constitute a problem for example in relation to Nord-Jyllandsverket in Aalborg, Preem in Lysekil, and Borealis in Stenungsund. Any project that is likely to have a significant effect on a Natura 2000 site, either by itself or in combination with other plans or projects, must be assessed in terms of its implications with a view to the site's conservation objectives. The project may only be allowed if it will not adversely affect the integrity of the site. Alternatively, if it will have negative implications, it may be allowed only if there are imperative reasons of overriding public interest for allowing it and no alternative solutions exist. In the latter case, all compensatory measures necessary must also be taken to protect the overall coherence of Natura 2000. This means that projects in or in the vicinity of Natura 2000 sites are likely to face very significant obstacles if they are deemed to have a significant impact on (certain aspects of) the natural environment. However, a detailed study of each location is required before any final conclusions may be drawn as to the obstacles this may pose to the laying of CO_2 pipelines from a particular source. The maps provided in Figure 5.1 to Figure 5.3, which show Natura 2000 areas in the vicinity of the most affected point sources, may be indicative of the situation, but should not in themselves be used to draw any conclusions as to the feasibility of connecting the sources in question to a CO_2 pipeline system.

Figure 5.1. ***Nord-Jyllandsverket site (arrow) in Aalborg. The green and violet areas are designated as Natura 2000 areas © Kort & Matrikelstyrelsen***

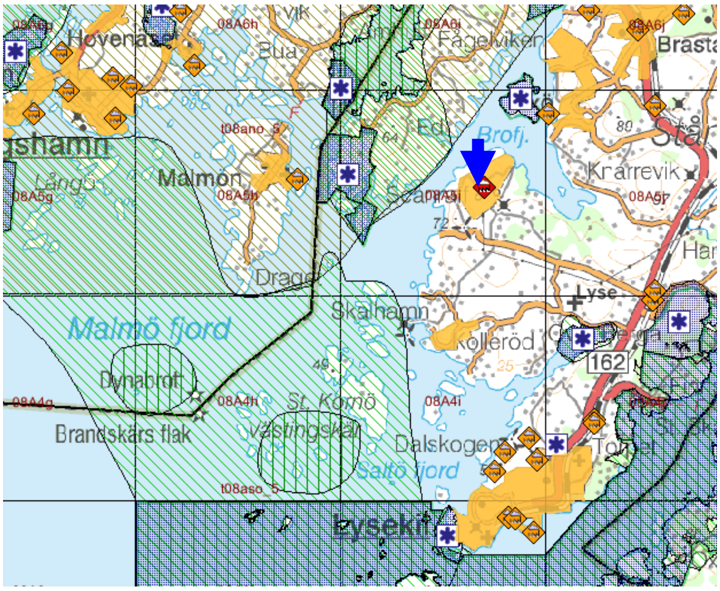

Figure 5.2. ***Preem site (arrow) in Lysekil. The areas of green hatching (in some areas overlapped by blue shading) are designated as Natura 2000 areas.© Lantmäteriet***

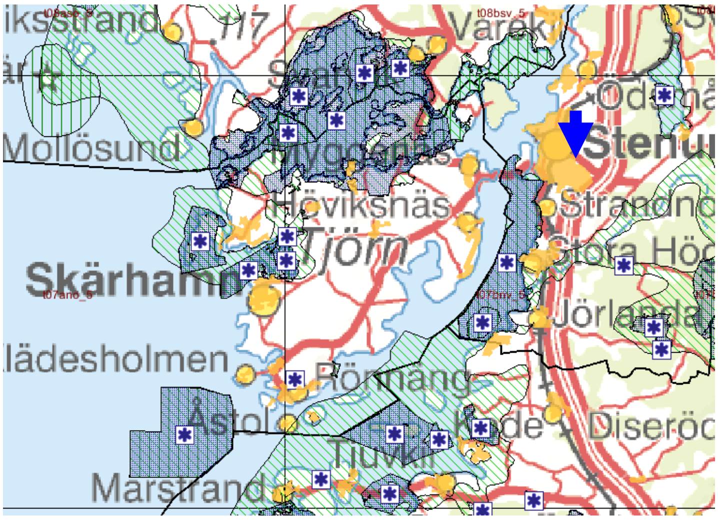

Figure 5.3. ***Borealis site (arrow) in Stenungsund. The areas of green hatching (in some areas overlapped by blue shading) are designated as Natura 2000 areas © Lantmäteriet***

5.4.2 Permit procedures

The laying of pipelines will generally be subject to permit requirements. Under EU law, an environmental impact assessment (EIA) will be compulsory for pipelines with a diameter of more than 800 mm and a length of more than 40 km if intended for CO_2 transport for the purposes of geological storage. Associated booster stations are to be included. Regarding smaller pipelines for the same purpose, the Member States must themselves determine through a case-by-case examination or thresholds or criteria set by the individual State, whether or not to require an EIA. In Denmark, the applicable regulation follows the EU legislation by requiring an EIA for sea-based CO_2 pipelines exceeding the same 800-mm diameter/40-km length thresholds. Smaller and/or shorter pipelines will be subject to an EIA requirement if they are likely to have significant effects on the environment according to criteria set out in the regulation. Under Swedish law, all CO_2 pipelines will require an EIA according to a proposed amendment. According to international law, different rules may apply to pipelines that do not enter the territorial waters of the coastal State but merely passes through its exclusive economic zone (EEZ).

The time needed for the permit procedure is difficult to predict. Whereas specific time limits apply to the assessment in Denmark, this is not the case in Sweden. The North Stream pipeline in the Baltic Sea provides an illustrative example. In Denmark, the permit procedure – not including the EIA process– took slightly more than 1 year. In Sweden, the same procedure took 23 months. A previous assessment of a permit application concerning a gas pipeline between Germany and Sweden required 34 months.

A worst-case scenario from the applicant's perspective would be denial of the permit after such a lengthy assessment. In the Swedish case, an appeal could be made to the Supreme Administrative Court, which would then examine whether the government had applied the law correctly. If the permit was granted, an appeal could also be launched by an affected individual or a non-governmental organisation promoting environmental protection. This would add up to 1 year to the process time. It is not unlikely that the court in such a case would deem it necessary to ask for a preliminary ruling from the EU court, so as to have some particular aspect of applicable EU law interpreted authoritatively. This could add another 1.5 years to the process.

Set timeframes are common in Norway, which means that Sweden is likely to be the weakest link in the system in terms of the time needed to obtain a permit (or a final denial of the permit application). Norway also has extensive experience with sea-based gas pipelines, which should make an application for one or several CO_2 pipelines less-problematic and less likely to meet significant opposition.

If the EIA procedure (including consultations with affected stakeholders and the general public) is included, a further 1.5 to 3 years need to be added to the general timeline. For a sea-based CO_2 pipeline, this gives a preliminary timeframe for the permit procedure, including EIA, of between 3.5 and 8 years.

5.5 Third party access to the CCS infrastructure

Pipelines that connect to a CO_2 storage site are deemed to be so-called ‘natural monopolies’. It is thus not surprising that the CCS Directive contains rules regarding access to transportation networks and storage sites. The requirements, however, are not very precise and allow considerable discretion to Member States.

Potential users must be able to obtain access to transportation networks and storage sites for the purposes of geological storage of captured CO_2. Access shall be provided in a transparent and non-discriminatory manner determined by each Member State. Although the Directive lists certain criteria that shall be taken into account, including storage and transport capacities that can reasonably be made available, these give little indication as to how the rules will play out in practice. It is clear that transportation network operators and the operators of storage sites may refuse access on the grounds of lack of capacity. However, Member States must ensure that an operator that refuses access on such grounds or due to a lack of connectivity makes the necessary enhancements in so far as it is economical to do so or when a potential customer is willing to pay for them, provided this does not negatively impact on the environmental security of transportation and storage. Thus, an operator will not fully control the design and capacity of the installations over time, if that would result in suboptimal or discriminatory use of transport or storage resources. It is unclear whether these rules, once elaborated and applied in Denmark, Norway, and Sweden, will be sufficiently clear and conducive to the promotion of investor confidence in the early CCS infrastructure. It is also unclear to what extent such rules will promote harmonisation between the countries. To date, little or no attention has been given to the issue of third-party access to the CCS infrastructure in the national implementation processes of the countries concerned. The Swedish proposal adheres closely to the directive. The same is true for the applicable Danish law, although it authorises the Minister for Climate and Energy to issue further rules on the subject.

One way to handle the uncertainties relating to infrastructure access would, at least initially, be for interested CO_2 producers to set up joint entities that act as operators of the transportation infrastructure and storage sites. However, such a scheme may encounter several problems, not least the need for CO_2 producers to agree to long-time commitments early in the CCS deployment process. These producers are also, with few exceptions, unlikely to have much expertise in fields pertinent to CO_2 storage. Another option could be for governments to play a significant role in the actual construction and operation of the CCS infrastructure, so as to guarantee the availability of capacity. Public-private partnerships could be a model for spreading risks and engaging concerned industries, while giving governments a say – apart from their purely regulatory role – in the management of the infrastructure.

It is likely that further harmonisation at the EU level will be necessary if different national rules turn out to distort competition and/or hamper CCS structures that involve several jurisdictions.

5.6 Liability under the EU Emissions Trading Scheme

Several liability issues arise regarding CCS operations. Liability in this context refers only to the assigning of responsibilities for the monitoring and reporting of CO_2 emissions across the CCS chain. In this section, a general outline of the EU Emissions Trading Scheme (EU ETS) is given and its implications for CCS operations are discussed.

Under the scheme, certain activities require a permit to emit greenhouse gases. Directive 2003/87/EC from 2003 (the Trading Directive), Annex I details the types of activities. Each tonne of greenhouse gas (CO_2 equivalents) emitted from such an installation must be covered by an emission quota, an EU Allowance (EUA). Each installation must also monitor and report its emissions. Allowances are then allocated to the installations for free or by auction, or simply by letting the operators buy allowances on the open market. Thus, the legal emissions from the collective activities covered are restricted to the amount of EUA:s issued.

The Trading Directive has been amended several times. The last amendment regulates the post-2012 phase in which additional gases (initially, only CO_2 was covered) and some new types of activities will be included. An important prerequisite of enlargement is that it must be possible to monitor, report, and verify emissions with at least the same amount of reliability as currently applies. Among the activities that will be included from 2013 is CCS.

5.6.1 Including CCS in the EU ETS

If the emissions from an installation are captured, transported, and stored in accordance with the CCS Directive, the installation may be released from the obligation to cover emissions with allowances. Since captured CO_2 never reaches the atmosphere (or is not supposed to), the obligation never arises. Not having to buy EUA:s (or being able to sell) is supposed to be the main long-term incentive for CCS. To create this incentive, no free allocations will be assigned to CO_2 capture installations, pipelines or storage sites.

The Trading Directive requires monitoring and reporting. Allowing EU ETS to cover CCS is also a way to handle the responsibility for accidental discharges. The purpose of including CCS in the EU ETS is thus twofold. The Trading Directive requires monitoring and reporting all along the chain. Should, for some reason, the CO_2 escape, allowances will have to be surrendered. This is why it is possible to release installations from their obligation; if the captured CO_2 escapes somewhere else along the chain, it will still be covered.

It is important that the captured CO_2 is classified in the same way within the EU ETS and the United Nations Framework Convention on Climate Change/Kyoto Protocol (UNFCCC/KP), since the registers within the EU ETS are connected to the so-called 'International Transaction Log'. According to the *IPCC Special Report on CO_2 Capture and Storage*, the two main options for including CCS in national greenhouse gas inventories are: *source reduction* (an option to reduce emissions to the atmosphere); and *sink enhancement* (in analogy to the treatment of CO_2 removal by sinks in the sector Land Use, Land-Use Change and Forestry; LULUCF).

Reduced emissions are reported in the category in which capture takes place. If capture takes place in power plants it will be reported using lower emission factors than if it occurs in plants without CCS. This could reduce the transparency of reporting and make a review of the overall impact on emissions more difficult, especially where transportation and storage include captured CO_2 from many sources or when these take place across national borders. However, the sink enhancement option is not very appropriate: CCS systems do not meet the definition of a sink, since the CO_2 captured has never reached the atmosphere. The UNFCCC defines a sink as any process, activity or mechanism that removes a greenhouse gas *from the atmosphere.*

Consequently, for the purposes of the UNFCCC/KP, stored CO_2 will most likely be classified as an emission reduction, which also seems to be the approach chosen for EU ETS. The obligation to surrender allowances does not arise if the CO_2 does not reach the atmosphere. The risk mentioned above, once again, emphasises the need for a fully monitored and transparent chain whereby any leakage must be "paid for" (in EUA:s) under the system.

5.6.2 CCS activities covered by the Trading Directive

The Trading Directive details the types of activities covered by the EU ETS in Annex I. Being covered has, as mentioned above, three main implications, and the key words are "permit", "monitor" and "report".

The obligation to monitor emissions follows not only from the permit but also directly from the Trading Directive. The principles are set out in Annex IV, which states that emissions monitoring shall be done either by calculation or on the basis of measurement. If emissions are calculated, information must be given on the factors used. If emissions are measured, information must be given as to the reliability of the measurement methods. Much emphasis is placed on calculation; if measurement is chosen, the supporting calculations must corroborate the measurements. In the reports, information must be given as to the total emissions as well as to the level of uncertainty.

The reports submitted by operators must be verified as satisfactory. A certain methodology for the verification process is prescribed in the Trading Directive, Annex V, and includes consideration of the report and of the monitoring during the preceding year. The verification addresses the reliability, credibility, and accuracy of both the monitoring systems and the reported data relating to emissions. The verifier must be independent of the operator, carry out its activities in a sound and objective professional manner and be given access to all sites and information in relation to the verification. Reported emissions may only be validated if reliable and credible data and information allow the emissions to be determined with a high degree of certainty. An operator whose report has not been verified as satisfactory for emissions during the preceding year is not allowed to make further transfers of allowances until such report is verified as satisfactory.

The Trading Directive prescribes that the Commission shall adopt guidelines for the monitoring and reporting of emissions. The Directive also requires the Member States to ensure that operators report their emissions in accordance with these guidelines. Thus, through the Directive, these guidelines become legally binding. Such guidelines were adopted in the Monitoring and Reporting Guidelines, MRG:s, in 2007. MRG Annex II applies to all activities covered by the Trading Directive and gives an overall formula for determining the total emissions of greenhouse gases from an emission source. The following annexes provide further activity-specific guidelines. In June 2010, the Commission released an amendment applicable to the different phases of CCS.

The Trading Directive covers the capture of greenhouse gases from installations covered by that directive for the purpose of CO_2 transportation and geological storage in a storage site permitted under the CCS Directive. Thus, to be covered by the Directive, the capture needs to take place at an installation that itself is covered by the Trading Directive. The capture must also be done for the purpose of CO_2 transportation and geological storage in a storage site permitted under the CCS Directive. Guidance for the determination of emissions from capture is found in MRG Annex XVI.

Potential emission sources during the capture operation, identified in Annex XVI, are CO_2 transferred to the capture installation (INPUT) and emissions from all other activities at the installation (potential emissions without capture). If there is no transferred CO_2 the input equals zero. Potential emissions are added and then the CO_2 transferred *to* a transportation network for storage ($T_{\text{for storage}}$) is subtracted. If there is a net emission, allowances must be paid. For each measurement point, the total uncertainty for the overall emissions should be less than ± 2.5 %.

The next CCS phase covered by the Trading Directive is the transportation of greenhouse gases by pipeline. The guidelines for monitoring are found in the MRG:s, Annex XVII, which permits two approaches to reporting the potential emissions. The operator must demonstrate that the chosen method (A or B) provides the most reliable results and entails the least uncertainty.

Method A is based on a m ass-balance (input-output) calculation. The CO_2 entering the pipeline at its “entry point” (INPUT) is added to the emissions from the transport networks’ own activities ($E_{\text{ownactivity}}$). This represents emissions not stemming from the CO_2 transported, but from, for example, fuel use in the booster stations. Then, the CO_2 transferred from the transport network at its “exit point” (OUTPUT) is subtracted. The net emissions must be covered by EUA:s. *Method B* involves calculating the CO_2 emissions of the network and is based on potential sources of emissions. Vented CO_2 and emissions from leakage events (to be determined by industry best practice) are added to emissions from combustion or other activities functionally connected to the pipeline transport in the transport network (e.g., booster stations) and fugitive emissions from the transport network.

The EU ETS also covers the geological storage of greenhouse gases in a storage site permitted under the CCS Directive. As noted above, the operation of a geological storage requires a permit from a competent national authority, according to the CCS Directive. This permit is important when it c omes to delimitating the boundaries for monitoring and reporting emissions under the EU ETS; they are based on how the storage site and storage complex are specified in this permit.

Since it is covered by the Trading Directive, Annex I, the storage operation also needs a greenhouse gas emissions permit. All emission sources from the injection facility shall be included in this permit. The guidelines for monitoring and reporting are found in MRG Annex XVIII. Potential emissions sources are described as including fuel use and other combustion activities, vented and fugitive emissions from injection, breakthrough CO_2 from enhanced hydrocarbon recovery operations, and leakage.

Combustion emissions from above-ground activities shall be determined in accordance with MRG Annex II. This prescribes, amongst other things, that the monitoring of emissions from combustion processes shall include emissions from the combustion of all fuels at the installation, as well as the emissions from scrubbing processes (for example, to remove SO_2 from the flue gas). All emissions from the combustion of fuels at the installation shall be assigned to the installation, regardless of exports of heat or electricity to other installations. The amount of CO_2 vented shall be determined using the emission measurement system according to Annex XII. In the monitoring plan, the operator shall provide an analysis of the potential sources of fugitive emissions and a suitable documented methodology, based on industry best practice, to calculate or measure the amount of emissions.

If any leakage (as defined in the CCS Directive) from the storage complex results in emissions or release to the water column it will be considered as an emission source for the storage installation and monitoring shall start. It is interesting to note that while the CCS Directive considers any release of CO_2 from the storage complex as leakage, quantification is only required when CO_2 is released into the air ("emissions") or into the water column. The leak will then be regarded as an emission source until no emissions or release into the water column from that leakage are detected anymore and the operator has notified the competent authority in accordance with the CCS Directive.

As shown above, all emissions escaping from the CCS chain under the EU ETS must be covered by allowances, even when they originate from the capture installation or the transport system itself. This is logical, since the installation that produced the captured CO_2 does not need to surrender allowances; if CO_2 is released to the atmosphere or water column somewhere along the chain, it must be covered. Otherwise, the environmental integrity of the system might be endangered. Something else that might endanger this integrity is a lack of experience with quantification of CO_2 released from storage sites into the air water. This uncertainty concerning quantification could be considerably higher than the average uncertainty associated with CO_2 monitoring in the existing EU ETS.

5.6.3 CCS activities NOT covered by the Trading Directive: Marine tankers

Transport of CO_2 by marine tankers is *not* covered by the EU ETS, simply because it is not mentioned in the Trading Directive's Annex I. Consequently, there are no European guidelines for the transportation of CO_2 *via* shipping. The main legal implication of this is that such transport does not require a permit to emit CO_2. It also means that the emissions from ship transports neither need to be monitored nor are they covered by allowances. In other words, the EU ETS does not put any legal obligations on the use of ships to transport CO_2. Under EU law, shipments of CO_2 for the purpose of geological storage have been excluded from the rules on shipments of waste, albeit only to the extent that storage takes place within the EU. Thus, there seem to be no significant legal obstacles to placing CO_2 on marine tankers.

However, if an installation is to be released from the obligation to surrender allowances, the CO_2 must be verified as captured, transported, and stored. Putting the CO_2 on a ship would break the chain of monitoring and covering emissions with EUA:s. It is very unlikely that CO_2 transported by ship would count as "verified transported" in the required manner. This means that although no major legal obstacle exists, the incentive for the entire CCS chain is taken away if the CO_2 is placed on a ship.

Would it then be possible for (for example) Sweden to include shipping in the EU ETS? The possibility to include unilaterally a certain type of activity (opt in) is regulated by Trading Directive, Article 24 (b), since shipping is not an installation but an activity not listed in Annex I. The allowed extent of opt-in measures is unclear. An activity may be included unilaterally by applying emission allowance trading *in accordance* with the Trading Directive. This indicates that the Directive must be possible to use as it is. Next, the article expresses that supplements may only amend *non-essential elements* of the Directive. This indicates that amendments are allowed to some extent. However, the leeway here seems to be very narrow. Primarily, the Trading Directive covers stationary installations. You know in which State a stationary installation is situated. The emissions are considered to take place in that State and the same State is responsible for the issuance of a permit, the monitoring, and the surrendering of EUA:s. A ship might originate from one country (the Flag State), be loaded with the captured CO_2 in another State, and then move across the border to a third State. Which of these States is to be responsible for potential emissions? The current Trading

Directive is not designed to handle such a situation. A similar situation with aircraft has been resolved by an amending directive, although the aviation sector is not fully linked to the trading scheme; operators of stationary installations covered by the scheme are not allowed to use allowances issued for aviation to cover their emissions, while aircraft operators are free to cover aviation emissions with allowances originally issued for either aircraft or stationary installations. This makes it impossible for ships to be handled in the same way as aircraft, since they should be fully included as a part of the CCS chain. Moreover, aircraft operators do not need a permit; instead each aircraft operator submits a monitoring plan to the competent authority in the administrating Member State.

In the end, it is for the Commission to decide whether a unilateral inclusion may be made, after which all the relevant criteria must be taken into account. It seems unlikely that a unilateral inclusion would be considered that would have any significant effects on the European transportation market or potential distortions of competition, since it would only address a very specific type of transport. When it comes to the environmental integrity of the Community scheme, monitoring and reporting become essential. When looking at the MRG concerning transport in pipelines, all types of emissions are considered, not only the INPUT (see above). This means that emissions generated by the transport system itself must be added to the total emissions (this is also the case in the MRG annex on capture). Following the MRG logic, the emissions from the ships themselves must be included when calculating emissions. This means that the ships must also be able to monitor and report their emissions and thus not only the cargo is affected. If one chooses not to consider the emissions from the ship, the environmental integrity of the Community scheme might be called into question.

Irrespective of whether the inclusion of shipping is unilateral or if it is done at the EU level, it must be coherent with the United Nations Convention on the Law of the Sea (UNCLOS), which differentiates between the different forms of jurisdiction, i.e., Flag State, Coastal State, and Port State. It also differentiates between legislative and executive jurisdictions. Legislative jurisdiction gives the State the competence to legislate, while executive jurisdiction defines the extent to which the State can enforce rules. A certain State's competence to regulate shipping thus depends on the kind of jurisdiction it enjoys in a certain case. A Coastal State has jurisdiction over ships within its territorial sea (12 nautical miles from the so-called baseline). From an environmental perspective, this means that this State may regulate and control routes, define marine protection areas, etc. Having said that, the State is not allowed to restrict the international principle of innocent passage or the passage through straits used for international navigation. Concerning ships exercising their right to innocent passage, the Coastal State may only adopt rules regarding construction, equipment etc. if they reflect internationally accepted standards, i.e., the rules laid down in international agreements. If ships are to monitor their emissions, some equipment would be required. When transporting CO_2 for geological storage the vessels will seek harbour in relevant countries, which means that those countries will act as Port States. Rules adopted by Port States may be enforced no matter which flag the ship flies, if they are necessary to protect the environment, proportional relative to their purpose and non-discriminatory. This might be an alternative way of handling the equipment issue, though it is debatable whether it is possible to use environmental protection as an argument. It is easier for a Flag State to regulate the ships equipment, but then it will only be possible to use the Flag State's ships for transport. This might raise questions about discrimination and disproportionality.

The reason why transport by marine tankers is not initially included is probably that it is more legally complicated than pipelines (which are stationary). The solution can be something similar to the Aviation Directive, though taking into consideration the particularities of ships. This is most probably best done at the EU level by means of harmonised measures.

5.7 Financial security

The CCS Directive requires the operator of a storage site to establish financial security – to be valid and effective before commencement of injection – in order to ensure that all obligations arising under the storage permit can be met. That includes closure and post-closure requirements and any obligations arising under the EU ETS. In particular, this means that the financial security must be able to cover the purchase of emission allowances for any future leakages. This necessitates estimations of highly uncertain future costs. According to nonbinding EU Commission guidelines, the cost for such leakages may be based on:

- a conservative estimate of the maximum portion of CO_2 that can be released from storage, which, in most situations, will be much less than 100%; or
- a calculation of the potential leakage amount based on a probability distribution of the amount of leakage from the storage complex.

It is not possible to say what level of financial security this will require until a significant amount of information regarding a particular storage site has been collected and a dialogue has been initiated with the competent national authorities. The financial security is to be periodically adjusted to take account of changes to the assessed risk of leakage and the estimated costs.

No clarification has so far been provided as to how these requirements will be applied in the countries concerned. The applicable Danish law largely restates the Directive's requirements, while providing more detailed rules to be adopted by the Minister of Climate and Energy.

The operator of a storage site will also be obliged to make a "financial contribution" available to the competent authority before transfer of responsibility takes place. This is designed to cover at least the anticipated cost of monitoring the site for a period of 30 years after the transfer of responsibility.

Although the financial contribution need not be made available until the end of the post-closure period, the EU Commission points out that since the operator's injection-related revenues will by then have ceased, the contribution will have to be secured at an early stage of the storage project. In effect, the financial security required during the operation of the site will also have to cover the financial contribution for the post-transfer phase. The CCS Directive leaves to the individual States to decide whether they want the financial contribution to cover more than the anticipated cost for 30 years of monitoring up to the full estimated amount of the costs that the competent national authority will incur for all post-transfer obligations. In Danish law, the contribution has been fixed to the anticipated cost of monitoring the site for a period of 30 years. Whether that will also be applied in Norway or Sweden is not yet clear.

5.8 Compatibility of rules in the three States concerned

The building of the CCS infrastructure, including land- and sea-based pipelines (possibly ports), and storage sites entails going through several permit procedures. These procedures are different in the different countries and the time required to obtain a particular permit may also vary significantly. The whole project may have to await the outcome of the most slowly moving permit procedure. The assessment of permits for individual parts of the project (e.g., a particular stretch of pipeline) may also include assessments of the overall environmental and health impacts of the whole CCS infrastructure. Ten years is not an overly pessimistic estimate of the time needed to obtain all the necessary permits, allowing for several appeals. It is also questionable whether a prospective operator would be willing to incur substantial costs, e.g., for carrying out an EIA procedure and initiating a permit procedure for a CO_2 pipeline, without having reasonable assurances that the storage facility to which the pipeline is to be connected will also be approved. This may call for a more coordinated approach, at least with respect to the governments and authorities in the countries concerned. A joint statement of intention and/or a joint regional strategy for CCS infrastructure could send important signals about shared views and common intentions. This is not to say that such a political act could, or should, prejudge the judicial assessment of the individual components of that infrastructure. It would, however, indicate a willingness to seek actively common solutions within the frames set by law and judicial review.

A joint regional strategy would also alleviate concerns associated with the different levels of familiarity with CCS activities and the significant differences in political commitment and engagement displayed to date, e.g., between Norway and Sweden. Technical compatibility is likely to be promoted by the application of international standards, such as the DNV-Recommended Practice on design and operation of CO_2 pipelines. No similar coordination exists – except for the often vague minimum standards of the CCS Directive and some other EU legislation – on the political and regulatory sides. For regional CCS projects to materialise, they may be just as essential.

5.9 Summary

Until an amendment to the London Dumping Protocol enters into force the export of CO_2 streams for geological storage in the seabed remains prohibited under international law. Up to May 2011, only a single ratification of the amendment had been achieved. This calls for intensified efforts to bring this issue to the forefront of the international political agenda and for constructive engagement with those weary of liberalisation of international dumping regulations.

Both the operation of storage sites and the laying of pipelines will require permits from national authorities. A likely timeframe for obtaining a permit for a sea-based CO_2 pipeline, including EIA, is between 3.5 and 8 years. The timeframe for a storage site permit could be shorter, although this is difficult to predict with precision as there are few precedents.

Protected areas, particularly those designated as Natura 2000 areas, are likely to complicate the laying of pipelines from some major CO_2 point sources in the region. This needs to be studied in detail on a case-by-case basis.

Third-party access to the CCS infrastructure has so far been given very little attention in the national implementation processes, despite the risk that the vagueness of existing rules deters investors.

The whole CCS chain is covered by the EU ETS, and any CO_2 that is released into the air or the water column must be covered by emissions allowances. The transportation of CO_2 by marine tankers is currently not covered by the EU ETS, which, in practice, makes such transport unfeasible. Although unilateral inclusion of marine transport by an individual Member State is not impossible, a formal amendment to the harmonising EU rules is probably a prerequisite for such transport to become a viable option.

A joint regional CCS strategy would alleviate concerns relating to the significant differences in political commitment and engagement displayed so far by the States concerned.

However, none of these problems or challenges is insurmountable if the will to find solutions exists with politicians and the industries concerned. Most challenging from a regional perspective may be the London Dumping rules, since the resolution of this problem requires action by a large number of States outside the region. Furthermore, the issue of ship transportation of CO_2 will require concerted action, this time within the EU, and some technical challenges need to be overcome. This could take some years if a sense of political urgency is not forthcoming. Other issues, such as elaborating the terms for third party access and agreeing on a joint strategy, are more amenable to resolution by the decision-makers in Denmark, Norway, and Sweden. These issues could be addressed more swiftly if there is a will to promote regional CCS operations.

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An extended version of this text with complete references can be retrieved from http://www.ccs-skagerrakkattegat.eu/

6 POLITICAL FRAMEWORK

The prospects for and timing of a plausible introduction of CCS in the Skagerrak region will, obviously, also depend on numerous non-technical factors. While there is a broad literature focusing on the technical aspects of CCS, studies on the non-technical dimensions of CCS are scarce. However, research on the social, political, and legal aspects of CCS is slowly gaining momentum (see Bäckstrand *et al*, 2011 for a review). The categorisation described below is an attempt to list a number of critical factors, which are discussed in this chapter.

The most obvious hindrance to the implementation of CCS is that investments in CCS will be justifiable first when the costs of capturing, transporting, and storing the CO_2 are equivalent to the cost of emitting CO_2. In addition, most of the subsidy schemes to date have been dedicated to CCS development projects directed towards the power sector. Under the EU NER300 programme, at least eight CCS projects will be funded. At this stage, 13 CCS projects are being considered, of which 11 involve CO_2 capture in the power sector and 2 focus on capture in the industrial sectors (IEA GHG, 2011). This imbalance in funding to CCS development projects across sectors is understandable. However, it is worth noting that while the power sector can take advantage of alternatives to fossil fuels, CCS may be the only alternative for several industries (of which some are represented in the Skagerrak region) if they are going to achieve substantial CO_2 emission reductions (IEA, 2011). The scale of the challenges associated with CCS will require the active involvement of authorities. To date, the level of engagement differs considerably across the countries in the Skagerrak/Kattegat region. Finally, public awareness and acceptance have been identified as key barriers to CCS deployment (Johnsson *et al*., 2010). Technological novelties are often met with scepticism and CCS is no exception.

6.1 EU climate change targets and the potential role of CCS

The EU has committed to reduce overall GHG (greenhouse gas) emissions by 20% in 2020 relative to the levels in 1990. As of September 2011, the EC is still considering raising the reduction target to 30%. Nevertheless, on July 5th, 2011, the European Parliament rejected a motion to increase the 2020 reduction target from 20% to 30% (Euractiv, 2011). In the longer term, up to 2050, the EU has on several occasions claimed that industrial countries should reduce their GHG emissions by 80% to 95% relative to the levels in 1990 (EC, 2011a). In 2009, combined GHG emissions from agriculture and road transport amounted to 1,391 Mt, accounting for between 30% and 33% of total GHG emissions, excluding and including, respectively, the impacts of LULUCF (Land Use, Land Use Change, Forestry) (EEA, 2011). This illustrates that although *all GHG emissions from all stationary sources* are neutralised, this will still not be sufficient to meet the suggested targets by 2050. The Commission has suggested in its low-carbon pathway to 2050 that agriculture and transport should reduce their emissions by 42% to 49% and by 54% to 67%, respectively, by 2050. For the power sector and industry, the Commission has suggested reductions that range from 93% to 99% and 83% to 87%, respectively. The low-carbon pathway envisages a substantial role for CCS in the power sector and concludes that a lower contribution from CCS and a delay in the introduction of CCS to the power sector will lead to significantly higher CO_2 prices and higher costs to achieve a low-carbon system by 2050. In this respect, it can be noted that for instance the IEA (2008) has calculated that the exclusion of CCS from its global mitigation portfolio would raise by 70% the cost of achieving a 50% reduction in emission by 2050. CCS is also assumed to play a significant role in the industrial sector albeit at a later stage, from around 2035 on wards. If the rest of the world is assumed not to implement corresponding strict CO_2 emission reductions, the roadmap suggests that CCS will not become a mainstream mitigation technology within industry (EC, 2011a, b).

Total Primary Energy Consumption (TPEC) in the EU amounted to just above 1,700 Mtoe in 2009, of which 77% was fossil fuels. Overall import dependency reached 55% and is expected to continue to rise as indigenous coal, gas, and oil resources are depleted (EC 2011c). Although the contribution from renewable energy has shown an impressive growth over the last decade and this growth is expected to continue, renewables will not fully replace fossil fuels for many decades. In addition, Europe has substantial lignite reserves and the search for unconventional gas within Europe has intensified over the last 2 years and is expected to make a substantial contribution to overall energy production at least in some Member States. From a security of supply perspective, the focus should be on reduced consumption, maximum extraction of own resources (fossil fuels *and* renewables), and the diversification of fuels, fuel suppliers, and fuel transport routes. From a climate change perspective, GHG emissions should be reduced dramatically. This paves the way for CCS, which the EU clearly has recognized, and CO_2 that is captured, transported and stored in a geological reservoir will be considered as not being emitted under the revised ETS (Emissions Trading Scheme). In April 2009, the Commission released the CCS Directive, which should have been transposed into national law within each Member State by June 25, 2011. The EU has also initiated two support schemes for up to 12 large-scale CCS demonstration projects: €1,050 million under the European Energy Program for Recovery (EEPR) divided between seven schemes (six coal power stations plus a steel plant) in France, Germany, Italy, the Netherlands, Poland, Spain, and the UK; and the so-called NER-300 program, which will distribute revenues from the auctioning of 300 million CO_2 emission allowances between innovative renewable projects and CCS schemes. No project will receive more than 50% of the net CCS costs calculated over a 10-year period and the aim is to have all schemes up and running in 2015. In addition, several MS, such as the Netherlands, Norway, and the UK have pledged significant additional financial support schemes for specific demonstration projects.

6.1.1 CCS and the EU greenhouse gas emissions trading scheme

The EU GHG ETS was launched in 2005, setting an annual cap and a price for CO_2 emissions from some 11,000 power stations and industrial plants in 30 countries (EU-27 plus Iceland, Lichtenstein, and Norway). Although the scheme covers emissions of other GHG (e.g., nitrous oxide), CO_2 is by far the most important GHG covered by the scheme. The facilities included in the scheme are responsible for some 40% of the total GHG emissions within the EU.

During the third trading period starting in 2013 (and ending in 2020), the number of emission allowances issued through the scheme will fall annually, so that in 2020 the total amount of issued allowances will be 21% lower than the allowances issued in 2005. For the EU, the cap for 2013 has been set at 2.04 billion emission allowances, while the annual reduction up to 2020 will amount to around 37.4 million emission allowances (EC, 2011d).

While most emission allowances up to 2013 have been and will be distributed for free, starting in 2013 more than half of the allowances will be auctioned. In the power sector, the main rule is that all allowances should be auctioned. In the industrial and heating sectors, up to 80% of the allowances can be distributed for free in 2013 based on a benchmark that stipulates the GHG emission intensity per unit product for the top 10% most efficient installations in the EU (producing the same product). The share of possible free allowances will be reduced each year, reaching 30% in 2020. For industries that are exposed to international competition, the number of free allowances is calculated in exactly the same way with benchmarks based on GHG emission intensity per unit of product. However, they can receive up to 100% of the allowances for free for *each year* up to 2020 (provided that their GHG emission intensity corresponds to the same as that for the top 10% most efficient installations) (EC, 2011d).

The main intention of the ETS is to provide a market-based mitigation environment, i.e., each company will usually select the most cost-efficient CO_2 emission reduction option within the market in which they operate and based on the overall corporate strategy, provided that the cost of emitting CO_2 is greater than the cost of avoiding CO_2. ZEP (2011) estimated the specific cost for capture, transport, and storage of CO_2 at around 34, 3 7, and 90 €/tCO_2 avoided for lignite-, coal-, and natural gas-fired power plants, respectively, which can be compared to a CO_2 emission price that has ranged from 10 to 17 €/tCO_2 over the last 2.5 years. It is generally expected that the price of emissions will rise as emission reduction requirements increase (i.e., the cap is being reduced in line with what is stated above) as we move towards 2020. Figure 6.1 shows the CO_2 emission prices quoted by Nordpool since the launch of the trading platform in February 2005, along with the costs for the CCS chain for lignite-, coal-, and natural gas-fuelled power plants, as calculated by ZEP (2011).

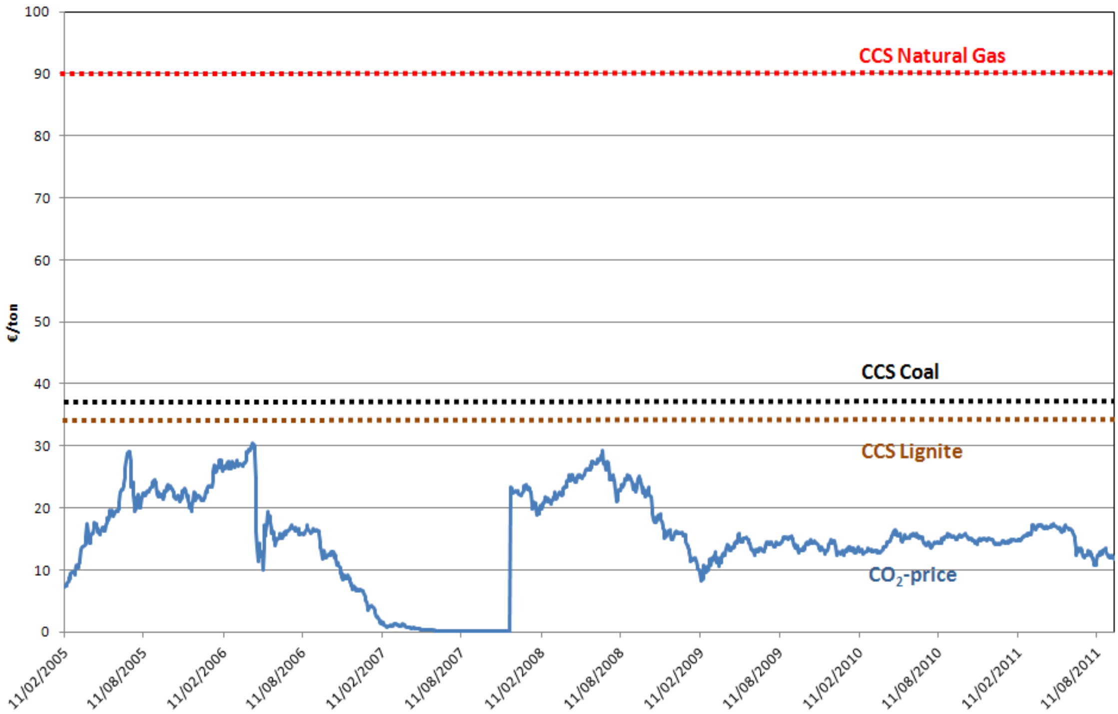


Figure 6.1. ***CO_2 emission prices (blue line) since the start-up of the EU ETS in February 2005, along with the estimated costs for a complete CCS chain involving lignite- (brown), coal- (black), and natural gas (red)-fuelled power plants. Sources: Nordpool, ZEP 2011.***

As can be seen from Figure 6.1, there is a substantial cost advantage to lignite- and coal-fired power plants in terms of the cost of CCS. Calculating instead the levelised cost of electricity, gas-fuelled power plants become more competitive due to, among other things, their higher conversion efficiencies (see for instance, ZEP, 2011).

However, the possibility of transferring emission allowances between trading periods, so-called 'banking', risks to seriously undermine the scheme, leading to a large surplus of emission allowances during the third trading period. Sandbag (2011) for instance, claims that the third trading period will be inflated with around 1.9 billion emission allowances, caused partly by the banking of almost 700 Mt from the second to the third period and partly by the number of emission allowances issued for the second period, which obviously has been too high (partly as a consequence of the 2009 economic crisis; see for instance, Climate Strategies 2011). This in turn leads to an inflated number of allowances issued for the third period, which Sandbag (2011) claims will amount to around 1,200 M t between 2013 and 2020. Climate Strategies (2011) claims that the ETS in addition to having a large surplus of allowances, is signalling a cap in 2030 that is too low and inconsistent with the EU's officially quoted long-term goal of at least 80% GHG emission reductions by 2050.

Other important factors with respect to CCS are the uncertain political framework and emission reduction requirements globally *after 2020,* and therefore also within the EU, coupled with the fact that billions of Euros will have to be invested between now and *up to 2020* in order to drive capture technology forward towards commercialisation. In fact, none of the four countries that constitute the world's four largest emitters of CO_2 (China, India, Russia, USA), and who combined are responsible for more than 50% of global energy-related CO_2 emissions, have so far committed to any emission reductions at all (IEA, 2010a).

Therefore, there are large uncertainties with regard to both the future CO_2 emission price and the post-2020 emission regime globally, and therefore also within the EU. Under these circumstances, companies may well decide to delay investments into new plants (including CCS plants) until the future regulatory regime becomes clearer. Sandbag (2011) suggests that the EU should remove 1.7 billion allowances from the third trading period, while Climate Strategies (2011) suggest that more focus should instead be placed on the cap being set for 2030, as this will provide more long-term regulatory certainty for investors. Tightening the 2020 cap without setting a strict reduction target also for 2030 will, according to Climate Strategies (2011), risk lock-in effects for relatively carbon-intensive technologies, such as natural gas. The best solution would probably be to do both, i.e., removing allowances for the period up to 2020 and increasing the reduction targets for 2030. However, both these actions may turn out to be politically difficult to implement, as for instance illustrated by the European Parliament's rejection in June 2011 of a proposal to raise the 2020 reduction target to 30% (Euractiv, 2011).

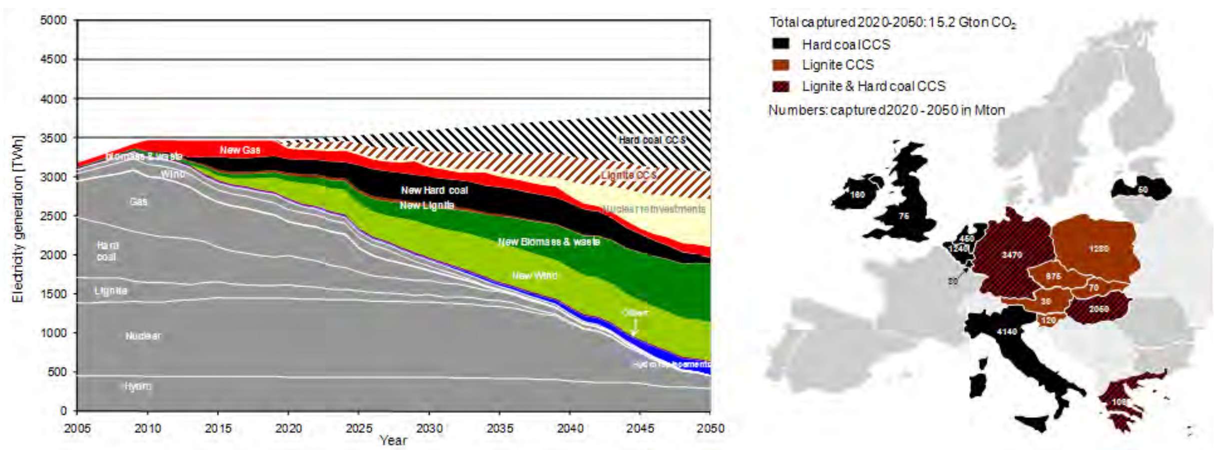
6.1.2 CCS in the power sector

The public power and heat sector accounted for 30% of total GHG emissions in the EU in 2009, not including the effects from LULUCF, or 1,400 $MtCO_2eq$ (including 1,393 $MtCO_2$). It is generally expected that large-scale CCS will start up from coal-based power plants, which is also reflected in the EEPR (European Energy Program for Recovery) support scheme, in which six out of seven projects that have been granted financial support are coal plants. Of the six power plants that have been granted financial support for a CCS scheme, two either have, or are, experiencing problems. The Jänschwalde CCS demonstration plant in Brandenburg, Germany, is facing considerable local opposition to its plans to store the CO_2 in an onshore aquifer in Brandenburg, while the owner of the Hatfield IGCC (Integrated Gasification Combined Cycle) CCS plant in Doncaster, UK, went into bankruptcy in December 2010. However, the UK project has since then been taken over by a new company and is now referred to as the Don Valley Power Project.

The large uncertainties described above in relation to the future CO_2 emission price and GHG emission regime have, together with local opposition, led to many coal-based power plants under development being abandoned or delayed, with utilities instead choosing to build wind-, biomass-, or gas-based power plants. It has been discussed to introduce so-called Emission Performance Standards (EPS), e.g., setting a maximum emission level of 350 gCO_2/kWh electricity, meaning that coal plants could only operate with CCS, but analyses have shown that such standards risk raising total system costs, distorting the ETS and locking the EU into larger dependency on natural gas (Odenberger *et al.*, 2011; Bloomberg, 2011). Nevertheless, as mentioned in Section 5.1.3, the European Commission will in March 2015 examine whether the EPS is needed and whether it is practicable to establish mandatory emission performance standards for new power plants. The ECN (2011) recommends the application of EPS in the Dutch power sector, but only as part of a package of policy measures *designed* to provide more certainty to investors and to *advance* the large-scale deployment of CCS without any considerations as to, for instance, total system cost. The UK Government has suggested a carbon price floor for the power sector starting at £16 per tonne in 2013, rising to £30 per tonne in 2020 (2009 prices, corresponding to roughly €18 and €34 per tonne, respectively) and possibly increasing to £70 per tonne in 2030 (UK Treasury Department, 2011).

Chalmers Electricity Investment Model (ELIN) is a techno-economic model of the European electricity system based upon a database of all the power plants in the EU, Norway, and Switzerland, listed on a block level with respect to capacity (power and heat), age, fuel, technology and other factors (Kjärstad *et al*., 2007). The model calculates future fuel and technology distributions within the system at the lowest total system cost given exogenously defined boundary conditions, such as CO_2 emission reductions, penetration levels of renewable and nuclear energy, and the effects of efficiency improvements. The model also includes existing interconnectors and can choose to invest in new transmission capacity. Furthermore, ELIN assumes that CCS will become commercially available from 2020, applying capture cost from the ENCAP project and country-specific cost for the transportation and storage of CO_2. Chalmers has on several occasions modelled the EU power sector assuming strict CO_2 emission reduction requirements along with greater penetration of renewables and a substantial effect from efficiency improvements. For instance, in the recent Policy Scenario (Odenberger *et al*., 2010), CO_2 emissions are reduced by 40% in 2020 and by 85% in 2050 (in both cases relative to the level in 1990), renewables are assumed to account for at least 30% of total generation in 2020 and for 45% of the total in 2050, while the effect of efficiency improvements leads to 13% lower demand in 2020 and 23% lower demand in 2050 relative to baseline demand, as provided by the EC (2007). The resulting fuel and technology distributions up to 2050 for the EU plus Norway is shown in Figure 6.2a, along with the corresponding geographical distribution of CCS in Figure 6.2b. The existing generation system being phased out over time is shown in grey colour (Figure 6.2a).

As can be seen from Figure 6.2, the penetration of CCS is substantial in spite of a large contribution from renewable energy and efficiency improvements in combination with strict CO_2 emission targets. In total, some 15 $GtCO_2$ is being captured and stored between 2020 and



a) b)

Figure 6.2. ***a) Power generation by fuel/technology in period 2005–2050 in the Chalmers Policy Scenario (for a detailed description of the scenario, see above or Odenberger et al., 2010). b) Corresponding distributions of CCS by country, as modelled in the Chalmers Policy Scenario. The Figures show a substantial contribution from CCS, albeit concentrated to coal-based power generation (Odenberger et al., 2010).***

2050 in the Policy Scenario, with Germany, Hungary and Italy accounting for almost 65% of the CO_2 captured and stored over this period. Lignite-based CCS appears to be the most cost-efficient CCS option (see Figure 6.1). However, since the scenario limits lignite production to current production levels, the model also selects the second most cost-efficient CCS option, i.e., hard coal CCS. Under the assumed cost for CCS, gas-based CCS is not considered to be commercially feasible from a system perspective (see also Figure 6.1). Figure 6.2b also shows that CCS is not considered as economical (from a system perspective) in the Nordic region. Of course, what is considered as economically optimal from a system perspective may not necessarily be optimal from the perspectives of the various utilities (plant owners).

As mentioned above, the Skagerrak/Kattegat project comprises two power plants: Nordjyllandsverket (NJV) in Denmark, which is a coal-fuelled combined heat and power plant (CHP) owned by the Swedish utility Vattenfall; and Ryaverket, which is a gas-fired Combined Cycle Gas Turbine (CCGT) CHP owned by Göteborg Energi. CCS has been planned for NJV for several years. In fact, NJV has been selected as one of the first commercial-scale CCS plants within the Vattenfall group and is destined to go on-line in the early 2020's. A preferential onshore storage site has already been selected: an aquifer named Vedsted located 30 km west of the plant and with a potential storage capacity of up to 160 $MtCO_2$ (Gestco, 2004). Vattenfall has plans to capture and store around 1.8 $MtCO_2$ annually at Vedsted. However, the company has experienced local opposition to their plans, and in October 2011, the Danish Ministry of Energy and Climate Change denied Vattenfall a permit to store CO_2 in the Vedsted structure. No plans for CCS have been published for the Ryaverket gas plant at the time of writing this report.

6.1.3 CCS in the industrial sector

It is generally expected that CCS will start later in the industrial sector than in the power sector. Five out of the seven facilities covered by the Skagerrak project are industrial plants: three refineries and two chemical plants, located on the Norwegian south coast and the Swedish west coast. All five plants are considered to be exposed to international competition and may therefore receive up to 100% of their emission allowances for free each year up to 2020 (based on a benchmark for GHG emission intensity per unit product, see Section 6.1.1). However, personal communications with plant representatives of each of the five plants investigated in this study reveal that none of the plants is likely to receive all their allowances for free. Combined annual emissions from the five industry plants are roughly 4.3 Mt (see Table 2.2), while some 3.5 Mt can be captured efficiently (see Table 2.9). As mentioned in Section 6.1, the European Commission expects CCS from industrial plants to start later than CCS from power plants, around 2035, and the Commission acknowledges the possibility that CCS may not become a mainstream mitigation technology for industry (EC, 2011a, b). The IEA (2010b) claims that CCS represents the most important new technology option to reduce direct emissions in industry, with a potential to save between 1.7 and 2.5 $GtCO_2$ in 2050. Specifically for Europe, the IEA claims that CCS in industry, along with energy efficiency, offers the greatest least-cost emission reduction potential. IEA also recommends that large-scale demonstration of CO_2 capture technologies in industry should be undertaken in parallel with the demonstration projects planned for the power sector, and underlines the need for adequate government funding for CCS demonstration projects in industry (IEA, 2010b).

A few CCS projects are under development at refineries and chemical plants in Europe, all of which have experienced different types of problems. Shell had to abandon its CCS project at the Pernis refinery in the Netherlands due to considerable local opposition to the plans to inject the CO_2 into two depleted gas fields in Barendrecht (see Chapter 6.4). Likewise, DSM Agro had plans to capture and inject CO_2 into sandstone layers beneath its ammonia plant in Chemelot, also in the Netherlands, but had to abandon the plans in 2011 due to local opposition. The European Carbon Dioxide Test Centre Mongstad (TCM) in Norway will during its first phase test and qualify CO_2 capture technologies and contribute to cost reduction and commercialisation of technologies. Two different capture technologies (amine and chilled ammonia) for the capture of the flue gases from a natural gas-fuelled combined heat and power plant (CHP) and the catalytic cracker at the refinery will be investigated, with expected start-up in 2012. The second phase of the Mongstad capture project will comprise a full-scale capture plant that will capture CO_2 from both the power plant and the refinery. However, due to uncertainties related to the potential health risks of using amines, a final investment decision (FID) to proceed with Phase 2 has now been delayed until 2016, despite the fact that the health risks of using amines have recently been scaled down considerably (see Section 2.2.2).

Concawe, the oil companies' European association for research on environmental issues relevant to the oil industry, is currently carrying out a study on CCS for refineries. As of September 2011, this study has not been completed. Concawe claims that although CCS at refineries is technically feasible, the cost of CO_2 avoided will be significantly higher than current (2011) ETS market prices (see Figure 6.1) and the €40 to €60 per tonne quoted for coal-based power. Norcem, Brevik, a cement manufacturer owned by the German Heidelberg Cement Group and located in the Kattegat/Skagerrak region, is another example of options being explored for CO_2 capture in industrial settings (Gassnova, 2010).

Efforts need to be intensified to enable a better understanding of the prospects for CCS in industrial applications. As mentioned above, while the power sector can take advantage of alternatives to fossil fuels, CCS may be the only alternative for several industries to achieve substantial CO_2 emission reductions.

6.2 CCS in the Nordic countries

As mentioned above, the level of engagement differs considerably between the countries in the Kattegat/Skagerrak region. While the Norwegian authorities have been in forefront of CCS development and deployment, their Swedish (with the exception of the state owned Vattenfall) and Danish counterparts has been relatively passive. While there are several explanations for this discrepancy, the level of engagement must be placed in the context of the overall energy situations in the three countries. Whereas both Norway and Denmark are net exporters of both oil and natural gas and have favourable geological conditions for CO_2 storage, Sweden appears to lack both these features.

All three countries have ambitious, long-term GHG emission reduction targets and are aiming to increase the share of renewable energy. However, the share of renewable energy is already substantial in all three countries and the potential for significant additions may therefore be limited in the near and medium terms. By 2050, Denmark is aiming to be independent of fossil fuels, while Sweden is aiming for zero net GHG emissions and Norway will reduce *global* emissions by an amount corresponding to 100% of its own emissions. It is obvious that CCS can play an important role in achieving such significant reductions in emissions. The EU ETS, carbon taxes and, in Norway and Sweden, green certificates are seen as the main policy instruments to achieve emission reductions (VTT, 2010).

In matching large-scale CO_2 emission sources with potential storage sites, the Skagerrak region is clearly of interest from a CCS perspective, with large emission sources in all three countries lying relatively close to potential storage sites in both Denmark and Norway, and possibly also in Sweden. It should be recognized that a large proportion of the emissions in both Norway and Sweden originates from the transport sector, from which future strict emission reductions may be difficult to achieve. Thus, the importance of achievable large emission reductions from stationary point sources in order to reach ambitious GHG emission reduction targets should not be underestimated. Moreover, Sweden has a significant amount of biogenic CO_2 emissions, some 29 M t in 2008 according to VTT (2010). Storage of biogenic CO_2 would in practice represent negative emissions, which would facilitate the achievement of ambitious GHG emission reduction targets. However, this would require the inclusion of biogenic CCS in the EU ETS.

Norway is particularly active in the research and development of CCS. Mongstad TCM may become the world's first large-scale installation for CO_2 capture from a gas-fuelled power plant; CO_2 has been injected and stored in subsea reservoirs since 1996 in the Sleipner project and since 2008 in the Snöhvit project in the Barents Sea. Norway and Denmark have both participated in the Gestco project to map CO_2 sources and subsurface CO_2 storage capacity. Denmark has also participated in the GeoCapacity project to update its storage capacity, while Norway currently is updating its storage capacity. Norway has also been particularly active in looking at the CO_2 value chain through research conducted by Statoil, Gassnova, Tel-Tek and the Norwegian Oil Department. Research and development efforts in this area in Sweden have mainly focused on the capture part and have only very recently started to look at value chains and domestic CO_2 storage capacity.

6.3 Possible business models and risk sharing

A business model should share risks and rewards so that acceptable returns are earned by each individual party and for the project as a whole. Four different business models can be considered for a CCS value chain that consists of a capture part, a transport part, and a storage part (Pöyry, 2011; Scottish Centre for Carbon Storage, 2009):

1. A fully integrated project, meaning that the partners form a single company (Joint Venture) in which all the parties are exposed to all the risks over the whole chain. Such a business model may be the most attractive model when it comes to risk sharing but since companies operating in different sectors expect different returns, this model may not work well in a CCS system that consists of several sources and storage sites linked by a common network.
2. Take or Pay (ToP) contract, which is a set of contracts each specifying a fixed payment to each partner. In this case, each partner bears full responsibility for its own operational risk with limited risk passed on to other parties, thereby providing the greatest incentive for each party to manage their own operational risk.
3. Full variable contract, which consists of contracts between a power plant, pipeline and storage site operators that specify a price per unit of CO_2. Operational risk can, to some degree, be passed on to parties down the chain but cannot be passed upwards, which means that the pipeline and storage operators are exposed to the operational risks of the emitter while they are unable to pass on their own risk in the same way.
4. A so-called 50:50 contract in which 50% of the revenues are fixed and 50% are variable.

Pöyry (2011) investigated the Internal Rate of Return (IRR) for the four business models outlined above. The CCS chain is assumed to be operated by three partners: an emitter (a power station), a transporter, and a storage company. The four models were applied, assuming a power station with base load versus 50% load and in which the power station receives revenues from the sale of electricity and dispenses these revenues to the other parties according to the four contract types. The results are shown in Figure 6.3, where the grey line indicates the IRR at base load.

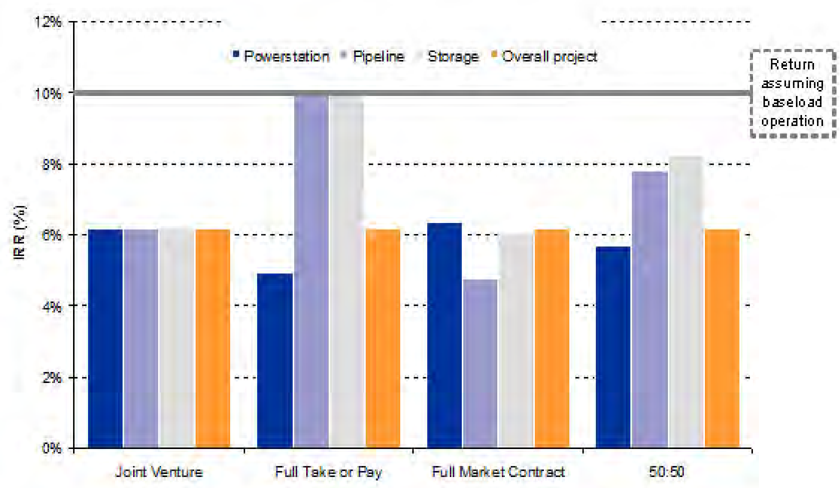


Figure 6.3. Internal Rate of Return values for different parts of a CCS chain, assuming a power station at base load and 50% load. Source: Pöyry, 2011

As can be seen from Figure 6.3, the power station (the emitter) bears the highest risk, receiving lower revenues (as opposed to the base load operation) in all the modelled applications, which probably is appropriate, since the variability in revenues originates from the power station. It can also be seen that the ToP model is the least advantageous model for entities upstream in the chain and the most advantageous for entities downstream in the chain.

The example given above raises several important issues, e.g., how can a business model adapt to a CCS system that consists of multiple sources and sinks?; how will TPA (Third Party Access, see Section 5.5) be implemented?; and, of particular interest for the Skagerrak project, can CO_2 emitters from different countries use the transport network and who will be responsible for the stored CO_2? In a case where additional revenues are being generated, for instance through CO_2 EOR, the question arises as to how these revenues would be distributed among the partners.

6.4 Public acceptance

CCS projects in Denmark, France, Germany and the Netherlands have all met with considerable local resistance and some projects, such as the Shell project in Barendrecht, the Netherlands and RWE's plans to store CO_2 in an aquifer in Schleswig Holstein, have been abandoned. More recently, it has become increasingly apparent that Vattenfall is facing significant problems with their CCS project in Brandenburg, Germany (see for instance, DN, 2011). Common to all these projects is that they involve onshore storage, whereas CCS projects in the Netherlands, Norway and the UK involving offshore storage do not seem to have encountered any resistance. For instance, CO_2 has been injected in the Dutch K12 gas field since 2004, as well as into two Norwegian aquifers in the North Sea and Barents Sea since 1996 and 2008, respectively. On the other hand, demonstration projects in Poland and Spain, also involving onshore storage, appear to have met none or little public opposition, respectively (see for instance www.ccsnetwork.eu). In this respect, it should therefore be noted that apart from some Danish aquifers, the bulk of the identified Nordic storage sites are located offshore.

The ECN (2010a) carried out a survey in five countries linking the survey questions to a specific CCS project within each country: the Hatfield project in the UK (now changed project name to the Don Valley Project); the Maasvlakta project in the Netherlands; Jänschwalde in Germany; Belchatow in Poland; and Ponferrada in Spain. While the British and Dutch projects refer to offshore storage, the other three refer to onshore storage. For each country, there were 200 respondents in a national sample plus 200 in a local sample. Apart from the Netherlands, a very large percentage of the respondents had never heard of CCS: between 42% and 56% in four of the countries, and only 23% in the Netherlands. In all the countries, with the exception of Germany, the respondents' attitudes towards CCS and specifically towards the CCS project in their own country was generally positive, with only a small difference noted in the percentages of respondents with a positive attitude towards CCS in general and the specific CCS project in that country. However, in Germany almost 50% of the respondents had a generally positive attitude towards CCS, while less than 35% felt the same about the domestic storage project (the Jänschwalde project).

A recent and more comprehensive study of public opinion towards CCS was conducted by Eurobarometer in February and March of 2011. More than 13,000 interviewees in twelve member states were interviewed; the only Nordic country that participated was Finland. The study showed that there is a widespread lack of knowledge about CCS, since only 10% of the respondents had heard about CO_2 capture and storage prior to the study. Awareness of CCS was noticeably higher in those countries that host CCS demonstration projects. More than 60% of the respondents would be worried if a storage site was to be located within 5 km of their home. Nearly 40% stated that they would like to be directly consulted and to participate in the decision-making process. Only 23% of the interviewees responded that they believed CCS would benefit them if it was used in their region, implying that individuals want to be convinced of a local benefit, e.g., new jobs, before accepting a new technology in their backyard. Perhaps surprisingly, 24% indicated that they preferred onshore storage in areas of low population density, while only 21% preferred an offshore storage site. Universities and research institutions were perceived as the most trustworthy sources of information on CCS (45%), while regional and local authorities, governments, and the EU were considered as the most reliable source by 23%, 20%, and 14%, respectively (Eurobarometer, 2011).

Some studies clearly indicate that awareness of the climate change problem and the seriousness of this problem are particularly high in the Nordic countries. In a recent poll conducted in Norway on the knowledge of CCS, 63% of the respondents claimed that they had heard of CCS. This is contrary to the results from most studies, which clearly indicate that few people are familiar with CCS (VTT, 2010). On the other hand, as envisaged by the ECN (2010a) study mentioned above, knowledge of CCS was also high in the Netherlands. This may reflect the high levels of CCS-related activities in Norway and the Netherlands. At the same time, the value of public opinion polls on CCS should be questioned if the awareness of CCS in that region is low.

In Norway, several NGO's have adopted a positive attitude towards CCS, e.g., Bellona and Zero. CCS may represent a business opportunity for Norway, since the country appears to be well endowed by offshore subsurface storage capacity. This may contribute towards a more positive attitude towards CCS in Norway.

Case study: Barendrecht

The Barendrecht case refers to 1 Mt/yr of almost pure CO_2 being produced during hydrogen production at the Pernis refinery in the Netherlands. The refinery is already supplying 150 ktCO_2 annually to soft drink producers and another 380 ktCO_2 during summertime to greenhouses in the region, and had plans to store around 400 ktCO_2/yr in two depleted gas fields, Barendrecht and Ziedewij. In total, some 9.5 MtCO_2 should be injected over 25 years at depths of 1,700 m and 2,700 m, respectively. The CO_2 would be transported from the refinery to the gas field in a 40-bar, 17-km pipeline that is being laid in an existing pipeline corridor. At the storage site, a compressor would bring the pressure up to 120–160 bar prior to injection. The Dutch Government has granted €30 million to the project. The project developers held information meetings and made the Environmental Impact Assessment (EIA) available to the public. At the request of the local municipality, additional studies were carried out, including an integrated safety assessment of CO_2 storage at Barendrecht and a study of possible health disorders that local residents might incur as a result of CO_2 storage under Barendrecht. While the integrated safety assessment study concluded that there were no risks attached to storage that went beyond the statutory norms, the study of possible health disorders made a number of recommendations in order to minimise such disorders. Although the Ministers of Economic Affairs and of Housing, Spatial Planning and the Environment (VROM) in November 2009 decided that the project could go ahead and although the local authorities had no formal legal say in the project, the local and provincial protests became so strong that the Government in November 2010 decided to shelve the project. The ECN (2010b), in analysing what went wrong in Barendrecht, claims that:

1) The project developers started to inform people but they were regarded as a poorly trusted source.
2) Concerns raised by the public were not taken (or were perceived to be not taken) seriously.
3) Argument and counter-argument led to the polarisation of proponents and opponents.

In addition, in April 2010, it was revealed that the Dutch government had withheld from the public a geological report on the area that raised doubts regarding the suitability of the two gas fields as CO_2 storage reservoirs. Although the report was later dismissed as not being scientifically correct, this contributed to a significant increase in the level of distrust between the government and the project developers on one hand and the local residents on the other hand (Bellona, 2010).

The ECN (2010b) concluded that the outcome of public participation will depend on the timing of public involvement and the ability of the public to influence project decision making. It is recommended that all stakeholders in the project be included in the process *at an early stage* and that during this process the demands, needs, values and interests of the different stakeholders should be defined, discussed, and *integrated into the project design*.

6.5 Summary

CCS is facing several non-technical barriers, the most prominent of which appear to be the uncertainties related to a future GHG emission regime globally (and therefore also within the EU) and the cost of CO_2 emissions, as provided by the EU ETS. EU and governmental funding clearly favour CCS in the power sector, and there are few CCS projects underway in industry.

There should be good prospects for CCS in the Nordic countries, in particular in the Skagerrak region, since the Nordic governments have ambitious long-term emission reduction targets and there are several clusters of large-scale emission sources in combination with relatively short distances to several potential storage sites. In addition, a large proportion of the GHG emissions in both Norway and Sweden is from the transport sector, highlighting the important role of large-scale reduction opportunities.

It could prove difficult to design appropriate business models for sharing revenues and risks in CCS chains that comprise multiple sources and sinks.

Public acceptance has turned out to be a significant obstacle for several CCS projects, although mostly with regard to onshore storage. Norway seems to have encountered little opposition to CO_2 storage, probably because all storage capacity is located offshore and CCS may in fact represent a business opportunity for Norway. Aside from that, Norway has extensive experience with the storage of CO_2.

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7 CCS ROADMAP FOR THE SKAGERRAK/KATTEGAT REGION

7.1 Background and basis

The national authorities have a combined target of reducing GHG emissions by 30% (relative to1990 levels) by 2020, two thirds of which is to be taken as national emission cuts.

According to the IPCC, CCS should account for 15% of the global emission cuts if we are to stay within the 2°C goal for global temperature change. The IEA asserts that by 2020 there must be 100 full-scale CCS projects globally, that by 2030 this number must have reached 850, and that by 2050 there must be 3000 CCS projects in operation worldwide. The Skagerrak/Kattegat region has great potential and a responsibility to contribute to these goals. Moreover, the ability to offer a fixed solution for CO_2 emission reductions may contribute to attracting industry to the region.

To ensure rapid and widespread deployment of CCS, the international framework is of great importance. As described in Chapters 5 and 6, legal aspects, financial support mechanisms and political/financial measures, such as the EU ETS, the price of CO_2 emissions, and the national standards regarding emission performance, are vital for the future of CCS. Without a proper regulatory framework and sufficient financial incentives, full-scale and widespread deployment of CCS will not happen.

Meeting the 2°C target will require close to zero CO_2 emissions from all large emission sources in the region, which implies that CCS can play a significant role, in particular with regard to emission reductions from industrial plants. The presence of the Gassum formation as a potential storage site may facilitate the establishment of a CCS scheme in the region.

7.2 Proposed roadmap

Several activities for realizing CCS in the Skagerrak/Kattegat region should be started in parallel, so as to have a full-scale CCS system in place by 2030. Figure 7.1 describes the main activities that will be required and a suggested time-line for the implementation of CCS in the region.

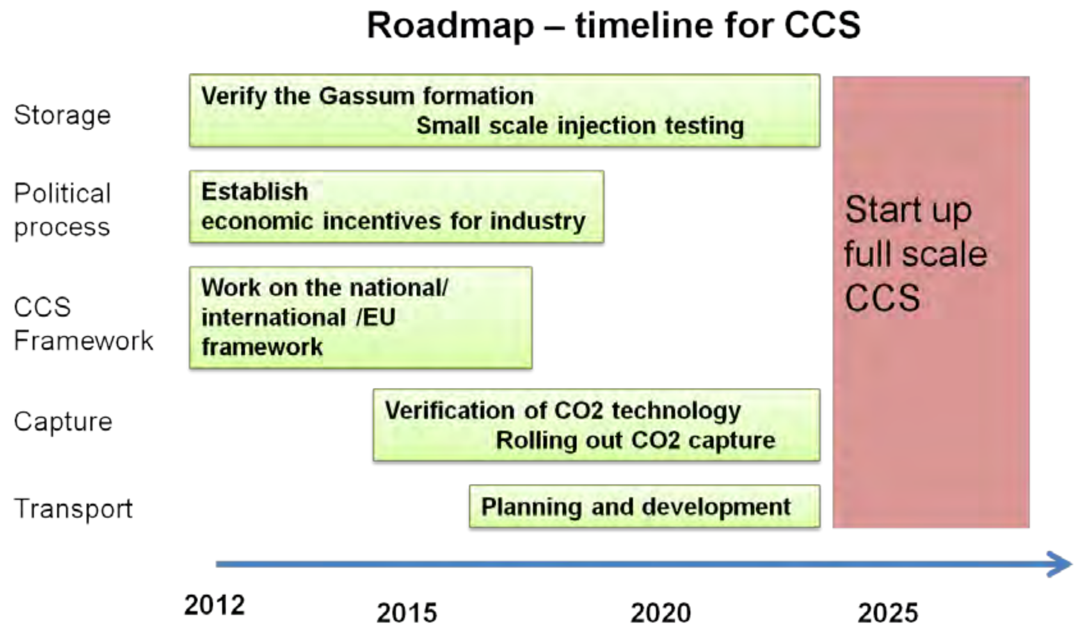

Figure 7.1 Main activities and suggested timeline for the implementation of CCS in the Skagerrak/Kattegat-region.

Based on the project, the following key actions will be required in a roadmap towards the implementation of CCS in the region, here divided into key topics:

- **Storage**
  - Verification of the Gassum formation as a CO_2 storage site
    - ✓ Further simulations and drilling will be required to qualify the site for CO_2 storage and to verify its actual storage capacity
    - ✓ Small-scale CO_2 injection testing
    - ✓ Full-scale injection start-up

The simulations of the Gassum formation indicate that the open dipping traps can permanently store at least 250 $MtCO_2$. More detailed mapping of the reservoir and overburden is required for better estimates of safe pressures and better simulations of CO_2 migration within the reservoirs, as well as for the design of an injection strategy with the locations of wells for injection/production (of reservoir water to alleviate pressure build-up in the aquifer) and observation. Examples of such activities are further reservoir simulations and the drilling of wells. The time period to develop the storage site from the current situation to being ready for operation is estimated to be up to 10 years.

- **Political process / CCS Framework**
  - Influencing the direction of politics and developing incentives for CCS
  - Implementation of EU/international framework into domestic laws

Even if it is expected that a new technology will reduce the capture cost, it will obviously be necessary for governments to establish a policy framework that makes CCS commercially viable. In the long run, such a policy must incorporate a sufficiently high cost for emitting CO_2. Thus, for widespread deployment of CCS beyond the fully financed demonstration projects, there needs to be investor confidence that the cost of CO_2 emissions will increase considerably after 2020. In its "Low Carbon Roadmap" up to 2050, the European Commission indicates that: 1) CCS is likely to be implemented later in the industrial sector (around 2035) than in the power sector; and 2) CCS may not become a mainstream mitigation technology in the industry, since most CO_2-intensive industries are exposed to global competition and are therefore not expected to pay fully for their CO_2 emissions until after 2027, if at all (EC, 2011). In contrast, the power sector will have to pay fully for CO_2 emissions already from 2013. The IEA, which recently released its 2011 edition of the World Energy Outlook, claims that time is running out to limit the global temperature increase to 2°C, since most of the total energy-related CO_2 emissions permissible to 2035 are already locked-in by the existing capital stock (IEA, 2011). Therefore, it is crucially important that the envisaged CCS demonstration projects be implemented on time.

CCS activities in the Skagerrak/Kattegat region will be affected by international, EU, and domestic laws, and to some extent by regional and local regulations. The focus here is mainly on EU and domestic laws in the three countries concerned, since these will be most influential in shaping the conditions for CCS.

It is difficult to predict when the necessary amendments to the London Dumping Protocol will come into force, which would allow for the export of CO_2 for geological storage in the seabed. With political commitment and a growing global momentum for CCS, this could occur well before 2020. In the absence of these factors, the problem could remain unresolved indefinitely. In the meantime, it should be noted that the London Protocol does not prevent the transportation of CO_2 from Norwegian sources to a storage site on the Norwegian Continental Shelf.

Amendments to the EU ETS to cover ship transportation of CO_2 should be attainable by 2015, given the necessary political commitment. If such commitment is not forthcoming at the EU level, the regional CCS infrastructure as such will not be impeded, since transportation by pipelines alone is a possibility. However, the cost will increase if the pipeline system is underutilised during the ramp-up period.

A likely timeframe for obtaining a permit for a sea-based CO_2 pipeline, including an environmental impact assessment, is between 3.5 and 8 years. The timeframe for a storage site is difficult to predict, since there are few precedents, but it could well be shorter. If there are several appeals, 10 years is not an overly pessimistic estimate of the time required for obtaining all the necessary permits for transport and storage, including those for ports and land-based pipelines.

Both the elaboration of a joint regional CCS strategy and the clarification of the rules on third-party access to CCS infrastructure are at the disposal of national decision-makers in the countries concerned, and these processes should not require more than 2 to 4 years if CCS is perceived as an important part of national climate strategies. In terms of legal issues, CCS could, in a best-case scenario, be implemented before 2020 in the Skagerrak region.

- **Capture**
    - Verification of CO_2 capture technologies
    - Rolling out of CO_2 capture

According to the results of this project, the cost of capturing CO_2 from industrial processes will be between 45 €/t and 65 €/t (excluding transport and storage). Thus, CO_2 capture will not be applied to industrial processes in the absence of technical developments that either lower the cost of capturing CO_2 or significantly increase the cost of emitting CO_2. It is also important to note that there are large differences in capture costs between sources. Therefore, carbon capture may not be implemented at the same time at all locations, which will have consequences for the development of the required infrastructure for transportation and storage. For example, coal-fired power plants, represented by Nordjyllandsverket in the present investigation, have a considerably lower capture cost than industrial sources. Furthermore, in accordance with current policy settings, power plants are the only large-scale CO_2 sources that will have to pay fully for all emission allowances already from 2013.

Assuming the successful deployment of early demonstration projects around 2015 and a steady increase in the cost of emitting CO_2, and assuming that within a few years there will be a post-2020 policy regime that clearly indicates a continuous increase in emission cost (say, up to € 50/tCO_2 by 2025-2030), it should be possible to install the first semi-commercial CCS plants relatively soon after 2020. Most likely, these first CCS plants will be coal-fired power plants for which the CO_2 capture cost is lowest, implying that CCS in the Skagerrak/Kattegat region will start in Denmark. The installation of CCS at industrial sources will benefit from the early projects on power plants, as similar technologies will be used. Therefore, the way forward to develop and lower the cost of capture is to push for the demonstration projects and to gain experience of the technology.

- **Transport**
    - Planning and optimisation of transportation routes for pipelines and/or ships
    - Development of the infrastructure

Assuming that a relevant storage site has been selected and that there is a commercial incentive to start building the capture plant, detailed planning of the transportation infrastructure could start. Prior to that, work has to be carried out to find the optimal locations for the onshore pipelines and hubs. Factors that may slow the development of a transportation network, such as protected areas, quay access, etc., can be time-consuming to resolve and have to be taken into consideration with regards to predicting the timeline.

Figure 7.2 shows a proposed fully developed CCS scheme in the Skagerrak/Kattegat region. The Danish sources may also choose to store in the Gassum formation.

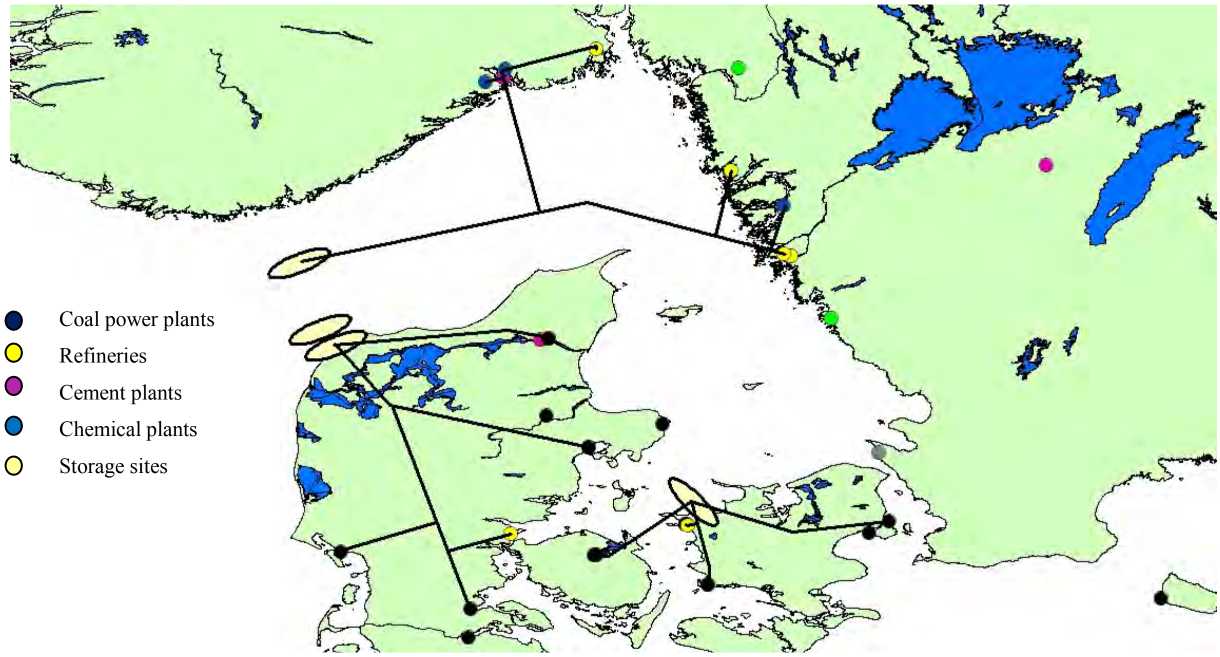

Figure 7.2 ***Illustration of a possible Nordic CCS system in which the Norwegian and Swedish industrial sources collaborate on a joint scheme for CO_2 storage in the Gassum formation. The figure also illustrates a possible Danish system that uses Danish aquifers for CO_2 storage.***

7.3 EOR

Injection of CO_2 into an oil field can, under certain favorable circumstances, enhance oil recovery, so-called 'CO_2 EOR' and this will offset part of the cost of CCS. As oil prices and the cost of CO_2 emissions are likely to increase in the future, CO_2 EOR may become increasingly interesting. Oil (and gas) fields also have the advantages of a proven seal and there will therefore be little need to perform costly seismic investigations and well drillings prior to injection, as most of the required reservoir data should already be available.

In the Skagerrak-Kattegat region, and in the present project and report, there is little focus on EOR due to the lack of available oil/gas fields. Assuming that the needed transport to fields outside the region can be established, CO_2 EOR could become a financial driver for increasing the implementation of CCS in the region. However, this will require that the extra cost of transporting the CO_2 over a longer distance will be more than offset by the additional revenues from the increased oil production. It should be noted that EOR is not a long-term mitigation option, since after all it increases the recovery of oil.

7.4 References

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8 CONCLUSIONS AND RECOMMENDATIONS

8.1 A CCS solution for regional industry and power production

This project has explored the feasibility of establishing a CCS network in the Skagerrak/Kattegat region of southern Scandinavia. In addition to developing the technical and economical parameters of the CCS chain and identifying possible storage locations, the project has also looked into the legal and regulatory requirements and the political framework needed to establish a possible CCS solution.

Potential CO_2 storage sites identified within the region

Several geological formations have been identified as potential reservoirs within the region. In particular, the Gassum and Haldager Sand formations have considerable potential. Two types of reservoir structures should be followed up with more detailed studies: 1) large gently dipping reservoirs in the northern Skagerrak area; and 2) closed dome structures above salt pillows in the Norwegian Danish basin.

Reservoir simulations have been made of two open dipping aquifers and one dome structure (Hanstholm) with homogenous properties and thicknesses. For modelling purposes, a total of 250 Mt CO_2 is injected down-flank using three injection wells over a period of 25 years. One open dipping aquifer is located south of Kristiansand, with injection 60 km offshore and approximately 2000 m below the seabed. Another site is northwest of Jutland in the Danish sector. Simulation results from these two storage sites are promising, although additional detailed work needs to be done to qualify and develop this geological structure into a safe and reliable site for CO_2 storage. This aquifer south of Kristiansand has been chosen as a possible storage site for the CCS evaluation in the present project.

Simulation of CO_2 injection into the Hanstholm structure has shown that the structure can accommodate 250 MtCO_2 injected down-flank using three horizontal injection wells over a period of 25 years. However, the resulting formation pressure was rather high, making seal leakage a risk. In addition, the Hanstholm structure requires additional detailed studies to qualify as a safe and reliable storage site.

Total CCS costs for a possible CO_2 network

The total CCS costs (capture, transport and storage) for the industrial plants are estimated as 67–82 €/tCO_2 in a low-energy-cost regime and 69–86 €/tCO_2 in a high-energy-cost regime. The observed variation within the same energy cost regime is due to different capture costs at the industrial plants, while for transportation and storage single cost numbers have been calculated based on a total amount of 14 MtCO_2/yr going through the network. Assuming 6 MtCO_2/yr, i.e., the amount of industrial CO_2 available from the project partners, the transportation and storage cost increase by approximately 20 %.

For the two power plants included in the study, the total CCS costs are 54–56 €/tCO_2 for the coal plant for low and high energy costs respectively while the corresponding cost for the gas plant are 139-151 €/tCO_2. The considerable difference in cost for the two power plants is due to the lower CO_2 content in the flue gas of the gas plant in combination with a lower annual load factor.

The most significant capture cost parameter is the cost of energy. In the present study, post-combustion capture technologies are assumed to be implemented using state-of-the-art MEA technologies for the industrial plants and chilled ammonia technology for the power plants. This implies demand for a low-quality steam supply to the stripping part of the capture plants.

In particular, various options to use in-house waste heat recovery as part of the energy supply to the capture plant have been studied in this project. In some of the plants, there is sufficient heat available to provide the stripper energy by direct heat exchange, while in other cases a combination with suitable heat pump concepts can be used. Using natural gas or other fossil fuels to fire boilers for steam generation will significantly increase the avoided CO_2 costs.

The CO_2 transportation costs are calculated at between 12 €/tCO_2 and 14 €/tCO_2 for the best cases of ship, ship/pipeline and pipeline network. These cost figures reflect the situation when the full capacity (14 MtCO_2/yr) of the chain is utilised, irrespective of the CO_2 transport distance. Under the current assumptions, transportation *via* ship to a hub in Grenland and then by pipeline to the injection wells at the Gassum formation is the most cost-efficient solution. However, the cost estimates for the alternatives studied are all within the range of the uncertainties in the calculated costs.

A major challenge when evaluating the transport part of the CCS chain is the ramping up of CO_2 flows to the full capacity of the network. A sensitivity calculation shows that the transport cost would increase by a factor of three depending of the strategy used for handling various load situations.

The cost of CO_2 storage has been estimated based on the available information, which is scarce, and amounts to approximately 9 €/ tCO_2 when 14 M tCO_2 is assigned as the annual capacity. The main cost-driving parameter is the number of injection wells that will be required. For the purposes of this study, five wells are assumed to be sufficient to handle 14 MtCO_2 annually, which corresponds to a relatively high capacity per injection well.

Lack of economic incentives for implementing CCS today

Overall, the techno-economical analysis shows that there is a significant gap between the actual estimated CCS costs and the current cost of emitting CO_2 to the atmosphere. Even when assuming a future scenario with a CO_2 emitting cost of 45 €/ tCO_2 there is lack of economic incentives for implementing CCS.

8.2 Main legal challenges to CCS identified in this study

Prohibition of the export of CO_2 under the London Dumping Protocol

The London Dumping Protocol is an international agreement for the protection of the seas against the dumping of waste. An amendment to the protocol was decided in October 2009 that enables the export of CO_2 streams for disposal, provided that an agreement or arrangement has been entered into by the countries concerned. It is difficult to predict when this amendment will take effect. In the meantime, the export of captured CO_2 from Sweden or Denmark to Norway for sub-seabed storage remains prohibited under international law.

Nature protection areas and pipeline routing

Protected marine areas, particularly those designated as Natura 2000 areas according to the EU's habitat directive, may significantly affect the laying of pipelines from some major CO_2 point sources in the region. This has been identified as a potential problem for Nord-Jyllandsverket in Aalborg, Preem in Lysekil, and Borealis in Stenungsund.

Ship transport not currently viable in the EU ETS

The EU Emissions Trading Scheme (EU ETS) does not currently allow for captured CO_2 to be transported by ship as part of a CCS operation. Although such transport is not prohibited, the use of ships in a CCS chain will have consequences for the eligibility to be relieved from the obligation to surrender allowances for captured CO_2. This problem has been acknowledged by the European Commission but a solution is likely to require cumbersome and time-consuming amendments to complex legislation.

Uncertainties regarding financial securities required from storage operators

The EU CCS directive requires the operator of a storage site to establish financial security in order to ensure that all obligations arising under the storage permit can be met. This includes closure and post-closure requirements and obligations arising from inclusion of the storage site under the EU ETS. It is not possible to define the level of financial security that this will require until a significant amount of information regarding a particular storage site has been collected and a dialogue has been initiated with the competent national authorities.

Vague rules on third-party access to CCS infrastructure

The ability of third parties to access the CCS infrastructure, such as storage sites and pipelines, could confer benefits in terms of competition and effective utilisation of the infrastructure. It is still not possible to say whether the rules that will be established in Denmark, Norway and Sweden will be sufficiently clear and precise to promote investor confidence.

Coordination across the region – different procedures, different timelines

The building of the CCS infrastructure, including land- and sea-based pipelines (possibly ports) and storage sites, entails several permit procedures. The assessment of permits for individual parts of the project (e.g., a particular stretch of pipeline) may also include assessments of the overall environmental and health impacts of the whole CCS infrastructure. Ten years is not an overly pessimistic estimate of the time that may be required for obtaining all the necessary permits, allowing time for several appeals.

8.3 Proposal for further studies

CO_2 storage

There is a need for more extensive geological work to map the properties of the Gassum formation, so as to qualify it as a safe and reliable CO_2 storage site with sufficient long-term capacity. The project recommends inclusion of the Gassum formation in the ongoing activity to map possible CO_2 storage sites on the Norwegian Continental Shelf.

CCS coordination within the Nordic countries

Time-consuming procedures to implement appropriate legal frameworks and permits to establish a CCS network seem to be unavoidable. The transportation of CO_2 across national borders demands that agreements be negotiated and approved. What is a realistic timeline to implement CCS on a regional basis and how could this process be facilitated? Coordination and harmonisation on a Nordic level may benefit the process to establish a CCS network in the Skagerrak/Kattegat region. A possible way in which this could be organised and established as a common Nordic Forum is *via* the NORDICCS Project, which has just started.

CCS from a low-carbon-area perspective

Taking a more holistic view of the challenges that industries, communities and regional authorities are facing with respect to targets for climate gas reductions, energy supply and the role of renewable energy sources might be a worthwhile exercise. Such a project could be geographically extended southwards, to include the Copenhagen region of Denmark.

9 ABBREVIATIONS

2D	.	Two-dimensional
BAT	:	Best available technology
BB	:	Biomass boiler
BHP	:	Bottom hole pressure
Capex	:	Capital expenditure
CCGT	:	Combined cycle gas turbine
CCS	:	Carbon capture and storage
CHP	:	Combined heat and power
CO	:	Carbon monoxide
CO_2e	:	Carbon dioxide equivalent
DEA	:	Diethanolamine
DK	:	Denmark
EEA	:	European Economic Area
EEPR	:	European Energy Program for Recovery
EEZ	:	Exclusive economic zone
EFTA	:	European Free Trade Association
EH	:	Excess heat
EIA	:	Environmental impact assessment
el	:	Electrical
ELIN	:	Electricity Investment Model
ENCAP	:	Enhanced Capture of CO_2 (EU FP6 Integrated Project)
EOR	:	Enhanced oil recovery
ETS	:	Emission Trading System
FID	:	Final investment decision
GHG	:	Greenhouse gas
H_2	:	Hydrogen
HP	:	Heat pump
HRSG	:	Heat recovery steam generator
IGCC	:	Integrated gasification combined cycle
IPCC	:	Intergovernmental Panel on Climate Change
is	:	Isentropic
KLIF	:	The Climate and Pollution Agency in Norway
KP	:	Kyoto Protocol
kt	:	Thousand metric tonnes
LGOFC	:	Lærdal-Gjende-Olestøl Fault Complex
LP	:	Low pressure
LULUCF	:	Land Use, Land Use Change, Forestry
MEA	:	Monoethanolamine
MRG	:	Monitoring and reporting guidelines
MS	:	Member state
Mt	:	Million metric tonnes
MW	:	Million watts
MWe	:	Million watts electric
MWth	:	Million watts thermal
NO	:	Norway
NB	:	Natural gas boiler
NGCC	:	Natural gas combined cycle
NH_3	:	Ammonia
NL	:	The Netherlands

NOx	:	Nitrogen oxide (NO and NO_2)
N-S	:	North-South
NW	:	North West
Opex	:	Operational expenditure
ppm	:	Parts per million
pVT	:	Pressure, volume and temperature
Q	:	Quarter
R&D	:	Research and development
RCI	:	Rotterdam area carbon initiative
SE	:	Sweden or South East
SO2	:	Sulfur dioxide
Toe	:	Tonnes of oil equivalent
TCM	:	Technology Centre Mongstad
TEA	:	Triethanolamine
ToP	:	Take or pay
TPA	:	Third Party Access
TPEC	:	Total Primary Energy Consumption
UK	:	United Kingdom
UNCLOS	:	United Nations Convention on the Law of the Sea
UNFCCC	:	United Nations Framework Convention on Climate Change
yr	:	Year
ZEP	:	Zero Emission Platform

10 PROJECT ORGANISATION

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