NORWEGIAN PETROLEUM DIRECTORATE

CO_2 STORAGE ATLAS

NORWEGIAN CONTINENTAL SHELF

Responsible publisher

Norwegian Petroleum Directorate
P O Box 600
NO-4003 Stavanger
Norway
Telephone: +47 51 87 60 00
Telefax: +47 51 55 15 71
E-mail: postboks@npd.no

Editorial team

Eva K. Halland
Jasminka Mujezinović
Fridtjof Riis

Production

Rune Goa
Arne Bjørøen
Printer: Kai Hansen, Stavanger

Layout/design

Janne N'Jai

www.npd.no

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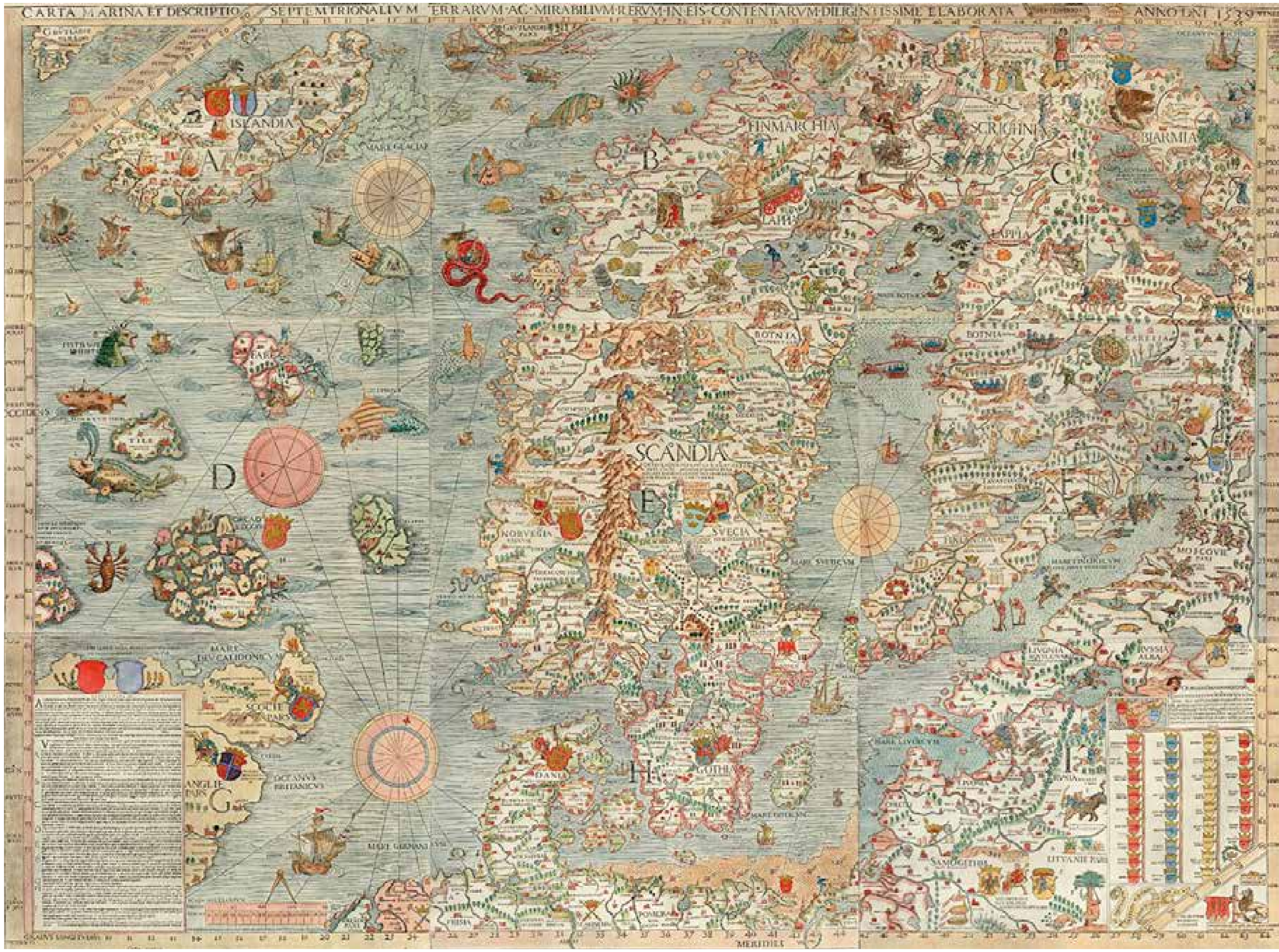
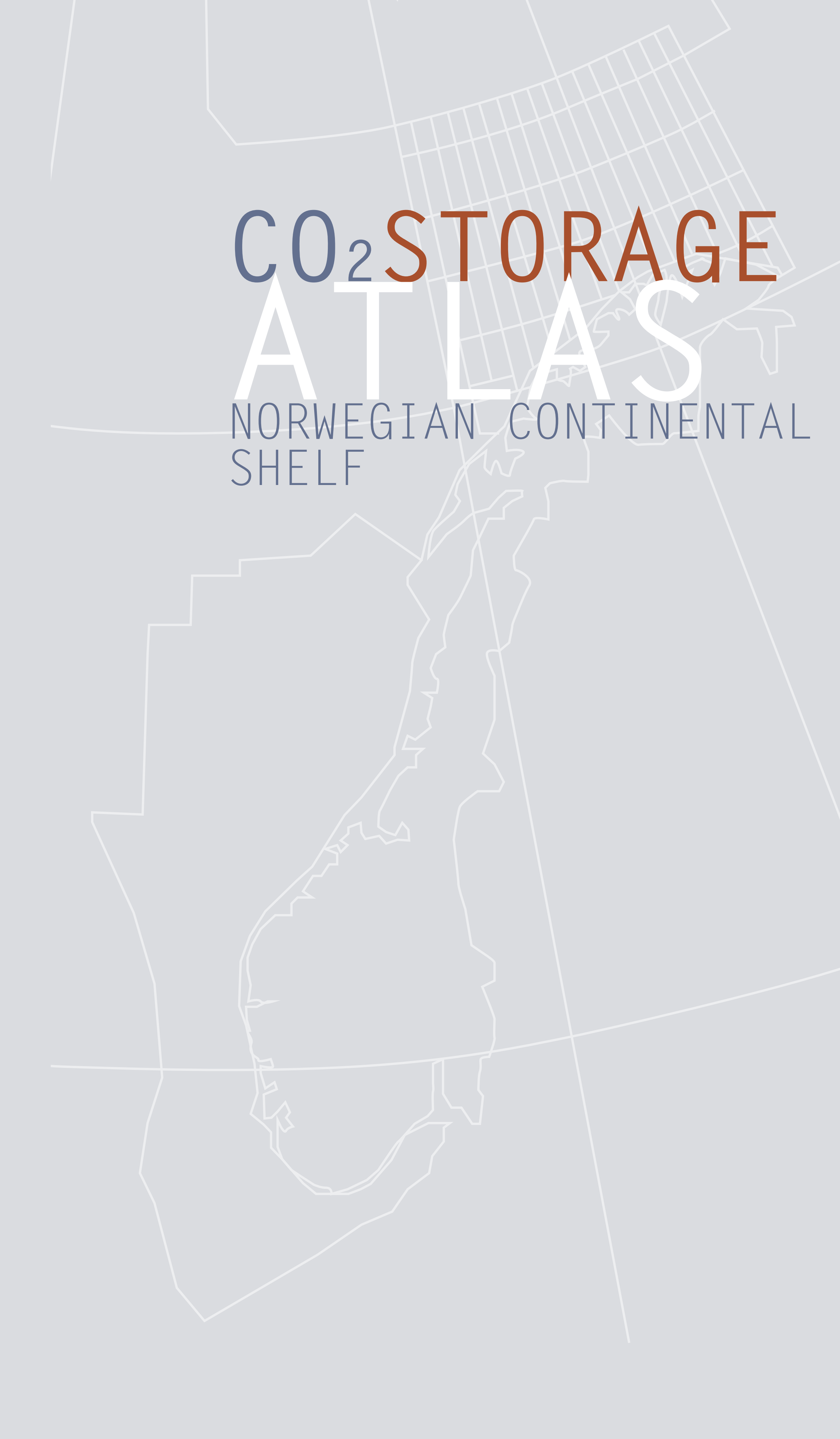


Norway's (Scandinavia's) first resource map, Olaus Magnus, 1539



CO_2 STORAGE ATLAS NORWEGIAN CONTINENTAL SHELF

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Preface

The CO_2 Storage Atlas of the Norwegian Continental Shelf has been prepared by the Norwegian Petroleum Directorate, at the request of the Ministry of Petroleum and Energy. The studied areas are located in parts of the Norwegian Continental Shelf (NCS) which are opened for petroleum activity. The main objectives have been to identify safe and effective areas for long-term storage of CO_2 and to avoid possible negative interference with ongoing and future petroleum activity. The atlas is based on knowledge from more than 40 years of petroleum activity and from the ongoing CO_2 storage projects on the NCS (Sleipner and Snøhvit).

Valuable knowledge has also been gained through the Norwegian R&D and Demo project Climit, UNIS CO_2 Lab and several large EU projects on storage and monitoring. Additionally, seismic data and results from exploration and production wells form an extensive database essential for the evaluation and documentation of geological storage prospectivity.

Geological formations have been individually assessed, and grouped into saline aquifers. The aquifers were evaluated with regard to reservoir quality and presence of relevant sealing formations. Those aquifers that may have a relevant storage potential in terms of depth, capacity and injectivity have been considered. Structural maps and thickness maps of the geological formations presented in the atlas were used to calculate pore volumes.

Several studies of the CO_2 storage potential in relevant aquifers, dry-drilled structures and mapped structures are hence provided, together with a summary of the CO_2 storage potential in oil and gas fields. The potential for CO_2 storage in enhanced oil recovery projects is also discussed.

The methodology applied for estimating storage capacity is based on previous assessments, but the storage efficiency factor has been assessed individually for each aquifer based on simplified reservoir simulation cases. The assessed aquifers have been characterized according to guidelines developed for the CO_2 Storage Atlas of the Norwegian North Sea (2011).

We hope that this study will fulfil the objective of providing useful information for future exploration for CO_2 storage sites. We have not attempted to assess the uncertainty range for storage capacities in this atlas, but we have made an effort to document the methods and main assumptions. The assessments described in this atlas will be accompanied by a GIS database (geographical information system).The database will be published on the NPD website *www.npd.no*.

Acknowledgements

This CO_2 Storage Atlas has been developed by a team at the Norwegian Petroleum Directorate. The support from colleagues through discussions, and the support from the Ministry of Petroleum and Energy have been of great importance. Sincere thanks to Asbjørn Thon, Robert Williams, Dag Helliksen, Alexey Deryabin and Rune Mattingsdal (NPD) for constructive contributions. The Norwegian CO_2 Storage Forum has contributed with its expertise in our meetings over the last four years. Arne Graue (University of Bergen), Ola Eiken (Statoil), Per Aagaard (University of Oslo), Erik Lindeberg (SINTEF), Svein Eggen (Climit/Gassnova), Rolf Birger Pedersen (University of Bergen), Mike Carpenter (DnV) and experts on well integrity from the Petroleum Safety Authorities have contributed with texts and figures to this atlas. AGR has contributed to the reservoir modeling related to CO_2 storage, and GEUS has contributed to the North Sea Basin Geology.

The CO_2 team at the NPD as follows:
Eva K. Halland (Project Leader)
Andreas Bjørnestad
Christian Magnus
Fridtjof Riis
Ida Margrete Meling
Ine Tørneng Gjeldvik
Inge M.Tappel
Jasminka Mujezinović
Maren Bjørheim
Rita Sande Rød
Van T. H. Pham

1. Introduction

1. Introduction

Power production and other use of fossil energy are the largest sources of greenhouse gas emissions globally. Capture and storage of CO_2 in geological formations represent an important measure with a great potential to reduce global emissions. In its Special Report on Carbon Dioxide Capture and Storage (2005), the United Nations Intergovernmental Panel on Climate Change (IPCC) concludes that capture and storage of CO_2 may account for as much as one half of emission reductions in this century. However, major challenges must be solved before this potential can be realized. The IPCC report points out that there is as yet no experience with CO_2 capture from large coal and gas power plants.

Norway has extensive experience with storage of CO_2 in geological structures. Since 1996, approximately 1 Mt of CO_2 have been separated from gas production annually at the Sleipner Vest Field in the North Sea for storage in the Utsira formation, a geological formation more than 8000 metres below the seabed. From 2014 a further 0.1-0.2 Mt of CO_2 from the newly developed Gudrun Field will be injected into the same formation every year.

In connection with treatment of the well stream from the Snøhvit Field and the LNG production on Melkøya in the Barents Sea, about 0.7 Mt of CO_2 have been safely injected and stored in the Tubåen sandstone annually. The Tubåen Formation is about 2 300 metres beneath the seabed, and CO_2 has been injected since 2008. CO_2 is removed from the gas stream onshore and piped 153 km back to the field. In early 2010 the field operator announced that they now realized there was less storage capacity than first expected at the Snøhvit injection site. Therefore the injection site was moved from the Tubåen Formation to the Stø Formation in 2011.

There is significant technical potential for storing CO_2 in geological formations around the world. Producing oil and gas fields, abandoned oil and gas fields and geological formations such as saline aquifers might all be candidates for such storage. Storage in reservoirs that are no longer in operation can be a good solution in terms of geology, since these structures are likely to be impermeable after having held oil and gas for millions of years.

Environmentally sounds storage of CO_2 is a prerequisite for a successful CCS chain. Consequently, the mapping, qualification and verification of storage sites are indispensable for CCS as a climate change mitigation measure. Geological formations offshore Norway are expected to be well-suited for storing large quantities of CO_2, and it is important to have the best possible understanding of the CO_2 storage potential.

These factors necessitate an enhanced effort to map and investigate CO_2 storage sites. The production of this CO_2 storage atlas is at the very centre of this effort. Various Norwegian research institutions and commercial enterprises have extensive experience and competence within CO_2 storage.

***Snøhvit:** There is capacity for separation and storage of 700 000 tons annually in water-saturated sandstone reservoirs under the Snøhvit Field in the Barents Sea. A shale cap which lies above the sandstone will seal the reservoir and ensure that the CO_2 stays underground.*

***Sleipner:** More than 13 million tons of carbon dioxide are now stored in the Utsira Formation in the North Sea. Every year since 1996, one million tons of carbon dioxide have been captured from natural gas production at the Sleipner Field and stored in an aquifer more than 800 metres below the seabed. The layer contains porous sandstone filled with saline water.*

1. Introduction

CLIMIT PROGRAMME

CLIMIT is the national programme for research, development and demonstration of technologies for CO_2 capture and storage (CCS) from power generation and industry.

The program covers both the Research Council of Norway's support scheme for research and development (CLIMIT R&D) and Gassnova's support scheme for development and demonstration of technology for CO_2 capture and storage (CLIMIT Demo).

The CLIMIT programme is leading a portfolio of projects in all stages of the development chain. The programme focuses on the development of knowledge, technology and solutions to reduce costs and to stimulate broad international implementation of CCS. Furthermore CLIMIT shall leverage national advantages and the development of new technology and service concepts with international potential.

The programme is aimed at Norwegian companies, research institutions and universities, preferably in cooperation with industry and international research institutions which can contribute to accelerate CCS commercialisation.

CLIMIT has the following objectives:

EFFECT-ORIENTED GOALS

- Lower costs and earlier international realisation of CCS.
- CCS in Norwegian enterprises.
- Realisation of the storage potential in the North Sea

RESULT OBJECTIVES

- Knowledge and expertise to close technology gaps and increase safety.
- Ground-breaking technologies and service concepts with international potential.

CLIMIT has three focus areas and targets national players with CCS potential. Environmental issues are covered in all three areas:

1. New innovative solutions that can give considerable cost reductions and increased safety.
2. Areas where Norway or Norwegian companies have advantages in CCS.
3. CCS in Norwegian industry with major CO_2 emissions.

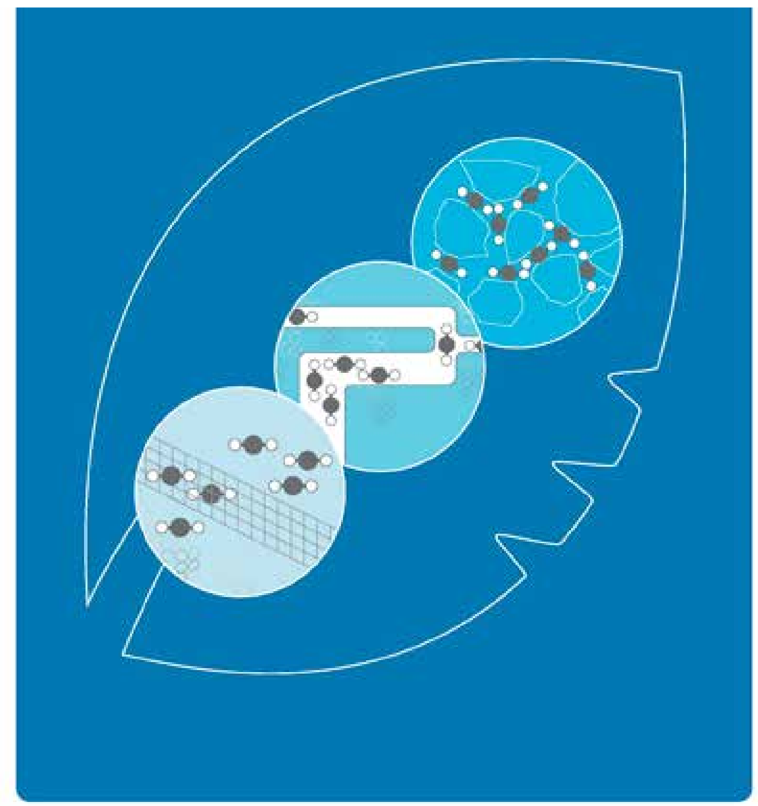
CO_2 STORAGE

Projects supported by CLIMIT will contribute to the safe and cost-efficient implementation of CO_2 storage in accordance with regulatory requirements and international agreements.

Key topics within CO_2 storage are i) the development of further methods to estimate and utilize the storage capacity on the continental shelf and ii) the development of methods and technology to develop storage locations, safe injection and appropriate monitoring technology.

CO_2 storage in combination with CO_2 used for enhanced oil recovery is also an important focus area.

CLIMIT



1. Introduction

UNIS CO_2 Lab - by Alvar Braathen and co-workers

The UNIS CO_2 Lab in Longyearbyen, Svalbard, Norway, is one of the demonstration projects currently carried out worldwide. The purpose is to learn more about CO_2 behaviour in high-pressure conditions and to assess the storage and sealing capacity of local subsurface rock successions.

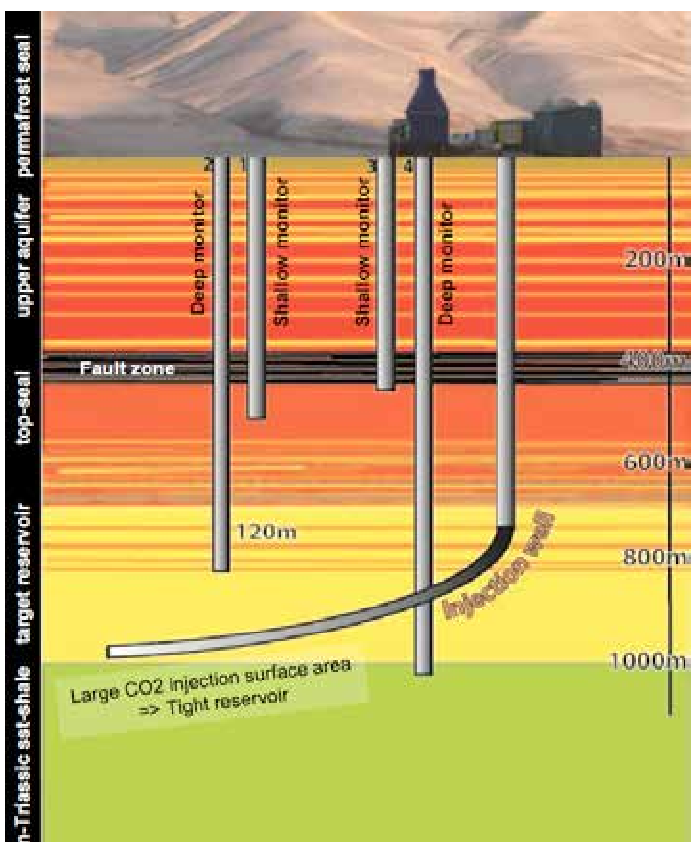
These pilot projects are meant to provide a foundation for worldwide commercial ventures of CO_2 sequestration.

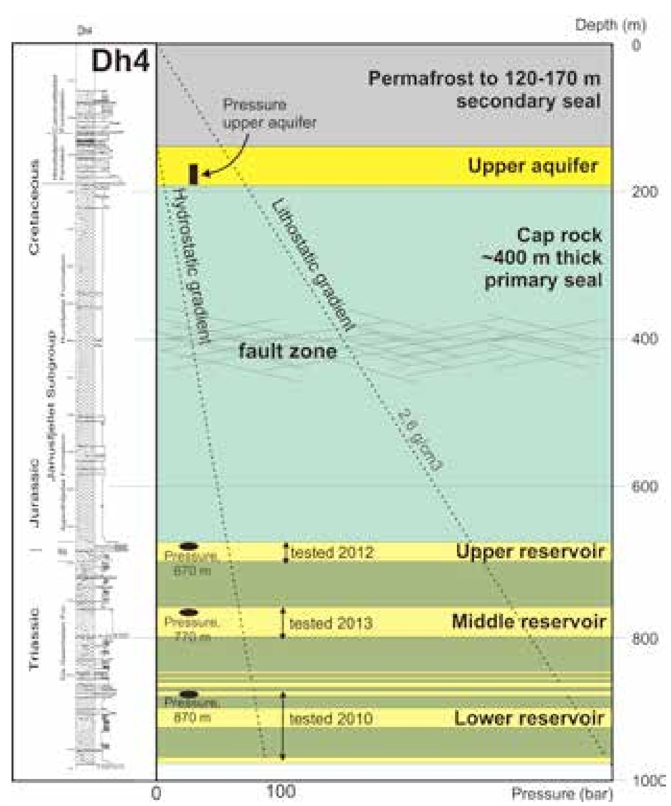
Longyearbyen has a population of around 2000 and is located in the polar wilderness of central Spitsbergen.

A coal-burning, single power plant in Longyearbyen provides both electricity and hot water and supports the city's entire house-heating system of radiators. One objective of the demonstration project is to investigate if there is sufficient storage capacity close to Longyearbyen to capture the CO_2 which can be sequestered from the power plant – a maximum of 60,000 tons /annually.

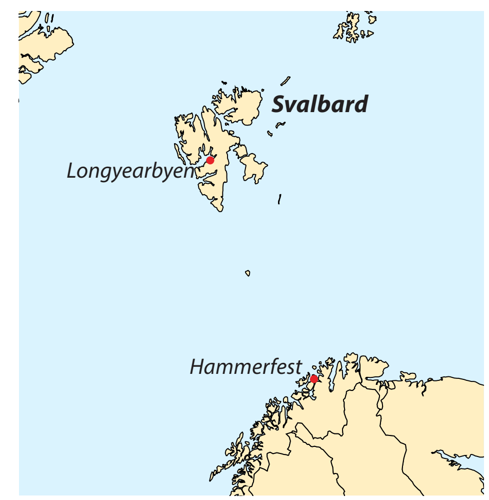
The aim of the project has been to evaluate local geological conditions for subsurface storage of the greenhouse gas CO_2. Project activity included drilling and logging of slim-hole cored wells, acquisition of seismic sections with snow streamer and a wide range of laboratory and field studies. The targeted reservoir is a paralic sandstone succession of the Upper Triassic–Middle Jurassic Kapp Toscana Group at ≥670 m depth. This is overlain by thick Upper Jurassic shales and younger shale-rich formations. The reservoir has a sandstone net gross ratio of 25–30% and is intruded by thin dolerite sills and dykes. The reservoir and cap-rock succession rise at 1–3° towards the surface and crop out 14–20 km to the northeast of Longyearbyen. Near the surface, all units appear to be sealed by permafrost. The reservoir is compartmentalized and shows considerable underpressure, in the lower part equal to 30% of hydrostatic pressure, which indicates good initial sealing conditions. Core samples indicate a reservoir with sandstones of moderate porosity (5–18%) and low permeability (max. 1–2 mD). Rock fractures are therefore important for fluid flow.

Water injection tests have indicated good injectivity in the lower part of the reservoir succession (870–970 m depth). The relatively more porous and permeable upper part (670–870 m depth) has only been partly tested. The injectivity increases with increasing pressure, suggesting that the fractures gradually open and grow under injection. Reservoir pressure compartments indicate bedding-parallel permeability barriers, although these may gradually yield under a growing cumulative pressure. The reservoir storage capacity and its apparent connection with the surface remain to be fully evaluated. However, the lateral expansion of the injected CO_2 plume in this large reservoir over a distance of 14 km to the outcrops, is projected to take thousands of years.





Results from Drillhole 4 in the UNIS CO_2 Lab.



1. Introduction

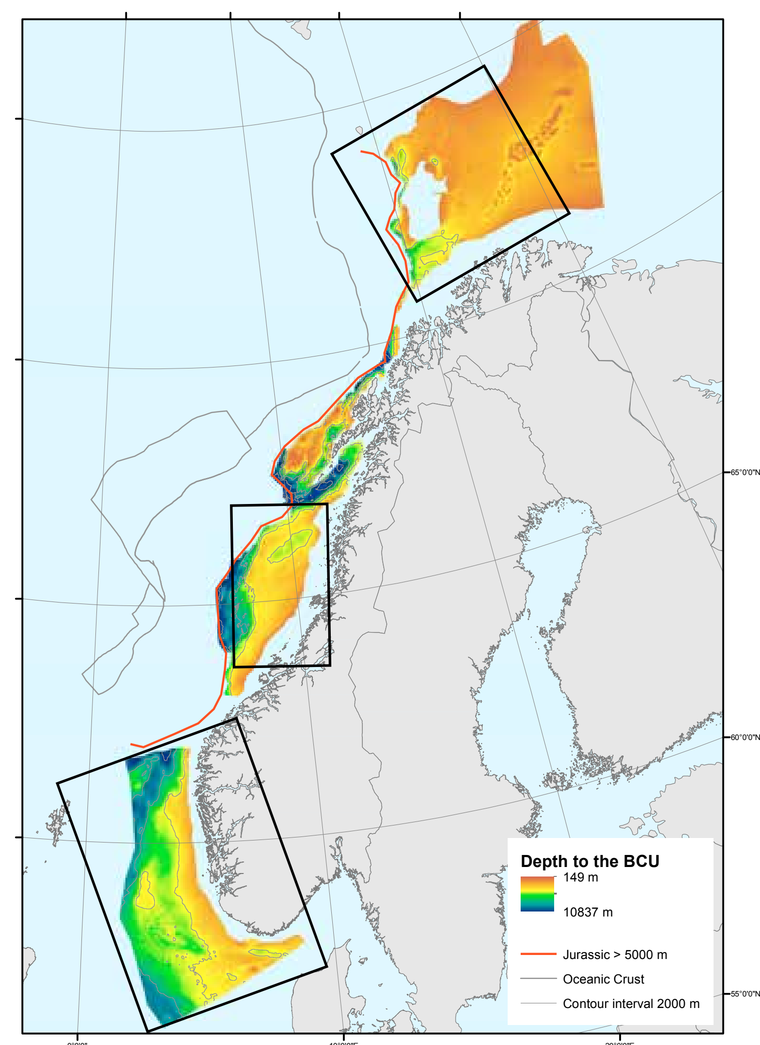
The Norwegian Continental Shelf

Petroleum activity in the Norwegian Continental Shelf (NCS) is restricted to the North Sea, the Norwegian Sea and the southern Barents Sea. These regions contain several aquifers at a suitable depth for CO_2 storage, and are also considered the most favourable for large scale CO_2 sequestration. The depth to the Base Cretaceous Unconformity (BCU) gives an indication of the major structural elements. Jurassic aquifers occur below the BCU in most of the NCS. Jurassic shales are the source rocks for most of the hydrocarbons generated in the North Sea and Norwegian Sea, They can be considered to be mature in the blue areas of the map, below approximately 4000 m. Most of the oil and gas fields in these regions are located within migration distance from these areas.

The Norwegian continental shelf belongs to three different geological provinces. The northern North Sea is a subsiding basin developed above the continental Paleozoic and Mesozoic rift between UK and Norway. The Base Cretaceous unconformity (BCU) marks the end of the last major rifting event and the top of the cap rock of the Jurassic aquifers. Younger sediments in the North Sea Basin were sourced from all land masses surrounding the basin and contain several important aquifers.

The Norwegian Sea shelf faces the oceanic crust in the Norwegian-Greenland Sea. The BCU is very deeply buried in the deep waters beyond the shelf slope. The map does not display the BCU at greater burial depths than 5000 m, as these depths are not relevant for CO_2 injection. The main aquifers suitable for CO_2 injection in the Norwegian Sea shelf belong to the Jurassic section. The storage capacities of the Møre Basin and the Lofoten-Vesterålen area were not studied. The geology of these areas is considered to be less favourable for storage of large volumes of CO_2 than the evaluated areas.
The Barents Sea shelf was filled in by thick sequences of Upper Paleozoic, Mesozoic and younger rocks following a major Carboniferous rifting phase. In the Norwegian sector, petroleum activity has been concentrated to the south-western part, which is made up by platforms, shallow basins and highs. The main aquifers consist of Jurassic and Triassic sediments. In the western margin, west of the mapped area in the figure, these sediments are too deeply buried to be suitable for CO_2 storage. The study area was exposed to deep erosion in the Cenozoic and in the Quaternary. Because reservoir properties reflect maximum burial and not the present burial, aquifers with good storage potential are located at relatively shallow depths.

Area status for the Norwegian Continental Shelf March 2012 (Source: NPD Facts 2013)



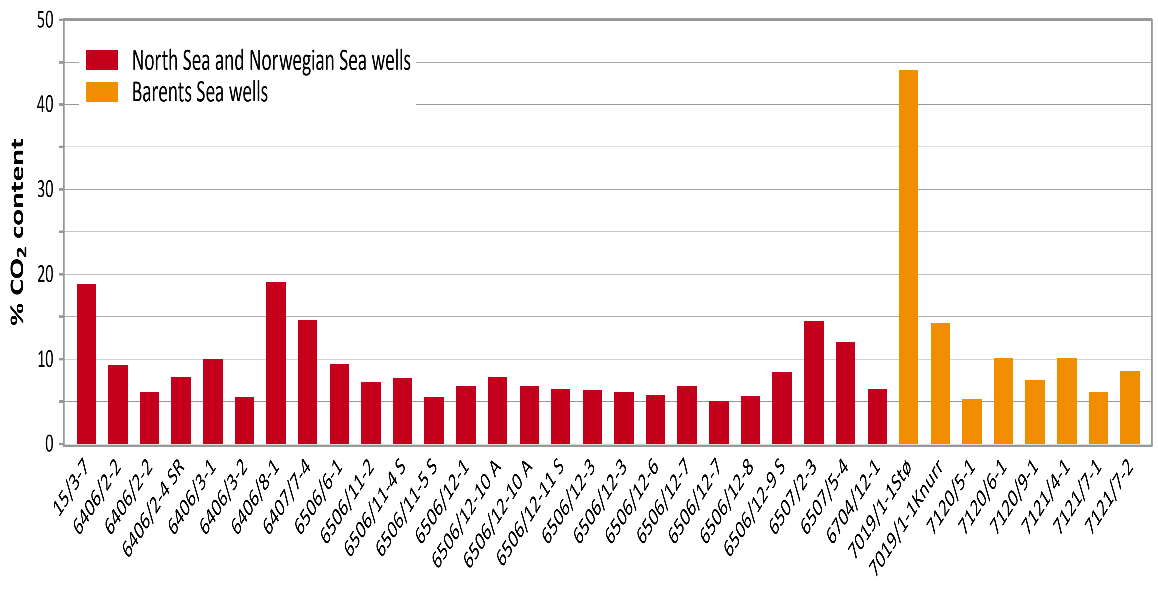
Depth map of The Base Cretaceous Unconformity and areas evaluated in the Atlas. The boundaries to oceanic crust and main volcanic provinces are indicated

Naturally occurring CO_2

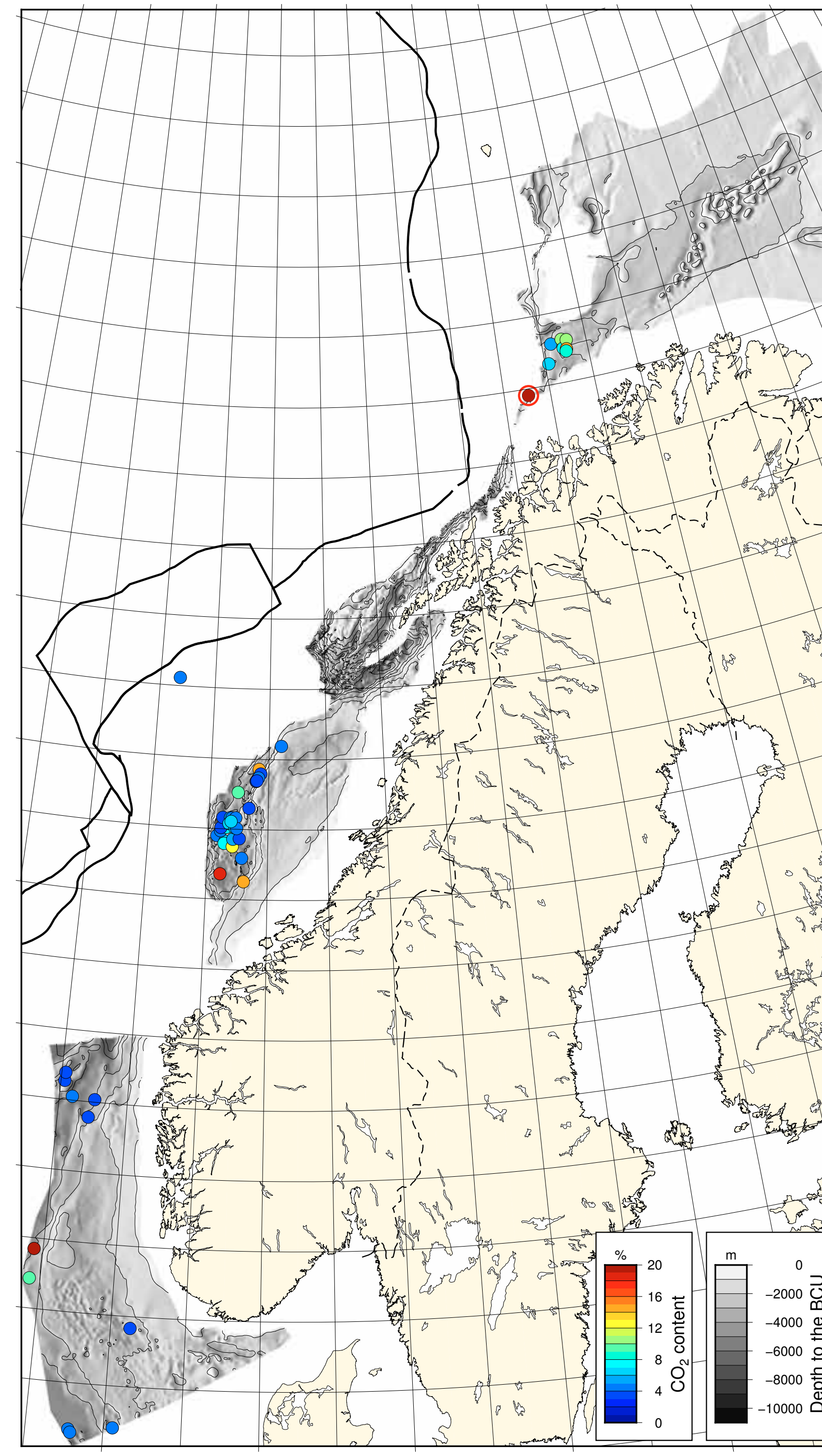
CO_2 occurs in some metamorphic rocks and is an integrated component in intrusive and extrusive volcanic rocks. The gas exported from Norway to the European continent cannot have more than 2.5% CO_2. Some producing gas fields in the Norwegian Continental Shelf have a higher CO_2 content which requires dilution with gas that has a low CO_2 content, or CO_2 has to be separated from the gas stream and injected into saline aquifers. Gas from the Snøhvit Field and the Sleipner Field has high CO_2 concentrations that require CO_2 capture and storage. Some discoveries in the Norwegian Sea offshore Nordland also have a high CO_2 content that will require CO_2 capture and storage if the gas is produced. CO_2-rich gas occurs in the western parts of the Halten- and Dønna Terraces. In the western part of the Vøring Basin, one well showed a CO_2 content of 7%. Other gas discoveries in the deeper parts of the Møre- and Vøring Basins do not show significant CO_2 content. The dots on the map show the location of exploration wells where CO_2 content higher than 3 % has been encountered in gas discoveries. In a few wells, CO_2 values range between 10 and 20 %.

There are many wells where the CO_2 concentration was not measured, but the map gives an indication of the areas which can become future sources of CO_2.

In general on the Norwegian shelf, the percentage of CO_2 associated with methane in gas fields can be correlated with the burial depth of the source rock which has generated the gas. In the Barents Sea, CO_2 rich gas has been encountered along the margins of the deep Harstad, Tromsø and Bjørnøya Basins. One accumulation of gas with a CO_2 content in the order of 50% was found in well 7019/1-1 (NPD website), while in other gas discoveries in the western Barents Sea, the percentage of CO_2 typically does not exceed 10. Further east, the CO_2 content appears to be lower. The reason for the increased CO_2 content in those areas is not clear, although the close vicinity to Paleogene volcanic sill intrusions may explain the amount of natural CO_2 in 7019/1-1. Both organic processes and degassing of metamorphic and overheated sedimentary rocks may contribute to the CO_2 generation.



A selection of wellbores with CO_2 content above 5%. Based on data from NPD fact pages.



Map of Base Cretaceous unconformity showing location of exploration wells where the measured CO_2 concentration in natural gas exceeds 3 %. 7019/1-1 is marked by a red ring. Residual oil zones are indicated by squares. Based on data from NPD fact pages.

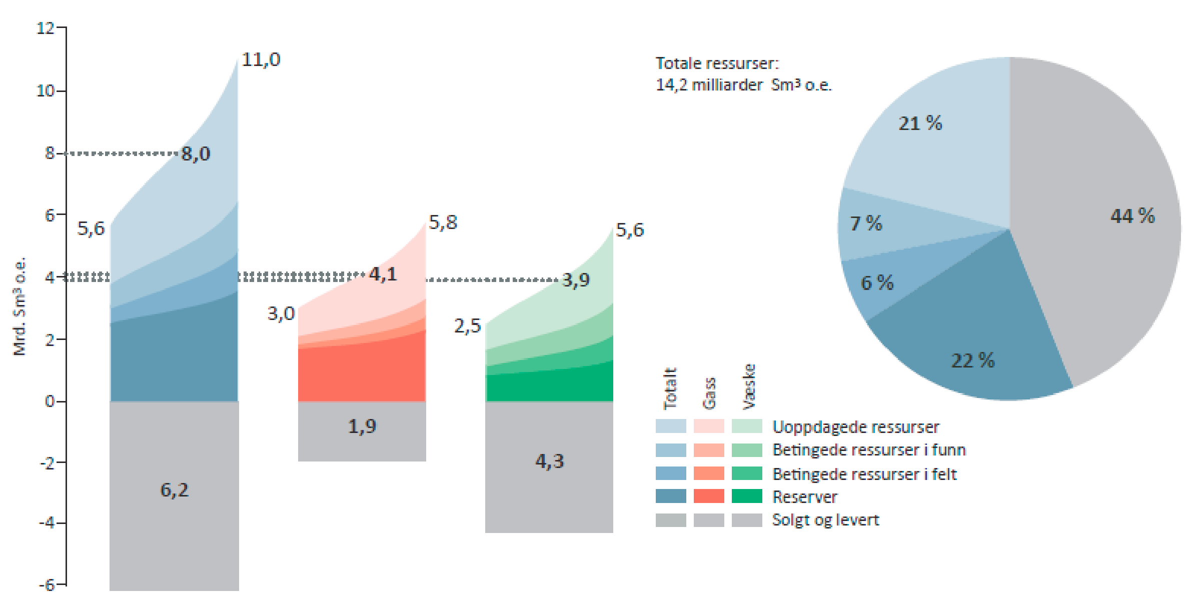
2. Petroleum activity on the Norwegian Continental Shelf

2. Petroleum activity on the Norwegian Continental Shelf

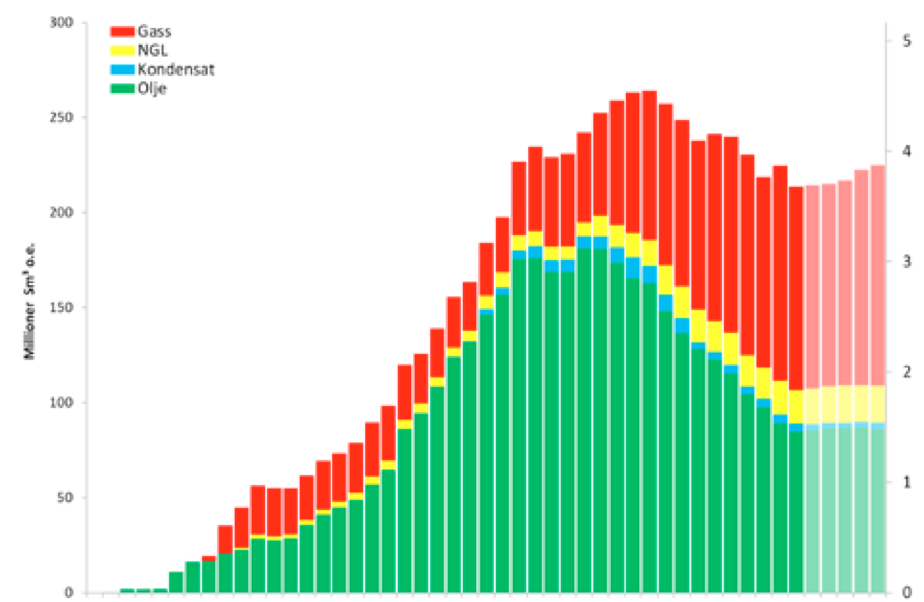
In May 1963, the Norwegian government proclaimed sovereignty over the Norwegian continental shelf (NCS). A new act stipulated that the State was the landowner, and that only the King (Government) could grant licences for exploration and production. Licences on the NCS are awarded in mature areas during APA (Awards in Predefined Areas) or during ordinary licensing rounds in frontier areas. The discovery of the Ekofisk field in 1969 started the Norwegian oil and gas adventure, and production from the field began 15 June 1971. During the following years, several large discoveries were made in the North Sea. In the 1970s exploration activity was concentrated in this area, but gradually expanded northwards during the 1980s. Only a limited number of blocks were announced for each licensing round, and the most promising areas were explored first. This led to world class discoveries.

Currently, 78 fields are in production on the Norwegian continental shelf (NCS). In addition, there are 12 abandoned fields, all in the North Sea. Production from the North Sea has been dominated by large fields such as Ekofisk, Statfjord, Oseberg, Gullfaks and Troll. These fields have been, and still are, very important for the development of petroleum activities in Norway. The large field developments have led to the establishment of infrastructure, enabling tie-in of a number of other fields. Current production and future opportunities in the southern part of the North Sea are linked to the chalk reservoirs in this area. The area is a mature petroleum province, and the majority of today's production comes from the Ekofisk, Eldfisk, Tor, Valhall and Hod chalk fields. Together, these fields still contain very significant oil volumes. Some chalk fields in the area have been shut down, and some discoveries are not yet developed.

The central part of the North Sea also has a long history of petroleum activity, and here discoveries have been made in several types of petroleum reservoirs. The first development in the area was the Frigg gas field, which produced for 27 years before it was shut down in 2004. At the Utsira High, which is considered a mature exploration area, new types of reservoirs have also been discovered during the last couple of years. These discoveries will be developed together under the name of the Johan Sverdrup field. This field might contain so much oil that it enters the top 10 list of discoveries on the NCS and might prove the biggest discovery here since the 1980s. The Sleipner field is an important hub for the Norwegian gas transport system, as both UK and the Continental Europe can be reached. In addition, this field has facilities designed to reduce the CO_2 content of the gas. For nearly 18 years, CO_2 extracted from the Sleipner Vest well stream has been stored under the seabed, yielding important experience and knowledge about subsurface storage of CO_2. Oil and gas have



Petroleum resources and uncertainty in the estimates for the Norwegian Continental Shelf per 31.12.2013. (Source: Norwegian Petroleum Directorate)



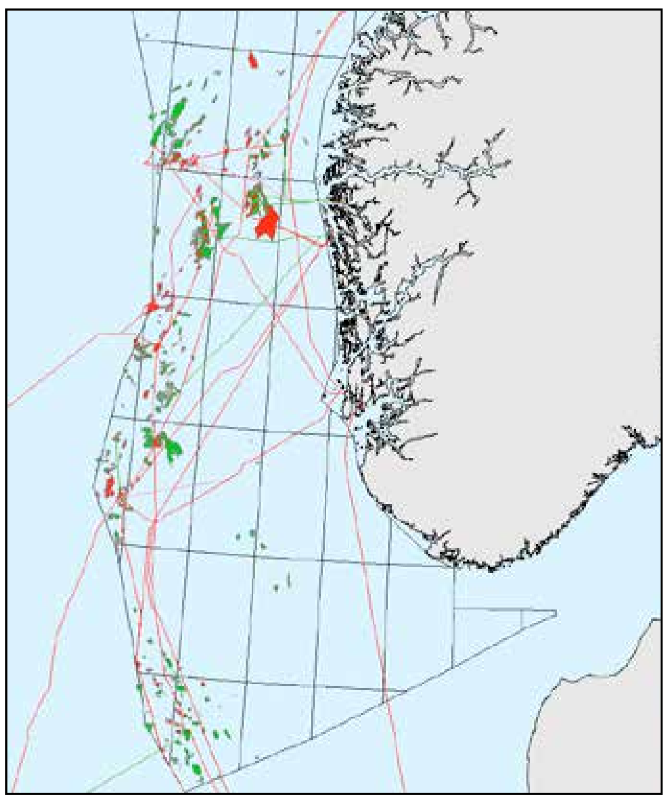
Historical petroleum production of oil and gas, and prognosis for production in coming years (Source: Norwegian Petroleum Directorate)

2. Petroleum activity on the Norwegian Continental Shelf

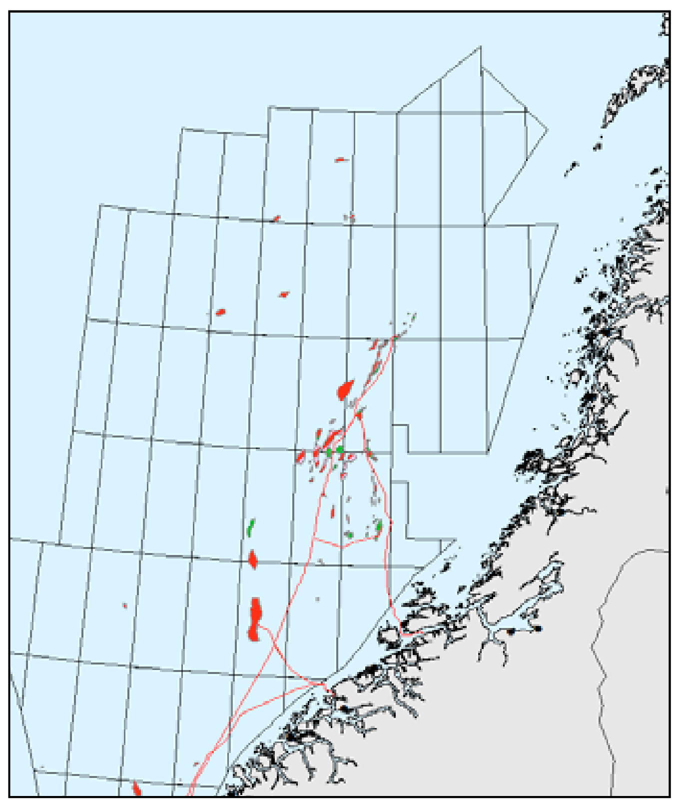
been produced in the northern part of the North Sea since the late 1970s. There are significant remaining reserves and resources in the area, both in fields and discoveries. The northern part of the North Sea consists of several petroleum provinces: with fields like Statfjord, Gullfaks, Snorre, Oseberg and Troll.

The Norwegian Sea was opened for exploration activity in 1980, and the first field in the area to commence production was Draugen in 1993. A number of fields have since been developed. Several smaller fields that are located around existing infrastructure have been put into production in recent years. Today, the Haltenbanken area and Ormen Lange field are mature areas with considerable oil and gas production along with well-developed infrastructure. There are also areas in the Norwegian Sea that have not yet been developed or even opened up for exploration activity. Oil production from the major fields in the area is declining. The gas export capacity from Haltenbanken, through the Åsgard transport system (ATS), is fully booked for several decades into the future. This could affect the timing for phase-in of new discoveries on Haltenbanken. The Norwegian Sea has also been proven to contain significant volumes of gas. Produced gas from the fields is transported through the ATS pipeline to Kårstø in Rogaland County, and in Haltenpipe to Tjeldbergodden in Møre and Romsdal County. The gas from Ormen Lange runs in a pipeline to Nyhamna, which is also in Møre and Romsdal, and further to the United Kingdom. The CO_2 content in the gas produced from several of these fields is relatively high, and that is also the case for some other discoveries in the area. Gas from these fields is therefore mixed with gas containing lower amounts of CO_2 to achieve compliance with gas quality requirements. The blending takes place from fields both in the Norwegian Sea and from fields located further south. This process creates interdependence between the fields in the Norwegian Sea, and affects how the individual fields are produced. The Vøring area in the Norwegian Sea currently has no infrastructure, but several gas discoveries have been made in the area.

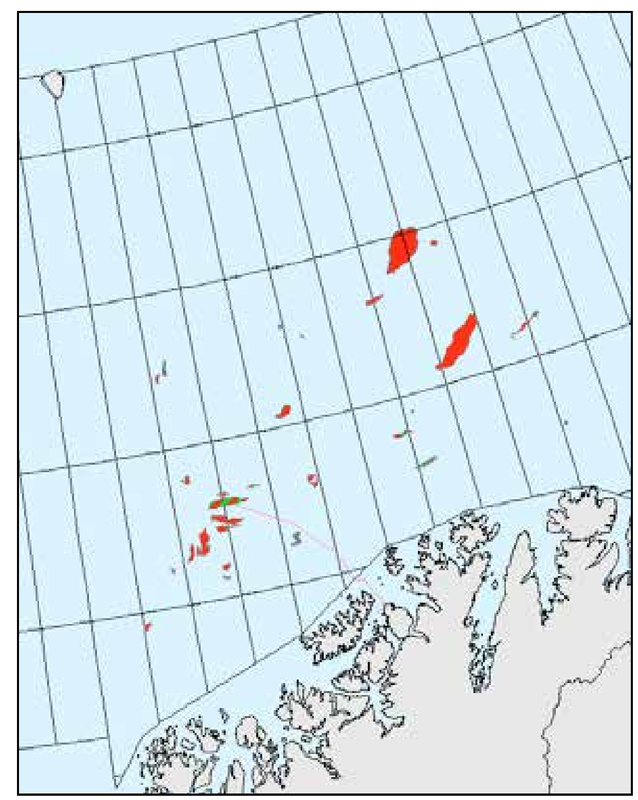
The Barents Sea is part of the Arctic Ocean and is considered an immature petroleum province. The area covers 1.3 million km^2, and the water depth varies between 200 and 500m. The southern part of the Barents Sea is in general opened for petroleum activities, with the first licensing round announced in 1979. The first wildcat wells in the Barents Sea were spudded in 1980, and the first discovery was made by



Norwegian North Sea, fields and discoveries (red= gas, green= oil), per March 2014.



Norwegian Sea, fields and discoveries (red= gas, green= oil) per March 2014.



Barents Sea, fields and discoveries (red= gas, green= oil) per March 2014.

2. Petroleum activity on the Norwegian Continental Shelf

the third wildcat, 7120/8-1 Askeladd. The biggest gas discovery is 7121/4-1 Snøhvit, drilled in 1984 with Statoil as operator. The Snøhvit gas field started production in 2007 and is the only field developed so far. The gas from Snøhvit is transported to a land terminal at Melkøya, where it is refrigerated into LNG (liquefied natural gas) and forwarded by ship. As in many gas discoveries in the Norwegian Sea, the CO_2 content in the Snøhvit area is high. CO_2 is therefore separated from the gas stream onshore on the Melkøya terminal, transported through a 153 km pipeline on the seabed and injected into the Stø formation in the Snøhvit field. The Upper Triassic to Middle Jurassic play in the Hammerfest Basin is the most thoroughly explored play in the Barents Sea. This play has been proved by both the Snøhvit discovery and the Goliat oil field, which is currently under development with Norwegian Eni as operator.

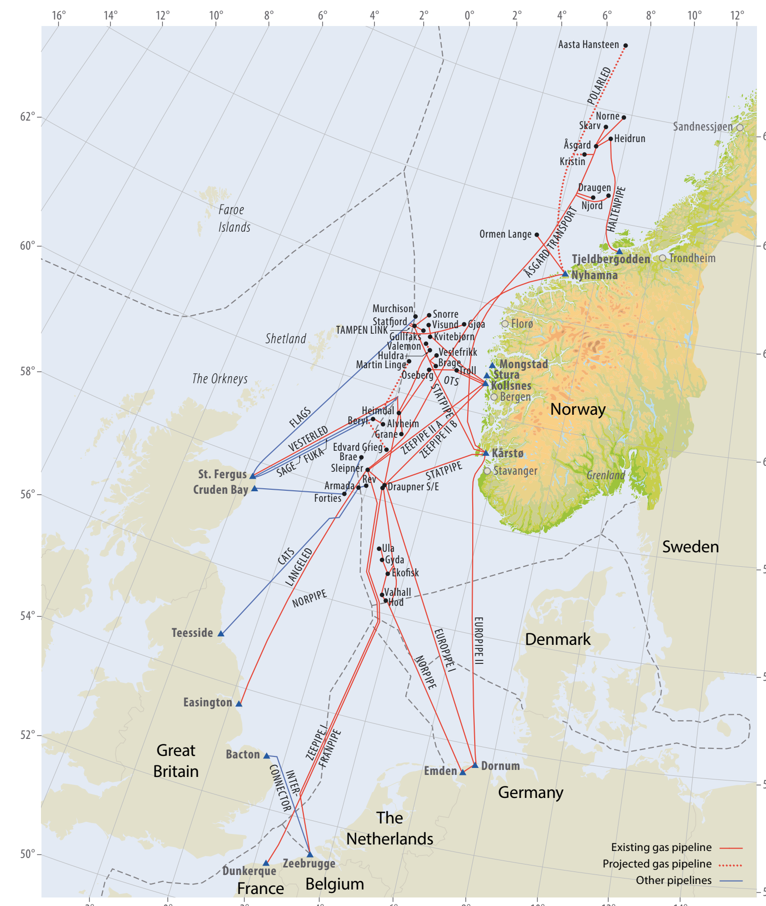
The Lower to Upper Triassic play on the Bjarmeland Platform is less explored. The first well to test this play was drilled in 1987, and the following five wells were dry. In addition, a couple of discoveries were significantly smaller than expected. Approximately 10 wildcat wells have been drilled and three gas discoveries made, with 7225/3-1 (Norvarg) as the largest. The Norvarg discovery is encouraging, and the estimate of undiscovered resources shows that the play potential remains large. The Upper Triassic to Lower Cretaceous plays along the Ringvassøya-Loppa and Bjørnøyrenna fault complexes are also relatively unexplored, with only about 16 wildcat wells. More than half of these were dry. The first well to test these plays was drilled in 1983, and the first gas discovery, 7019/1-1, was made in 2000. This discovery contained gas with a very high CO_2 content.

Today there are 53 active licences in the Barents Sea. Approximately 100 exploration wells have been drilled and they have resulted in about 35 discoveries.

Norway's gas pipelines have a total length of about 8000 kilometres. The gas flows from production installations to process plants where natural gas liquids are separated out and exported by ship. The remaining dry gas is piped on to receiving terminals in continental Europe and the UK. There are four receiving terminals for Norwegian gas on the Continent; two in Germany, one in Belgium and one in France. In addition, there are two receiving terminals in the UK. Norwegian gas is important for the European energy supply and is exported to all the major consumer countries in Western Europe. Norwegian gas export covers close to 20 per cent of European gas consumption. The transport capacity in the Norwegian pipeline system is currently about 120 billion scm per year.

Norway was in 2012 the world's seventh largest exporter of oil and the third largest exporter of natural gas. Oil production declined after a peak in 2001, but it is expected that future production of oil will be relative stable for some years to come. Gas production has increased steadily since 1995, and the total production on the shelf is expected to stabilize for the next five years. The North Sea is the most mature area on the NCS with regard to petroleum activity. About 615 wells have been drilled, and the geology is well known. Consequently, there is less uncertainty in our estimates of undiscovered resources in the North Sea than in our estimates for the Norwegian Sea or the Barents Sea. As seen from the estimates of undiscovered resources in the NCS, the seabed offshore Norway still hides significant volumes of oil and gas.

The year 2014 marks the 48th anniversary of the arrival of *Ocean Traveler* in Norway and the spudding of the first well on the Norwegian Continental Shelf (NCS). Since then, the geological knowledge of the shelf has increased greatly. Exploration activity on the NCS is still high, with extensive seismic surveys and a large number of exploration wells. Maintaining a high level of exploration activity will also be necessary in the years to come, in order to clarify the potential of the undiscovered resources and to make new discoveries which can be developed.



Gas pipelines (NPD 2013)

Area status for the Norwegian Continental Shelf March 2012 (Source: NPD Facts 2013)

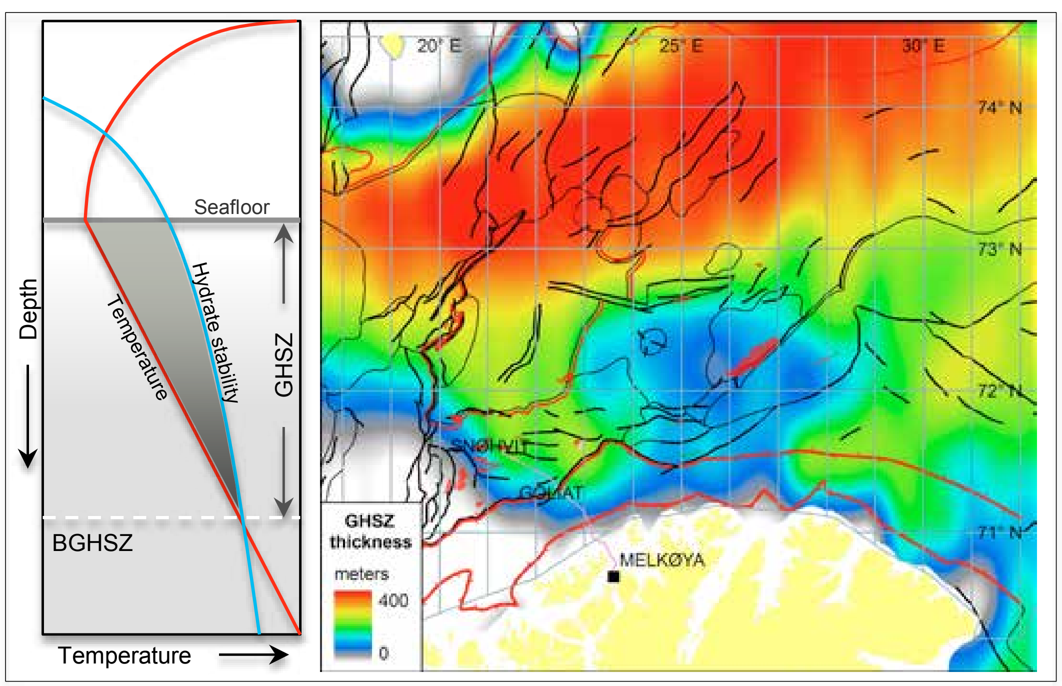
Gas hydrates in the Barents Sea
by Rune Mattingsdal, Alexey Deryabin (NPD) and professor Arne Graue (UiB)

Natural gas hydrate is a solid, consisting mostly of methane and water. It form crystals where gas molecules are trapped in cage-like structures formed by water molecules. Gas hydrates can be found in Arctic regions below permafrost and in the marine subsurface at deep water, high pressure conditions and low temperatures (typically above 60 bar and below 100°C). Hydrate is a highly condensed form of natural gas bound with water; one cubic metre of hydrate corresponds to ca. 160 cubic metres of natural gas at atmospheric conditions. The zone where gas hydrates can form is referred to as the gas hydrate stability zone (GHSZ). In the marine environment, the GHSZ is located between the sea floor and the base of the stability zone defined by the phase diagram. The limits of the stability zone are determined by bottom water temperature, sea level, geothermal gradient, gas composition and pore water salinity.

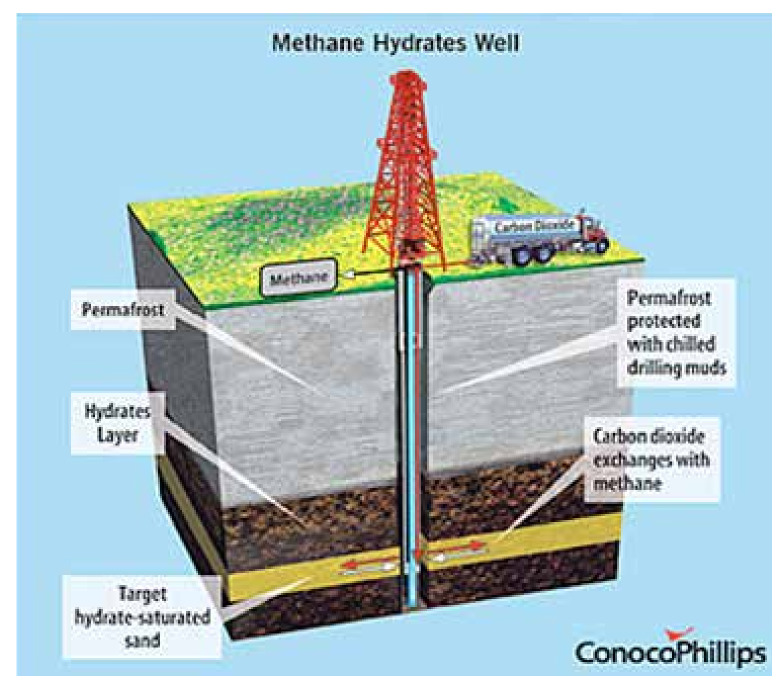
The Barents Sea is a relative deep continental shelf with water depths of up to 500 metres, mainly due to several episodes of glacial erosion. This, combined with bottom water temperatures that can be as low as 0°C or colder, results in a GHSZ thickness which might vary from a few tens of metres to 400 metres, depending on the gas composition and geothermal gradient (Chand et al, 2008). The figure below shows a modelled GHSZ thickness map. Within this zone, gas hydrates can form in areas where there is sufficient flux of thermogenic methane or deposits of biogenic methane. In the southwestern Barents Sea, the thickest GHSZ generally coincide with the deeper parts of the shelf. Here gas hydrates might in theory act as a seal for hydrocarbons in shallow reservoirs. In the Barents Sea, gas hydrates have been drilled in the Vestnesa Ridge area west of Spitsbergen, and there are good geophysical indications of gas hydrates in the Bjørnøya Basin.

CO_2 storage in hydrates
CO_2 may be stored in gas hydrates. Exposing methane hydrate to CO_2 will cause a solid exchange of CO_2 and CH4 as guest molecules within the hydrate; an exchange caused by the fact that it is thermodynamically more favourable for water to form hydrates with CO_2 than with methane. CO_2 sequestration in hydrates is a win-win process, since associated natural gas will be produced as CO_2 and is sequestered in the form of CO_2 hydrates. The regenerated CO_2 hydrate is thermodynamically more stable than the methane hydrate; thus the replacement of natural gas hydrate with CO_2 hydrate will increase the stability of hydrate formations.

From an energy perspective, natural gas hydrates may



Left: Conceptual model of the gas hydrate stability zone (GHSZ) for a marine setting. BGHSZ is the bottom of the GHSZ. Right: GHSZ thickness map calculated assuming 96% methane + 3% ethane + 1% propane and sea water with a geothermal gradient of 31 °C/km, adapted from Chand et al. (2008). Fields, discoveries, faults and boundaries are indicated.

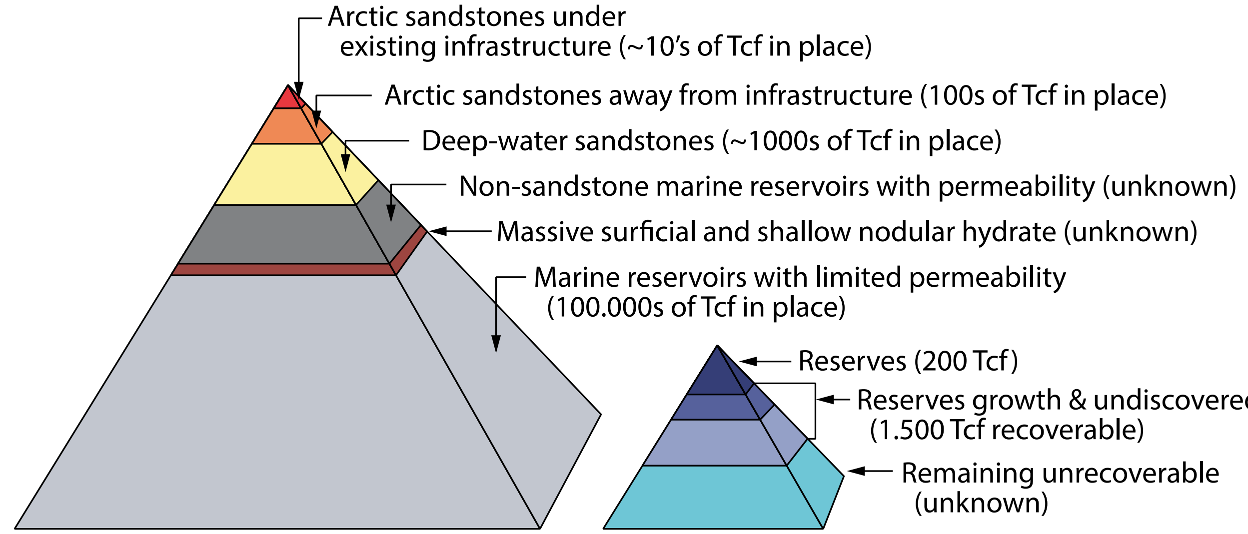


CO_2 storage in hydrate formations, as demonstrated in the Alaskan Injection test by ConocoPhillips and USDOE (Courtesy ConocoPhillips)

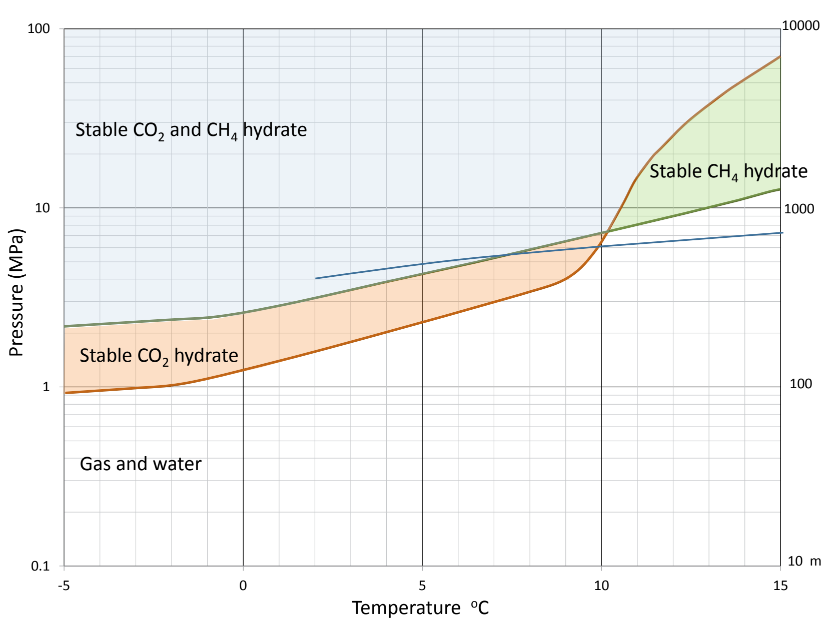
Gas hydrates

represent an enormous energy potential (Boswell and Collett 2006). Some authors claim that the total energy of natural gas entrapped in hydrate reservoirs worldwide might be more than twice the energy of all known coal, oil and gas energy sources. To store CO_2 in natural gas hydrate reservoirs by replacing the CH4 in the hydrate with CO_2 may become very attractive, compared to other methods of producing natural gas from hydrates. Besides the CO_2 storage potential, this method benefits from little or no associated brine production, which has been a severe limitation in previous attempts to produce natural gas from hydrates by depressurization and heat injection. Another benefit is its ability to maintain the geomechanical stability to avoid formation collapse or subsidence. A field pilot in Alaska performed by ConocoPhillips and US DOE in 2012 concluded that CO_2 was stored and methane successfully produced during a huff and puff operation injecting 200 000 scf of CO_2 and nitrogen.

Storage of CO_2 as hydrates below the sea floor is a possible trapping mechanism, but it has not been considered here because the long term behaviour of such hydrates in shallow sediments is not well known. It should be noted that within the gas hydrate stability zone, a seepage of CO_2 will be trapped as hydrates before reaching the sea floor.

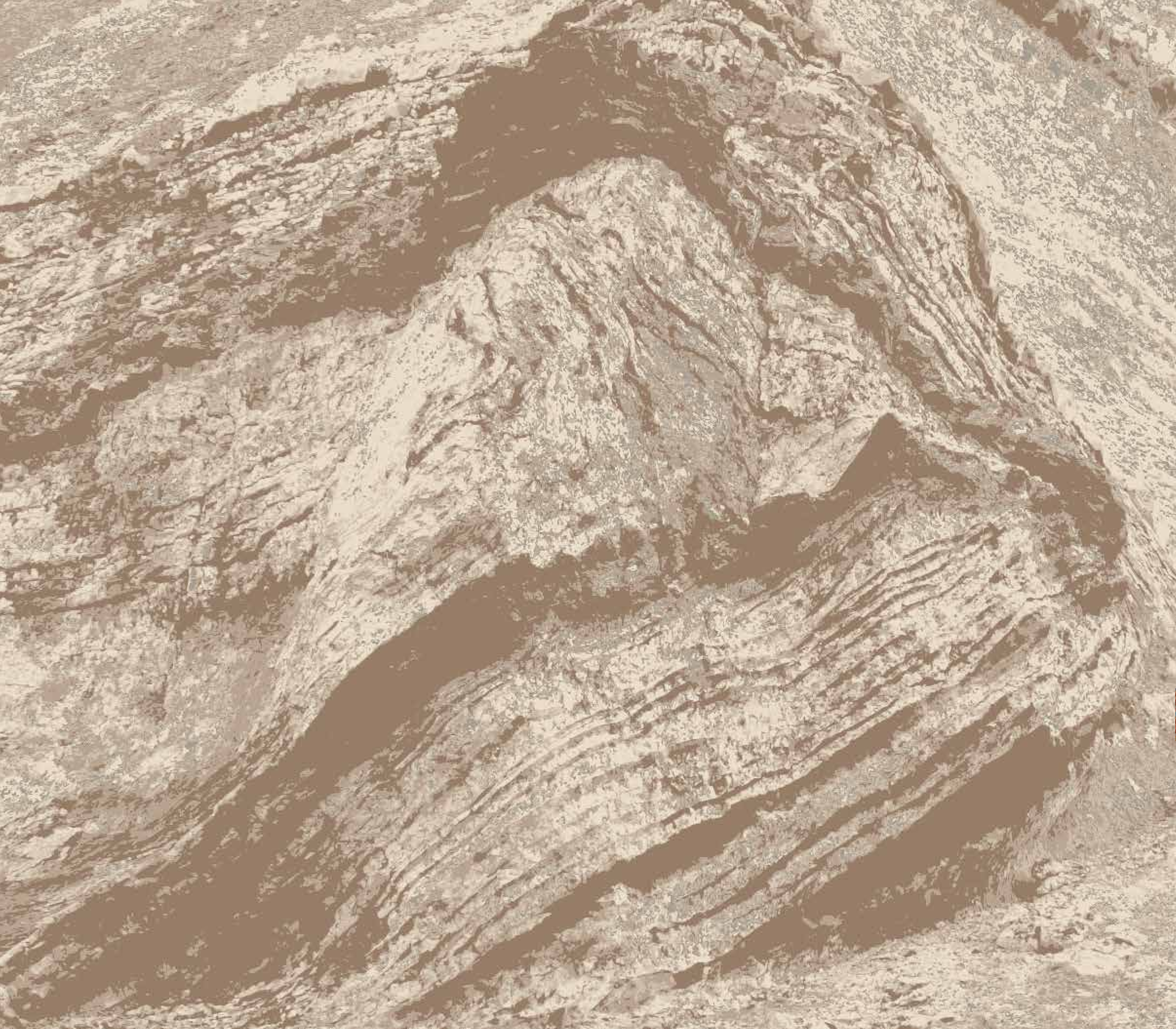


Boswell, R. and Collett, T.S.: "The gas hydrate resource pyramid", Fire in the ice, Netl fall newsletter, 5-7, 2006



Phase diagram for water, methane and CO_2. The scale to the right shows approximate water depth converted from the pressure scale. CO_2 hydrate is more stable than methane hydrate at depths shallower than 700 m. The blue line shows pressure and temperature below the sea bed assuming a sea water temperature of 2 °C and a gradient of 40 °C/km.

Natural Gas Hydrate on Fire; "Fiery Ice" (Courtesy USGS)



3. Methodology

3. Methodology

3.1 Geological storage

Depending on their specific geological properties, several types of geological formations can be used to store CO_2. In the North Sea Basin, the greatest potential capacity for CO_2 storage will be in deep saline-water saturated formations or in depleted oil and gas fields.

CO_2 will be injected and stored as a supercritical fluid. It then migrates through the interconnected pore spaces in the rock, just like other fluids (water, oil, gas).

To be suitable for CO_2 storage, saline formations need to have sufficient porosity and permeability to allow large volumes of CO_2 to be injected in a supercritical state at the rate it is supplied at. It must further be overlain by an impermeable cap rock, acting as a seal, to prevent CO_2 migration into other formations or to sea.

CO_2 is held in-place in a storage reservoir through one or more of five basic trapping mechanisms: stratigraphic, structural, residual, solubility, and mineral trapping. Generally, the initial dominant trapping mechanisms are stratigraphic trapping or structural trapping, or a combination of the two.

In residual trapping, the CO_2 is trapped in the tiny pores in rocks by the capillary pressure of water. Once injection stops, water from the surrounding rocks begins to move back into the pore spaces that contain CO_2. As this happens, the CO_2 becomes immobilized by the pressure of the added water. Much of the injected CO_2 will eventually dissolve in the saline water, or in the oil that remains in the rock. This process, which further traps the CO_2, is solubility (or dissolution) trapping. Solubility trapping forms a denser fluid which may sink to the bottom of the storage formation.

Depending on the rock formation, the dissolved CO_2 may react chemically with the surrounding rocks to form stable minerals. Known as mineral trapping, this provides the most secure form of storage for the CO_2, but it is a slow process and may take thousands of years.

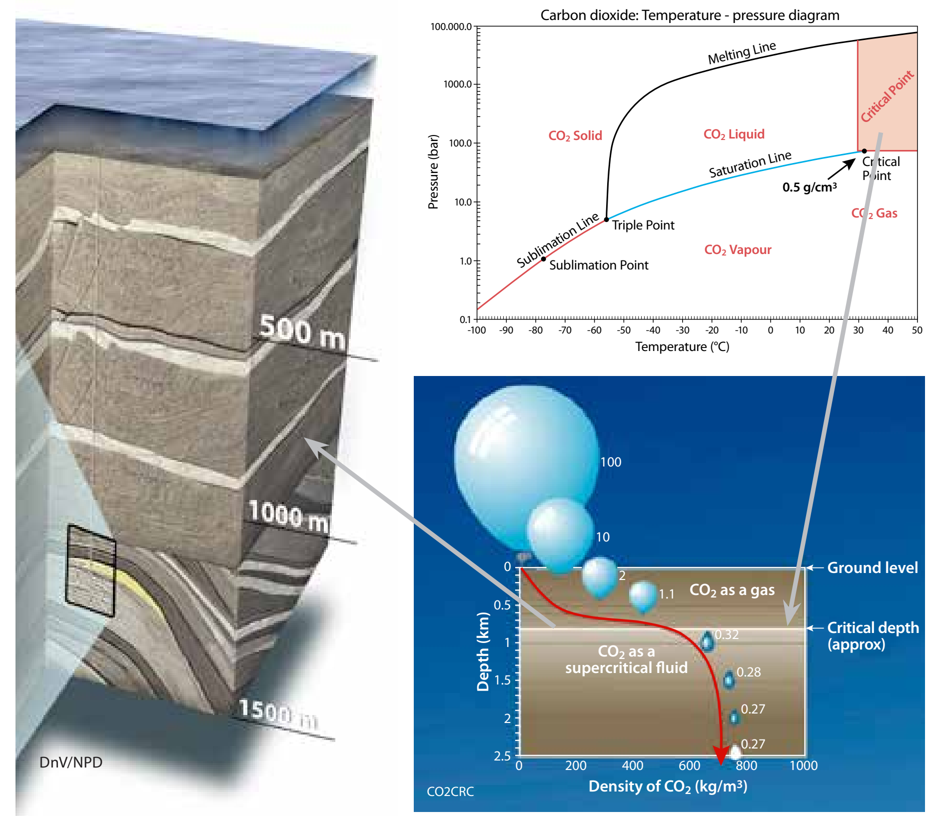
Porosity is a measure of the space in the rock that can be used to store fluids. Permeability is a measure of the rock's ability to allow fluid flow. Permeability is strongly affected by the shape, size and connectivity of the pore spaces in the rock. By contrast, the seals covering the storage formation typically have low porosity and permeability so that they will trap the CO_2. Another important property of the storage site is injectivity, the rate at which the CO_2 can be injected into a storage reservoir.

Oil and gas reservoirs are a subset of saline formations, and therefore they generally have similar properties. That is, they are permeable rock formations
acting as a reservoir with an impermeable cap rock acting as a seal.

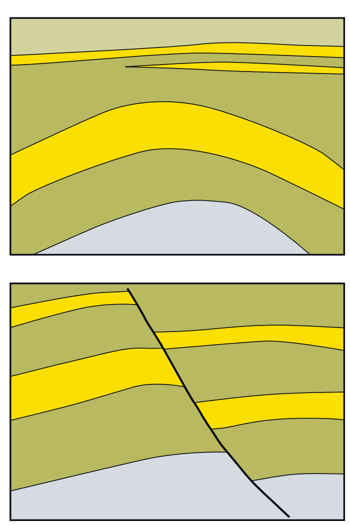
The reservoir is the part of the saline formation that is generally contained within a structural or stratigraphic closure (e.g. an anticline or dome). Therefore it is also able to physically trap and store a concentrated amount of oil and/or gas.

There is great confidence in the seal integrity of oil and gas reservoirs with respect to CO_2 storage, as they have held oil and gas for long time periods. However, a drawback of such reservoirs compared with deep saline aquifers is that they are penetrated by many wells. Care must be taken to ensure that exploration and production operations have not damaged the reservoir or seal.

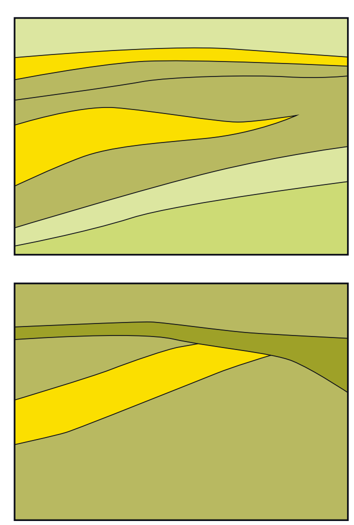
An aquifer is a body of porous and permeable sedimentary rocks where the water in the pore space is in communication throughout. Aquifers may consist of several sedimentary formations and cover large areas. They may be somewhat segmented by faults and by low permeable layers acting as baffles to fluid flow. Maps, profiles and pore pressure data have been utilized in order to define the main aquifers. All the identified aquifers in the area of this atlas are saline, most of them have salinities in the order of sea water or higher.



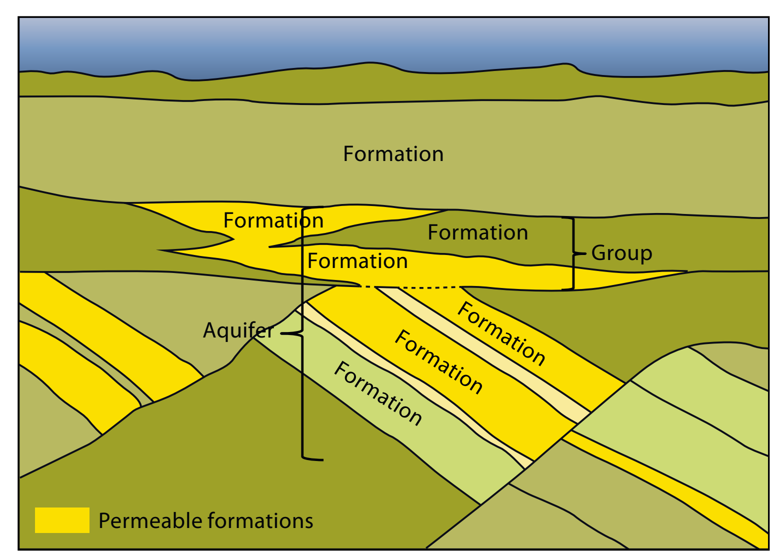
Supercritical fluids behave like gases, in that they can diffuse readily through the pore spaces of solids. But, like liquids, they take up much less space than gases. Supercritical conditions for CO_2 occur at 31.1°C and 7.38 megapascals (MPa), which occur approximately 800 meters below surface level. This is where the CO_2 has both gas and liquid properties and is 500 to 600 times denser (up to a density of about 700 kg/m3) than at surface conditions, while remaining more buoyant than formation brine.



Structural traps

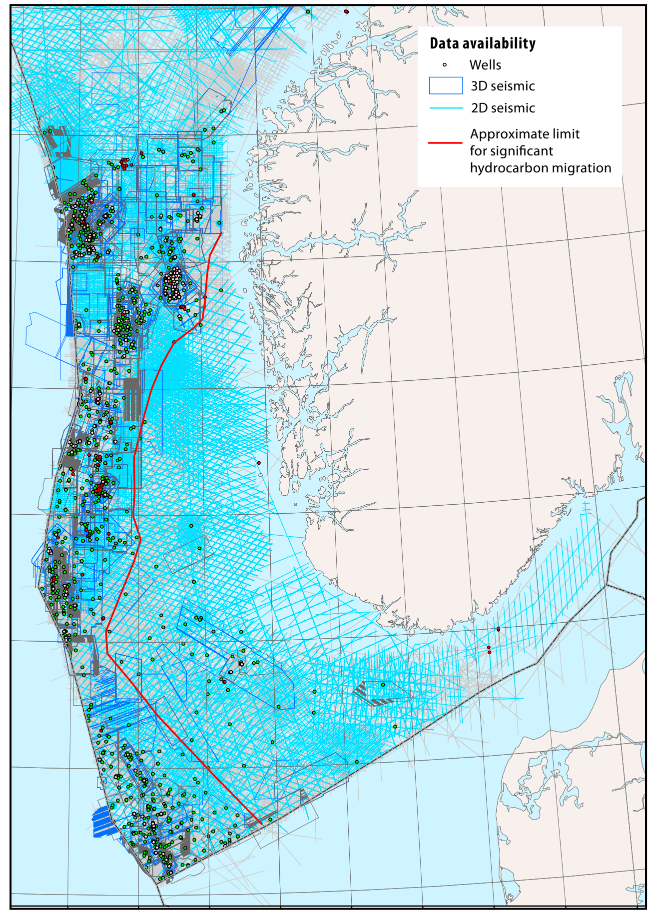


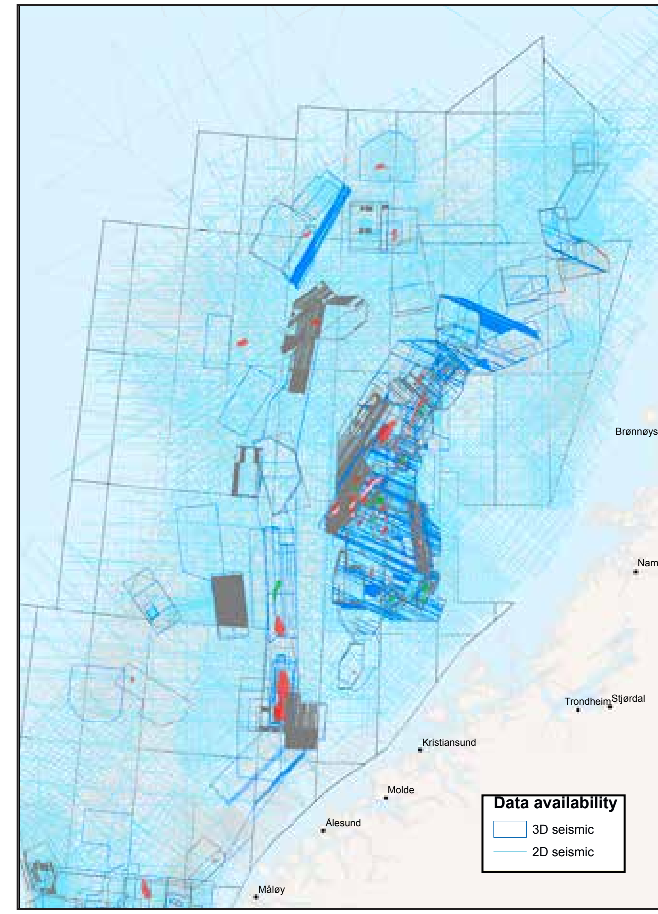
Stratigraphical traps



Relation between geological formations and aquifers.

3.2 Data availability



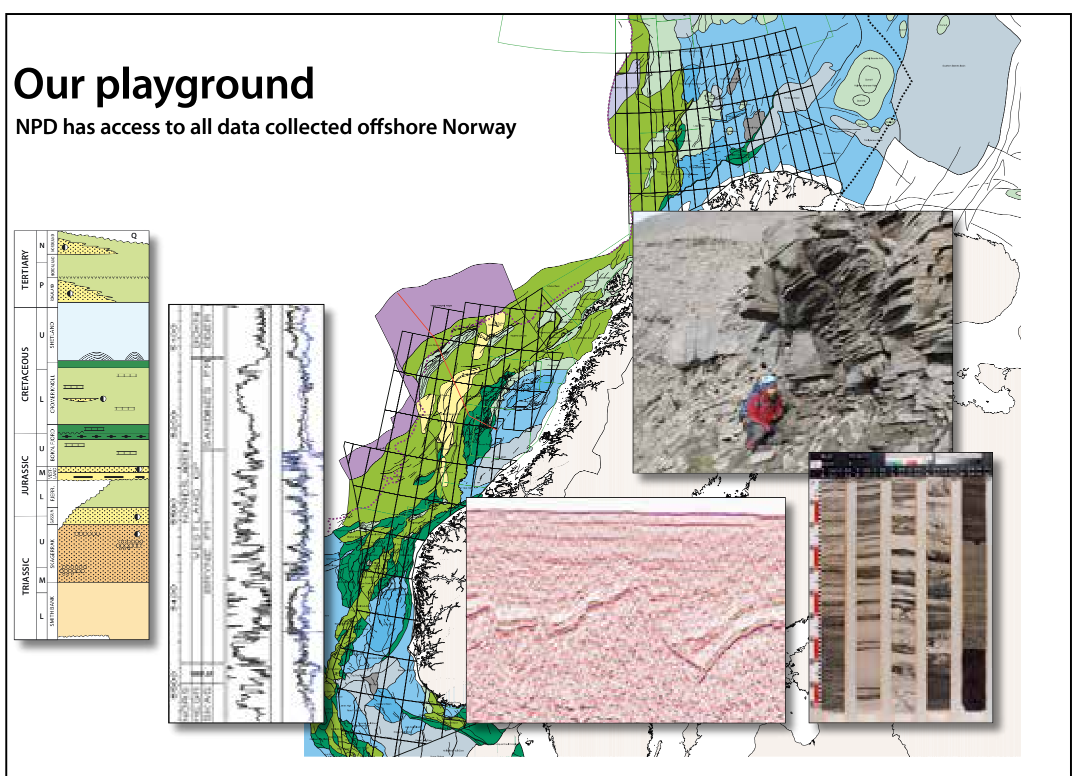


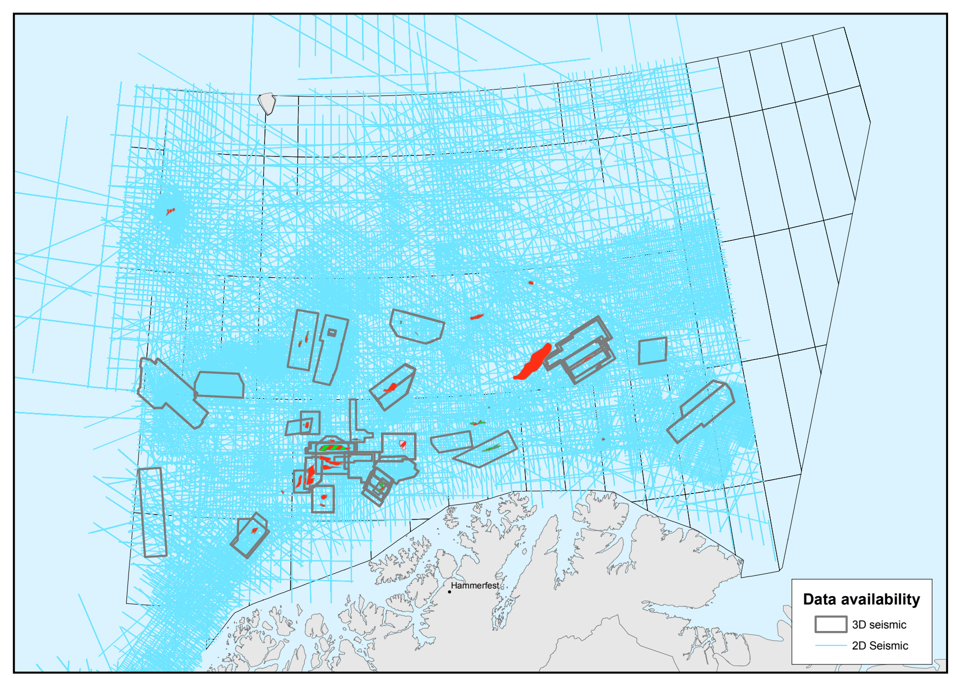
The authorities' access to collected and analysed data is stipulated in law and based on the following statements: "The Norwegian State has the proprietary right to subsea petroleum deposits and the exclusive right to resource management" and "The right to submarine natural resources is vested in the State". This is regulated by The Petroleum Act (29 November 1996 No.72 1963), Regulations to the Act, the Norwegian Petroleum Directorate's resource regulations and guidelines, and Act of 21 June 1963 No. 12 "Scientific research and exploration for and exploitation of subsea natural resources other than petroleum resources".

The Norwegian Petroleum Directorate (NPD) has access to all data collected on the NCS and has a national responsibility for the data. The NPD's data, overviews and analyses make up an important fact basis for the oil and gas activities.

The main objective of these Reporting Requirements from the NPD is to support the efficient exploitation of Norway's hydrocarbon reserves. More than 40 years of petroleum activity has generated a large quantity of data. This covers 2D and 3D data, data from exploration and production wells such as logs, cuttings and cores as well as test and production data. These data, together with many years of dedicated work to establish geological play models for the North Sea, have given us a good basis for the work we are presenting here.

How these data are handled is regulated in: *http://www.npd.no/en/Regulations/Regulations/Petroleum-activities/*





Seismic coverage

3.3 Workflow and characterization

Characterization

Aquifers and structures have been characterized in terms of capacity, injectivity and safe storage of CO_2. To complete the characterization, the aquifers are also evaluated according to the data coverage and their technical maturity. Some guidelines (a check list) were developed to facilitate characterization. Parameters used in the characterization process are based on data and experience from the petroleum activity on the NCS and the fact that CO_2 should be stored in the super-critical phase to obtain the most efficient and safest storage.

The scores for capacity, injectivity and seal quality are based on evaluation of each aquifer/structure. The checklist for reservoir properties gives a more detailed overview of the important parameters regarding the quality of the reservoir. Important elements when evaluating reservoir properties are aquifer structuring, traps, the thickness and permeability of the reservoir. A corresponding checklist has been developed for the sealing properties. Evaluation of faults and fractures through the seal, in addition to old wells penetrating the seal, provides important information on the sealing quality. An extensive database has been available for this evaluation. Nevertheless, evaluation of some areas is more uncertain due to limited seismic coverage and no well information. The data coverage is colour-coded to illustrate the data available for each aquifer/structure. Characterization and capacity estimates will obviously be more uncertain when data coverage is poor.

CHARACTERIZATION OF AQUIFERS AND STRUCTURES

	Criteria		Definitions, comments
Reservoir quality	Capacity, communicating volumes	3	Large calculated volume, dominant high scores in checklist
		2	Medium - low estimated volume, or low score in some factors
		1	Dominant low values, or at least one score close to unacceptable
	Injectivity	3	High value for permeability * thickness (k*h)
		2	Medium k*h
		1	Low k*h
Sealing quality	Seal	3	Good sealing shale, dominant high scores in checklist
		2	At least one sealing layer with acceptable properties
		1	Sealing layer with uncertain properties, low scores in checklist
	Fracture of seal	3	Dominant high scores in checklist
		2	Insignificant fractures (natural / wells)
		1	Low scores in checklist
Other leak risk	Wells	3	No previous drilling in the reservoir / safe plugging of wells
		2	Wells penetrating seal, no leakage documented
		1	Possible leaking wells / needs evaluation
Data coverage	Good data coverage	Limited data coverage	Poor data coverage

Other factors:
How easy / difficult to prepare for monitoring and intervention. The need for pressure relief. Possible support for EOR projects. Potential for conflicts with future petroleum activity.

Data coverage
Good : 3D seismic, wells through the actual aquifer/structure
Limited : 2D seismic, 3D seismic in some areas, wells through equivalent geological formations
Poor : 2D seismic or sparse data

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3.3 Workflow and characterization

The scores for capacity, injectivity and seal were determined from the individual parameters established in the guidelines. Each parameter was given a score, and the scores were combined to give the final score for the aquifer. Some parameters were weighted, as shown in the tables.

The methods used for characterization of reservoir properties are similar to well-established methods used in petroleum exploration. Characterization of cap rock and injectivity is typically conducted in studies of field development and to some extent in basin modelling. For evaluation of regional aquifers in CO_2 storage studies, the mineralogical composition and the petrophysical properties of the cap rocks are rarely well known. In order to characterize the sealing capacity in this atlas, we have mainly relied on regional pore pressure distributions and data from leak-off tests combined with observations of natural gas seeps.

CHECKLIST FOR RESERVOIR PROPERTIES

	Typical high and low scores	
Reservoir Properties	High	Low
Aquifer Structuring	Mapped or possible closures	Tilted, few /uncertain closures
Traps	Defined sealed structures	Poor definition of traps
Pore pressure	Hydrostatic or lower	Overpressure
Depth	800- 2500 m	< 800 m or > 2500 m
Reservoir	Homogeneous	Heterogeneous
Net thickness	> 50 m	< 15 m
Average porosity in net reservoir	> 25 %	< 15 %
Permeability	> 500 mD	< 10 mD

CHECKLIST FOR SEALING PROPERTIES

	Typical high and low scores		
Sealing Properties	High	Low	Unacceptable values
Sealing layer	More than one seal	One seal	No known sealing layer over parts of the reservoir
Properties of seal	Proven pressure barrier/ > 100 m thickness	< 50 m thickness	
Composition of seal	High clay content, homogeneous	Silty, or silt layers	
Faults	No faulting of the seal	Big throw through seal	Tectonically active faults
Other breaks through seal	No fracture	sand injections, slumps	Active chimneys with gas leakage
Wells (exploration/ production)	No drilling through seal	High number of wells	

Reservoir Parameters	Capacity weight	Injectivity weight	Comment
Rock volume	3		Net rock volume is appropriate in case of low net reservoir
Structuring	1		Potential for the top surface to form closures
Traps	1		Mapped structures interpreted to be 4-way closures
Pore pressure	1	1	Depleted, hydrostatic, overpressured
Depth	1	1	Depth of burial relative to optimal window 1000-2500 m
Reservoir		3	Homogeneous - heterogeneous
Thickness		1	Net thickness of reservoir sand
Porosity	3		Average porosity in net reservoir
Permeability		3	Average horizontal permeability

Cap rock Parameters	Seal weight	Well weight	Comment
Number of seals	1		Overlying sealed aquifer(s) with storage capacity
Thickness/barriers	1		Thickness of seal/ seal capacity proved in analogous cases
Composition	1		Shale, silty layers, mineralogy of shale
Faults	1		Geometry and modelled property of fault zone
Other indications	1		Seismic indications of gas leakage
Well penetrations		1	Number and status of wells penetrating seal

In exploration wells on the Norwegian shelf, pressure differences across faults and between reservoir formations and reservoir segments are commonly observed. Such pressure differences give indications of the sealing properties of cap rocks and faults. Based on such observations in the hydrocarbon provinces, combined with a general geological understanding, one can use the sealing properties in explored areas to predict the properties in less explored or undrilled areas.

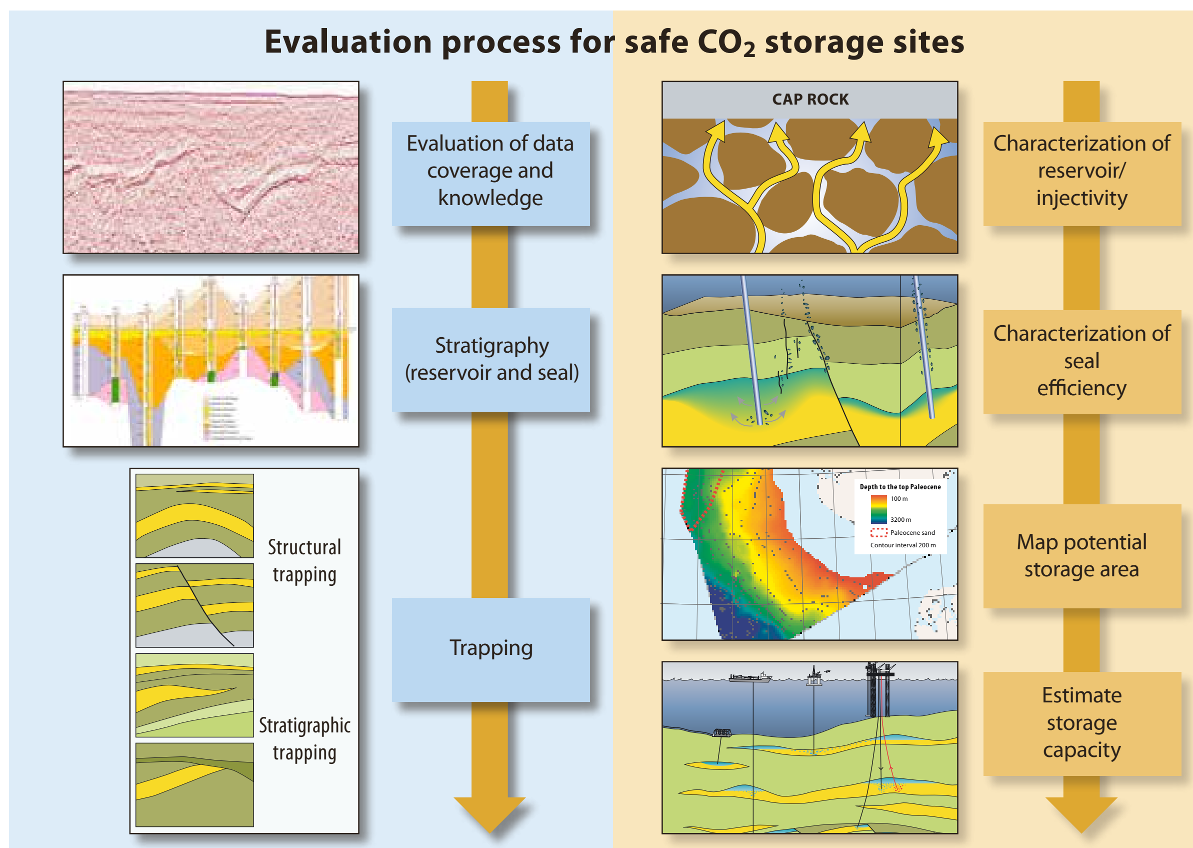
Natural seepage of gas is commonly observed in the hydrocarbon provinces in the Norwegian continental shelf. Such seepage is expected from structures and hydrocarbon source rocks where the pore pressure is close to or exceeds the fracture gradient. Seepage at the sea floor can be recognized by biological activity and by free gas bubbles. Seismically, seepage is indicated by gas chimneys or pipe structures. The seepage rates at the surface show that the volumes of escaped gas through a shale or clay dominated overburden are small in a time scale of a few thousand years. Rapid leakage can only take place if open conduits are established to the sea floor. Such conduits could be created along wellbores or by reactivation of faults or fractures. Established natural seepage systems are also regarded as a risk factor for CO_2 injection.

In summary, the capacity of each aquifer is given in the tables as a deterministic volume. The injectivity and sealing properties are indicated by scores 1 to 3. The characterization is based on a best estimate of each parameter. Uncertainty is not quantified, but is indicated by the colour coding for data availability and maturity.

Workflow

NPD's approach for assessing the suitability of the geological formations for CO_2 storage is summed up in this flowchart. The intention is to identify, in a systematic way, the aquifers and which aquifers are prospective in terms of large-scale storage of CO_2.

In subsequent steps in the workflow, each potential reservoir and seal identified, are evaluated and characterized for their CO_2 storage prospectivity. Based on this, the potential storage sites are mapped and the storage capacity is calculated. The evaluation is based on available data in the given areas. This evaluation does not provide an economic assessment of the storage sites.



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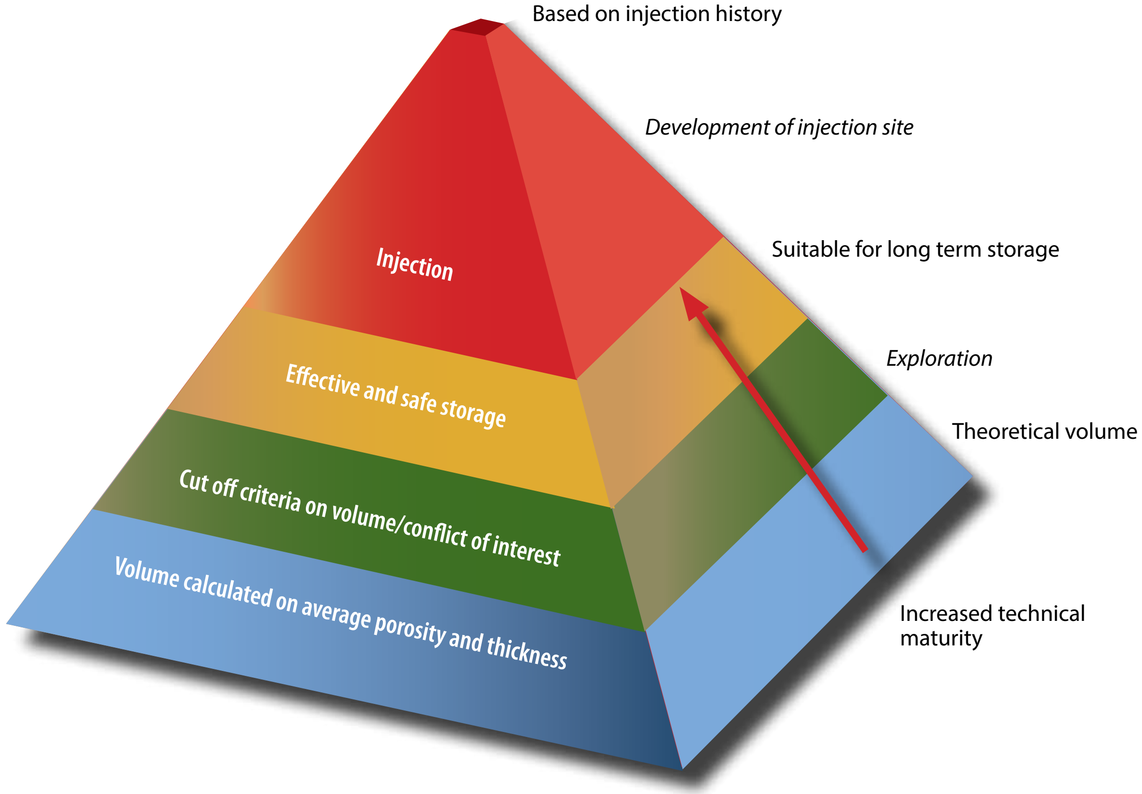
3.3 Workflow and characterization



The maturation pyramid

The evaluation of geological volumes suitable for injecting and storing CO_2 can be viewed as a step-wise approximation, as shown in the maturation pyramid. Data and experience from over 40 years in the petroleum industry will contribute in the process of finding storage volumes as high up as possible in the pyramid.

Step 4 is the phase when CO_2 is injected in the reservoir. Throughout the injection period, the injection history is closely evaluated and the experience gained provides further guidance on the reservoirs' ability and capacity to store CO_2.

Step 3 refers to storage volumes where trap, reservoir and seal have been mapped and evaluated in terms of regulatory and technical criteria to ensure safe and effective storage.

Step 2 is the storage volume calculated when areas with possible conflicts of interest with the petroleum industry have been removed. Only aquifers and prospects of reasonable size and quality are evaluated. Evaluation is based on relevant available data.

Step 1 is the volume calculated on average porosity and thickness. This is done in a screening phase that identifies possible aquifers suitable for storage of CO_2. The theoretical volume is based on depositional environment, diagenesis, bulk volume from area and thickness, average porosity, permeability and net/gross values.

1 tonne	= one metric tonne	= 1000 kg	
1 Mt	= one megatonne	= 10^6 tonnes	
1 Gt	= one gigatonne	= 1000 Mt	= 10^9 tonnes

3.4 Estimation of storage capacity

CO_2 can be stored in produced oil and gas fields, or in saline aquifers. In a producing oil field, CO_2 can be used to combine storage with enhanced recovery. A depleted gas field can be used for CO_2 storage, which will increase the pore pressure in the reservoir. There may be an option to recover some of the remaining natural gas during the CO_2 injection. Even if EOR is not the purpose, oil and gas fields can be used for CO_2 injection and storage.

In saline aquifers, CO_2 can be stored as dissolved CO_2 in the water phase, free CO_2 or residual (trapped) CO_2 in the pores.

When fluid is injected into a closed or half-open aquifer, pressure will increase. The relation between pressure and injected volume depends on the compressibility of the rock and the fluids in the reservoir. The solubility of CO_2 in the different phases will also play a part. Safe injection of CO_2 or any other fluid requires that the injection pressure in the reservoir is less than the fracturing pressure. Pressure increase can however be mitigated by production of formation water. The fracturing pressure depends on the state of stress in the bedrock and is typically 10-30 % lower than the lithostatic pressure. Fracturing gradients were estimated by comparing pore pressures in overpressured reservoirs with data from leak-off tests. Storage capacity depends on several factors, primarily the reservoir pore volume and the fracturing pressure. It is important to know if there is communication between multiple reservoirs, or if the reservoirs are in communication with larger aquifers. The CO_2 will preferably be stored in a supercritical phase to take up the least possible volume in the reservoir.

For saline aquifers, the amount of CO_2 to be stored can be determined using the following formula:

$$M_{CO_2} = Vb \times Ø \times n/g \times \rho_{CO_2} \times S_{eff}$$

- M_{CO_2} *mass of CO_2*
- *Vb* *bulk volume*
- *Ø* *porosity*
- *n/g* *net to gross ratio*
- ρ_{CO_2} *density of CO_2 at reservoir conditions*
- S_{eff} *storage efficiency factor*

(Geocapasity 2009)

S_{eff} is calculated as the fraction of stored CO_2 relative to the pore volume. The CO_2 in the pores will appear as a mobile or immobile phase (trapped). Most of the CO_2 will be in a mobile phase. Gradually, some CO_2 will be dissolved in the water and simulations show that approximately 10-20% of the CO_2 will behave in this manner. When injection in an aquifer stops, CO_2 may continue to migrate in the aquifer, and the water will follow, trapping some of the CO_2 behind the water. The trapped gas saturation can reach about 30% depending on how long the migration continues. The diffusion of CO_2 into the water will be small, but may have an effect over a long time period.

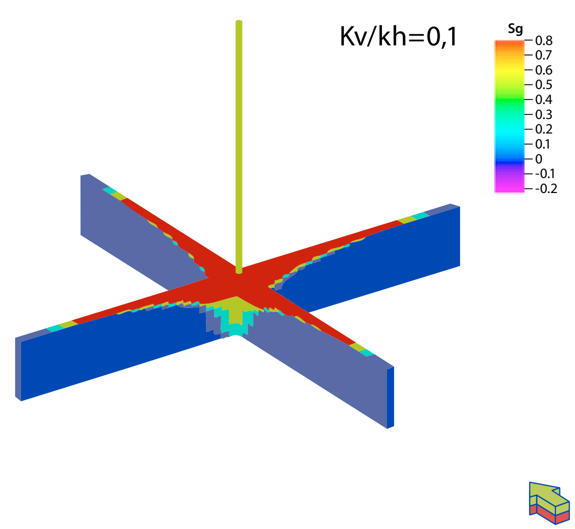
The injection rate will depend on the permeability and how much of the reservoir is exposed to the injection well. The number of wells needed to inject a certain amount of CO_2 will depend on the size of the reservoir and the injectivity.

For a homogenous reservoir with a permeability of 200mD and reservoir thickness of 100m, the storage efficiency in a closed system is simulated to be 0.4 to 0.8%, with a pressure increase of 50 to 100 bar. As shown in the figure, a pressure increase between 50 and 100 bar may be acceptable for reservoirs between 1500 and 3000m, but this must be evaluated carefully for each reservoir.

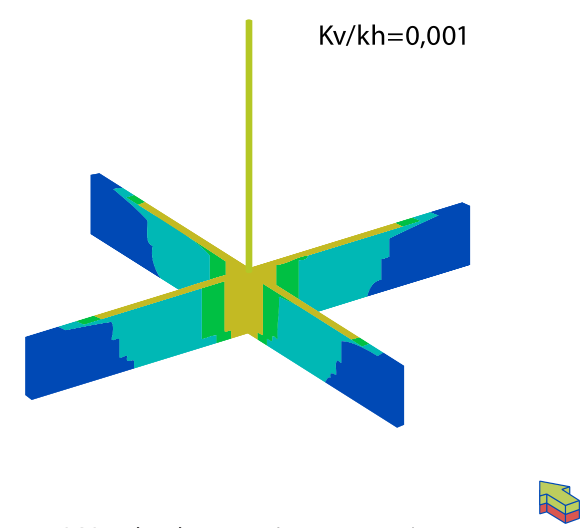
If the reservoir is in communication with a large or open aquifer, the reservoir pressure will stay almost constant during CO_2 injection, as the water will be pushed beyond the boundaries of the reservoir. The CO_2 stored will be the amount injected until it reaches the boundaries. The storage efficiency will in this case be ~5 % or more, depending primarily on the relationship between the vertical and horizontal permeability. A low vertical to horizontal permeability ratio will distribute the CO_2 better over the reservoir than a high ratio. This is illustrated in the model below of a horizontal reservoir with injection for 50 years.

For abandoned oil and gas fields, the amount of CO_2 that can be stored depends on how much of the hydrocarbons have been produced, and to what extent the field is depleted.

The gas fields will normally have low pressure at abandonment, and the oil fields will have a low oil rate and high water cut. The oil fields may have an EOR potential with CO_2 at abandonment, which must be considered. For a gas field, the storage potential can be calculated as the volume of CO_2 which can be injected to increase pore pressure from abandonment pressure up to initial pressure. For an oil reservoir, CO_2 can be stored by allowing pressure increase or by producing formation water. CO_2 storage can be combined with EOR by replacing some of the water and the remaining oil.



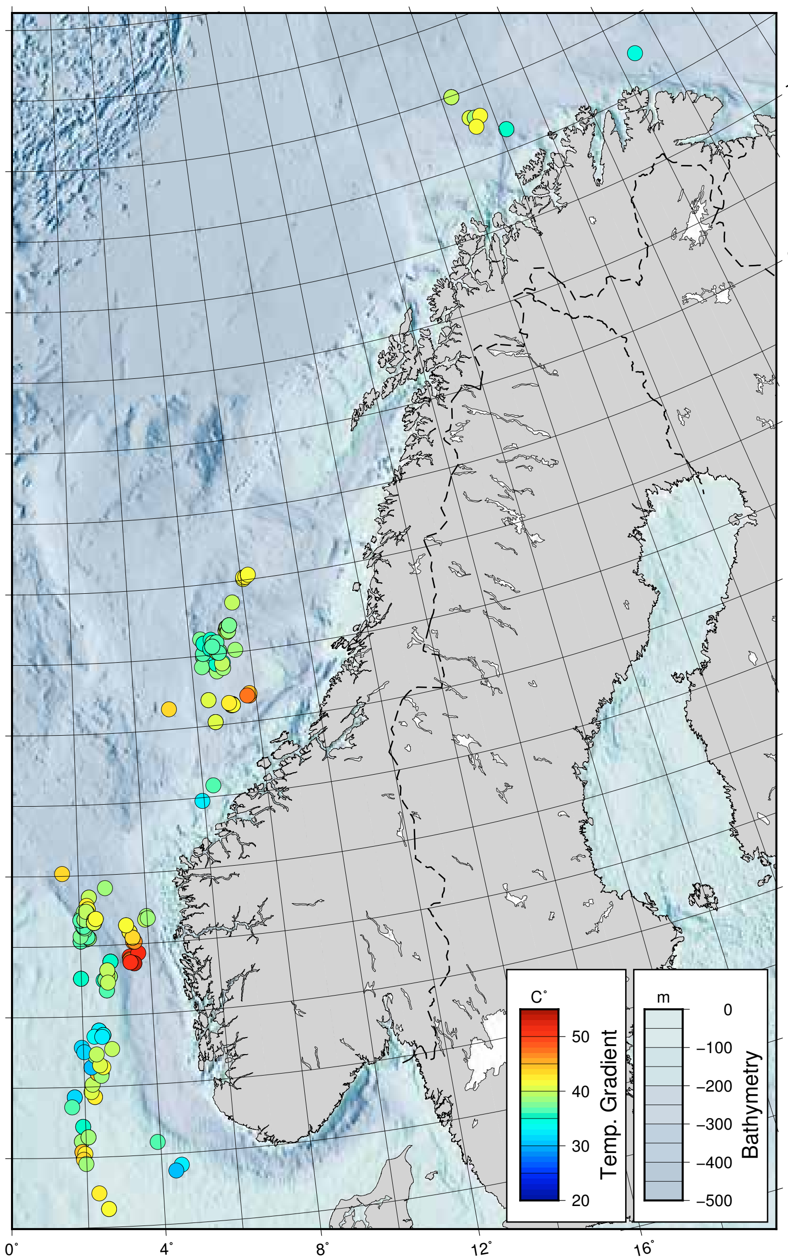
SCO_2 development (open system)



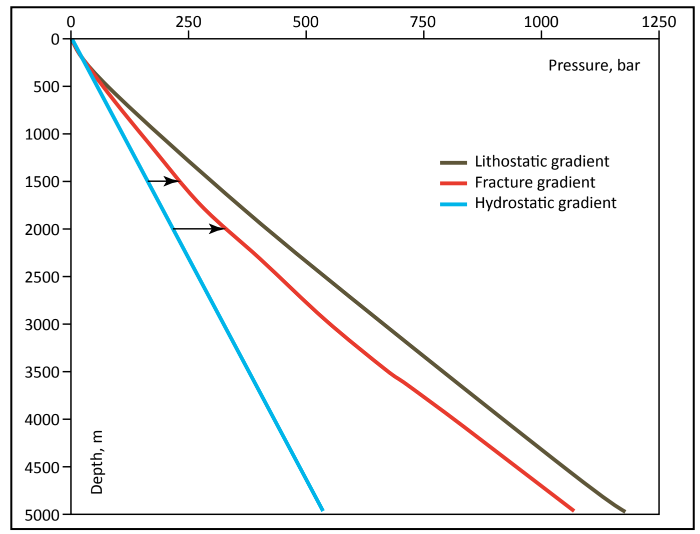
SCO_2 development (open system)

A cross section of a flat reservoir with injection for 50 years.

3.4 Estimation of storage capacity



Temperature gradients obtained from drill stem tests in the NCS. The selected exploration wells have temperature measurements from drill stem tests where oil or water was produced. The colours show calculated temperature gradients from the sea floor to the depth of the test, typically 1500 m to 4000 m. High temperature gradients in the order of 40^o C appear to be related to basement highs, salt structures and areas with significant glacial erosion. Gradients lower than 35^{o}C seem to correlate with areas of rapid Quaternary subsidence.



Pressure gradients obtained from pore pressure data and leak-off tests in wells from the Norwegian Sea Shelf and North Sea at water depths between 250 and 400 m. The fracturing gradient marks the lower boundary of measured leak-off pressures and the upper boundary of measured pore pressures. The lithostatic gradient was calculated from general compaction curves for shale and sand with a 300 m water column. The hydrostatic gradient assumes sea water salinity. The arrows show how much pressure can be increased from hydrostatic pressure before it reaches the fracure gradient.

For the evaluation of CO_2 storage it is important to understand the relations between volumes of fuels, energy content and how much pore space they occupy in the subsurface. The table below shows approximate values for how much natural gas, diesel and coal which will generate 1 Gt of CO_2 with 100 % combustion, and how much energy is generated. The values for crude oil depend on the composition, but are quite similar to diesel.

When CO_2 in dense phase is injected into a saline aquifer , the density is typically 600-700 kg/m^3. With a density of 700, 1 Gt will require a subsurface volume of 1.4 x 10^9 m^3. With a storage efficiency of 4 %, this corresponds to an aquifer volume of 36 x 10^9 m^3.

The subsurface volume occupied by the volume of natural gas in the table, assuming 100 % gas saturation, is approximately twice the subsurface volume of 1 Gt CO_2. The subsurface volume of oil is approximately half of the CO_2 volume. These subsurface volumes are depth dependent.

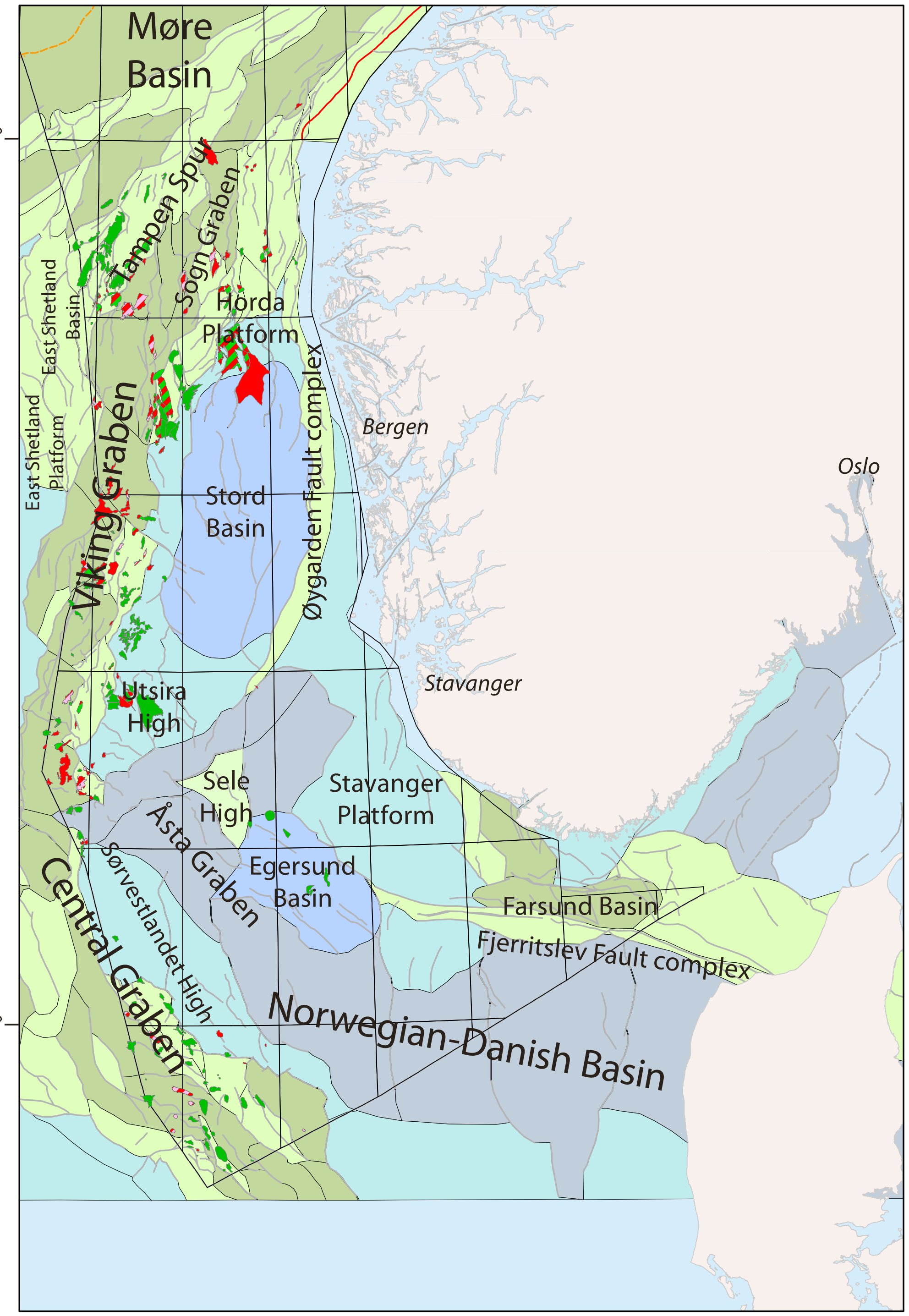
This means that abandoned gas fields produced by pressure depletion can be good candidates for CO_2 injection. These fields can accommodate more CO_2 than was generated by combustion of the gas before the aquifer pressure comes back to the initial pressure prior to production.

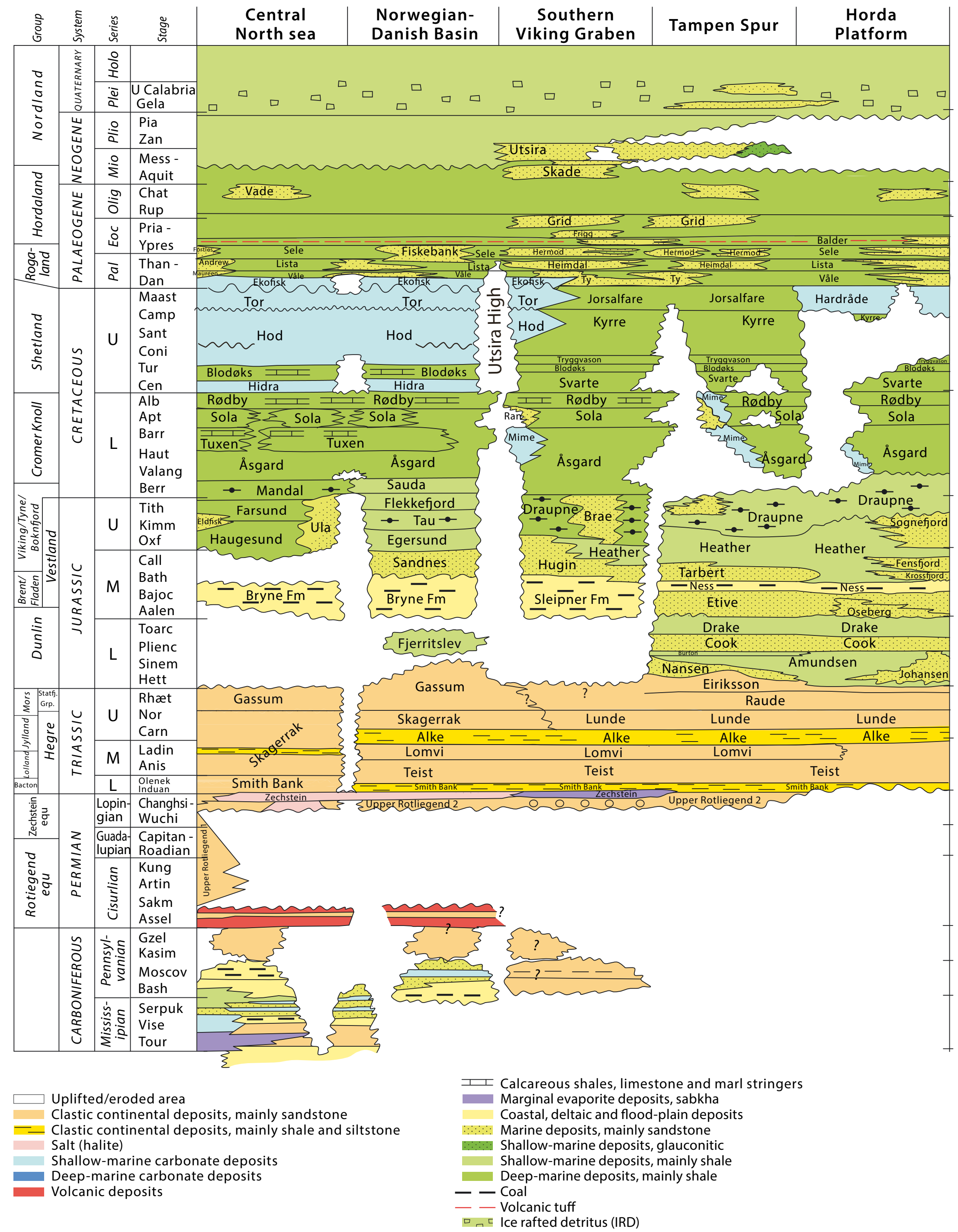
	Volume/weight	**Energy**	**CO_2 formed**
Natural gas	532 GSm^3	5300 TWh	1 Gt
Diesel	372 Mt	3800 TWh	1 Gt
Coal	413 Mt	2800 TWh	1 Gt

Sources http://energilink.tu.no/leksikon/co2.aspx and www.epa.gov/greenpower/pubs

4. The Norwegian North Sea

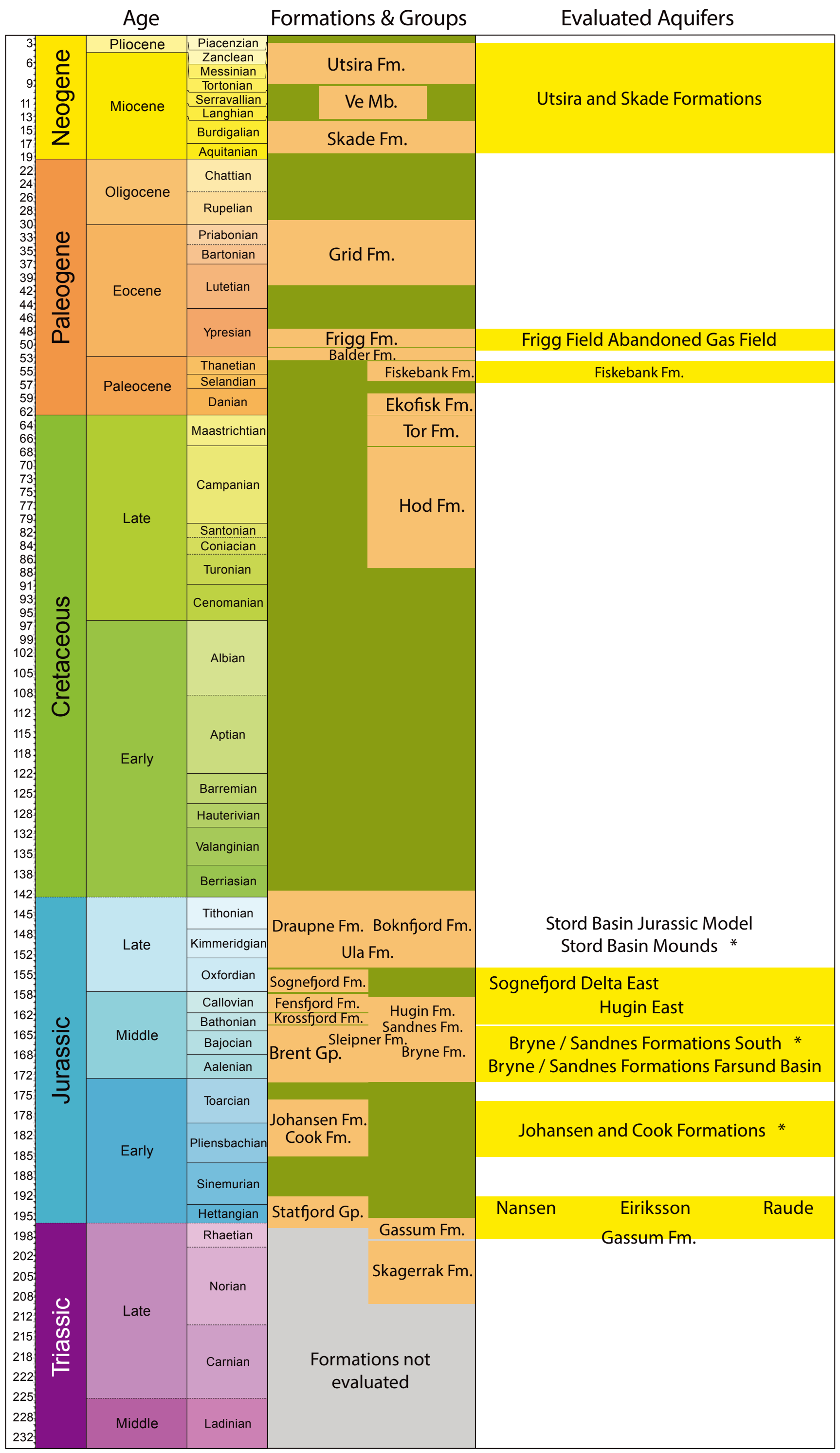
Eva K. Halland (Project Leader), Ine Tørneng Gjeldvik, Wenche Tjelta Johansen, Christian Magnus, Ida Margrete Meling, Stig Pedersen, Fridtjof Riis, Terje Solbakk, Inge Tappel



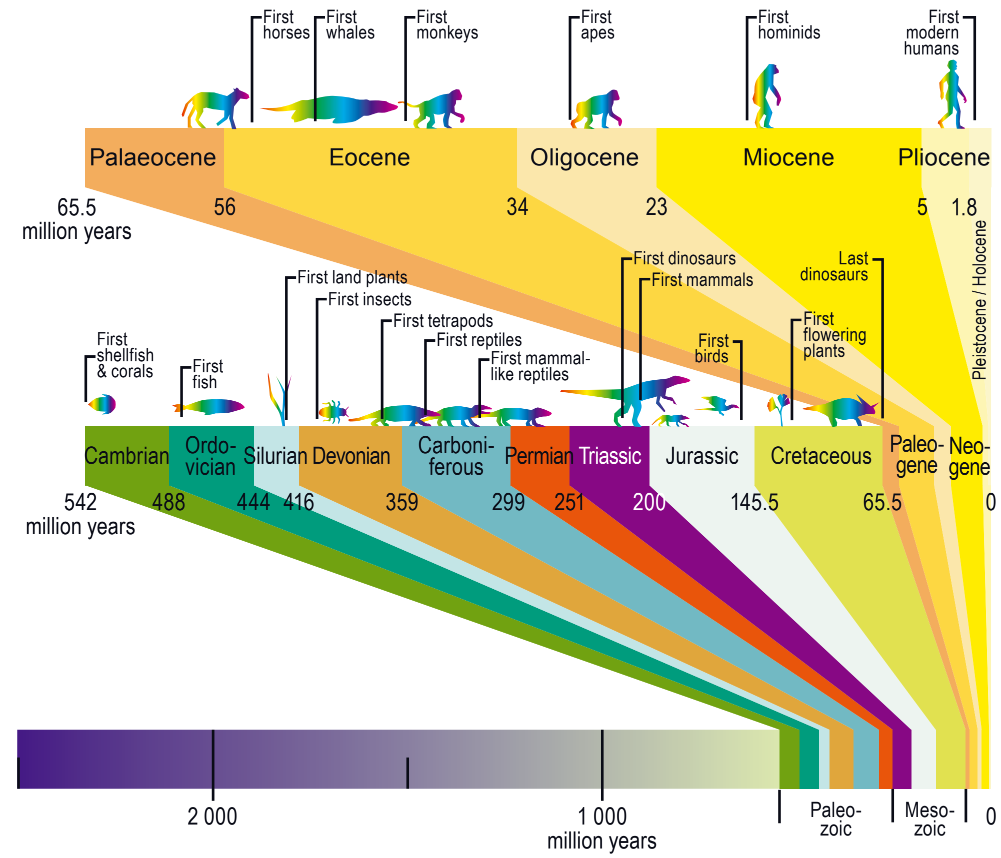


Lithostratigraphic chart of the North Sea (NPD)

4.1 Geology of the North Sea



* Evaluated prospects



Geological time scale

4.1 Geology of the North Sea

The basic structural framework of the North Sea is mainly the result of Upper Jurassic/ Lower Cretaceous rifting, partly controlled by older structural elements.

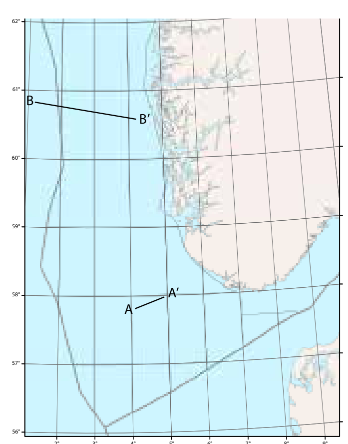
Carboniferous-Permian: Major rifting with volcanism and deposition of reddish eolian and fluvial sandstones (Rotliegendes). Two basins were developed with deposition of thick evaporate sequences (Zechstein). When overlain by a sufficient amount of younger sediments, buoyancy forces caused the salt to move upwards (halokinesis). This is important for generation of closed structures, including hydrocarbon traps, in the southern part of the North Sea and also as a control on local topography and further sedimentation.

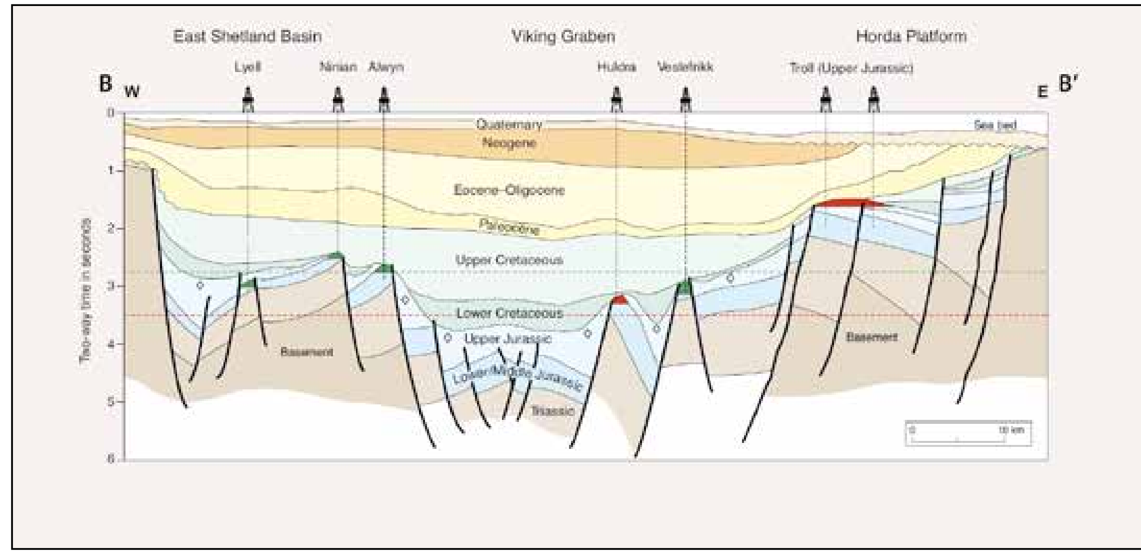
Triassic: Major N-S to NE-SW rifting with thick coarse fluvial sediments deposited along rift margins, grading into finer-grained river and lake deposits in the center of the basins. The transition between the Triassic and Jurassic is marked by a widespread marine transgression from north and south.

Jurassic: The marine transgression was followed by the growth of a volcanic dome centered over the triple point between the Viking Graben, the Central Graben and the Moray Firth Basin. The doming caused uplift and erosion, and was followed by rifting. Large deltaic systems containing sand, shale and coal were developed in the northern North Sea and the Horda Platform (Brent Group). In the Norwegian-Danish Basin and the Stord Basin, the Vestland Group contains similar deltaic sequences overlain by shallow marine/ marginal marine sandstones. The most important Jurassic rifting phase in the North Sea area took place during the Late Jurassic and lasted into the Early Cretaceous. During this tectonic episode, major block faulting caused uplift and tilting, creating considerable local topography with erosion and sediment supply. In anoxic basins thick sequences of shale accumulated, producing the most important source rock and also the Draupne Formation, which is an important seal for hydrocarbon traps in the North Sea area.

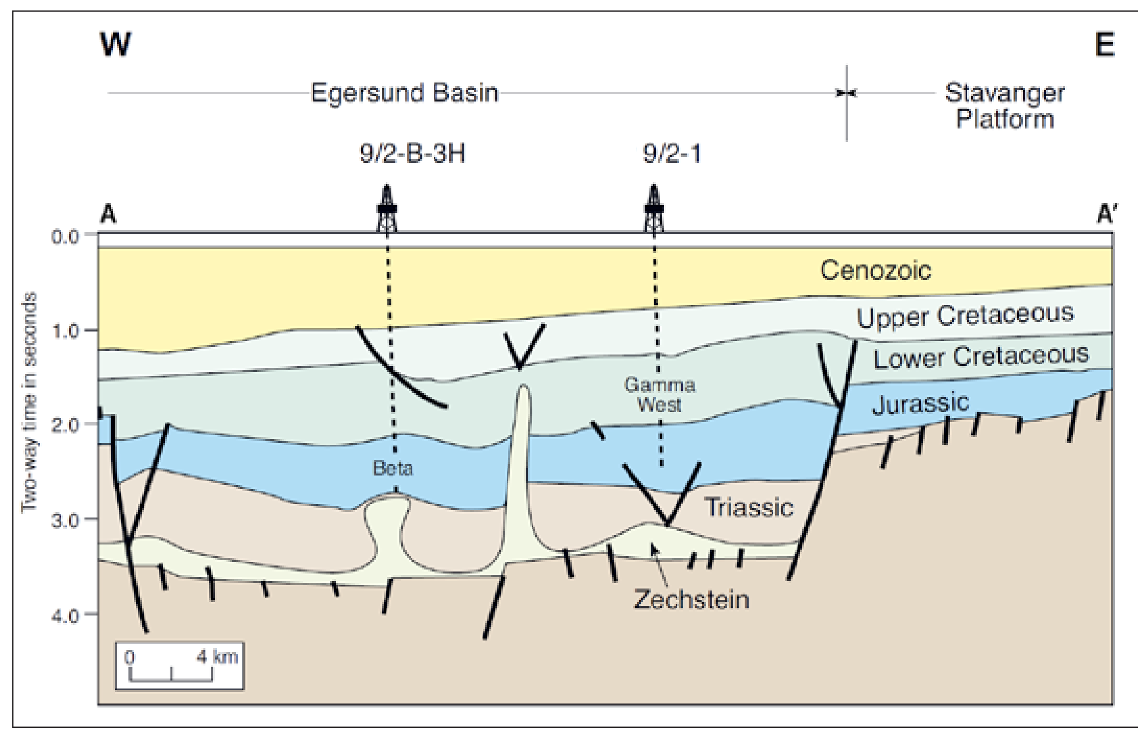
Cretaceous: The rifting ceased and was followed by thermal subsidence. The Upper Cretaceous in the North Sea is dominated by two contrasting lithologies. South of 61º N there was deposition of chalk, while to the north the carbonates gave way to siliclastic, clay-dominated sediments.

Cenozoic: In the Paleocene/Eocene there were major earth movements with the onset of sea floor spreading in the north Atlantic and mountain building in the Alps/Himalaya. In the North Sea, deposition of chalk continued until Early Paleocene. Uplift of basin margins, due to inversion, produced a series of submarine fans transported from the Shetland Platform towards the east. These sands interfinger with marine shales in both the Rogaland and the Hordaland Groups. In the Miocene a deltaic system had developed from the Shetland Platform towards the Norwegian sector of the North Sea, and is represented by the Skade and Utsira Formations. Due to major uplift and Quaternary glacial erosion of the Norwegian mainland, thick sequences were deposited into the North Sea during the Neogene. This led to burial of the Jurassic source rocks to depths where hydrocarbons could be generated and the seals were effective.



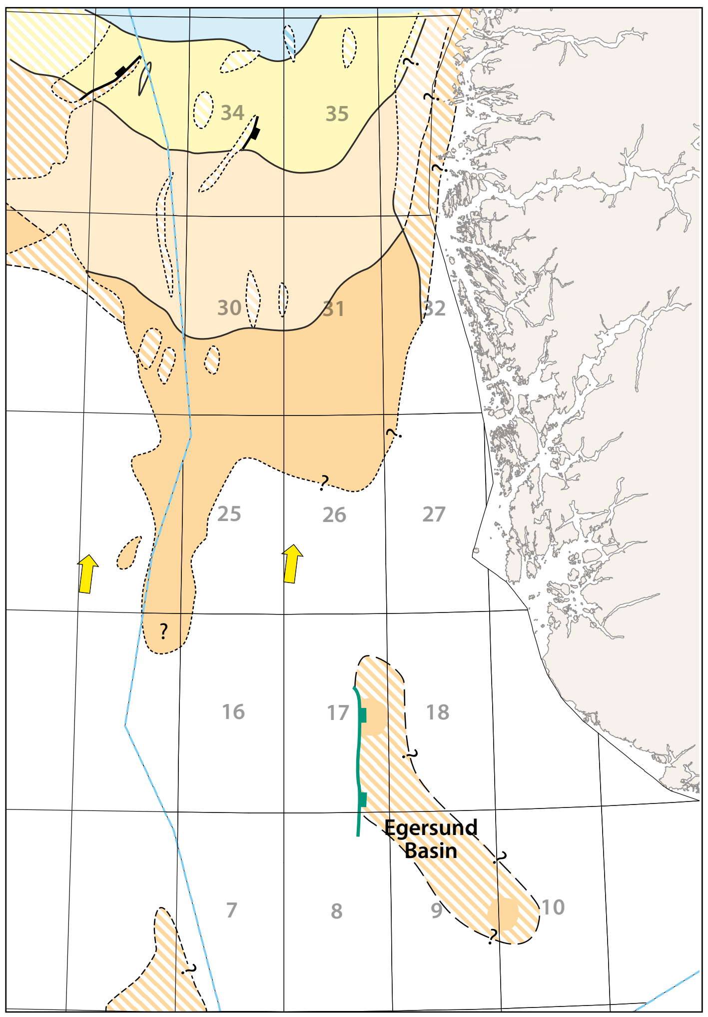


Geoseismic cross section in the northern North Sea. From the Millennium atlas 2001

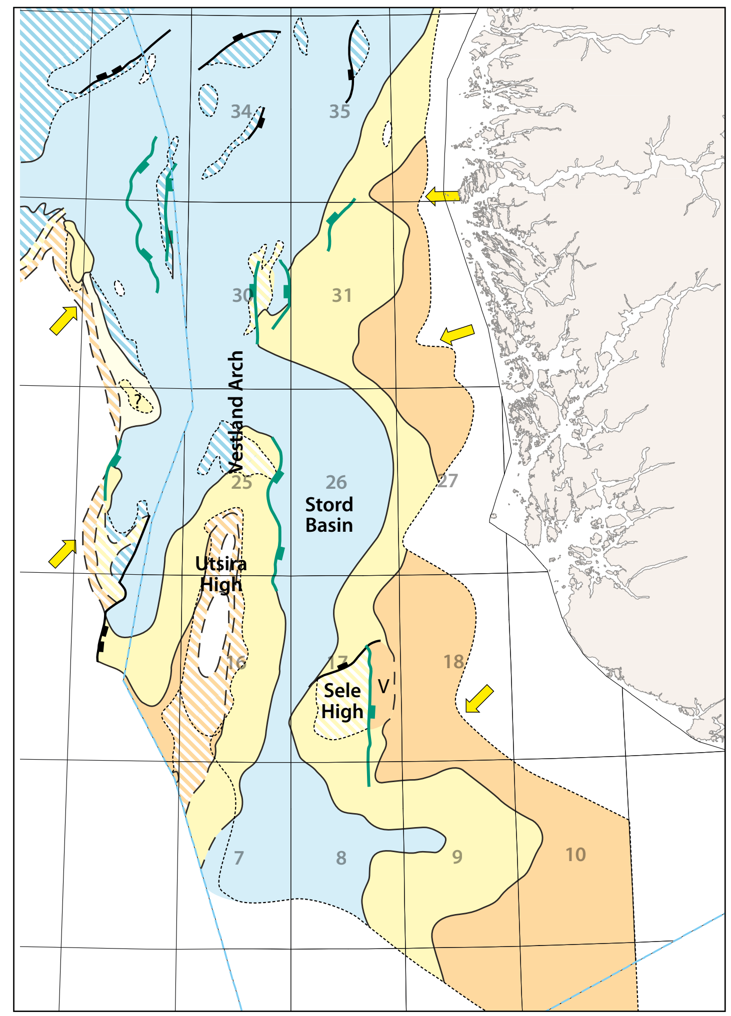


Geoseismic cross section in the Egersund basin. From the Millennium atlas 2001

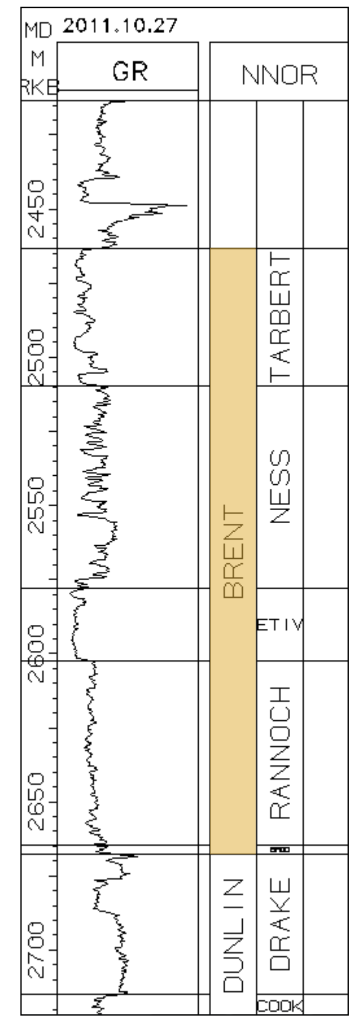
FACIESMAP Bajocian



FACIESMAP Mid- to late Callovian

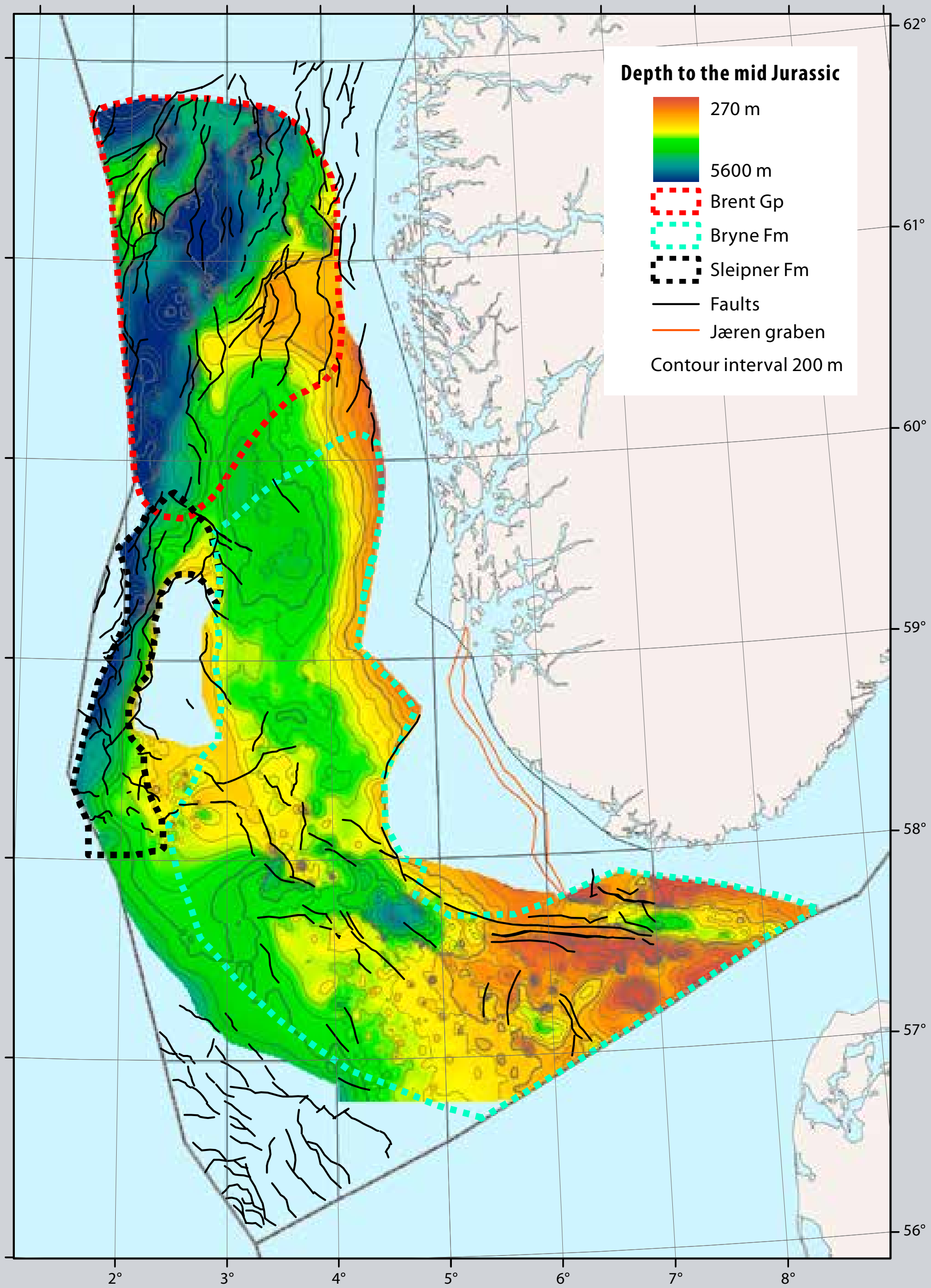


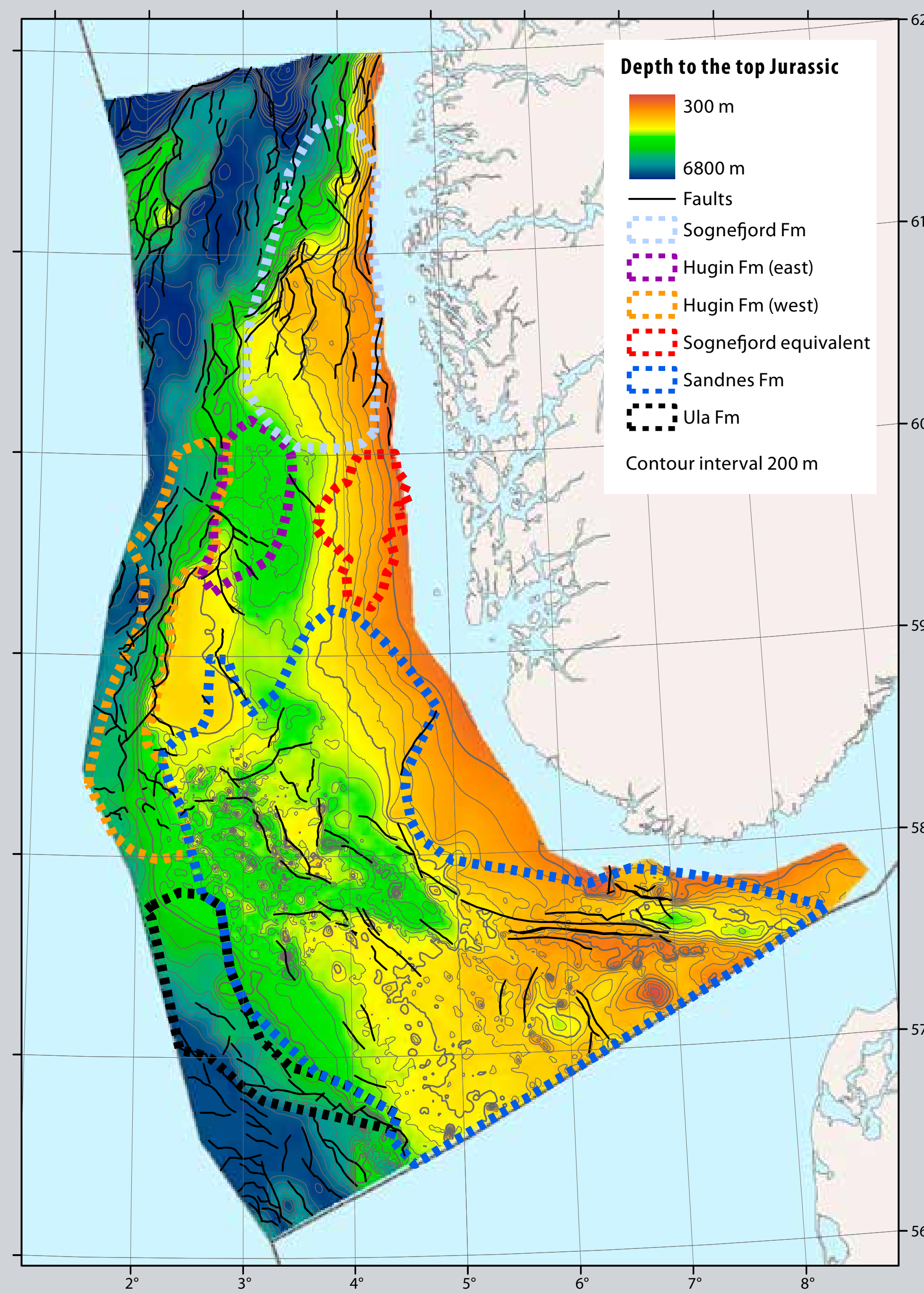
WELL LOG 33/9-1



Examples of mid Jurassic relationship between continental and marine deposits in central and northern North Sea. Continental sediments in brownish colour, shallow marine in yellow and offshore marine in blue.

The map to the left displays the development of the Brent delta and the early stage of the deposition of the Bryne Formation. The map to the right shows the development of the Sognefjord delta and the Sandnes and Hugin Formations after the Brent delta was transgressed.





Mapping of the upper and middle Jurassic forms the basis of many of the following depth and thickness maps of assessed geological formations.
The top Jurassic refers to the top of Upper Jurassic sandstones or their equivalents.

The Statfjord Group

Uppermost Triassic and Lower Jurassic
(Rhaetian to Sinemurian)

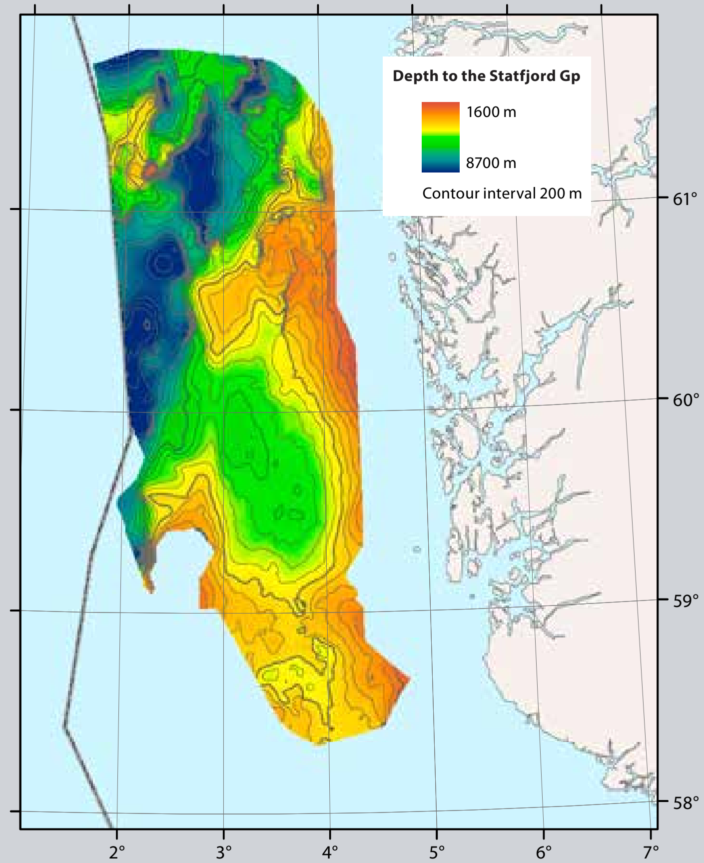
In the type well (33/12-2) the base of the Statfjord Gp is defined at the transition from the fining upward mega-sequence of the Lunde Fm and a coarsening upward mega-sequence of the Statfjord Gp. The Statfjord Gp is sub-divided into three formations (Raude, Eiriksson and Nansen). The upper boundary of the Statfjord Gp is sharp against the fully marine mudstones of the overlying Dunlin Group that could act as a regional seal.

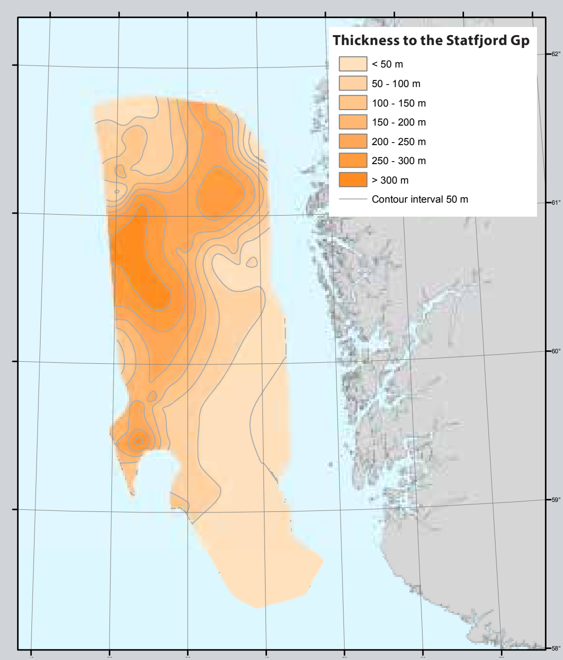
The Statfjord Gp can be recognized in the entire area between the East Shetland Platform to the west and the Øygarden Fault Complex against the Fennoscandian Shield to the east. To the south the Statfjord Gp has been recognized as far south as Norwegian blocks 25/8 and 11, and has not to date been identified north of the Tampen Spur. Thickness from wells in the type area varies from 140 m to 320 m. The Statfjord Gp displays large thickness variations due to regional differential subsidence as seen in a NW-SE traverse from the Tampen Spur to the Horda Platform. The Statfjord Group is relatively thin in the Tampen area (140 m). On the Snorre Field it increases across the Viking Graben and thins on the Horda Platform towards the Norwegian mainland.

Depositionally, the Statfjord Gp records the transition from a semi-arid, alluvial plain (Raude Fm) to dominantly fluvial sandstones (Eiriksson and Nansen fms) with occasional marine influence in the upper part (Nansen Fm). Generally the formation is buried in excess of 2000 m.

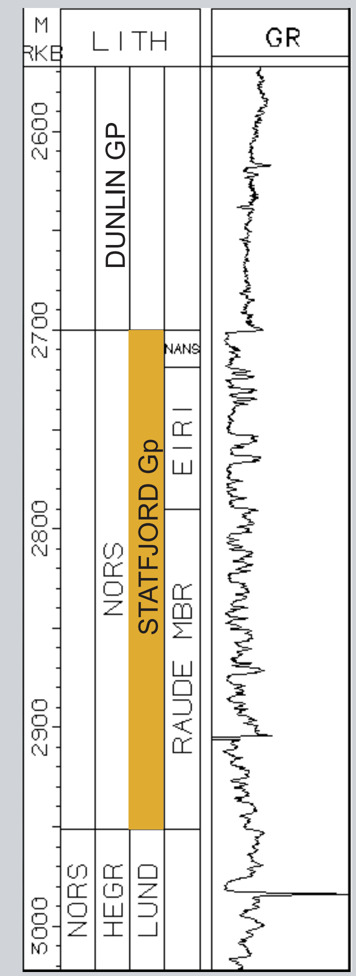
In the Snorre Field where the crest of the structure is 2335 m, porosities between 16-28% and permeabilities in the order of 250-4000 mD have been reported.

The Gassum Fm in the Norwegian-Danish Basin is time equivalent to the Statfjord Gp.





WELL LOG 33/12-2



Core photo well 34/7-13, 2873-2878 m

The Dunlin Group

Lower to Middle Jurassic
(Hettangian to Bajocian)

The Dunlin Gp represents a major marine transgressive sequence overlying the Statfjord Gp. It is divided into five formations; the Amundsen, Johansen, Burton, Cook and Drake fms. The type well is well 211/29-3 (British side), and well 33/9-1 is a Norwegian reference well. The Amundsen, Burton and Drake Fm are mainly silt and marine mudstones, while the Johansen and Cook fm are mainly marine/marginal marine sandstones. The upper boundary is the deltaic sequences of the Brent Gp.

The group is recognized over most of the East Shetland Basin, fringing the East Shetland Platform, and the northern part of the Horda Platform. To the south the Dunlin Gp has been recognized in wells as far south as 59ºN. In the type well, the thickness is 222 m and in the reference well the thickness is 255 m. The Dunlin Gp has its maximum thickness (possible 1000 m) in the axial part of northern Viking Graben, and a thickness of more than 600 m has been drilled in the western part of the Horda Platform (well 30/11-4).

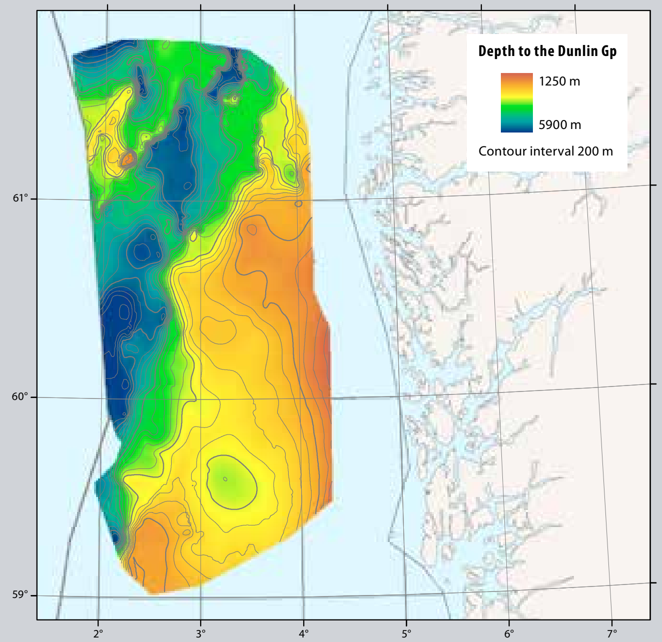
The Amundsen Fm (Sinemurian to Pliensbachian) contains mainly marine silts and mudstones deposited on a shallow marine shelf. It is distributed widely in the East Shetland Basin and in the northern Viking Graben, forming a seal to the underlying Statfjord Gp and possibly to the Johansen Fm.

The Johansen Fm (Sinemurian to Pliensbachian) sandstones split the Amundsen Fm in an area restricted to the eastern part of the Horda Platform (well 31/2-1), and the formation can be mapped northwards to approximately 600 N. The Johansen Fm is interpreted in terms of deposition on a high energy shallow marine shelf with sediment input from the east.

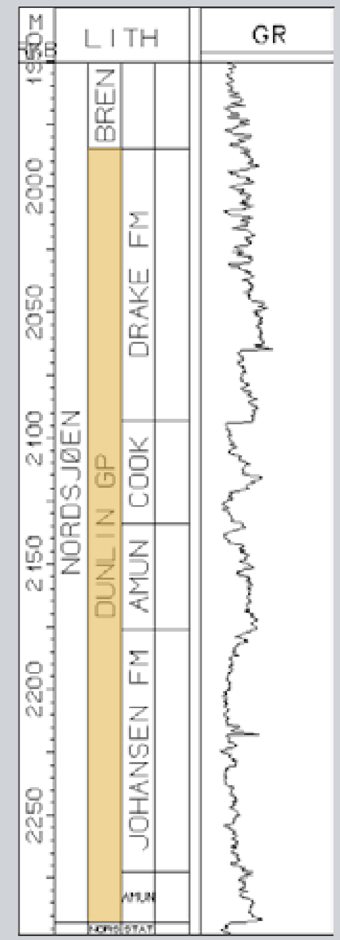
The Burton Fm (Sinemurian to Pliensbachian) is mainly marine mudstones that overlie the Amundsen Fm. This formation is found over most of the area, but it is not present on the Horda Platform. It forms mainly basinal facies and passes into the Amundsen Fm towards the margins.

The Cook Fm (Pliensbachian to Toarcian) is dominated by sandstone tongues that interfinger with the Drake mudstones at several distinct stratigraphic levels. Typically each of the sandstones are characterized by a lower zone of sharp-based, upward-coarsening shoreface sand and siltstones and an upper erosive surface consisting of thin tidal flat and thick deltaic/estuarine sandstones.

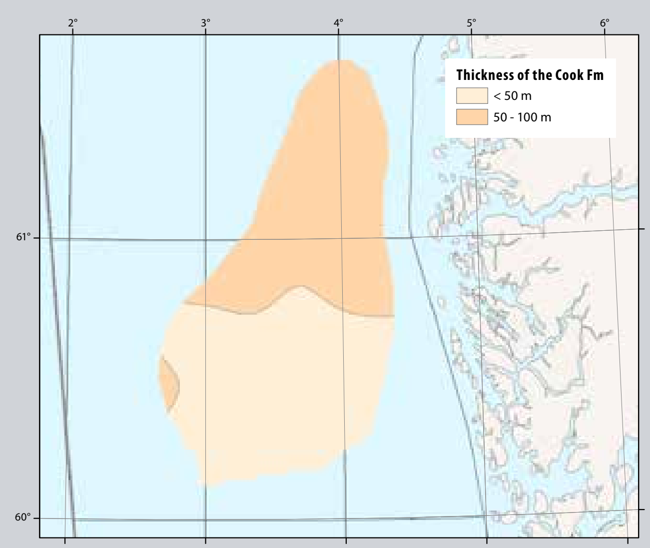
The Drake Fm (Toarcian to Bajocian) consisting of silt and mudstones were deposited during a continued rise in the relative sea level and the formation acts as a seal towards the underlying Cook sandstones. The upper boundary of the Drake Fm is marked by the more sandy sediments at the base of the deltaic Brent Group. Locally there is some sand towards the top of the Drake Fm. A time equivalent to the Dunlin Gp is the Fjerritslev Fm in the Norwegian–Danish Basin.



WELL LOG 31/2-1



Core photo well 34/4-5, 3427-3430 m



The Drake Fm (Toarcian to Bajocian) silts and mudstones were deposited during a continued rise in the relative sea level and the formation acts as a seal towards the underlying Cook sandstones. The upper boundary of the Drake Fm is marked by the more sandy sediments at the base of the deltaic Brent Group. Locally there is some sand towards the top of the Drake Fm.

A time equivalent to the Dunlin Gp is the Fjerritslev Fm in the Norwegian –Danish Basin.

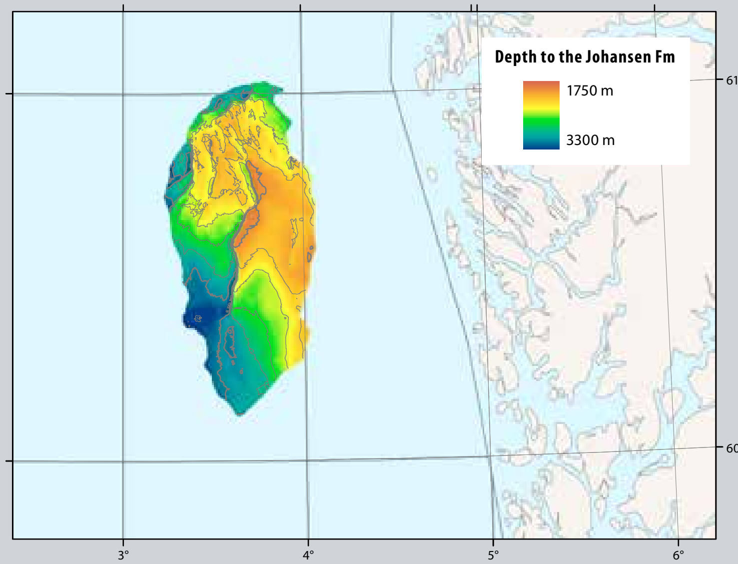
The Dunlin Group - Johansen Formation

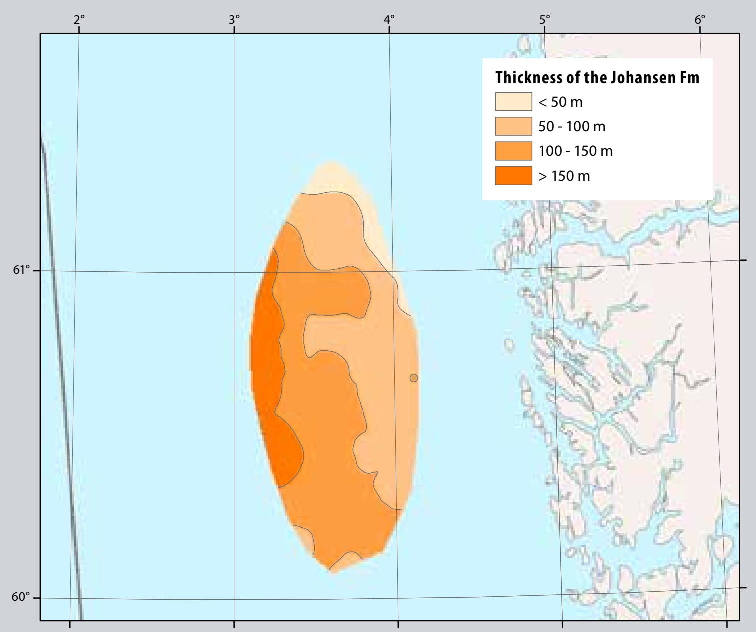
Lower Jurassic
(Sinemurian to Pliensbachian)

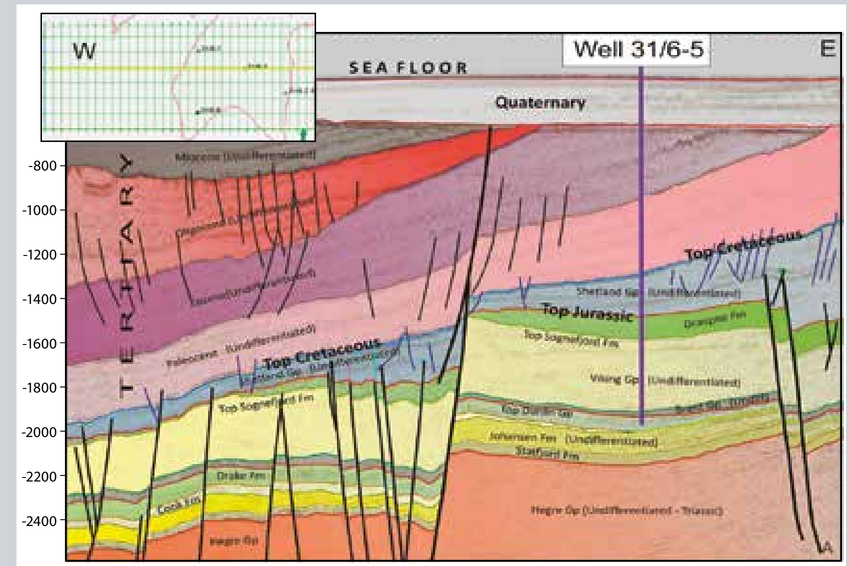
The Johansen Fm has its type area on the Horda Platform (type well 31/-2-1) where the sandstones in the formation interfingers with the marine silt and mudstones of the Amundsen Fm. Thus, the Amundsen Fm might act as a seal for the Johansen Fm.

The Johansen Fm is found in a restricted area extending from the eastern part of the Horda Platform and north towards 62°N.The thickness in the type well is 96 m. In an E-W traverse on the northern part of the Horda Platform the formation thickens to the west towards the northern Viking Graben, where thicknesses in excess of 200 m have been drilled (well 30/11-4). Towards the east the formation thins into a thickness of some tens of meters towards the Øygarden Fault Complex. The Johansen Fm was probably deposited in a high energy shallow marine shelf with sediment input from the East.

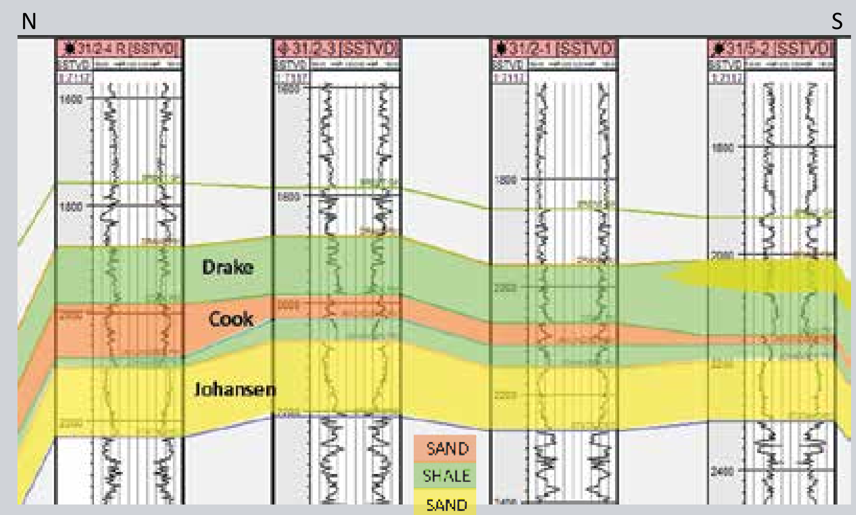
Generally the formation is buried to a depth of more than 2000 m, increasing towards the West into the northern Viking Graben area. In the Troll Field, where the crest of the Johansen Fm is approximately at 2300 m depth, porosity and permeability is in the order of 15-24% and 100-1000 mD respectively.







Gassnova



Core photo well 31/2-3, 2116-2118 m

The Brent Group

Uppermost Lower Jurassic to Middle Jurassic (Upper Toarcian–Bajocian)

The Brent Gp has its type area in the East Shetland Basin and contains five formations; the Broom, Rannoch, Etive, Ness and Tarbert Fm. On the Horda Platform, the Oseberg Fm is defined as part of the Brent Gp. Type and reference well for the Brent Gp is well 211/29-3 (UK) and well 33/9-1. For the Oseberg Fm the type well is 30/6-7. The lower boundary is the marine silts and mudstones of the Dunlin Gp. The upper boundary is the Heather/Draupne Fm marine mudstones of the Viking Group, forming a regional seal.

The Brent Gp is found in the East Shetland Basin and is recognizable over most of the East Shetland Platform and the northern part of the Horda Platform. South of the Frigg area, broadly equivalent sequences to the Brent Gp are defined as the Vestland Group. To the North, the deltaic rocks of the Brent Gp shales out into marine mudstones between 61°30´N and 62° N. The thickness of the group varies considerably due to differential subsidence and post Middle Jurassic faulting and erosion. Variable amounts of the group may be missing, particularly over the crests of rotated fault blocks.

The deposition of the Brent Gp records the outbuilding of a major deltaic sequence from the south and the subsequent backstepping or retreat. The Oseberg sandstones form a number of fan-shaped sand-bodies with a source area to the east. The sandstones in the lower part are deposited in a shallow marine environment, overlain by more alluvial sands and capped by sand which has been reworked by waves.

Due to the Upper Jurassic faulting, uplift/erosion and differential subsidence, the Brent Group is located at a wide range of depths, varying from 1800 m on the Gullfaks Field to more than 3500 m on the Huldra Field. As a result there is a complex distribution of porosity and permeability.

The Broom Fm (Upper Toarcian to Bajocian) is thin and locally developed. It consists of shallow marine, coarse-grained and poorly sorted conglomeratic sandstones and is a precursor for the regressive sequence of the overlying Rannoch Fm.

The Rannoch Fm (Upper Toarcian to Bajocian) in the type area is well-sorted very micaceous sandstones, showing a coarsening upwards motif, deposited as delta front or shoreface sands. The upper boundary is defined by cleaner sandstones of the overlying Etive Fm. The thickness of the Rannoch Fm in the type area varies between 35 and 63 m.

The Etive Fm (Bajocian) contains less micaceous sandstones than the underlying Rannoch Fm. The upper boundary is the first significant shale or coal of the overlying Ness Fm. The depositional environment for the Etive Fm is interpreted as upper shoreface, barrier bar, mouth bar and channel deposits. The thickness of the formation varies considerably from 11 m to more than 50 m.

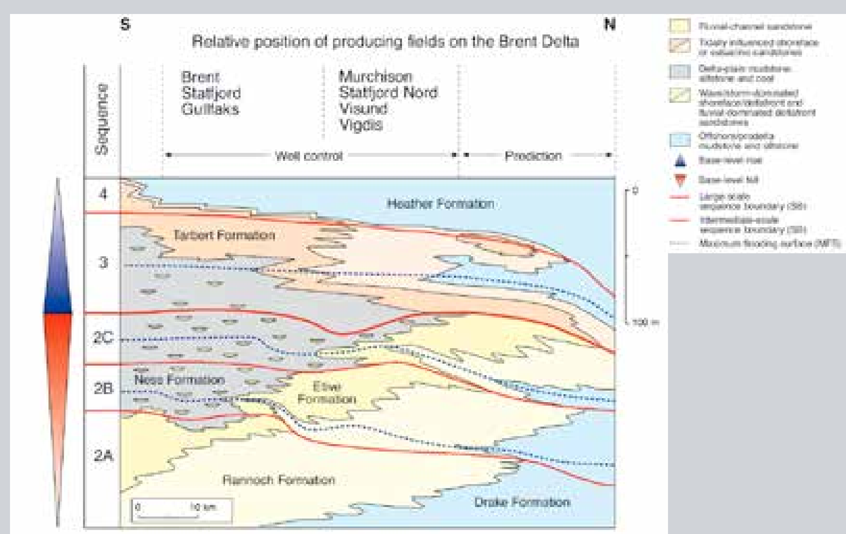
The Ness Fm (Bajocian to Bathonian) consists of an association of coals, mudstones, siltstones and fine to medium sandstones. Characteristic features are numerous rootlet horizons and a high carbonaceous content. The upper boundary is the change to the more massive and cleaner sandstones of the overlying Tarbert Fm. The formation is interpreted to represent delta plain or coastal plain deposition. The amount of silt and mudstones in the formation may act as a local seal. The Ness Fm shows large thickness variations ranging from 26 m up to about 140 m.

The Tarbert Fm (Bajocian to Bathonian) consists of grey to brown sandstones. The base of the formation is taken at the top of the last fining upward unit of the Ness Fm, either a coal-bearing shale or a coal bed. It is deposited in a marginal marine environment. Thickness in the type area varies between 14 and 45 m.

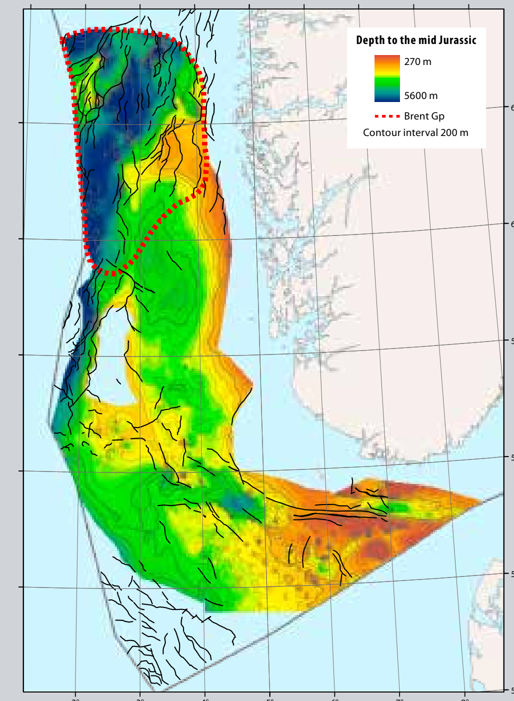
The Oseberg Fm (Upper Toarcian to Lower Bajocian) consists of relatively homogenous coarse-grained sandstones defined from the Oseberg Field (block 30/6) between the Viking Graben and the Horda Platform. The base of the formation is shales of the Dunlin Gp and the upper boundary is the micaceous sandstones of the Rannoch Fm. The formation has been correlated with various formations of the Brent Group, but whereas the Brent Group forms a deltaic unit building out from the south, the Oseberg Fm has its source area to the east. The thickness in the type area is between 20-60 m. The sandstones in the lower part are deposited in a shallow marine environment, overlain by alluvial sands and capped by sand reworked by waves.

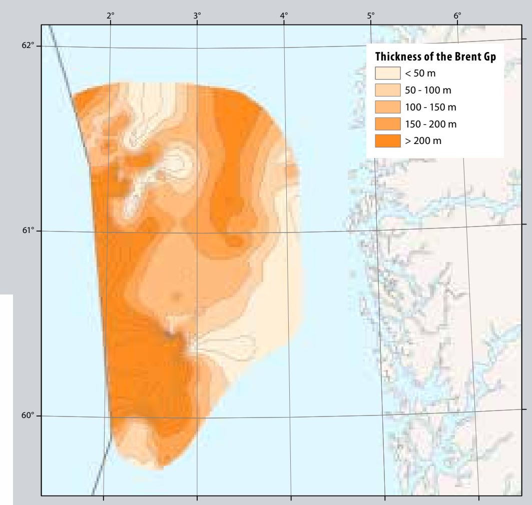
Burial depth of the Oseberg Fm varies between 2100 and 2800 m and porosities and permeabilities in the order of 23-26% and 250-2000 mD, respectively, are reported.

A time equivalent to the Brent Gp is the Vestland Gp which is defined in the southern part of the Norwegian North Sea.



Cross section through the Brent delta





Core photo well 30/6-7, 2679-2683 m (Ness Fm)

The Viking Group

Upper Middle Jurassic to Upper Jurassic / Lower Cretaceous (Bathonian to Ryazanian)

The Viking Gp has its type area in the northern North Sea north of 58°N and east of the East Shetland Platform boundary fault. The Viking Gp is subdivided into five formations: the Heather, Draupne, Krossfjord, Fensfjord and the Sognefjord Fms. The lower boundary is marked by finer-grained sediments deposited over the sandy lithologies of the Brent and Vestland gps. In the northernmost area, where the Brent Gp is missing, the Viking Gp often sits unconformably on the Dunlin Gp. The upper boundary is, over most of the area, an unconformity overlain by low radioactive Cretaceous to Paleocene sediments.

The Heather and Draupne Fms are regionally defined and contain mainly silt and mudstones. The Draupne Fm in particular contains black mudstone with very high radioactivity due to high organic carbon content. The Krossfjord, Fensfjord and Sognefjord Fms represent more sandy facies and are restricted to the Horda Platform and northwards towards 62°N.

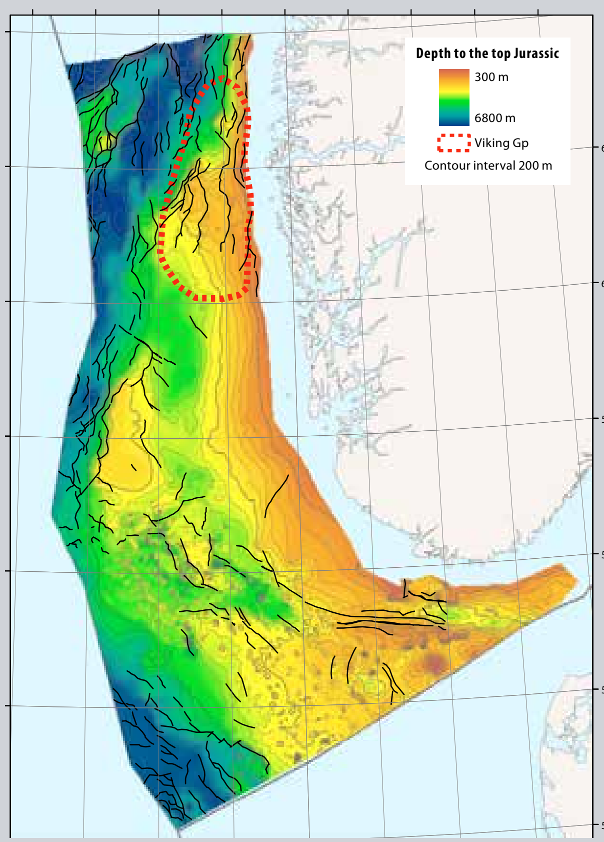
The thickness of the group varies considerably since the sediments were deposited on a series of tilted fault blocks, reflecting pre and syn-depositional fault activity and differential subsidence. The thicknesses in wells vary from a few meters up to 1039 m.

The Heather Fm (Upper Middle Jurassic to Upper Jurassic), overlying the Brent Gp sandy sequences, consists of mainly grey silty claystones, deposited in an open marine environment. The type well for the Heather Fm is well 211/21-1A (UK) and 33/9-1. The upper boundary is the radioactive and carbonaceous Draupne Fm.

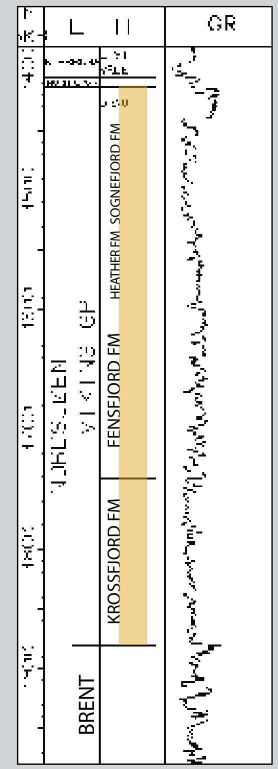
The Draupne Fm (Upper Jurassic/Lower Cretaceous) overlies the Heather Fm diachronically, and on the northern part of the Horda Platform, the formation overlies the sandstones of the Sognefjord Fm (type well 30/6-5). The Draupne Fm was deposited in a marine environment with restricted bottom circulation, often with anaerobic conditions. This led to the most prolific hydrocarbon source in the northern North Sea. Time-wise and environmentally, the Draupne Fm is equivalent to the UK Kimmeridge Clay Fm and the Tau Fm of the Norwegian-Danish Basin.

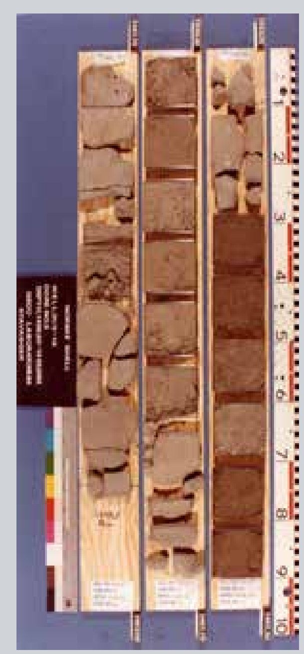
The Krossfjord Fm (Upper Middle Jurassic, Bathonian), the Fensfjord Fm (Upper Middle Jurassic, Callovian) and the Sognefjord Fm (Upper Jurassic, Oxfordian to Kimmeridgian) represent three coastal-shallow marine sands that interfinger with the Heather Fm on the gigantic Troll Field on the northern part of Horda Platform. The type well is 31/2-1. The total thickness of the three formations is in the order of 400-500 m. Each of the formations has been interpreted in terms of a “forestepping to backstepping” rift marginal wedge. This pattern has been interpreted as the response to eustatic sea-level changes or basin-wide changes in sediment supply, but also as a response to three separate rift events.

The burial depth varies from 1500-1600 m on the Horda Platform to more than 3500 m in the Sogn Graben. Porosities and permeabilities in the order of 19-34% and 1-1000 mD, respectively, have been reported from the Troll Field. The abundance of detrital mica in the sands is important in controlling the permeability.

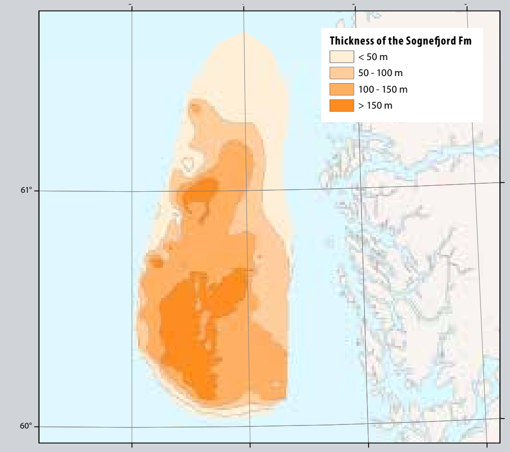


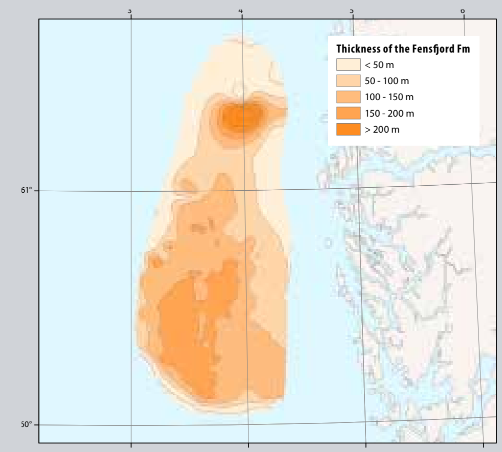
WELL LOG 31/2-1

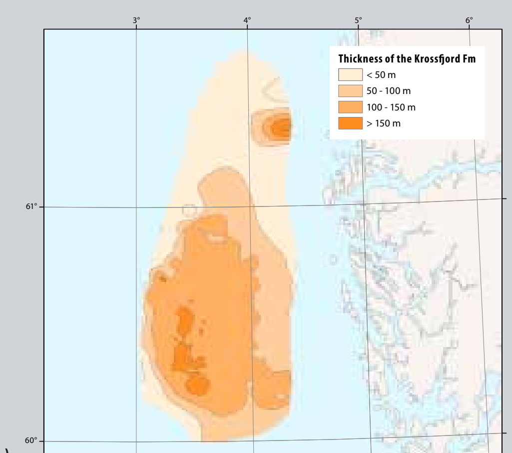




Core photo well 31/2-1R, 1459-1462 m (Sognefjord Fm)







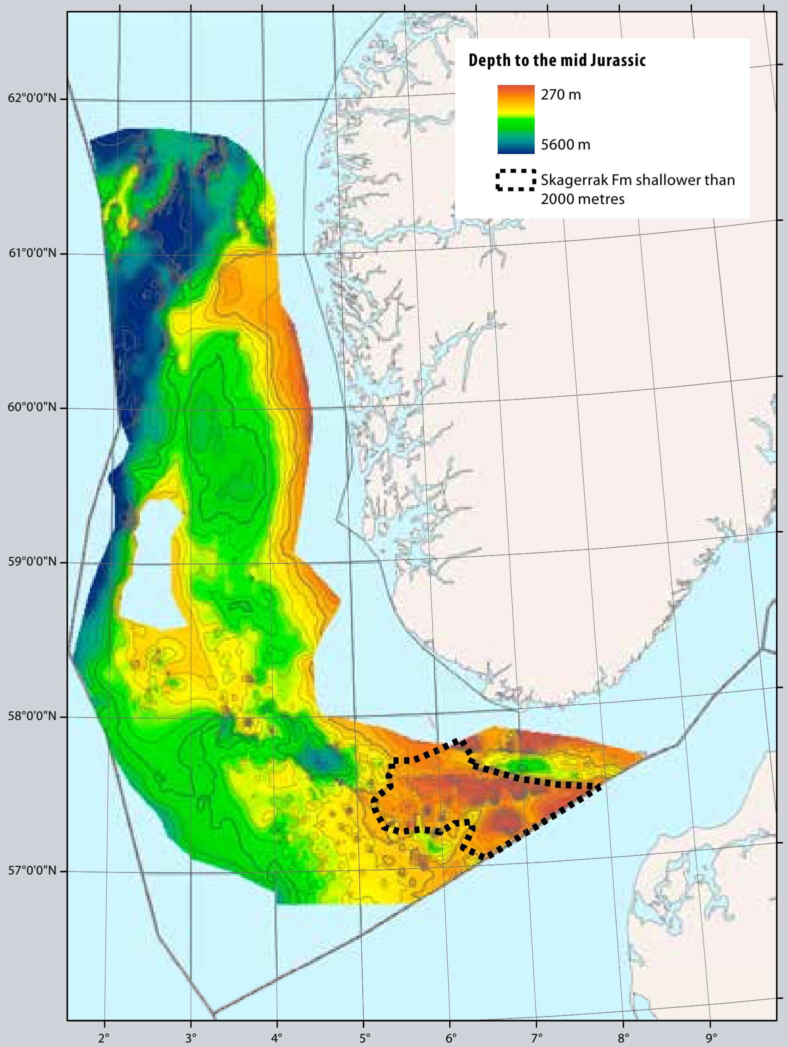
The Hegre Group - Skagerrak Formation

Middle to Upper Triassic

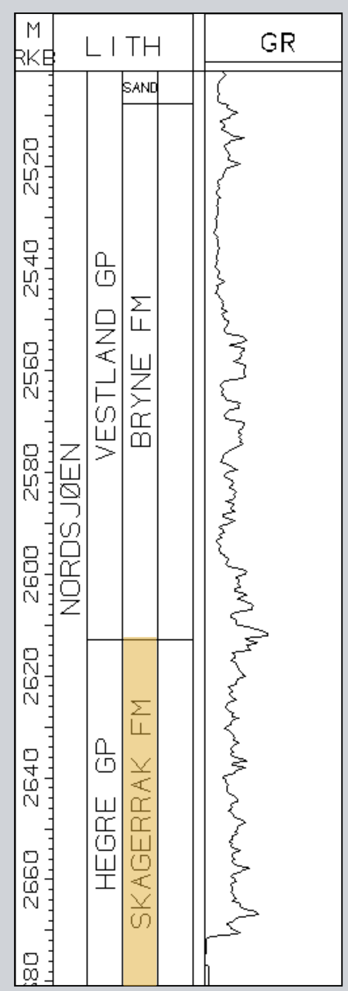
The Skagerrak Fm is present throughout the eastern part of the Central North Sea and the western Skagerrak, but may be missing over structural highs due to erosion and/or halokinesis. The type section is defined in well 10/8-1 in the eastern part of the Norwegian-Danish Basin. The base of the formation is sharp or gradational over claystones of the Smith Bank Fm. Over structural highs the formation may rest on pre-Triassic rocks. The upper boundary is normally an unconformity and overlain by Jurassic or younger sediments, but in a few wells it passes up into the Gassum Fm, a time equivalent to the Statfjord Gp of the northern North Sea.

The thickness in the type well is 1182 m, but based on seismic data a maximum thickness in excess of 3000 m is indicated further to the east. To the north-west and south-west, well control indicates a maximum thickness in the order of 660 and 250 m respectively.

The sediments were mainly deposited in alluvial fans and plains in a structurally controlled basin. Minor marine incursions are reflected by the local occurrence of glauconite in the uppermost part of the formation.
The burial depth of the formation in general exceeds 1500 m in western Skagerrak and more than 3000 m in the Egersund and Farsund basins. Porosity and permeability calculations shows mean values of 12.8% and <10 mD, respectively.



WELL LOG 9/4-3



Core photo well 15/6-7, 3414-3419 m

The Gassum and Fjerritslev Formations

Uppermost Triassic to Lower Jurassic
(Rhaetian in the west, Hettangian-Sinemurian in the northeast)

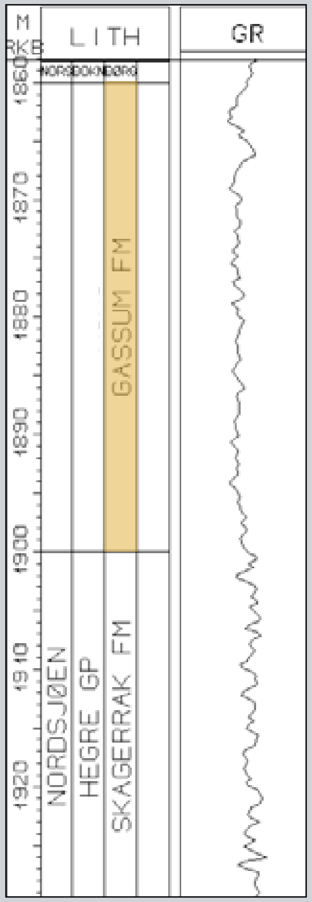
The Gassum Fm is defined from the Danish well No 1, and in the Norwegian-Danish Basin, well 17/10-1 is used as the reference well. The base of the formation is the Skagerrak Fm and the upper boundary is often the Lower Jurassic shales of the Fjerritslev Fm. In well 11/10-1 the Gassum Fm is overlain by marine silts and mudstones of the Boknfjord Gp forming a regional seal.

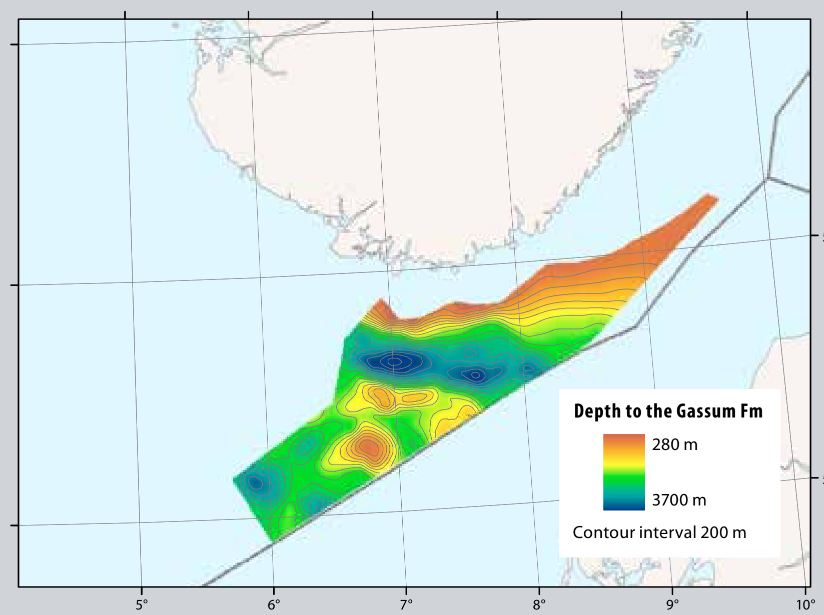
The formation is considered to occur throughout the Norwegian-Danish Basin, on the Sørvestlandet High and along the north-eastern margin of the Central Graben. In the Danish part of the basin, the thickness of the Gassum Fm varies from 50 m to more than 300 m northeast of the Fjerritslev Fault Complex. The distribution of the formation in the Norwegian part of the basin is more ambiguous because few wells have penetrated the unit. However, very often the wells are located on top or on the flanks of salt structures where the Gassum Fm most likely has been removed by erosion due to halokinesis and/or in relation to the mid-Jurassic erosional episode. Seismic profiles may indicate that the Gassum Fm is present in the Farsund Basin and sub-basins south of the Fjerritslev Fault Complex. Further to the west the formation is absent or below seismic resolution.

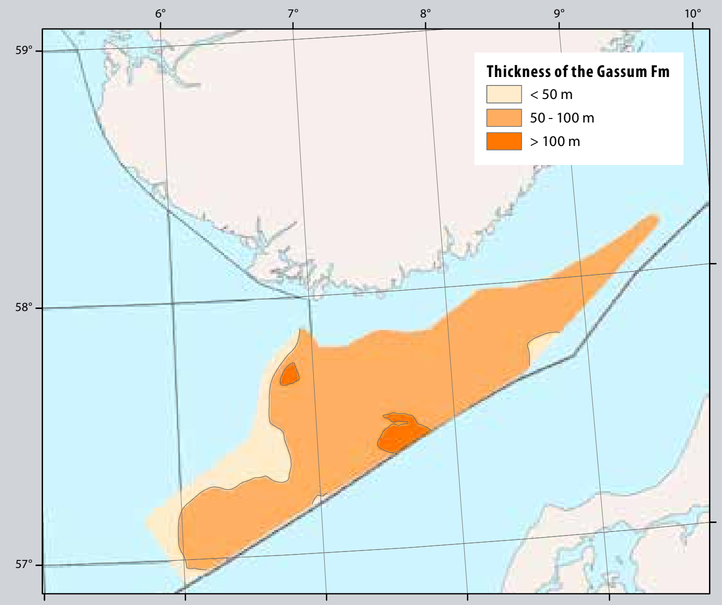
The formation represents deposition in fluvio-deltaic, deltaic and shoreface environments influenced by repeated sea level fluctuations. The mean burial depth exceeds 2000 m in the Norwegian part of the basin, but is less than 1500 m over structural highs, e.g. salt structures. Porosity and permeability calculations are based on Danish well data and show mean values of 20.3% and 400-500 mD, respectively. A time equivalent to the Gassum Fm is the Statfjord Gp in northern North Sea.

The Fjerritslev Fm is predominantly a silt and mudstone sequence. The type section of the formation is defined in the Fjerritslev-2 well. The lower boundary is defined at an abrupt change from sandy deposits of the Gassum and Skagerrak Fms to the claystones of the Fjerritslev Fm that may form a regional seal. The upper boundary is the overlying Middle to Upper Jurassic sandstones of the Haldager Fm. The formation is present over most of the Danish part of the Norwegian-Danish Basin. The thickness of the formation may exceed 1000 m locally, but is very variable due to basin relief, halokineses and mid-Jurassic erosion. In the Norwegian part of the basin the formation is discontinuous. However, similar to the Gassum Fm, seismic profiles reveal intervals, locally more than 300 m thick, which are thinning out or become truncated toward the flanks of salt structures. The formation represents deposition in a deep offshore to lower shoreface environment.

WELL LOG 11/10 1







The Vestland Group

Middle Jurassic to Upper Jurassic
(Bajocian to Volgian)

The Vestland Gp is divided into five formations: The Sleipner, Hugin, Bryne, Sandnes and Ula Fms.

The lower boundary is the Lower Jurassic mudstones of the Dunlin Gp or the Fjerritslev Fm and the upper boundary is defined by the incoming of mudstone-dominated sequences: The Viking Gp in the Southern Viking Graben, the Tyne Gp in the Central Graben and the Boknfjord Gp in the Norwegian-Danish Basin. These mudstone-dominated groups are important as regional seals.

The Vestland Gp is widely distributed in the southern part of the Norwegian Sea. The Sleipner and Hugin fms are defined from the Southern Viking Graben fringing the Utsira High. The Bryne Fm is defined from the Central Graben and the Norwegian-Danish Basin, the Sandnes Fm from the Norwegian Danish Basin and the Ula Fm from the western margin of the Sørvestlandet High. The thickness of the group varies considerably, from 123 to more than 450 m reported from wells. Seismic mapping indicate greater thicknesses in syn-sedimentary fault-bounded sub-basins related to halokinesis. On structural highs the group or part of the group may be missing due to erosion.

The depositional environment varies from deltaic coal-bearing, silt and shale sequences at the base with more marine-influenced sands in deeper parts of the basin. The upper part of the group consists mainly of fairly clean marine sands.

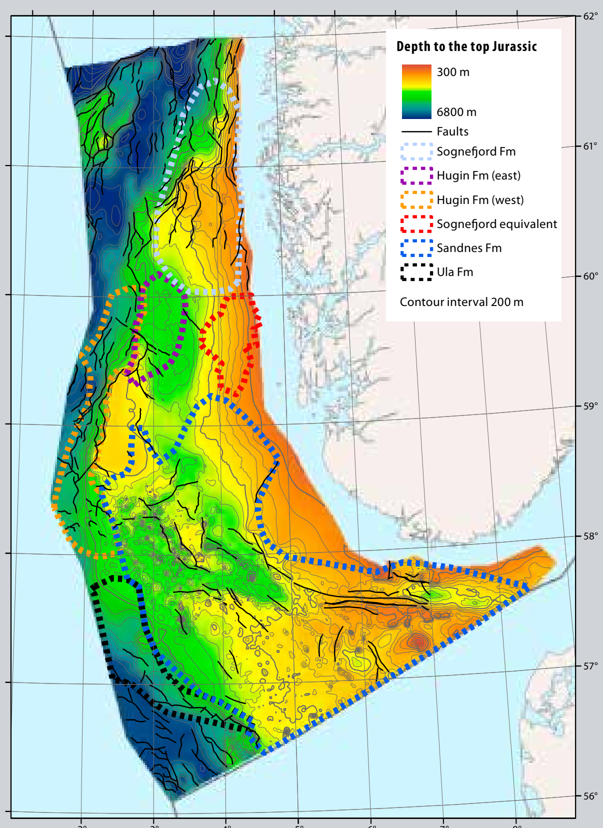
The Sleipner Fm is defined in the southern Viking Graben between approximately 580 and 600N, in a fluvio-deltaic coaly setting. The Fm is broadly equivalent to the Ness Fm of the Brent Gp in the East Shetland Basin. Thickness in the type area varies between 40 and 50 m. Non-marine sands of equivalent age in the Central Graben and Norwegian-Danish Basin are referred to as the Bryne Fm.

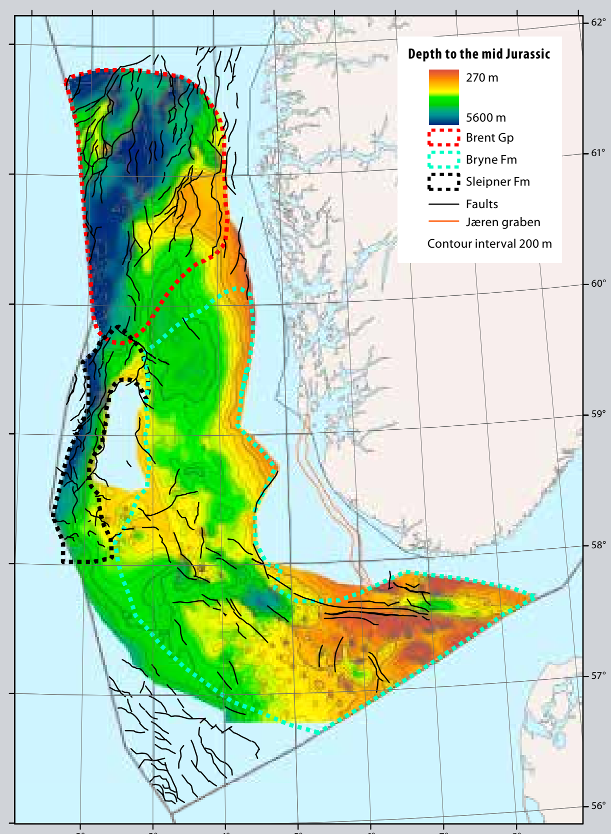
The Hugin Fm, overlying the Sleipner Fm, represents mainly a near-shore, shallow marine sandstone. The Fm is located in the southern Viking Graben in the northern part of the Sørvestlandet High. The upper boundary of the formation represents a transition into silt and mudstones of the Viking Gp. Thicknesses, according to wells in the type area, are in the order of 50 to 170 m.

The Bryne Fm is defined from the Norwegian-Danish Basin and Central Graben, representing a fluvial/deltaic environment. The base of the Fm is the partly eroded shales of the Fjerritslev Fm or Triassic sandy rocks. The top is defined by siltstones and mudstones of the Boknfjord Gp, forming a regional seal.

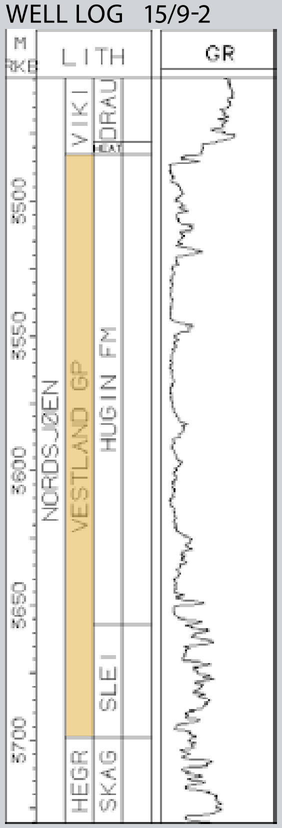
The Sandnes Fm is defined from the northern part of the Åsta Graben and Egersund Basin representing a coastal/shallow marine environment. The contact with the underlying Bryne Fm or older rocks is usually an unconformity and it is overlain by siltstones and mudstones of the Boknfjord Gp.

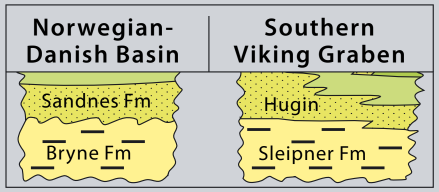
The Ula Fm is defined around the eastern highs flanking the Central Graben and represents a shallow marine deposit. The base of the Fm is towards the non-marine Bryne Fm, and the top is where the marine sands are overlain by the silts and mudstones of the Tyne Gp.





WELL LOG 15/9-2





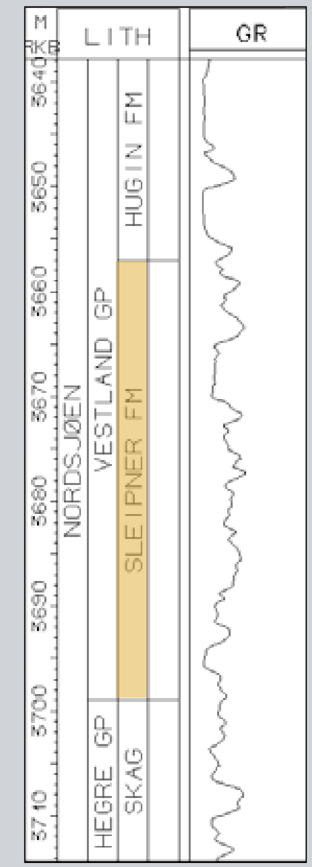
The Vestland Group - Sleipner Formation

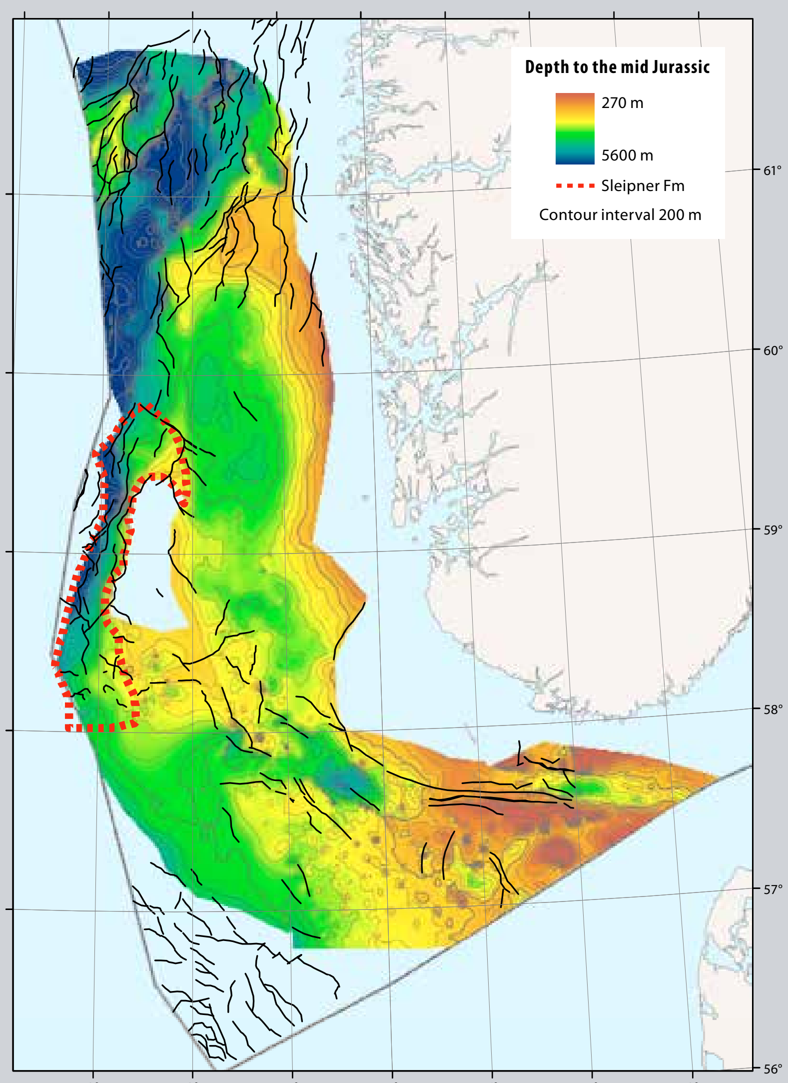
Middle Jurassic (Bajocian to Early Callovian)

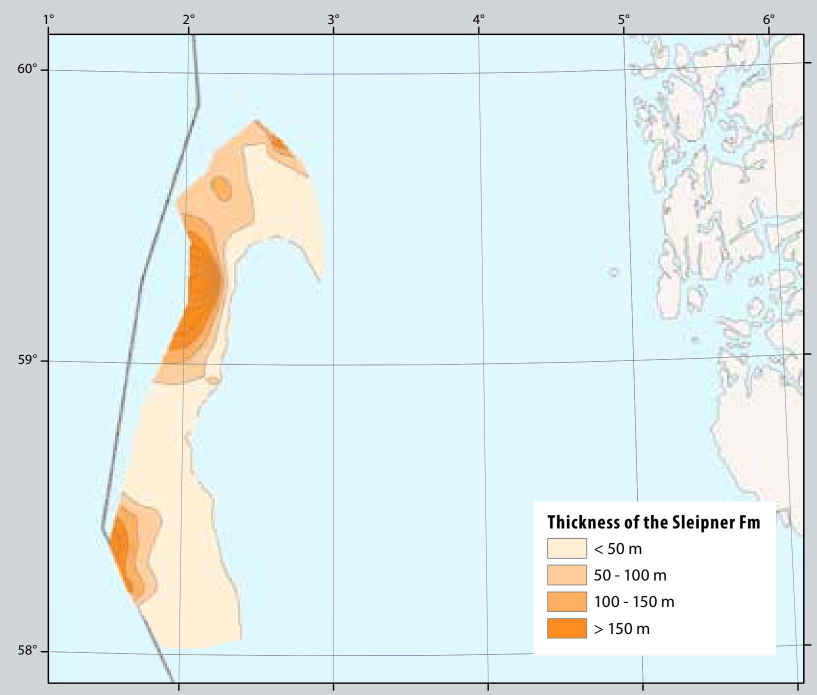
The Sleipner Fm is defined at the base of the Vestland Gp in the southern Viking Graben. The formation lies unconformably over Lower Jurassic and older rocks. The upper boundary in the type well (15/9-2) is the sands of the Hugin Fm, but the formation can also be overlain by shales of the Viking Gp.

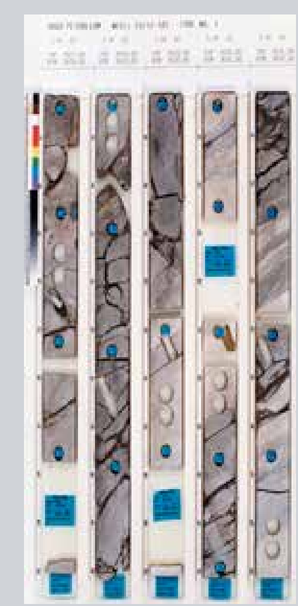
The Sleipner Fm is found in the southern Viking Graben between approximately 580 and 600N, and is broadly equivalent to the Ness Fm of the Brent Gp in the northern North Sea. The name Sleipner Fm should be applied when the marine sandstones underlying the coal-bearing sequence is missing. Non-marine sands of equivalent age in the Central Graben and the Norwegian-Danish Basin are defined as the Bryne Fm. Thickness in the type area varies between 40 and 50 m. The Sleipner Fm represents a continental fluvio-deltaic coal-bearing sequence. Burial depth of the formation over the Sleipner West Field is approximately 3400 m and average porosities and permeabilities of 16-20% and 0.1-4000 mD, respectively, are reported.

WELL LOG 15/9-2









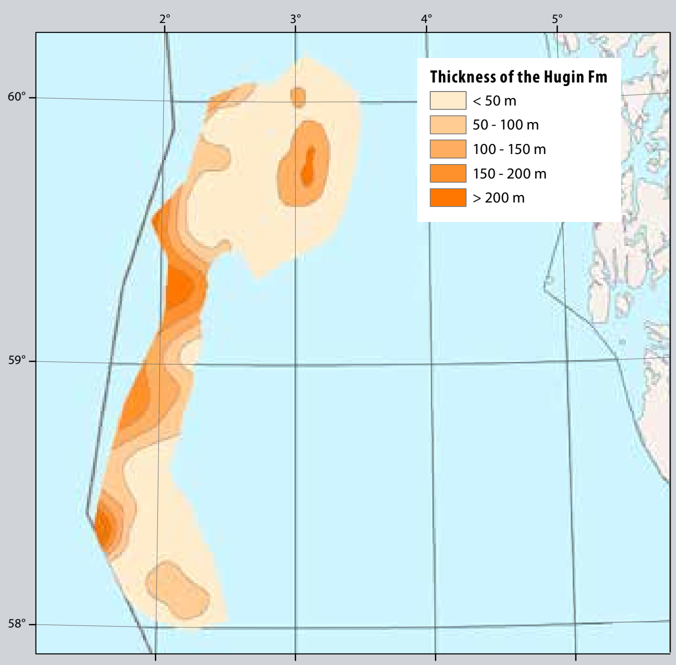
Core photo well 15/12-10 S, 3427-3432 m

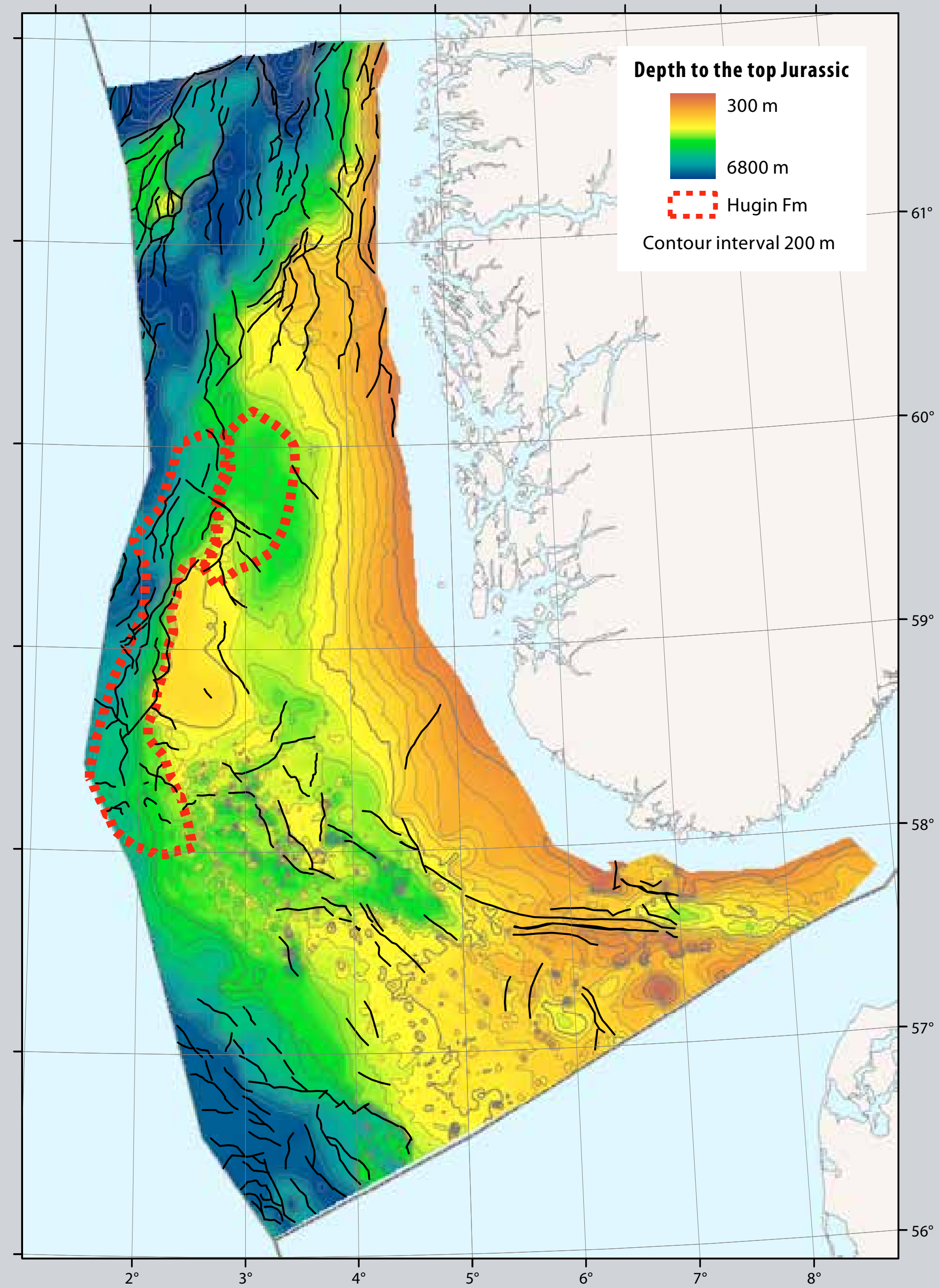
The Vestland Group - Hugin Formation

Middle Jurassic to Upper Jurassic
(Lower Bathonian to Lower Oxfordian)

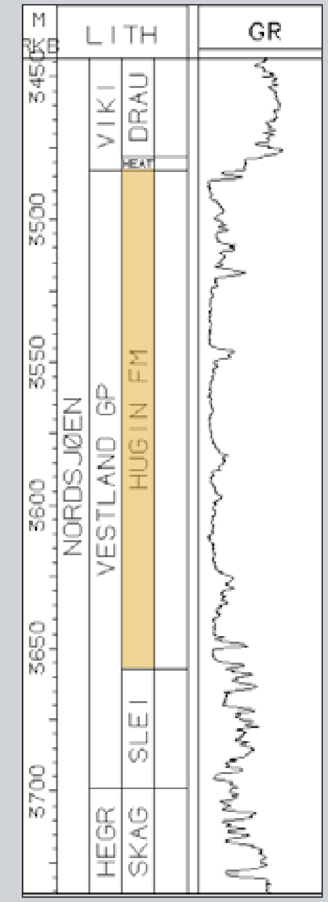
The Hugin Fm is found in the southern Viking Graben in the northwestern part of the Sørvestlandet High, where it overlies the deltaic coal-bearing Sleipner Fm. The upper boundary is the shales of the Viking Gp.

Thickness in the type well 15/9-2 is 174 m. Generally the thickness decreases to the east and north. The thickness distribution of the Hugin Fm is partly controlled by salt tectonics. The depositional environment is interpreted in terms of a near-shore, shallow marine environment with some continental fluvio-deltaic influence. Burial depth of the formation over the Sleipner West Field is approximately 3400 m and reported average porosities and permeabilities is in the range between16-20% and 0.1-4000 mD, respectively.





WELL LOG 15/9-2



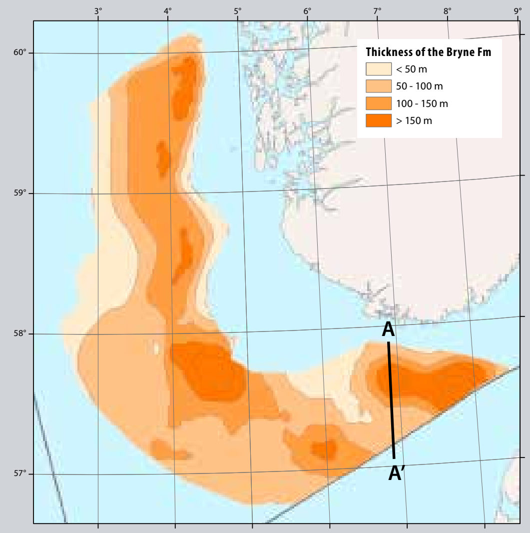
Core photo well 25/2-15R2, 3574-3579 m

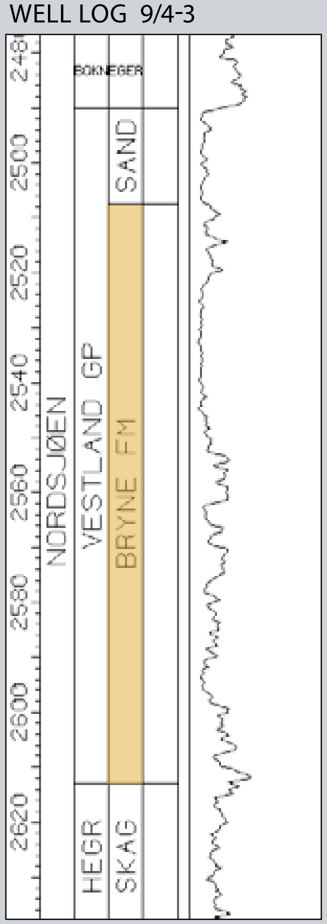
The Vestland Group - Bryne Formation

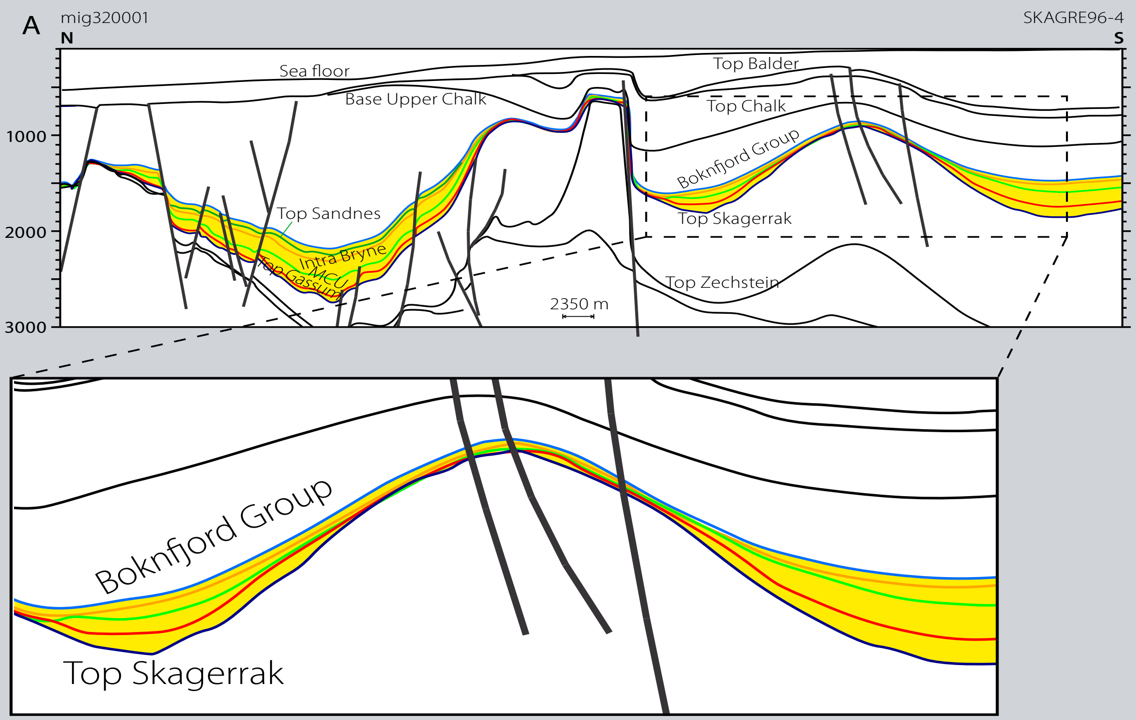
Middle Jurassic (Bajocian to Early Callovian)

The Bryne Fm forms the base of the Vestland Gp in the Norwegian-Danish Basin and in the Central Gaben. The lower boundary represents an unconformity, with partly eroded shales of the Fjerritslev Fm or with Triassic rocks below. The upper boundary is siltstones and mudstones of the Boknfjord Gp that could form a regional seal. The type section for the formation is defined in well 9/4-3 with a thickness of 106 m. The formation is thin and patchy in western Skagerrak, but the seismic indicates thicknesses of several hundred meters in syn-sedimentary fault-bounded sub-basins, e.g. Egersund and Farsund Basins, and local depocentres south of the Fjerritslev Fault Zone.

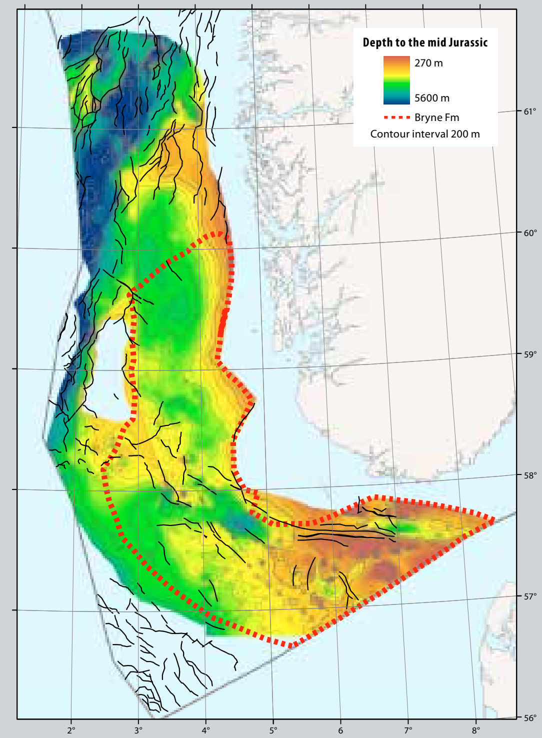
The Bryne Fm reflects deposition in fluvial, deltaic and lacustrine environments. Shallow marine environments may in periods have prevailed in the fault-controlled sub-basins. The burial depth is in general more than 1500 m, except over structural highs where it may be less than 1000 m. In the Egersund Basin the burial depth exceeds 3000 m. Porosity and permeability calculations show mean values of 20.4% and 100-200 mD, respectively. The formation corresponds to the Haldager Fm in the Danish part of the Norwegian-Danish Basin.







The enlarged rectangle shows the Jurassic section within a salt-induced structure.
MCU is the base of the Bryne Formation.



Core photo well 3/7-4, 3479-3483 m

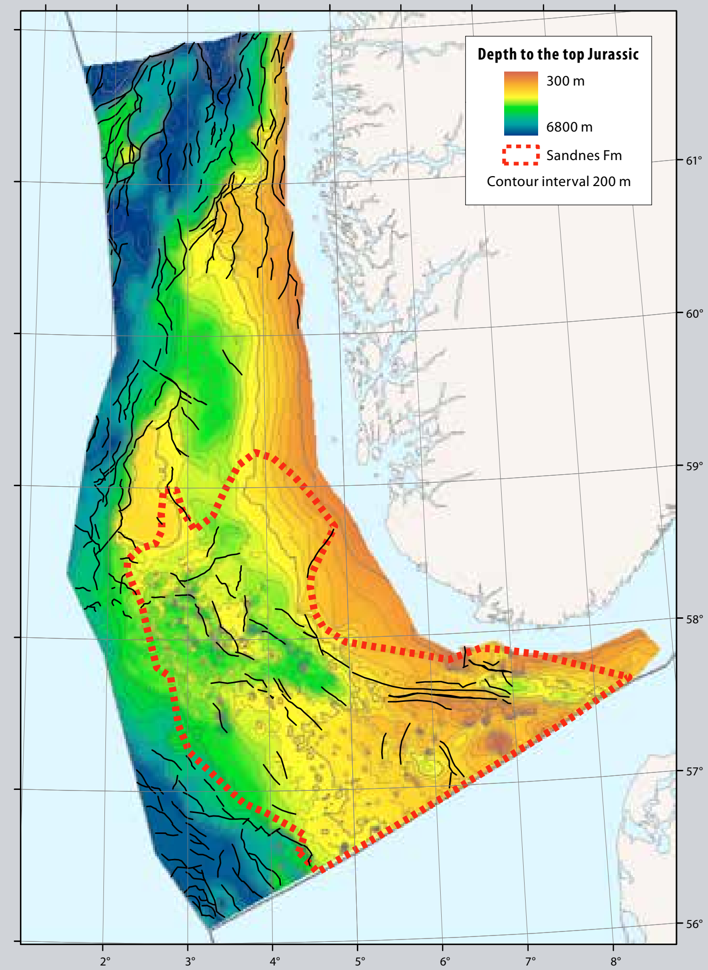
The Vestland Group - Sandnes Formation

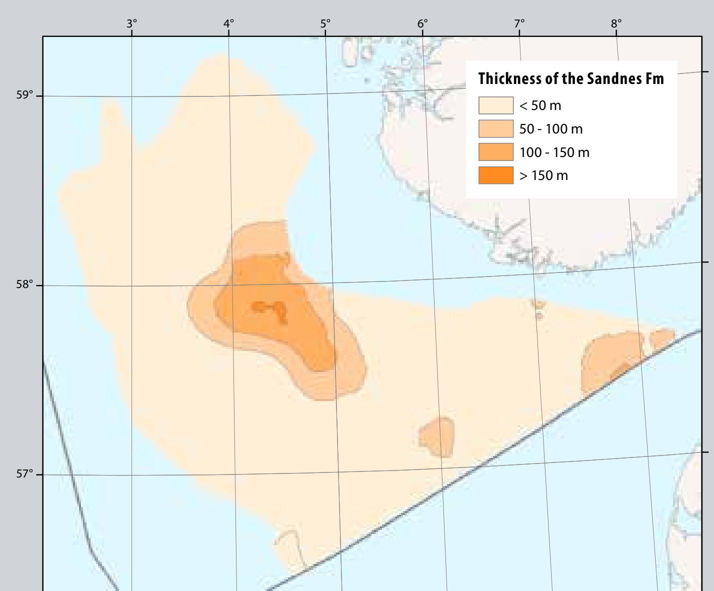
Middle Jurassic to Upper Jurassic
(Upper Callovian to Lower Oxfordian)

The Sandnes Fm is defined from the Norwegian-Danish Basin. The lower boundary, the non-marine Bryne Fm or older rocks, is commonly defined at the base of massive and clean sand. The upper boundary is the marine silts and mudstones of the Boknfjord Gp, which could form a regional seal. The type section for the formation is well 9/4-3.

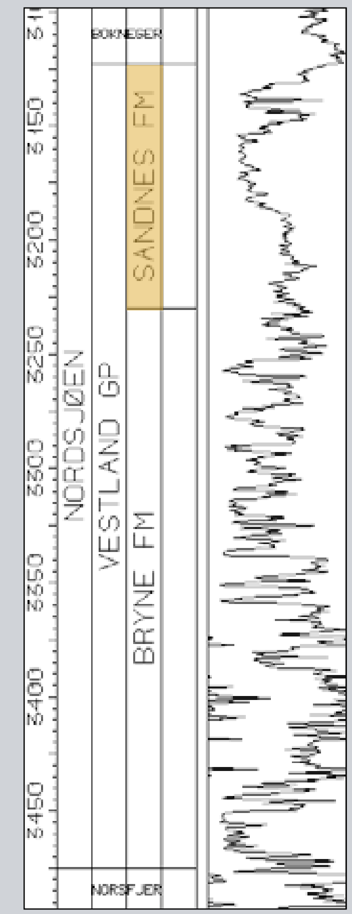
The formation is developed in the southern part of the Åsta Basin and the Egersund Basin. Based on seismic mapping and well data in the Egersund Basin, the thickness exceeds 100 m in large areas. Similar thicknesses may be reached in local depocentres, elsewhere the thickness is less than 50 m. Where the Sandnes Fm is thick, the lower part may represent a distal facies that is time equivalent to the uppermost part of the Bryne Fm. The Sandnes Fm mainly reflects deposition in a shallow marine (e.g. shoreface) to offshore environment. The burial depth is in general more than 1500 m except over structural highs where it may be less than 1000 m. In the Egersund and Farsund basins and the south-western part of the Åsta Graben the burial depth exceeds 2500 m. Porosity and permeability calculations show mean values of 23.0% and 400-500 mD, respectively.

The formation is broadly comparable in lithofacies and depositional environments with the Hugin Fm in the southern Viking Graben.





WELL LOG 9/2-2



Core photo well 3/7-4, 3452-3457 m

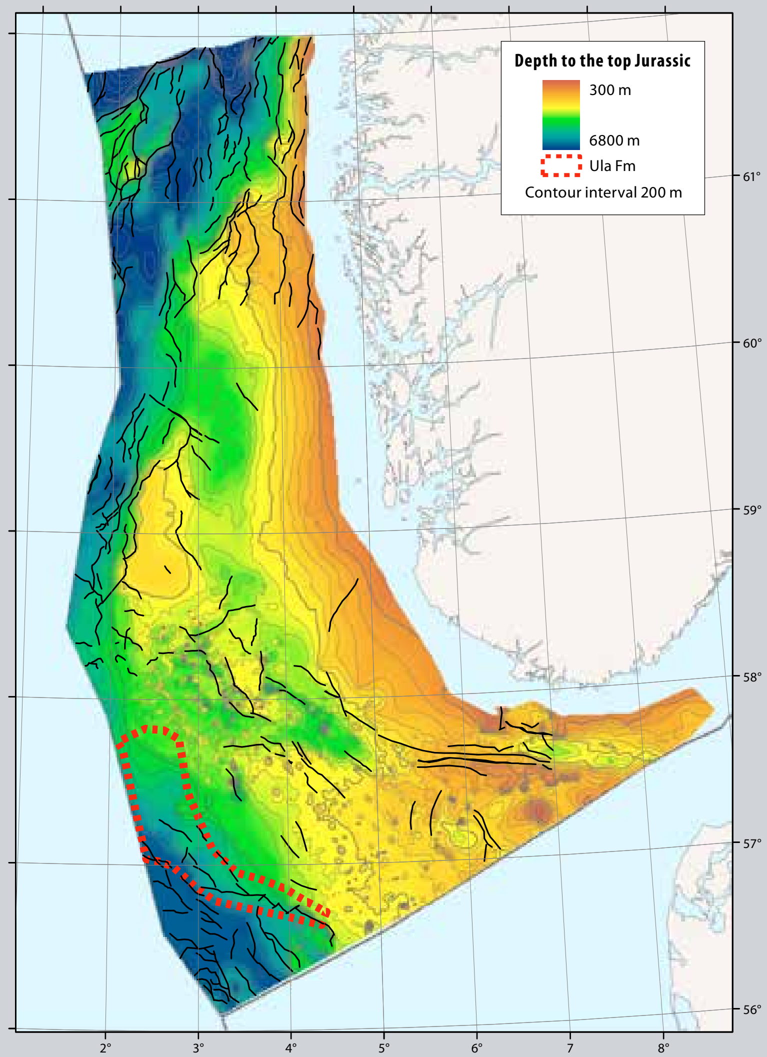
The Vestland Group - Ula Formation

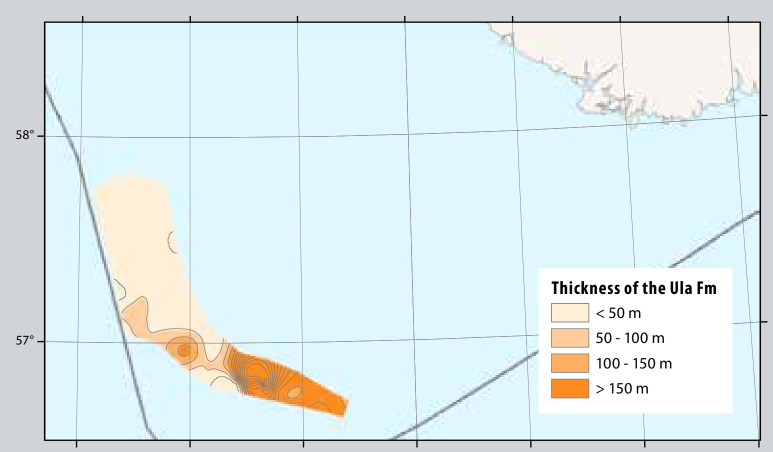
Upper Jurassic-Lower Cretaceous
(Oxfordian- Ryazanian)

The Ula Fm is defined from the western boundary of the Sørvestlandet High from the Ula Field. The base of the formation is the non-marine Bryne Fm and the top is the marine siltstones and mudstones of the Tyne Gp, forming a regional seal. The Ula Fm is defined around the eastern flanking highs of the Central Graben, in particular on the south-west flank of the Sørvestlandet High, and moving towards the basin, i.e. to the west, into marine shale. In the type well 7/12-2 the thickness is 152 m. It thins rapidly towards the east, but can be followed along the NW-SE structural grain controlled by halokinesis. The sands of the Ula Fm are generally deposited in a shallow marine environment.

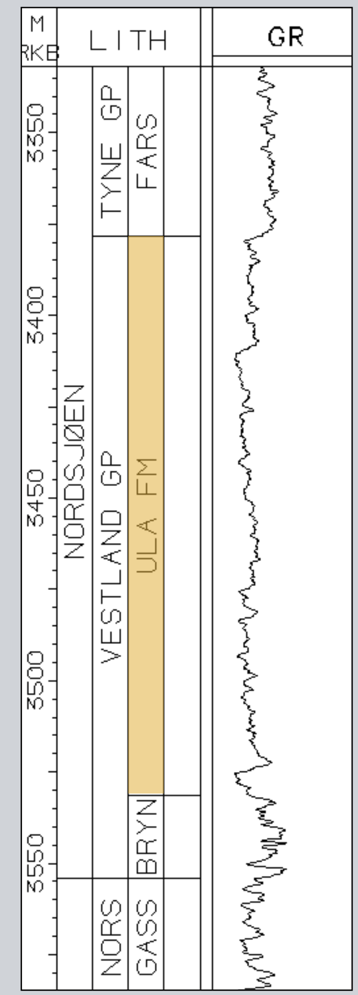
In the type area, the Ula Fm is buried to a depth of more than 3000 m. In the Ula Field, the crest of the structure is 3345 m and porosities and permeabilities are reported in the range 15-22% and 0.2-2800 mD, respectively.

The Ula Fm has similarities both in lithofacies and partly in age with the Hugin Fm in the southern Viking Graben (Sleipner area) and the Sandnes Fm in the Norwegian-Danish Basin.





WELL LOG **7/12-2**



Core photo well 2/12-1, 4648-4653 m

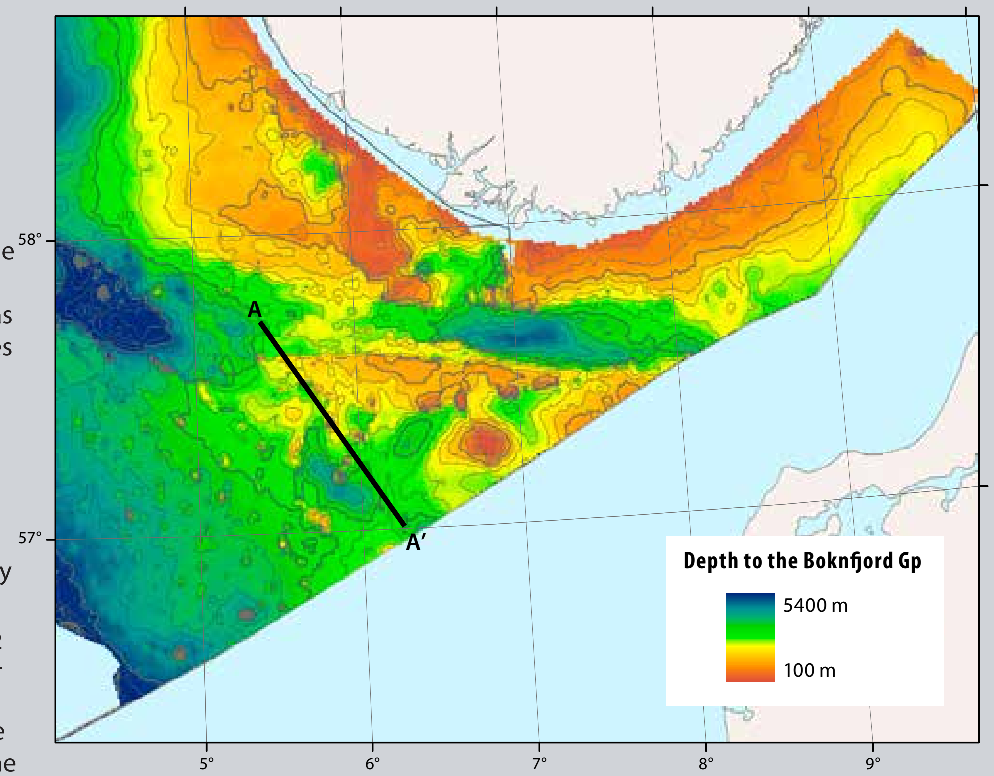
The Boknfjord Group

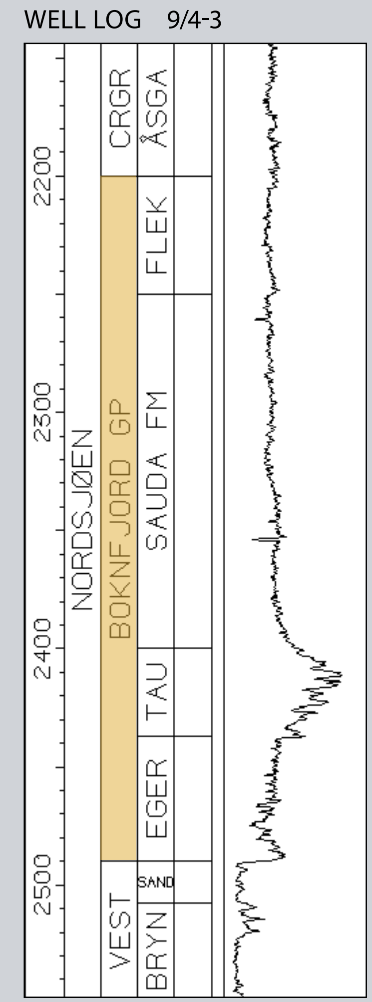
Middle Jurassic to Upper Jurassic
(Callovian to Ryazanian)

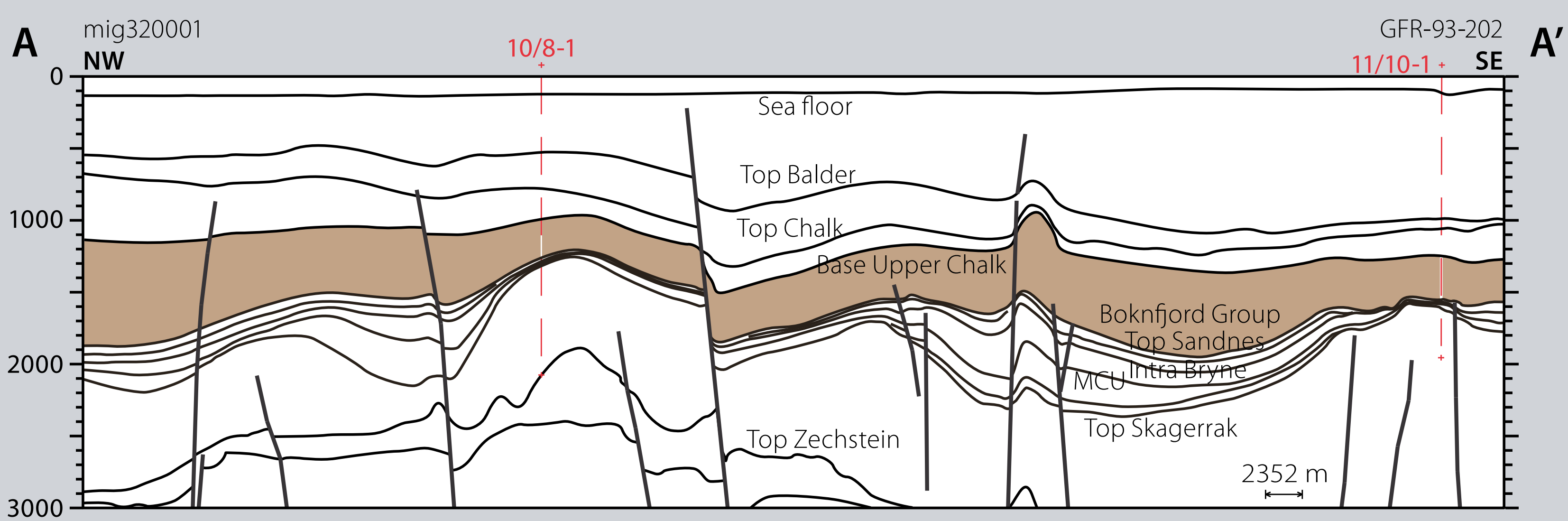
The Boknfjord Gp is defined from the Fiskebank and Egersund Basin and the type well is well 9/4-3. The Boknfjord Gp is dominated by shales and is considered as the primary seal for the underlying potential CO_2 aquifers. The group is subdivided into four formations: The Egersund (base), Tau, Sauda and Flekkefjord Fms. As all of the formations have seal properties, they will be treated as one composite seal. The lower boundary is the sandstones of the Sandnes or Bryne formations. The upper boundary is the Cromer Knoll Gp dominated by claystones.

The Boknfjord Gp is present in the Norwegian part of the Norwegian-Danish Basin. Well data show that the group in general is more than 100 m thick in western Skagerrak, and in the Egersund Basin up to 500 m thick. The upper boundary is the Cromer Knoll Gp dominated by mudstones with a varying content of calcareous material. It forms a secondary seal for the underlying potential CO_2 aquifers. The Boknfjord and Cromer Knoll Gp form a combined seal which can be mapped seismically. The seal is in general several hundred metres thick and may be more than 2000 m thick in the Egersund and Farsund Basins. The sealing package is locally truncated by salt diapirs, as seen in well 11/9-1.

The sediments of the Boknfjord Group were mainly deposited in open marine, low energy basin environments.







The Rogaland Group

Paleocene-Lower Eocene

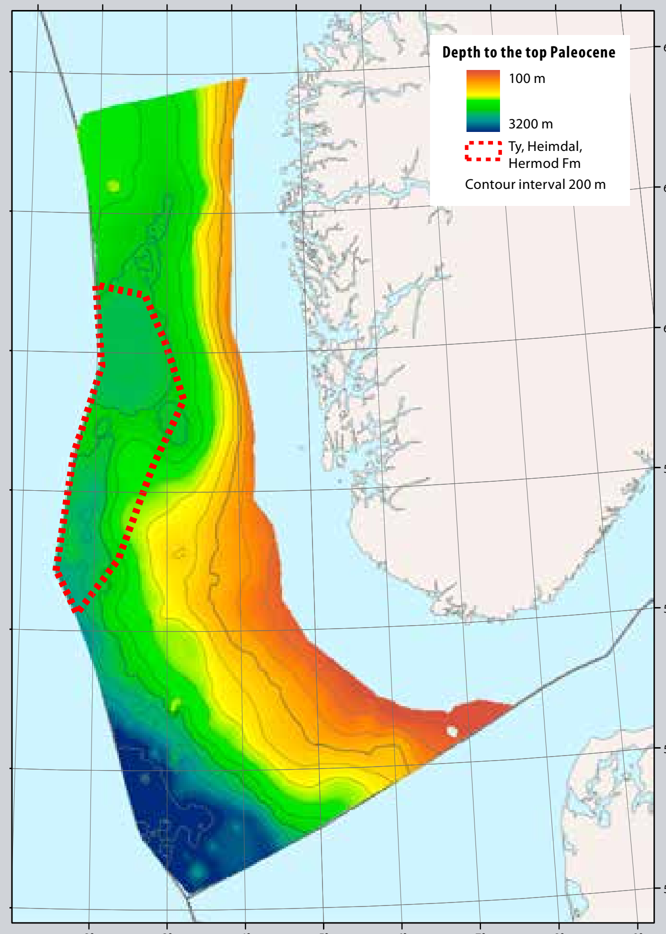
The Rogaland Gp is subdivided into twelve formations. This description will focus on possible aquifers. In general the sequences start off from the west as more proximal and interfinger with more distal sediments to the east. The group is widely developed in the northern and central North Sea. The base of the group is the contact with underlying chalk or marl sequences of the Shetland Gp. The upper boundary is the change from laminated tuffaceous shales (Balder Fm) to sediments of the Hordaland Gp.

The Rogaland Gp is thickest in the west in the UK sector (about 700 m), thinning eastwards and southwards with recorded well thicknesses in the order of 100 m. Depositionally, the Rogaland Gp represents submarine fan / gravity flow sediments transported into deeper water. The sand-bodies are generally lobe shaped and pass laterally into silt and mudstones to the east.

The Ty Fm (Lower Paleocene) was deposited from the Shetland Platform as a deep marine fan and has been identified in the southern Viking Graben in the north-western part of quadrant 25, and northern part of quadrant 15. The formation consists mainly of clean sandstones with a thickness in well 15/3-1 of 159 m. The lower boundary is calcareous rocks of the Shetland Gp, and the upper boundary is transitional to the shales of the Lista Fm, but also against the sands of the Heimdal Fm. The formation may also interfinger with the Våle Fm to the east.

The Heimdal Fm (Paleocene) was deposited as a submarine fan sourced from shallow marine sands on the East Shetland Platform. It is identified in the western parts of quadrant 30, most of quadrant 25 and 15 and as cleaner sand in the south-eastern part of quadrant 15 into the north-western part of quadrant 16 (Meile Mbr (informal)). The thickness of the Heimdal Fm is 356 m in the type well (25/4-1) and 236 m in well 15/9-5. It thins rapidly east of these wells and south of well 15/9-5. The base is usually the transition from the shales of the Lista Fm, but also sandstones of the Ty Fm. The upper boundary is usually a transition from the Heimdal sandstones into the shales of the Lista Fm. Locally it is overlain by the sands of the Hermod Fm.

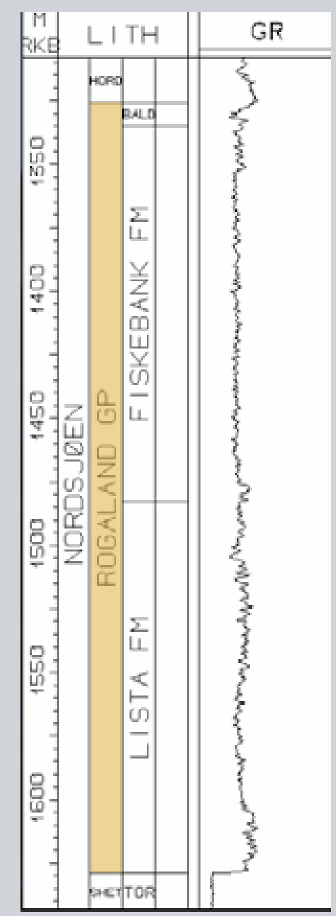
The Hermod Fm (Upper Paleocene) consists of mainly fine-grained sandstones deposited in a submarine fan setting connected to the deltaic Moray Gp in the UK sector. The formation is located mainly in the South Viking Graben in the north-western part of quadrant 25 and extends into the southern part of quadrant 30. The thickness of the formation is 140 m in the type well 25/2-6 and it thickens toward the central part of the distribution area. The lower boundary of Hermod Fm is usually a transition to silts and mudstones of the Lista Fm or the Sele Fm. It may also rest directly on the more varied sandstones of the Heimdal Fm. The upper boundary of the Hermod Fm is sharp against the dark silt and mudrocks of the time-equivalent Sele Fm.



The Fiskebank Fm (Upper Paleocene) has been identified from the Norwegian-Danish Basin and in the type well, 9/11-1, with a thickness of 148 m. The lower boundary is silt and mudstones of the Lista Fm and the upper boundary is tuffaceous shales of the Balder Fm. The formation is developed mainly in the Åsta Graben in the Norwegian-Danish Graben. The thickness in wells varies between 26 to 148 m. The Fiskebank Fm probably represents basin margin deposits and appears to be mostly time equivalent with the Sele Fm.

The Balder Fm (Paleocene to Upper Eocene) consists of vari-coloured laminated shales, interbedded with sandy tuffs and distributed over much of the North Sea. The thickness varies between less than 20 m to more than 100 m. The Balder Fm was deposited in a deep marine environment and the tuffaceous material probably came from more than one volcanic source. The lower boundary of the Sele or Lista fms is marked by the incoming of tuffaceous material. The upper boundary is defined at the transition from the laminated Balder Fm to the non-laminated, often glauconitic and reddish overlying sediments of the Hordaland Gp.

WELL LOG 9/11-1



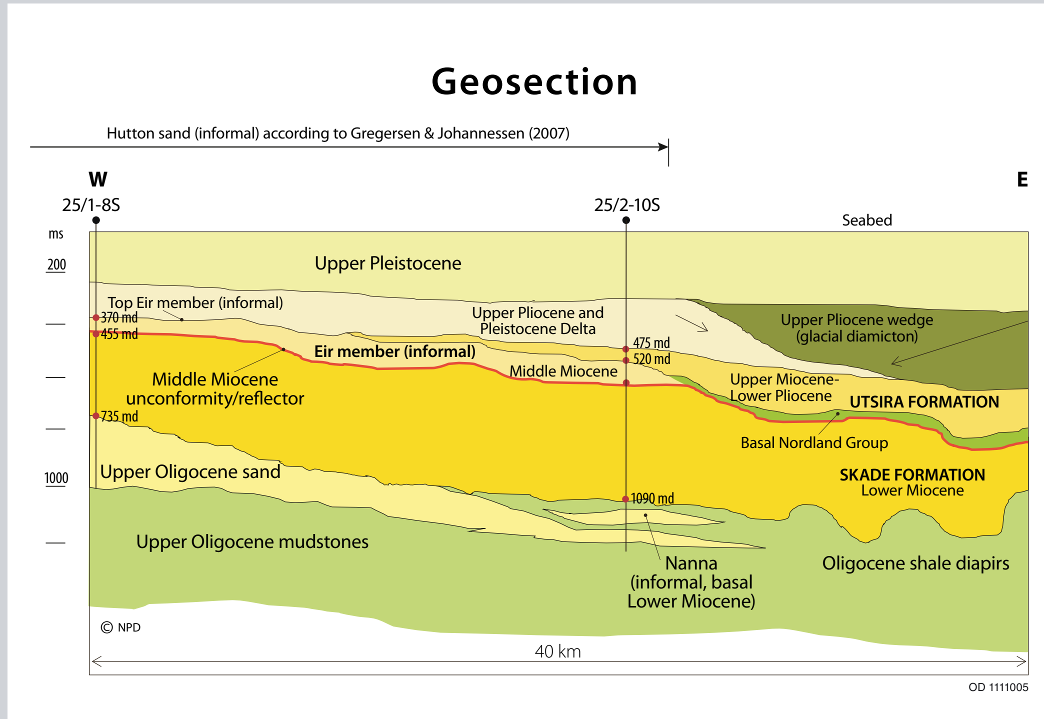
The Hordaland Group - Skade Formation

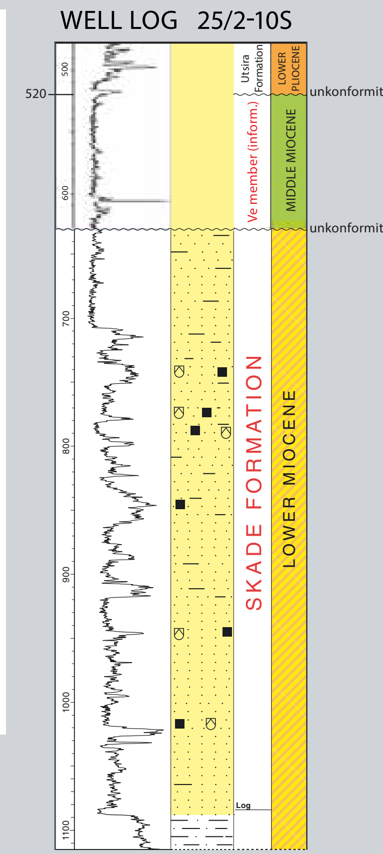
Eocene to Middle Miocene

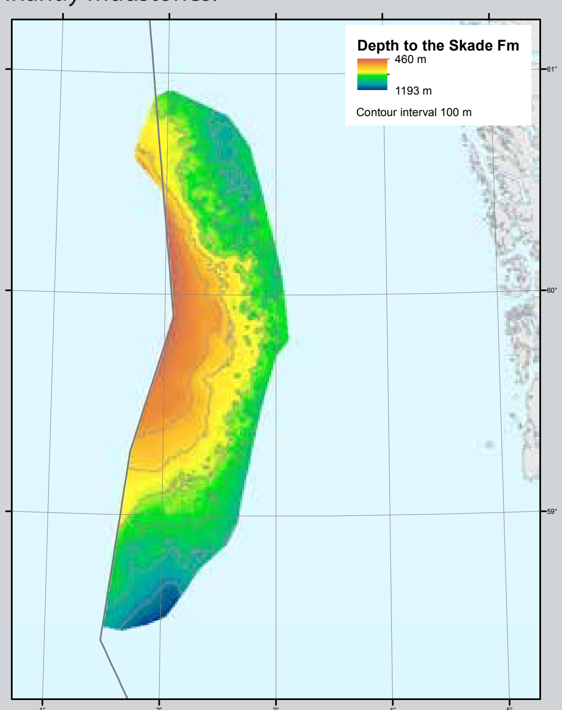
The Skade Formation of the Hordaland Group together with the Eir (informal) and Utsira Formations and the Upper Pliocene sands of the Nordland Group form the outer part of a large deltaic system with its source area on the East Shetland Platform. The proximal parts of this system are mainly located in the UK sector, and these deposits are named the Hutton sand (informal). In the Norwegian sector, sands belonging to the system are the Miocene–Lower Pliocene Skade, Eir (informal) and Utsira Fm, and Upper Pliocene sands of the Nordland Group (no formal name).

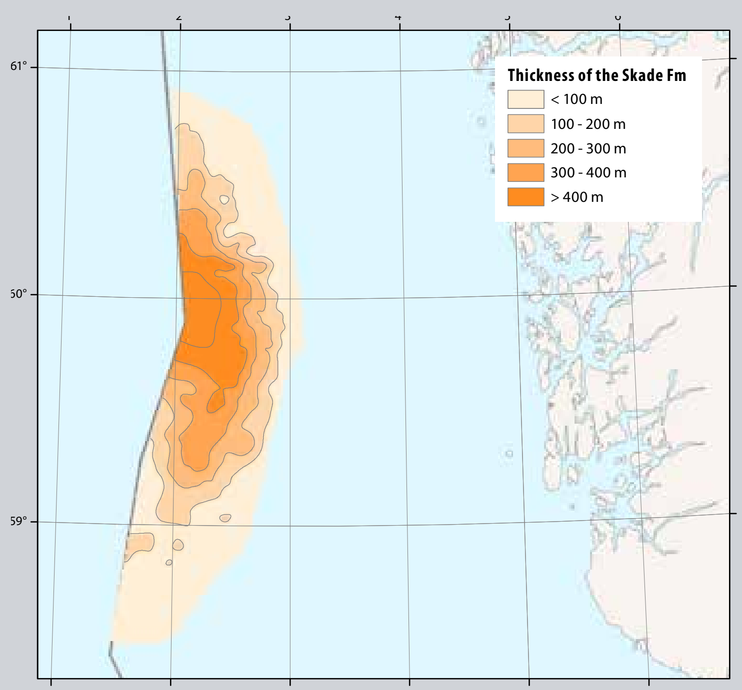
The Skade Fm, Lower Miocene, consists of marine sandstones (mainly turbidites) deposited over a large area of the Viking Graben (from 16/1-4 in the south to 30/5-2 in the north). The maximum thickness exceeds 300m and decreases rapidly towards the east, where the sands shale out or terminate towards large shale diapirs.

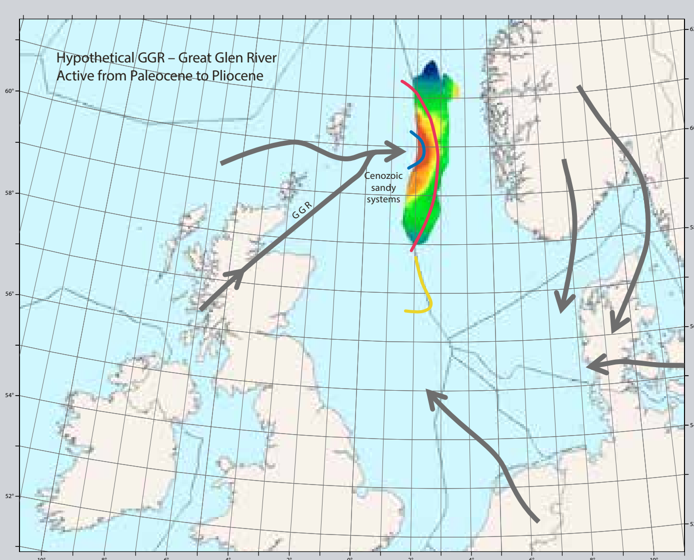
The Eir Fm (informal), Middle Miocene, is recorded in several wells in the Viking Graben, including 15/9-13 in the south-east and 25/2-10S and 30/6-3 further north. The thickness map shows the distribution of the northern part of the formation. In the southern part of the deltaic system, the sand is generally shaling out closer to the UK/Norway boundary line. The Eir Fm (informal) overlies the mid Miocene unconformity and forms the base of the Nordland Gp. Elsewhere in the North Sea the Middle Miocene is dominantly mudstones.











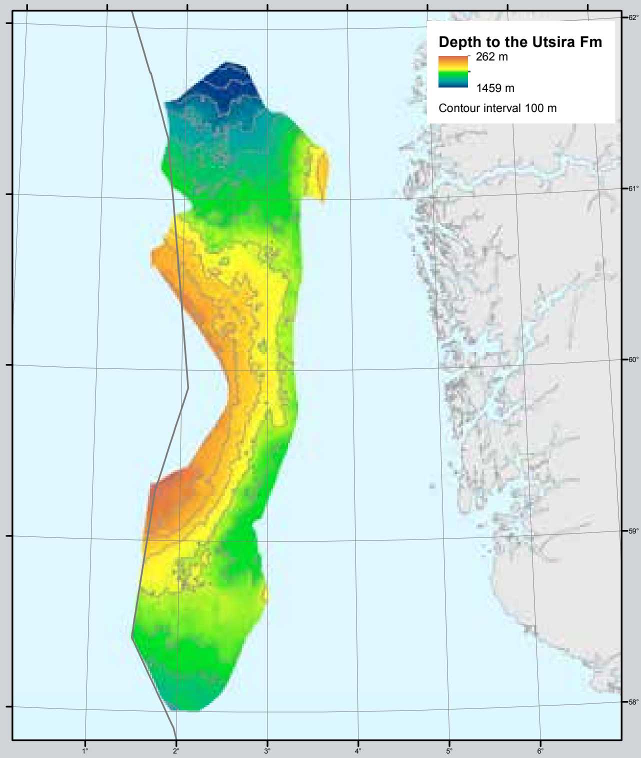
Suggested drainage patterns for Miocene deposits in the North Sea area. Drainage through the Great Glen trend in Scotland has not been documented.

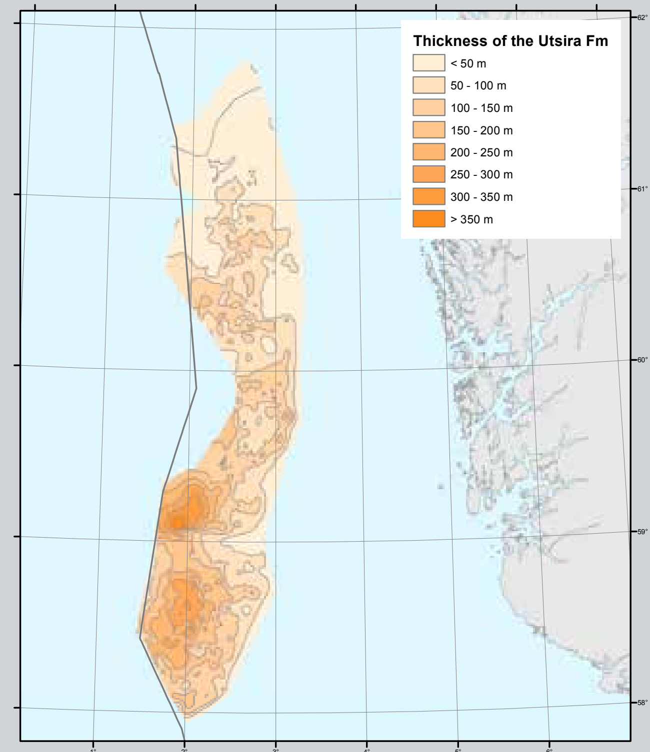
The Nordland Group - Utsira Formation

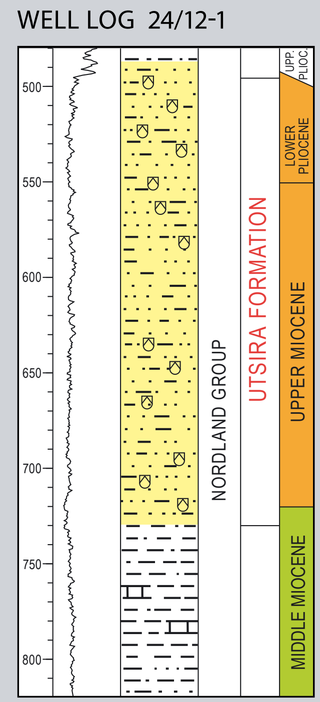
Uppermost Middle Miocene to Quaternary

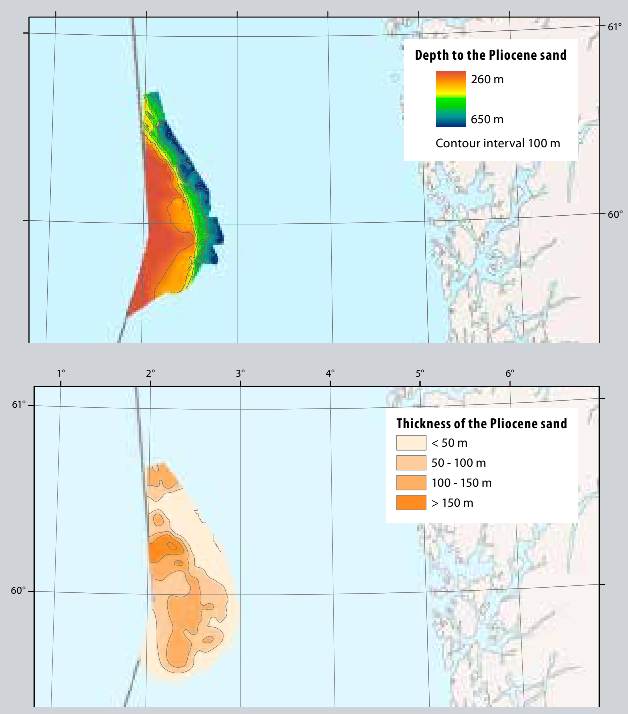
The Utsira Fm of the Nordland Group (uppermost Middle Miocene to Quaternary) consists of marine sandstones with source area mainly to the west. The maximum thickness exceeds 300 m. The sands of the Utsira Fm display a complex architecture and the elongated sand body extends some 450 km N-S and 90 km E-W. The northern and southern parts consist mainly of large mounded sand systems. In the middle part the deposits are thinner, and in the northernmost part (Tampen area) they consist of thin beds of glauconitic sands.

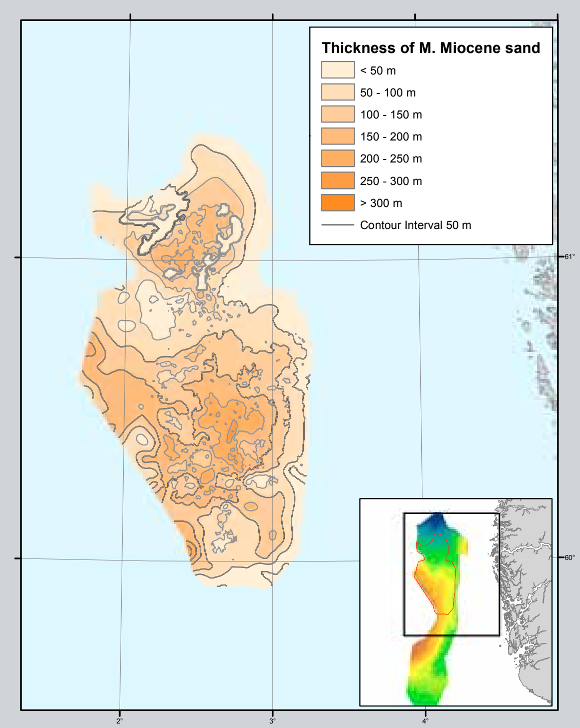
Upper Pliocene deltaic sand deposits overlie the Utsira Formation and Eir formation (informal) with a hiatus. In the wells we have investigated, there is sand-sand contact at the boundary, consequently we regard the Upper Pliocene sand as a part of the large Utsira-Skade aquifer system. The Upper Pliocene sand has previously often been assigned to the Utsira Formation. The top of the sand is found at about 150 m below the sea floor in the Norwegian sector. Seismic data indicates that the latest active progradation of these sands took place towards the north-east in the Tampen area, where their distal parts interfinger with glacial sediments derived from Scandinavia.











The Hordaland Group - Claystones

Eocene to Lower Miocene, possibly Middle Miocene in the Central Graben

The Hordaland Gp has its type area in the North Sea Basin. The main lithology of the group is marine claystones with minor sandstones. Within the Hordaland Gp, four sandstone formations are defined: The Frigg, Grid, Skade and Vade Fms.

Maximum thickness of the group varies from 1100-1400 m in the central and southern part of the Viking Graben, thinning towards the margins. Thicknesses of wells in the type area (wells 2/2-1 and 24/12-1) are 1060 m and 1365 m. In the northern Viking Graben the group is only a few hundred meters thick. The group was deposited in an open marine environment. The base of the Hordaland Gp is the Balder Fm or sands of the Frigg Fm.

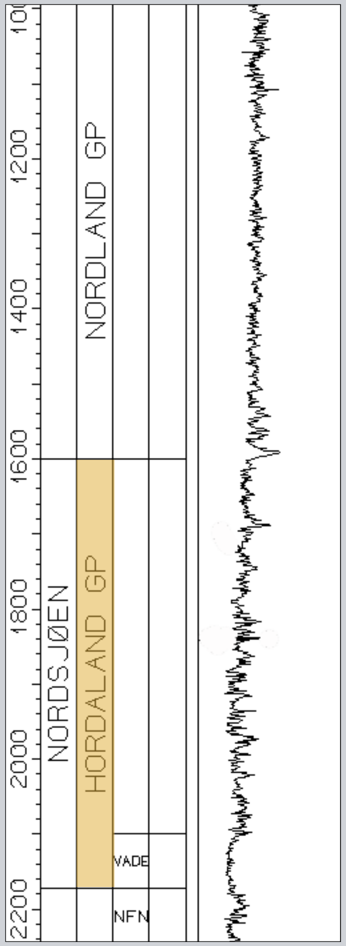
The Skade Fm is in communication with overlying Miocene and Pliocene sands and is described above.

The Frigg Fm (Lower Eocene) was deposited as submarine fans sourced from the East Shetland Platform to the west. The Formation is located in the south-western part of quadrant 30 and north-western part of quadrant 25. At about $59^0$30'N, the Frigg sands are connected to the sands in the UK sector. The thickness of the Frigg Fm is 279 m in type well (25/1-1) and it is located in a depocentre with a maximum thickness of approximately 300 m. The lower boundary is the Balder Fm and the upper boundary is claystones of the Hordaland Gp that could form a regional seal. The crest of the Frigg Field is approximately 1850 m and porosities and permeabilities are reported in the range of 27-32% and 1-4 Darcy, respectively.

The Grid Fm (Middle to Upper Eocene) consists of a series of sand-bodies probably sourced from the East Shetland Platform and located in the Viking Graben between 58^o30'N and approximately 60^o30'N. The type well is 15/3-3. The lower and upper boundaries are towards marine claystones of the Hordaland Gp. The thickness in the type well is 370 m. The formation thins eastward. There is a considerable difference in thickness north and south of 590N. To the north the thickness is less than 200 m and to the south nearly 400 m. This is due to the fact that sand deposition started earlier in the south. Due to soft sediment deformation, there may be poor connectivity between individual sand bodies, and some sands may be interpreted as injectites. The deposition of the formation took place in an open marine environment during regression.

The Vade Fm (Upper Oligocene) is defined in well 2/2-1 located on the Sørvestlandet High, east of the Central Graben. The lower and upper boundaries are claystones of the Hordaland Gp. In the type well the thickness is 72 m, but the formation has only been penetrated by a few wells. Regional considerations indicate a source area for the Vade Fm sandstones to the east or north-east. They were deposited in a shallow marine environment in 11/10-1 and prograded into deeper waters to the west as shown in well 2/2-2.

WELL LOG 2/2-1



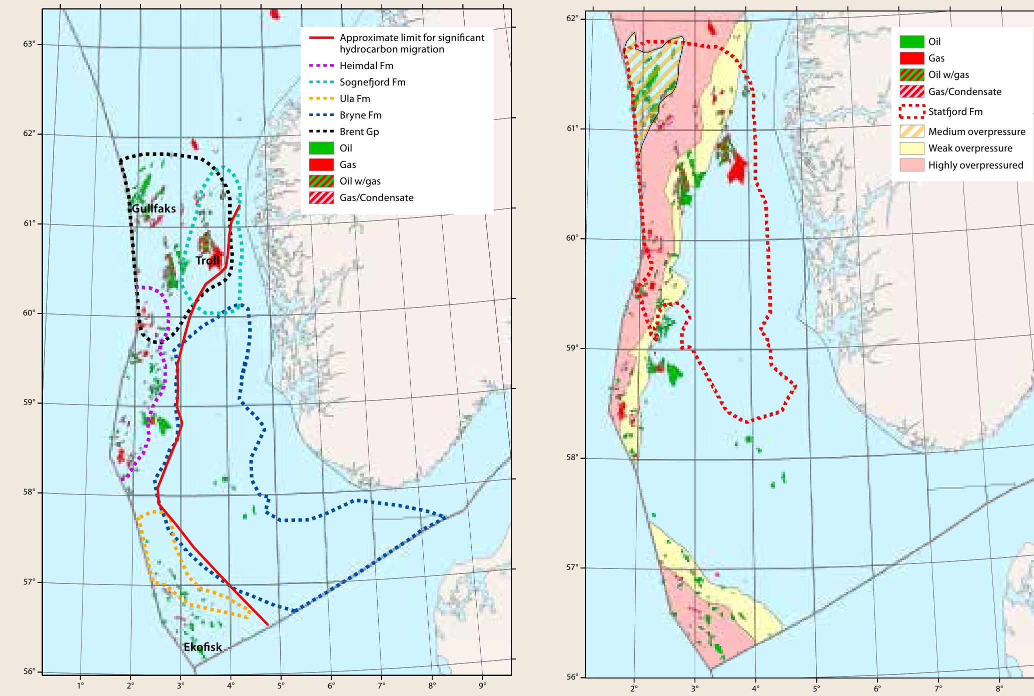
4.2.1 Saline aquifers

Introduction

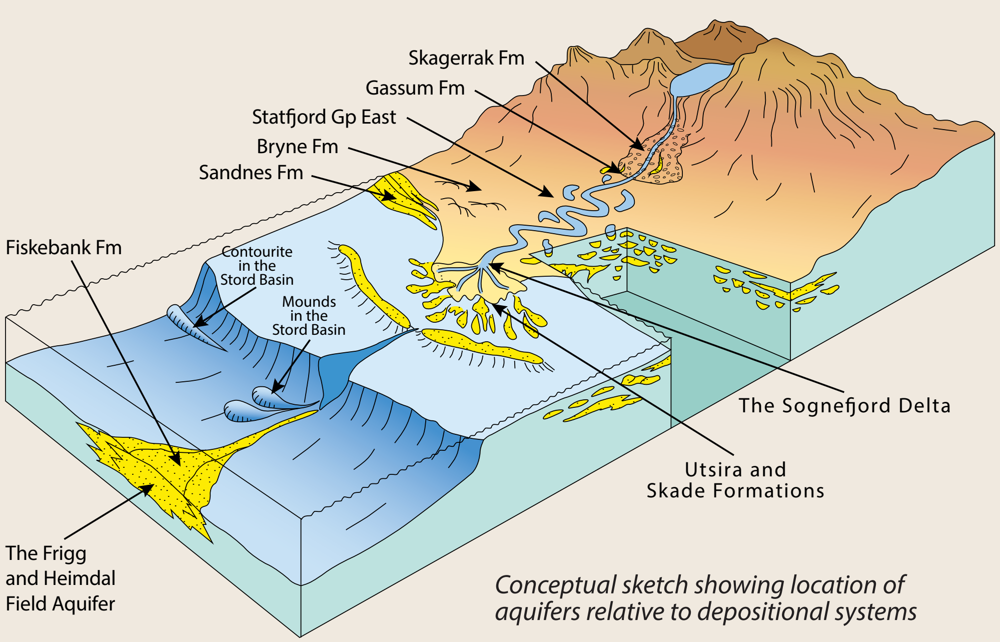
In the western provinces, west of the red line in the lower middle figure, Paleogene and older aquifers contain hydrocarbons. East of the line, discoveries have only been made in local basins where the Jurassic source rock has been buried to a sufficiently high temperature to generate hydrocarbons.

In the eastern area, all the large aquifers have been selected based on the established criteria (section 3.3) and storage capacity is estimated by the method described in section 3.4. In the petroleum provinces, it is considered that exploration and production activities will continue for many years to come. The most realistic sites of CO_2 storage will be some of the abandoned fields, in particular the gas fields. Consequently, an indication of the storage capacity of the fields has been given, but no aquifer volumes have been calculated. Some of the oil fields are considered to have a potential for use of CO_2 to enhance oil recovery (EOR, section 8). Some of the CO_2 used for EOR will remain trapped. The capacity for this type of CO_2 trapping has not been calculated.

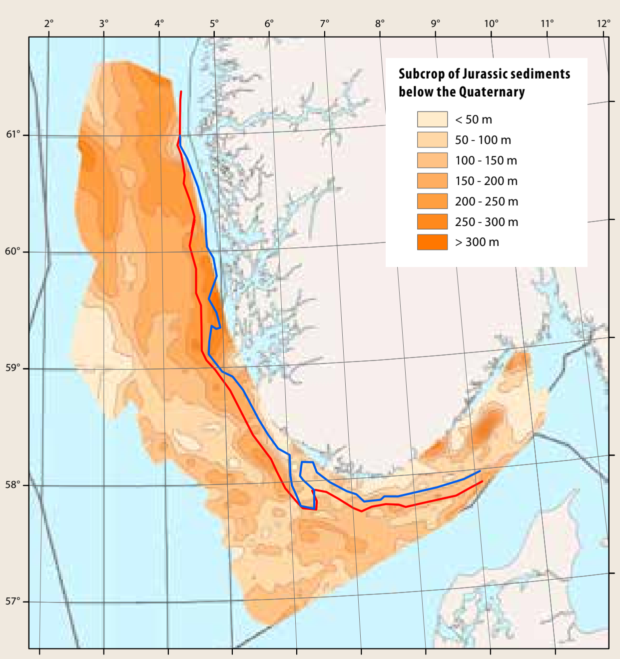
The Sognefjord Delta aquifer and the Statfjord Formation aquifer (figure) are developed both within the petroleum provinces in the west and as saline aquifers with small amounts or no petroleum in the east. In these cases, only the eastern parts have been evaluated for CO_2 storage.



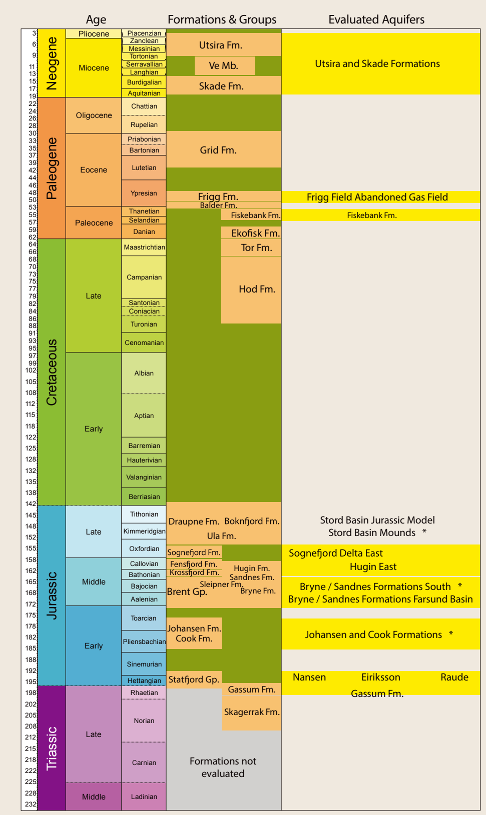
Distribution of major aquifers at the Jurassic levels relative to the petroleum provinces



Conceptual sketch showing location of aquifers relative to depositional systems



Thickness of Quaternary deposits and Jurassic subcrop



* Evaluated prospects

4.2.1 Saline aquifers

Stord basin - long distance CO_2 migration

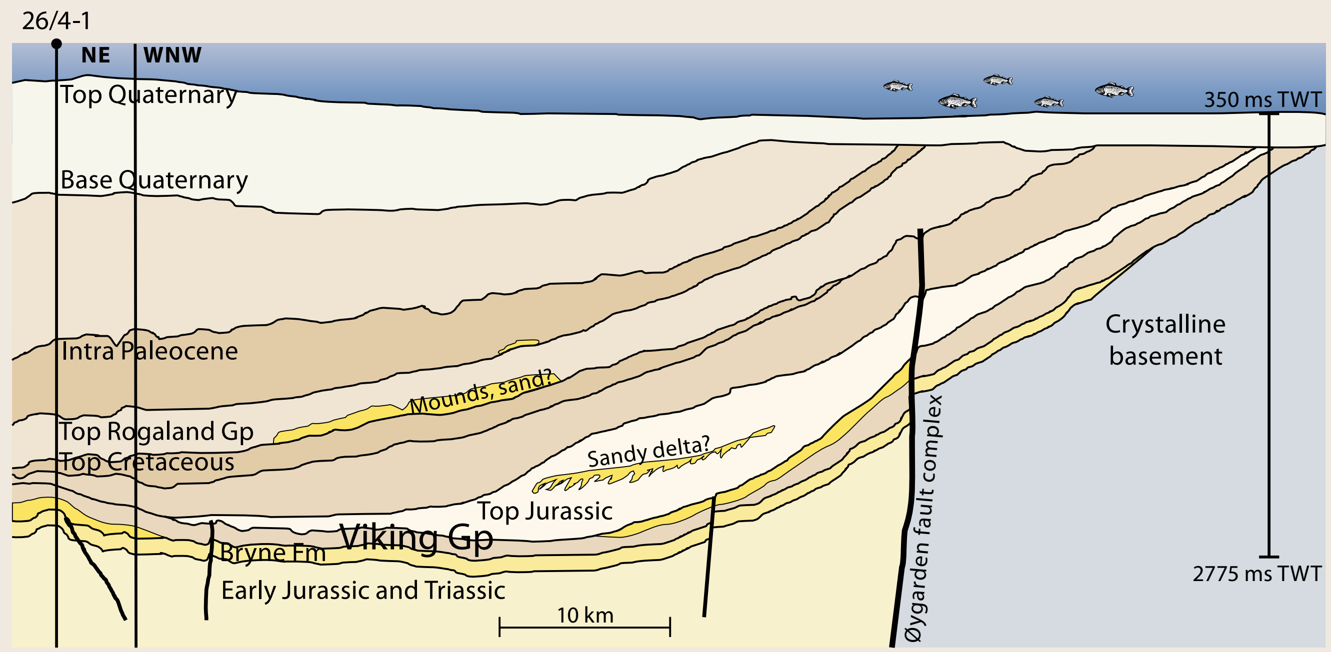
Modelling of CO_2 injection and migration in the Stord basin. The aquifers in the eastern part of the North Sea typically have a consistent dip of about one degree from the Norwegian coast down to the basinal areas. In the case that there are permeable beds along this dip slope, there is a risk that CO_2 injected in the downdip aquifer can migrate up to where the aquifer is truncated by Quaternary glacial sediments. At that depth, the CO_2 will be in gas phase. The glacial sediments mainly consist of clay and tills and their thickness ranges from about 50 m and up to more than 200 m (figure). Understanding the timing and extent of long distance CO_2 migration is of importance for the evaluation of the storage capacity of outcropping aquifers. Consequently, a modelling study was set up on a possible aquifer in the Stord Basin.

The Stord Basin is bordered by faults between the Utsira High in the west and the Øygarden fault complex in the east. The syn-rift basin acted as a depocentre for infilling sediments from all surrounding highs, the main source being the eastern hinterland. The basin is overlain by post-rift sediments ranging from late Jurassic to Quaternary age. Sand is mainly found in the Triassic and Jurassic. The main risks of leakage of injected CO_2 in the Stord basin area are sideways migration towards the east, and migration along fault planes. Absence of syn-rift sedimentary rocks on the upthrown side of the Øygarden fault complex may reduce the risk of sideways migration in this section.

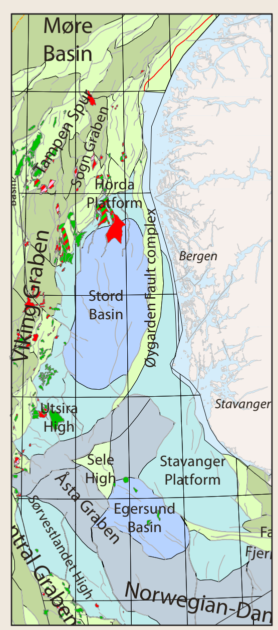
A simulation model of a possible Upper Jurassic sand deposit (referred to as Sandy delta in the cross section) was built based on a geological model derived from seismic interpretation. The model shown in the figure has been used to simulate CO_2 injection in the sand deposit, which will act as an aquifer.

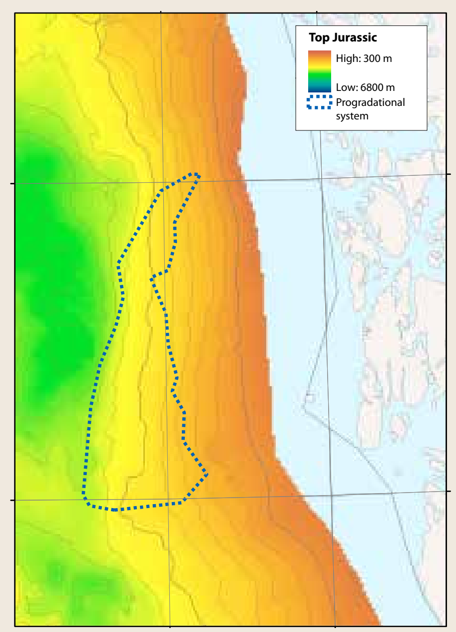
The modeled depositional system has not been drilled, and the interpretation is based on seismic 2D data. Although there is a reservoir risk in this particular model, the results can be applied to analogous aquifers with gentle dips.

Three injection wells are shown in the areas with highest permeability (green). A water producer is located on the east side of the grid, acting as a leaking point in the shallowest part. The permeability and porosity distribution around well 1 is shown in the profiles. The model was run with 50 years of injection with different rates. After shut-in of injection, migration continued until the CO_2 had migrated up to the east side of the model and begun to enter the Quaternary formations above. The simulations were run with one, three and five wells.



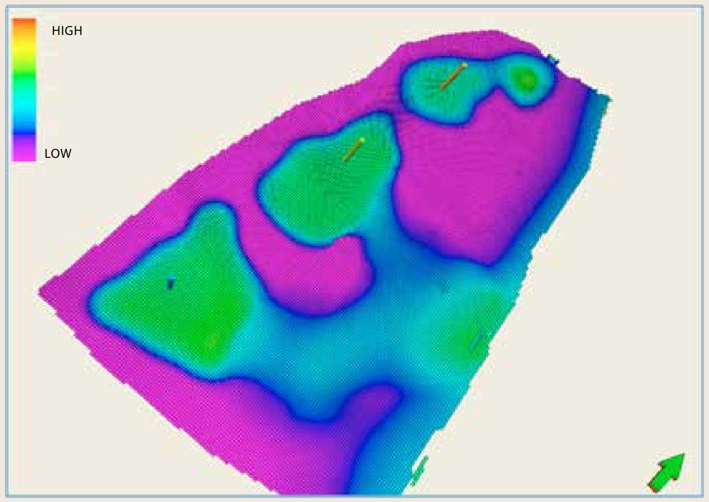
Seismic panel including well 26/4-1, Stord basin



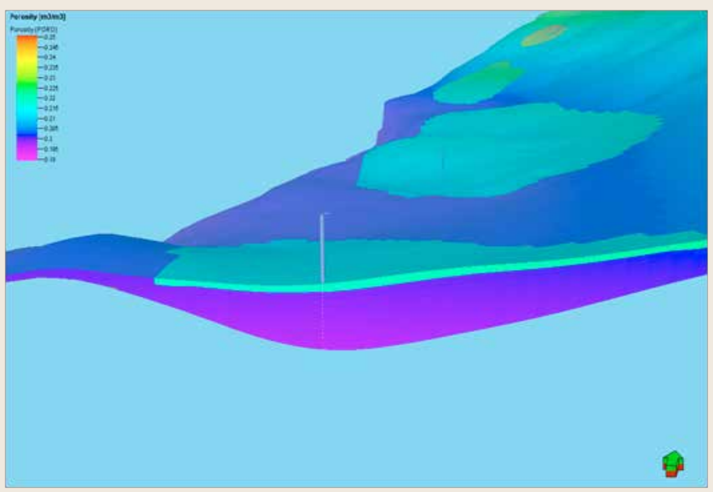


Polygon depicting modelled aquifer

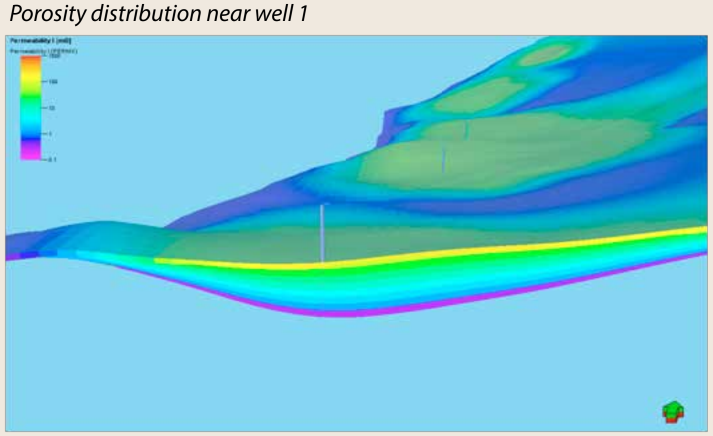
Stord basin - long distance CO_2 migration



Permeability in upper layer 1



Porosity distribution near well 1



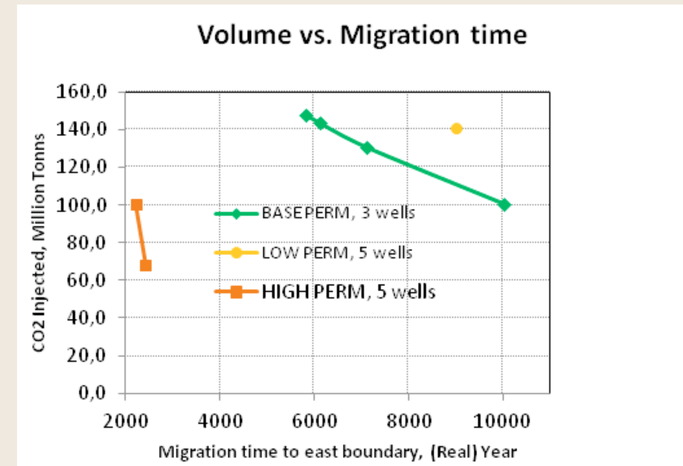
Porosity distribution near well 1

Three cases with different x-y permeabilities were run. Near well 1 the permeabilities vary from 0.14 mD in the bottom layer, to 199 mD in the top layer. The cases were run with the following model setups:

1. Base model
2. High perm model (permeability 20 times base case in top layer)
3. Low perm model (0.5 times base permeability in all layers)

The results for the different models are shown in the figure, with three and five wells.
The results show that in the base model with 3 mill Sm^3/d, the reservoir can store 100 Mt CO_2 before CO_2 reaches the eastern boundary of the reservoir in the year 10 000. If extrapolated to 10 000 years of storage, the maximum amount stored will be about 75 Mt. With a high permeability layer at the top (high case), and 3 mill Sm^3/d, the CO_2 will reach the boundary in year 2416 after about 400 years of migration.

When the CO_2 reaches the eastern boundary it is in gas phase and might migrate slowly upwards into the overlying Quaternary layers as discussed above.



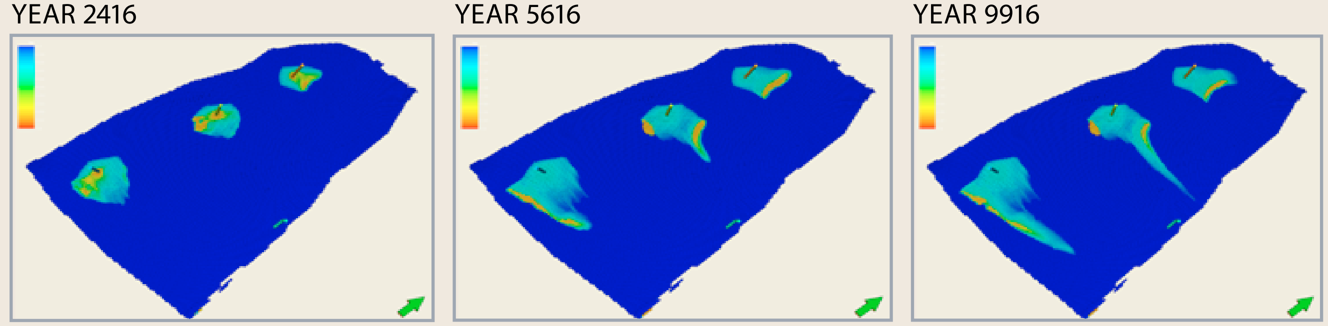
Volume of CO_2 injected vs. migration time

Conclusions

The results show that the CO_2 plume is distributed mostly in the high permeability (upper) layers of the reservoir.

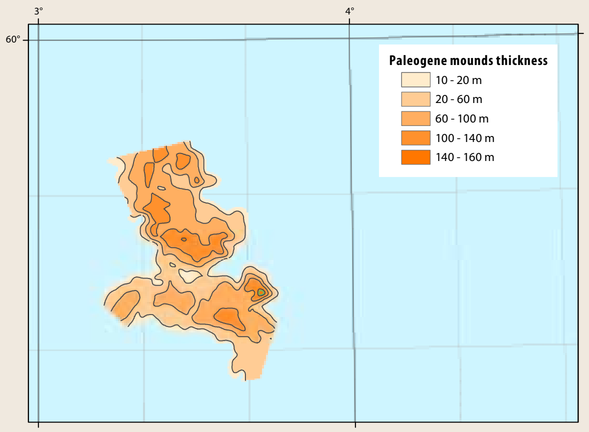
With the base permeability model, about 100 Mt is the maximum storage capacity with migration for about 8000 years to boundary (year 10 000), if 3 mill Sm^3/d is injected in three wells. Higher rates will give a shorter migration time. With the low perm model and 9 mill Sm^3/d with five wells, the injected volume might be up to 140 Mt. A high permeability streak in the top layer will result in a short migration time, about 400 years. Low permeability and favourable communication reduces the risk of CO_2 escape. The results indicate that migration velocities are slow unless the permeability and communication are very high, implying that subcropping aquifers could be of interest for CO_2 storage.

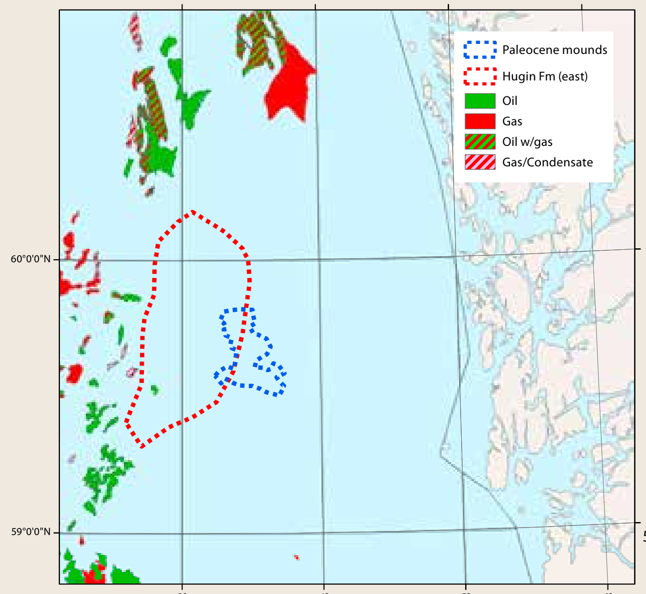
YEAR 2416 YEAR 5616 YEAR 9916

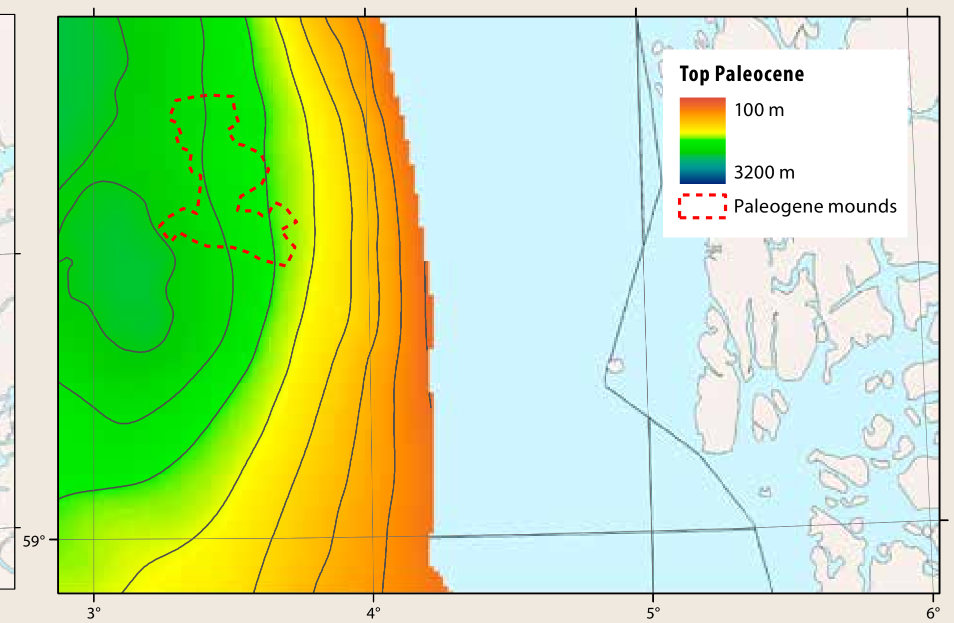


Volume of CO_2 injected vs. migration time

Paleogene Mounds, Stord Basin
The Hugin East Formation aquifer







Paleogene mounds
This prospect is based on seismic 2D interpretation on a mounded reflector in the Paleocene/Eocene sequence in the central part of the Stord Basin. The reflection pattern has been interpreted as a possible deep marine fan system which could have a high content of reservoir sand. There are few wells in the area, and sand have not been proved by drilling in this particular interval. If sand is present, the mapped structure can be regarded as a structural/stratigraphical trap with good seals. The aquifer outside the mapped structure is considered to be limited. Calculation of storage capacity is based on 28 % porosity and a net gross ratio of 0.8 within a closed aquifer volume.

Mounds, Stord basin		
Storage system	half open	
Rock volume		45 Gm^3
Pore volume		9.7 Gm^3
Average depth		1900 m
Average permeability		1000 mD
Storage efficiency		0.8 %
Storage capacity aquifer		
Storage capacity prospectivity		50 Mt
Reservoir quality		
	capacity	2
	injectivity	2
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		

Hugin East Aquifer
One well has been drilled in this aquifer, which has been mapped on 2D seismic data. The reservoir rock is equivalent to the Hugin and Sandnes Formations, and is believed to have good quality. A simplified calculation of theoretical storage capacity was carried out, using a constant net gross value and a porosity trend similar to the Sandnes Formation.

Hugin fm east of the Utsira High		
Storage system	half open	
Rock volume		19 Gm^3
Pore volume		2.4 Gm^3
Average depth		1700 m
Average permeability		500 mD
Storage efficiency		5.5 %
Storage capacity aquifer		100 Mt
Storage capacity prospectivity		
Reservoir quality		
	capacity	1
	injectivity	3
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		

4.2.1 Saline aquifers

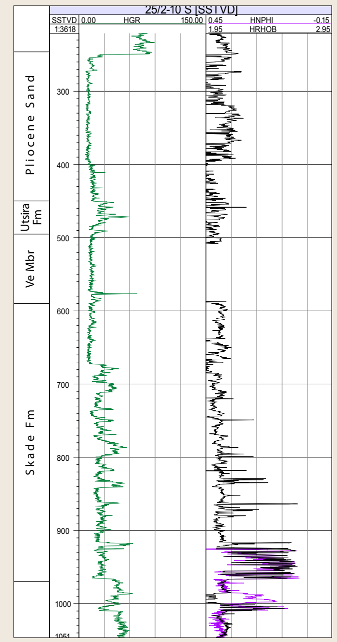
The Utsira and Skade aquifer

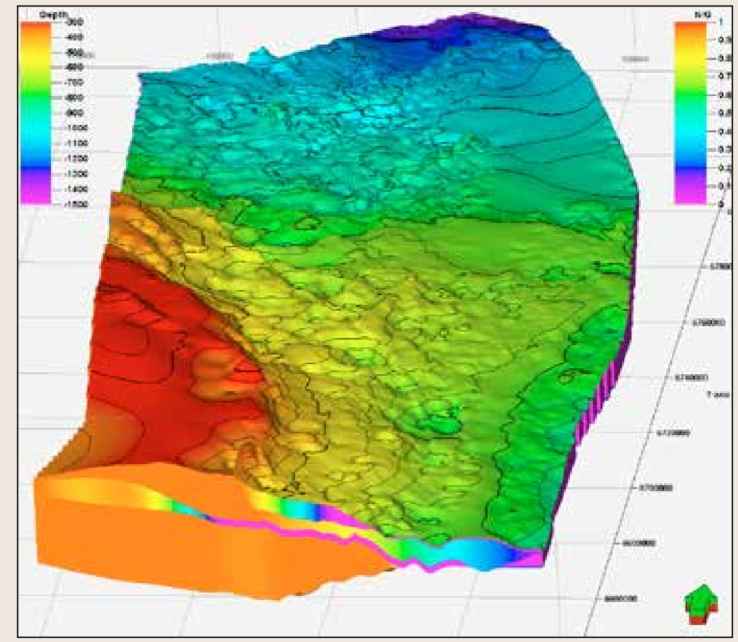
Approximately 1 Mt CO_2 from the Sleipner Field has been successfully injected annually in the Utsira Formation since 1996, proving that the formation is an excellent reservoir for CO_2 storage. Due to its size, the formation has been regarded as attractive for storage of large volumes. However, the formation is part of a much larger sandy deltaic complex located at both sides of the UK-Norway boundary. The upper parts of this system are buried to less than 200 m below the sea floor, and the communication between the different sandy formations has not yet been studied in detail. In this atlas we present the results of an NPD study based on 3D seismic interpretation and biostratigraphy. The Miocene and Pliocene aquifer is subdivided into four major units which are in communication towards the west. The largest pore volumes in the system are in the Utsira and Skade Formations, which appear to be separated by a Middle Miocene shale in the eastern/distale parts. There is a regional dip upward towards the west, and consequently there is a risk that injected CO_2 will migrate updip to levels which are too shallow to be accepted for storage. Three areas are assumed suitable for CO_2 injection:

1. The southern part of the Utsira Formation below approximately 750 m. This area has several structures which could accumulate CO_2 and prevent it from migrating upslope. Large volumes can also be trapped as residual and dissolved CO_2 in the aquifer.
2. Volume in the NE part of the Utsira Formation. This part of the Utsira Formation is in communication with a delta which was built out from the Sognefjord area in the east. The top of the eastern fan reaches the base of the Quaternary and it has not been evaluated for storage.
3. The outer part of the Skade Formation where it is sealed by Middle Miocene shale and could be trapped within structures formed by clay diapirism.

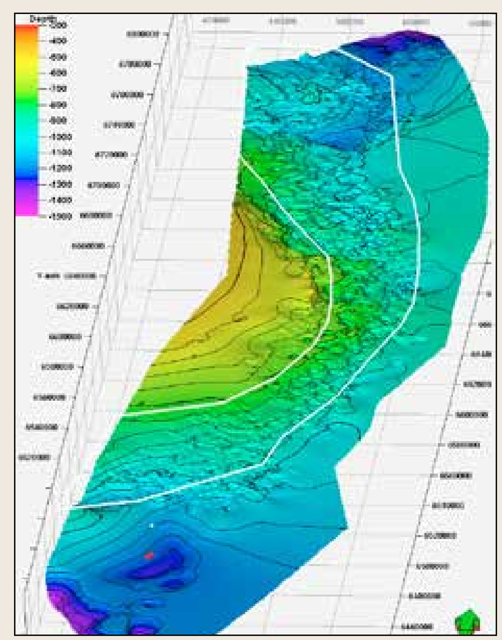
Pore volumes for this aquifer are presented together with storage capacities calculated for the three suggested sub- areas.

Utsira and Skade Fms		
Storage system	half open to fully open	
Rock volume		2500 Gm^3
Pore volume		526 Gm^3
Average depth		900 m
Average permeability		>1000 mD
Storage efficiency		4 %
Storage capacity aquifer		16 Gt
Storage capacity prospectivity		0,5-1,5 Gt
Reservoir quality		
	capacity	3
	injectivity	3
Seal quality		
	seal	2
	fractured seal	3
	wells	2
Data quality		
Maturation		

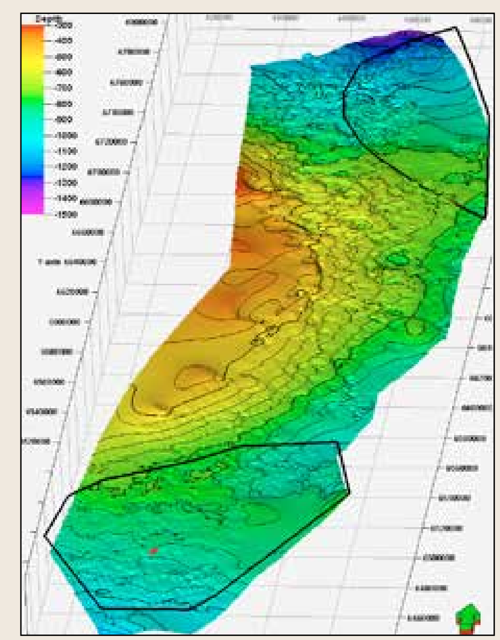




Cross section and top surface of the aquifer model. Cross section shows net-gross values.



Top of Skade Formation. The white polygon indicates area which may be favorable for CO_2 storage. Red dot shows Sleipner injection area. The grid squares are 20 km x 20 km.



Top of Utsira Formation. The black polygons indicate areas which may be favorable for CO_2 storage.

4.2.1 Saline aquifers

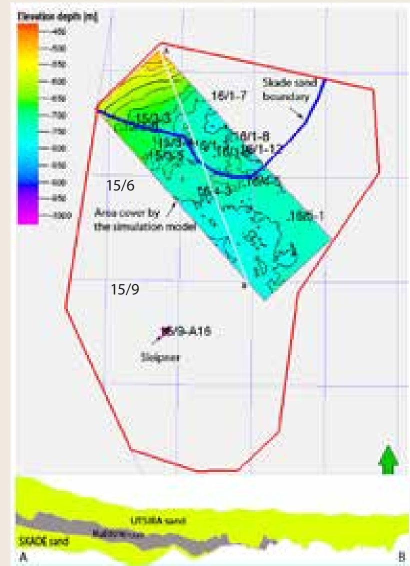
The Utsira and Skade aquifer

To estimate the capacity of CO_2 storage in a southern part of Utsira/Skade aquifer, a reservoir model was built to simulate the long-term behavior of CO_2 injection. The model covers 1600km^2 in the southern part of the Norwegian sector. The study illustrates potential migration and forecast possible migration of CO_2 from the Skade Formation into the Utsira Formation above.

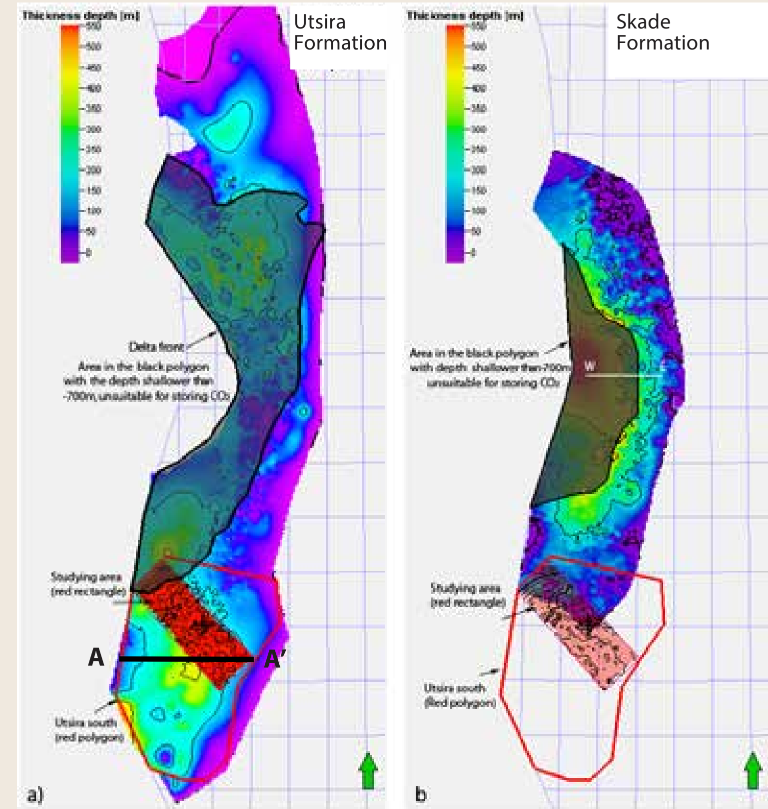
CO_2 injected in the Skade sand may penetrate through a intermediate clay layer into Utsira sand if the clay has permeability from 0.1 mD or higher. Approximately 170 Mt CO_2 can be injected in Utsira-Skade aquifer within the segment model, with four horizontal wells injecting over 50 years, with BHP change of 10 bars, and with no water production. After 8000 years of storage, the dissolved part is nearly 70%, residual trapping is less than 1%, and mobile CO_2 has decreased to 29% of the total amount of injected CO_2.

These results are based on a residual saturation of CO_2 of 0.02. If a residual saturation of CO_2 is 0.3, CO_2 trapped by residual mechanisms is 13% of total CO_2 injected after 8000 years. Mineral trapping by geochemical reactions was not considered in the simulation, but will add additional storage capacity.

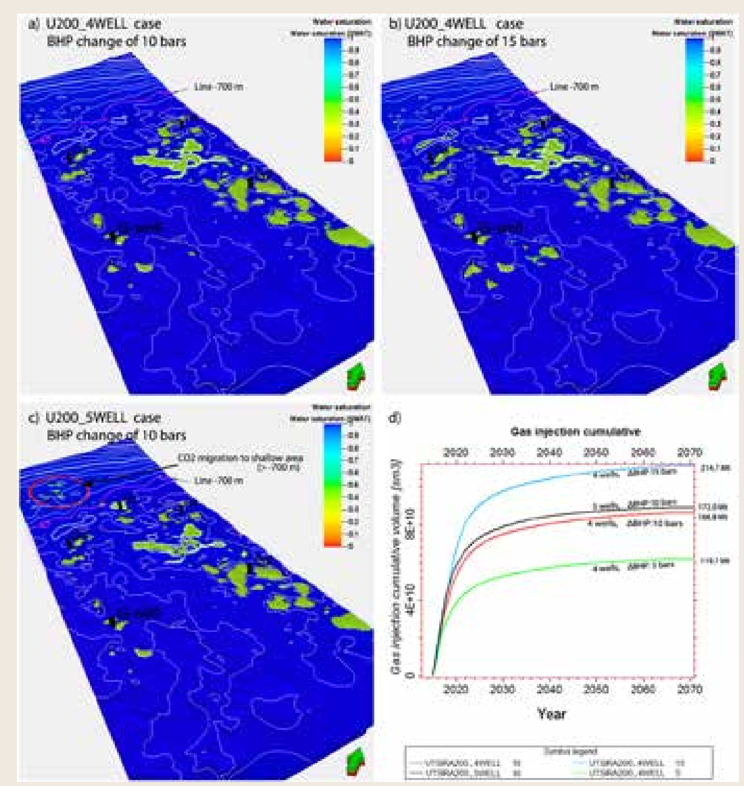
The NPD has calculated that 0.5-1.5 Gt of CO_2 can be stored in the southern area of the Utsira-Skade aquifer, based on in house simulation calculations.



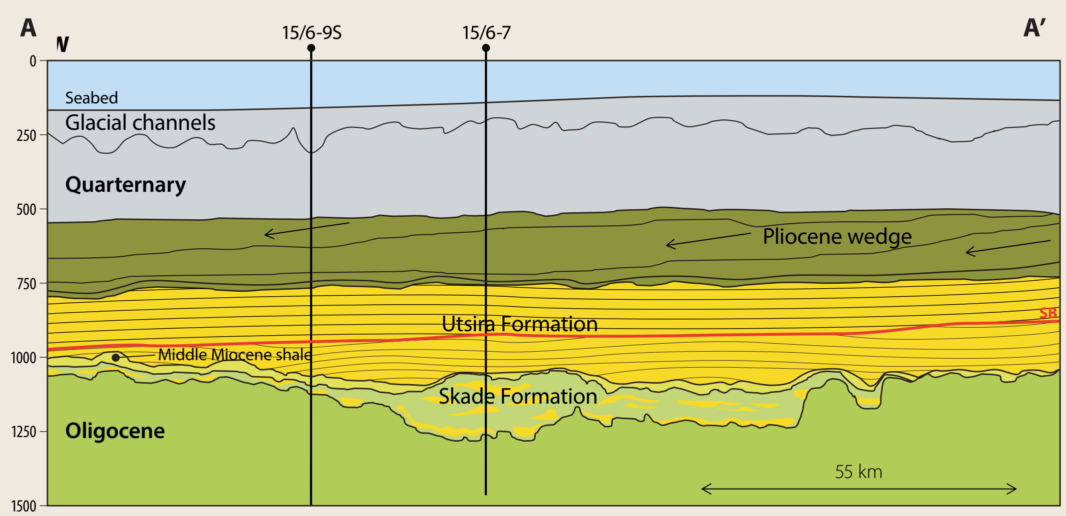
Red boundary defines the southern depocenter of the Utsira Formation. Skade Formation thins rapidly towards south and east, and is only observed as a few meters thick in well 15/6-7. The simulation model covers an area of 1600 m2 within the southern depocenter.



Thickness map (right) of Utsira and Skade Formations illustrating the extent of the formations and the area which is above 700 meters depth and thereby unsuitable for CO_2 storage.



8000 years after injection the CO_2 migrates and follows the topography and accumulates in surrounding structures. The graph illustrates that there is not much difference using 4 or 5 injection wells. The biggest difference occurs when there is an increase in the bottom hole pressure from 10 to 15 bars.



The Skade Fm, Lower Miocene, consists of marine sandstones (mainly turbidites) deposited over a large area of the Viking Graben (From 30/5-2 in the north, to 15/6-7 in the south). The maximum thickness exceeds 300 m and decreases rapidly towards the south and east, where the sands terminate towards large shale diapirs.

4.2.1 Saline aquifers

The Bryne and Sandnes Formations

The southern part of the Norwegian Sea has a well developed sandy sequence, which is made up of the Lower Jurassic, Sandnes and Bryne formations with occasional contact with the sands of the Triassic Gassum and Skagerrak formations. The fine grained, lowermost Jurassic Fjerritslev Formation, is partly developed as a seal between the Gassum and Bryne Formations.

The Sandnes formation is generally developed as a well sorted and widely distributed sand, above the thicker silt and sandstones of the Bryne formation. The vertical permeability of the Bryne formation is lowered by the coaly layers developed in most of the formation. The connectivity in the Bryne formation is hampered by the typical development of isolated channels and channel belts of the delta plain. The two formations typically thin on the crests of salt structures and thicken in the basins. The yellow polygon in the figure outlines the Farsund Basin. This basin is bounded by a basement high to the south, and has been treated as a separate segment within the aquifer.

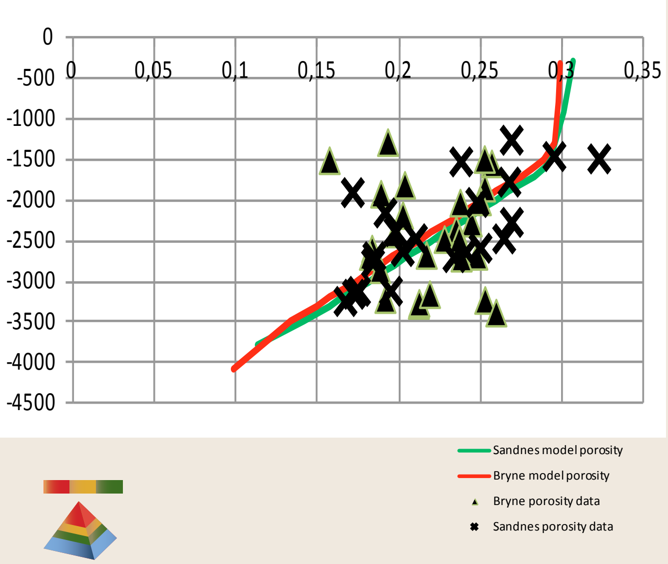
There is a limited amount of well data for constructing detailed petrophysical maps. In the present aquifer model, an average thickness is presented. For the porosity a general depth trend was applied, and for the net gross factor, a correlation to the formation thickness was attempted.

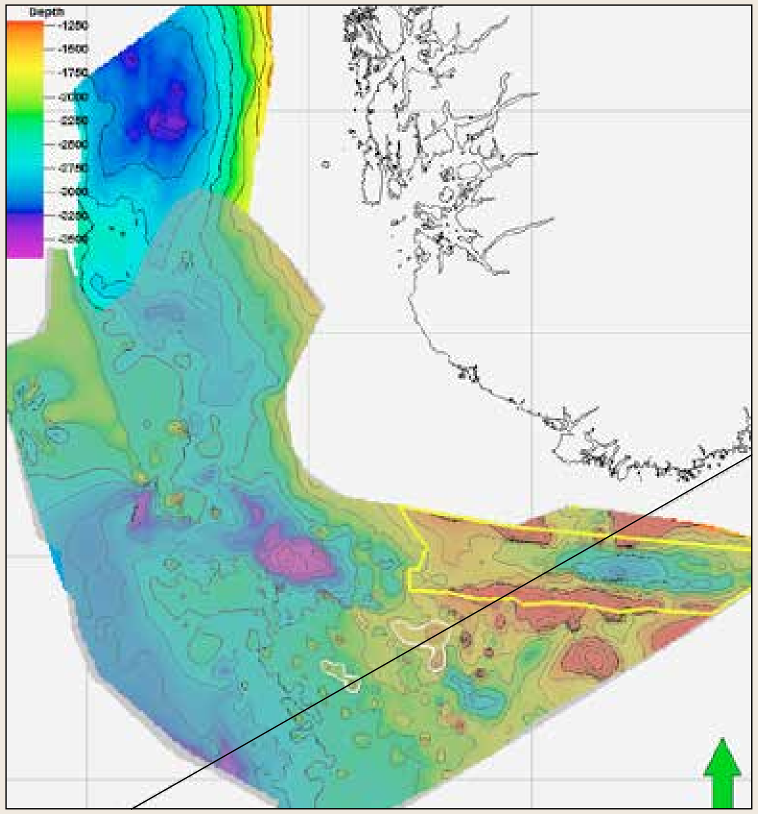
The aquifer is considered quite well suited for CO_2 storage due to the well developed reservoir rocks. The aquifer is capped by the generally thick and robust mud- and claystones of the Boknfjord Formation.

Seal integrity should be investigated further above salt structures and in major faults. To get an idea of the storage capacity of these structures is an estimation of two structural closures presented in the table. The smaller structure is thought to be representative for the aquifer. There also seems to be a possibility for larger structures in the saddle area between the Stord Basin and the Egersund Basin. Assuming that the aquifer could contain a few of the bigger structures and that there are many salt structures which could form prospects, a capacity range of 0.5 to 2 Gt for the prospects is assumed. The integrity and reservoir quality of each prospect would have to be investigated, hence they are assigned to level 2 in the pyramid.

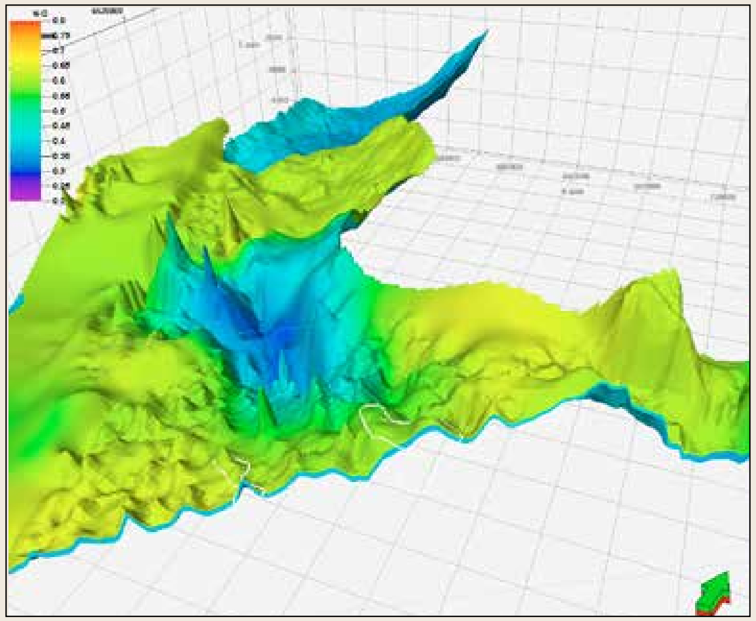
Farsund Basin		
Storage system	half open	
Rock volume		855 Gm^3
Pore volume		82 Gm^3
Average depth		
Average permeability		
Storage efficiency		4
Storage capacity aquifer		2 Gt

Bryne and Sandnes Fms		
Storage system	half open	
Rock volume		500 Gm^3
Pore volume		440 Gm^3
Average depth		1700 m
Average permeability		150 mD
Storage efficiency		4,5 %
Storage capacity aquifer		14 Gt
Storage capacity prospectivity		0,5-2 Gt
Reservoir quality		
	capacity	3
	injectivity	2
Seal quality		
	seal	3
	fractured seal	2
	wells	3
Data quality		
Maturation		





The Bryne and Sandnes aquifer. Yellow polygon shows Farsund Basin, white polygons show evaluated prospects.



Top surface and cross section of the Bryne-Sandnes aquifer.

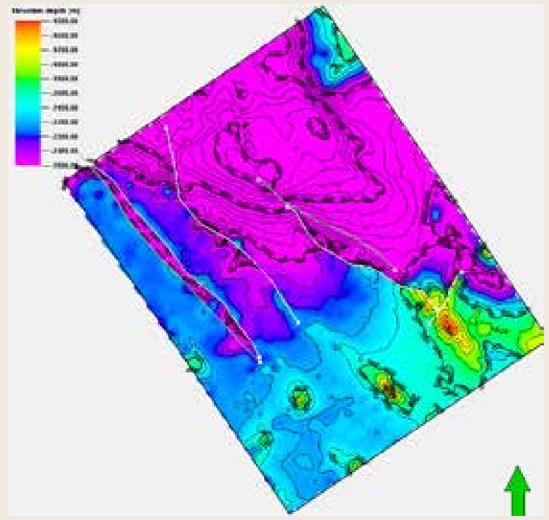
4.2.1 Saline aquifers

Egersund Basin case study

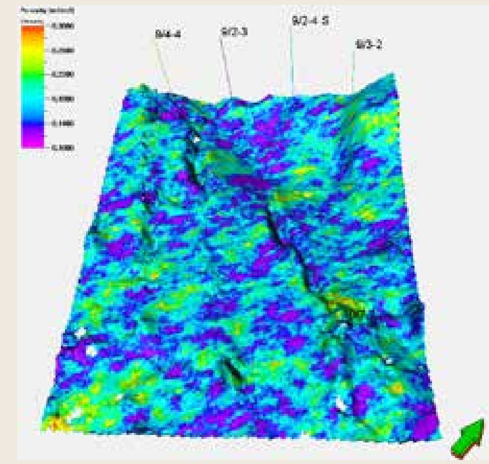
Geological model

The main target for CO_2 injection is the extensive middle Jurassic sands of the Sandnes and Bryne Formations in the Egersund Basin southwest of Stavanger. The Egersund Basin is a local deepening between the Norwegian-Danish Basin and the Stavanger Platform in the North Sea. The southern part of the basin is the focus for this study. The Egersund Basin has a small local oil kitchen to the NW, charging the Yme Field which is situated in the northern part of the basin. The development of lower and middle Jurassic sandstones is partly influenced by the tectonic structuring and salt movement. Later, the upper Jurassic – Lower Cretaceous tectonic development created a series of NW-SE faults. In the late Neogene the basin was lifted obliquely eastward and up towards the Norwegian mainland.
This is a promising area with good reservoir sand, well suited for containment of substantial volumes of CO_2. Migration of CO_2 into to salt structures penetrating the post Permian sequences and further into the Neogene, should however be avoided.

The Sandnes Formation contains marine sands with a high net/gross ratio, whereas the underlying Bryne Formation represents continental sand deposits with marine incursions. The lateral and vertical communication of the Bryne Formation is considered to be uncertain, and consequently it is not as suitable for large scale CO_2 injection. However, the Bryne Formation and some of the upper Triassic sands will contribute to the active aquifer volume. The reservoir sands are sealed by thick Jurassic and Cretaceous shales.

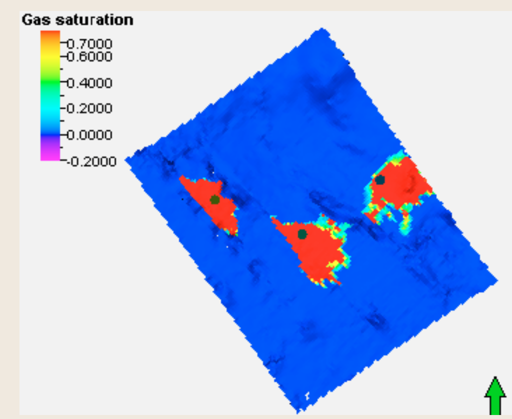


The simulated part of the Egersund Basin area.

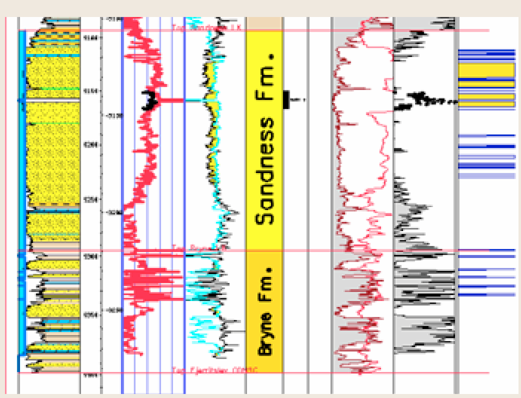


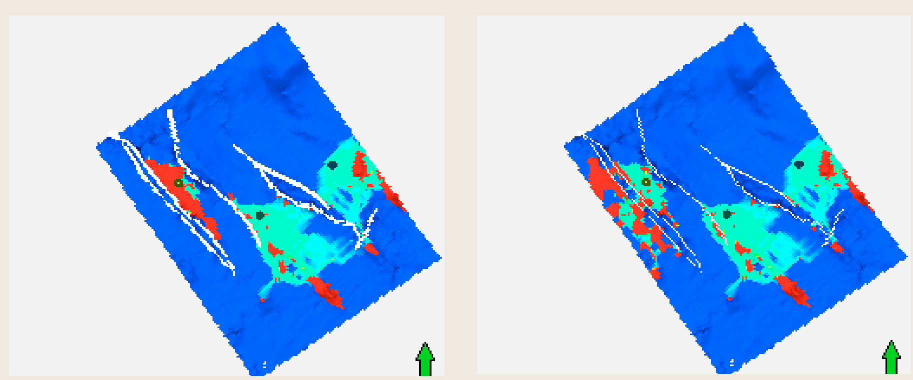
Porosity map of the uppermost layer of the Sandnes Formation used in the simulation

Results from the reservoir simulation of the Egersund Basin.
A segment model (48km x 62km) of the Egersund Basin was contructed to estimate the storage capacity and the migration paths. Different cases were run with 1-3 injection wells and injection rates from 2 to 10 MSm^3 CO_2/year in 50 years. Bottomhole pressure change is limited to 30 bar. Faults in the model were simulated with open and closed scenarios. Results showed that the volume of CO_2 injected is not very different between open and closed faults cases, but the distribution of the CO_2 plume is different (se figure).



CO_2 distribution after 50 years injection in three wells.





CO_2 distribution after 1000 year from injection start. With closed faults (left), and open faults (right). A part of the CO_2 migrates through the faults to the west.

Conclusion
Using the model and relative permeability curves from the Frigg field with a residual CO_2 saturation of 0.3, the storage capacity is:

- 180 GSm^3 or 0.36 Gigatons assuming a reservoir pressure buildup of 9 bar with 1 injector
- 546 GSm^3 or 1.1 Gigatons assuming a reservoir pressure buildup of 26 bar with 3 injectors

4.2.1 Saline aquifers

The Sognefjord Delta aquifer

The Sognefjord delta aquifer includes the sandstones belonging to the Viking Group. The Krossfjord, Fensfjord and Sognefjord Formations are partly separated by thin shale units (Heather Formation). Oil and gas production from the giant Troll Field has caused pressure reduction in all the three formations. The three formations are here treated as one aquifer. Influence of the Troll depletion on the aquifers in the older Jurassic formations is less pronounced. These sandy formations will be in communication through local juxtaposition along faults or by local sand-sand contact. In the area east of the Troll Field the sands are in direct contact with each other and constitute a good reservoir.

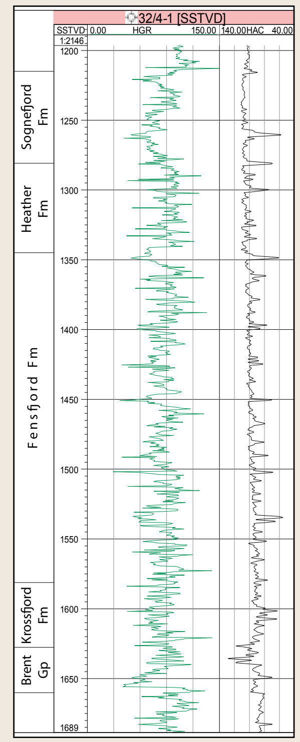
The storage capacity of the western part of the Sognefjord delta has not been included because it forms reservoir rock of the Troll field and other fields north of Troll. The aquifer is treated in the same way as in the main petroleum provinces.

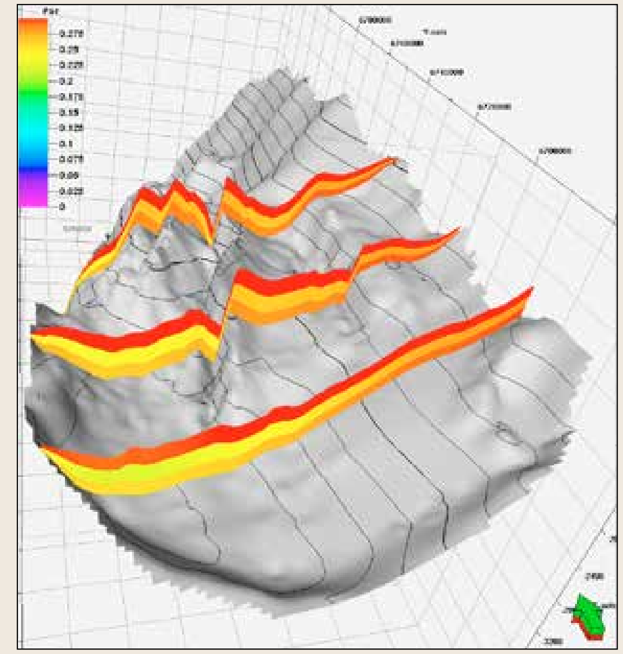
The eastern part of the Sognefjord Delta aquifer (within the black polygon in the figure) is structured by faults in the Øygarden Fault Complex. Two water-filled structural traps have been drilled in this area. This part of the aquifer is considered to be outside the area of large scale hydrocarbon migration, and closed structures may be attractive for CO_2 storage.

The porosity used for volume calculation is based on depth trends derived from wells in the area.

Several gas accumulations in the western part of the aquifer indicate a good quality seal. The sealing capacity of the fault zones in the Øygarden Fault Complex has to be investigated further. The aquifer subcrops below the Quaternary in the east, and there might be a risk of lateral migration of injected CO_2 towards the subcrop area.

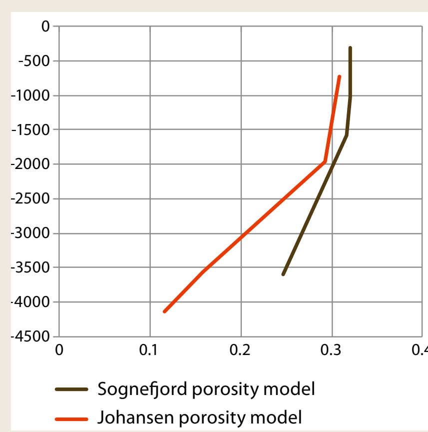
WELL 32/4-1

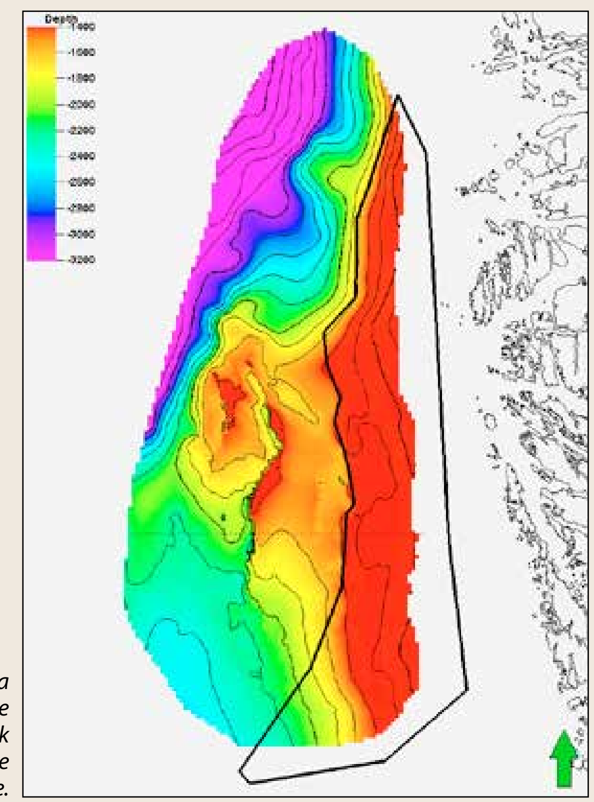




Cross sections showing the Krossfjord, Fensfjord and Sognefjord formations with modelled porosity values above the Top Brent surface within the Sognefjord Delta.

Sognefjord Delta		Total aquifer Summary	East aquifer Summary
Storage system	half open		
Rock volume		2670 Gm^3	554 Gm^3
Pore volume		480 Gm^3	110 Gm^3
Average depth		1750 m	1750 m
Average permeability		300 mD	300 mD
Storage efficiency		5,5 %	5,5 %
Storage capacity aquifer		18 Gt	4 Gt
Storage capacity prospectivity			
Reservoir quality			
	capacity	3	3
	injectivity	3	3
Seal quality			
	seal	3	3
	fractured seal	2	2
	wells	2	2
Data quality			
Maturation			





Top of the Sognefjord delta aquifer. The eastern past of the aquifer, outlined by the black polygon, is outside the petroleum province.

4.2.1 Saline aquifers

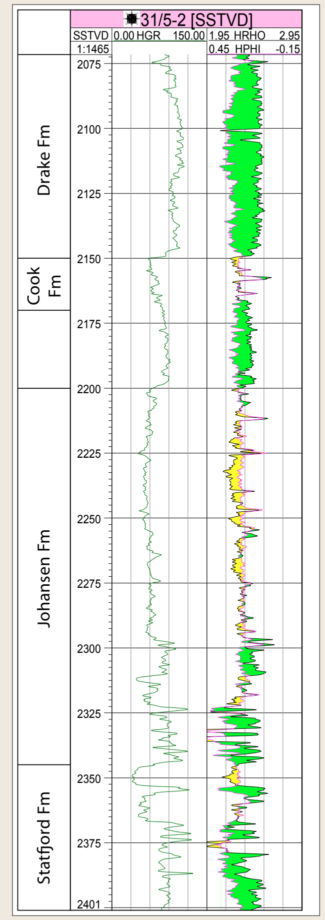
The Johansen and Cook Formation aquifer

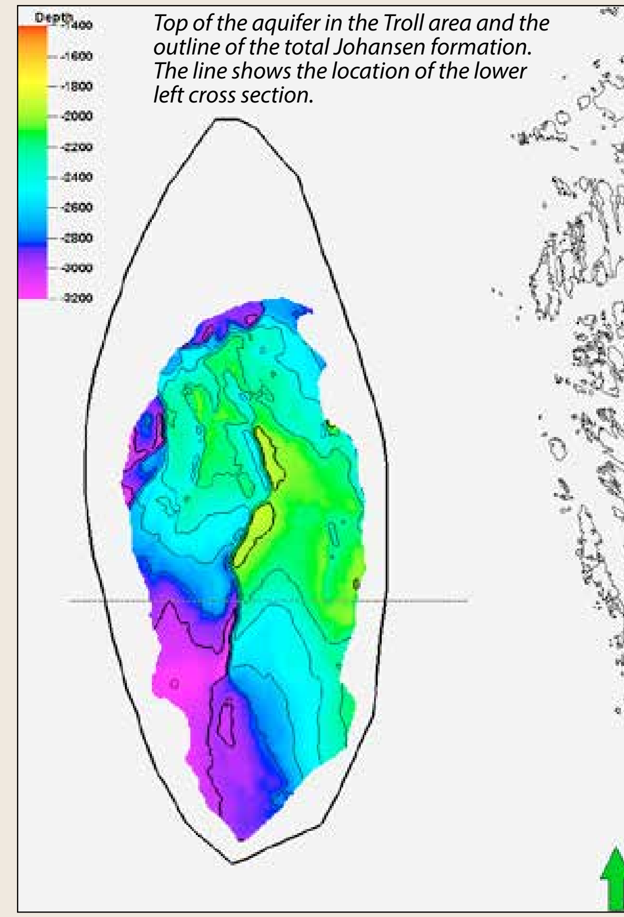
The Johansen and Cook Formations are mainly separated by shales and siltstones, but due to fault juxtaposition, they will be treated as one aquifer. The Johansen Formation sandstones have good reservoir properties in several wells in the Troll Field, and seismic data imply that the sand distribution is similar to the overlying Sognefjord Delta. The Cook Formation and the underlying Statfjord Formation extend to the Tampen Spur. The upper part of the Dunlin Group in the Troll area consists of the thick Drake Formation shale which is the main seal (figure).

The Johansen Formation south of the Troll Field was suggested by the NPD in 2007 as a potential storage site for CO_2 from Mongstad, and several studies have been carried out in order to qualify the aquifer for CO_2 storage. The NPD and Gassnova have acquired 3D seismic data in the most promising area. The studies indicate that the formation has sufficient capacity to store the volumes from Mongstad, but a well is important to clarify the reservoir and seal properties in the area south of Troll. Migration of CO^2 to the surface is unlikely due to the large capacity of the Sognefjord Delta aquifer.

The capacity of the Johansen and Cook aquifer depends on the communication within the aquifer, and if it is in communication with the Statfjord and/or the Sognefjord Delta aquifers across major faults.

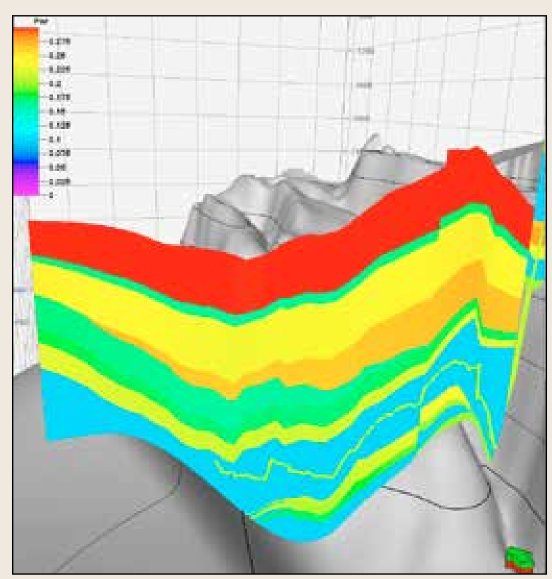
The pore volume and the storage capacity in prospects given in the table are based on calculations by Gassnova. These calculations do not include the northernmost part of the aquifer in the area north of Troll, see figure.



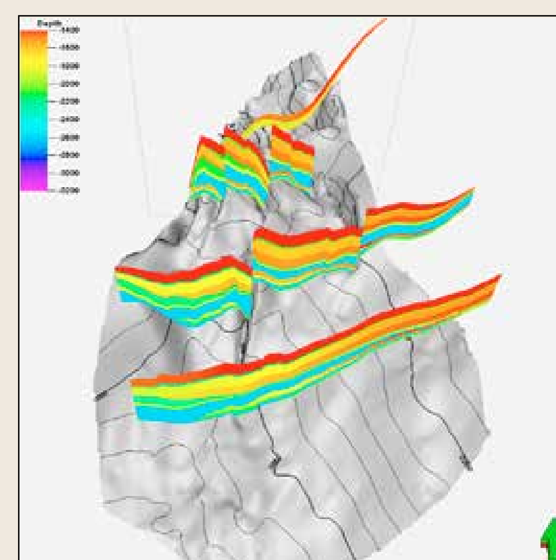


Top of the aquifer in the Troll area and the outline of the total Johansen formation. The line shows the location of the lower left cross section.

Cook Johansen aquifer		
Storage system	half open	
Rock volume		590 Gm^3
Pore volume		90 Gm^3
Average depth		1700 m
Average permeability		400 mD
Storage efficiency		3 %
Storage capacity aquifer		2 Gt
Storage capacity prospectivity		150 Mt
Reservoir quality		
	capacity	3
	injectivity	2
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		



Cross section of the porosity model of the Sognefjord delta. The Johansen and Cook Formations are the two deepest porous layers.



Several cross sections showing juxtaposition of porous formations across faults. The basal surface is the top of the Statfjord Formation.

4.2.1 Saline aquifers

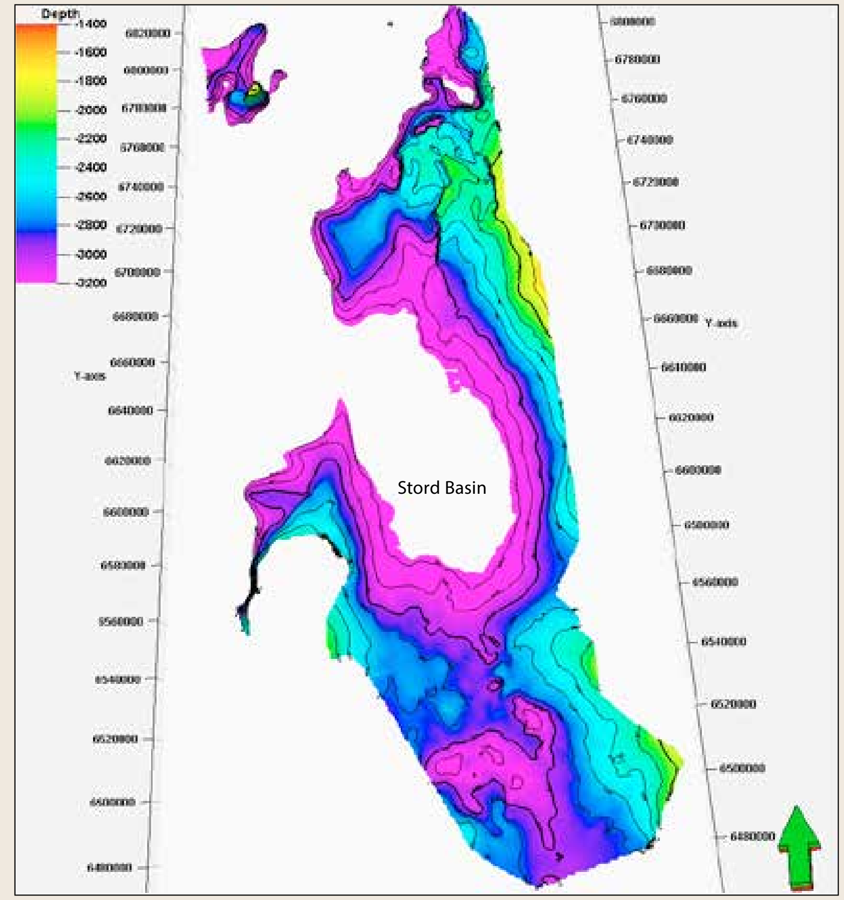
The Statfjord Formation aquifer

The Statfjord Formation contains hydrocarbons in the Viking Graben, Tampen High and north of the Stord Basin. South of the Horda Platform, it is assumed to be mainly water bearing. In the Stord Basin and its surroundings, it is separated from the overlying Jurassic aquifers by the Dunlin Group which is expected to form the seal. Towards the south and towards the Norwegian coast, the Lower Jurassic and large parts of the Middle Jurassic pinch out, and there may be communication between the Statfjord Formation aquifer and the shallower aquifers.

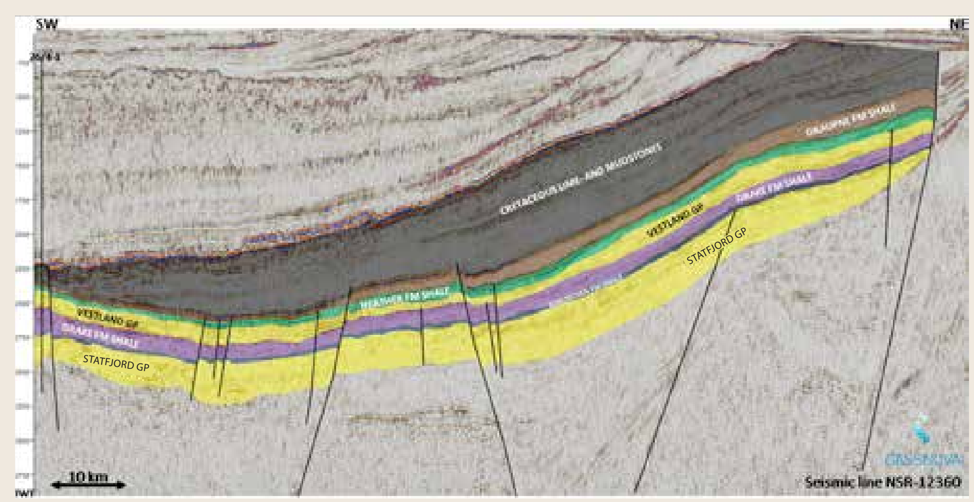
Few wells have been drilled in the Stord Basin area, and neither the formation properties nor its distribution and thickness are well known.

A heterogeneous formation with locally good quality reservoirs, but with limited lateral and vertical continuity can be expected. For the purpose of calculation of theoretical storage capacity, an average net gross of 50 % has been applied to the whole area and a porosity-depth trend similar to the Bryne Formation was applied. This is based on the general geological understanding of the area. In the Stord Basin (fig), parts of the formation are located below 3500 m, and has been excluded from the volume calculation.

Statfjord Gp East		
Storage system	half open	
Rock volume		1130 Gm^3
Pore volume		120 Gm^3
Average depth		2400 m
Average permeability		200 mD
Storage efficiency		4,5 %
Storage capacity aquifer		4 Gt
Storage capacity prospectivity		
Reservoir quality		
	capacity	3
	injectivity	2
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		



The top of the Statfjord Formation above 3500 m. The Tampen area to the NW was not included in the volume calculations.



SW-NE cross section in the northern part of the Stord Basin

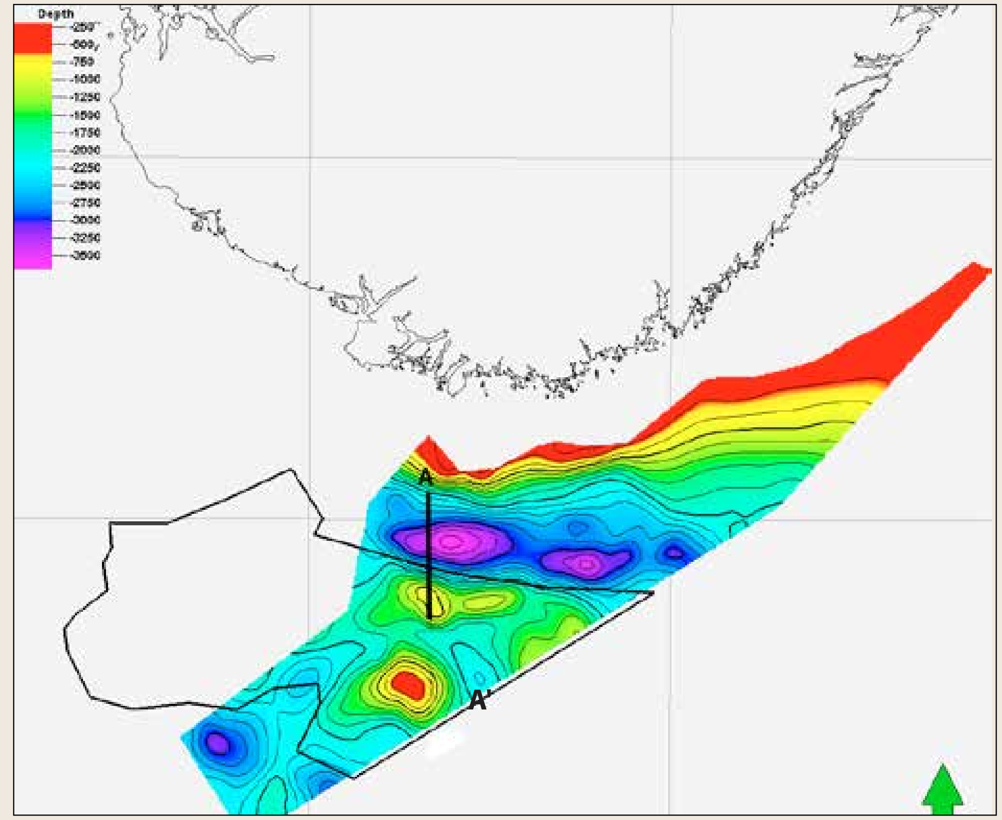
4.2.1 Saline aquifers

The Gassum Formation aquifer and the Skagerrak Formation

The aquifer was developed as river dominated system in the latest Triassic time, mainly as a well drained braided river system . The sandstones are believed to be of good quality. The type wells for these sandstones are in the Danish sector, and the Norwegian part is not explored in the same detail. Outside the mapped area indicated in the figure, the latest Triassic fluvial systems are more clay rich and are developed as discontinuous river sands. In the area indicated, the formation is sealed by the Fjerritslev Formation.

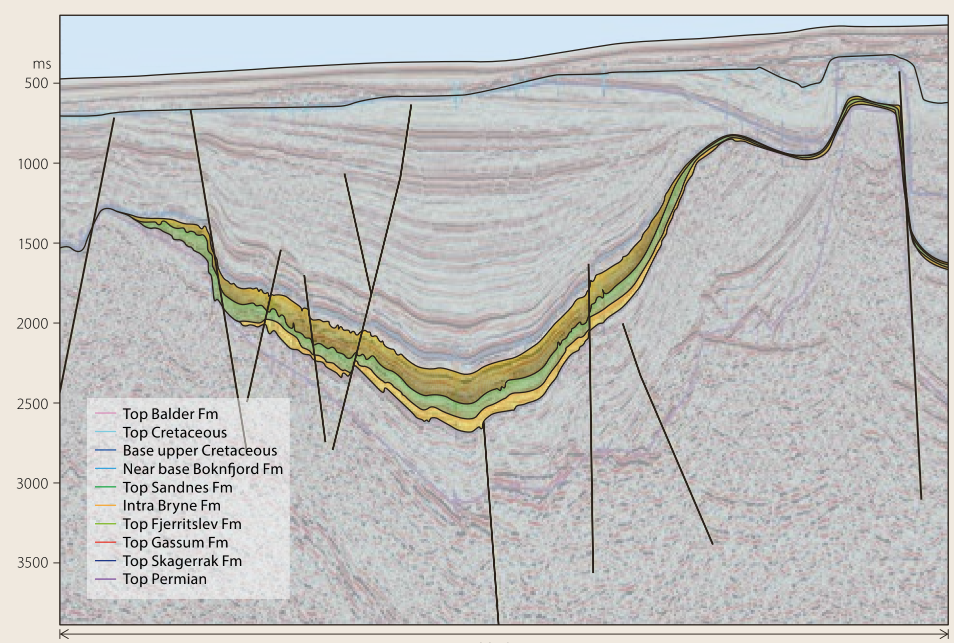
In the Skagerrak area, the Gassum Formation outcrops to the sea floor, and is covered by a Quaternary section which is typically less than 100 m thick. The sealing risks include faults, fracturing above salt structures and long distance migration towards the sea floor. The red areas in the map shows where the burial depth is less than 600 m. Migration of CO_2 into these areas should be avoided. The Gassum Formation can be a candidate for CO_2 injection in the Skagerrak area, but more data is required to investigate its potential.

The underlying Skagerrak formation is developed as a braidplain in an arid desert environment and as alluvium bordering the emergent land area east of the Danish-Norwegian Basin. Scarce well data indicate that the thick sandy sequences of the formation have low permeability, but locally they could interact with the overlying Gassum aquifer. The Skagerrak Formation in the Norwegian sector is poorly known, and with more data it is possible that a storage potential could be defined. In the figure, the outlined area indicates where the Skagerrak Formation is buried to less than 2000 m.



Top of the Gassum Formation

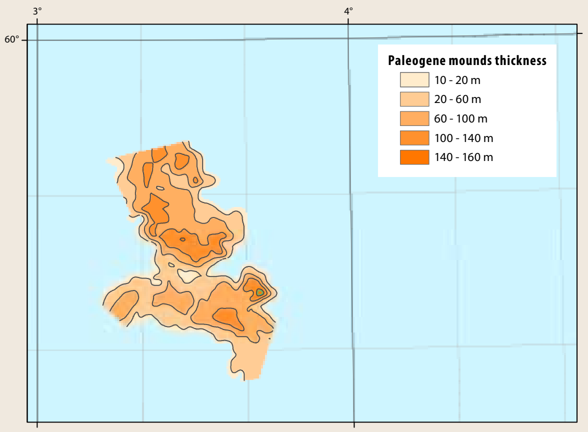
Gassum Fm		
Storage system	half open	
Rock volume		6500 Gm^3
Pore volume		756 Gm^3
Average depth		2200 m
Average permeability		450 mD
Storage efficiency		5,5 %
Storage capacity aquifer		3 Gt
Storage capacity prospectivity		
Reservoir quality		
	capacity	2
	injectivity	3
Seal quality		
	seal	3
	fractured seal	2
	wells	3
Data quality		
Maturation		

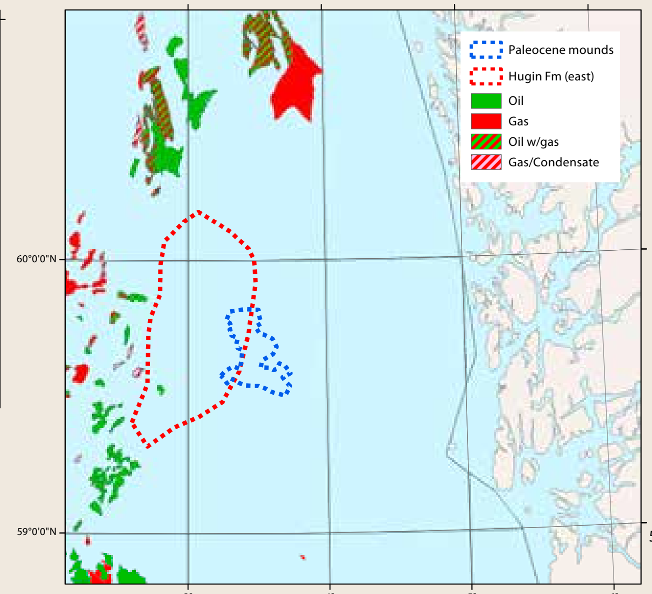


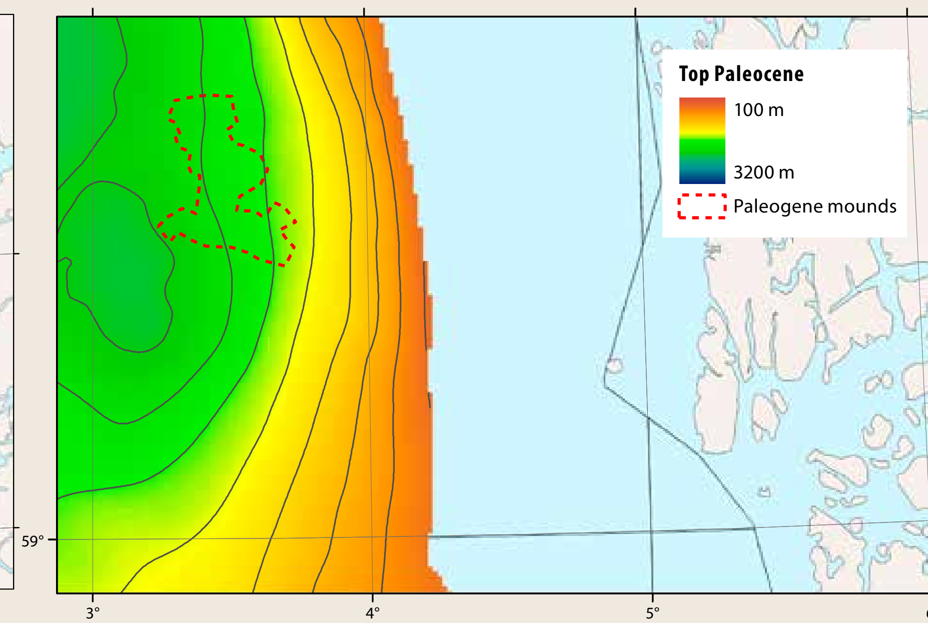
Seismic section across the Farsund Basin. The Gassum aquifer is located between the red and the dark blue horizon at the base of the Jurassic section.

4.2.1 Saline aquifers

Paleogene Mounds, Stord Basin
The Hugin East Formation aquifer







Paleogene mounds
This prospect is based on seismic 2D interpretation on a mounded reflector in the Paleocene/Eocene sequence in the central part of the Stord Basin. The reflection pattern has been interpreted as a possible deep marine fan system which could have a high content of reservoir sand. There are few wells in the area, and sand have not been proved by drilling in this particular interval. If sand is present, the mapped structure can be regarded as a structural/stratigraphical trap with good seals. The aquifer outside the mapped structure is considered to be limited. Calculation of storage capacity is based on 28 % porosity and a net gross ratio of 0.8 within a closed aquifer volume.

Mounds, Stord basin		
Storage system	half open	
Rock volume		45 Gm^3
Pore volume		10 Gm^3
Average depth		1900 m
Average permeability		1000 mD
Storage efficiency		0.8 %
Storage capacity aquifer		
Storage capacity prospectivity		50 Mt
Reservoir quality		
	capacity	2
	injectivity	2
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		

Hugin East Aquifer
One well has been drilled in this aquifer, which has been mapped on 2D seismic data. The reservoir rock is equivalent to the Hugin and Sandnes Formations, and is believed to have good quality. A simplified calculation of theoretical storage capacity was carried out, using a constant net gross value and a porosity trend similar to the Sandnes Formation.

Hugin fm east of the Utsira High		
Storage system	half open	
Rock volume		19 Gm^3
Pore volume		2.5 Gm^3
Average depth		1700 m
Average permeability		500 mD
Storage efficiency		5,5 %
Storage capacity aquifer		100 Mt
Storage capacity prospectivity		
Reservoir quality		
	capacity	1
	injectivity	3
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		

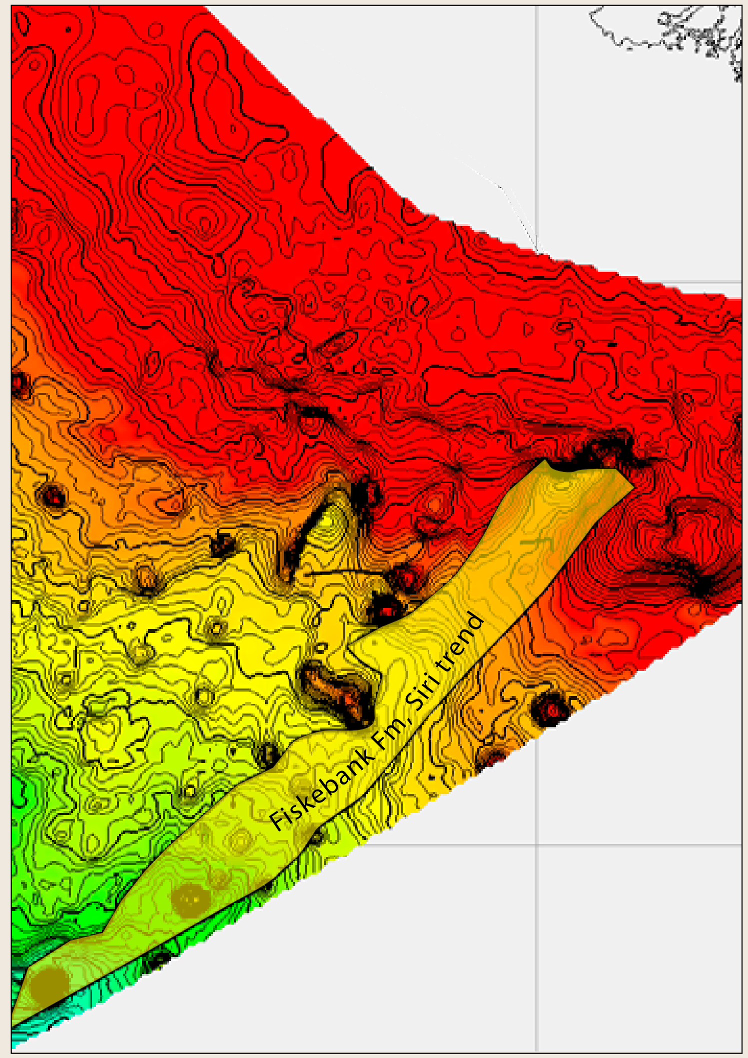
4.2.1 Saline aquifers

The Fiskebank Formation aquifer (The Siri trend)

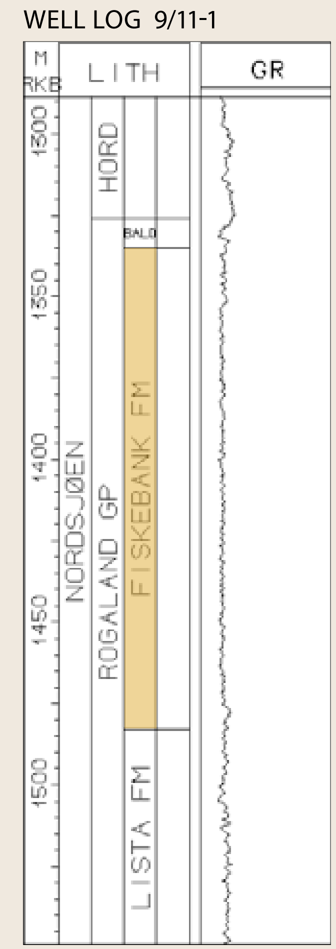
In the Norwegian-Danish Basin, deep water sandstones of upper Palaeocene age, hold some smaller hydrocarbon fields and discoveries on the Danish sector close to the border with Norway. The sands on the Norwegian side have been drilled by the dry well 3/6-1 and are highly porous and permeable.

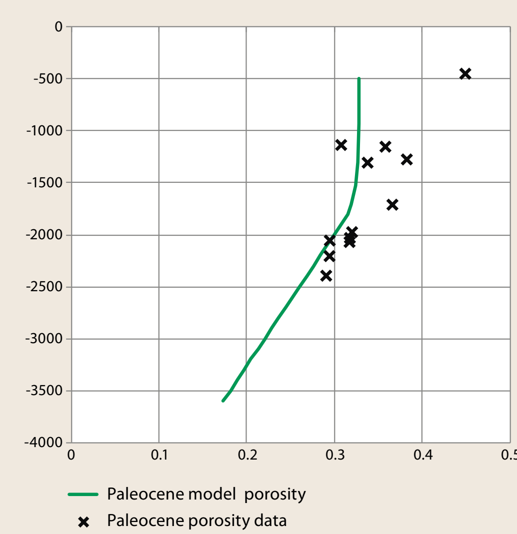
The suggested Fiskebank Formation aquifer is located in a depression in the top chalk surface as shown in the figure. More wells are needed to confirm the existence of high quality sands.

There is some hydrocarbon exploration activity in this area, which is not considered to be fully explored.
The sealing capacity of the Paleocene caprocks is generally thought to be good. Fracturing related to salt structures may occur.



Top of the chalk surface. The polygon shows the location of the Fiskebank Formation aquifer.





Fiskebank Fm, (Siri trend)		
Storage system	half open	
Rock volume		100 Gm^3
Pore volume		25 Gm^3
Average depth		
Average permeability		1000 mD
Storage efficiency		5.5 %
Storage capacity aquifer		1 Gt
Storage capacity prospectivity		
Reservoir quality		
	capacity	3
	injectivity	3
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		

4.2.2 Abandoned hydrocarbon fields

Storage in abandoned fields

The estimate of CO_2 storage potential in the petroleum provinces is based on abandoned fields. This is in accordance with the Governmental policy that any negative consequences of CO_2 storage projects for existing and future petroleum activity should be minimized.

At the end of 2013 there are 12 abandoned fields on the Norwegian shelf. Of these three oil fields, four gas-condensate fields and five gas fields. Of the 12 fields, CO_2 storage volumes have been calculated for nine. The chosen fields have been pressure depleted, and the calculations are based on material balance, taking into account the produced volumes of oil, condensate and gas. Some of the fields are chalk fields in the Ekofisk area with low permeability reservoirs. To get decent injection rates, the wells need to be long with advanced completions. The fields have an EOR potential because they contain a rest of hydrocarbons that might be mobilized and produced during the injection. The CO_2 storage capacity for today's producing fields are estimated based on the close of the production year, and summarized for the years 2030 and 2050.

The Frigg field is studied in more detail and simulated due to its large storage potential. The fields and the main aquifers in the petroleum provinces in the North Sea are shown in the maps.

Many of the big fields in the Lower –Middle Jurassic Statfjord, Brent and Sleipner aquifers are located in areas with weak to moderate overpressure. In parts of the aquifers, the pressure has been depleted due to production. The highly overpressured parts of the aquifers (red color in the pressure maps) are not suitable for CO_2 injection.

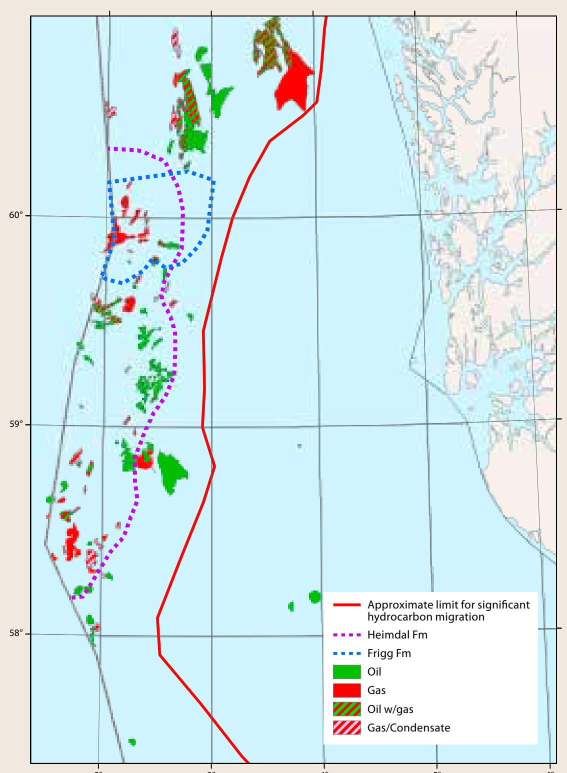
The Sognefjord and Hugin aquifers are hydrostatically pressured to weakly overpressured. The aquifers surrounding the big gas fields have been depleted due to gas production. The Ula Formation has oil fields which are weakly overpressured and relatively deeply buried.

The chalk formations in the southern part of the Norwegian sector have low permeabilities and have not been evaluated for CO_2 storage. The large oil fields have interesting potential for use of CO_2 to enhance the recovery (section 8).

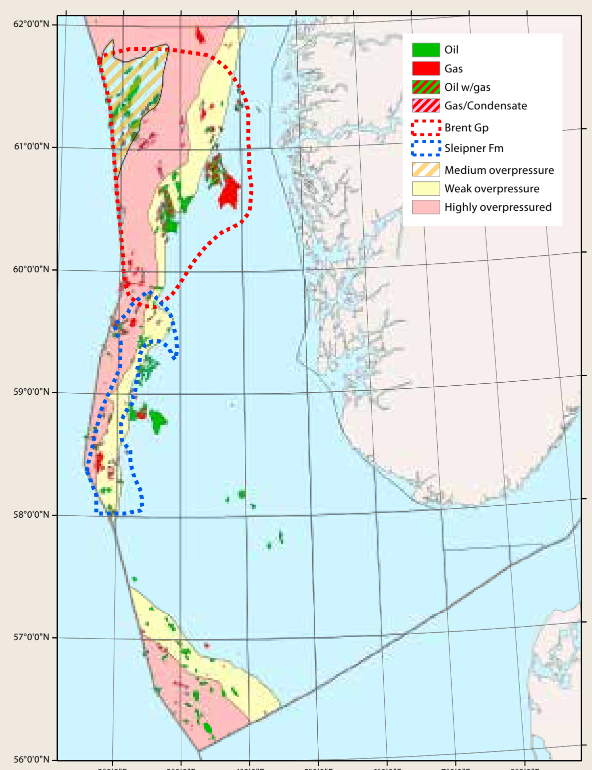
Abandoned fields	Storage capacity, Gt
CO_2 storage in depleted fields	3 Gt
Producing fields	
Close of production in 2030	4 Gt
Close of production in 2050	6 Gt
Storage potensial in the Troll field is not included, expected to be available after 2050.	

The Paleocene and Eocene Ty, Heimdal, Hermod, Balder and Frigg Formations constitute a large hydrostatically pressured aquifer with both oil and gas fields. There is a significant pressure depletion due to gas production in Frigg and Heimdal. The storage potential in the abandoned Frigg Field is presented in the following section.

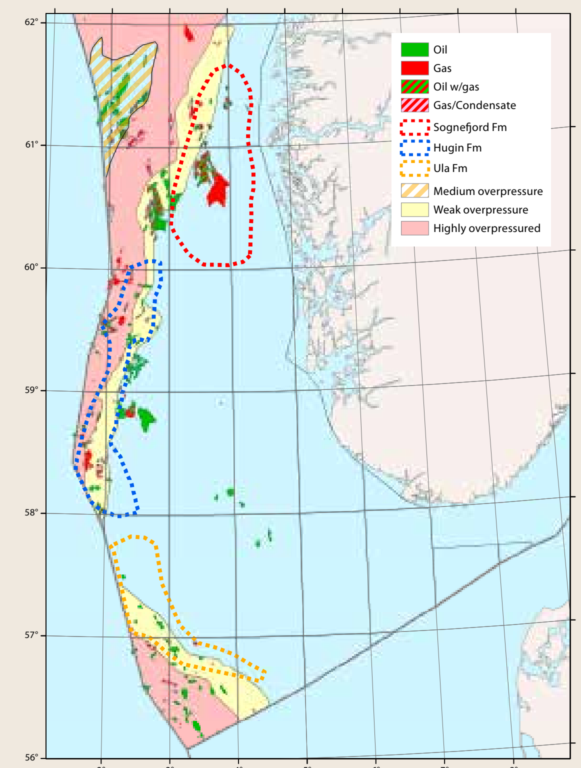
The table shows an evaluation of storage potential in abandoned fields and in today's producing fields, based on close of production year.



Frigg and Heimdal Formations. Hydrostatic pressure/underpressure



Brent Gp and Sleipner Fm, and overpressured areas.



Sognefjord, Hugin and Ula Formations

Lower Jurassic Bridport sandstone, Dorset, England. High porosity, good reservoir quality sandstone with calcite cemented beds and nodules, deposited in a shallow marine environment. The thickness of the sandstone formation in this area is 40-50 m. The Bridport sandstone has been regarded as a reservoir analog for the Sognefjord Formation in the Troll area. Photo: NPD

4.2.2 Abandoned hydrocarbon fields

FRIGG FIELD

The Frigg field was abandoned in 2004 after 27 years of gas production. The field was produced together with Nordøst Frigg, Lille-Frigg, Øst Frigg and Odin, which used the process facilities on Frigg. The field is located approximately 190 km west of Haugesund in Norway. Frigg is a transboundary field between Norway and the UK.

The reservoir consists of unconsolidated sand in the upper part. The properties are generally very good with porosity ranging from 27% to 32% and permeability from 1 to 5 Darcy.

The initial gas pressure was 197.9 bars at 1900 m MSL, and the initial aquifer pressure (Sele/Lista formations) was found to be 223.4 bars at 2191 m MSL. The water depth in the area is about 100 m.

The initial gas in-place volume was 247 GSm^3, of which about 191 GSm^3 has been recovered.

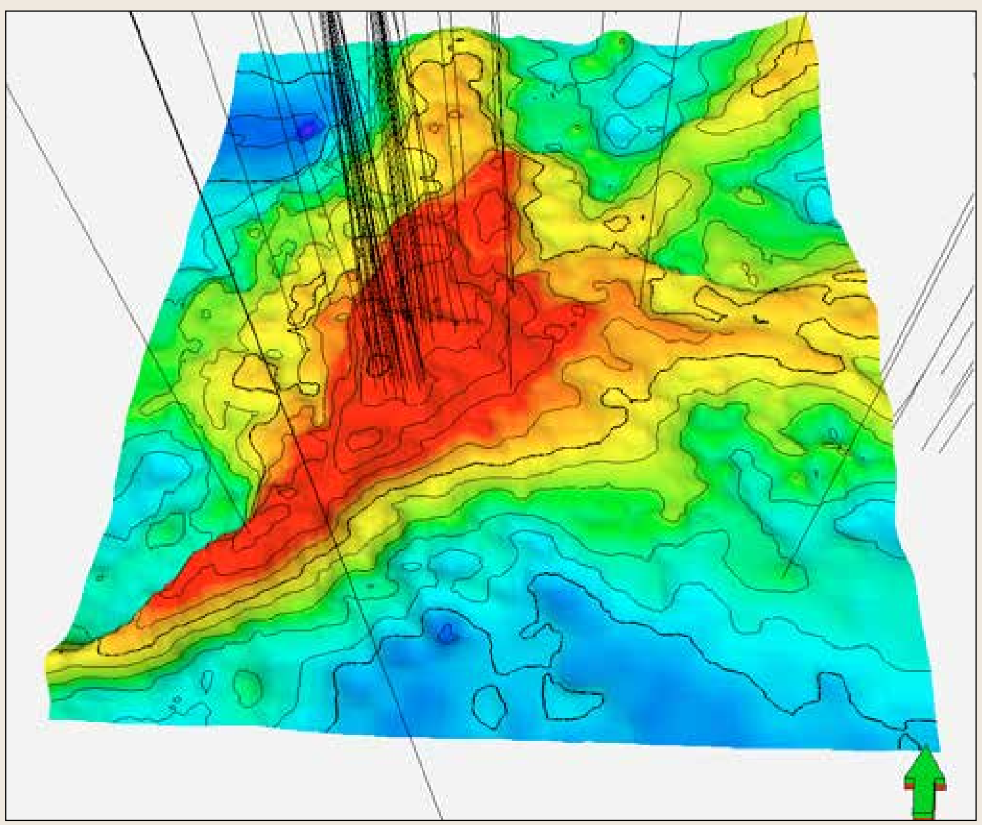
A CO_2 injection study was done by the NPD in 2010 to see if the abandoned field and its satellites might be a candidate for future CO_2 storage. A reservoir simulation model made by Total for the full field was used and converted to an Eclipse E300 compositional model. The model was matched both with regard to PVT and production history. The fluid was described with four component groups: CO_2, N2+C1, C2-C6 and water.

The simulation model included a huge aquifer around the Frigg fields. The model is shown in the lower right figure with grid cells, hydrocarbon accumulation and rock compaction regions. The main cases run were the following:

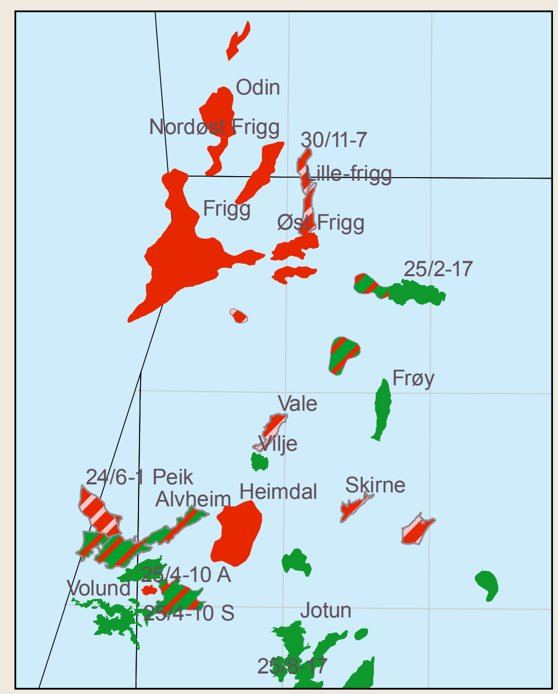
1. Production of remaining gas together with CO_2 injection
2. Injection with closed aquifer, no gas production
3. Injection with leaking aquifer, no gas production.

In case 1, 10 mill Sm^3/d of CO_2 was injected for 55 years from one well in the aquifer, and remaining methane gas was produced from the top of the Frigg field. In cases 2 and 3, CO_2 injection with 10 and 50 mill Sm^3/d was applied in an open aquifer. An open aquifer was simulated by producing water in the corners of the aquifer, thus keeping the pressure increase quite slow. The results are shown in Table 5.2.1. The range in methane gas volume produced is due to the uncertainty in trapped gas saturation, where low values of trapped gas correspond to high volumes produced. Base case trapped gas saturation (Sgr) is 0.28 and gives 0.3 Gsm^3. An Sgr of 0.14 gives 18.8 GSm^3.

In cases 2 and 3, pressure builds up from about 183 bar in Frigg, which is about 20 bars below initial pressure, to 208 bars in case 2 and 278 bars in case 3. The behaviour of CO_2 in the formation water has a long-term effect, as more and more of the free CO_2 will dissolve. This leads to heavier formation water which will start to move downward as shown in the figure.



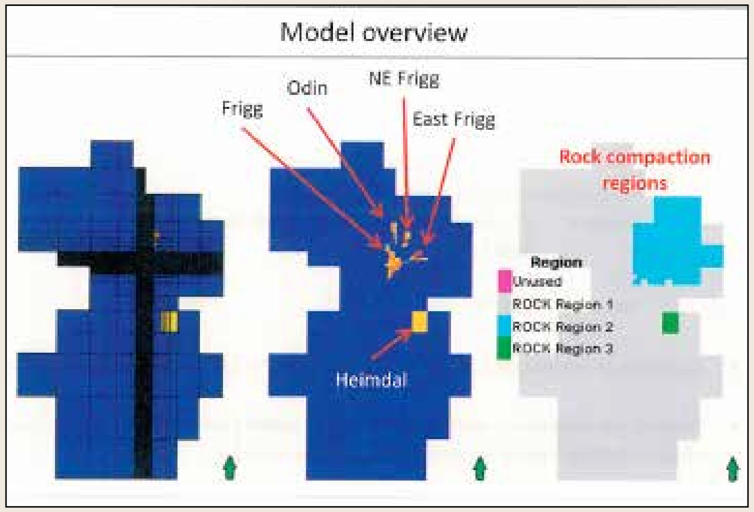
Structural map of the Frigg field with all wells



Frigg field with satellites. Hydrocarbon fields in the Frigg area

4.2.2 Abandoned hydrocarbon fields

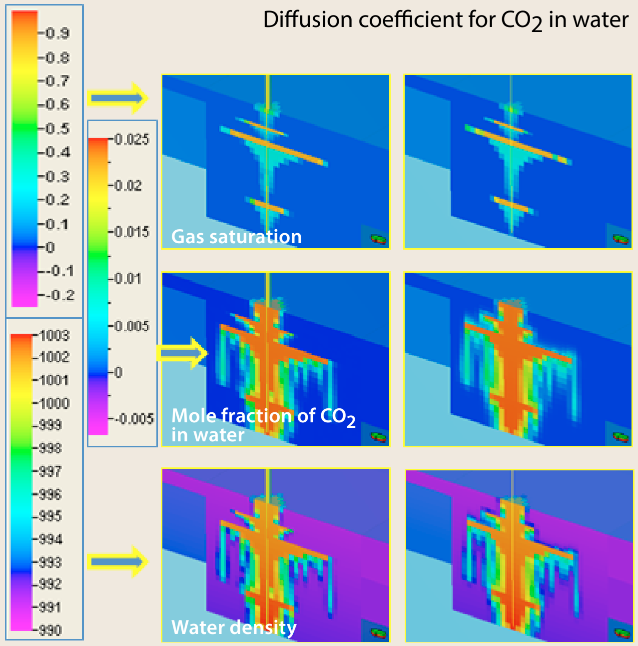
Case	Description	Gas produced, GSm3	Injection period, years	Injection rate	Pressure increase, bar	CO_2 injected Mt	Storage efficiency, % of PV (incl. aquifer)
1	Gas production and CO_2 injection	0.3 – 18.8	55	10		445	0.06
2	Injection in half open aquifer		85	10	25	689	0.09
3	Injection in half open aquifer		85	50	95	3443	0.46
The results show that remaining gas can be produced without CO_2 contamination into the gas.							



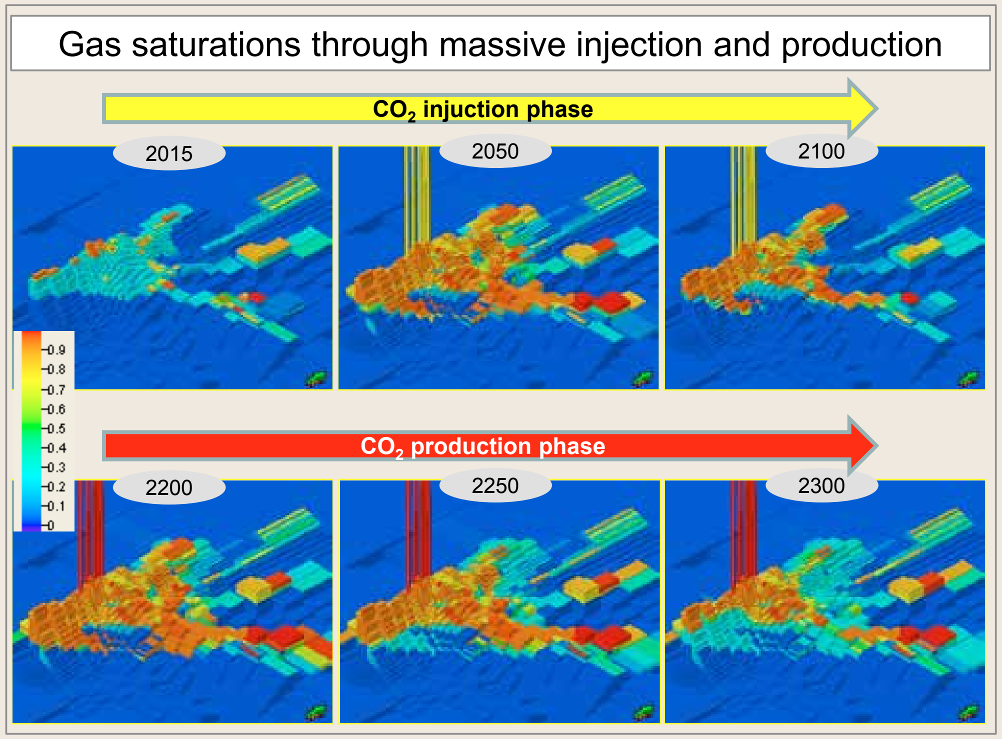
Simulation model

Conclusion
The Frigg field has a large potential for CO_2 storage due to remaining gas in the field itself and a huge aquifer that is connected to the field. The simulation shows that there is a higher potential than what is simulated if the pressure increase is compensated with more water production out of the aquifer.

Some thought should be given to the abandoned wells on the Frigg field and its satellites as their sealing capacity for CO_2 has not been studied in detail. If storage is implemented in Frigg, integrity studies and monitoring of the old wells will be an important issue.



Long term effects of CO_2 injection for two alternative values of diffusion coefficient.



The figure shows the gas saturation during the injection and production. Some of the CO_2 will be trapped behind the waterfront due to relative permeability effects. No diffusion is assumed in this case. 50 MSm^3/d. CO_2 injection during 2015-2100 and reproduction from year 2200 at 5 MSm^3/d.

4.2.3 Summary

The results of the evaluation of theoretical storage capacity in the North Sea are summarized in the tables. Excluding the aquifers in the petroleum systems, two aquifers with significantly greater theoretical storage potential than the others have been identified. These are the Utsira – Skade Formation aquifer and the Bryne – Sandnes Formation aquifer.

The Utsira Formation is already used by the petroleum industry for CO_2 storage. Structures in the Utsira Formation which are equivalent to the site used for the Sleipner injection have been classified within the 3rd level of the maturation pyramid. Only about 25 % of the total pore volume of the Utsira – Skade aquifer has been included in the calculation of storage capacity. The reason is that the top of the aquifer is too shallow to be suitable for CO_2 storage.

The Bryne-Sandnes aquifer has a lower level of maturity than the Utsira formation. In any proposed storage site, reservoir quality and seal integrity must be studied carefully. The aquifer is located in a salt basin, and closed structures formed by salt tectonics may be attractive for CO_2 injection.

The Johansen – Cook Formation aquifer has a smaller pore volume than the two aquifers mentioned above, but it has good reservoir and seal properties. A potential storage site in the Johansen Formation has recently been matured by Gassnova, and is here included in the 3rd step of the pyramid.

In the petroleum provinces, the storage potential was calculated from the extracted volume of hydrocarbons in depleted fields. The main contribution to the present theoretical storage capacity comes from the abandoned Frigg Field and its satellites, which are located in the huge Frigg-Heimdal Formation aquifer. The increase of storage capacity in abandoned fields has been estimated for 2030 and 2050. The storage capacity of that part of the large Sognefjord Delta aquifer which belongs to the Troll Field has been grouped together with the abandoned fields.

CO_2 storage in abandoned and depleted fields will usually require a careful study of the integrity of the wells which have been drilled into the field. If oil has been present, it is relevant to study the potential for enhanced recovery by CO_2 injection. The CO_2 storage potential achieved by potential EOR projects is discussed, but has not been quantified in this study.

Evaluated Aquifers	Avg Depth	Bulk volume	Pore volume	Avg K	Open/closed	Storage eff	Storage Vol	Density in reservoir	Storage Capasity
Unit	*m*	*Gm^3*	*Gm^3*	*mD*		*%*	*GRm^3*	*kg/m^3*	*Gt*
Utsira Formasjon and Skade	1000	2500	530	>1000	Open	4	21	750	15.77
Bryne/Sandnes Formations	1700	5000	440	150	Half open	4.5	20	690	13.60
Sognefjord Delta East	1750	550	110	300	Half open	5.5	5.9	690	4.09
Statfjord Gp East	2400	1100	120	200	Half open	4.5	5.4	660	3.59
Gassum Formation	1700	650	76	450	Half open	5.5	4.2	680	2.85
Farsund Basin	2000	860	82	150	Half open	4	3.3	700	2.30
Johansen and Cook Form.	1700	N/A	91	300	Faults	3	2.7	650	1.78
Fiskebank Formation	1600	100	25	1000	Half open	5.5	1.4	700	0.96
Stord basin, Jurassic model	1450	270	16	5 - 20	Half open	0.8	0.14	710	0.10
Hugin East	1700	19	2	500	Half open	5.5	0.13	700	0.09

Evaluated Prospects	Avg Depth	Bulk volume	Pore volume	Avg K	Open/closed	Storage eff	Storage Vol	Density in reservoir	Storage Capacity
Unit	*m*	*Gm^3*	*Gm^3*	*mD*		*%*	*GRm^3*	*kg/m^3*	*Mt*
Bryne/Sandnes1	1700	13	1.6	150	Open	20	0.32	0.69	220
Bryne/Sandnes2	1700	3.3	0.15	150	Open	20	0.030	0.69	21
Johansen	2900	N/A	N/A	300	Half Open	N/A	N/A	N/A	150
Stord Basin mounds	1900	45	9.7	1000	Closed	0.8	0.078	0.69	53

Total aquifers	Avg Depth	Bulk volume	Pore volume	Avg K	Open/closed
Unit	*m*	*Gm^3*	*Gm^3*	*mD*	
Utsira total	1000	8500	1800	>1000	Open
Sognefjorddelta total	1750	2700	480	300	Half open

Abandoned and producing Fields	Storage Capacity Gt
Abandoned fields	3
Producing fields	
Close of production within 2030	4
Close of production within 2050	6

4.2.3 Summary

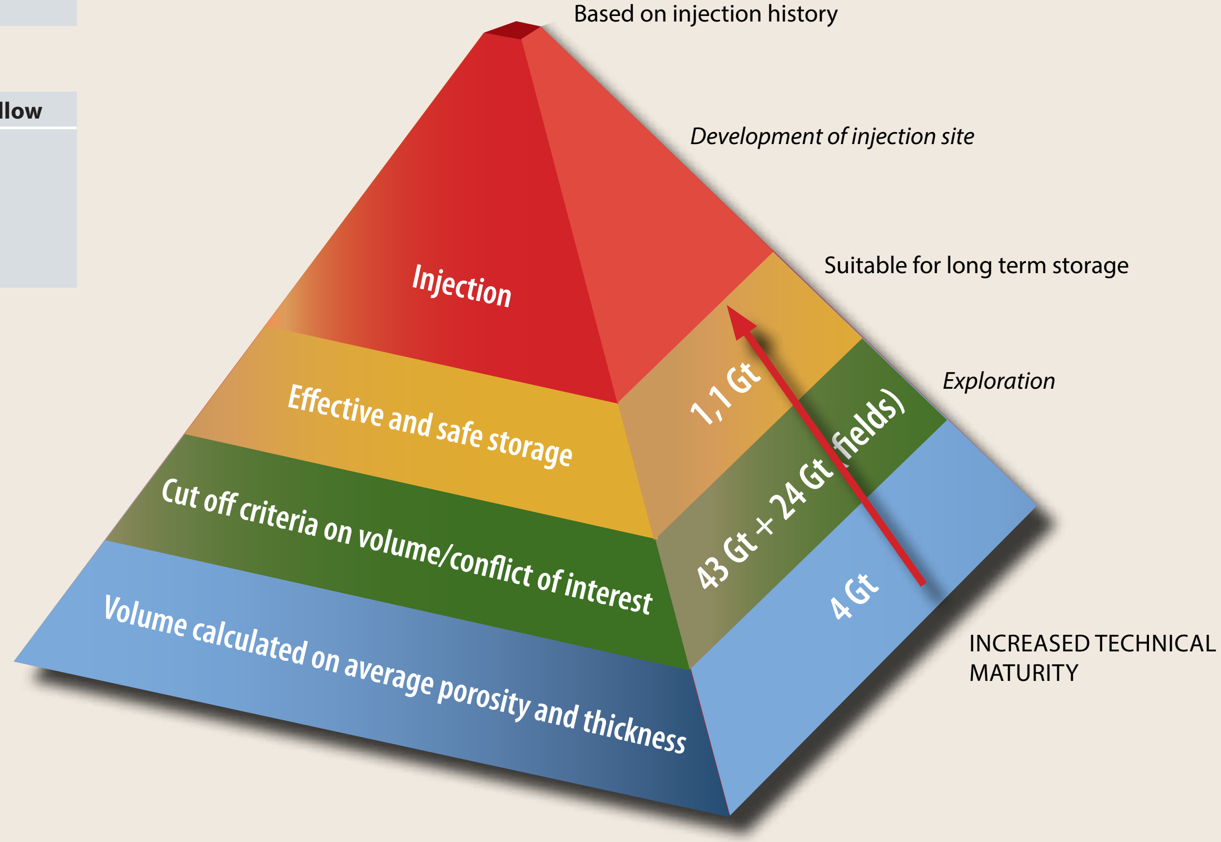
Storage capacity in Gt and technical maturity

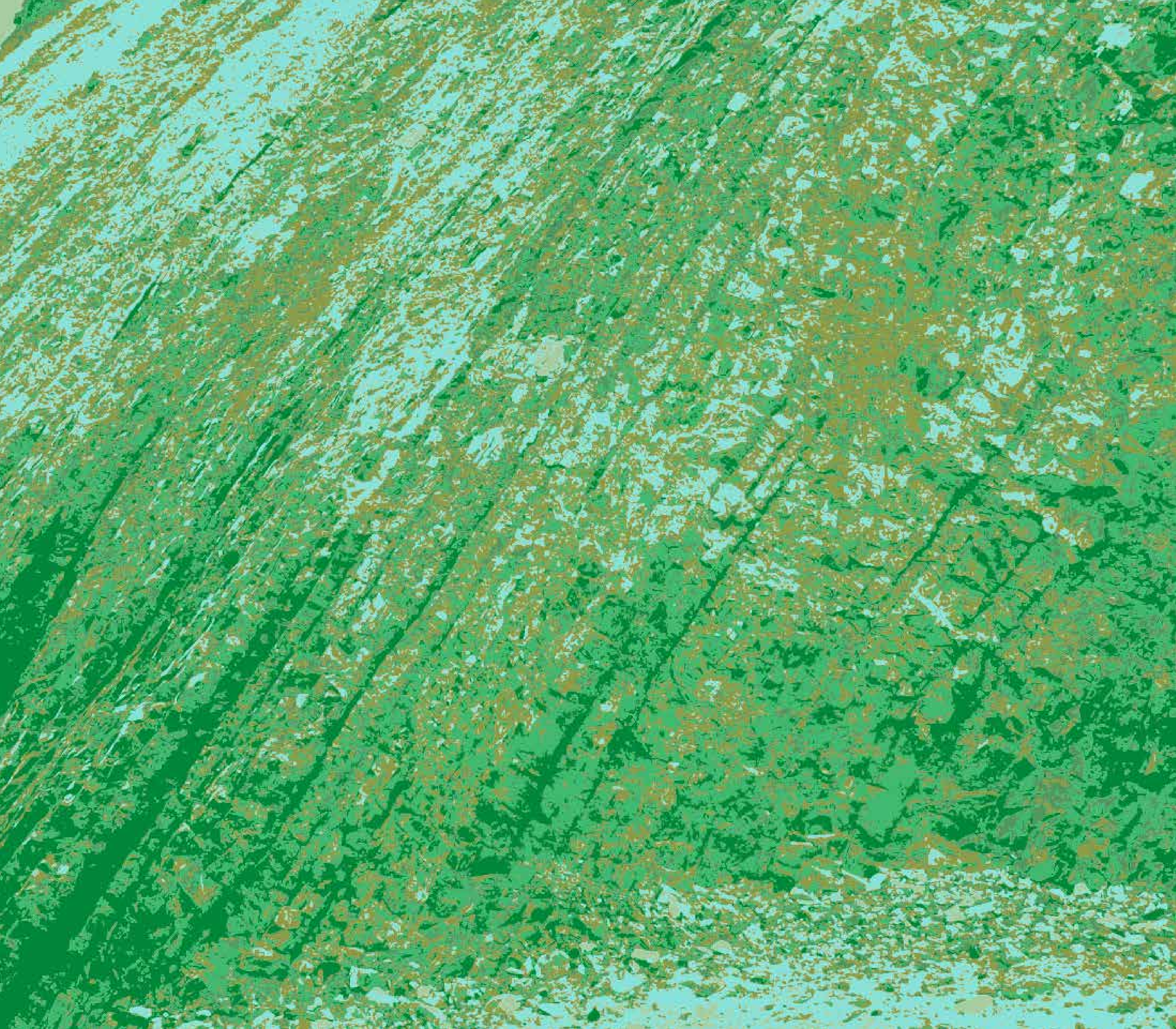
Aquifers

Basin/reservoir	**Storage capacity**	**Maturity**		
	Total	Blue	Green	Yellow
Utsira and Skade	15.8		14.8	1
Bryne/Sandnes southern parts	13.6		13.6	
Sognefjord Delta East	4.1		4.1	
Statfjord Gp East	3.6		3.6	
Gassum	2.9	2.9		
Bryne/Sandnes Farsund basin	2.3		2.3	
Johansen and Cook	1.8		1.7	0.1
Fiskebank	1	1		
Hugin East	0.1		0.1	
Stord basin, Jura	0.1	0.1		
Stord basin , mounds	0.05	0.05		

Field related

		Blue	**Green**	**Yellow**
Abandoned fields	3		3	
Fields in production 2030	4		4	
2050	6		6	
Sognefjord delta including Troll	14		14	

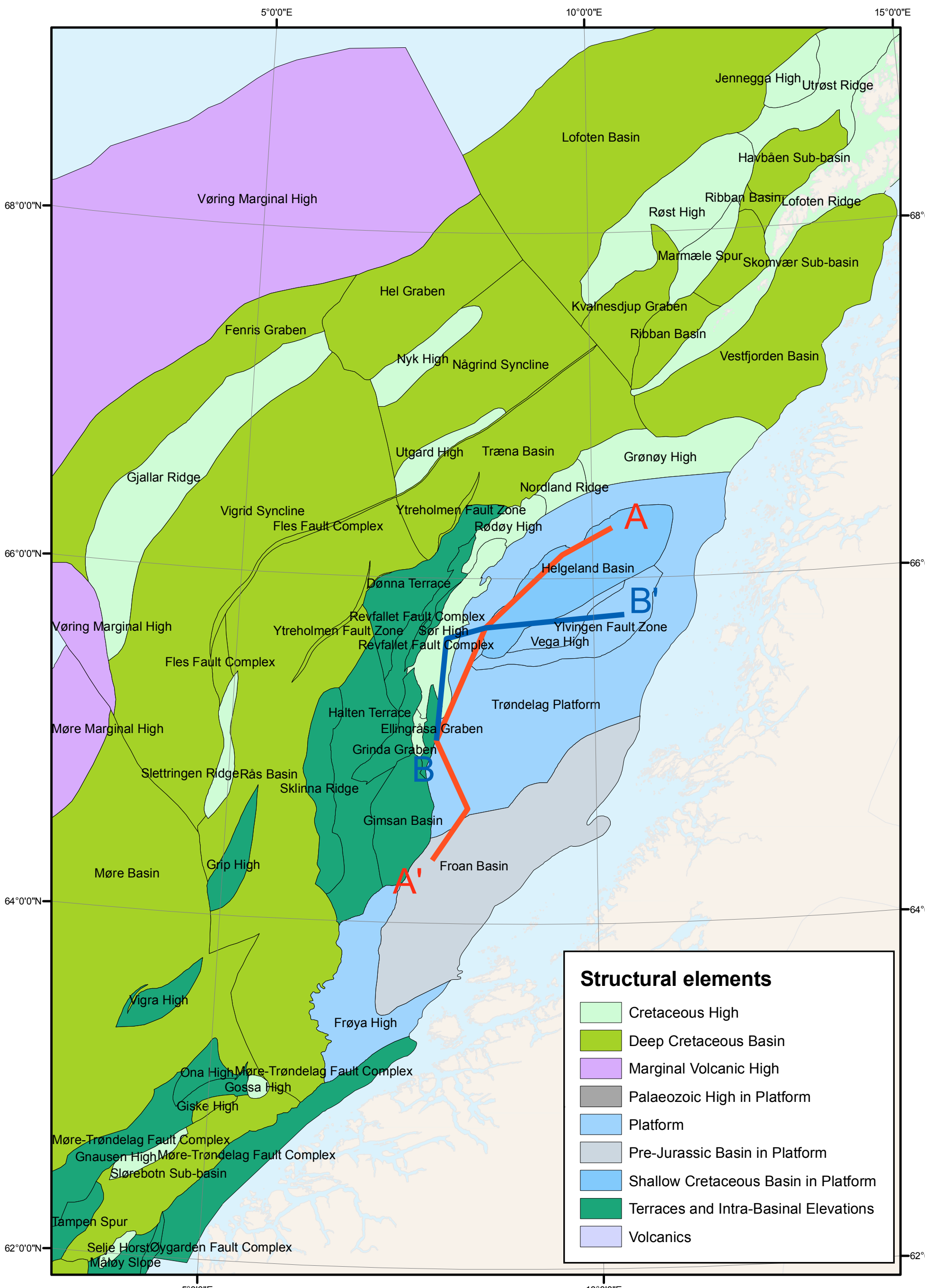




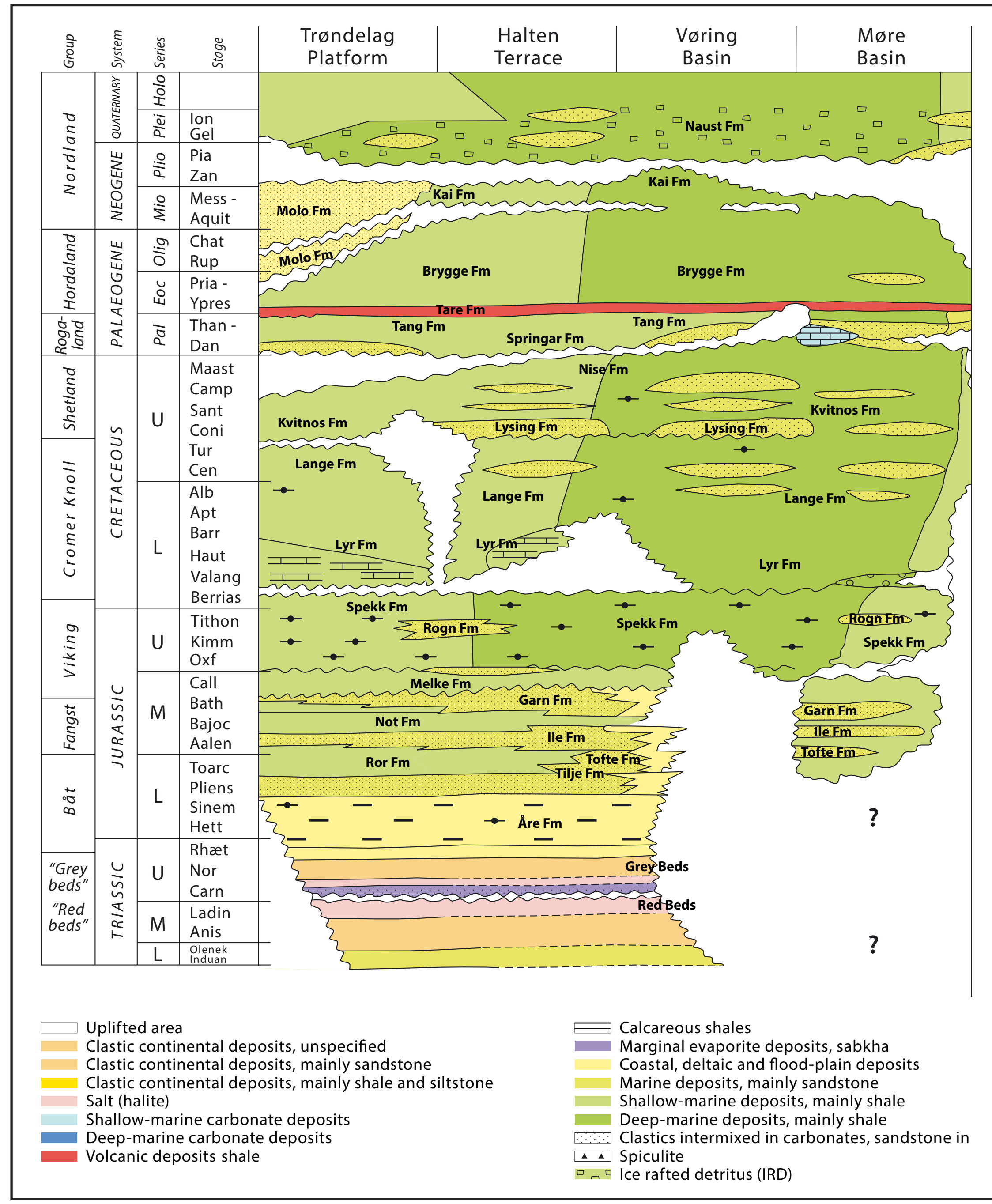
5. The Norwegian Sea

Eva K. Halland (Project Leader), Ine Tørneng Gjeldvik, Wenche Tjelta Johansen, Christian Magnus, Ida Margrete Meling, Jasminka Mujezinović, Fridtjof Riis, Rita Sande Rød, Van T. H. Pham, Inge Tappel

5.1 Geology of the Norwegian Sea

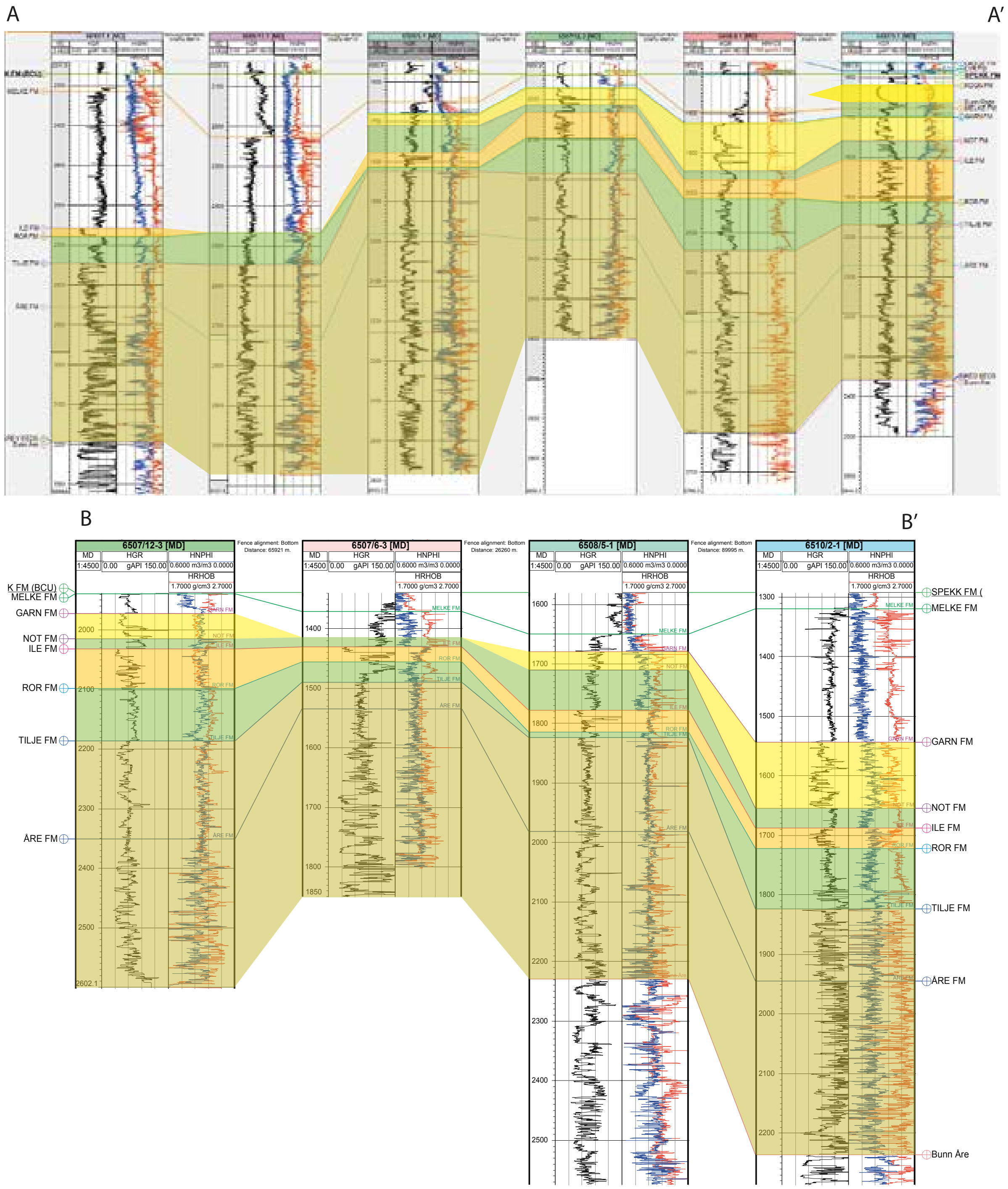


Structural elements in the Norwegian Sea.

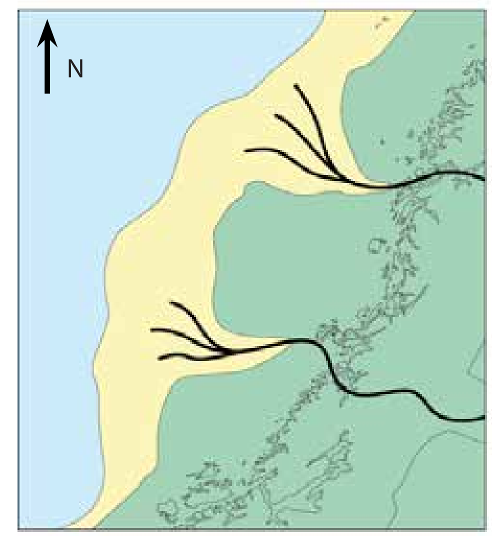


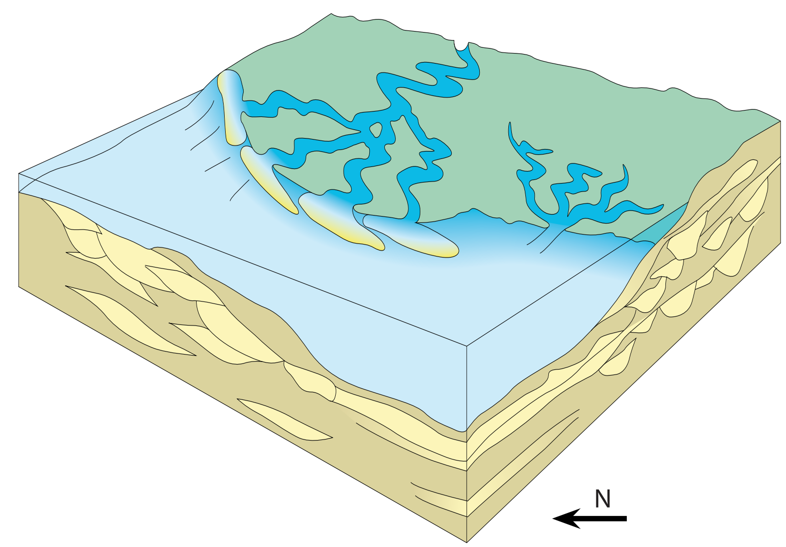
Lithostratigraphic chart of the Norwegian Sea (NPD).

5.1 Geology of the Norwegian Sea



Well section panels showing gamma and neutron/density logs reflecting thickness variations of the different formations. The Åre and Tilje Fms show more or less constant thickness throughout the area. The Ile and Garn Fms are thinning and shaling out towards the north. The Garn Fm is quite thick in well 6510/2-1, but less sandy, and is thinning towards the west.





Depositional environment of Tilje Formation. Conceptual sketch of an early stage in the development of the Tilje formation in parts of the Norwegian Sea.

- Shallow shelf
- Fluvial/tidal delta
- Delta plain
- Deep shelf

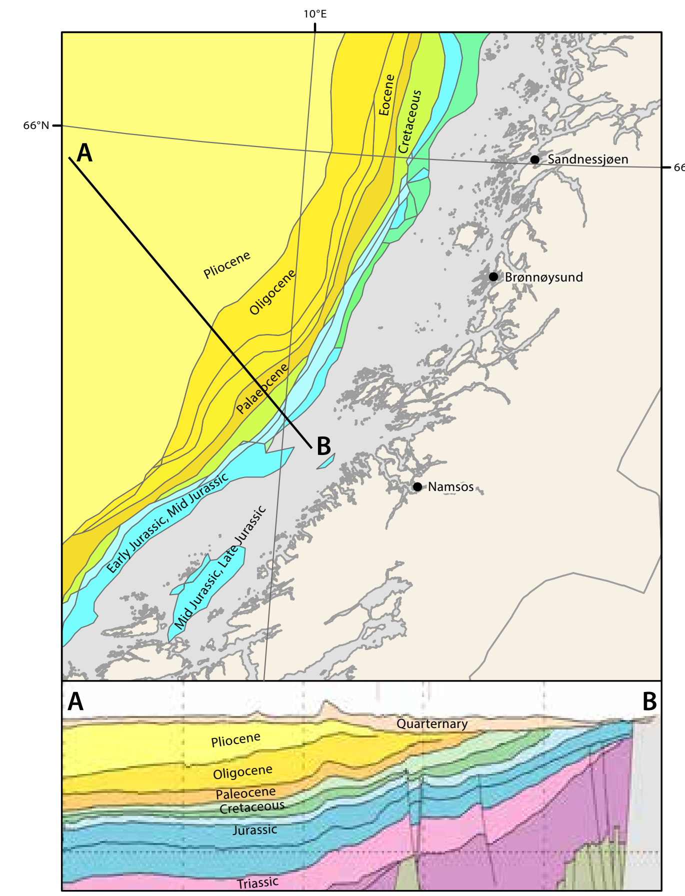
5.1 Geology of the Norwegian Sea

The Norwegian Sea covers most of the continental margin between approximately 62° and 69°3°′ N. The tectonic history of the Norwegian Sea can be divided into three major episodes: A) Final closure of the Iapetus Ocean during the Caledonian Orogeny (Late Silurian/ Early Devonian). B) A series of mainly extensional deformation episodes (Late Devonian to Paleocene), culminating with the continental separation between Greenland and Eurasia. C) Active seafloor spreading in the North Atlantic between Eurasia and Greenland (Earliest Eocene to present).

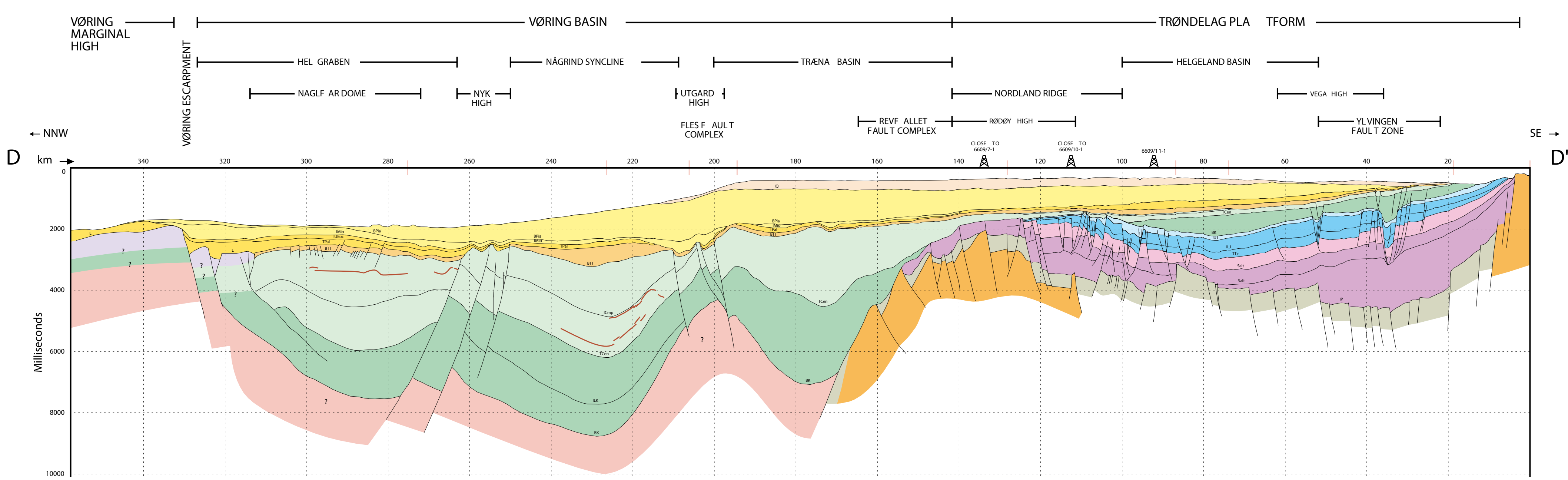
The area with the best potential for storage of CO_2 is the Trøndelag Platform (63° to 67° N), one of the main structural elements of the Norwegian Sea. The Trøndelag Platform contains the following structural elements: the Nordland Ridge, the Helgeland Basin, the Vega High, the Ylvingen Fault Zone, the Froan Basin and the Frøya High. The areas further west and south are considered less suitable for storage of CO_2 due to the active production of hydrocarbons, high temperature and high pressure and the depth of the relevant reservoirs.

Carboniferous, Permian and Triassic: Rifting and formation of N-S to NE-SW trending rotated fault blocks occurred on the Halten Terrace and parts of the Trøndelag Platform in late Permian/early Triassic times. This was followed by deposition of a thick continental Triassic succession. Drilling in the Helgeland Basin has proven up to 2500m thickness of Triassic (Grey and Red beds) including two Middle Triassic evaporite intervals up to 400m thick. The evaporite intervals represent detachment levels for later extensional faults. These thick sequences are related to pronounced subsidence and deposition in a fluvial sabkha environment. This tectonic event was possibly preceded by Carboniferous and Permian rifting.

Jurassic and Cretaceous: During the Early and Middle Jurassic, the Trøndelag Platform and the Halten/ Dønna Terrace were parts of a large NS-trending subsiding basin which was infilled by a deltaic to fluvial depositional system. Sediment input from several directions through time has been interpreted. The Jurassic sediments become thinner towards the Nordland Ridge and the thickness increases over the Vega High and the Helgeland Basin. Starting in



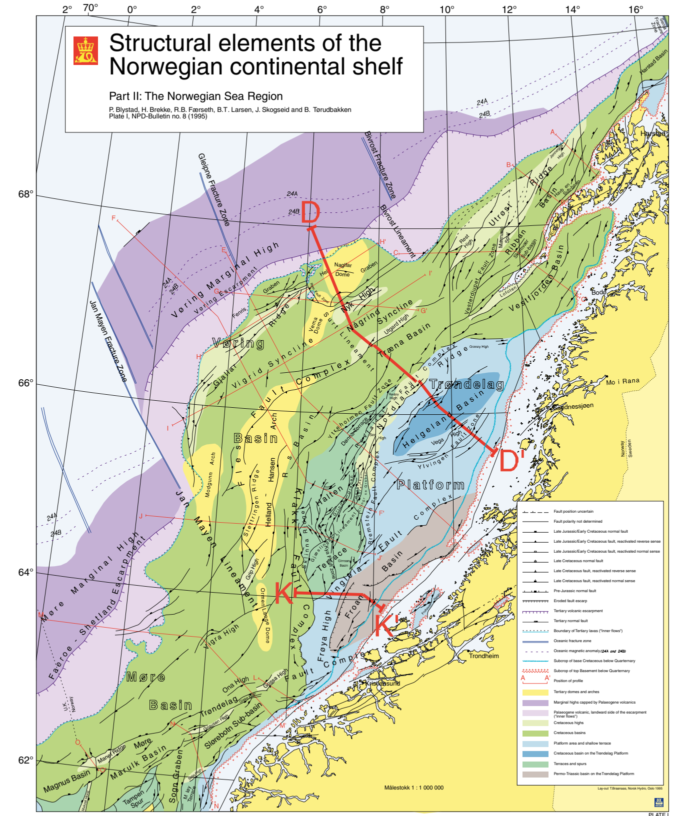
Subcroping strata under the Quaternary offshore Mid Norway. Offshore map from NGU, Sigmond.



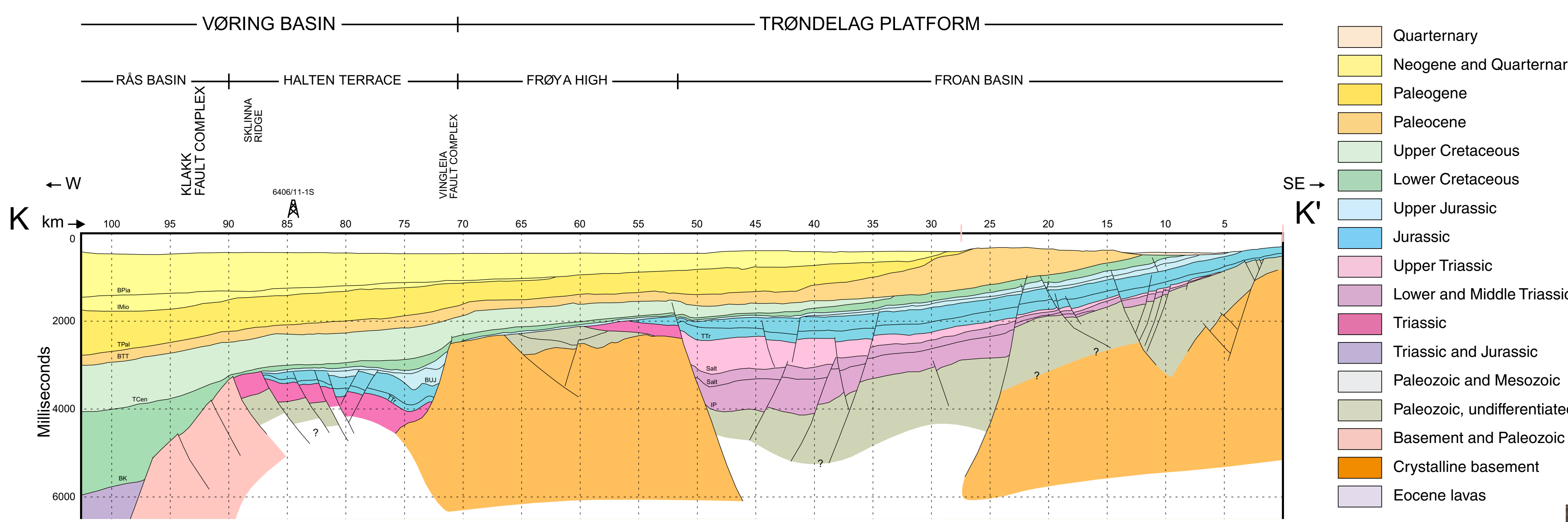
5.1 Geology of the Norwegian Sea

the middle Jurassic and culminating in the late Jurassic/early Cretaceous, the Norwegian Sea underwent a major tectonic phase with extension, faulting and thinning of the upper crust. The Halten and Dønna Terrace were downfaulted in relation to the Trøndelag Platform. Further to the west, the Vøring Basin subsided in relation to the terrace areas. During this extensional phase, both large-scale basement faults and listric faults were active, soling out into the Triassic salt. In the middle Jurassic, the Nordland Ridge and the Frøya High were uplifted, while the Helgeland Basin area subsided. Later, the Vega High was inverted, and faulting continued along the major faults well into the Cretaceous. The Froan Basin was a shallow sea during Late Jurassic, and it was later covered by thin, condensed Cretaceous sediments. In contrast, the Helgeland Basin area continued to subside. It has a thickness of up to 1500m of Cretaceous sediments. During the Late Cretaceous, there was a rapid subsidence west of the Nordland Ridge due to increased rifting in the west. At the same time, the structural highs and the Lofoten-Vesterålen area were uplifted.

Cenozoic: In the Paleocene, uplift of the Norwegian mainland resulted in progradation of clastic sediments from Scandinavia into the Norwegian Sea. Sandy deposits, sometimes with good reservoir properties, have been recorded north of the Nordland Ridge and in the Møre Basin (Egga sand). The progradation continued into the Eocene. The separation between Greenland and Eurasia and the onset of ocean floor spreading started in the Earliest Eocene. This is reflected in deposition of tuffs and tuffaceous sediments on a regional scale (the Tare Fm). On the Vøring and Møre Marginal Highs, lava flows and basaltic dike complexes were emplaced. The sediment input from Scandinavia was reduced in the Oligocene and Miocene. The deltaic Molo Formation has good reservoir sands, but is not sealed towards the sea floor. The Nordland Ridge was uplifted in the Late Cenozoic. In the Pliocene and Pleistocene, new uplift and glaciations caused erosion and deposition of thick sedimentary wedges onto the mid Norwegian shelf.



Structural element map of the Norwegian Sea. The Trøndelag Platform is shown by blue and gray colours. The depth and thickness maps in the following pages cover the Trøndelag Platform.



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Permian-Triassic sediments

Upper Permian to Upper Triassic

On the Rødøy High, along the western margin of the Nordland Ridge, well 6609/7-1 drilled 34m of Upper Permian dolomitic limestone with thin sandstone layers overlying metamorphic quartzites.

The Permian rocks have not been given formal group or formation status, but are often correlated with the Permian in East Greenland.

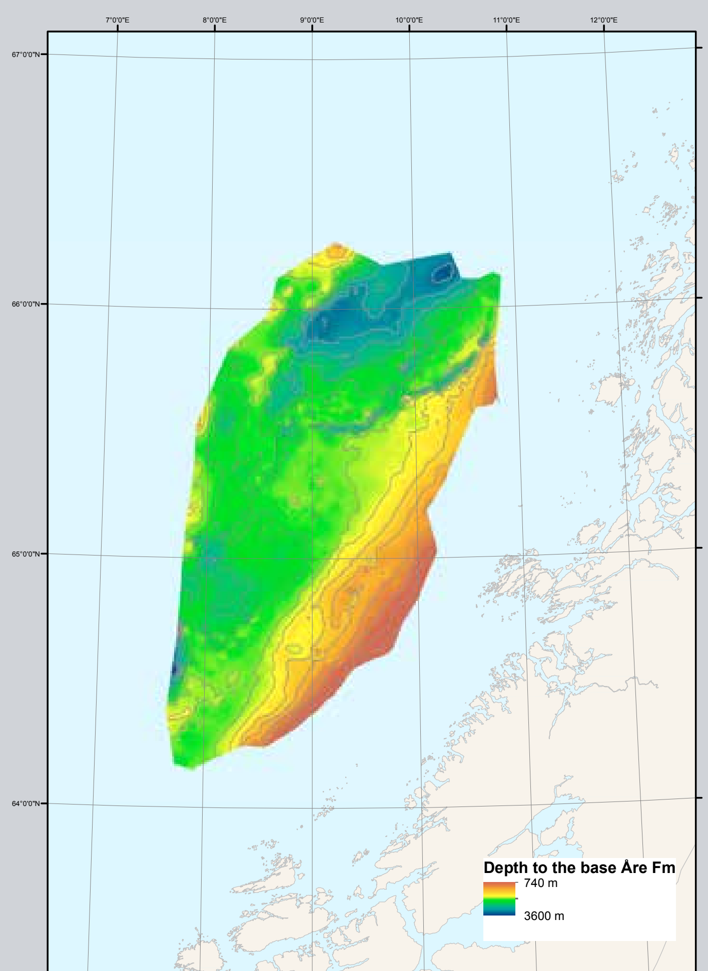
The Triassic rocks are given informal group names: Grey beds and Red beds. So far, no complete Triassic section has been drilled, but combined thicknesses of more than 2700m of both Grey beds and Red beds have been drilled (well 6507/6-1).

The Red beds form the lowest part of the drilled Triassic sequences and represent continental clastics deposited in an arid climate. The maximum thickness of Red beds is in the order of 2600m (well 6507/6-1, 2615m) and has been drilled on the southern extension of the Nordland Ridge.

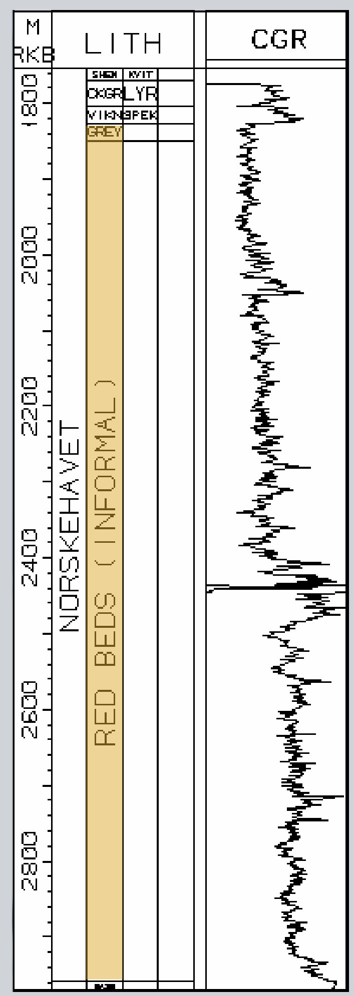
The Grey beds are interpreted to represent continental clastics deposited in a more humid climate than the Red beds. Maximum thickness of the Grey beds is in the order of 2500m (well 6610/7-2, 2489m).

The upper boundary of the Grey beds is towards the Upper Triassic and Lower Jurassic (Rhaetian to Toarcian) coal-bearing sediments of the Båt Gp (the Åre Fm).

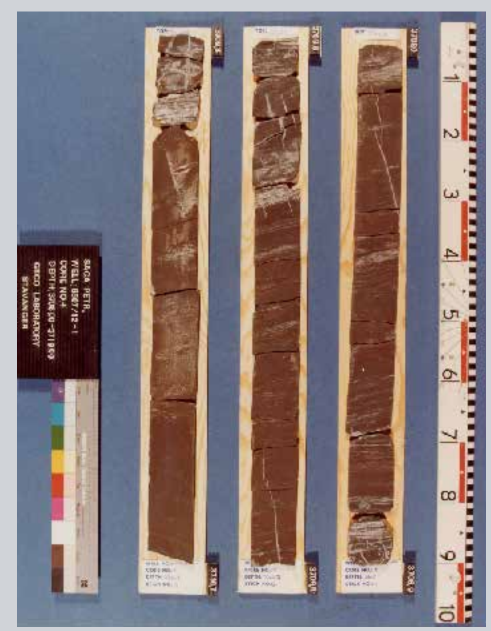
The Triassic also contains two evaporite sequences of Upper/Middle Triassic age (Ladinian–Carnian). Shallow boreholes (6611/09-U-1 & 2) along the Norwegian coast (66ºN) have drilled a combined thickness of 750m of Upper Permian and Lower Triassic sediments, including a possible source rock.



WELL LOG 6407/10-3



6507/12-1 RED BEDS, 3710.7 - 3708.9 m



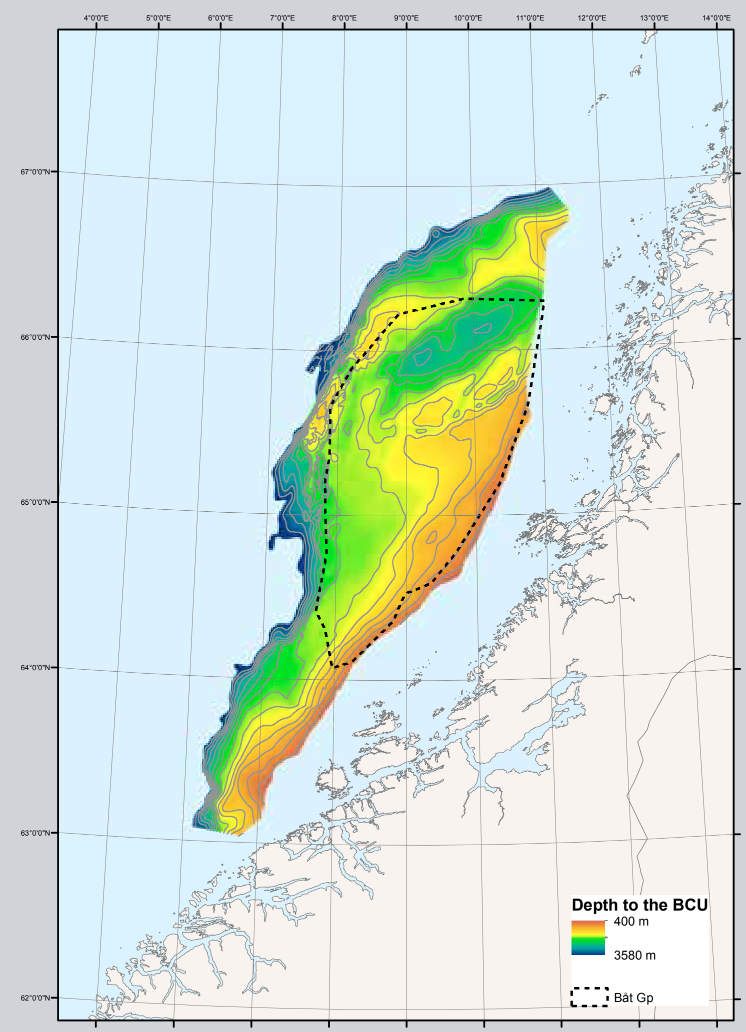
The Båt Group

Uppermost Triassic and Lower Jurassic
(Rhaetian to Toarcian)

The Båt Group is dominated by sediments deposited in deltaic to shallow marine environments overlying the Triassic Grey and Red beds (informal). This group is subdivided into four formations, the Åre, Tilje, Ror and Tofte Formations. The type well (6507/12-1) is located in the transition zone between the Halten Terrace and the Trøndelag Platform. The lower boundary of the group is defined below the first appearance of coal above the Triassic Grey beds. The upper boundary is defined at the base of a coarsening upwards sequence of the Ile Fm in the Fangst Gp. Marine influence increases towards the top of the succession and also to the north and west.

The Båt group is present in most of the wells drilled on Haltenbanken and Trænabanken with a maximum thickness up to 1000m (707m in the type well) in the eastern part of the Halten Terrace. Due to erosion, the upper part of the succession is progressively truncated towards the crestal parts of the Nordland Ridge. Shallow boreholes off the Trøndelag and Nordland coast indicate that mid Jurassic sediments onlap the metamorphic basement.

The burial depth of the Båt Gp. varies from 1000-2500m on the Trøndelag Platform and marginal areas of the Helgeland Basin. West of the Nordland Ridge the burial depth increases to more than 4000m. Porosities and permeabilities in the order of 25-35% and 100 mD to several darcys have been reported. However, rocks on the eastern part of the Trøndelag Platform have probably been buried deeper than the present depths indicate, due to Neogene erosion.



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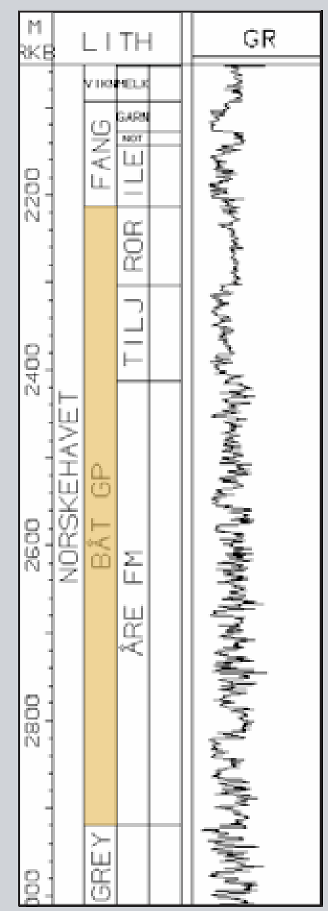
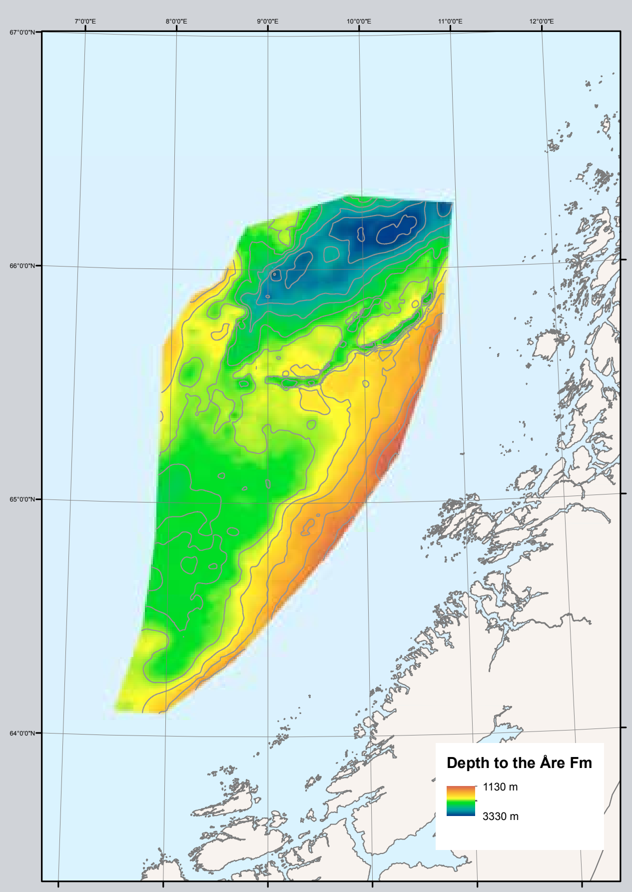


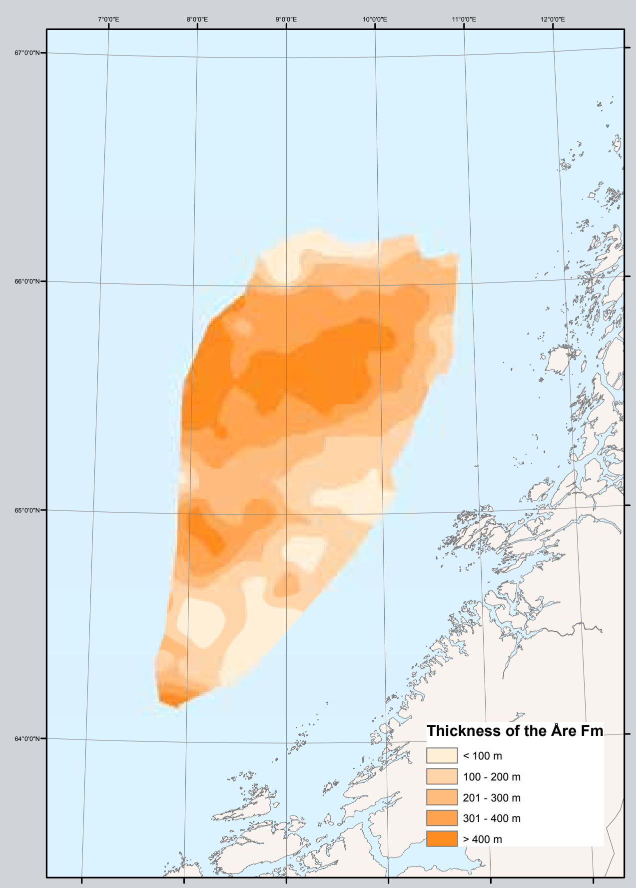
The Båt Group - Åre Formation

The Åre Formation (Rhaetian to Pliensbachian) represents delta plain deposits (swamps and channels) at the base with up to 8m thick individual coal seams. Where the coal bearing sequences are thinner, the sandstones are generally more coarse-grained. The Åre Fm is present in most wells drilled in the Haltenbanken and Trænabanken region, but is missing locally over the crest of the Nordland Ridge due to erosion.

The thickness in the type well (6507/12-1) is 508m, and in the reference well (6047/1-2) the thickness is 328m. Generally, the thickness of the Åre Fm varies between 300 and 500m, with a maximum thickness of 780m in the eastern part of the Halten Terrace (Heidrun area).

The well coverage over the central and eastern Trøndelag Platform is limited. Well 6510/2-1R, located on the Vega High and Ylvingen Fault Zone, drilled 291m of Åre Fm. Wells along the western margin of the Trøndelag Platform down to the Draugen field show thicknesses of the Åre Fm between 250 and 300m. In the Froan and Helgeland Basins area, the Åre Fm varies in thickness between 300 and 500m from south to north.





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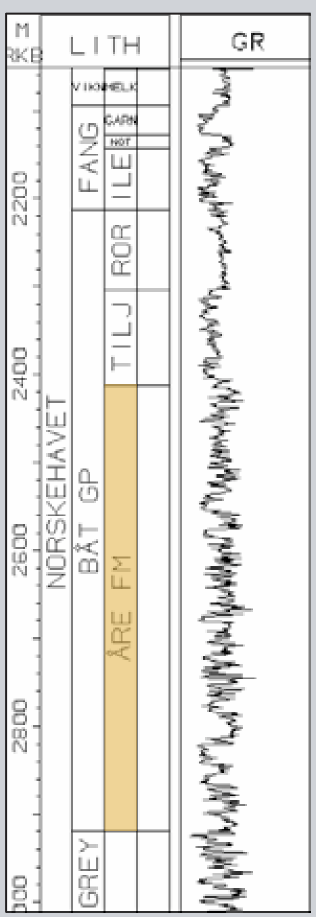
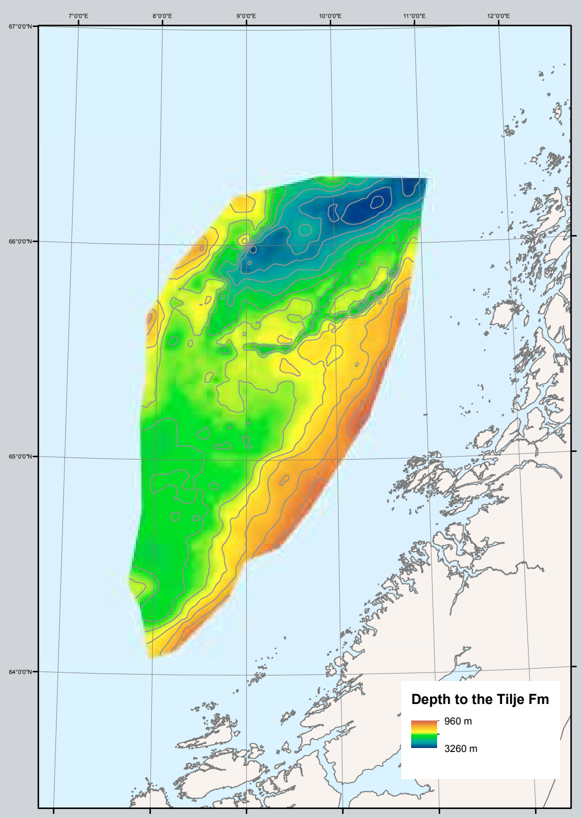


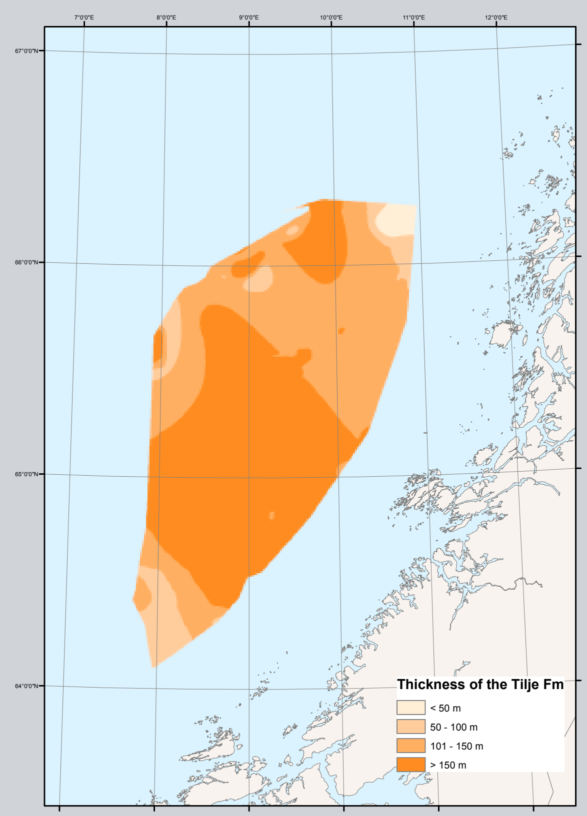
6507/12-1 ÅRE 2707.0 - 2709.7 m

The Båt Group - Tilje Formation

The Tilje Formation (Sinemurian to Pliensbachian) is defined at the top of a mudstone interval and consists of more sandy sediments deposited in near shore to intertidal environments with increased thickness of individual sandbodies. The mudstone interval is most pronounced on the Halten Terrace, but is difficult to pick further east on the Trøndelag Platform. Here coal beds are developed at a higher stratigraphic level than on the Halten Terrace. The formation is present in most wells in the Haltenbanken and Trænabanken region, but locally absent on the Nordland Ridge.

In the type well (6507/11-1), the thickness of the Tilje Fm is 98m, and on the Halten Terrace, thicknesses in the order of 100-150m are reported. Shallow boreholes close to the coast indicate time equivalent deposits dominated by coarser clastics. The same thicknesses are observed in the Trøndelag Platform area.





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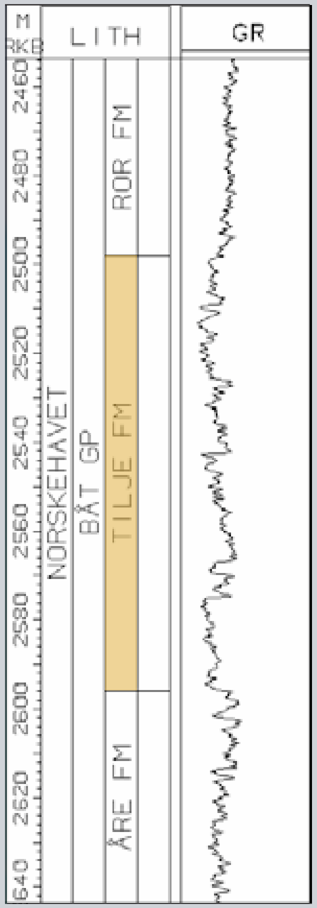
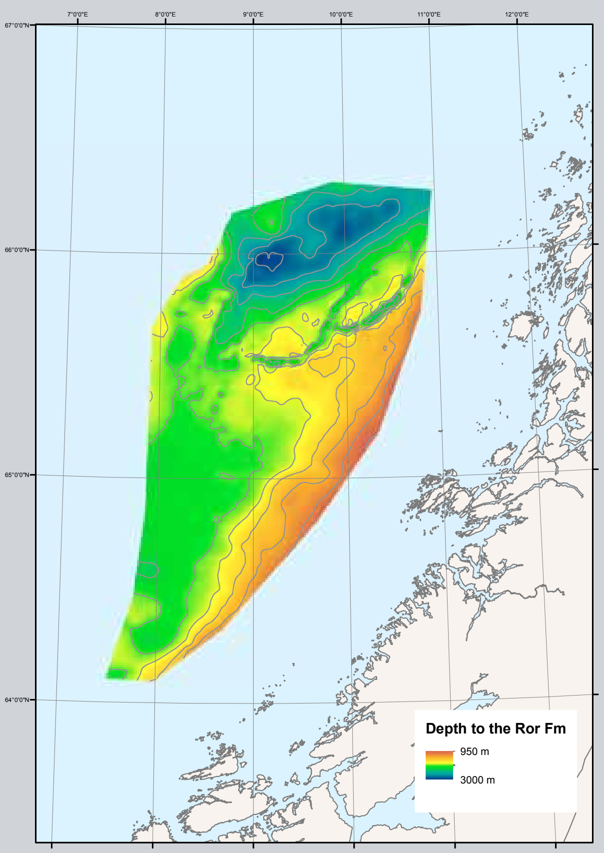


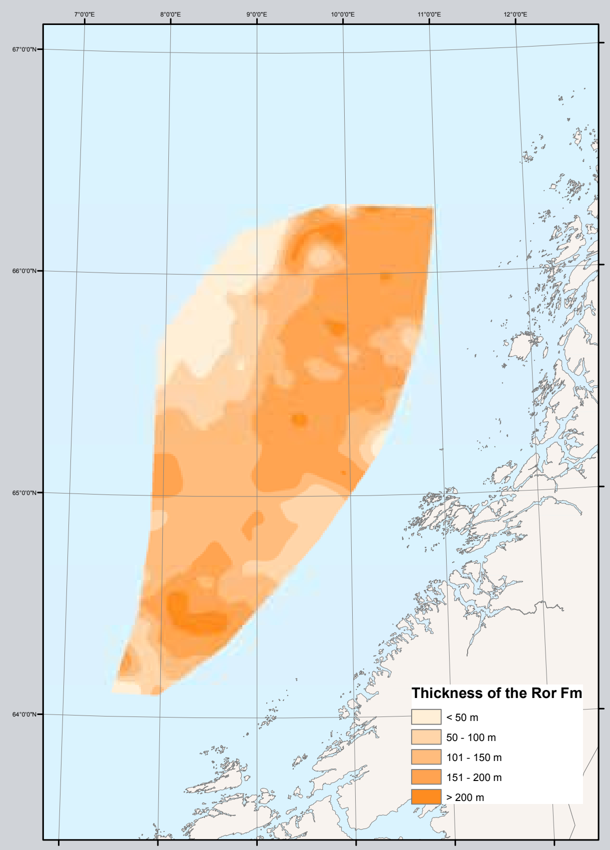
6507/11-1 TILJE 2527.7 - 2543.0 m

The Båt Group - Ror Formation

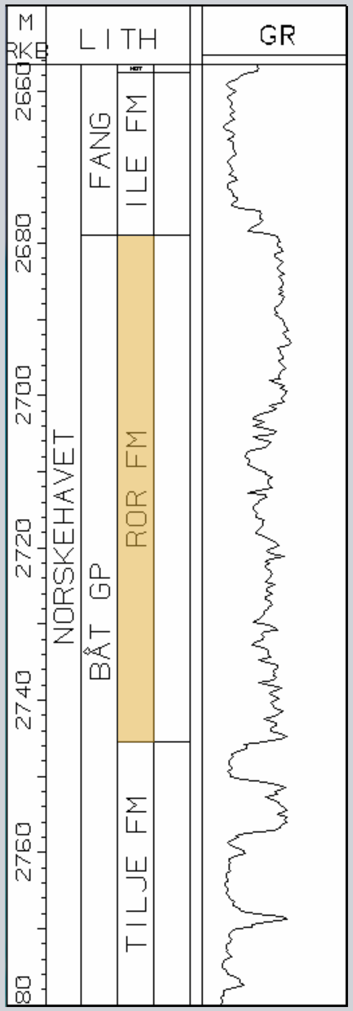
The Ror Formation (Pliensbachian to Toarcian) is defined by the abrupt transition from the sandstones in the Tilje Fm into mudstones, indicating an erosive base. The Ror Fm is present in all wells drilled on Haltenbanken, generally thinning towards the north-east. To the west, it interfingers with the sandstones of the Tofte Fm, and the oldest part of the Ror Fm is often absent. The Tofte Fm represents an eastward prograd-ing fan delta, reflecting a source area in the west. In the study area, the Tofte Formation does not occur, although local sandy beds have been encountered in the wells. The Ror Fm does not occur over large areas on the Nordland Ridge due to erosion/non-deposition. In the basinal areas, the mudstones of the Ror Fm might represent a seal, particularly towards the east.

In the type well (6407/2-1), the thickness of the Ror Fm is 104m, and thicknesses in the order of 70 to 170m have been recorded in wells on the Halten Terrace. On the Trøndelag Platform thicknesses between 100 and 200m are observed.





WELL LOG 6610/7-1



6610/7-1 ROR 2707.0 - 2713.0 m

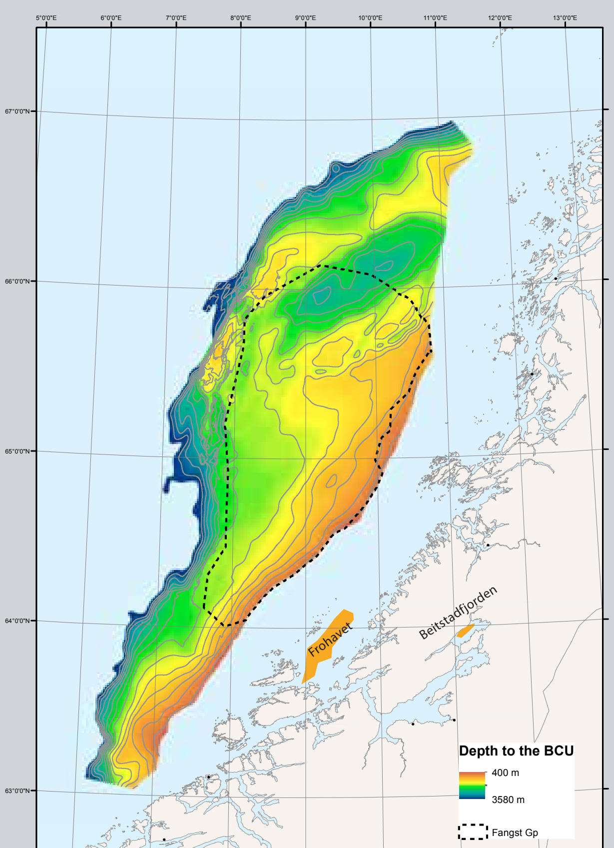
The Fangst Group

Lower to Middle Jurassic
(Upper Toarcian to Bathonian)

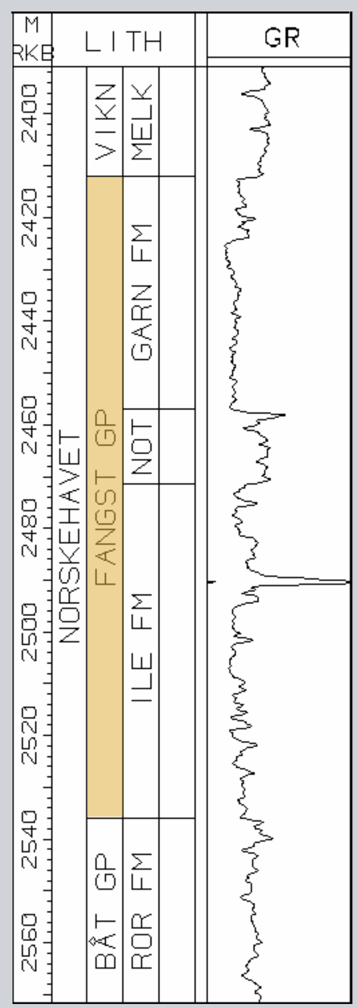
The Fangst Group is dominated by sediments deposited in shallow marine to coastal/deltaic environments overlying the Båt Group. It is divided into three formations, the Ile, Not and Garn Formations. The group is present over most of the Haltenbanken and Trænabanken area, except for the crestal parts of the Nordland Ridge, where it is eroded. The main development of the Fangst Gp is on the Halten Terrace. Along the southern margin of the Nordland Ridge, the succession is much thinner. On Trænabanken, there is a lateral facies change to marine mudstones of the Viking Gp, and only the lowest part of the Fangst Gp (the Ile Fm) is recognised.

Time equivalent sandstone dominated sequences subcrop on the seafloor along the eastern margin of the Trøndelag Platform. Outliers of Middle Jurassic sediments are present east of the Froan islands and in the Beitstadfjorden area in Trøndelag. Increased continental influence is inferred towards the Trøndelag Platform to the east, but well control is limited.

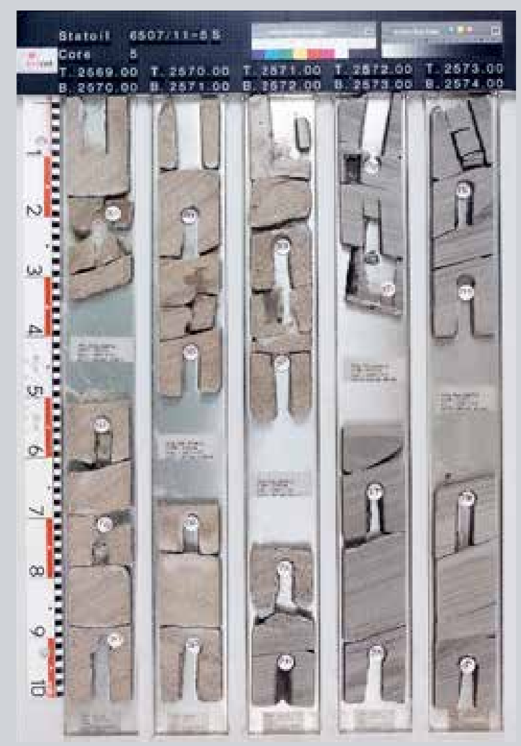
In the type well (6507/11-3), the thickness of the Fangst Gp is 124m and it typically varies between 100 and 250m.



WELL LOG 6507/11-3



6507/11-5s ILE 2569-2574m

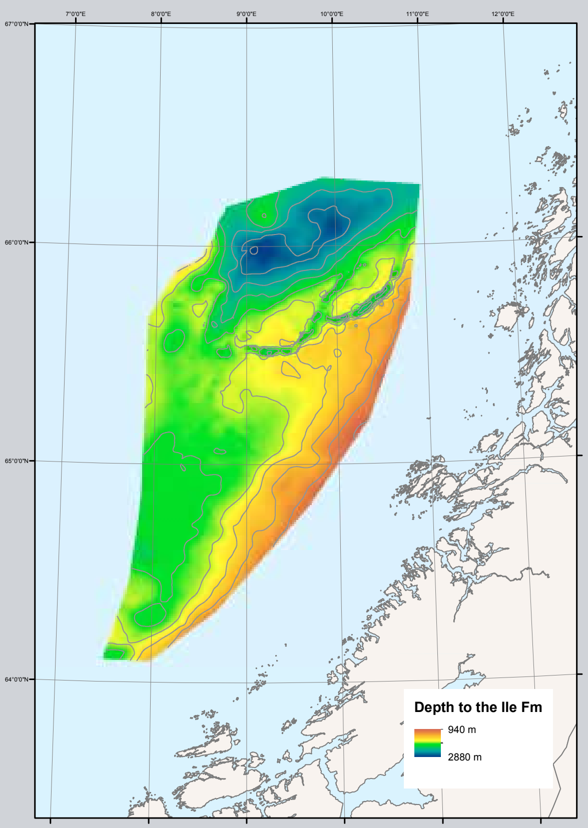


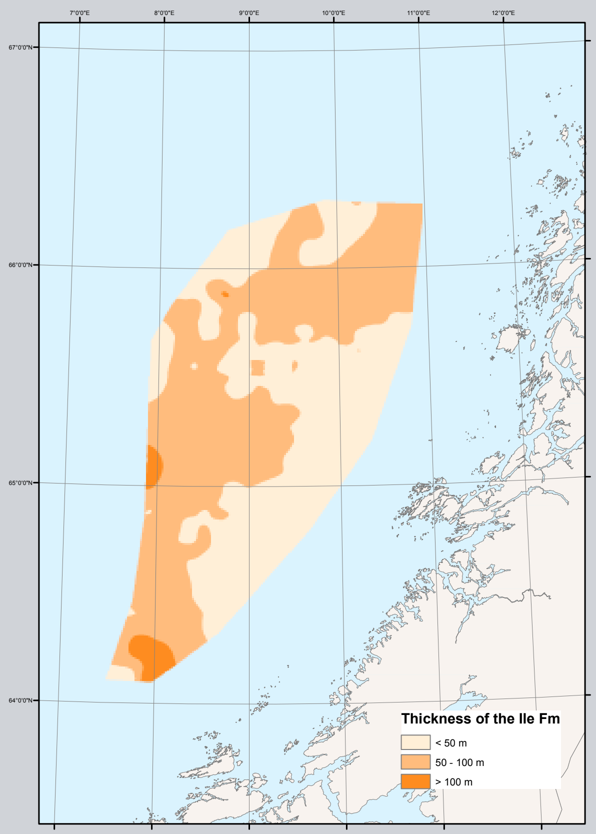
The Fangst Group - Ile Formation

The Ile Formation (Upper Toarcian to Aalenian) is defined at the base of a generally upwards coarsening sequence from siltstone to sandstone, often associated with more carbonate beds. The sediments of the Ile Fm are deposited in tidal or shoreline environments. The upper boundary is defined by the mudstones of the Not Fm. The Ile Fm is present over most of Haltenbanken, with a general thickening to the west and marked thinning to the northeast.

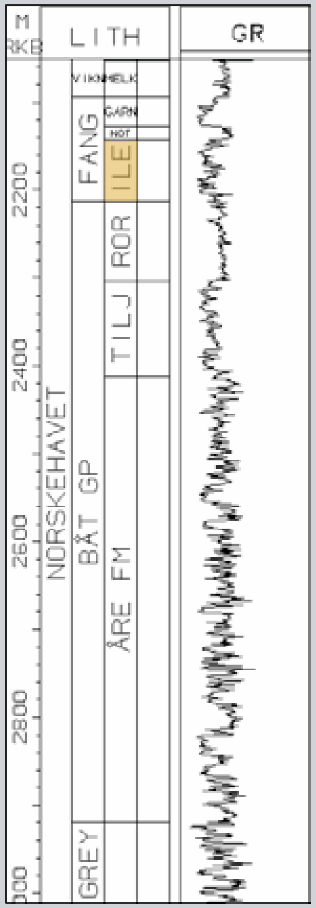
The thickness in the type well (6507/11-3) is 64.5m and 72m in the reference well (6407/1-3). The thickness of the Ile Fm varies between 50 and 100m over most of the Haltenbanken-Trænabanken area.

Sandstone dominated successions of similar age have been reported from shallow boreholes and sea bottom sampling in the eastern part of the Trøndelag Platform. The succession is thinner, however, ranging from 30 to 60m. The formation is shale dominated in the Vega High and Helgeland Basin.





WELL LOG 6507/12-1

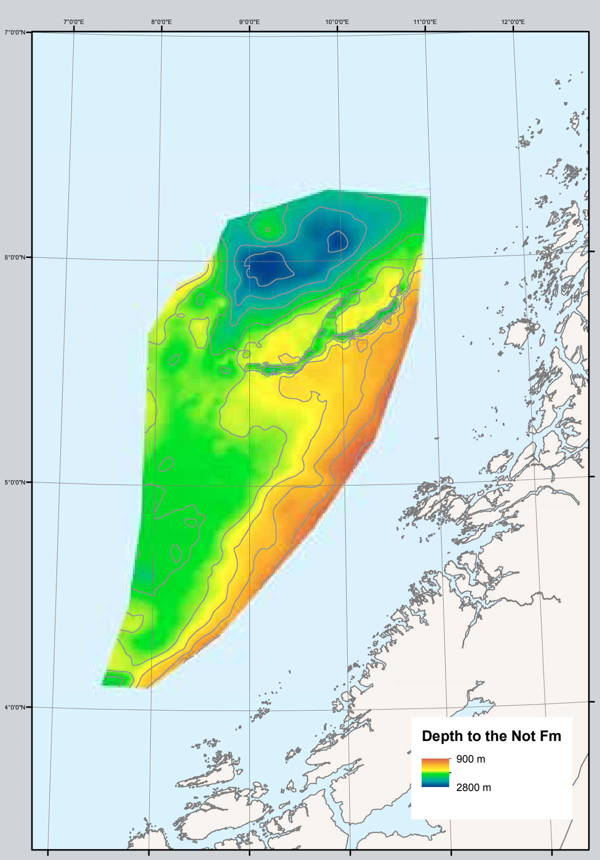


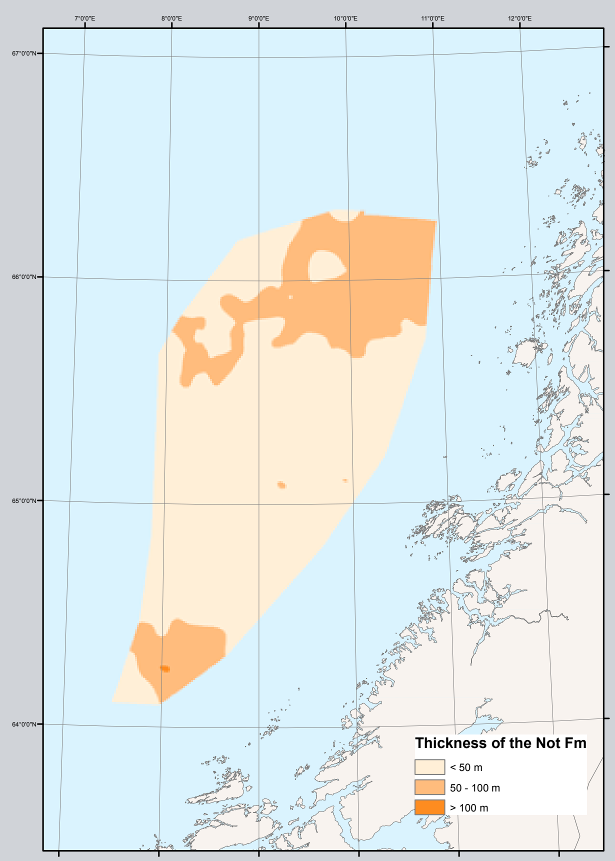
6508/5-1 ILE 1791 - 1795 m

The Fangst Group - Not Formation

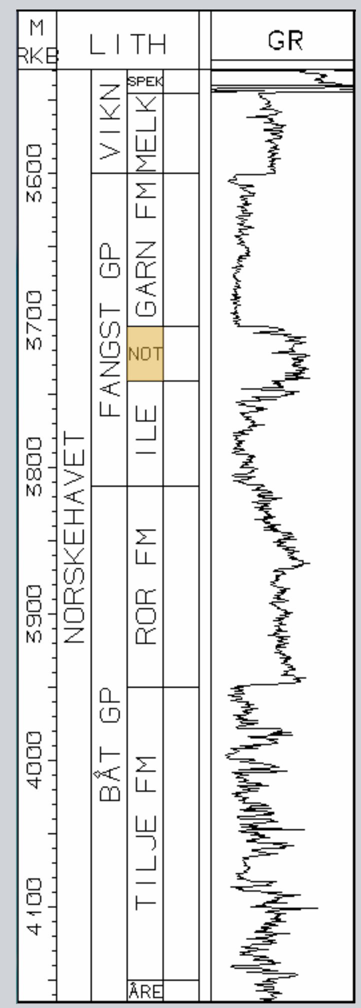
The Not Formation (Aalenian to Bajocian) is developed as a mudstone dominated sequence coarsening upwards into bioturbated fine-grained sandstones deposited in lagoons or sheltered bays. The Not Fm is recognised over the entire Haltenbanken area, except on the eroded highs. The thickest development (<50m) of the Not Fm is on the southwestern part of the Halten Terrace, and the unit thins towards the east. On the Trøndelag Platform it has a consistent thickness of approximately 40m. The mudstones of the Not Fm could act as a seal.

In the type well (6507/1-3) the thickness is 14.5m and 37m in the reference well (6407/1-3).





WELL LOG 6407/1-3



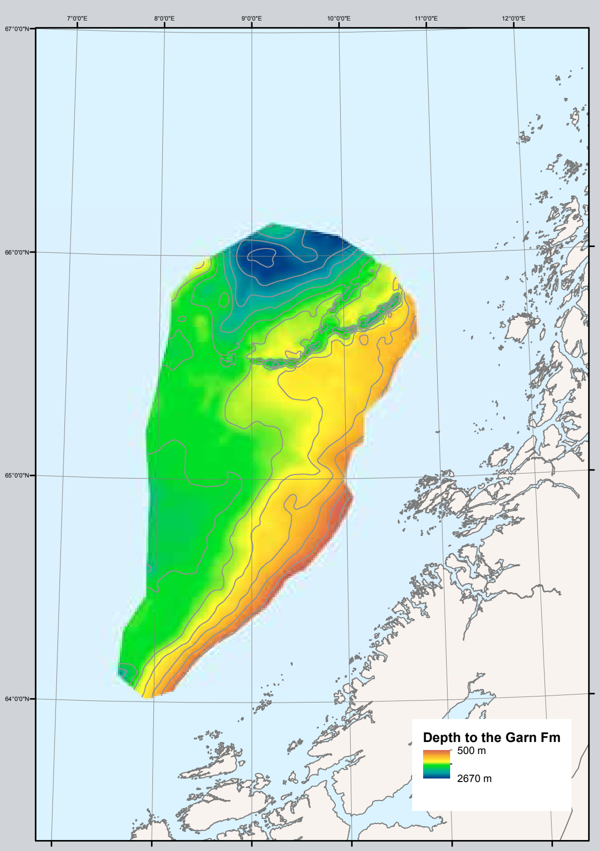
6507/11-3 NOT 2467 - 2472 m

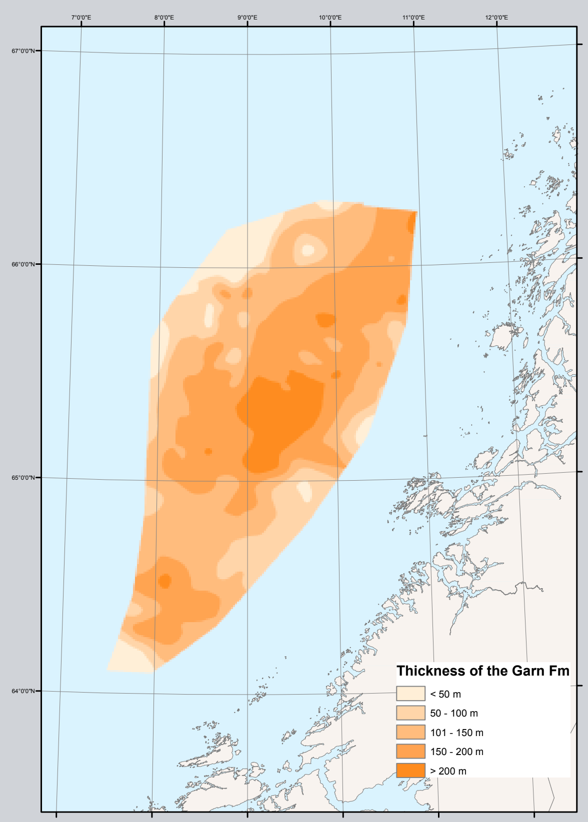
The Fangst Group - Garn Formation

The Garn Formation (Bajocian to Bathonian) is interpreted as progradation of braided delta lobes over the mud dominated Not Fm. The Garn Fm is present over the central part of the Halten and Dønna Terraces and the Trøndelag Platform, except over structural highs (Nordland Ridge) where the entire formation may be eroded. In the Ylvingen Fault Zone (well 6510/2-1R), the Garn Fm contains more silt, and further north, siltstones and mudstones are the lateral equivalents of the sandstones in the Garn Fm. It must be noted that well control on the eastern part of the Trøndelag Platform and in the deeper areas to the west is limited.

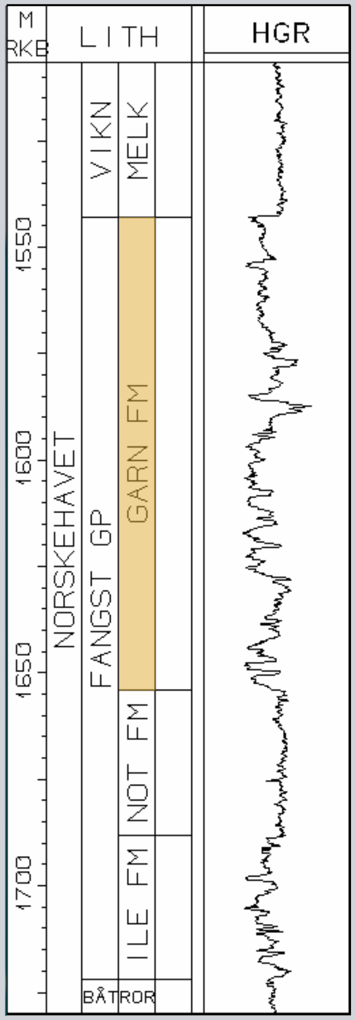
Depositionally, the sandstones of the Garn Fm are interpreted as a wave-dominated shoreface system with marine mud-dominated sediments deposited towards the north and south.

The thickness in the type well (6407/1-3) is 104m, and the formation may reach more than 100m on the Halten Terrace. The thickness of the Garn Fm is about 150m on the Trøndelag Platform. In the Froan Basin the formation is sand dominated compared to the northern part, where it becomes more shale dominated





WELL LOG 6510/2-1R



6407/1-3 GARN 3671.0 - 3675.0 m

The Viking Group

Middle Jurassic to Upper Jurassic/Lower Cretaceous
(Bajocian to Berriasian)

The Viking Group is defined in the northern North Sea and on Haltenbanken and Trænabanken. It is divided into three formations, the Melke, Rogn and Spekk Formations. The group is present over most of the Trøndelag Platform, but thins toward the Nordland Ridge where it is locally absent. The dominant lithology of the Viking Gp is mudstones and siltstones, with the exception of locally developed sands (Rogn Fm) in the Draugen field area and on the Frøya High. Sediments correlated with the Viking Gp have been found by shallow drilling and seafloor sampling in the eastern part of the Trøndelag Platform.

The thickness of the Viking Gp in the type well (6506/12-4) is 124.5m and 61m in the reference well (6407/9-1). Thicknesses up to 1000m are indicated on seismic data in down-faulted basins, and well 6507/7-1 on the Dønna Terrace drilled 658m sediments of the Viking Gp.

The Melke Formation (Bajocian to Oxfordian) is deposited in an open marine environment over most of Haltenbanken, but contains local sands in parts of the Dønna Terrace, the Revfallet Fault Complex and over the southern part of the Rødøy High. In the type well (6506/12-4), the thickness is 116.5m, but thicknesses in the order of 550m have been drilled in the area west of the Nordland Ridge.

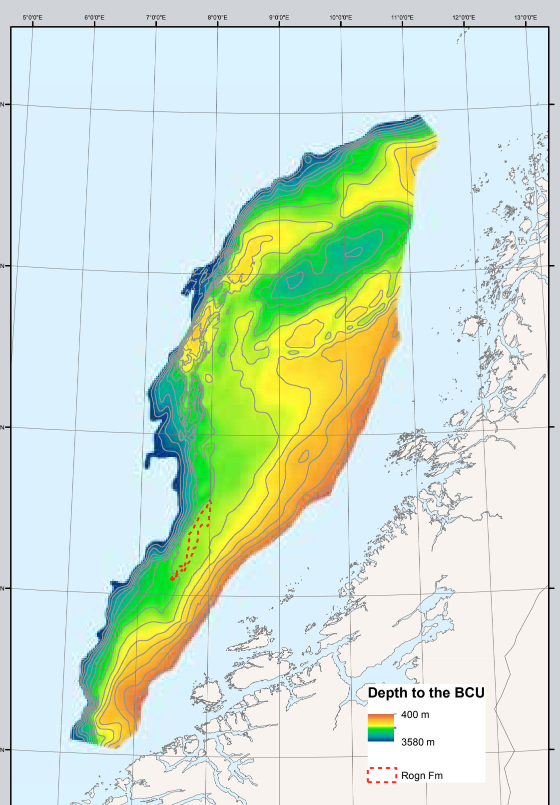
The Rogn Formation (Oxfordian to Kimmeridgian) sandstones occur within mudstones of the Spekk Fm in the Draugen field, the western part of the Froan Basin. A similar development is found on the Frøya High (well 6306/6-1). The sandstones of the Rogn Fm are interpreted as shallow marine bar deposits.

In the type well (6407/9-1), the thickness of the Rogn Fm is 49m and in the reference well (6306/6-1) the thickness is 93m.

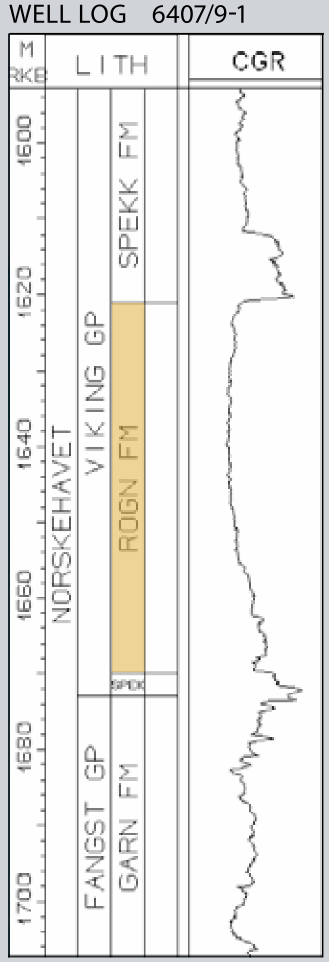
The burial depth of the sandstones of the Rogn Fm is around 1600-1700m in the Draugen field, and porosities in the order of 30% and permeabilities up to 6 darcy have been reported.

The Spekk Formation (Oxfordian-Berriasian) overlies the Melke Fm. The Spekk Fm was probably deposited over most of the Haltenbanken and Trænabanken area, but may be absent over structural highs such as the Nordland Ridge. The mudstones were deposited in marine anoxic water conditions, resulting in high organic content comparable with the time equivalent Draupne Fm in the northern North Sea, thus forming a major hydrocarbon source rock.

In the type well (6407/2-1), the thickness of the Spekk Fm is 65.5m, but thicker sections may be present in structural lows as on the Dønna Terrace. Black mudstones of similar age, also with high organic content, have been found in shallow boreholes off the coast of Trøndelag.



WELL LOG 6407/9-1



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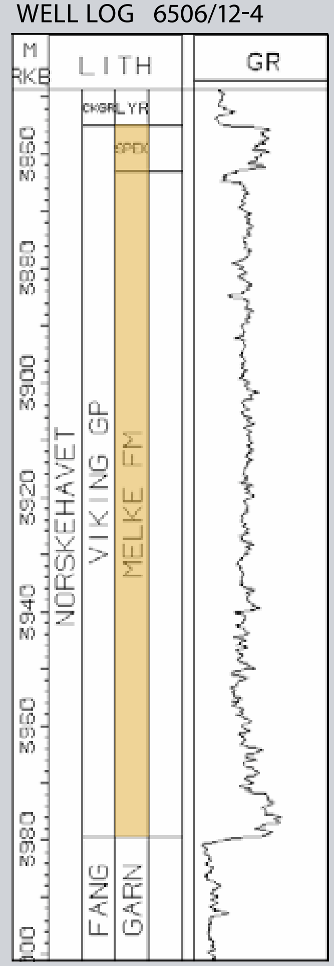
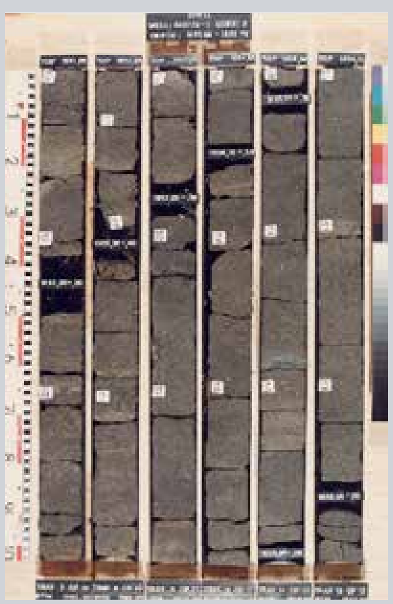


6407/9-1 ROGN 1651.0 - 1656.8 m



6306/10-1 MELKE 2747.0 - 2752.0 m

The Cromer Knoll and Shetland Groups

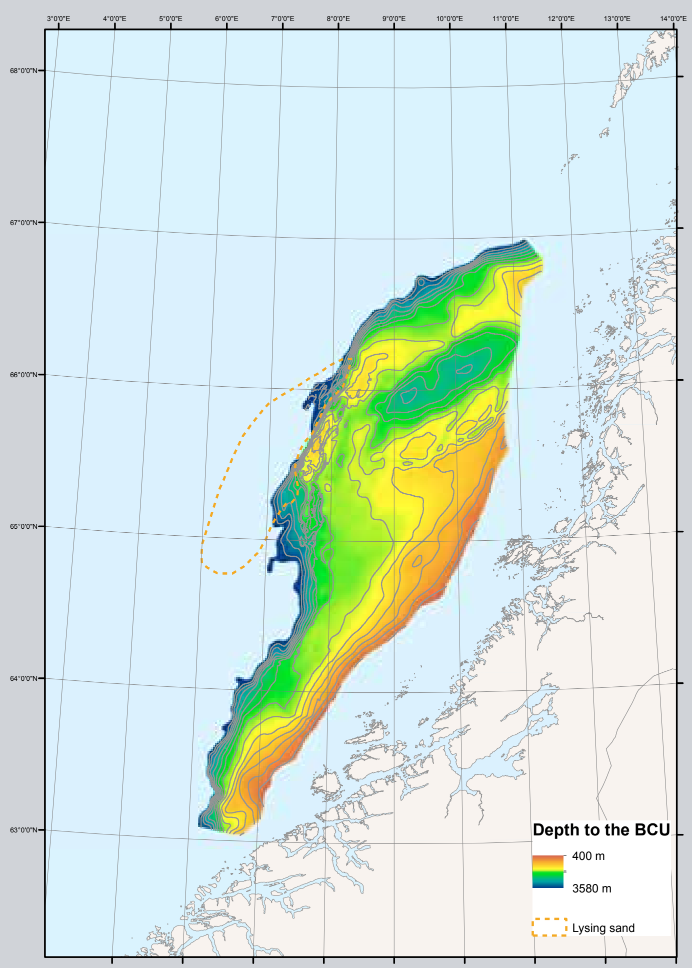
Upper Cretaceous
(Turonian to Maastrichtian)

The Cretaceous sediments in the Norwegian Sea are dominated by mudstones and siltstones, which form good seals. In the Halten and Dønna Terrace, certain intervals including the Lower Cretaceous Lange Formation and the Turonian-Coniacian Lysing Formation, contain locally developed sandstone units. In the northern part of the Vøring Basin, north of 67°N, the Nise Formation contains a thick succession of sandstones deposited as mass flows in a deep marine environment. The Santonian - Campanian sandstones of the Nise Formation were sourced from Greenland and shale out towards the south and east. Some methane gas discoveries have been made in the Nise Fm sandstones. Although these sandstones have quite good reservoir properties and a large volume, their CO2 storage potential was not evaluated, due to their remote location, and because they are located within a petroleum province. The Lange Fm, dominantly consisting of claystones, contains several local sandstone bodies which could act as thief sands. They are buried too deeply and have too small volumes to have any CO_2 storage potential.

Maastrichtian sandstones within the Springar Formation occur locally in the deep water areas. Their small volumes and poor reservoir properties make them unattractive for CO_2 storage.

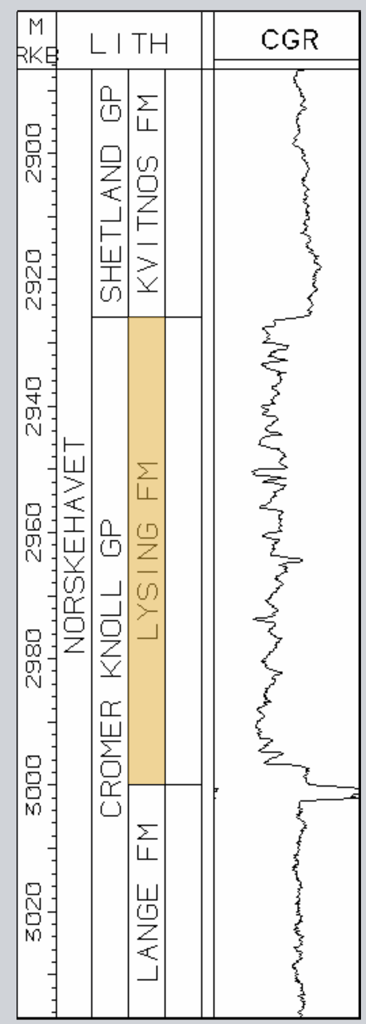
The Lysing Formation (Upper Cenomanian to Turonian/Coniacian)
The Lysing Fm forms the upper part of the Cromer Knoll Group, which consists of the Lyr, Lange and Lysing Formations. In the type well (6507/7-1), on the Halten Terrace west of the Nordland Ridge, the thickness of the Lysing Fm is 74m. In the Dønna Terrace area, sandstones within the Lysing Formation form a reservoir section with a thickness up to about 70 m. The Lysing Fm sandstones in the Dønna Terrace were probably deposited as submarine fans in a deep marine environment. Their source area is believed to be the Nordland Ridge and the highs further north. A few methane gas discoveries have been made in the Lysing Fm sands west of the Skarv Field.

Although the Lysing Fm sands have a significant aquifer volume, it was decided to exclude this formation from a further evaluation of its storage potential. The main reason is that the aquifer is overpressured in the main depositional area in the Dønna Terrace, leaving a small pressure window for CO_2 injection before the fracture gradient is reached. Also, it is located in a zone of petroleum exploration and future production, where conflicts of interest with CO_2 injection projects could occur.

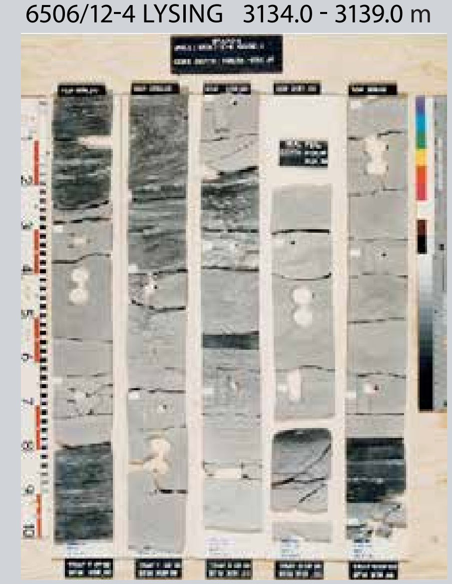


Outline of the Lysing Formation and Base Cretaceous depth map.

WELL LOG 6507/7-1



6506/12-4 LYSING 3134.0 - 3139.0 m



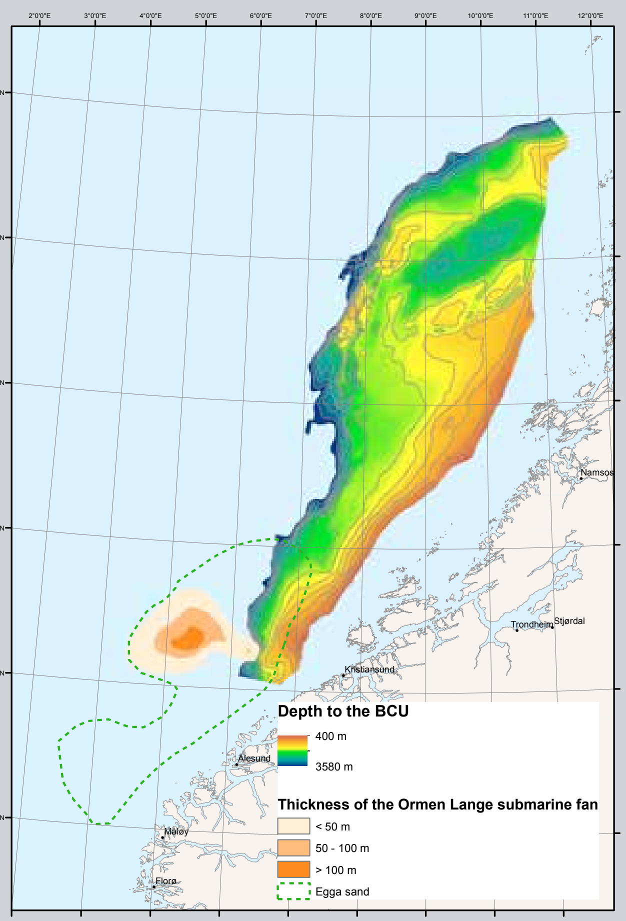
The Rogaland Group

Paleocene
(Danian)

The Late Cretaceous deposits in the Norwegian Sea were dominated by fine-grained sediments, and the source areas for sands were located to the north and west. In the Paleocene, the transport of sediments from Greenland to the Vøring Basin continued, but there was also significant sediment supply from Scandinavia to the Trøndelag Platform and Møre Basin. The main reservoir sand from the Paleocene-Eocene period is the Danian Egga sandstone.

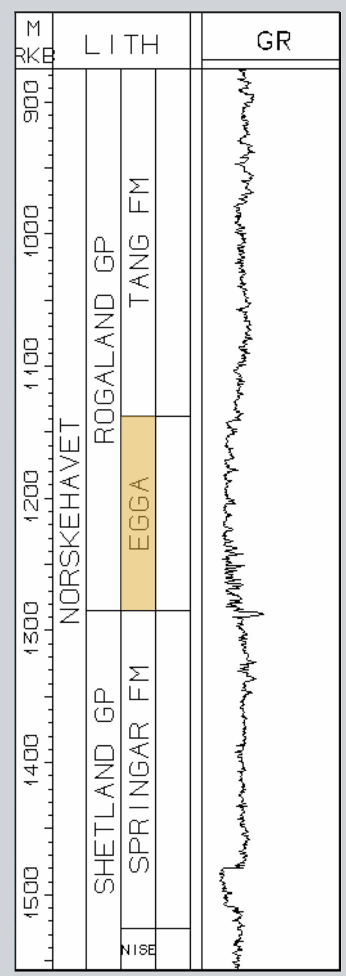
The Egga sandstone (Danian)
This Danian sandstone forms the main reservoir of the giant Ormen Lange gas field. At present, there is no type well or reference well defined. The sandstone has so far no formal stratigraphic formation name, but it has been referred to informally as the Egga formation on the NPD website. At the Ormen Lange field it is defined as a deep marine mass flow sandstone unit within the Rogaland Gp. In the field, a maximum thickness of 80m was found in well 6305/7-1. The Egga sandstones are found in several exploration wells in the Møre Basin and Slørebotn Sub-basin. The reservoir quality and thickness vary considerably depending on where the well is positioned in the different submarine fan systems. The Ormen Lange fan is possibly the largest submarine fan within the Egga sandstone, and the map below shows a thickness map of this fan along with the approximate outline of the sand system.

The shallow eastern part of the Møre Basin has a monoclinal structure where all sedimentary beds dip from the coast into the basin. Any structural closures are likely to be small. Consequently, an injection site for large volumes of CO_2 would probably need to have a stratigraphic component to the structure. Possibly the Egga sandstone aquifer could be used for injection of small volumes of CO_2, which could be residually trapped before they migrate to the sea floor. Such a case has been modelled for a Jurassic aquifer in the Froan Basin in section 5.2. This case has not been evaluated for the Møre Basin.

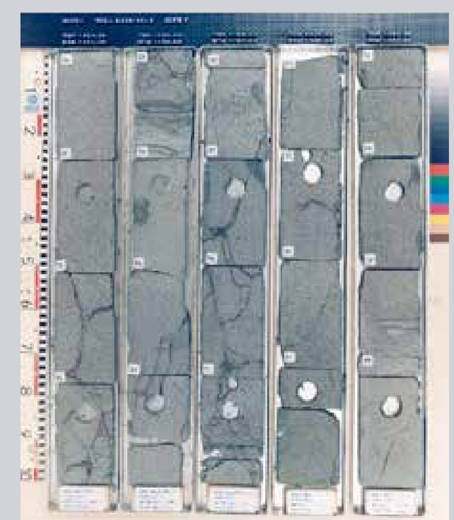


Base Cretaceous map and outline of the Egga formation. Distribution and thickness of the Ormen Lange submarine fan.

WELL LOG 6306/10-1



6306/10-1 EGGA 1164.0 - 1169.0 m



5. 2 Storage options in the Norwegian Sea

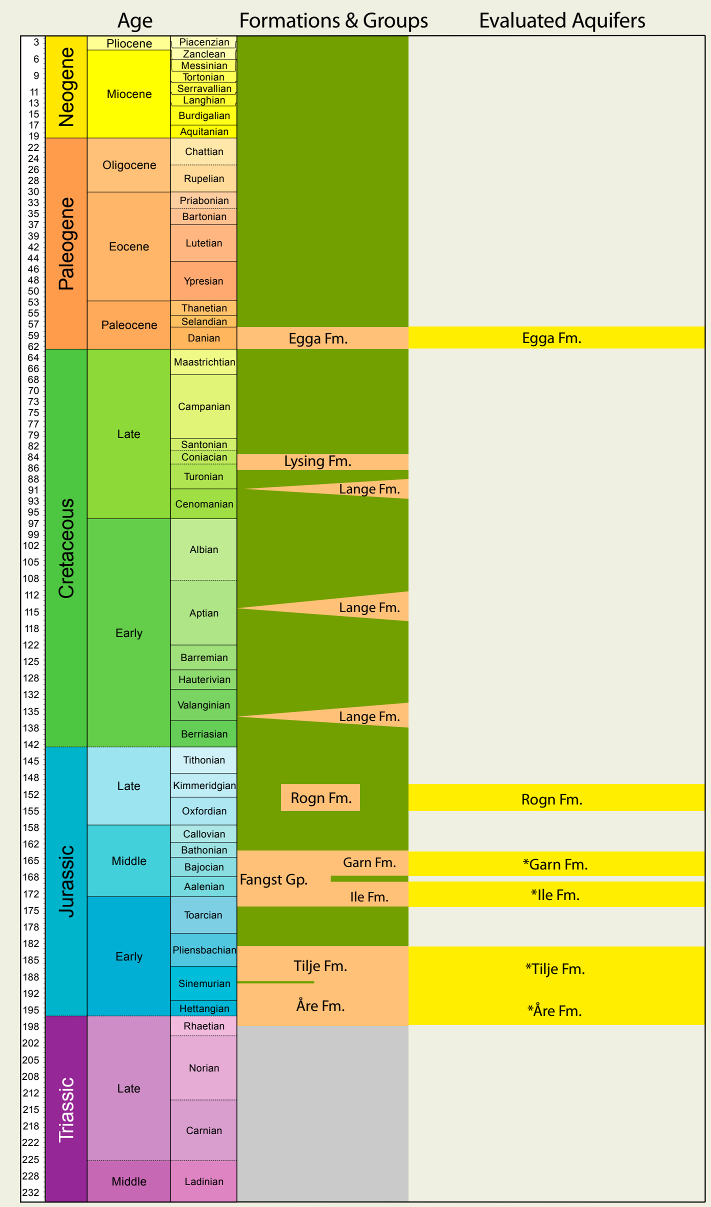
In the Norwegian Sea, the general conditions are met in the Trøndelag Platform including the Nordland Ridge and in the Møre Basin. Potential CO_2 storage in the shelf slope and deep sea provinces of the Norwegian Sea has not been evaluated (Cretaceous formations, section 4).

The aquifers in the Trøndelag Platform have been studied by compilation of published maps, new seismic mapping, well studies and well correlation. The Draugen area and the Nordland Ridge have good data coverage with 3D seismic and several wells, while the remaining area has 2D seismic data and a few exploration wells.

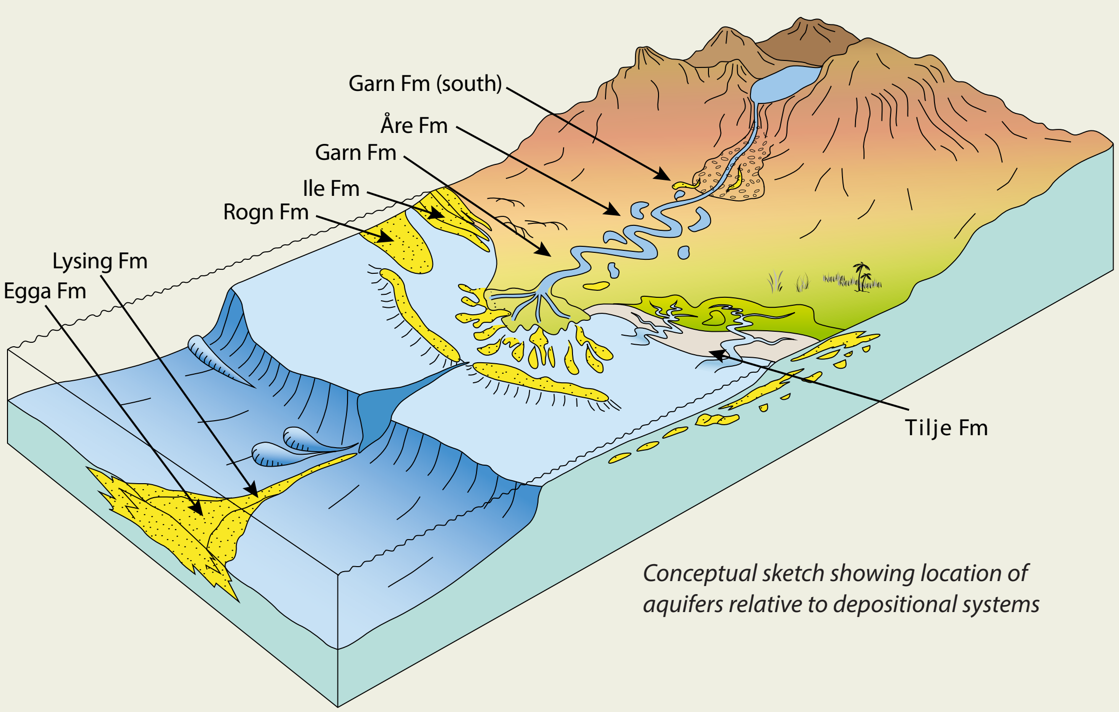
As described in section 4, the Jurassic succession in the Norwegian Sea Shelf is thick and contains several aquifers with storage potential for CO_2. The Halten and Dønna Terraces are important petroleum provinces. The hydrocarbons in these provinces are believed to be generated from Jurassic source rocks, mainly from the Spekk and Åre Formations. In the Trøndelag Platform, the Jurassic source rocks have not been buried deep enough to reach the oil and gas maturation window, and the hydrocarbons occurring here have migrated from the deeper basins and terraces. The approximate limit for hydrocarbon generation and migration is indicated by the red line (page 94). Some oil and gas may have been generated in the deepest part of the Helgeland Basin, although so far there has been no exploration success in this area.

In the petroleum provinces (west of the red line), exploration and production activities are expected to continue for many years to come. The most realistic sites for CO_2 storage in the petroleum provinces will be some of the abandoned fields. Consequently, an indication of the storage capacity of the fields has been given, but no aquifer volumes have been calculated for this area. Some of the oil fields are considered to have a potential for enhanced oil recovery (EOR) by use of CO_2 (section 8). A certain amount of the CO_2 used for EOR will remain trapped.

In the eastern area, all the large aquifers have been selected based on the established criteria (section 3.3), and storage capacity is estimated by the method described in section 3.4.



* Evaluated prospects



Conceptual sketch showing location of aquifers relative to depositional systems

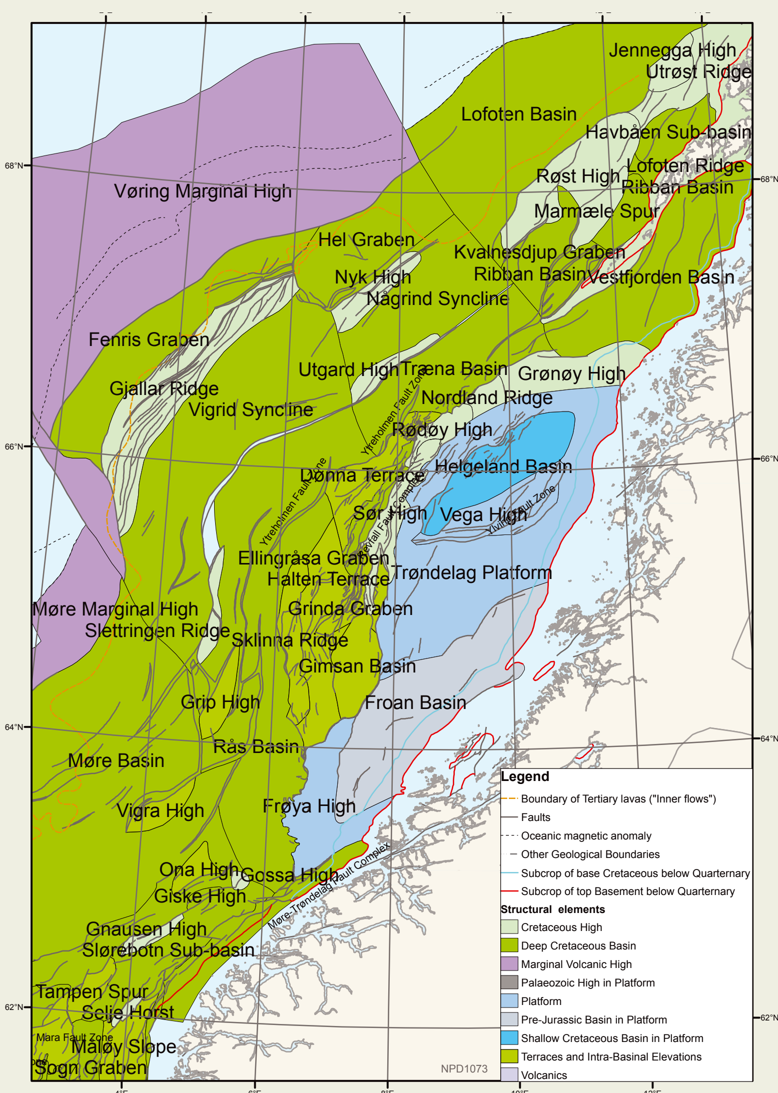
5.2.1 Saline aquifers

Froan and Helgeland Basins

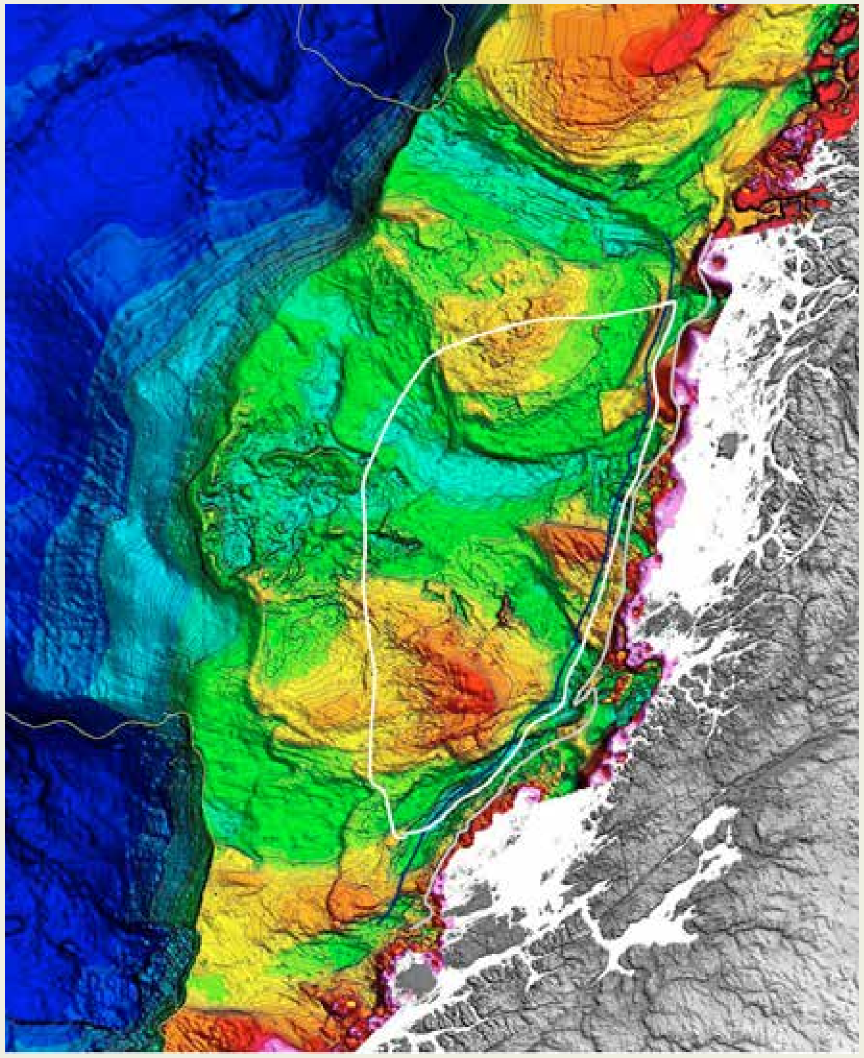
The evaluated Jurassic aquifers are located at the Trøndelag Platform, east of the Cretaceous basins which have a green colour in the structural element map. The aquifers are bounded by the subcrop to the Quaternary along the coast to the east, by the Nordland Ridge to the NW and north, and the Frøya High to the SW. The shallow Jurassic aquifers are separated from the Gimsan Basin by large faults and steep slopes. The pore pressure regimes show a general trend transition from high overpressure in the Halten Terrace in the west to hydrostatic pressure towards the Trøndelag Platform in the east. This indicates pressure equilibration across the faulted boundary in geological time. In the Helgeland and Froan Basins, all pore pressures are hydrostatic.

The Åre and Tilje Formations are treated as one aquifer at a regional scale due to the lack of regional sealing shales in the stratigraphy. Both these formations are heterogeneous, with coal beds and shale beds separating channelized sandstones. Internal baffles and barriers at a km scale should be expected, both within the Åre Formation and possibly between Åre and Tilje. Consequently, there is a risk of significant internal barriers within the aquifer and that the communicating volumes may be less than predicted. In the case of low connectivity, a higher number of injection wells than anticipated would be necessary to realize the desired injection volume of CO_2.

The Ror Formation is assumed to form a regional seal between the Tilje and Ile formations. The formation often forms a pressure barrier in the fields in the Halten Terrace, and tight shales have been proved in the Ror Fm in wells drilled in the Trøndelag Platform. Laterally, the seal might be broken by large faults.



Structural element map. The green area represents basins with thick Cretaceous infill, where Jurassic sediments are generally deeply buried.



Bathymetry map with outlines of the main study area and subcrop lines of Base Cretaceous and the basement. Bathymetry from the Geological Survey of Norway (NGU). Storegga slide to the SW.

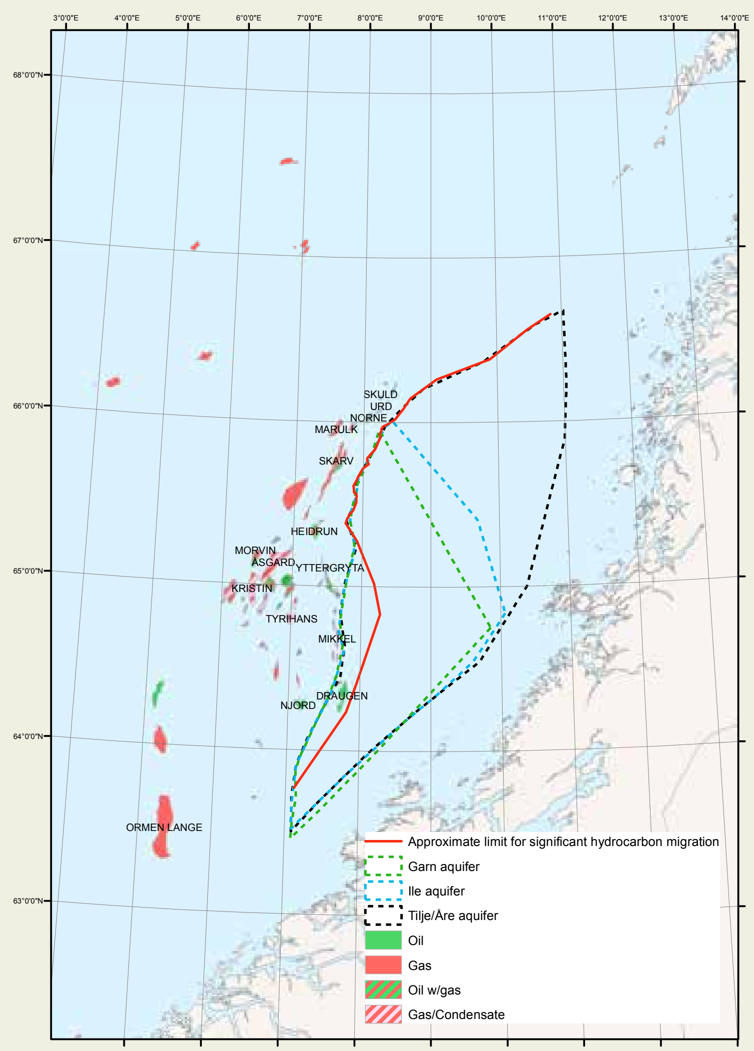
5. 2 Storage options in the Norwegian Sea

5.2.1 Saline aquifers

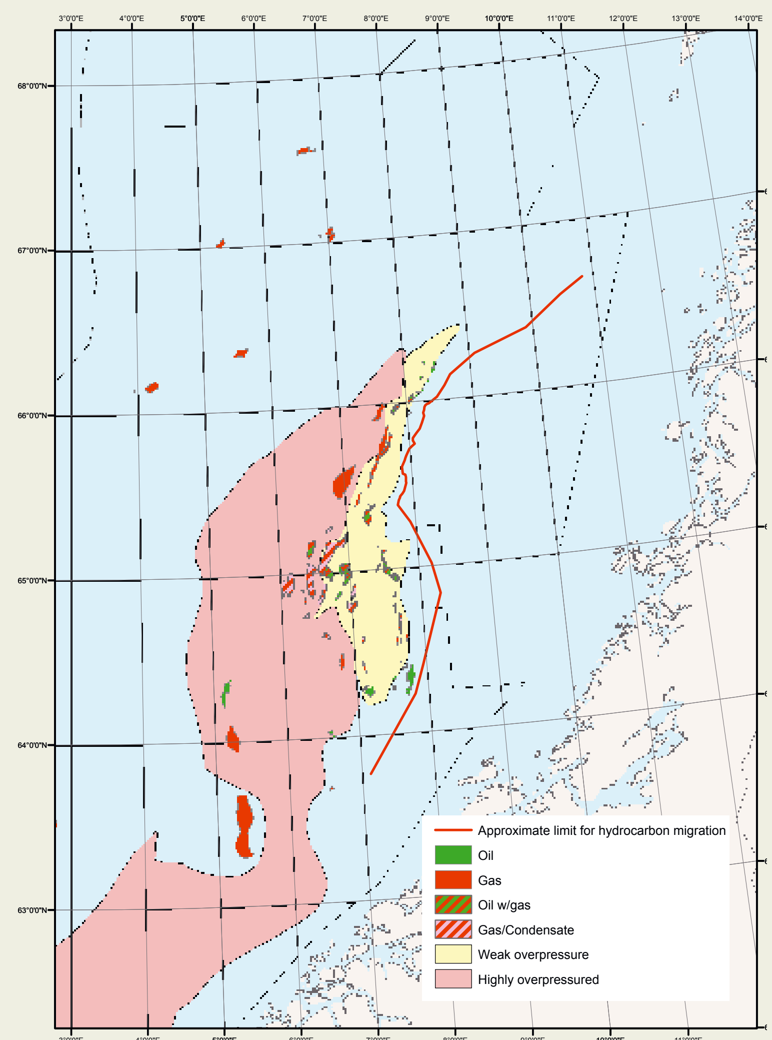
The Not Formation is developed as shale in the Trøndelag Platform, and the seismic data indicate a regional distribution. Consequently, it might be expected that the Not Formation will act as a barrier between the Ile and Garn Formations. In the modelling, however, Ile and Garn Formations have been grouped as one aquifer. This simplification was made because of the small volume of the Ile Fm and the existence of faults which could offset the Not Formation and juxtapose Ile with Garn.

The Ile and Garn Formations have very good reservoir properties at the shallow depths encountered in the Trøndelag Platform. The porosity and permeability used in the geomodel are based on the well log data and a few core measurements. The Garn Formation in the Froan Basin is dominated by shallow marine sediments where much better connectivity can be expected than in the tidal-dominated Ile and Tilje Formations. The Ile and Garn formations become more shale-rich towards the Helgeland Basin.

The Rogn Formation in the Draugen area has very good reservoir properties. It is separated from the Garn Formation by shales within the Spekk Formation with variable thickness. It is likely that there will be communication between the Rogn and Garn reservoirs. The Spekk, Melke and Cretaceous shales above the Garn Formation constitute an excellent top seal for the Jurassic aquifers.



Distribution of aquifers in the Trøndelag Platform. Red line shows the approximate limit for hydrocarbon migration

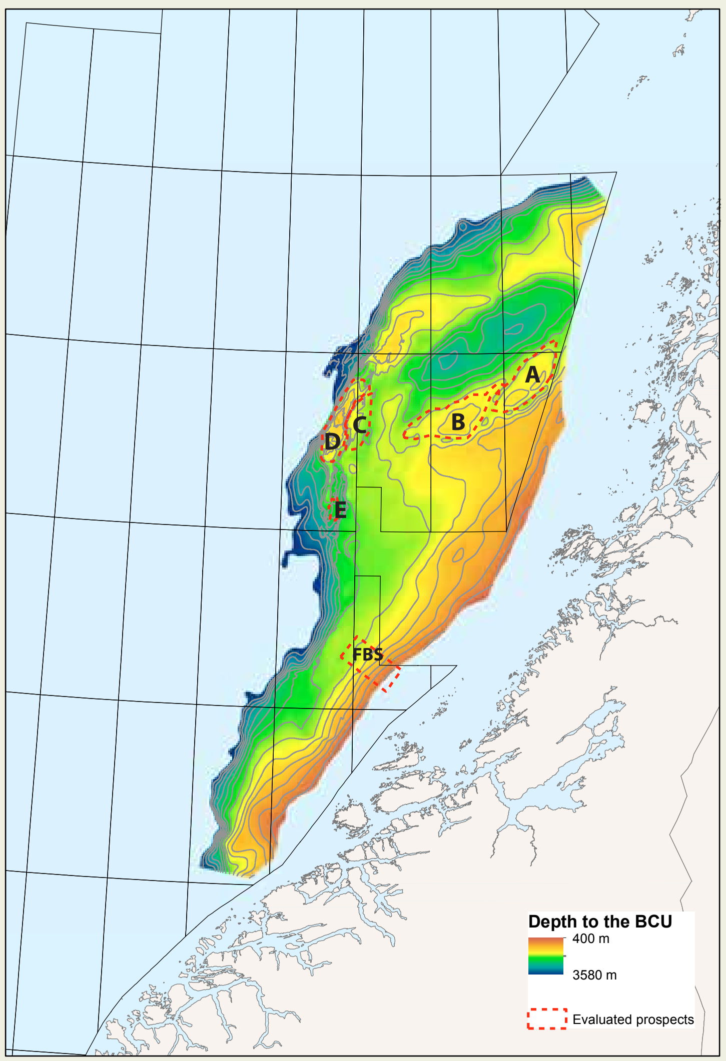


Hydrocarbon accumulations and pore pressure regimes in the Jurassic aquifers

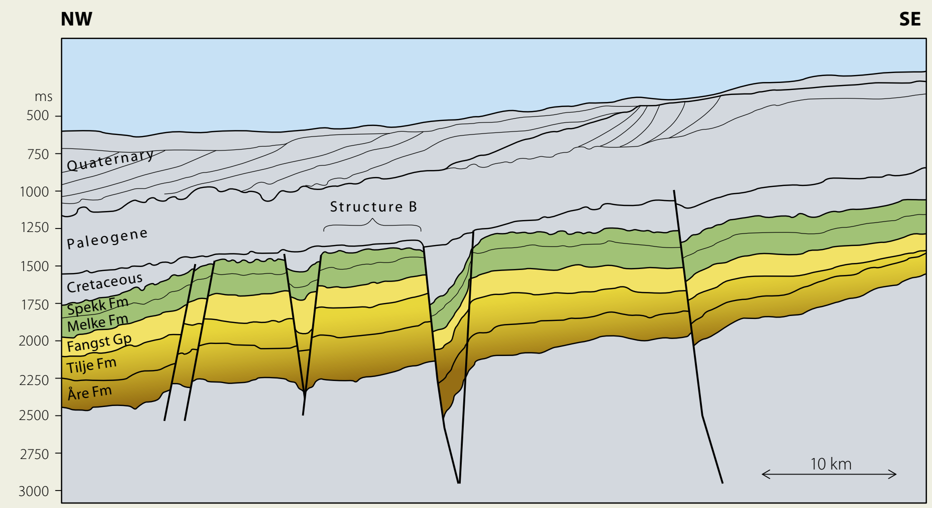
5.2.1 Saline aquifers

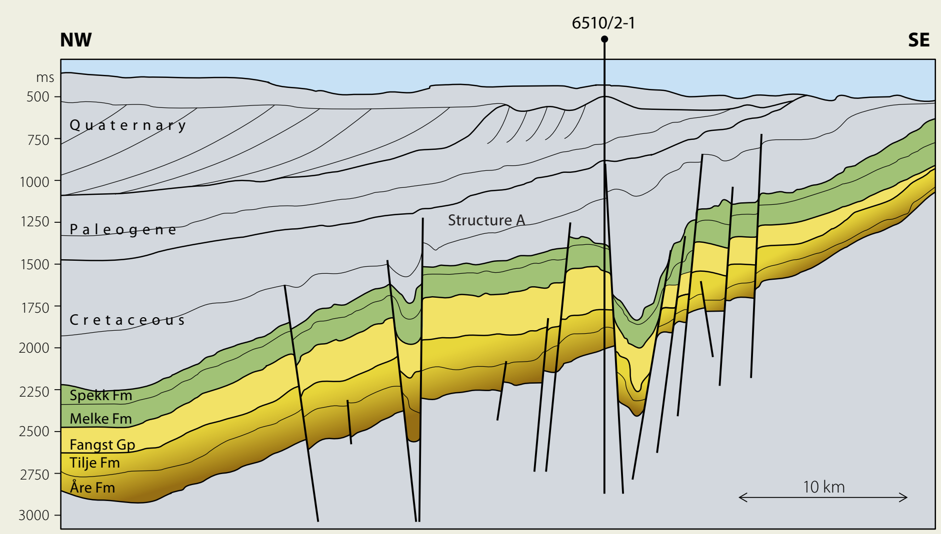
Compartmentalization
The northern part of the Trøndelag Platform and the Sør High of the Nordland Ridge are characterized by large graben features such as the Ylvingen Fault Zone and the Ellingråsa Graben. These grabens were probably formed by extension and collapse in the late Jurassic and early Cretaceous. Their size and depth suggest that they could be barriers to fluid flow in the Jurassic aquifers.

In the geomodel, the Ellingråsa Graben is treated as the western boundary of the Jurassic aquifers in the Trøndelag Platform. The Ylvingen Fault Zone could possibly seal off the northern from the southern part of the Åre-Tilje aquifer. Towards the north, in the Grønøy High, the aquifers are truncated by erosion. In the modelling of CO_2 injection, the lateral boundaries towards fault structures in the south, west and north are assumed to be closed. Towards the east, aquifers in the Froan Basin terminate at the base of Quaternary sediments below the sea floor. The sealing capacity of the Quaternary sediments along the eastern subcrop is probably low. As shown in the map, the topography of the sea floor is rugged, with basins and ridges carved out by glacial erosion. Comparison with seismic data indicates that the Quaternary cover can be several tens of metres thick in the basins, but much thinner in the slopes. The shallow well 6408/12-U-1 in the Froan Basin has only 6 m Quaternary cover. Most likely, there will be pressure communication between the Jurassic aquifers and the sea water along the subcrop line.



Regional BCU map showing the locations of prospects A to E and the location of the simulation grid in the Froan Basin (FBS). The map to the left is zoomed in on structures C, D and E.





NW – SE profiles across the SE flank of the Helgeland Basin. The closed structures A and B are indicated. The location is shown in p. 44.

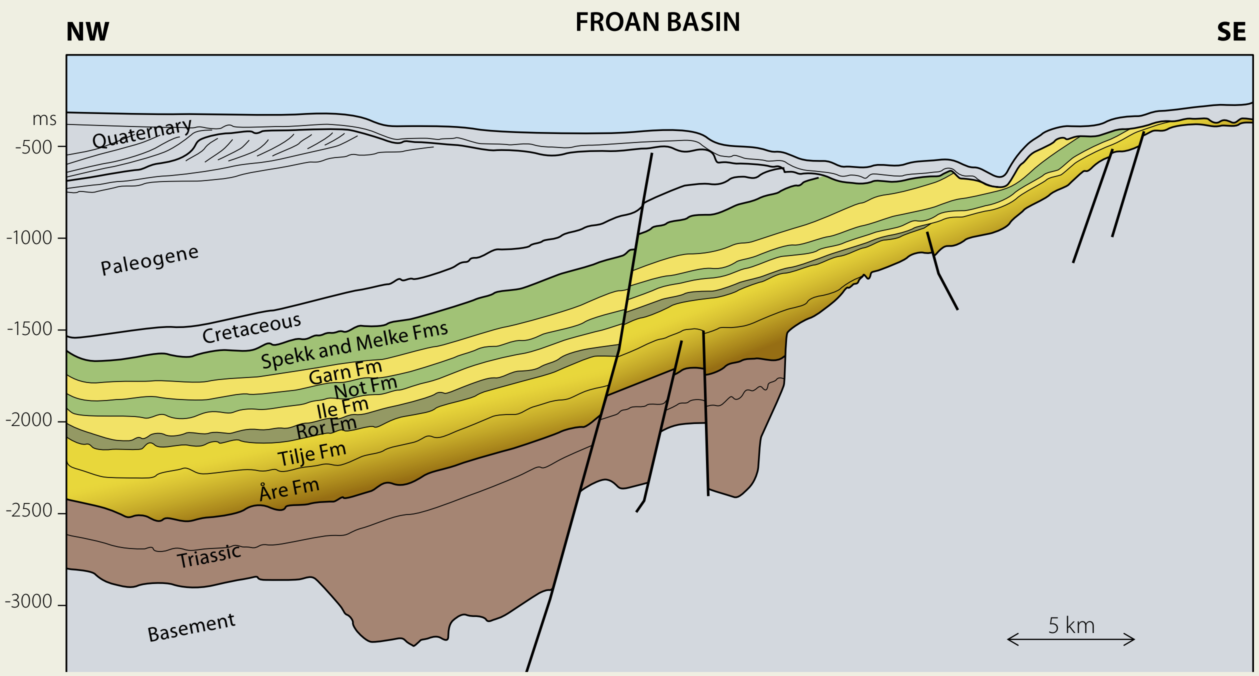
Froan Basin – long distance CO_2 migration

Modeling of CO_2 injection and migration in the Froan Basin

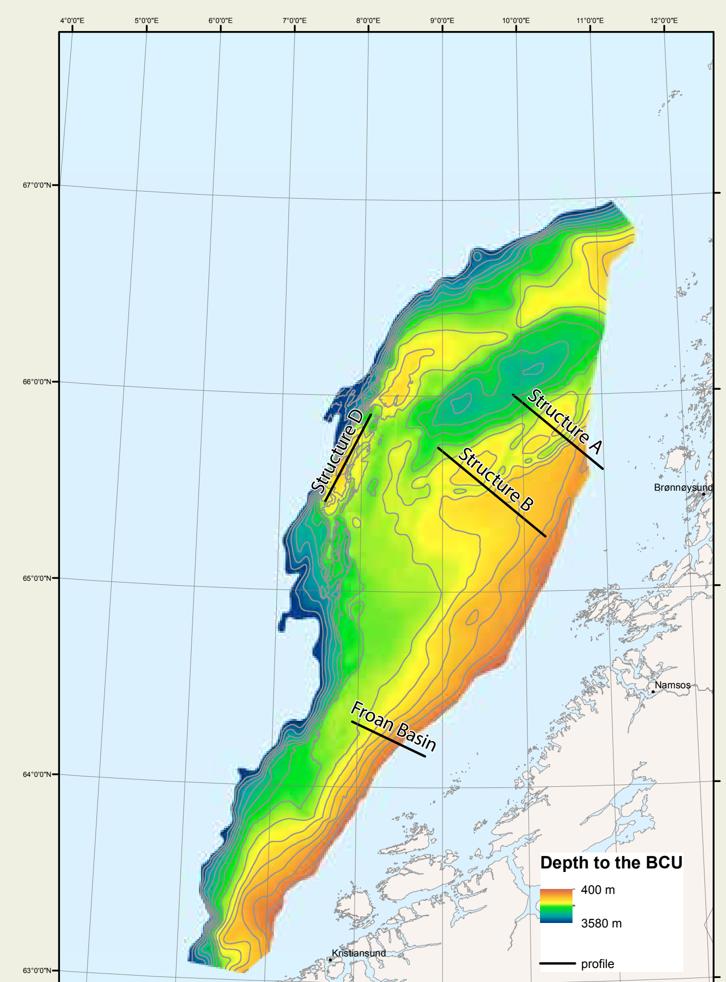
The aquifers in the southeastern part of the Norwegian Sea typically have a consistent dip of 1-2 degrees from the Norwegian coast to the basinal areas. In the case of permeable beds occurring along the dip slope, there is a risk that CO_2 injected down dip can migrate upwards where the aquifer is truncated by Quaternary glacial sediments. At that depth, CO_2 will be in gas phase. The glacial sediments mainly consist of clay and tills, and their thickness ranges from about 10 m to more than 200 m. Understanding the timing and extent of long distance CO_2 migration is of importance for evaluation of the storage capacity of outcropping aquifers. Consequently, a modelling study has been conducted on possible aquifers in the Froan Basin.

The Froan Basin is a sub-element of the Trøndelag Platform. It is bound by the Frøya High in the south, the Gimsan Basin and the Halten Terrace in the west, an outcropping basement in the east and the Trøndelag Platform in the north. The Froan Basin was formed by Permian-Early Triassic block faulting. The pre-Jurassic rocks of the Trøndelag Platform were deposited in the NE-SW trending echelon basins. In the early and middle Jurassic, the platform area subsided as one large basin, and the rate of sedimentation was in equilibrium with the rate of subsidence. Consequently, there is a relatively uniform thickness of Jurassic sediments overlying the Triassic and locally the Paleozoic graben infill. Reservoirs which could possibly be used for CO_2 injection are the Triassic and Jurassic sandstones. The main seal rocks are the middle to upper Jurassic Melke Fm and Spekk Fm shales as well as the overlying fine grained Cretaceous section. The main risk of leakage is the migration of CO_2 towards the Quaternary layer.

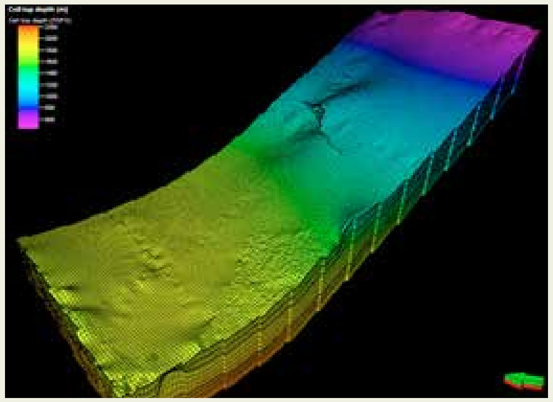
Based on simulation results (upscaling of sector model), about 400 mill tons CO_2 can be stored in the Garn and Ile aquifer (8 mill tons/year over 50 years). This will require 4 injection wells (2 mill tons/year per well) and yield an acceptable pressure increase (<20bar). After 10,000 years most of the gas will have gone into solution with the formation water or will be residually trapped.



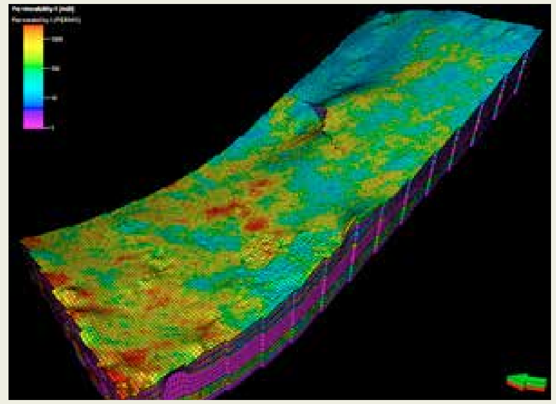
NW-SE profile showing the geometry of aquifers (yellow) and sealing formations (green) in the simulation model.



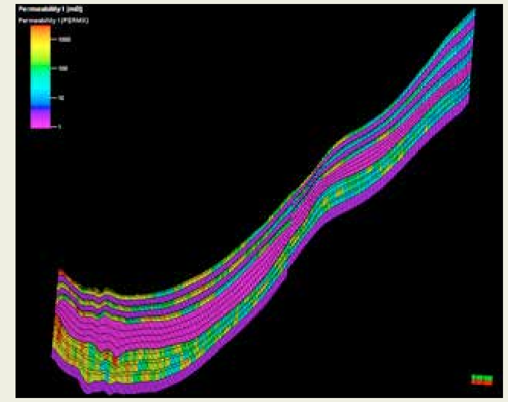
Froan Basin – long distance CO_2 migration



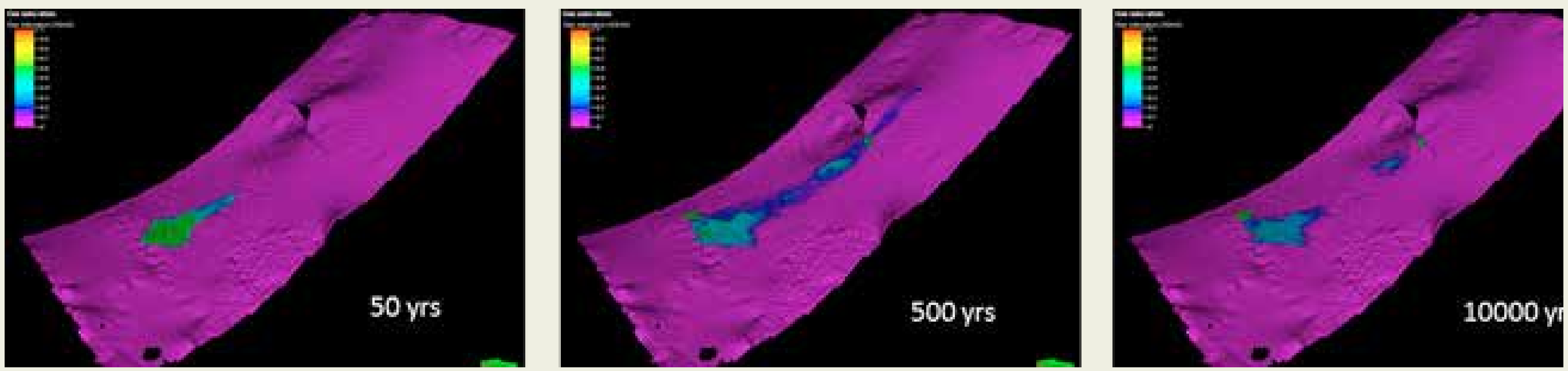
Simulation sector model, depths



Permeability distribution, top Garn



Permeability distribution, west-east cross section



CO_2 plume top Garn vs. time. The size of the model is 16 x 35 km.

A simulation sector model of the Garn, Not and Ile Formations was built covering about 10% of the total expected communicating aquifer volume. The top structure (Garn Fm) depth is about 1800 m in the western area and becomes shallower towards the east, with model cut-off at about 500 m depth. The main storage reservoirs are the Garn and Ile Formations with an average permeability of about 400 mD, separated by tight shales within the Not Formation. The Garn Formation consists of three reservoirs, separated by low permeable shale. The porosity and permeability have been stochastically modelled with both areal and vertical variation. The model layers are fine (<1m) at the top reservoir and underneath the shales to capture the vertical CO_2 saturation distribution.

The CO_2 injection well is located down dip, but alternative locations and injection zones have been simulated, with different injection rates. The injection period is 50 years, and the simulation continues for 10,000 years to verify the long term CO_2 migration effects.

The main criteria for evaluation of CO_2 storage volumes are the acceptable pressure increase and confinement of CO_2 migration (no migration to eastern model boundary within 10,000 years). CO_2 will continue to migrate upwards as long as it is in a free movable state. Migration stops when CO_2 is permanently bound or trapped, by going into solution with the formation water or by being residually or structurally trapped (mineralogical trapping has not been considered). The trapping achievement of sufficient volumes is depending on a good spreading of the injected CO_2. Vertical spreading can to some extent be controlled by injecting into lower reservoir zones, but it is sensitive to vertical permeability and also zonal permeability distribution in the area near the well. Areal spreading can mainly be achieved through use of several injectors.

The figures in the second row illustrate the free CO_2 saturation (green/blue) over 10,000 years.

Lower Jurassic interbedded sandstones, siltstones and shales belonging to the Neill Klinter Group at Constable Pynt, Jameson Land, East Greenland. The section is about 300 m high. These formations are time equivalent to parts of the Tilje, Tofte, Ror and Ile Formations in the Norwegian Sea, and the depositional environment is similar. Photo: NPD.

5. 2 Storage options in the Norwegian Sea

5.2.1 Saline aquifers

The Nordland Ridge aquifer

The Nordland Ridge has three large culminations, the Sør High, the Rødøy High and the Grønøy High. To the west these highs are separated from the petroleum-bearing terraces and basins by large faults. The Sør High is located close to many producing fields, discoveries and prospects. Because some of the gas discoveries, like 6506/6-1 Victoria, have a high CO_2 content, it is of interest to identify possible storage sites close to these discoveries where it might be possible to inject excess CO_2 from future production.

The Sør High is a structural closure with a culmination at 1000 m below sea level and an area exceeding 500 km^2. It is covered by 3D seismic data, and four wells have been drilled. The stratigraphy in the wells is interpreted in the NPD website as a few metres of Fangst Group overlying the Åre Formation. The seismic data show that there is an angular unconformity between the Åre Formation and the thinned Fangst Group. Small amounts of dry methane gas, possibly biogenic, have been encountered. There were no shows indicating heavier hydrocarbons. Due to tilting and block faulting below the unconformity, the Åre Formation has a variable thickness, commonly more than 200 m. The sandstones in the Åre Formation have similar properties as in the Froan Basin. Triassic Grey beds may contribute to the volume of the aquifer.

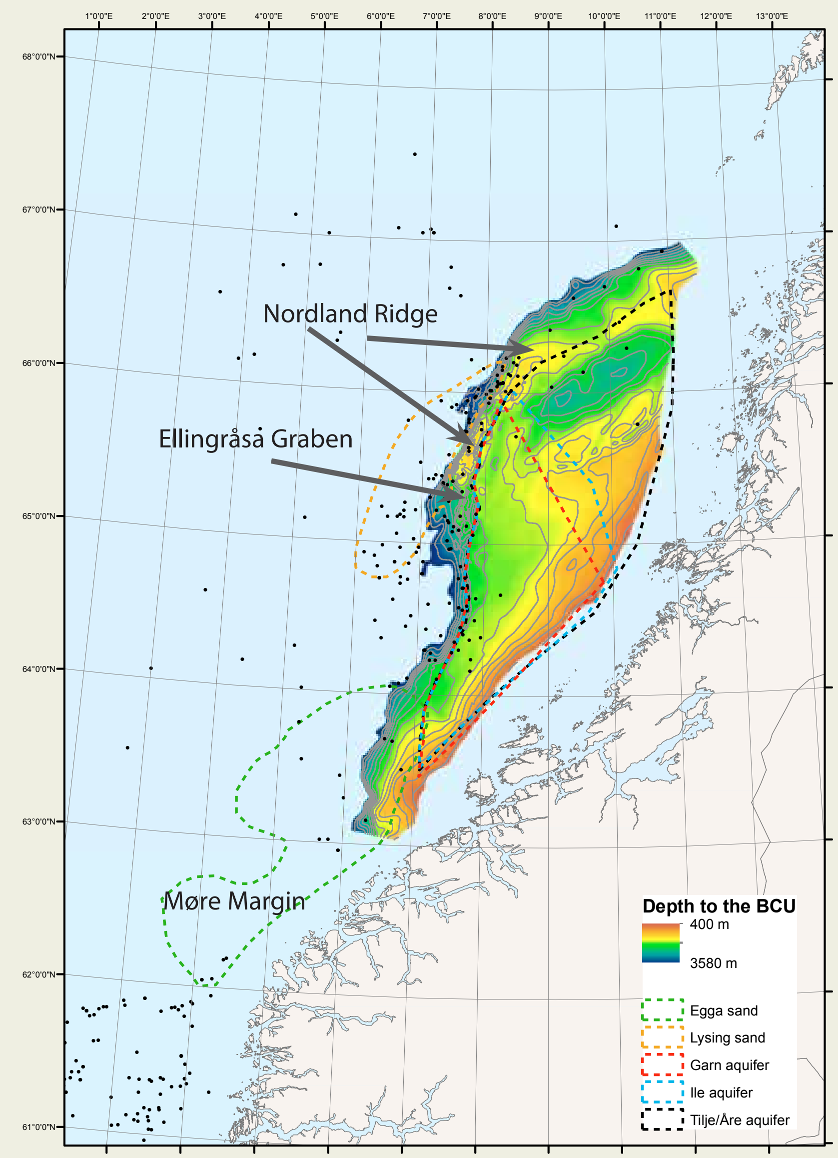
The Åre aquifer will probably have several local internal baffles and barriers. The top seal will be the overlying Quaternary sediments belonging to the Naust Formation, which has a minimum thickness of about 650 m. The sediments in the Naust Formation are unfaulted and consist of silt and clay. The geological setting of this top seal is analogous to the Utsira Formation in the Sleipner area. The small accumulations of methane gas in the Sør High show that the Naust Formation has a sealing capacity. Further maturation of the Sør High as an injection site for CO_2 would require a better quantification of the Naust sealing capacity.

Møre Margin

The Møre Margin south of the Frøya High is separated from the Froan Basin by the Jan Mayen Fracture Zone lineament. Its Mesozoic and Cenozoic geology is very different from the Trøndelag Platform. Along the Møre Margin, a thin Jurassic and thick Cretaceous section dip towards the deep Møre Basin. In this setting of regionally dipping strata, only a few closed structures of small sizes exist. The Jurassic reservoir sands tend to be thin, and no Cretaceous reservoir of interest has so far been proved by drilling. A few exploration wells drilled in the area have proved that gas has migrated into closed structures close to the coast. A possible storage option in the Møre Margin is thought to be the Paleocene submarine fans of the Egga sandstone, which constitute the reservoir of the Ormen Lange Field. This sand was derived from the Møre Paleogene highlands and has not been encountered in the Froan and Helgeland Basins. A limited Jurassic storage potential could exist in a narrow zone close to the coast. Both the Egga sandstone and the Jurassic aquifers subcrop towards a thin Quaternary section below the sea floor. CO_2 migration to the subcrop area and leakage to the sea is the most obvious risk for these aquifers. No closed structures suitable for CO_2 injection have been identified in the Møre Margin.

Ellingråsa Graben

The dry exploration well 6507/12-1 was drilled near the culmination of a large closed structure in the southern part of the Ellingråsa Graben. The well penetrated the Åre-Tilje, Ile and Garn aquifers between 2100 and 2900 m depths below sea level. The structure is within the area of possible hydrocarbon migration. Since this well was dry and no shows were reported, it is very unlikely that hydrocarbons can have migrated further into the Ellingråsa Graben. The 6507/12-1 structure has been assessed as a possible target for CO_2 injection. The storage efficiency depends on communication with the aquifers in the Halten Terrace and the producing Midgard gas field to the west. The calculation of the storage volume within the structure is based on a closure of 200 m and storage in all aquifers with a storage efficiency of 10%. Maturation of this prospect should include an evaluation of the communication with the Halten Terrace, Nordland Ridge and Trøndelag Platform. The 3D seismic data show that the Jurassic aquifers are strongly faulted, with the risk that the reservoir might be divided in many compartments. The faults do not appear to offset the Upper Jurassic and Lower Cretaceous sealing shales.



5.2 Storage options in the Norwegian Sea

5.2.1 Saline aquifers

Simulation model of the The Nordland Ridge Structure D

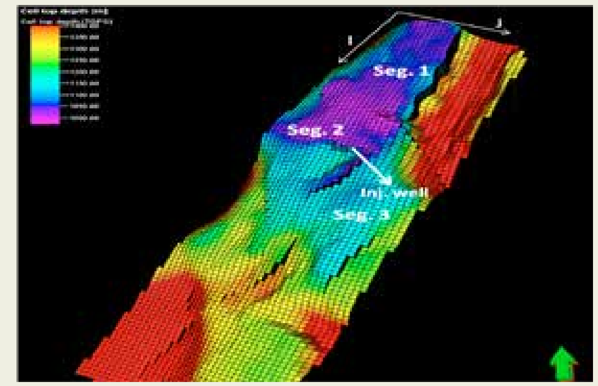
The simulation model of the Nordland Ridge Structure D was built for the purpose of assessing its CO_2 storage potential within the Åre Formation (Rhaetian-Pliensbachian, Lower Jurassic). The modelled Structure D is a closed structure with CO_2 storage potential in two structural domes.

Segment 3 is the deepest dome, and segments 1 and 2 combined represent the shallowest dome. There is a possibility for down flank aquifer communication to areas outside of the model.

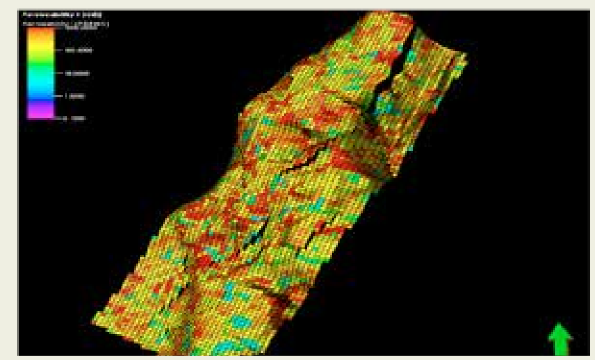
The depth of the top reservoir (Åre Formation) in two main storage domes is between 1000 m and 1150 m.

Generally the thickness of the Åre Fm varies between 300 and 500 m, with a maximum thickness of 780 m in the eastern part of the Halten Terrace (Heidrun area).

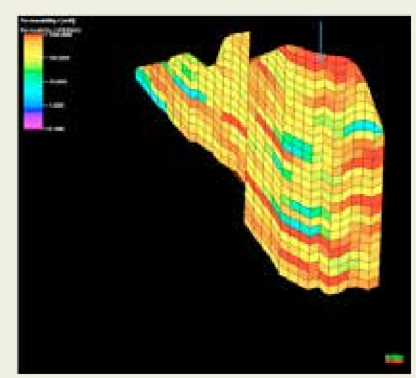
The Åre Formation consists of heterogeneous fluvial deposited sand channels with an uncertain communication. The average sand permeability is about 500 mD. The porosity and permeability have been stochastically modelled with both lateral and vertical variation. The CO_2 injection well is located down dip, at the apex of the two deepest main storage domes (segment 3).



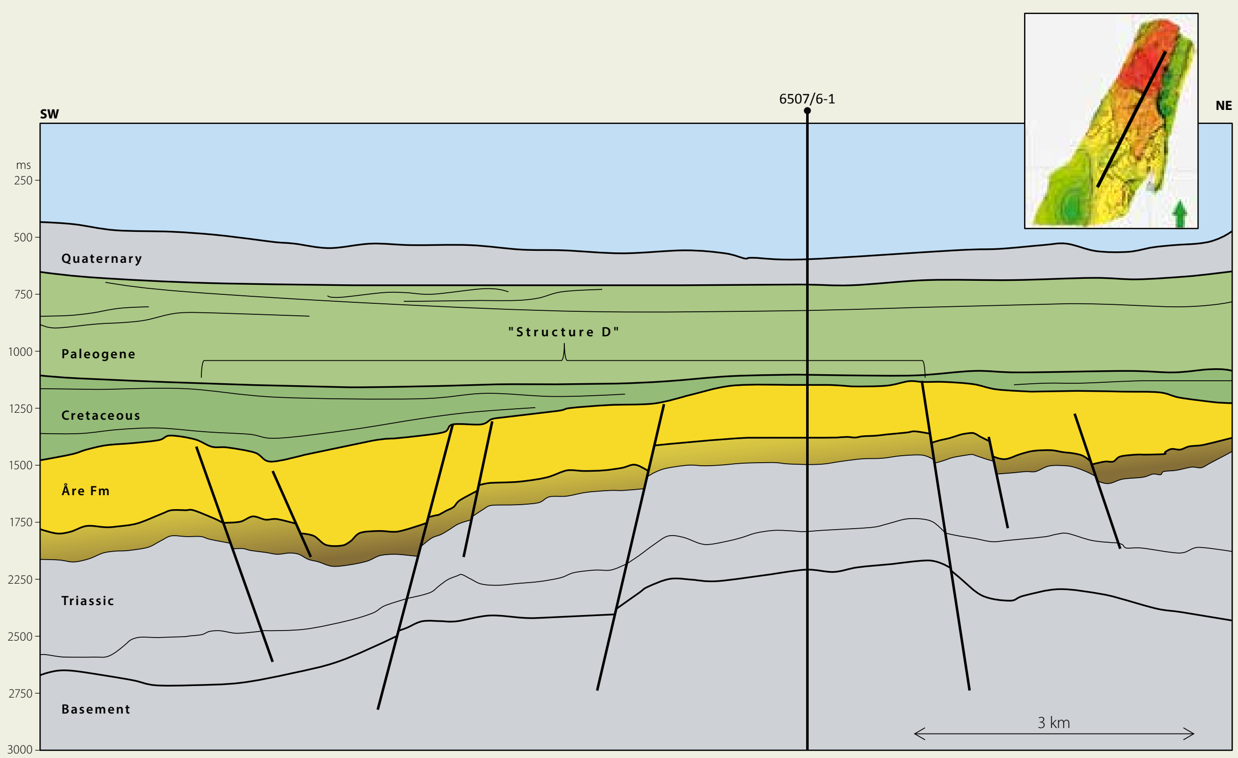
Simulation model depth, top Åre Fm.



Lateral permeability variations.



Vertical permeability variations (x-z, through well).



SW-NE profile showing the geomery of aquifer (yellow) and sealing formations (green) in the simulation model. The location is shown on p.44.

5. 2 Storage options in the Norwegian Sea

5.2.1 Saline aquifers

Different injection rates and volumes have been simulated. The figures above illustrate CO_2 saturation (green/blue) over 50 and 1000 years. The main simulation case injects 2 mill SM^3 CO_2/day (daily rate of 1/5000 of total volume) for 28 years with acceptable pressure increase and CO_2 plume spreading. CO_2 will continue to migrate upwards as long as it is in a free movable state.

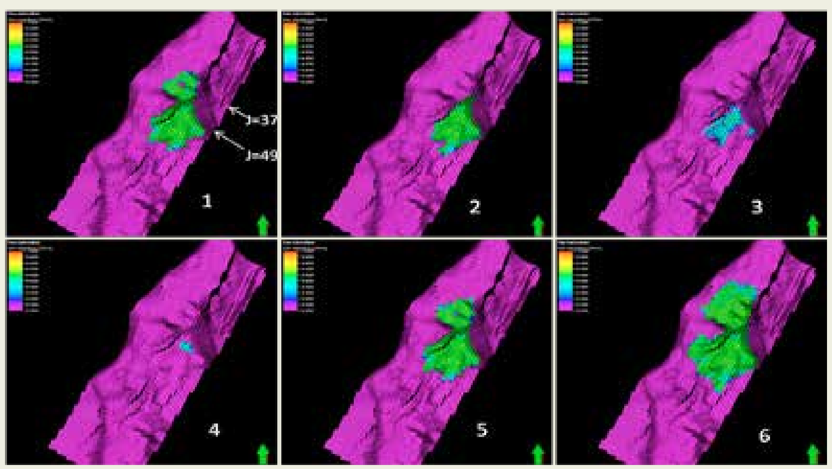
Migration ends when CO_2 is permanently bounded or trapped, by going into solution with the formation water or by being residually trapped (mineralogical trapping has not been considered).

Structural trapping is the main storage mechanism in the simulation model of the Nordland Ridge.

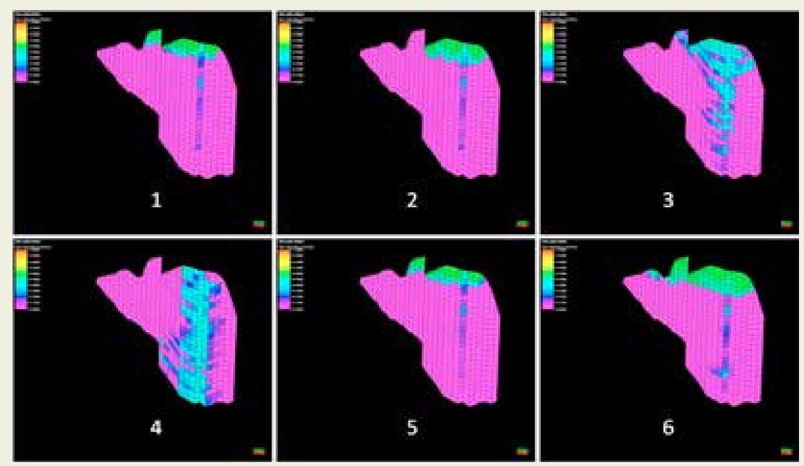
Applying a safety factor of 2 to the acceptable pressure increase, shows that 18.7 Mt of CO_2 can safely be stored in the Nordland Ridge within the Åre Formation.

Simulation Cases:

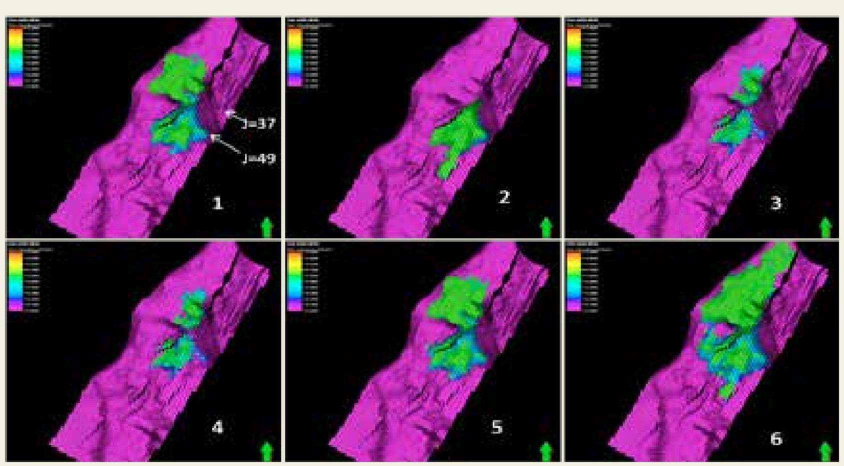
1. Geological model and properties.
2. Zero transmissibility (communication) across modelled faults. Most faults are not extensive and do not fully close off model communication. The degree of communication across faults is uncertain.
3. Zero transmissibility (communication) between model layers. Reflects that well logs show sand/shale sequence in individual model layers, but zero vertical communication is an extreme case, since the sand/shale sequences are not extensive. Vertical communication still goes on through "zig-zag" vertical communication via faults.
4. Combines Case 2 & 3 above.
5. Case with no CO_2 going into solution with water. Not expected to have significant effect when main storage mechanism is structural trapping.
6. Increased model pore volume by multiplying the pore volume of the boundary grid cells. Total model pore volume increases from 27 GSm^3 to 100 GSm^3, reflecting possible communicating pore volume. Injects 2.5 times the rates and volumes of the Case 1.



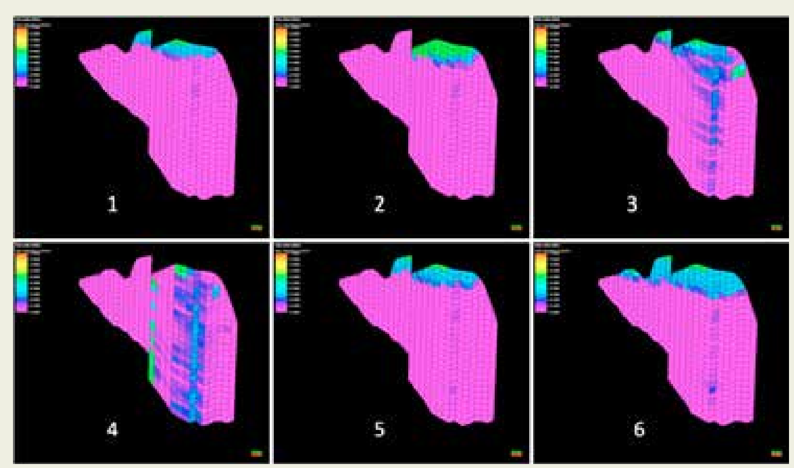
CO_2 plume top reservoir end of injection (50 yrs)



CO_2 plume x-z cross section (J=49) end of injection (50 yrs).



CO_2 plume top reservoir after 1000 yrs.



CO_2 plume x-z cross section (J=49) after 1000 yrs.

5. 2 Storage options in the Norwegian Sea

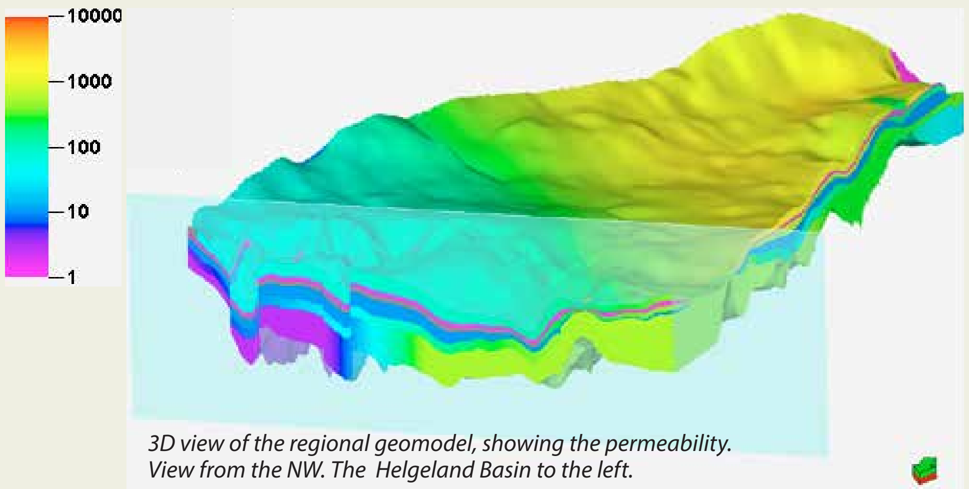
5.2.1 Saline aquifers

Storage capacity Tilje/Åre

In order to estimate the pore volumes and storage capacities of the aquifers, a regional geomodel was built with the Petrel software. The model was set up with a 500x500 m grid in the horizontal directions. In the vertical direction, each formation was represented by one layer. Average values for net/gross and porosity were estimated based on the logs and well reports from exploration wells in the area and manually contoured between the wells. The maps show that the Ile and Garn formations generally become more shale-rich to the NE. The major faults which have a potential to form barriers between different segments of the aquifers, were included in the model.

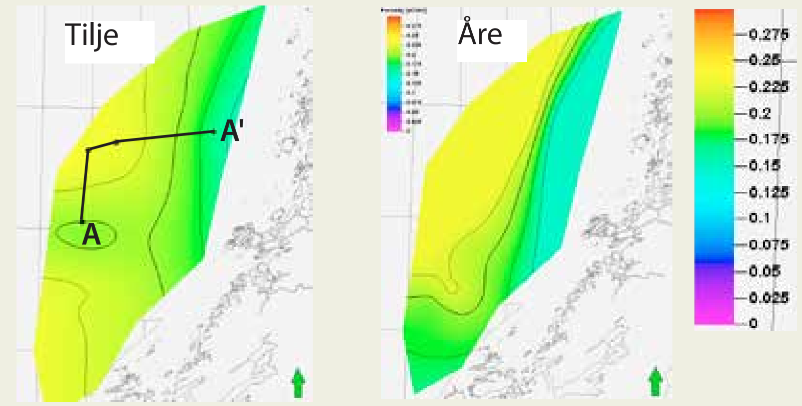
The purpose of this model was to calculate the total pore volumes of each aquifer and to assess how they are connected. Different approaches have been tested to estimate the storage capacity of the aquifers.

Permeability

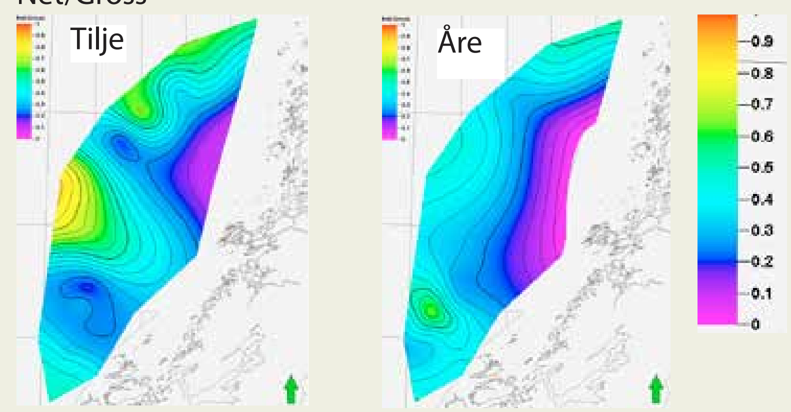


3D view of the regional geomodel, showing the permeability. View from the NW. The Helgeland Basin to the left.

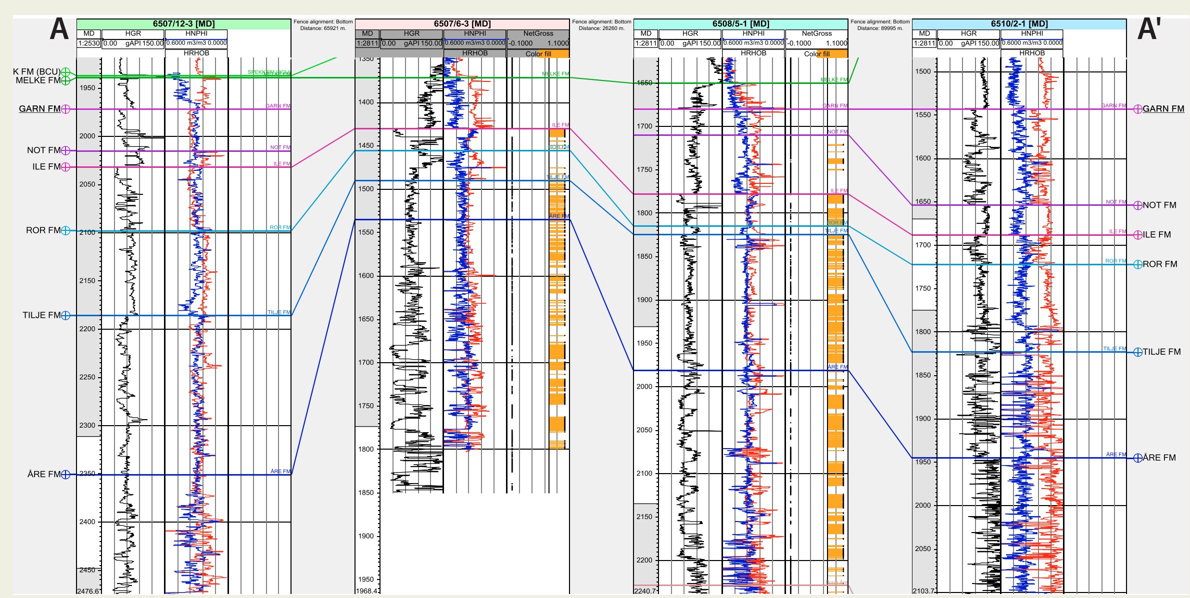
Porosity



Net/Gross



The Tilje/Åre aquifer		
Storage system		closed
Rock volume		9200 Gm³
Net volume		2700 Gm³
Pore volume		900 Gm³
Average depth		1940 m
Average net/gross		0.30
Average porosity		0.21
Average permeability		140 mD
Storage effieciency		0.7 %
Storage capacity aquifer		4.0 Gt
Reservoir quality		
	capacity	2
	injectivity	2
Seal quality		
	seal	3
	fractured seal	2
	wells	3
Data quality		
Maturation		



Log correlation panel with gamma, porosity density and calculated net/gross. Layout showed in Tilje porosity map.

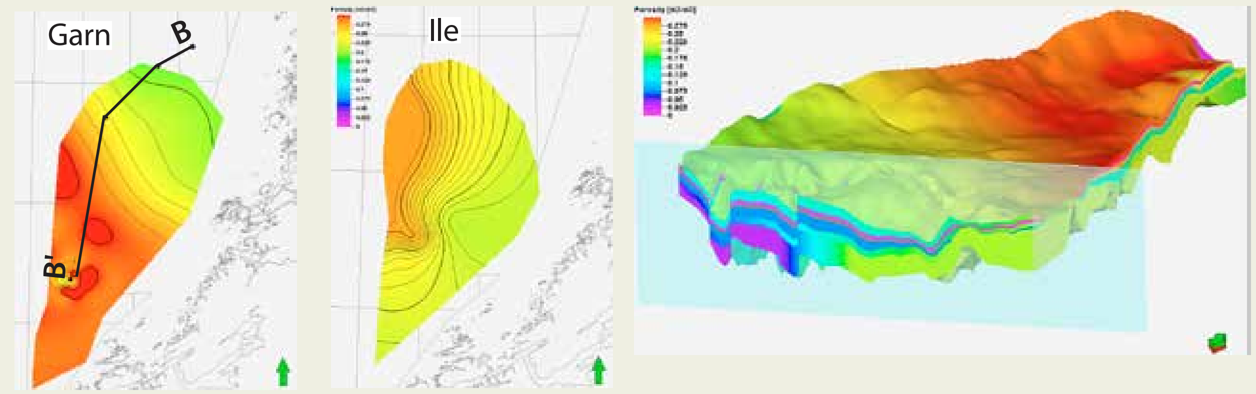
5.2.1 Saline aquifers

Storage capacity Garn/Ile

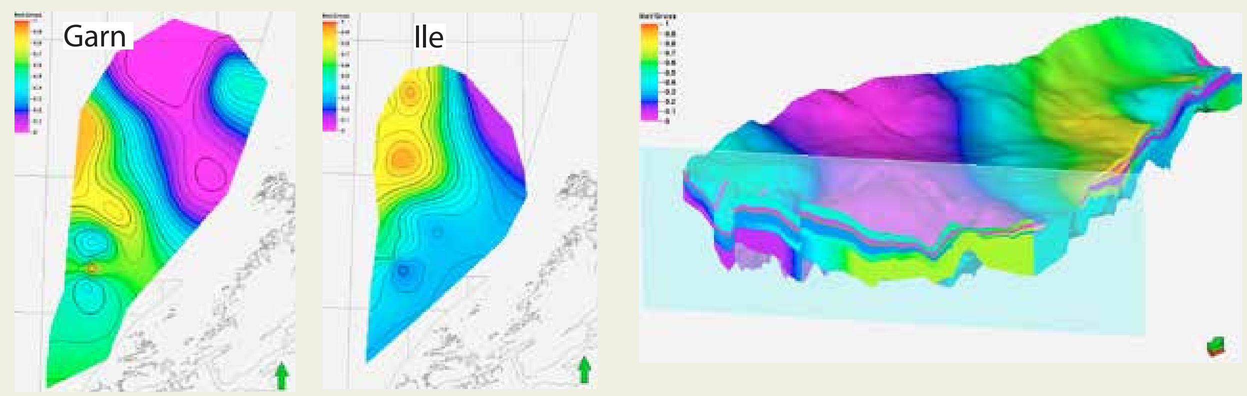
The first approach was to calculate the total pore volume and use a storage efficiency representing a closed system. The second approach was to calculate the pore volumes of the largest closed structures A, B and C presented below, and assume that they are in communication with the larger aquifer (half-open system). The third approach was to simulate injection in the Garn-Ile aquifer presented above, where the injected CO_2 volume is restricted because it is not allowed to reach the coastal subcrop.

In the table below, showing the results for the Garn – Ile aquifer, a half-open case and a closed case for the whole aquifer are presented to illustrate how important this is for the estimates of storage volumes. Large volumes can theoretically be stored if the aquifer is in pressure communication with additional large water volumes. In the Garn-Ile case, such pressure communication could take place with the sea along the subcrop line. Another alternative to creating a half-open system might be to inject CO_2 and produce water. The most optimistic case would be to assume that closed structures with a large storage capacity exist and could be filled with CO_2, without any migration to the half-open eastern boundary. Although interesting structures exist, we have not been able to identify such large storage volumes in closed structures in our mapping of the Garn-Ile aquifer. Based on the structures we can map and the simulations we have performed, we have chosen the lower estimate (closed aquifer) as the most likely scenario.

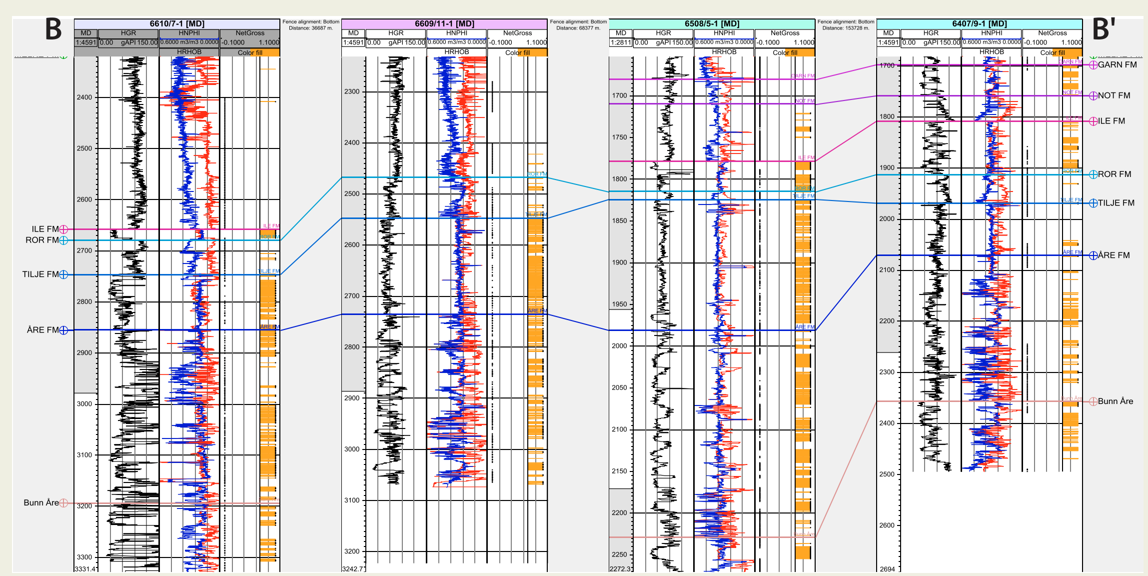
Porosity



Net/Gross



The Garn/Ile aquifer		Summary	Summary
Storage system		half open	closed
Rock volume		4400 Gm^3	4400 Gm^3
Net volume		1100 Gm^3	1100 Gm^3
Pore volume		300 Gm^3	300 Gm^3
Average depth Garn Fm		1675 m	1675 m
Average depth Ile Fm		1825 m	1825 m
Average net/gross		0.25	0.25
Average porosity		0.27	0.27
Average permeability		580 mD	580 mD
Storage effieciency		4 %	0.2 %
Storage capacity aquifer		8 Gt	0.4 Gt
Reservoir quality			
	capacity	2	2
	injectivity	3	3
Seal quality			
	seal	3	3
	fractured seal	3	3
	wells	3	3
Data quality			
Maturation			



Log correlation panel with gamma, porosity density and calculated net/gross. Layout showed in Garn porosity map.

5.2.1 Saline aquifers

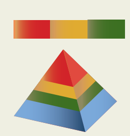
Possible injection prospects

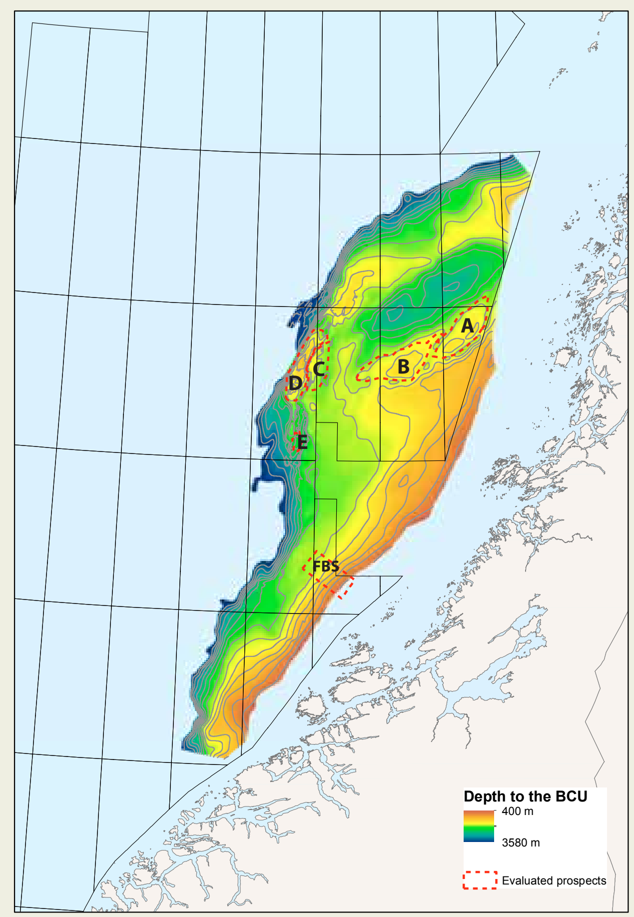
CO_2 can be injected in closed structures or in open aquifers. In a closed structure, the amount of CO_2 injected will be restricted by the maximum fracing pressure of the structure with a safety margin. Some of the CO_2 will be trapped as free CO_2 by the seal of the structure, and a certain amount will be dissolved in the water. In an open aquifer the amount of CO_2 will not be restricted by pressure, but it can gradually be trapped as residual and dissolved CO_2 in the water phase. In the Trøndelag Platform and Nordland Ridge, both alternatives have been studied. The map shows the outlines of five large closed structures which have been identified in the study. Structures A and B are located SE of the Helgeland Basin and comprise only the Åre-Tilje Trøndelag Platform aquifer. Structure C is bounded by the Ellingråsa Graben to the west, and it could trap CO_2 in all the aquifers of the Trøndelag Platform. Structure D belongs to the Nordland Ridge Åre Formation aquifer, while structure E is located in the Ellingråsa Graben, outside the Trøndelag Platform aquifer. The volumes of structures D and E are listed in the table. The volumes of prospects A, B and C are included in the calculation of the Trøndelag Platform aquifers. In a closed aquifer, the limiting factor for the volume which can be injected is the total pore volume of the aquifer, not the pore volume of the structure.

Seismic mapping was also carried out east of the Frøya High, south of the Draugen Field, to search for closed structures suitable for CO_2 trapping in that area. It was concluded that such structures may exist, but there is uncertainty related to their definition on 2D seismic data and to how far petroleum has migrated into the area east of the Frøya High.

The rectangle in the map shows the model area for the study of open aquifer injection into the Ile and Garn Formations.

Prospects			
Prospect name		D	E
Storage system		Half open	Open
Rock volume		270 Gm^3	10 Gm^3
Net volume		50 Gm^3	4 Gm^3
Pore volume		14 Gm^3	1 Gm^3
Average depth		1300 m	2200 m
Average net/gross		0.3	0.4
Average porosity		0.26	0.25
Average permeability		140 mD	300mD
Storage efficiency		1 %	10 %
Storage capacity prospect		100 Mt	70 Mt
Reservoir quality			
	capacity	3	2
	injectivity	2	2
Seal quality			
	seal	2	3
	fractured seal	3	3
	wells	3	3
Data quality			
Maturation			





Regional BCU map showing the locations of prospects A to E and the location of the simulation grid in the Froan Basin (FBS). The map to the left is zoomed in on structures C, D and E.

5. 2 Storage options in the Norwegian Sea

5.2.2 Summary

The results of the evaluation of aquifer storage capacity are summarized in the tables. The Trøndelag Platform including the Nordland Ridge is the area best suited for CO_2 storage. A thick Jurassic section is present and has been divided in two aquifers. The burial depth is approximately 1500-2000 m, and the reservoir quality of the clean sandstones is excellent.

The lower Åre-Tilje aquifer is distributed over the whole area and the potential injection volume is calculated to about 4Gt. The reservoir is heterogeneous, dominated by fluvio-deltaic to tidal deposits, and the connectivity both on a local and regional scale is uncertain. The upper Ile and Garn aquifers are developed as good reservoirs in the southern part (Froan Basin). The Garn reservoir has the best permeability and connectivity of the Jurassic sandstones. All the aquifers are subcropping towards the sea floor along the coast. The thickness of the Quaternary cover is variable. CO_2 injection projects should be planned to avoid long distance migration towards the subcrop and possible further seepage to the sea floor. Modelling of injection in the aquifer indicates that it is possible to inject at a rate and volume where the CO_2 is trapped and/or dissolved before it reaches the subcrop area. The conclusion is that the Garn and Ile storage capacity is relatively low, about 0.4 Gt.

Five large structural closures have been identified. Two of them (structures D and E) are located outside the Trøndelag Platform and add storage capacity to the area. Structures D and E are covered by 3D seismic data and wells and are regarded as more mature than the other structures and evaluated aquifers.

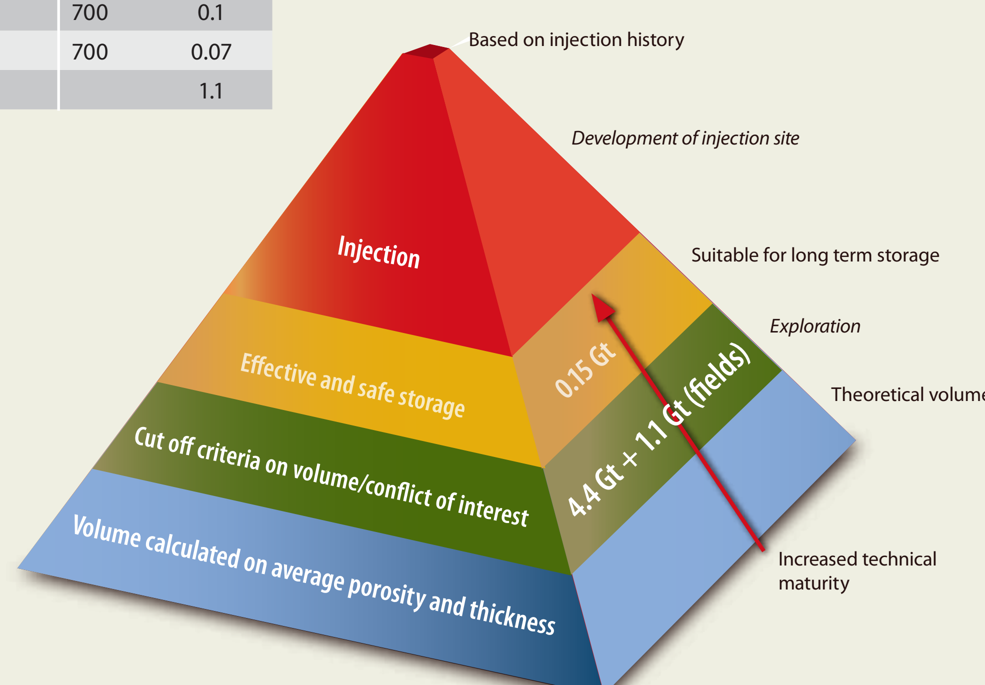
The Møre Margin is geologically different from the Trøndelag Platform and does not seem to hold a large storage potential due to its proximity to deep basins and subcropping aquifers.

In the petroleum provinces, the storage potential was calculated from the extracted volume of hydrocarbons in depleted fields. Such storage will usually require a study of the integrity of the wells which have been drilled into the field. If oil has been present, it is relevant to study the potential for increased recovery by CO_2 injection. Studies of EOR by CO_2 injection were performed some years ago for the Draugen and Heidrun fields.

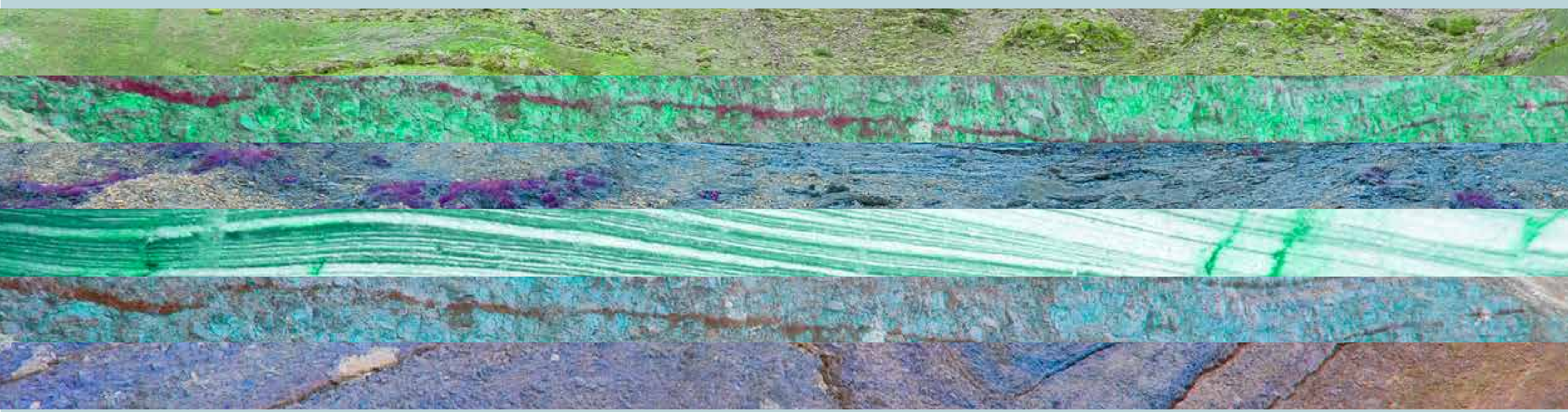
Evaluated aquifers	Avg depth	Bulk volume	Pore volume	Avg K	Open/closed	Storage eff	Storage volume	Density in reservoir	Storage capacity
Unit	*m*	*Gm³*	*Gm³*	*mD*		*%*	*GRm³*	*kg/m³*	*Gt*
Garn/Ile	1675	4400	300	580	closed	0.2	0.6	700	0.4
Tilje/Åre	1940	9200	600	140	closed	1	6.0	700	4.0
Evaluated prospects									
Prospect D Åre	1300	270	14	140	half open	1	0.14	700	0.1
Prospect E Åre-Tilje, Ile-Garn	2200	10	1.0	300	open	10	0.1	700	0.07
Producing fields									1.1

For the Norwegian Sea, the total storage capacity in the green level of the pyramid is estimated to be 5.5 Gt. In the more mature areas (yellow level) the capacity is estimated to be 0.17 Gt.

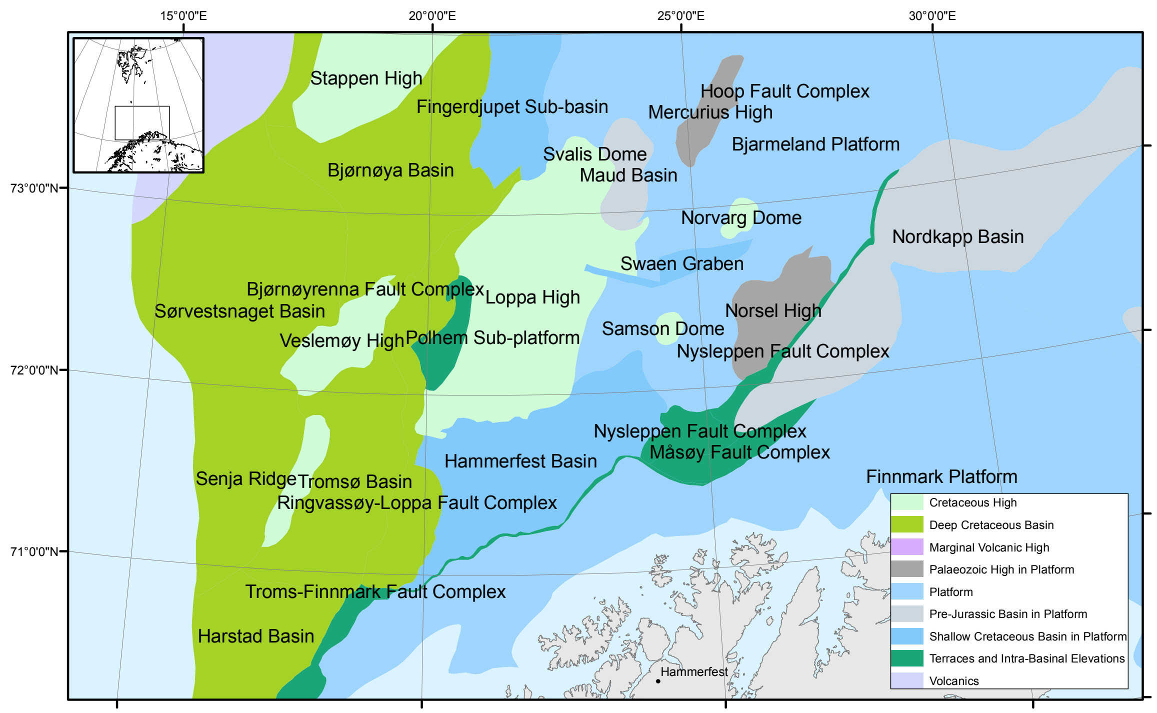
Abandoned fields	Storage capacity, Gt
Producing fields	
Closure of production 2020 -2030	0.9
Closure of production 2030 -2050	0.2



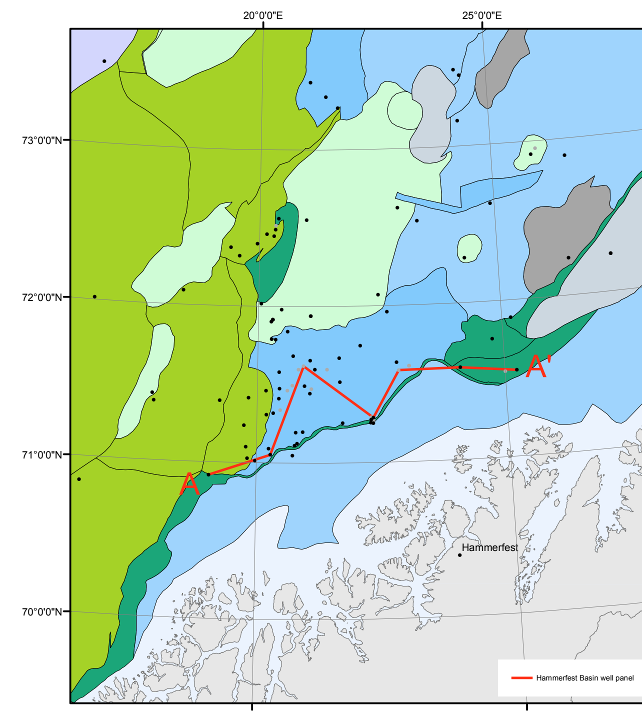
6. The Barents Sea



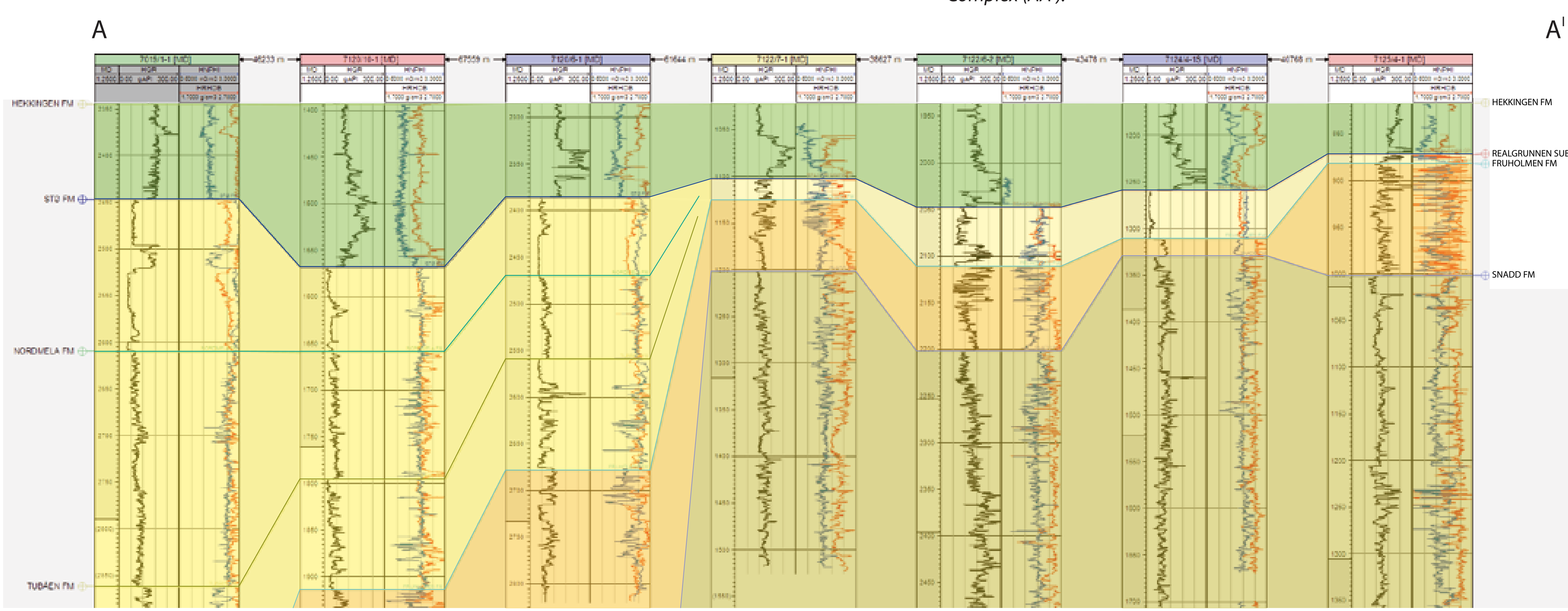
Eva K. Halland (Project Leader), Andreas Bjørnestad, Ine Tørneng Gjeldvik, Maren Bjørheim, Christian Magnus, Ida Margrete Meling, Jasminka Mujezinović, Fridtjof Riis, Rita Sande Rød, Van T. H. Pham, Inge Tappel



Structural elements of the Southern Barents Sea.

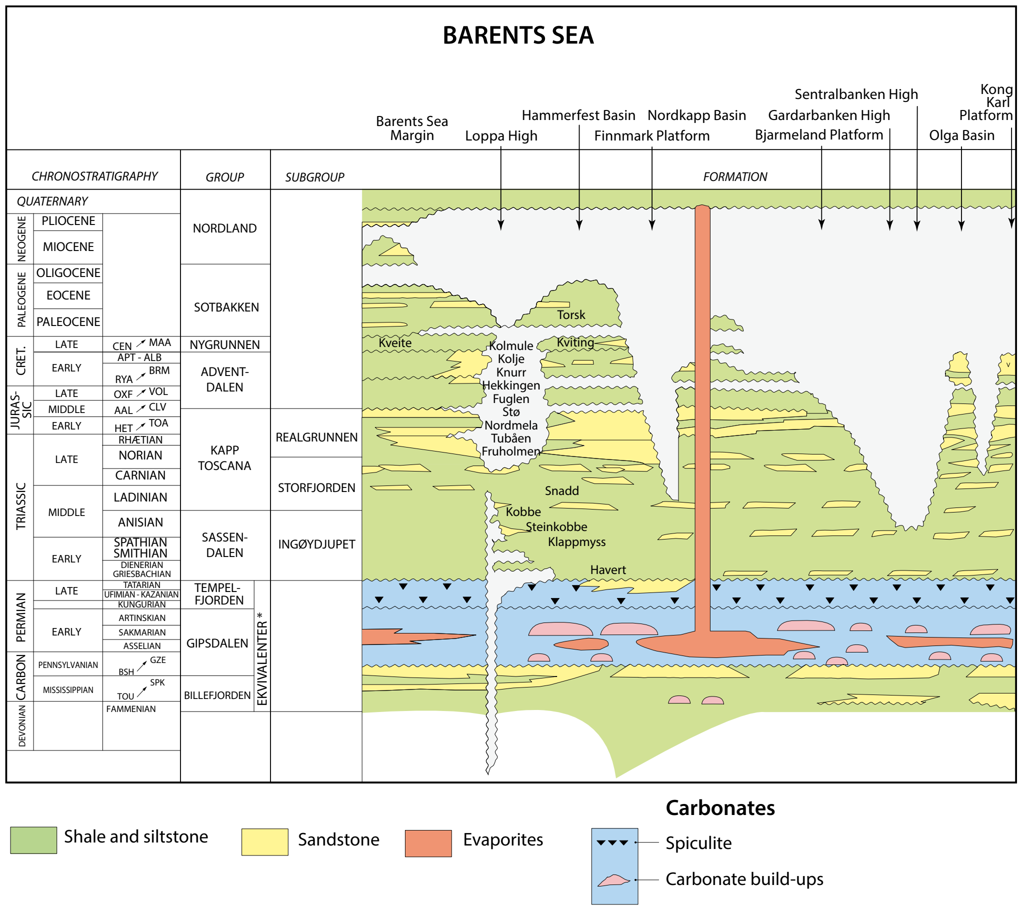


Transect from the Harstad Basin to the Måsøy Fault Complex (AA`).

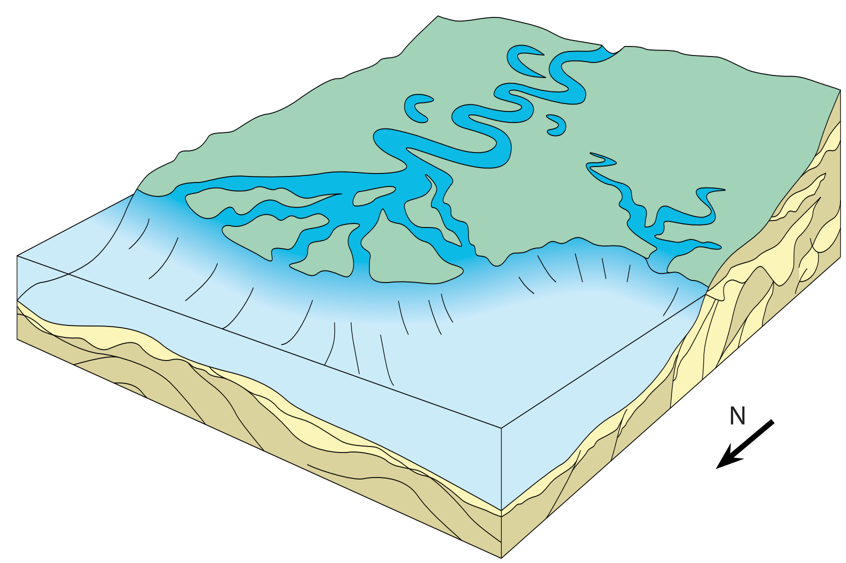


Well section panels (AA`) showing gamma and neutron/density logs reflecting thickness variations of the different formations.

6.1 Geology of the Barents Sea



* Lithostratigraphic nomenclature for The Barents Sea Paleozoic (NPD).



Conceptual sketch of an early stage in the development of the Stø formation in the southern parts of the Barents Sea.

Lithostratigraphic nomenclature

The lithostratigraphic nomenclature for the post-Caledonian successions of the southern Barents Sea has been a matter of discussion since the southern Barents Sea was opened for hydrocarbon exploration and the first well was drilled in 1980.

In NPD Bulletin No 4 (Dalland et.al. 1988) a lithostratigraphic scheme was defined for the Mesozoic and Cenozoic successions offshore mid- and northern Norway.

Dallmann et.al (1999) suggested a revised lithostratigraphic scheme for the Upper Paleozoic, Mesozoic and Cenozoic successions from the Svalbard area including the southern Barents Sea.

NPD Bulletin No 9 (Larssen et.al 2002) presented a formalized Upper Paleozoic lithostratigraphy for the southern Norwegian Barents Sea.

The official stratigraphic nomenclature for the Barents Sea is as follows:

The CO_2 Storage Atlas for the Norwegian Continental Shelf has followed the definitions from Dallmann et.al (1999) and suggested a revised lithostratigraphic scheme for the Mesozoic. For the Upper Paleozoic successions, the official nomenclature from NPD Bulletin No 9 (Larssen et.al 2002) has been used. For the Cenozoic, we follow NPD Bulletin No 4.

6.1 Geology of the Barents Sea

The Barents Sea is located in an intracratonic setting between the Norwegian mainland and Svalbard. It has been affected by several tectonic episodes after the Caledonian orogeny ended in Late Silurian/Early Devonian.

There is a marked difference, both in time, trend and magnitude, between the tectonic and stratigraphic development in the western and eastern parts of the southern Barents Sea. This boundary is defined by the dominantly N-S to NNE-SSW trending Ringvassøy-Loppa and Bjørnøyrenna Fault Complexes. The area to the west of this boundary was tectonically very active throughout Late Mesozoic and Cenozoic times, with deposition of enormous thicknesses of Cretaceous, Paleogene and Neogene sediments in the Harstad, Tromsø and Bjørnøya Basins. NNE-SSW, NE-SW and locally N-S trending faults dominate in this western part. In contrast, the southeastern Barents Sea is dominated by thick Upper Paleozoic and Mesozoic sequences, where E-W, WNW-ESE to ENE-SSW fault trends dominate.

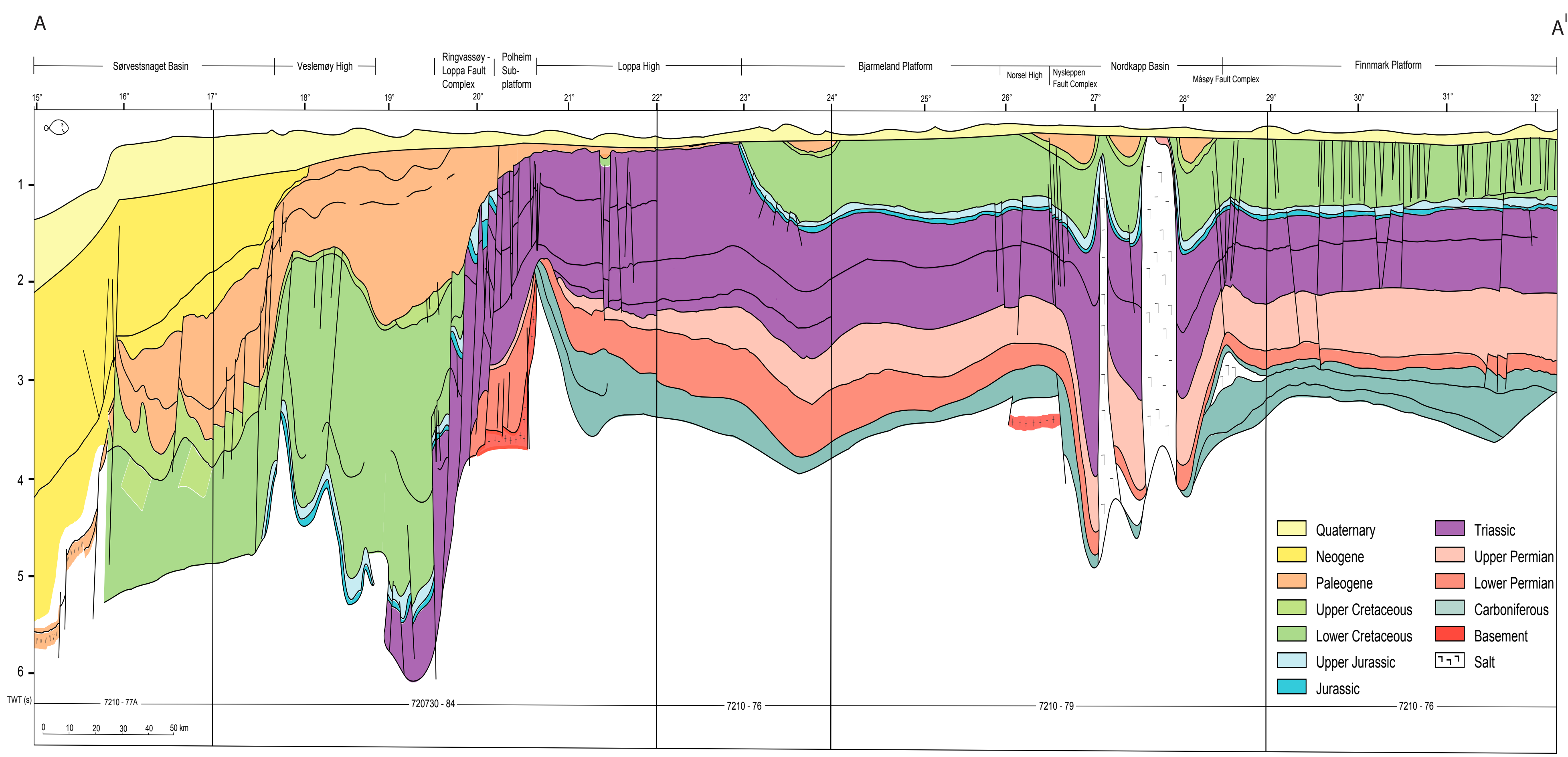
The area evaluated for CO_2 storage is defined to the west by the N-S to NNE-SSW trending Ringvassøy-Loppa and Bjørnøyrenna Fault Complexes, to the south/southeast by the Troms-Finnmark Fault Complex and the Finnmark Platform, to the north by an east-west line approximately along the 73^{O} N parallel, and to the east by a north-south line running approximately along the 28^{O}E meridian.

The southern Barents Sea shelf is divided into several main structural elements. The most important ones are: The Hammerfest and Nordkapp Basins, the Finnmark and Bjarmeland Platforms and the Loppa High. There are also several smaller structural elements, like the Polheim Sub-platform, Senja Ridge, Veslemøy, Norsel High. Bordering and partly defining the main structural elements are a series of complex fault zones: Troms-Finnmark, Ringvassøy-Loppa, Bjørnøyrenna, Måsøy, Nysleppen and Asterias Fault Complexes.

The Hammerfest Basin is fault-controlled: To the west against the Ringvassøy-Loppa Fault Complex; to the south against the Finnmark Platform (Troms–Finnmark Fault Complex); to the north against the Loppa High (Asterias Fault Complex) and the Bjarmeland Platform. Internally E-W to WNW-ESE trending faults dominates.

The basin was probably established by Early to Late Carboniferous rifting. Two wells have penetrated the Upper Paleozoic succession. Well 7120/12-2, drilled on the southern margin, penetrated a 1000m thick Upper Permian sequence overlying Lower Permian dolomites and Red beds resting on Precambrian/Caledonian basement. Well 7120/9-2 in the central part of the basin reached TD 117m into the Upper Permian Røye Formation.

Major subsidence occurred in the Triassic, Jurassic and Early Cretaceous, overlain by a thin, highly condensed sequence of Late Cretaceous and Early Paleocene shale. There is no evidence for diapirism of Upper Paleozoic evaporites as seen in the Tromsø Basin to the west and the Nordkapp Basin to the east. Internally the basin is characterized by a central E-W trending faulted dome-structure, related to the Late



6.1 Geology of the Barents Sea

Jurassic tectonic episode.

The Nordkapp Basin is fault-controlled and located along a SW-NE trending Upper Paleozoic rift. It is bounded by the Bjarmeland Platform to the northwest and the Finnmark Platform to the southeast. The northwestern boundary is defined by the Nysleppen Fault Complex, and the southeastern boundary is defined by the Måsøy Fault Complex.

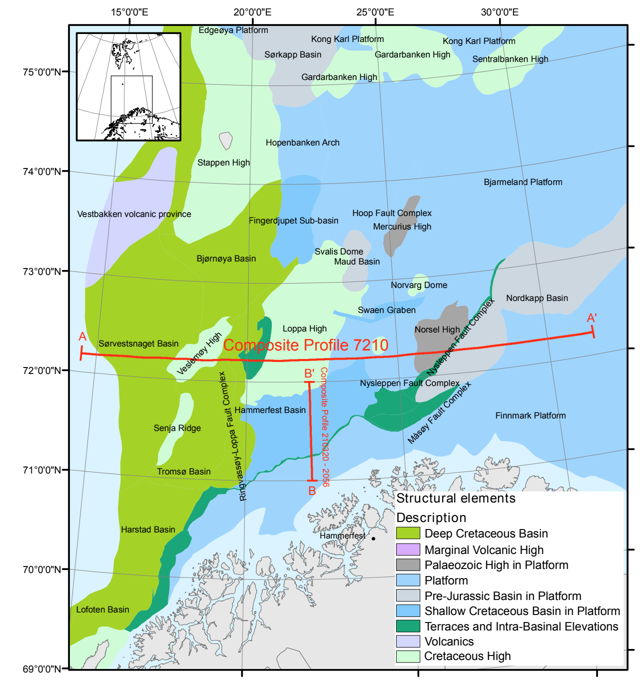
During the Late Paleozoic (Late Carboniferous to Early Permian), thick sequences of halite were deposited (Gipsdalen Gp) giving rise to pronounced salt diapirism, beginning in the Early Triassic. The basin is dominated by thick Mesozoic, mainly Triassic successions, with a significant thickness of Upper Paleozoic rocks.

The Troms-Finnmark Platform is bounded by the Norwegian mainland to the south, to the west by the southwestern extension of the Ringvassøy-Loppa Fault Complex and by the Hammerfest and Nordkapp Basins to the north.

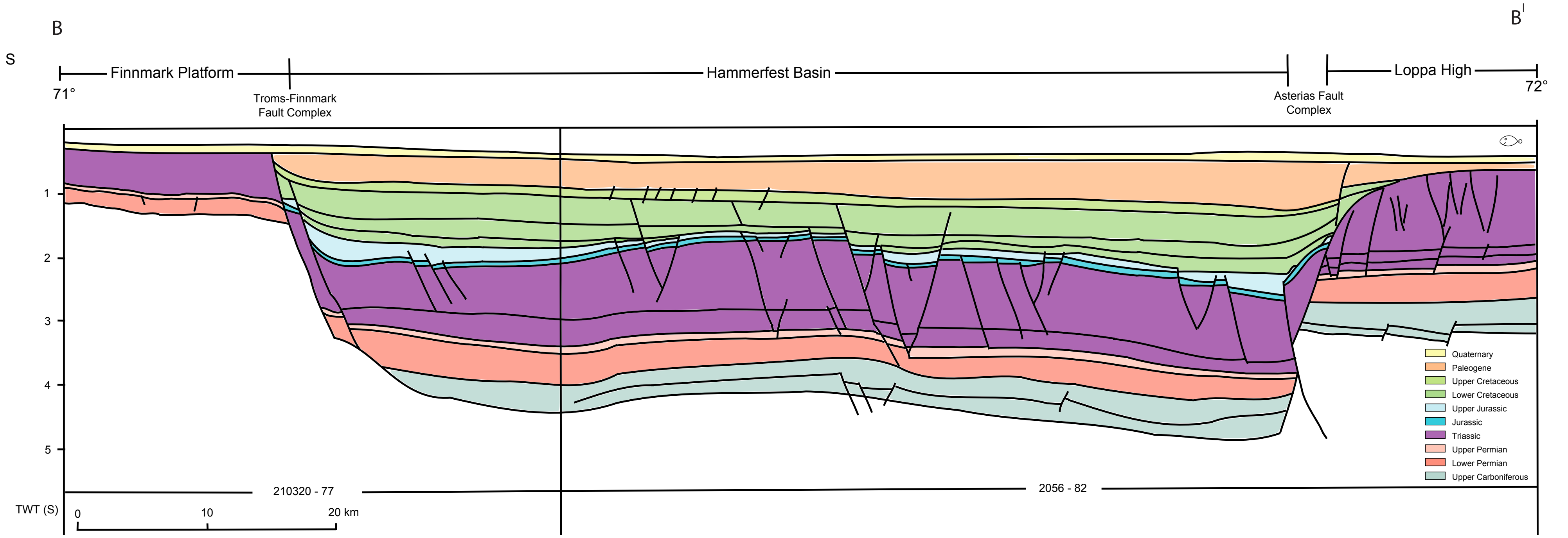
The central part of the Troms-Finnmark Platform in the Norwegian sector shows a rift topography with half-grabens containing siliciclastic rocks of Early Carboniferous age (Billefjorden Gp). During the Permian, the stable western part of the platform was transgressed. Late Permian and Late Jurassic movements followed by Cenozoic tectonism, and uplift resulted in a gentle northward tilt of the Finnmark Platform. In the northeastern part of the Platform, thick sequences of Mesozoic, mainly Triassic rocks have been drilled.

The Bjarmeland Platform is part of an extensive platform area east of the Loppa High and north of the Nordkapp Basin. The platform was established in the Late Carboniferous and Permian, but subsequent Paleogenetectonism tilted the Paleozoic and Mesozoic sequences towards the south, so that presently unconsolidated Pleistocene sediments overlie successively older rocks to the north. Towards the south and west, the platform is divided into minor highs and sub-basins mainly formed by salt tectonics (Samson Dome).

The Bjarmeland Platform is characterized by a thick Triassic succession of the Ingøydjupet Subgroup, with a maximum drilled thickness of 2862m on the Nordvarg Dome (well 7225/3-1). The thickness of the Realgrunnen Subgroup varies between 100 and 200m.

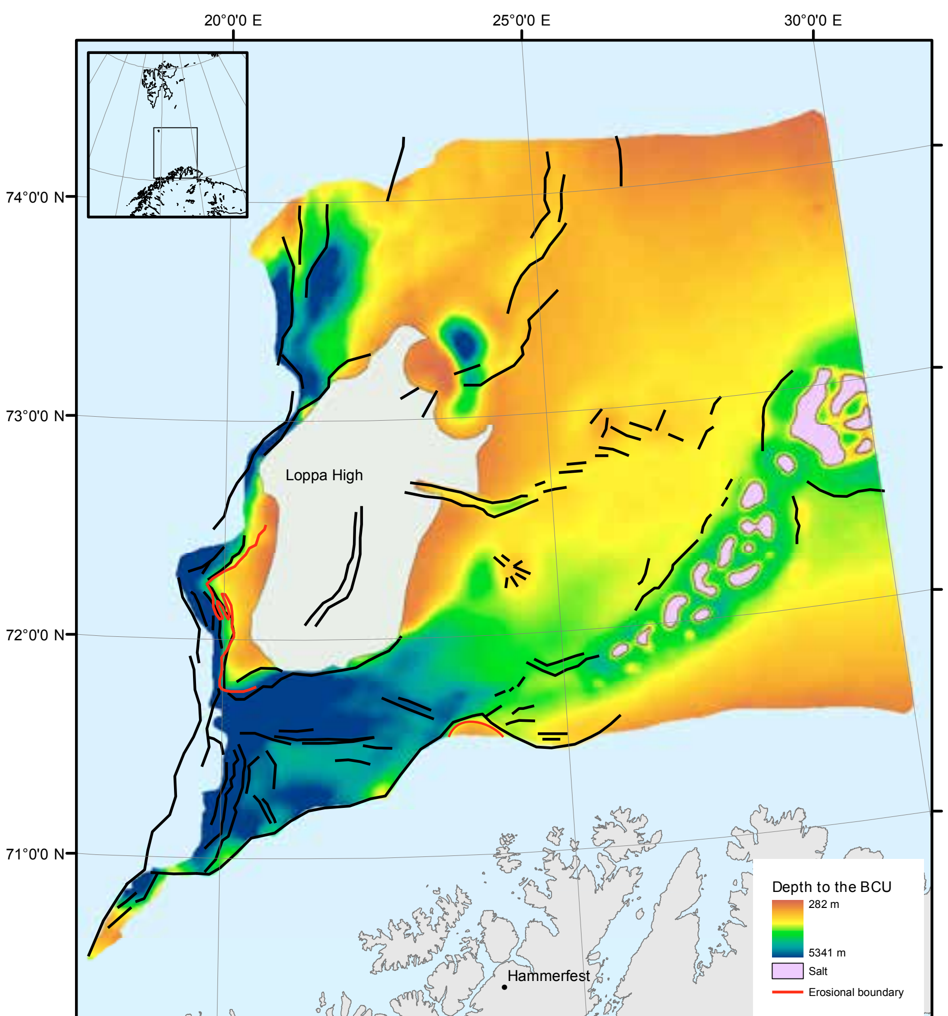


Transects of the geosections from the western part of the Sørvestsnaget Basin to the eastern part of the Finmark Platform (AA`) and from the Finmark Platform across the Hammerfest Basin to the Loppa High (BB`). Gabrielsen et al. 1990.

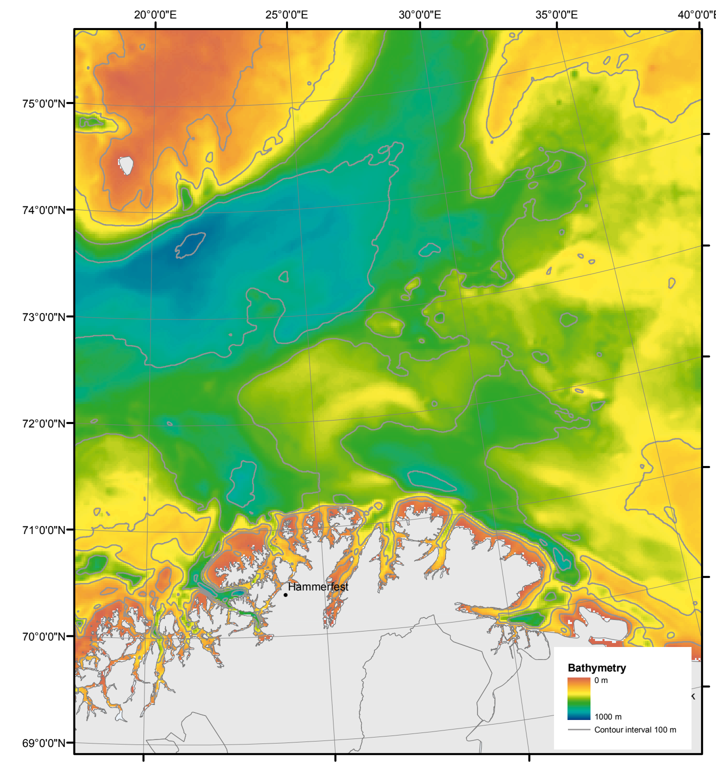


6.1 Geology of the Barents Sea

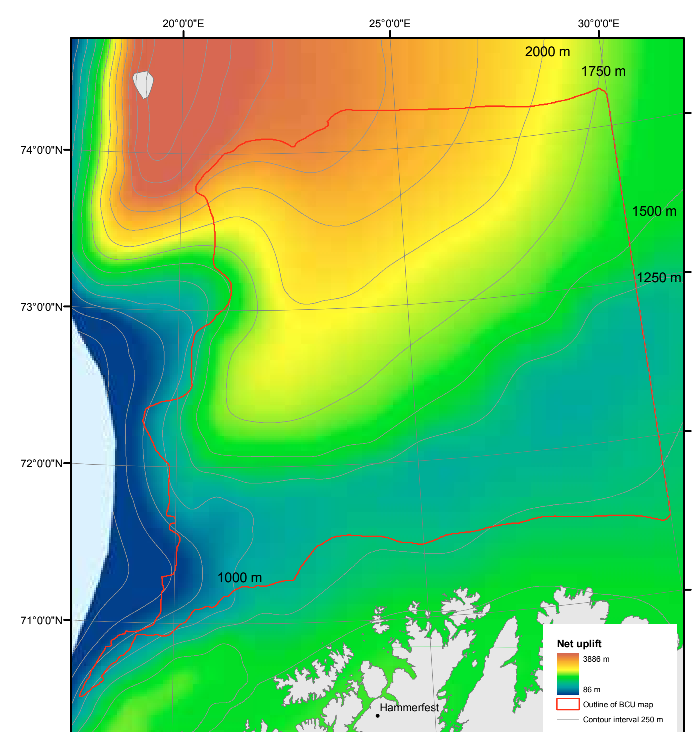
The Loppa High is a marked (N-S) trending structural feature, separated from the Hammerfest Basin in the south by the E-W trending Asterias Fault Complex. To the west it is separated from the Tromsø and Bjørnøya Basins by the Ringvassøy-Loppa and Bjørnøyrenna Fault Complexes. To the east it grades into the Bjarmeland Platform. The Loppa High has a complex geological history with several phases of uplift/subsidence followed by tilting and erosion. Late Carboniferous rift



Depth to the Base Cretaceous Unconformity. To the west the surface is deeper than 3000m. The red line outlines areas where the Jurassic section is eroded.



Bathymetri of the southwestern Barents Sea. Based on Jakobsson et al. 2012.

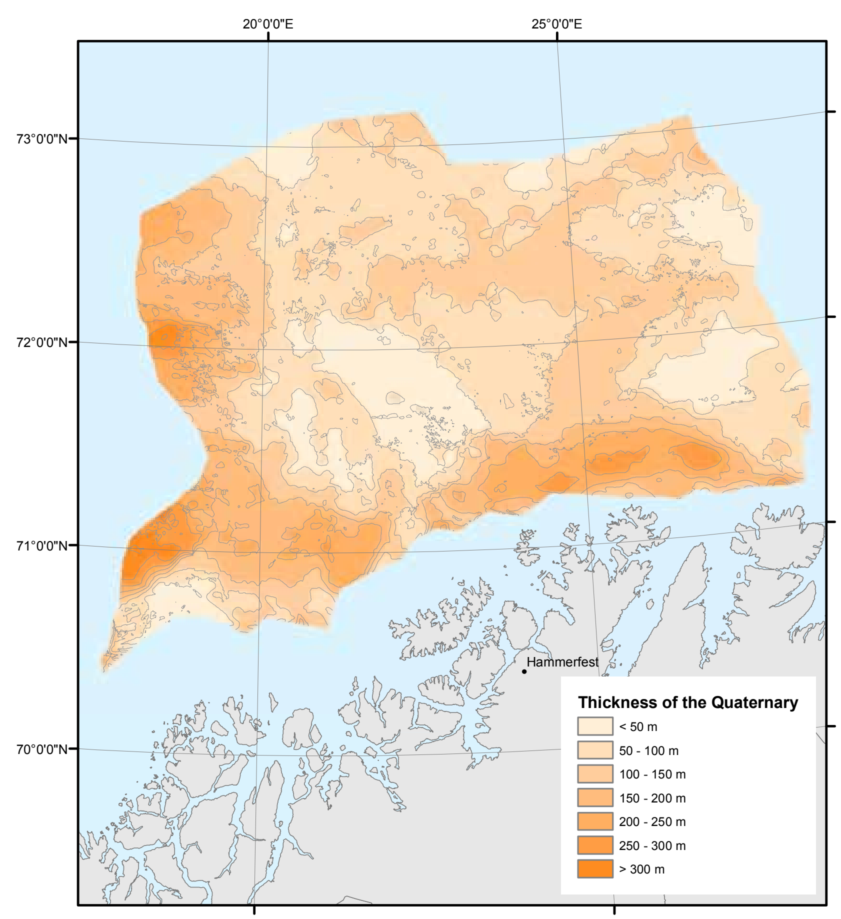


Map showing Cenozoic and Quaternary erosion of the Barents Sea. Modified from Henriksen et al. 2011.

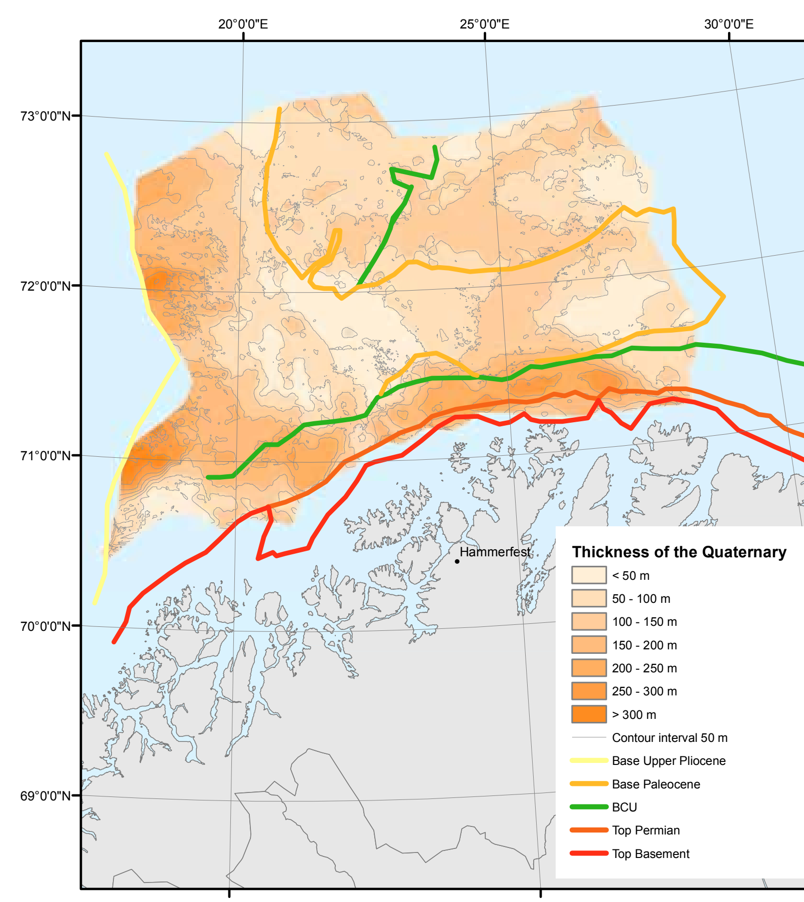
6.1 Geology of the Barents Sea

topography was filled and overlain by Upper Paleozoic siliciclastics, evaporites and carbonate. During the Late Permian to Early Triassic the Loppa Ridge was uplifted and tilted. This was followed by a gradual onlap during the Early and Middle Triassic, before deposition of a thick Upper Triassic succession (Snadd Fm). On the southern crest of the Loppa High, the eroded remnants of a sequence of Paleogene shale (Sotbakken Gp) is overlying Middle Triassic claystones.

An important geological factor for the Barents Sea region is the major Paleogene tectonism and uplift and the following Paleogene and Neogene erosion. Generally the net uplift, defined as the difference between maximum and present burial, is greatest in the northwestern part towards Bjørnøya/Stappen High (calculated to be up to 3000m), and is less towards the east and south. The Paleogene tectonism is suggested to be partly related to the plate tectonic movements in relation to the opening of the Atlantic and Arctic Oceans. An important part of the erosion took place in the Quaternary, when erosion rates increased due to the glacial conditions.



Thickness map of Quaternary in the Barents sea. During the last 2.5 m years glaciers and cold climate dominated in the region, eroding the remnant highs offshore Finnmark and Northern Troms.



Thickness map of Quaternary sediments including subcrop lines of basement, top Permian, BCU, base Paleocene and base upper Pliocene

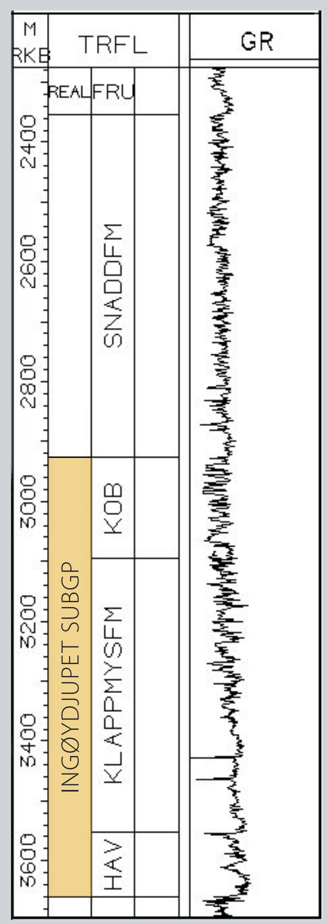
The Sassendalen Group

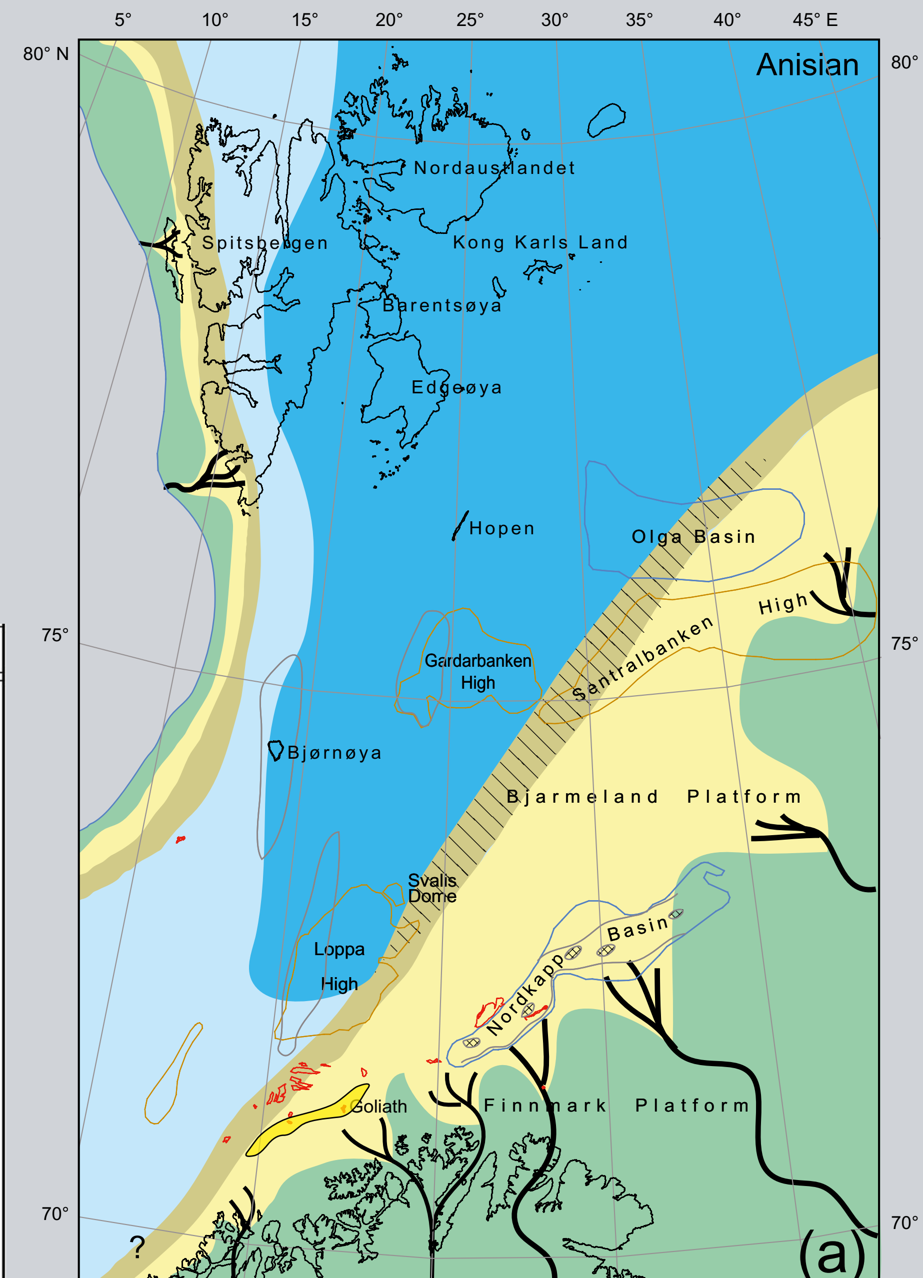
Lower and Middle Triassic

(Induan to Anisian)

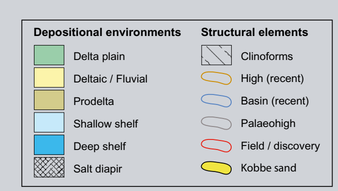
The Sassendalen Group on the Barents Sea shelf is divided into the **Ingøydjupet Subgroup** which consists of three formations: Havert, Klappmyss and Kobbe. The lower boundary is defined towards the Upper Paleozoic by mixed siliciclastic and carbonate sequences, while the upper boundary is marked by a shale interval at the base of the Fruholmen Formation (Realgrunnen Subgroup). This represents an important transgressive event which formed a traceable sequence boundary throughout most of the Arctic from the Barents Sea to the Sverdrup Basin. The type and reference area for the Ingøydjupet Subgroup is represented in blocks 7120/12 and 7120/9 in the western part of the Hammerfest Basin. In the type area the thickness is approximately 1700m, thickening northwards towards the reference area to 2400m (well 7120/9-2). The subgroup is thick throughout the Hammerfest Basin, where the lower part is onlapping the Loppa High to the north. Thick sequences are also found to the east on the Bjarmeland Platform, Norsel High and along the southeastern margin of the Nordkapp Basin. The dominant lithology of the Ingøydjupet Subgroup is black shale and claystone with thin grey silt- and sandstones, occurring particularly in the upper parts. Minor carbonate and coal interbeds are also present. Marine environments encountered by wells in the lower parts of the subgroup, together with seismic data, show evidence for coastlines to the south and southeast of the Hammerfest Basin, and progressive onlap of the submerged Loppa High to the north. The upper parts of the subgroup reflect northwestward outbuilding of deltaic sequences over an extensive, low relief depositional basin.

INGØYDJUPET SUB GP
WELL LOG 7120/12-2





Palaeogeographic map showing the prograda-tion of sediments into the Middle Triassic marine embayment, and the development of a paralic platform in the Late Triassic. In the map, the detailed boundaries between depositional areas are simplified, and the positions of the rivers are conceptual. The Kobbe aquifer in the Goliat area is indicated. (Riis et al. 2008)

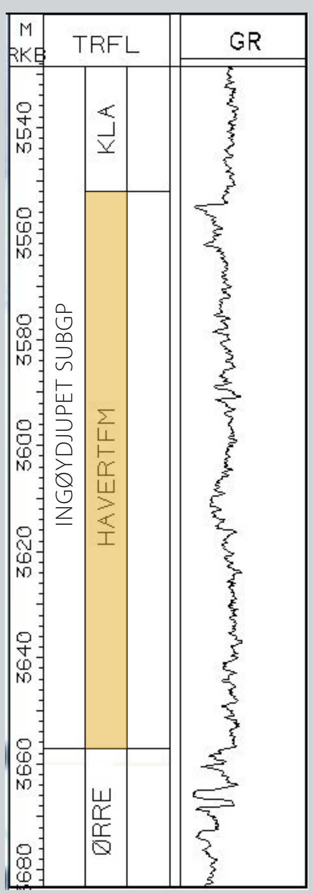


The Sassendalen Group

The Havert Formation (Induan)
In the type well (7120/12-2) in the Hammerfest Basin, the formation consists of medium to dark grey shale with minor grey siltstone and thin sandstone layers, comprising two generally coarsening upwards sequences. The thickness in the type well is 105m. Further to the north, the reference well (7120/9-2) has a thickness of 150m with a more monotonous silt and shale sequence. Further to the east, on the Bjarmeland Platform and Norsel High, thicknesses in the order of 1000m have been reported, dominated by silt and claystone with subordinate sandstone lithologies. On the Finnmark Platform a thickness of more than 600m has been drilled. In well logs the lower boundary is defined at the top of the underlying Upper Paleozoic mixed siliciclastic and carbonate rocks. The formation was deposited in a shallow to open marine setting with coastal environments to the south and southeast

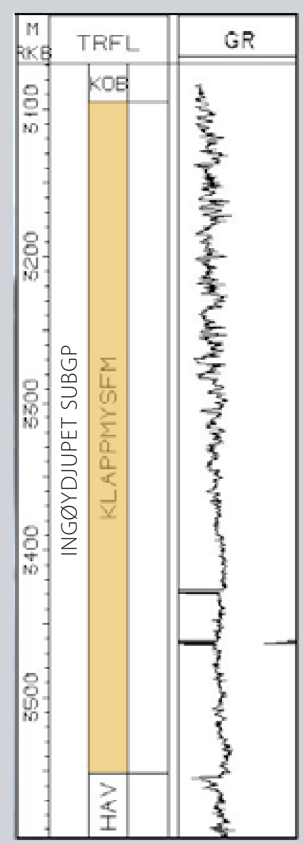
The Klappmyss Formation
(Olenekian)
In the type well (7120/12-2) in the Hammerfest Basin, the formation consists of medium to dark grey shale passing upwards into siltstones and sandstones. The reference well (7120/9-2) shows a similar trend, but with higher content of shale. The thickness is 457m in the type well and 561m in the reference well. Thicknesses as high as 600m have been reported from the Bjarmeland Platform (well 7226/2-1) and the Norsel High (well 7226/11-1). On the central Finnmark Platform (well 7128/4-1 and 6-1), thicknesses around 260m have been drilled. Generally the formation thickens and becomes finer northwards from the southern margins of the Hammerfest Basin. In well logs the lower boundary is defined at the top of the underlying Havert Formation, interpreted to represent a sequence boundary. This boundary can be correlated across the southwestern Barents Sea shelf indicating a lower Triassic transgression. The Klappmyss Formation was deposited in a shallow to open marine environment, with renewed north- to northwestward coastal progradation.

WELL LOG 7120/12-2



7226/11-1 - HAVERT, 3057-3062 m

WELL LOG 7120/12-2



7228/7-1A - KLAPPMYSS, 2852-2857 m

The Kapp Toscana Group

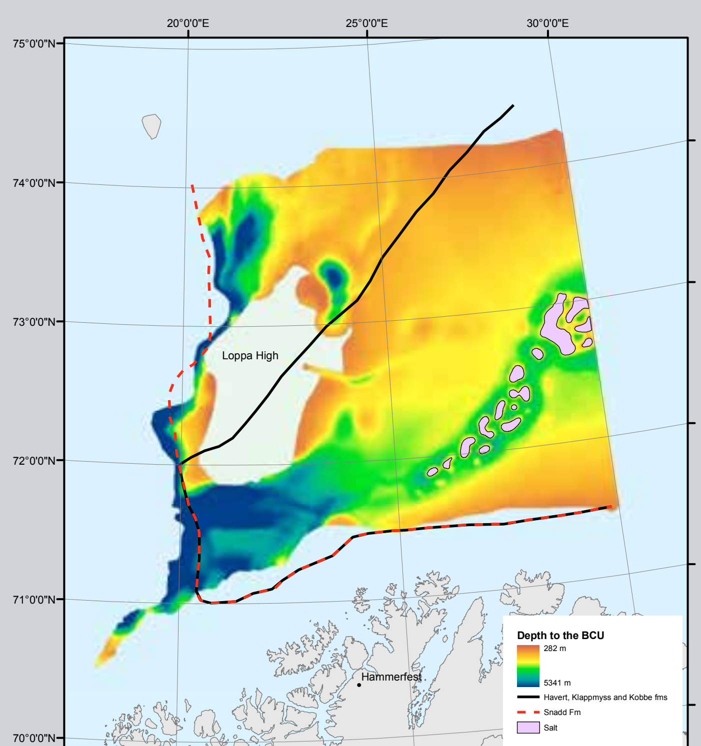
Lower Triassic and Middle Jurassic
(Ladinian-Bathonian)

The Kapp Toscana Group on the Barents Sea shelf is divided into two subgroups: the Storfjorden (Ladinian to Norian) and Realgrunnen (Early Norian to Bathonian).

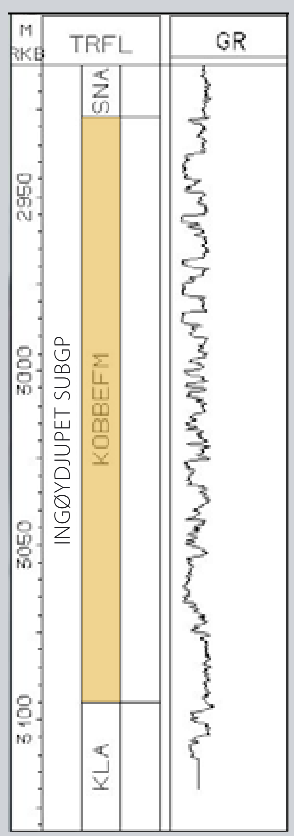
The Storfjorden Subgroup
(Ladinian to Norian)

The Storfjorden Subgroup consists of the **Snadd Formation** and is defined at the base of a 60m shale interval above the mixed lithologies of the Kobbe Formation. The upper boundary is defined at the basal shales of the Fruholmen Formation.

In the reference wells (7120/12-1 and 7120/9-2) the thickness is 944m and 1410m respectively, while in the type well (7120/12-2) the thickness is only 573m due to faulting 400m of the middle and upper part of the unit. On the Loppa High, thicknesses are in the order of 1300-1400m. On the Nysleppen and Måsøy Fault the thickness is between 200 and 550m. The Bjarmeland Platform has thicknesses in the order of 600 to 850m. The basal grey shale coarsens up into shale interbedded with grey siltstones and sandstones. In the middle and lower parts of the unit, calcareous layers are relatively common, with thin coaly lenses occurring in the upper part. High rates of deposition occurred throughout the area with little differentiation between negative and positive elements. The Ladinian sequence represents relatively distal marine environments, following a major transgression which submerged all structural highs and platform areas. The Carnian is marked by a large scale progradation of deltaic systems derived from the south-southeast over the entire region. The upper part of the Storfjorden Subgroup has been eroded on the Finnmark Platform, but still more than 1000m have been drilled in the central parts (wells 7128/4-1 and 7128/6-1).

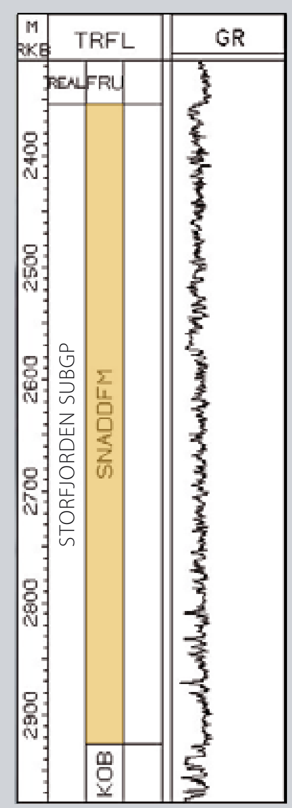


WELL LOG 7120/12-2



7120/12-1
KOBBE, 3521-3524 m

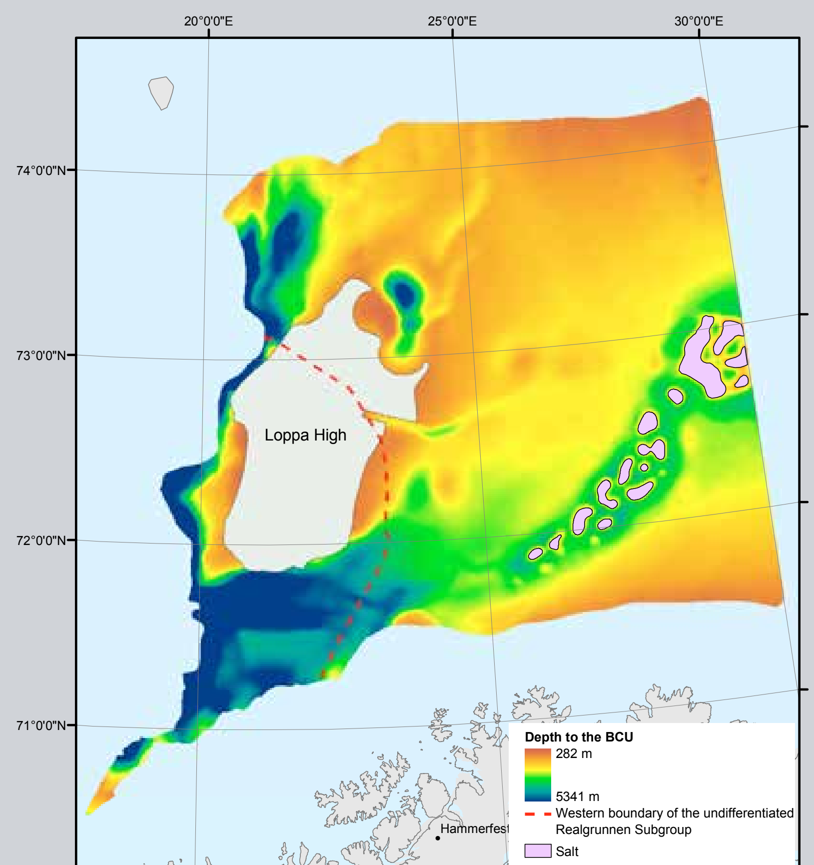
WELL LOG 7120/12-2

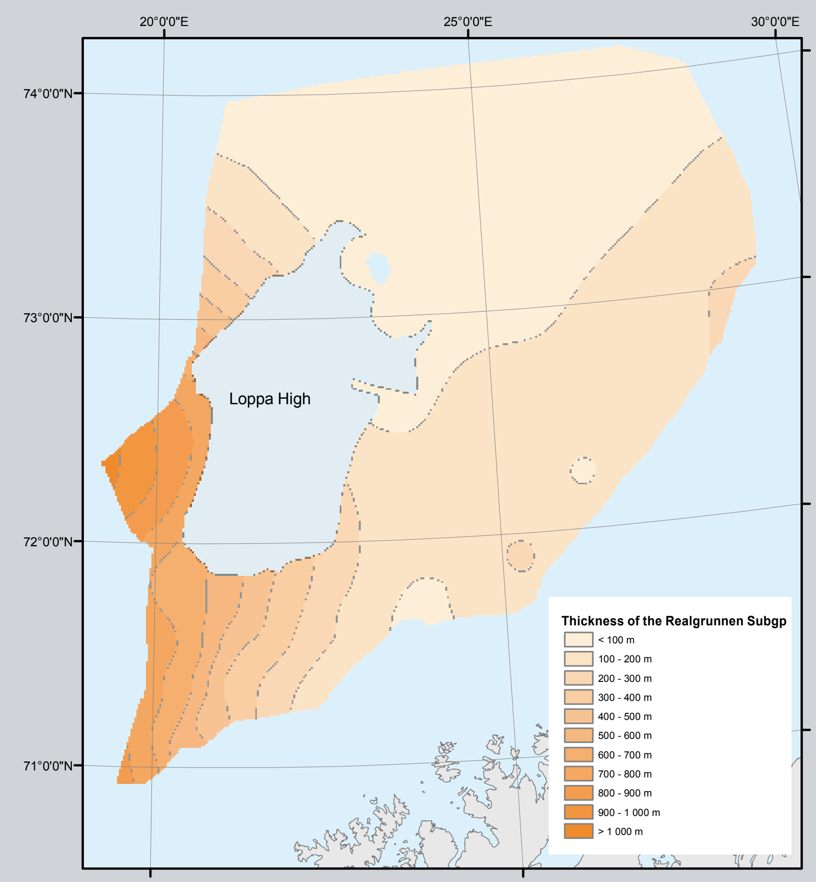


7121/5-1 - SNADD, 3088-3094 m

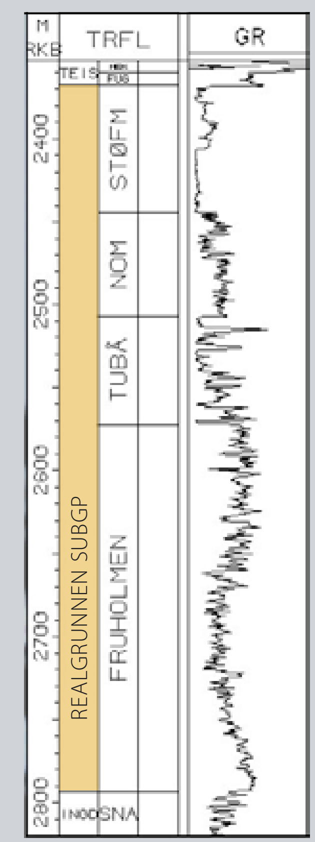
Early Norian to Bathonian

The Realgrunnen Subgroup was originally defined in the west central Hammerfest Basin with its type area in block 7121/5. It is subdivided into four formations; Fruholmen, Tubåen, Nordmela and Stø. The thickness in the type well (7121/5-1) is 424m, and 488m in well 7120/12-1. Thicknesses of up to 871m have been drilled in the southern part of the Bjørnøyrenna Fault Complex (well 7219/9-1). The subgroup is thinly developed on the Bjarmeland Platform, and the definition of various formations is therefore unclear. The subgroup is mostly eroded on the Troms-Finnmark Platform. The dominant lithology is pale grey sandstone, especially in the middle and upper parts, while shale and thin coal are more common in the lower parts. The lower boundary is defined by the lower Norian basal shales of the Fruholmen Formation. Following the transgression in the early Norian, deltaic systems developed over the southern parts of the Hammerfest Basin up through the Triassic. In the early Jurassic, coastal marine environments developed, grading into a variety of shoreface, barrier and tidal environments from the Toarcian to the Bajocian. Sediments of the Realgrunnen Subgroup have been deposited in general near-shore deltaic environments, characterized by shallow marine and coastal reworking of deltaic and fluviodeltaic deposits.



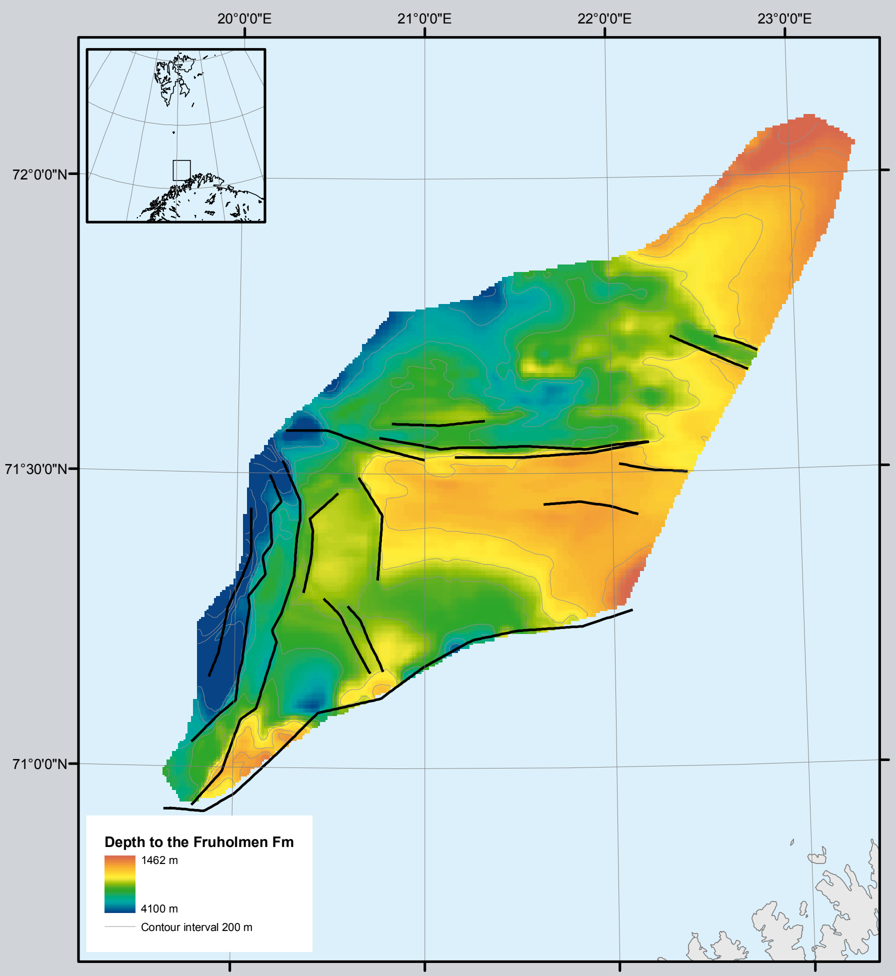


REALGRUNNEN
WELL LOG 7121/5-1

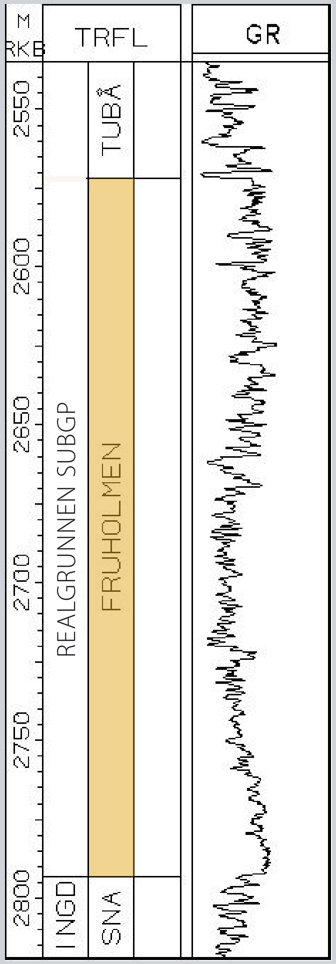


The Kapp Toscana Group - Realgrunnen Subgroup

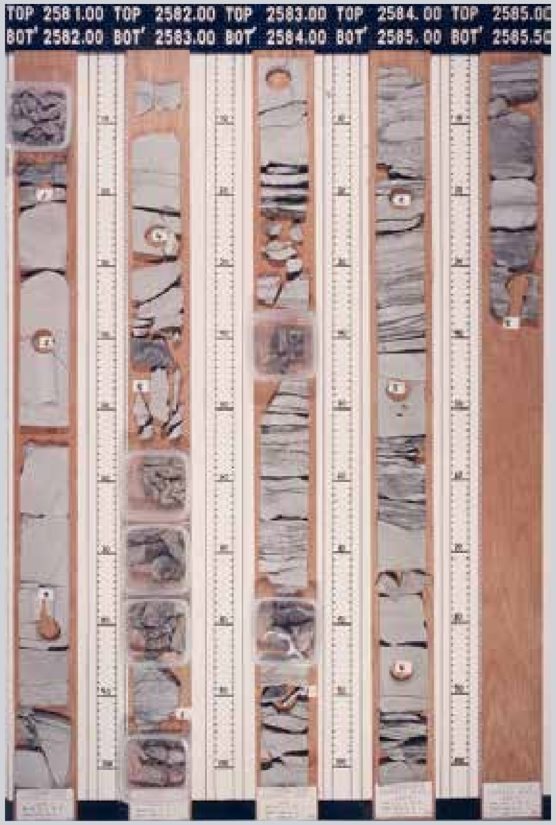
The Fruholmen Formation
(Norian to Rhaetian) consists of grey to dark shale passing upwards into interbedded sandstone, shale and coals. Sandstone dominates in the middle part of the formation, while the upper part is dominated by shales. This lithological development has resulted in a threefold subdivision of the formation with the shale-dominated Akkar Member at the base, overlain by the more sandy Reke Member which in turn is overlain by the more shale-rich Krabbe Member. Depositionally this has been interpreted in terms of open marine shales (Akkar Mb) passing into coastal and fluvial-dominated sandstones of the Reke Formation. These represent northward fluviodeltaic progradation with a depocentre to the south. As the main deltaic input shifted laterally, most of the central and southern parts of the basin became the site of flood-plain deposition, with more marine environments to the north (Krabbe Member). In the type well (7121/5-1) the thickness of the formation is 221m and 262m in the reference well (7120/9-2). The thickest sequence drilled so far (572m, well 7219/9-1) is within the Bjørnøyrenna Fault Complex.



WELL LOG 7121/5-1

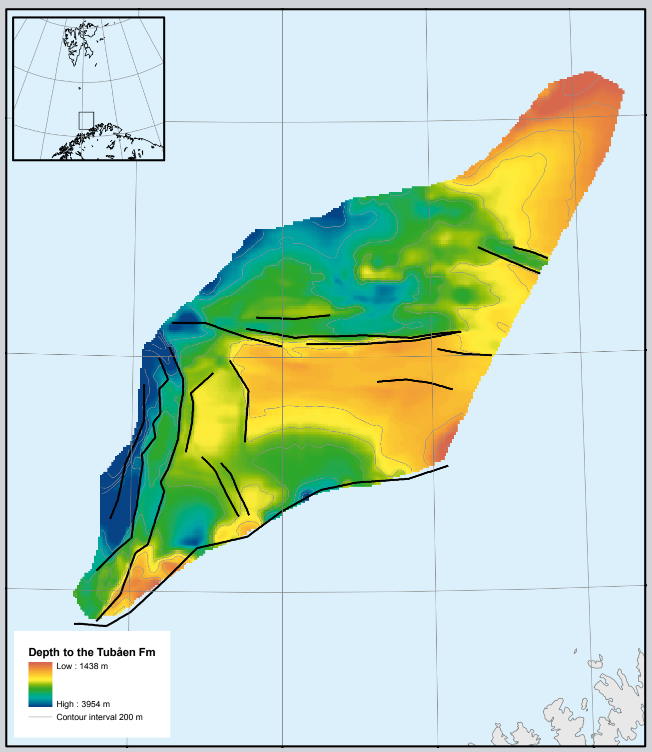


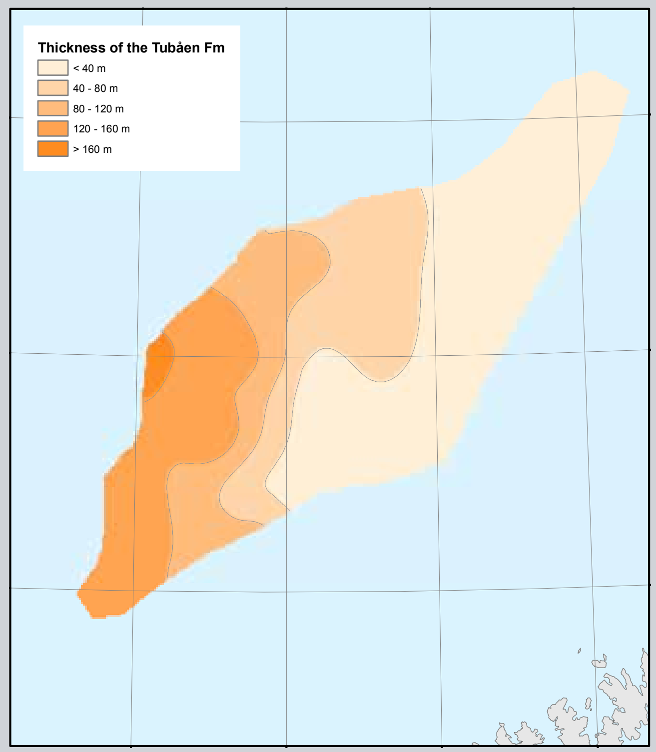
7120/1-2 - FRUHOLMEN, 2581-2585 m



The Kapp Toscana Group - Realgrunnen Subgroup

The Tubåen Formation (Late Rhaetian to early Hettangian,locally Sinemurian) is dominated by sandstones with subordinate shale and coals. Coals are most abundant near the southeastern basinal margins and fade out towards the northwest. Generally the formation can be divided into three parts with a lower and upper sand-rich unit separated by a more shaly interval. The shale content increases towards the northwest, where the Tubåen Formation may interfinger with a lateral shale equivalent. In the type well (7121/5-1) the thickness of the Tubåen Fm is 65m, and in the reference well (7120/12-1) it is 85m with a maximum thickness of 261m (well 7120/6-1) in the Snøhvit Field. The sandstones of the Tubåen Formation are thought to represent stacked series of fluviodeltaic deposits (tidal inlet and/or estuarine). Marine shales reflect more distal environments to the northwest, while coals in the southeast were deposited in protected backbarrier lagoonal environments.





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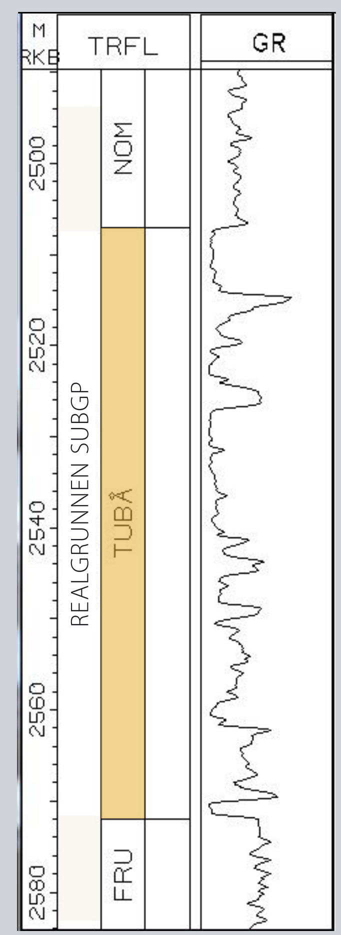
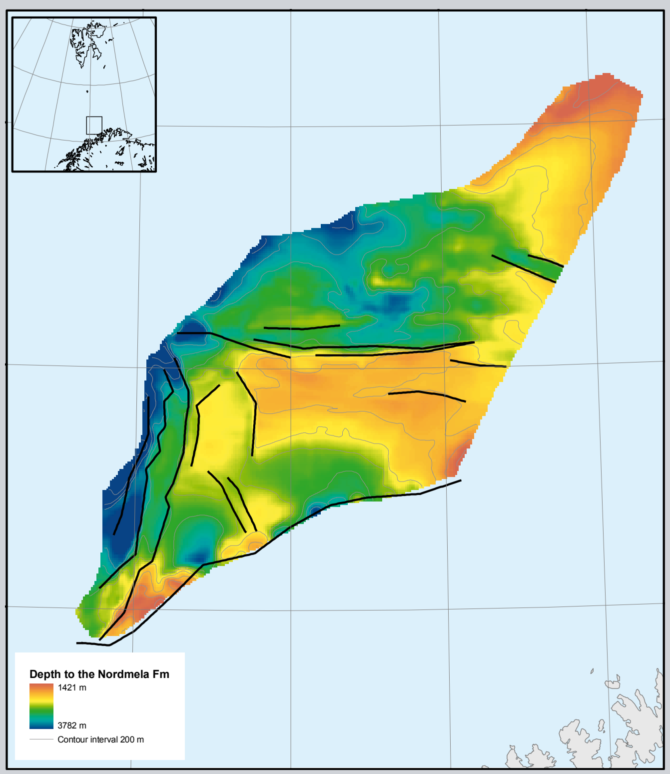
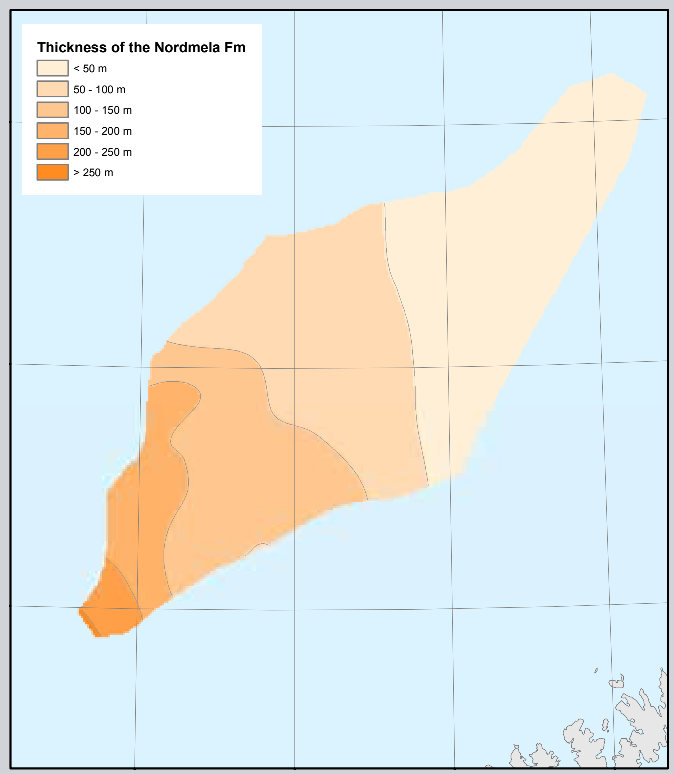


7121/5-1 - TUBÅEN, 2519-2524 m

The Kapp Toscana Group - Realgrunnen Subgroup

The Nordmela Formation (Sinemurian-Late Pliensbachian) consists of interbedded siltstones, sandstones, shale and mudstones with minor coals. Sandstones become more common towards the top. In the Hammerfest Basin the formation seems to form a west-southwest thickening wedge, similar to the underlying Tubåen Fm. It may be diachronous, becoming younger eastwards. The formation represents deposits in a tidal flat to flood-plain environment. Individual sandstones represent estuarine and tidal channels. In the type well (7121/5-1) the thickness is 62m, and in the reference well (7119/12-2) it is 202m. This thickness variation between the type well and reference well clearly illustrates a southwest oriented thickening wedge. Westward thickening is characteristic for all the three Lower and Middle Jurassic formations and may be the result of early Kimmerian subsidence and tilting towards the Tromsø and Bjørnøya Basins.





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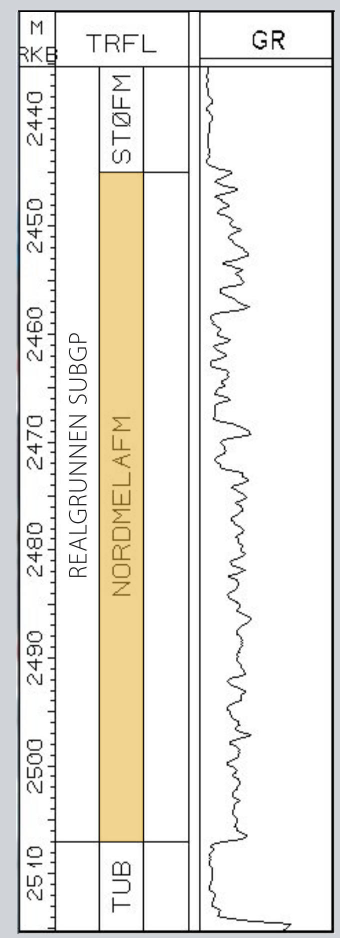
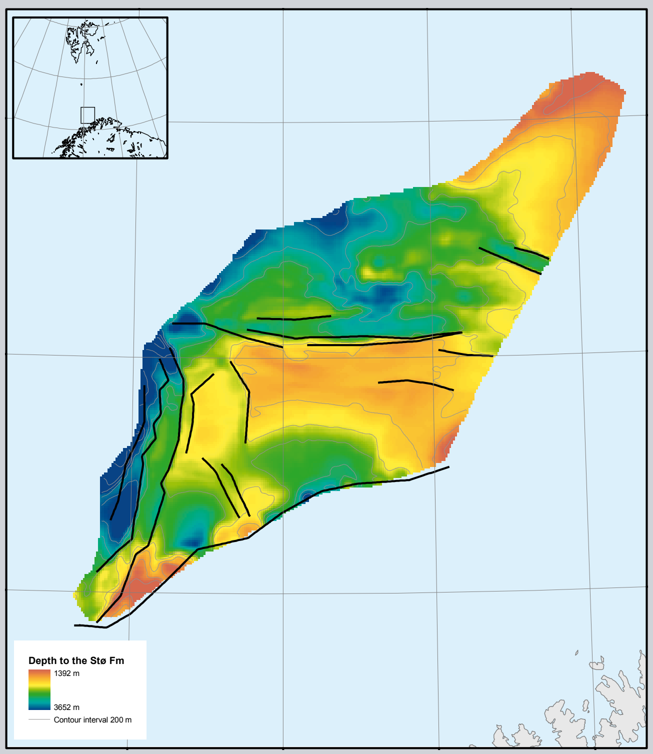
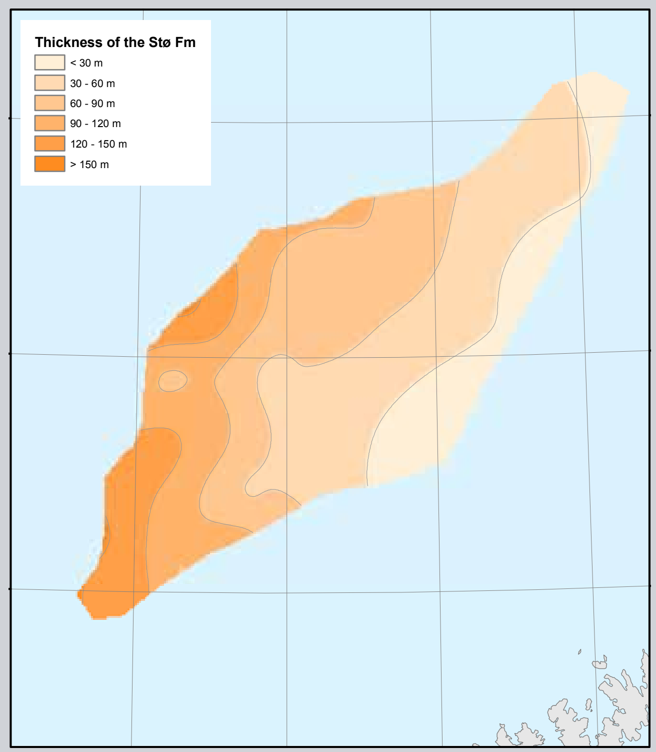


7121/5-1 - NORDMELA, 2503-2506 m

The Kapp Toscana Group - Realgrunnen Subgroup

The Stø Formation (Late Pliensbachian to Bajocian) is defined with the incoming of sandy sequences above the shale-dominated sediments of the Nordmela Formation. The dominant lithology of the Stø Formation is mineralogically mature and well sorted sandstone. Thin units of shale and siltstone represent regional markers. Especially in the upper part of the Stø Fm, phosphatic lag conglomerates can be found. In the type well (7121/5-1) the thickness is 77m, and in the reference well (7119/12-2) it is 145m. In general the Stø Fm thickens westwards in consistence with the underlying Nordmela Formation. The unit may be subdivided into three depositional episodes with bases defined by transgressions. The basal unit is only present in the western parts of the Hammerfest Basin. The middle part (Upper Toarcian–Aalenian) represents the maximum transgression in the area. The uppermost (Bajocian) unit is highly variable owing to syndepositional uplift and winnowing as well as later differential erosion. The sands in the Stø Formation were deposited in prograding coastal regimes, and a variety of linear clastic coast lithofacies are represented. Marked shale and siltstone intervals represent regional transgressive pulses in the late Toarcian and late Aalenian.





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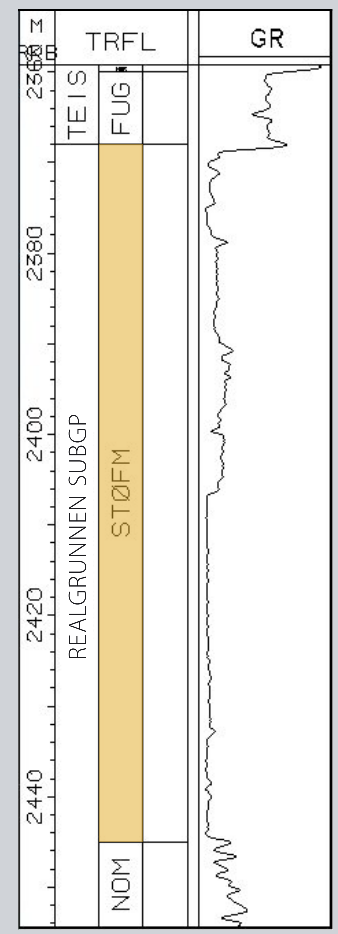


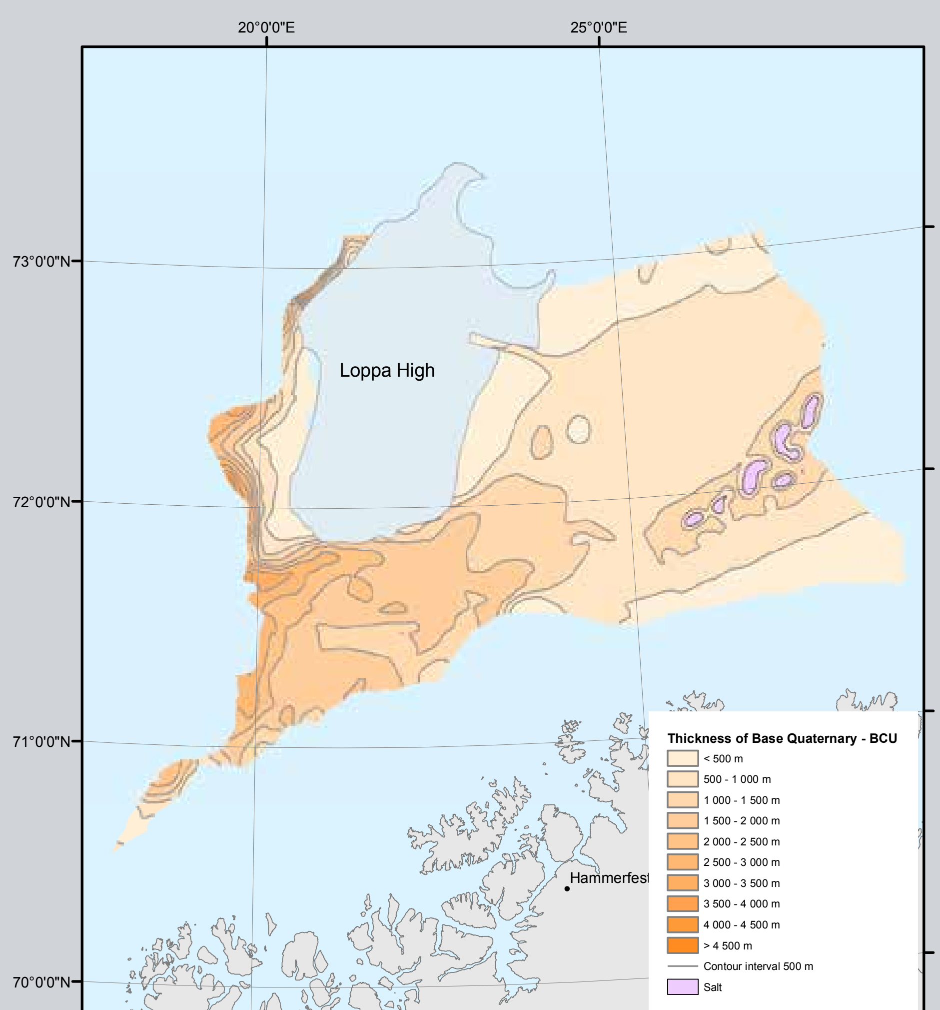
7121/5-1 - STØ, 2400-2405 m

The Adventdalen Group

Middle Jurassic to Lower Cretaceous
(Bathonian to Cenomanian)

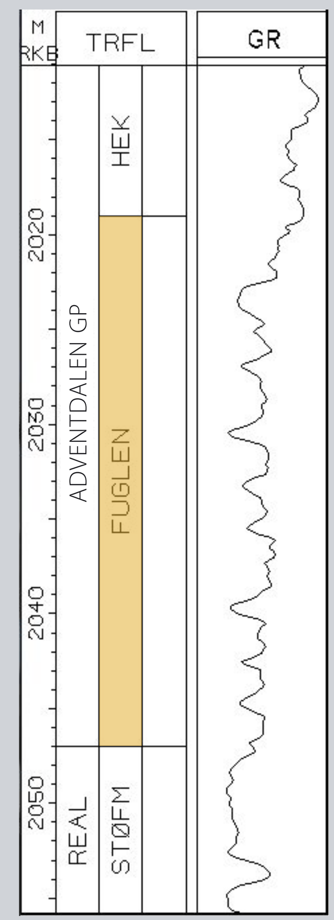
The Adventdalen Group is subdivided into the Fuglen, Hekkingen, Knurr, Kolje and Kolmule formations, with its type area in the northern part of block 7120/12 in the Hammerfest Basin and in 7119/12 in the eastern part of the Ringvassøy-Loppa Fault Complex. The thickness varies from more than 900m in the Bjørnøyrenna Fault Complex (7219/8-1S) to 300m north of the Troms-Finnmark Fault Complex. Nevertheless, the thickness decreases to approximately 60m or less on structural highs in the centre of the Hammerfest Basin, reflecting the effect of Upper Jurassic tectonic movements. The group is dominated by dark marine mudstones, locally including deltaic and shelf sandstones as well as carbonate.

The Hekkingen Formation is an important hydrocarbon source rock. Both the Fuglen and Hekkingen formations constitute good cap rocks. The Hekkingen Fm (Upper Oxfordian–Tithonian) has been drilled in the Hammerfest Basin, the eastern part of the Bjørnøya Basin (Fingerdjupet Subbasin) and the Bjarmeland Platform. The lower boundary is defined by the transition from carbonate cemented and pyritic mudstone to poorly con-



Thickness of the secondary seal, defined as the thickness between the BCU and the base Quaternary

WELL LOG 7120/12-1

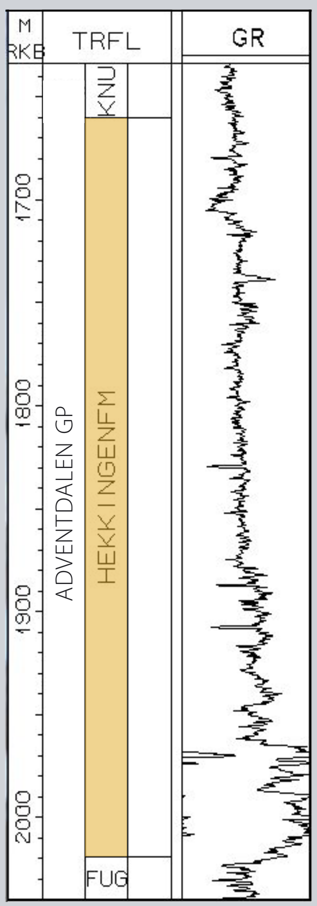


7120/12-1 - FUGLEN, 2044-2047 m

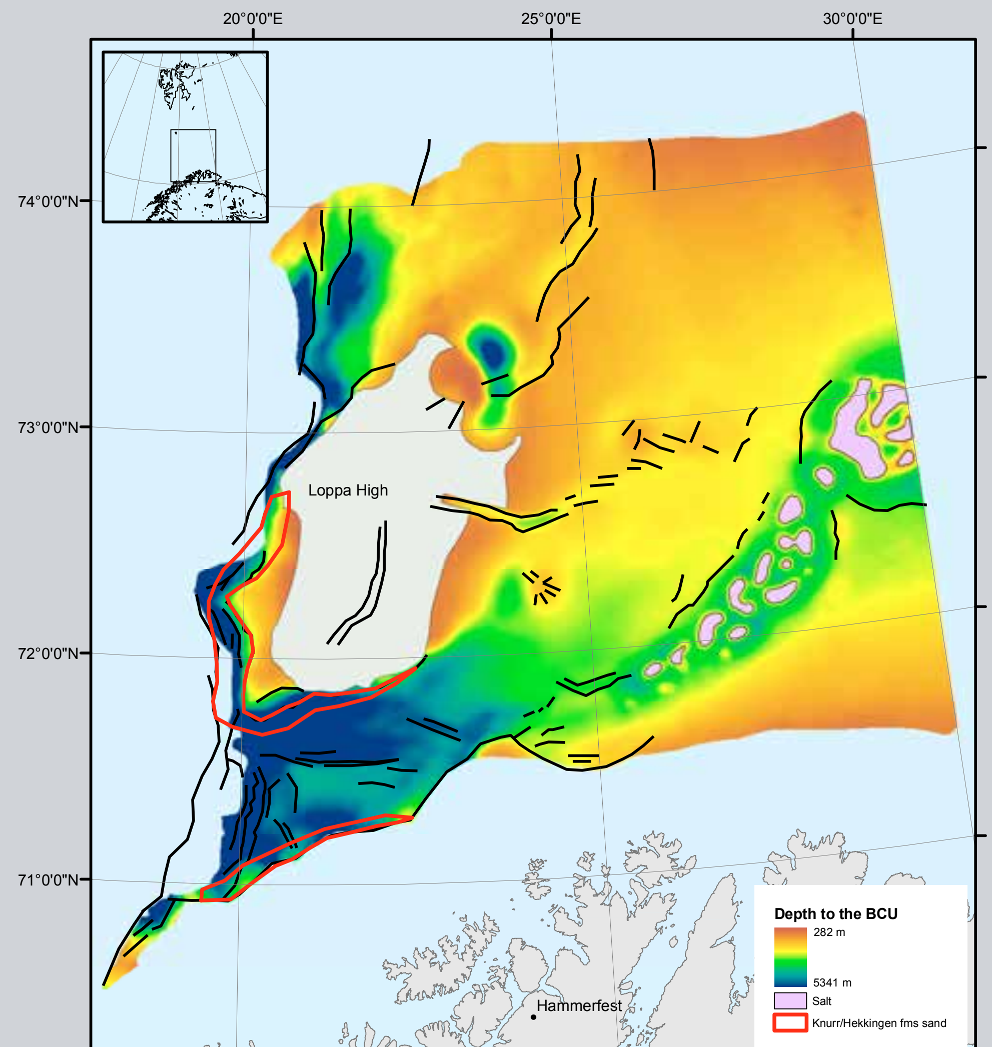
The Adventdalen Group

solidated shale in the Fuglen Formation. The upper boundary in the reference well (7120/12-1) is defined towards the thin sandy limestone of the Knurr Formation. The thickness in the type well (7120/12-1) is 359m, and in the reference well (7119/12-1) the thickness is 113m. Within the Hammerfest Basin the thickest sequence is found in the type well, thinning northwards to less than 100m. Very high thicknesses are interpreted along the eastern margins of the Harstad Basin and Bjørnøya Basin, as seen in well 7219/8-1S in the southern part of the Bjørnøyrenna Fault Complex (856m thickness). Thin sequences are found on the Bjarmeland Platform. The dominant lithology in the formation is shale and mudstone with occasional thin interbeds of limestone, dolomite, siltstone and sandstone. The amount of sandstone increases towards the basin margins. The formation was deposited in a deep shelf with partly anoxic conditions.

WELL LOG 7120/12-1



7120/12-1 - HEKKINGEN, 1702-1705 m



Areas where Knurr and/or Hekkingen sandy deposits occur are outlined.

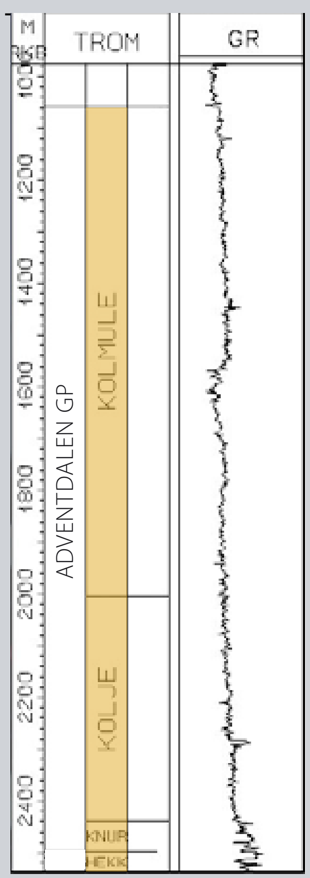
The Adventdalen Group

Createceous
Berriasian to Cenomanian

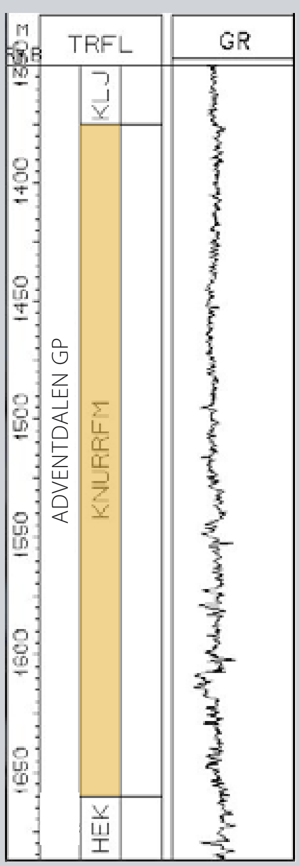
The Cretaceous sucsession is subdivided into three formations: The Knurr, Kolje, and Kolmule Formations. The dominant lithology of the Knurr, Kolje and Kolmule formations is dark to grey-brown shale with thin interbeds of siltstone, limestone, dolomite and local sandstone. The thickness is in the order of 1000-1400m in the type area (blocks 7119/12 and 7120/12). Thicknesses within the Hammerfest Basin are closely related to Upper Jurassic structural development. The formations are thickest along basin margins and thin towards the central part of the Hammerfest Basin. In our study we have focused on the Knurr Formation, as this may represent thief sands in relation to the main Mesozoic aquifers. The Knurr Formation (Berriasian/Valanginian to lower Barremian) is distributed over the southwestern part of the Barents shelf, mainly in the Hammerfest Basin, the Ringvassøy-Loppa Fault Complex and the Bjørnøyrenna Fault Complex. A thin Knurr section is also found locally on the Bjarmeland Platform. The thickness of the Knurr Formation is 56m in the type well (7119/12-1) and 285m in the reference well (7120/12-1). The thickest drilled section so far is 978m (well 7219/8-1S) in the Bjørnøyrenna Fault Complex east of Veslemøy High. The base is defined by a thin sandy limestone overlying the Hekkingen Formation, and the upper boundary is defined with a presence of dark brown to grey shale in the Kolje Formation.

Although the formation shows similar lithology in most wells, the sand content is higher close to the Troms-Finnmark Fault Complex and in the Ringvassøy-Loppa Fault Complex. The sandstones are located in the lower part of the formation, pinching out laterally into the Hammerfest Basin and Bjørnøya Basin. The formation was deposited in an open and generally distal marine environment with local restricted bottom conditions.

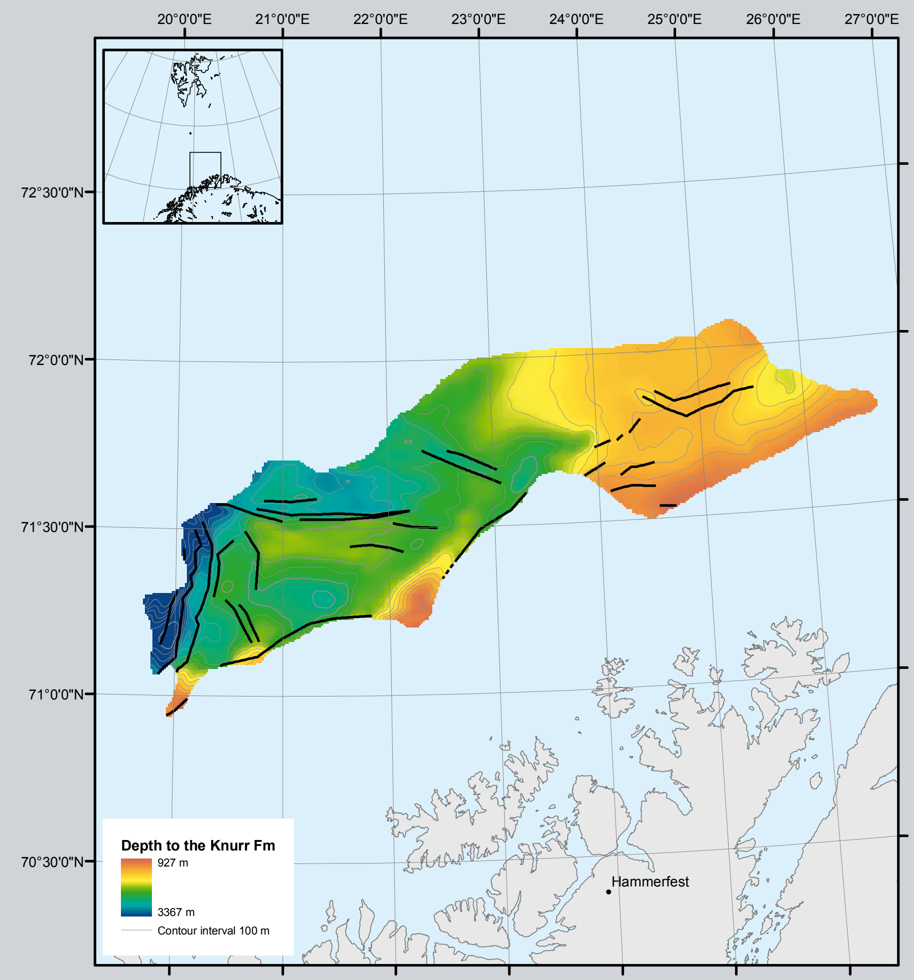
ADVENTDALEN
WELL LOG 7119/12-1



WELL LOG 7120-12-1



7019-1-1 - KNURR, 2225-2230 m



The Triassic succession in the southern Barents Sea continues to the north and the outcrops of Svalbard are very good analogs. The photo shows the Triassic section at Blanknuten, Edgeøya, with the distal Lower Triassic Vikinghøgda Formation, the distinct Middle Triassic Botneheia and Tschermakfjellet shales and the overlying channelized Upper Triassic reservoir sandstones in the de Geerdalen Formation. The cliff-forming Botneheia shale is analogous to the Steinkobbe shale and the de Geerdalen Formation is analogous to the Snadd Formation. Photo: NPD.

Introduction

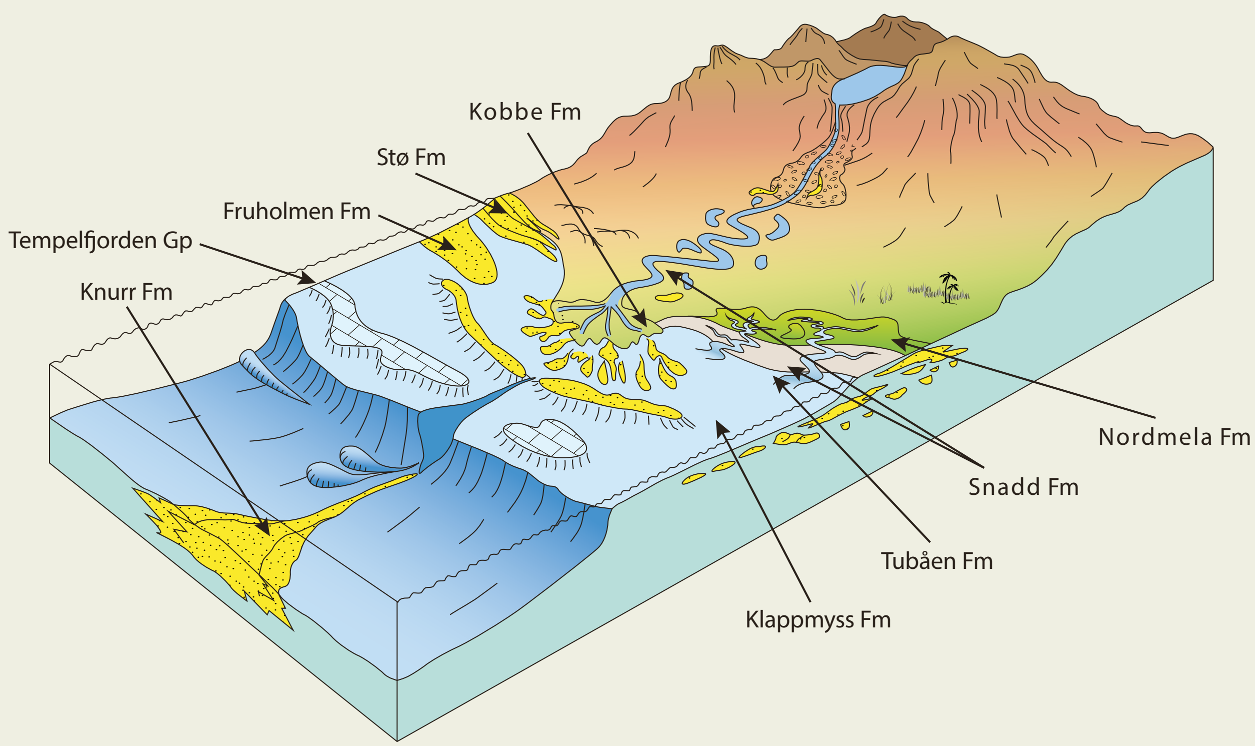
The parts of northern Fennoscandia adjacent to the Norwegian sector of the Barents Sea are sparsely populated, and the industrial activity generates only small amounts of CO_2 emissions. CO_2 associated with the production of natural gas in the Snøhvit Field is extracted at Melkøya, Hammerfest, and injected in the aquifer of the field. CO_2 associated with gas production is believed to be the main source for CO_2 storage and EOR in the near future. In a more distant future, storage of anthropogenic CO_2 from industrial activity may become an option.

For detailed evaluation of storage capacity, large areas in the north and east were eliminated. The areas north of 74° were excluded because they were considered too remote and because the good Jurassic aquifers are generally thin and poorly sealed due to a shallow overburden. The Finnmark Platform east of 29° was eliminated because there is limited infrastructure and industrial activity in this area, and the main aquifers of interest are poorly structured and generally dipping with only a Quaternary seal towards the sea floor. The area selected for detailed evaluation of storage capacity is shown in the map.

The petroleum systems of the Barents Sea are more complex than in the North Sea and Norwegian Sea. Important source rocks occur in the Upper Jurassic, Middle Triassic and Late Paleozoic sections. Because of Cenozoic tectonism and Quaternary glacial erosion, the maximum burial of these source rocks in the evaluated area occurred in the past. The reservoir porosity and permeability are related to the temperature and pressure at maximum burial. Due to extensive erosion, good reservoir quality is encountered only at shallower depth than what is found in the North Sea and Norwegian Sea. Below 3000 m the porosity and permeability is generally too low for large scale injection.

The Cenozoic history has also affected the distribution of hydrocarbons in the evaluated area. Residual oil is very commonly found, both in water-bearing traps and below the gas cap in gas-bearing traps. Hydrocarbons and traces of hydrocarbons have been found in several aquifers, and at the present stage in exploration, it is thought that most of the area selected for evaluation of CO_2 storage will also be subject to further exploration and exploitation by the petroleum industry. Consequently, storage of CO_2 in the southern Barents Sea must take place in accordance with the interests of the petroleum industry. The main storage options considered in this study are limited to structurally defined traps, and to depleted and abandoned gas fields. In areas where the pressure exceeds the miscibility pressure of CO_2 and oil, one might consider using CO_2 injection to recover some of these oil resources (CCUS).

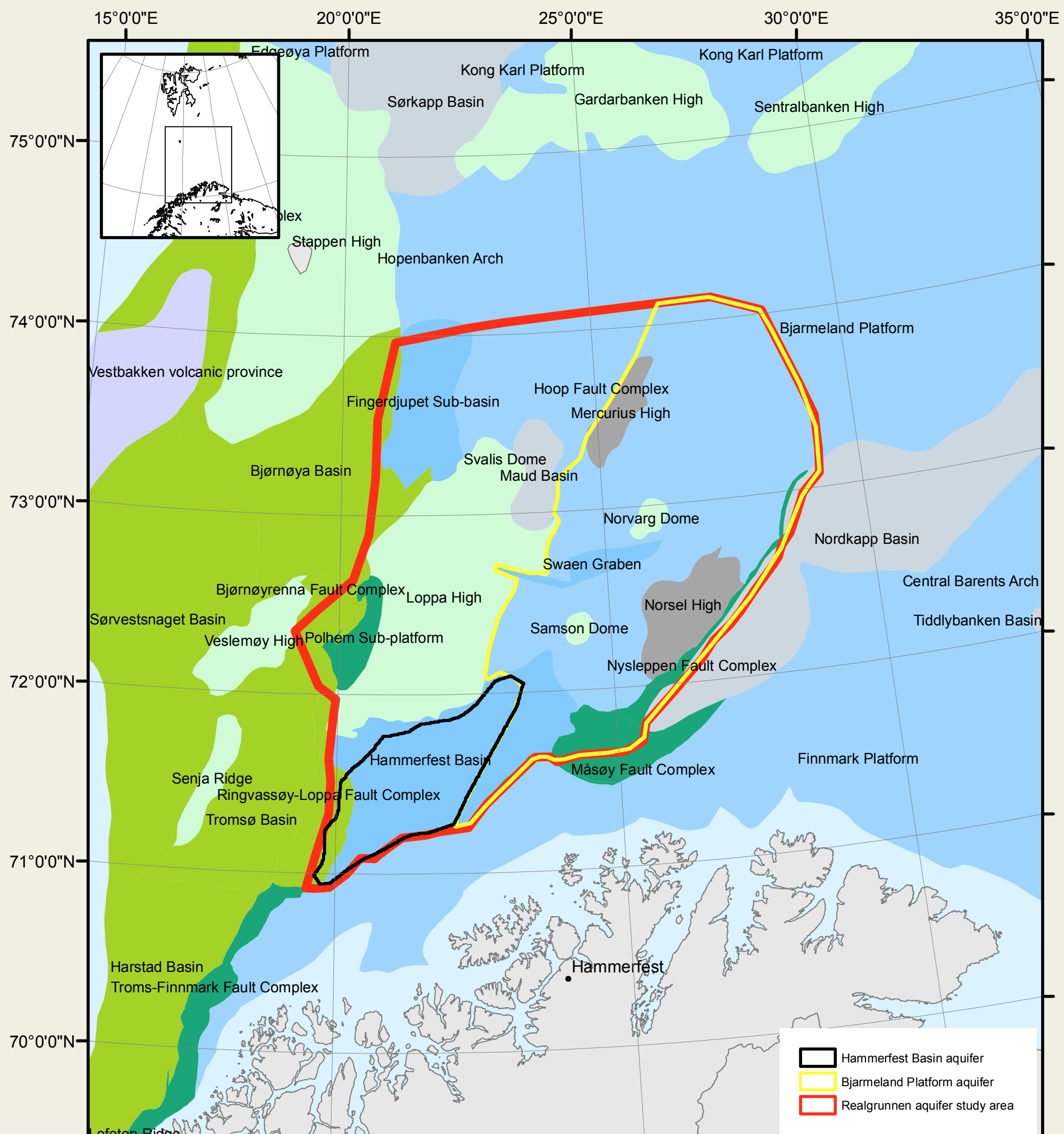
The main aquifer system in the study area consists of Lower and Middle Jurassic sandstones belonging to the Realgrunnen Subgroup. This aquifer system can be defined in three distinct geographical areas which are described in the following section. Hydrocarbons have been encountered in several reservoir levels pre-dating the Jurassic, notably in the



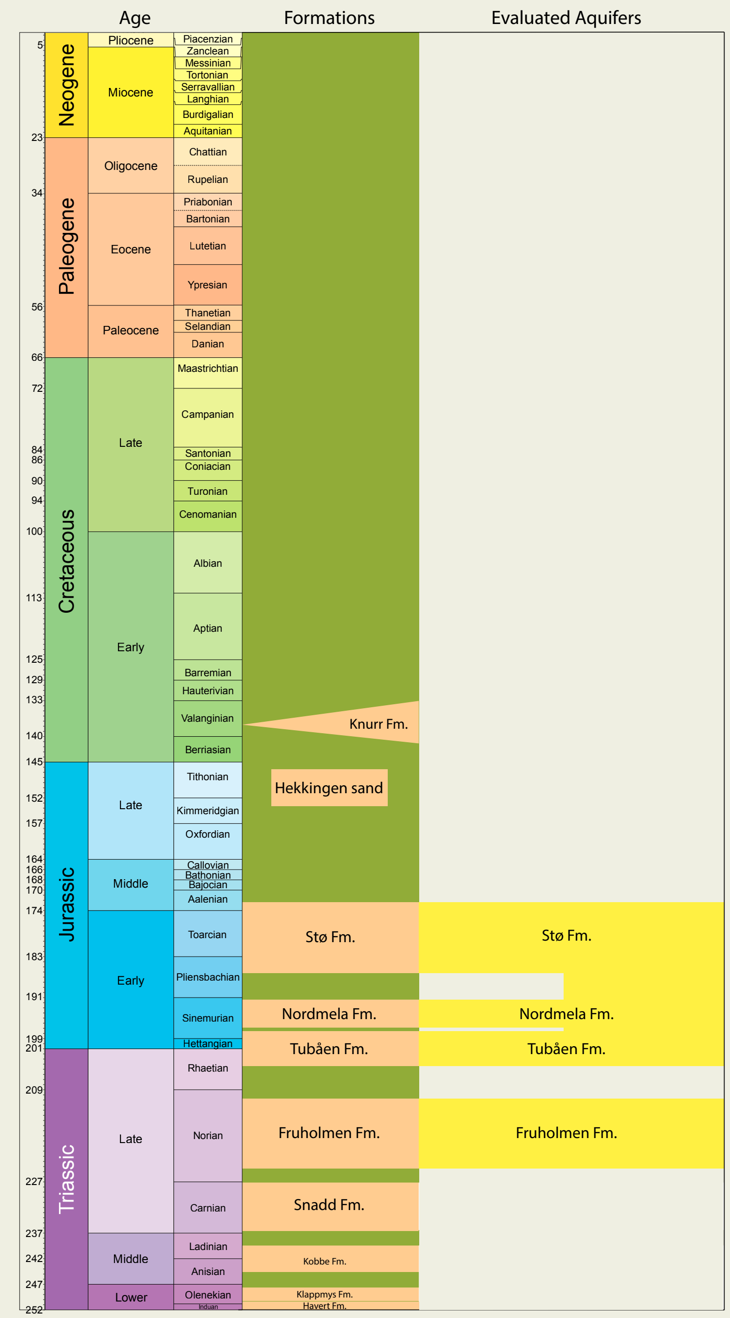
Conceptual sketch showing the depositional environments of the different aquifers.

Introduction

Late Triassic Fruholmen and Snadd Formations, the Middle Triassic Kobbe Formation and in Permian carbonates and spiculites, thus proving there is a reservoir and seal potential for these formations. Their storage potential is not as promising as for the Jurassic aquifer and is only briefly discussed. Upper Jurassic and Lower Cretaceous sandstones are limited to the flanks of active highs and do not form major aquifers. Eocene reservoir sandstones have been encountered in two wells in the western margin of the Barents Sea, but they are not considered for this study.



The evaluated area (red outline). The Jurassic aquifers are eroded in the Loppa High.



Evaluated geological formations, and aquifers.

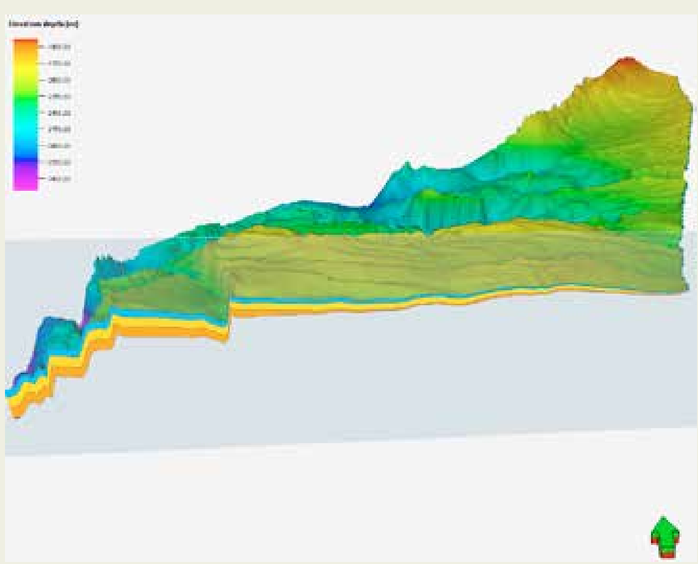
Hammerfest Basin

In the Hammerfest Basin, the Jurassic Tubåen, Nordmela and Stø Formations increase in thickness towards the west. The western part of the basin is bounded by large faults to the north and south which juxtapose the Jurassic aquifer towards tight Triassic formations. Towards the northeast, the Jurassic aquifers subcrop against the sea floor with a thin Quaternary cover, while in the eastern part there is a gradual transition to thinner formations in the Bjarmeland Platform aquifer. Faults within the basin commonly juxtapose Stø towards the Nordmela and Tubåen Formations. Paleofluid contacts indicate that the faults are open where there is sand-sand contact.

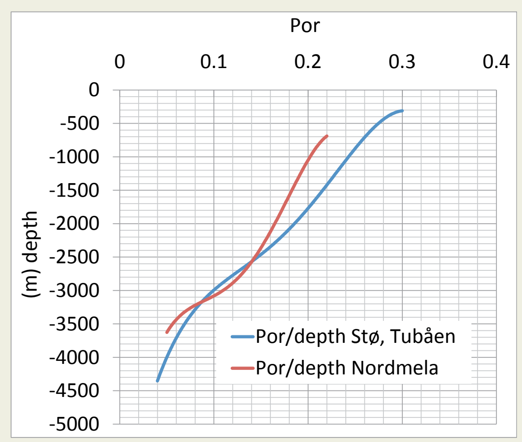
Pressure data from exploration wells show that the Jurassic formations are hydrostatically pressured at depths shallower than 2600 m. The data indicates that the pore pressure has equilibrated between the three formations. The most important regional stratigraphic barrier in the succession is considered to be the shaly lower part of the Nordmela Formation. Pressure data indicate that the thin shaly continuous layers in the middle part of the Stø Formation can create baffles for vertical flow during production. In general, the Tubåen and Nordmela Formations are heterogeneous reservoirs where individual channels have good reservoir properties while they may be poorly connected to other parts of the reservoir.

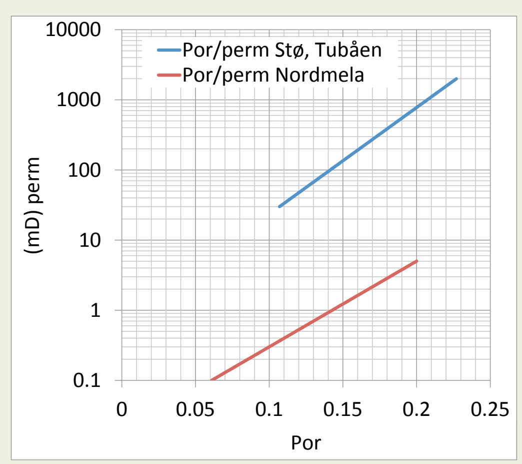
For the evaluation of storage potential, it was decided to define the Stø, Nordmela and Tubåen Formations as one single aquifer system. The geological data show that the Stø Formation is very well connected laterally. The underlying, heterolithic formations are believed to contribute to the aquifer at a regional scale. At a smaller scale, in an injection site, stratigraphic barriers may allow gas to accumulate at different stratigraphic levels within a structural closure. This is shown by local small oil and gas accumulations below the main contacts of the Snøhvit and Albatross accumulations. The experience from CO_2 injection in the Snøhvit Field showed that CO_2 was contained within the Tubåen Formation with no upwards migration into the Nordmela and Stø Formations.

The calculations of storage capacity in structures are based on injection and storage in the Stø Formation. For the aquifer volume, the storage capacity includes the Nordmela and Tubåen Formations. Experience from Snøhvit CO_2 injection shows that many injection wells may be needed to realize a large storage potential in these heterolithic formations. The formation water in the aquifer is strongly saline, with salinities generally exceeding 100 000 ppm. The water density at standard conditions in the Snøhvit Field is around 1.1 g/cm^3.



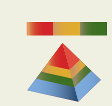
W–E cross section through the Hammerfest Basin 3D geological model, showing the Stø, Nordmela and Tubåen aquifers in blue, yellow and orange respectively.





Porosity / depth and porosity / permeability plots based on core and log data from the Hammerfest Basin.

Hammerfest Basin aquifer	Summary
Storage system	Half open
Rock Volume	1200 Gm^3
Net volume	790 Gm^3
Pore volume	120 Gm^3
Average depth	2400 m
Average net/gross	0,65
Average porosity	0,15
Average permeability	1-500 mD
Storage effeciency	3 %
Storage capacity aquifer	2500 Mt
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	



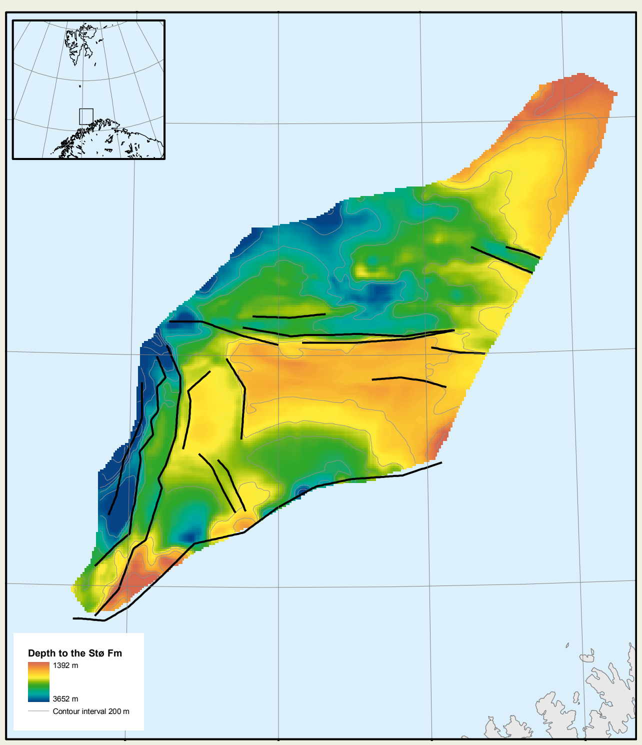
6.2 Storage options of the Barents Sea

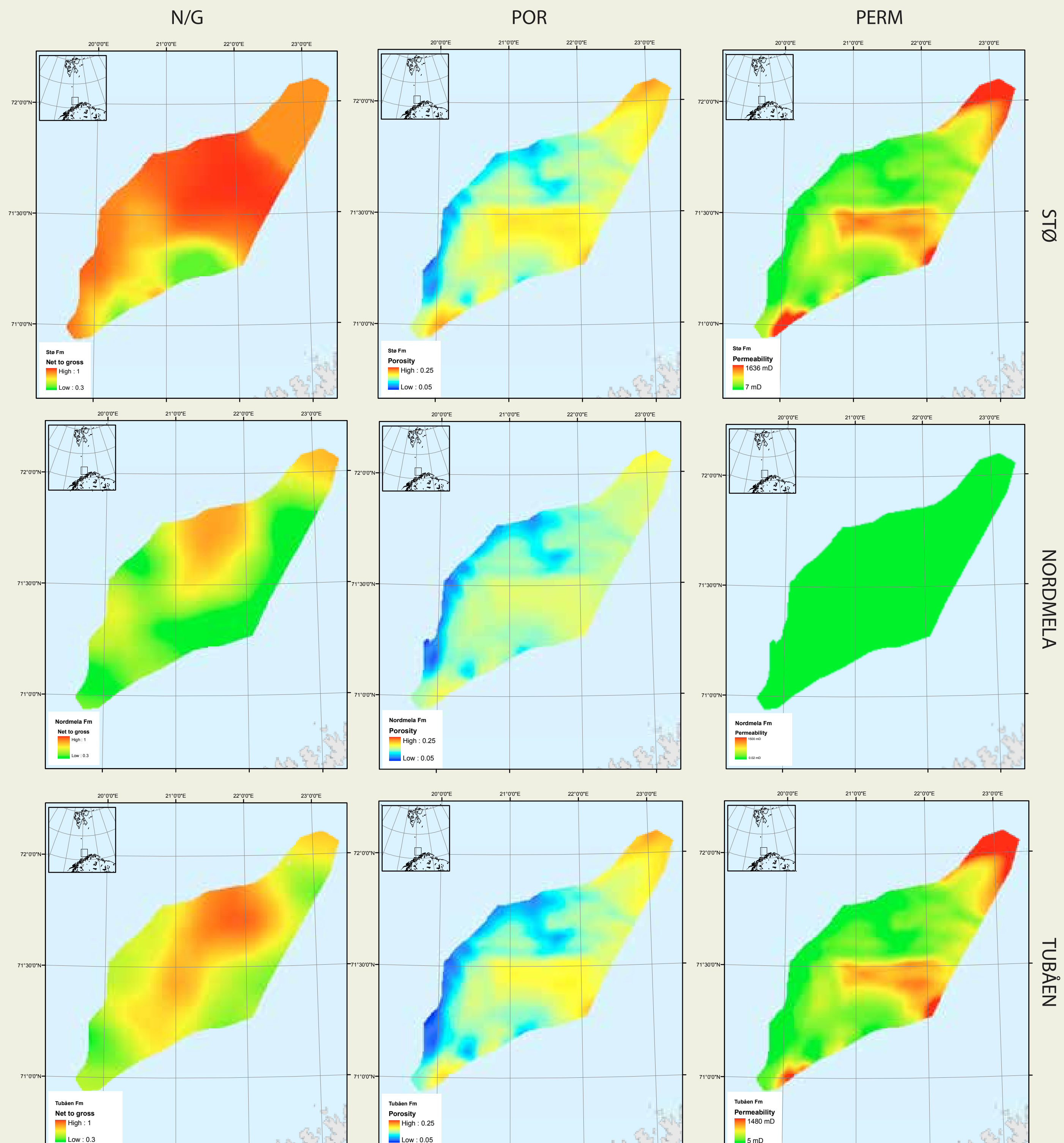
6.2.1 Saline aquifers

Hammerfest Basin

Somewhat lower salinity is indicated in the 7125/4-1 discovery and in some wells in the southwestern part. High salinity may cause problems for CO_2 injection due to salt precipitation near the wells. Another effect of salinity is that CO_2 is less soluble in high salinity brines than in sea water. The amount of CO_2 trapped by dissolution can then be relatively small.

Residual oil is widely distributed in the Jurassic Hammerfest Basin aquifer. Apparently, the mega-structures in the central part of the basin were filled with oil and gas at the time of maximum burial. Large volumes of gas have seeped out, whereas the oil is still remaining. The oil saturation is believed to be small. Theoretically, residual oil will reduce the effective permeability of the aquifer due to relative permeability effects.





Depth and property maps of the Stø Fm in the Hammerfest Basin.

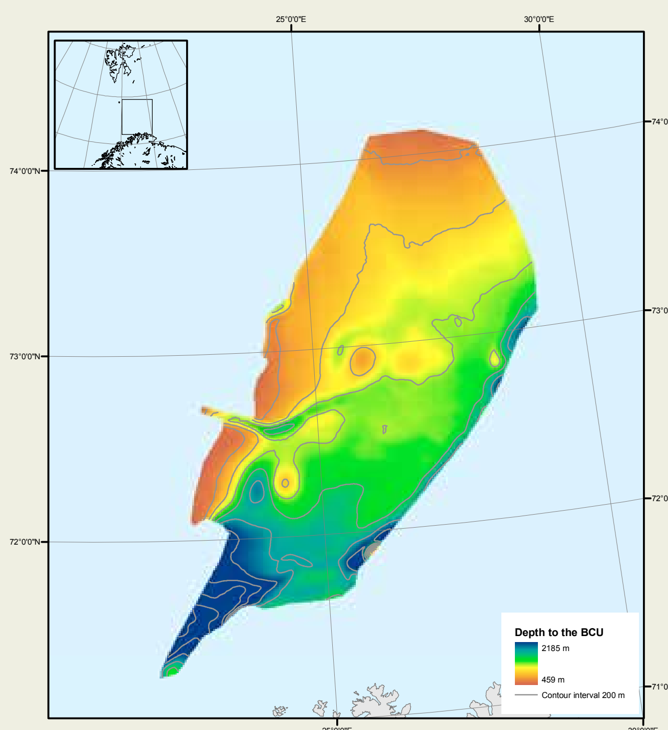
Bjarmeland Platform

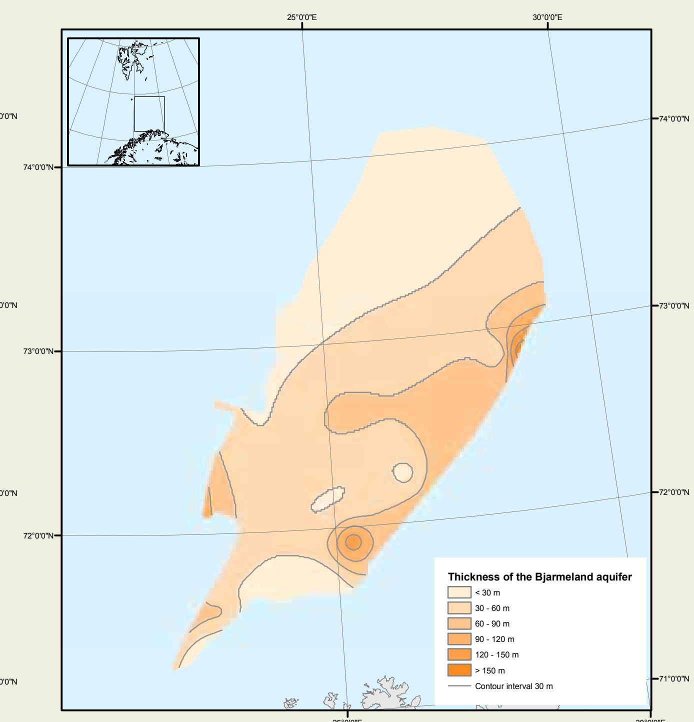
The Bjarmeland Platform is located north of 72°N and extends beyond 74°N, north of the Nordkapp Basin. Ten exploration wells and some shallow stratigraphic wells are drilled (by 2013) in the larger area of the Bjarmeland Platform including the western part towards the Loppa High.

A condensed Lower and Middle Jurassic section is developed in large areas in the central Barents Sea and Svalbard. In the Bjarmeland Platform the thickness of the Realgrunnen Subgroup decreases from around 100 m in the south to a few tens of metres in the north. The sedimentary facies are similar to the Tubåen, Nordmela and Stø Formations in the Hammerfest Basin. The boundary between the Hammerfest Basin aquifer and the Bjarmeland Platform aquifer is transitional.

According to well data, the best quality aquifer in the Bjarmeland Platform is found in the saddle area between the Nordkapp and Hammerfest Basins. The structuring of the Bjarmeland Platform is mainly related to salt tectonics which has resulted in domes, rim synclines and normal faults. In the northern part of the platform and towards the Loppa High and the Svalis Dome in the west, the Jurassic strata are eroded and Triassic sedimentary rocks outcrop at the seabed. The Quaternary thickness is generally less than 100 m along the subcrop lines.

The pore pressure is hydrostatic. It is likely that the degree of communication within the regional Bjarmeland Platform aquifer is not as good as within the upper part of the Hammerfest Basin aquifer (Stø Formation), due to reduced thickness and more heterolithic facies.





Bjarmeland Platform aquifer	Summary
Storage system	Half open
Rock Volume	1500 Gm^3
Net volume	1100 Gm^3
Pore volume	250 Gm^3
Average depth	1100 m
Average net/gross	0,72
Average porosity	0,23
Average permeability, mD	5-1000 mD
Storage effeciency	3 %
Storage capacity aquifer	4800 Mt
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	

Depth map and thickness map of the Bjarmeland Platform aquifer which consists of the Realgrunnen Subgroup.

Additional aquifers and Seal Capacity

Fruholmen Formation
The sandy parts of the Fruholmen Formation were deposited in large parts of the evaluated area in a fluvio-deltaic environment. The channelized sandstones have good reservoir properties along the basin margins where they are not too deeply buried. In the 7125/4-1 discovery of the Goliat field, these sandstones have trapped oil. The Fruholmen Formation is not evaluated as an aquifer with large injection potential, since the lateral connectivity is uncertain. On a regional scale, the formation may contribute to the aquifer volume of the overlying Realgrunnen Subgroup aquifer.

Snadd Formation
The sandstones in the Snadd Formation are separated from the sandy part of the Fruholmen Formation by a shale section (Akkar Member) which acts as a regional seal. Channelized sandy systems are widely distributed in the Snadd Formation, and can be mapped on 3D seismic data. Gas accumulations have been encountered in a few wells. The Snadd formation has not been evaluated for large scale CO_2 injection, due to poor lateral connectivity and because several of the undrilled channel sandstones may have a potential for hydrocarbons.

Kobbe Formation
The Kobbe Formation consists of marine shales, silts and deltaic sands, mainly fine to medium grained. The formation is developed as reservoir sandstones along the Troms-Finnmark fault zone as described in section 6.1. The Kobbe Formation constitutes the main reservoir in the Goliat Field. It has not been evaluated for large scale CO_2 injection because only a limited volume of the aquifer is buried at sufficiently shallow depth to maintain high porosity and permeability.

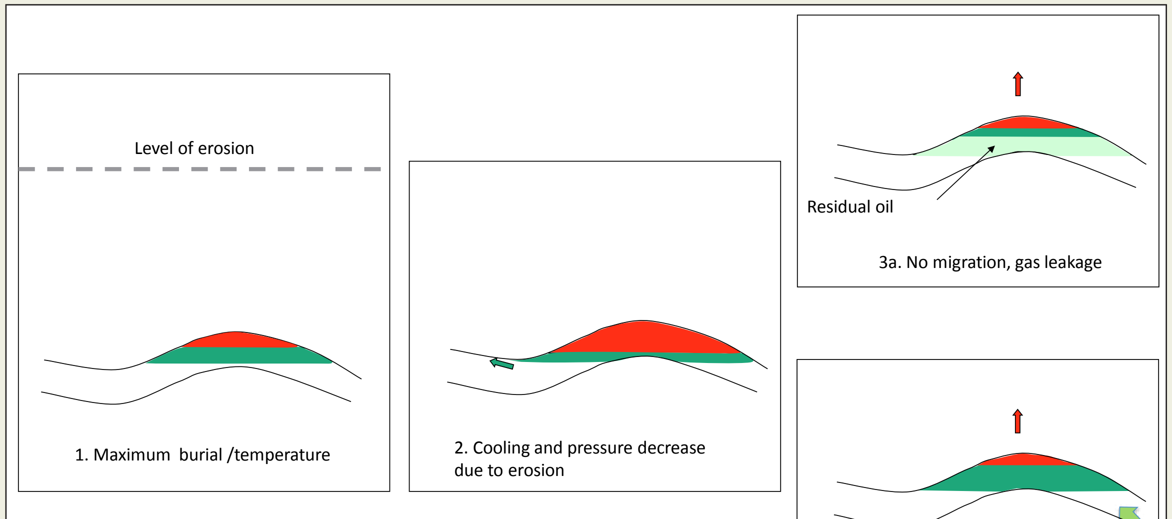
Late Paleozoic reservoirs
Late Paleozoic sandstones and carbonates and Early Triassic sandstones outcrop along the coast of Troms and Finnmark south of the evaluated area. Reservoir properties have been proved by a few exploration wells and stratigraphic cores. Because of limited seismic and well data coverage close to the coast, no attempt was made to map potential prospects for CO_2 storage.

Sealing properties

The Jurassic reservoirs in the Hammerfest Basin and Bjarmeland Platform have thick zones with residual oil and oil shows. The distribution of oil in the Hammerfest Basin indicates that the main structural closures in the central part of the basin were filled with oil and gas to spill point in the past. The gas has seeped or leaked out of the structures, while most of the oil may be preserved as residual oil down to the paleo oil-water contact. This setting is important for the evaluation of the properties of the sealing rocks. There are two important questions:

1. What is the typical rate of methane seepage from gas filled structures in the Barents Sea ?
2. What will be the rate of seepage from a plume of CO_2 in dense phase compared with a methane seepage ?

Methane seepage is commonly observed on seismic data and on the seabed at the NCS, in particular in areas of active hydrocarbon generation. In the studied area, gas chimneys and shallow gas are seen on seismic data in the Bjørnøya Basin and the western part of the Hammerfest Basin. In the Bjørnøya Basin, gas chimneys are commonly capped by gas hydrates and associated with gas flares (Chand et al. 2012). This shows that gas seepage is active today. The most active seepage takes place in the Bjørnøya Basin and the Bjørnøyrenna Fault Complex. Here, the source rocks generate hydrocarbons, and several traps are filled to spill point. This indicates that the rate of gas seepage is slower than, or in equilibrium with, the rate of gas generation. Consequently, this is interpreted as a slow process related to a time scale of hundreds or thousands of years, which is the time scale of interest for CO_2 sequestration. Concerning the sealing capacity for CO_2 compared to methane, the case of well 7019/1-1 shows that the Upper Jurassic seal in this well is capable of maintaining a 30 bar pressure difference between the 50% CO_2/methane mixture in the Jurassic reservoir and the methane with 10-15% CO_2 in the Cretaceous reservoir. Our interpretation is that in this well, the rate of seepage of CO_2 is significantly lower than for methane. These observations and interpretations are used in the characterization of the sealing rocks. The conclusion is that one can use the same guidelines for the Barents Sea as for the North Sea and the Norwegian Sea. There is, however, a concern that some types of cap rocks and some structural settings could have been influenced by the unloading and cooling processes to become more fractured, and consequently have a reduced sealing capacity.



Conceptual model for development of residual oil zone following deep erosion. Red colour is gas, green is oil.

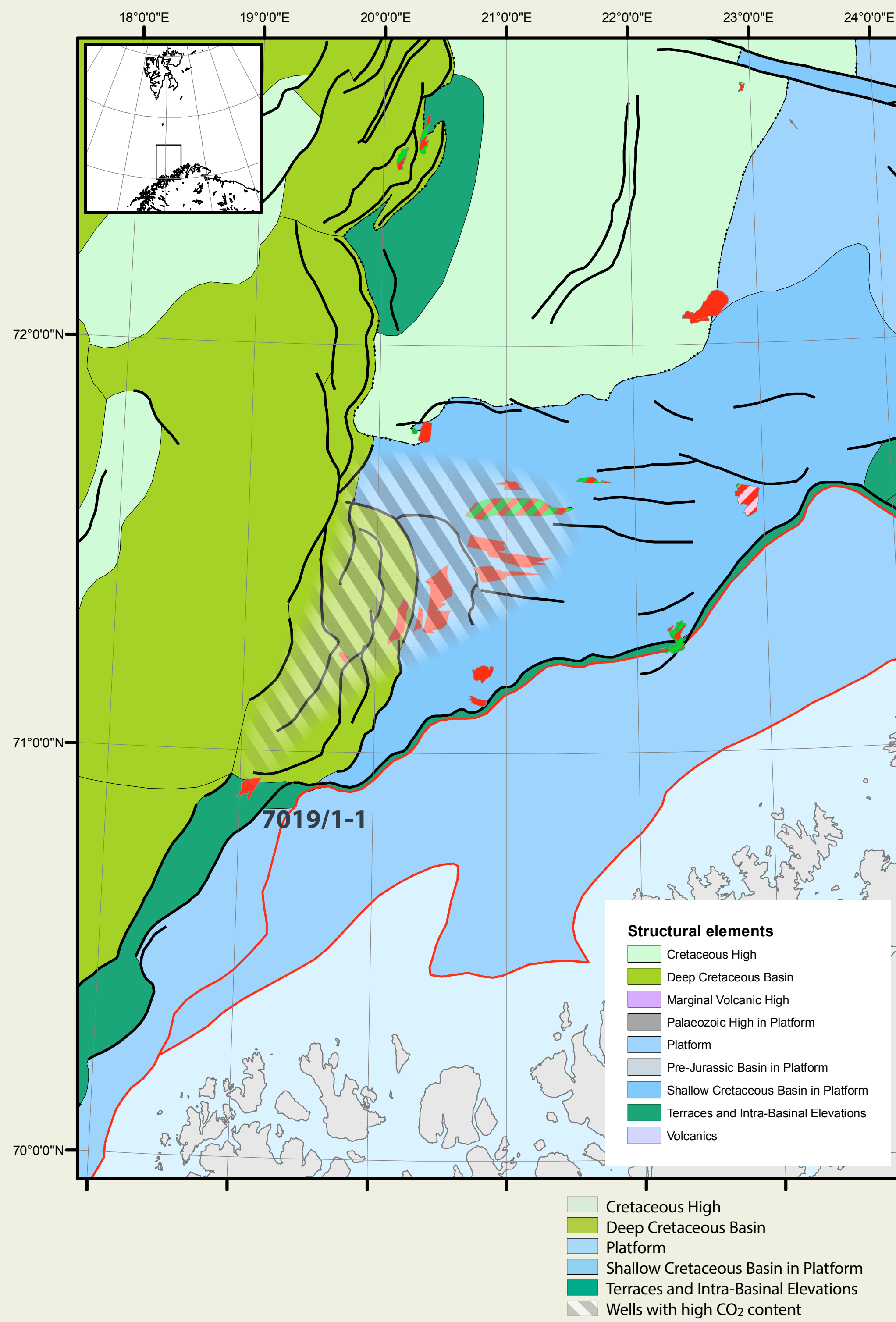
7019/1-1 discovery

The 7019/1-1 well was drilled by ENI in 2000 on a rotated, down-faulted block facing the Harstad Basin. The well encountered gas in two reservoir horizons, the Middle Jurassic Stø Formation and the Lower Cretaceous Knurr Formation. It was reported that the Jurassic Stø Formation contained at least 50% CO_2. The gas would not ignite during a short test. The CO_2 content in the Lower Cretaceous is less, roughly 15%. The permeability was low in the Stø Formation due to diagenesis and stylolitization at that depth, while some of the sandstone layers in the Lower Cretaceous 300 m shallower had good permeability and porosity.

A test was performed in the interval 2526 to 2563 m in the Stø Formation. The well flowed 606,000 m^3 gas per day (no liquid) from a 40/64 choke. Gas gravity was 1,133 (air = 1), CO_2 content 60 - 70%, and H2S content 6 - 13 PPM. The test was stopped during the clean-up phase due to the high CO_2 content.

A plot of the pore pressures shows that the difference in pressure between the Cretaceous and Jurassic gas gradients is almost 3 MPa (30 bar). There are no pressure data from the water zone in the Knurr Formation. Assuming a contact of 2250 m based on the log data, the pressure difference between the water zones is 0.5 MPa (5 bar). The Cretaceous gas gradient from the pressure plot is similar or slightly lower than the gas gradient in the Snøhvit field (0.018 bar/m), while the Jurassic gradient indicates a considerably heavier gas (more than 0.03 bar/m). These gradients seem to be consistent with a high CO_2 content in the Jurassic reservoir reported from the well test, while the proportion of CO_2 in the Cretaceous reservoir is interpreted to be similar to the Snøhvit area.

The pressure data show that the Upper Jurassic shale between the two reservoirs has good sealing properties. A large difference in CO_2 concentration between the two reservoirs implies that the Upper Jurassic seal is capable

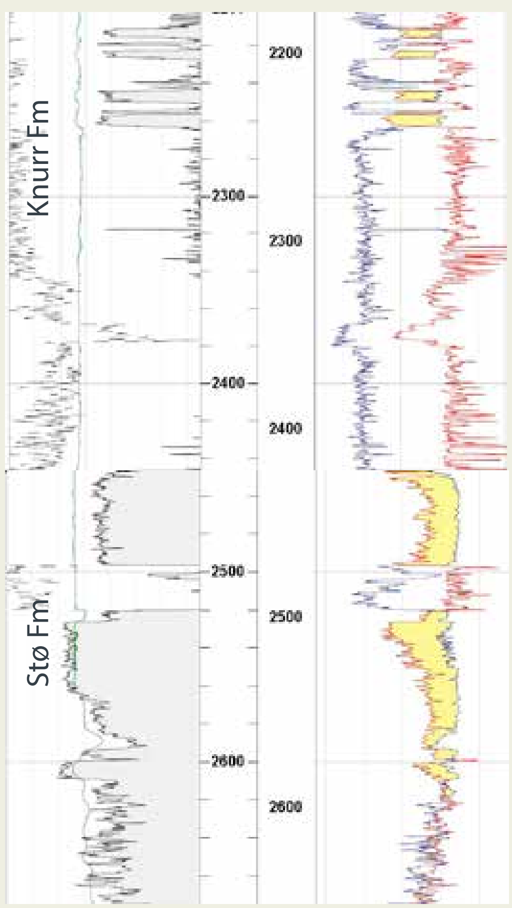


Seal capacity

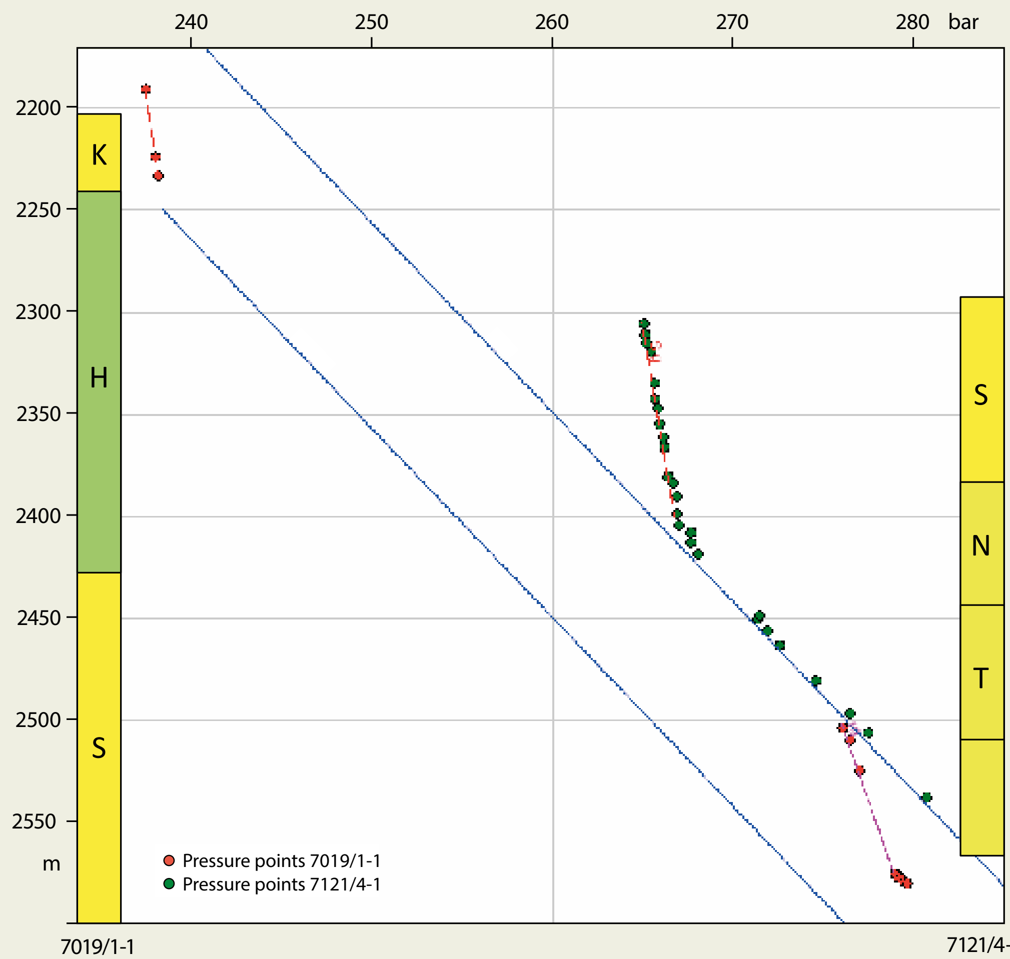
of containing CO_2 for a long period (geological time scale). The sealing capacity of the Upper Jurassic cap rock in the Barents Sea has been debated, because many wells in areas with net uplift show evidence that methane gas has leaked from the reservoirs. The amount of erosion of the overburden in the typical Hammerfest Basin wells is estimated to be less than in 7019/1-1. Consequently, other factors than net uplift are also considered important for the evaluation of seal capacity.

The pressure plot also shows that the pore pressure in the water zone is lower in 7019/1-1 than in the Snøhvit area. Similarly, slightly lowered water pressures are observed in block 7120/12. One possible explanation for this is that the salinity of the aquifer brine is lower in these areas.

7019/1-1



Gammalog *Density - neutron log*



Plot of measured pore pressure in the 7019/1-1 well compared with 7121/4-1 in Snøhvit. Upper blue line: Average water gradient in the Snøhvit area. Lower blue line: Interpreted water gradient in the Cretaceous section of 7019/1-1. Red lines: gas gradients. Color bars show the formation depth in each well. K – Knurr, H – Hekkingen, S- Stø, N – Nordmela, T- Tubåen Formations. Vertical scale: Depth below sea level.

Storage capacity Snøhvit area

The Snøhvit Field is located in the central part of the Hammerfest Basin in the Barents Sea. The water depth is 330 m, and the reservoirs are found in the Stø and Nordmela Formations (Early and Middle Jurassic age), at depths of approximately 2300 m. The hydrocarbon phase in the Snøhvit main field is largely gas with minor condensate with a 10-15 m thick oil leg.

The Stø Fm is mainly shallow marine, while the Nordmela Fm was deposited in a coastal environment. Maximum burial of the reservoirs was approximately 1000 m deeper than the present depth, resulting in massive quartz cementation of the sandstones and a poorer reservoir quality below 2900-3000 m. The reservoir quality in the fields is fairly good. Porosity as high as 20% and permeability at 700 mD have been interpreted on logs in the best zones of the Stø Formation. The Snøhvit field developments include the Askeladd and Albatross structures. These structures have reservoirs in the same formations. In addition the 7121/4-2 Snøhvit North discovery contains gas and condensate which is still not in production.

The natural gas produced from the fields contains about 5-8% CO_2. CO_2 is separated from the gas at Melkøya in an amine process. Compressed CO_2 in liquid phase is returned to the field in a 153 km long pipeline, to be stored 2500 m below sea level.

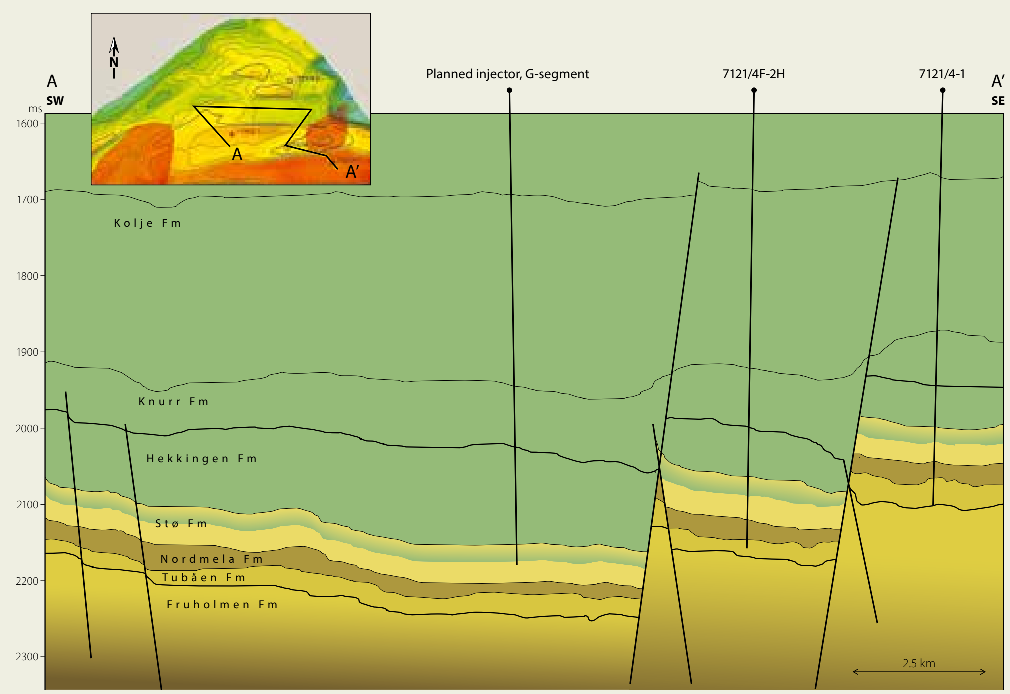
CO_2 storage at the Snøhvit Field started in 2008, and CO_2 was until April 2011 injected in well 7121/4F-2H in the Tubåen Fm, which is dominated by fluvial sandstone. After a while the pressure built up faster than expected, and an intervention was performed to avoid fracturing of the seal. In 2011, the injection in the Tubåen formation was stopped, and the shallower Stø formation was perforated as the new storage formation for CO_2.

After the intervention in 2011, all CO_2 from the Snøhvit Field has been injected in the water zone of the Stø Formation. Until 2013 a total of 1.1 Mton CO_2 has been injected in the Tubåen Fm and 0.8 Mton in the Stø Formation.

In contrast to the Tubåen Formation, the Stø Formation is in pressure communication with the gas producers on Snøhvit, and no significant pressure build-up is expected in the injection site. However, a new injection well for CO_2 is considered in segment G (SW-SE profile) to prevent future migration of injected CO_2 into the natural gas of the main Snøhvit Field. This segment is located between the Snøhvit main structure and Snøhvit North.

The new well will inject into the Stø Formation. In order to investigate the storage potential for the new well, the minimum and maximum pore volumes with good communication to the planned well area have been estimated. The maximum connected pore volume, “Snøhvit 2800”, represents the pore volume of the water zone in the Stø, Nordmela and Tubåen Formations in the Snøhvit and Snøhvit north area down to 2800 m.

Map showing the location of the Snøhvit Field, the pipeline and the Melkøya terminal. Blue circle indicates main study area for the CO_2 storage aquifer.



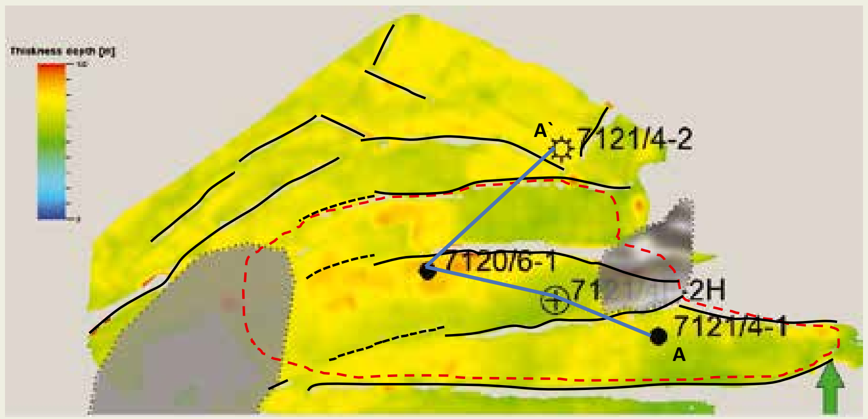
SW-SE profile showing the geometry and thickness –variations in the Snøhvit area. Location of CO_2 injection is illustrated. Sealing formations indicated in green color. 7121/4F-2H is the current CO_2 injector.

6.2.1 Saline aquifers

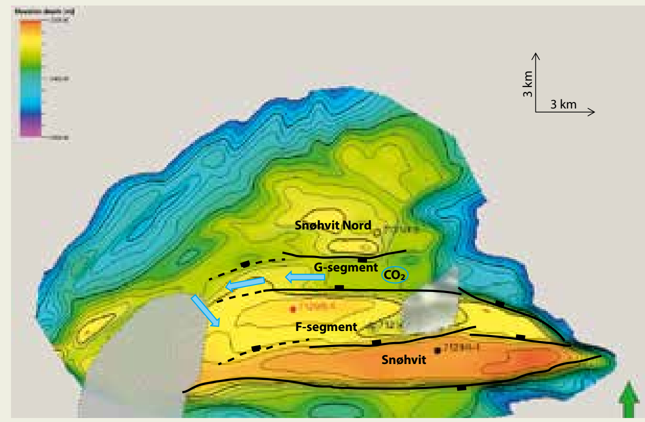
Storage capacity Snøhvit area

2800 m was selected because permeability deteriorates below this depth. The minimum pore volume, "Snøhvit central Stø", was calculated as the pore volume of the Stø Formation in the areas surrounding the G segment. This is interpreted to represent a water volume where good communication to the new injection site is very likely. Communication through major faults is not expected where the throw is larger than the thickness of the Stø Formation, but in this minimum case, structural ramps create corridors of communication within the Stø Formation.

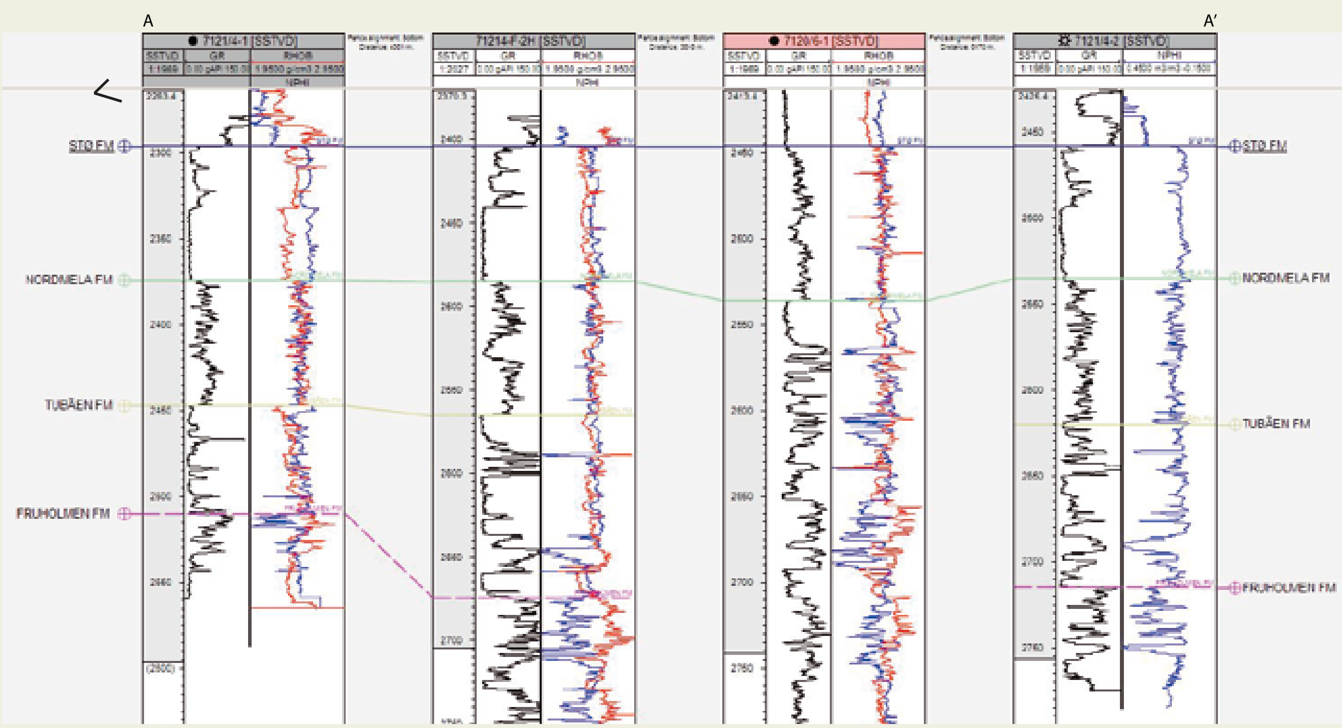
The calculation of maximum and minimum pore volumes resulted in 6400 Mm^3 for the "Snøhvit 2800" case and 680 Mm^3 for Snøhvit central Stø. These pore volumes indicate that there are sufficient aquifer volumes available to support the planned CO_2 injection in the Stø Formation at Snøhvit.



Stø Fm thickness map. Grey areas indicate shallow gas. AA' shows the location of the log correlation profile.



Stø depth map where blue arrows illustrate a possible CO_2 migration after injection in the G segment. Black solid lines illustrate faults with big throw, while black dotted lines indicate where the throw dies out.grey polygons shows location of shallow gas.



Log correlation panel with gamma and neutron/density, flattened on the Stø Fm. Location of profile is shown in the Stø Fm thickness map.

Snøhvit Central Stø	Summary
Storage system	Half open
Rock Volume	6.1 Gm^3
Net volume	4.8 Gm^3
Pore volume	680 Gm^3
Average depth	2320-2400m
Average net/gross	0,8
Average porosity	0,14
Average permeability	300 mD
Storage effeciency	5 %
Storage capacity aquifer	24 Mt
Reservoir quality	
capacity	3
injectivity	2
Seal quality	
seal	3
fractured seal	3
wells	2
Data quality	
Maturation	

6.2.1 Saline aquifers

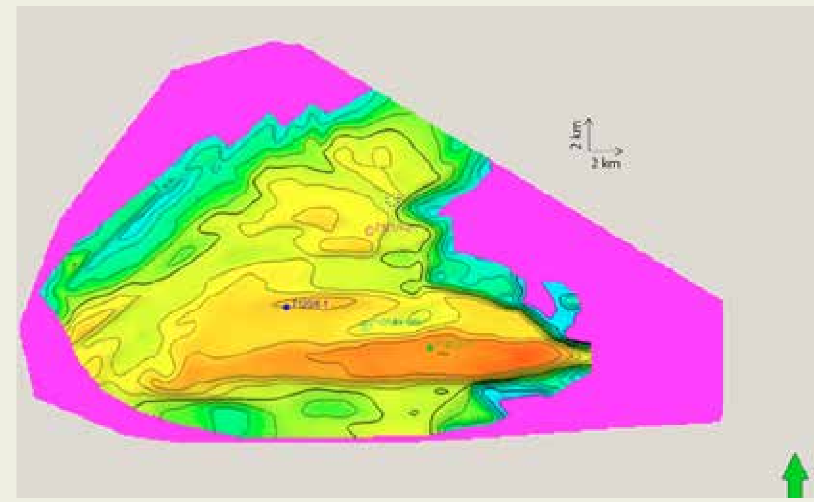
Storage capacity Snøhvit area

The expected flow direction for the injected CO_2 will be towards the west. As seen in the well section profile, thick packages of shale seal the Stø Formation and are expected to prevent vertical leakage of CO_2. Seepage of gas along the faults is regarded as a risk, in particular in the areas with shallow gas clouds. Monitoring of the injection (section 9) will be important to control the injection and the movement of the CO_2 through time. Data quality in the area is good, except in the areas with gas clouds. There is sufficient experience with injection in the Stø Formation to conclude that the area has been matured as a storage site.

In addition to the CO_2 storage potential related to the ongoing injection in the Stø Fm, interpretation and calculations were performed to evaluate the storage potential in the Snøhvit Jurassic aquifer consisting of the Stø, Nordmela and Tubåen Formations above the spill point for the main Snøhvit Field. This pore volume case is called the Greater Snøhvit area. It may represent the pore volume which has been filled with hydrocarbons in geological history and is analogous to the Greater Albatross and the Greater Askeladd areas. The results show a pore volume of 4100 Mm^3.

All parameters used in the calculations and presented in the table, are based on well information. Key wells are 7121/4-1, 7121/4-2, 7120/6-1 and 7121/4F-2H. Porosity and permeability trends and input to depth conversion were derived from several wells in the area. The reservoir quality varies in the different formations in the "Snøhvit 2800" case. The best quality is seen in the lowermost part of the Stø Fm, but more shaly zones in the middle part of the formation most likely act as an internal barrier or baffle for injected CO_2.

Data quality is good, as indicated in the table. Due to possible conflicts with the petroleum activity, maturation is shown in blue colour. This represents a theoretical volume of the CO_2 storage potential calculated for the Jurassic aquifer. Uncertainty in the calculation is mostly related to interpretation, depth conversion and a simplified approach to the distribution of the aquifer.



Depth map of the Stø Fm, where the pink surface at 2800 m represent the base of the Jurassic aquifer.

Snøhvit 2800m	
Storage system	Half open
Rock Volume	89 Gm^3
Net volume	54 Gm^3
Pore volume	6.4 Gm^3
Average depth	2404-2800m
Average net/gross	0,6
Average porosity	0,12
Average permeability	150 mD
Storage effeciency	2 %
Storage capacity aquifer	90 Mt
Reservoir quality	
capacity	3
injectivity	2
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	

Storage in depleted and abandoned fields

The Snøhvit development includes several gas discoveries within the greater Snøhvit, Askeladd and Albatross structures. The potential of CO_2 storage after abandonment of the smaller of these discoveries was calculated from the pore volume of their gas zones. It was assumed that after production there will remain residual gas and minor amounts of free gas and that injected CO_2 can occupy 40 % of the initial pore volume. Based on this assumption, which is regarded as conservative, the storage capacity of the abandoned field is 200 Mtons.

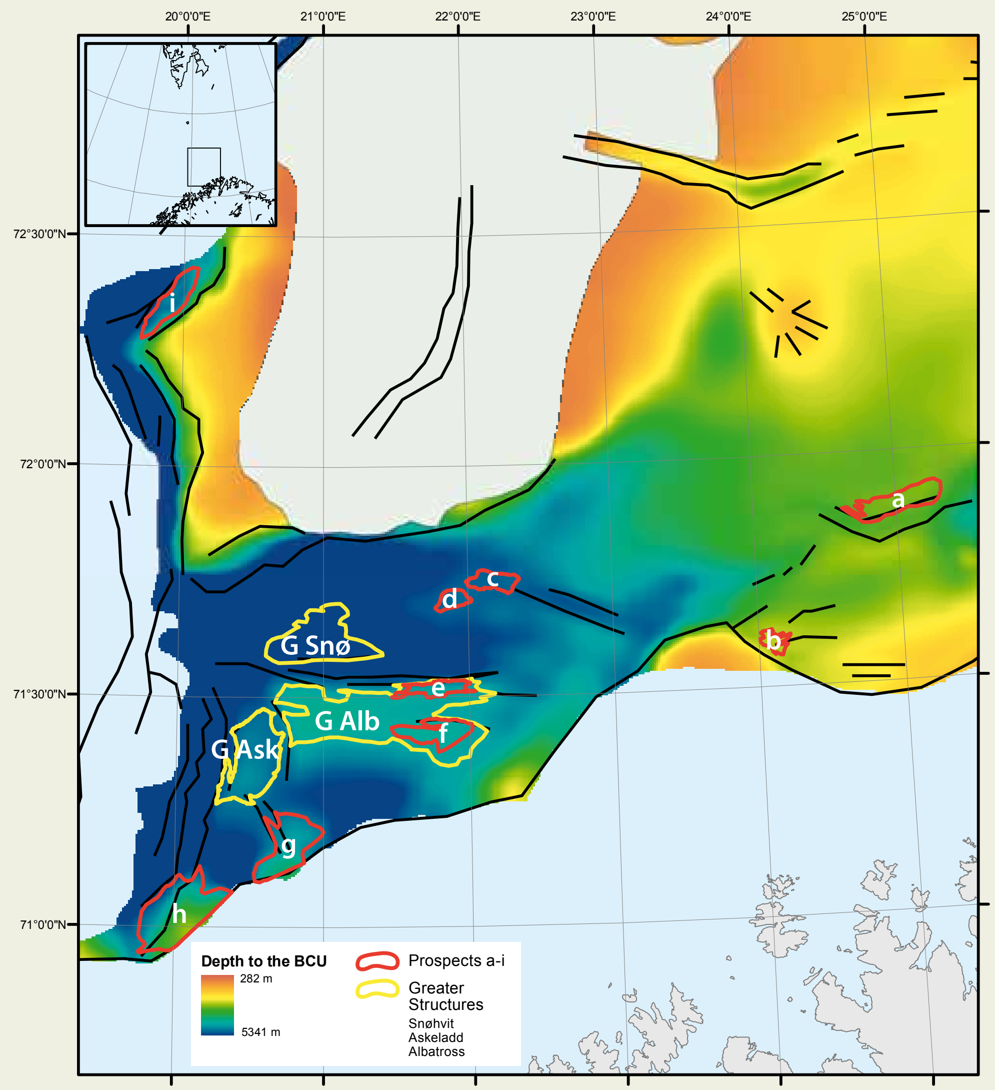
6.2 Storage options of the Barents Sea

6.2.2 Prospects

Introduction

The preferred locations for CO_2 sequestration in the Barents Sea are structural traps which have been proved to contain brine and no moveable hydrocarbons. In the future, depleted and abandoned gas fields can also be developed as storage sites.

Nine structures (named prospects A to I) within the aquifer systems of the Realgrunnen Subgroup have been mapped and characterized by their storage capacity, injectivity and seal quality. The storage capacity of a structural trap can be limited by the pore volume of the structural closure and by the pore volume and permeability of the connected aquifer. The evaluation of Prospect A is based on a simulation model that takes these factors into account. Evaluation of the other prospects is based on pore volumes of the structural closures and a storage efficiency factor based on the geological conditions for each prospect. Pore volumes are calculated based on mapped surfaces, porosity and net/gross maps. For the reservoirs in the Hammerfest Basin, average permeability is indicated in the tables for the Nordmela Formation (low values) and Stø Formation (high values). Provided that the CO_2 will be injected in the Stø Formation, injectivity is considered to be medium to high in most prospects. The seal quality is characterized by the thickness of the primary seal (the Hekkingen and Fuglen Formations) and the faulting intensity of the reservoir. Seismic anomalies indicating shallow gas were also taken into account. Leak-off tests indicate that the typical fracturing pressures in the Barents Sea are somewhat lower than in the North Sea and the Norwegian Sea. A prospect simulation was run with a maximum pressure build-up of 30 bar. Maturation of prospects which may be of interest for petroleum exploration is considered to be low (blue colour). Prospects which have been drilled and that proved only brine or brine and residual oil, are considered more mature (green colour). The yellow colour is applied to prospects which are approaching a development plan, such as in the Snøhvit area. These prospects require more in-depth studies than what was possible in this study. In addition to the prospects, the Greater Snøhvit, Greater Askeladd and Greater Albatross areas are defined. These areas represent structural closures with several culminations. Some of the culminations are hydrocarbon-filled, and some of them have only residual hydrocarbons. There are indications in the wells that these greater structural closures have been filled with hydrocarbons at the time of maximum burial. CO_2 injected in these is not likely to migrate out.

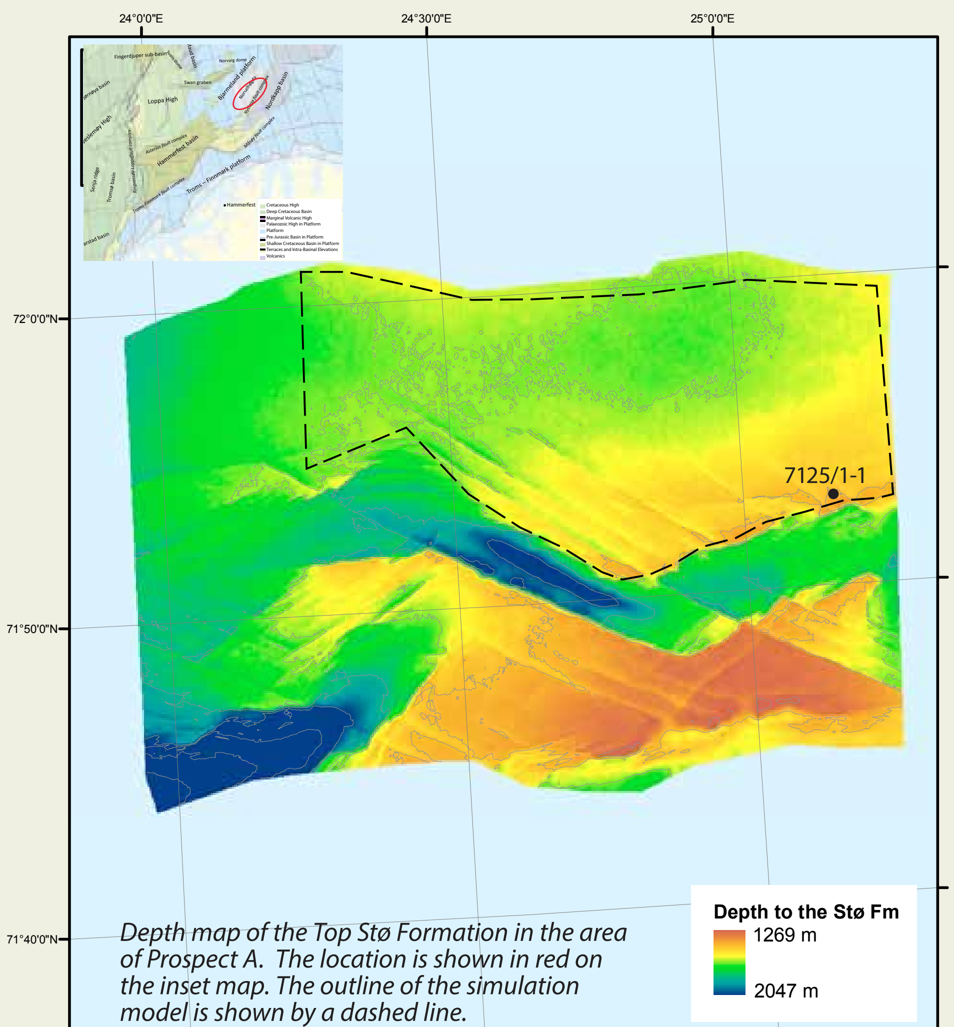


Location of evaluated prospects (red) and large structural closures (yellow).

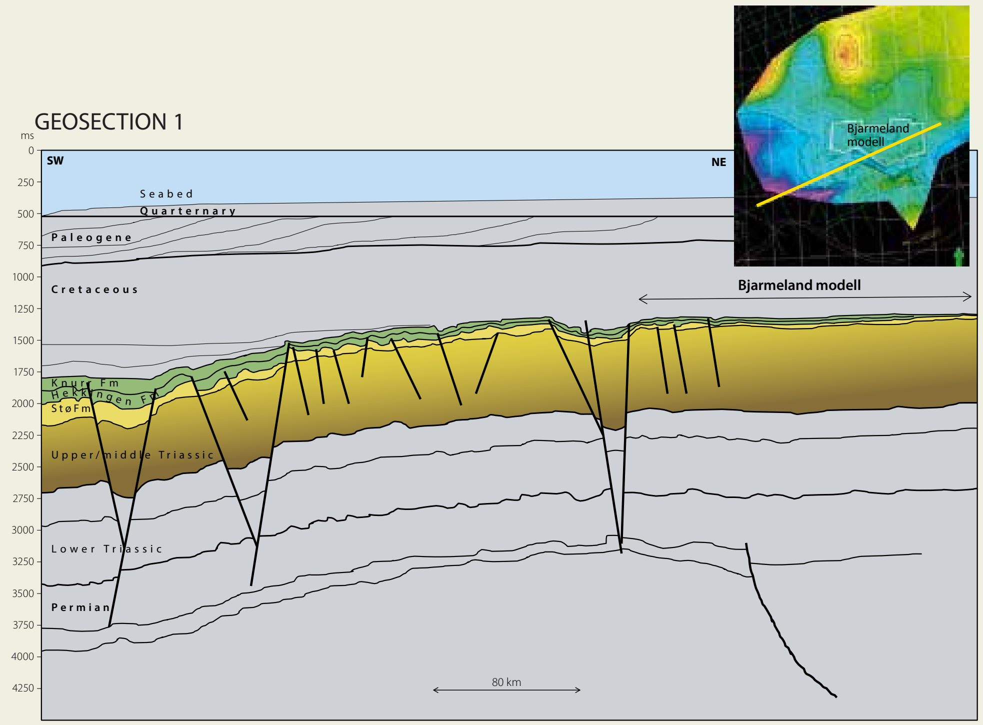
6.2.2 Prospects

Bjarmeland Platform prospects

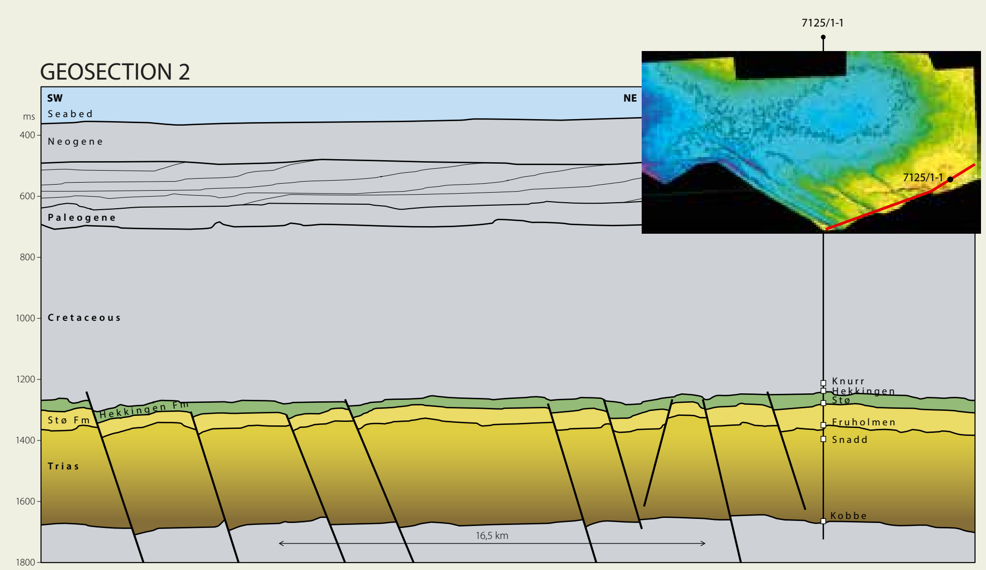
Prospect A is defined as a closed structure located east of the Loppa High in the southernmost part of the Bjarmeland Platform, west of the Nysleppen Fault Complex. The structure is drilled by the7125/1-1 well. 1 m oil saturation was encountered in the top of the main reservoir, with a residual oil zone below. The main reservoir zone evaluated for CO_2 storage is the Stø Formation with a thickness of 130 m in well 7125/1-1. The Stø Formation is part of the Realgrunnen Subgroup, which thickens westwards into the Hammerfest Basin. Depth to top of the interpreted structure is about 1400 m. The Stø Formation overlies a thick Triassic succession of the Ingøydjupet Subgroup. No shallow gas indications have been observed along the boundary faults to the south. However, the residual oil observed in the exploration well 7125/1-1 indicates that leakage or seepage has taken place. As discussed in section 6.2.1, this seepage is believed to be a slow process, and the seal risk is characterized as relatively low. The geomodel of the Realgrunnen Subgroup is based on interpretation of 3D seismic data and data from the exploration well. The geomodel is developed into a reservoir simulation model in order to study the behaviour of CO_2 injection in this reservoir with brine and residual oil.



Depth map of the Top Stø Formation in the area of Prospect A. The location is shown in red on the inset map. The outline of the simulation model is shown by a dashed line.



Structural setting of prospect A.



The Realgrunnen aquifer is shown as a thin yellow layer below the green primary seal of the Hekkingen formation.

Bjarmeland Platform prospects

The simulated CO_2 injection well is located down dip with plume migration towards south-southeast, but alternative locations with different injection rates have been simulated.

The injection period is 50 years, and simulation continues for 1000 years to follow the long term CO_2 migration effects. CO_2 will continue to migrate upwards as long as it is in a free, movable state. Migration stops when CO_2 is permanently trapped, by going into a solution with the formation water or by being residually or structurally trapped (mineralogical trapping is not considered here).

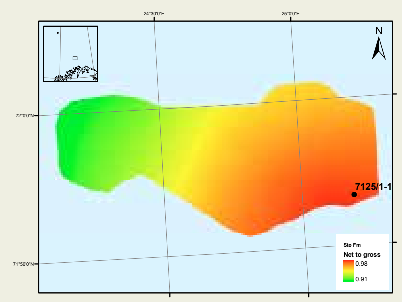
Confinement of CO_2 requires prevention of migration of the CO_2 plume to potential leakage areas. For Prospect A, the fault/graben system to the west and south will seal the structure in that direction. The structurally highest point on the Bjarmeland structure is located along this fault.

To obtain confinement of CO_2, the injection pressure must not exceed fracturing pressure. The fracturing pressure increases with depth. The depth of the maximum acceptable pressure increase was calculated for the shallowest point of CO_2 plume migration during the period of injection (1400m). The structure is hydrostatically pressured. Fracture gradients established from the North Sea and Norwegian Sea indicate that a maximum acceptable pressure increase of 75 bar could be applied at that depth. However, as discussed in section 6.2.1, the fracture gradients in the eroded regions of the Barents Sea could be lower, and the effects of a maximum pressure of 30 bar were also investigated. The pressure build-up depends on the volume and connectivity of the surrounding aquifer. The aquifer used for modelling covers the area of the thick Stø Formation and has excellent reservoir properties. Further north in the Bjarmeland Platform, the Realgrunnen Subgroup is thinning, but good porosity and permeability is developed in a large area.

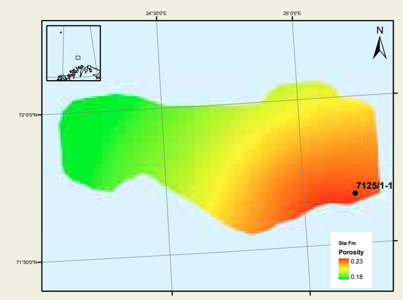
The volume of the active aquifer system is conservatively estimated to be 25 times the volume of the geological model, and this volume is added to the simulation model volume.

In the simulation model, CO_2 injection was stopped when the plume reached the eastern boundary of the model. This boundary was regarded as the spill point of the structure. East of this boundary there is only seismic coverage by 2D lines, and the spill point is regarded as conservative.

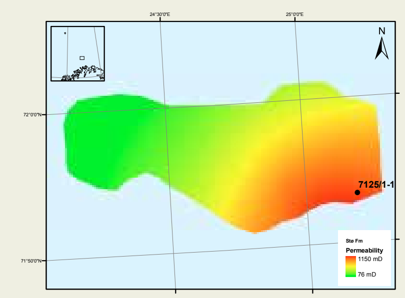
Prospect A	
Storage system	Open
Rock Volume	55 Gm^3
Net volume	52 Gm^3
Pore volume	10 Gm^3
Average depth	1525 m
Average net/gross	0,94
Average porosity	0,20
Average permeability	500 mD
Storage effeciency	2.5 %
Storage capacity aquifer	176 Mt
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	



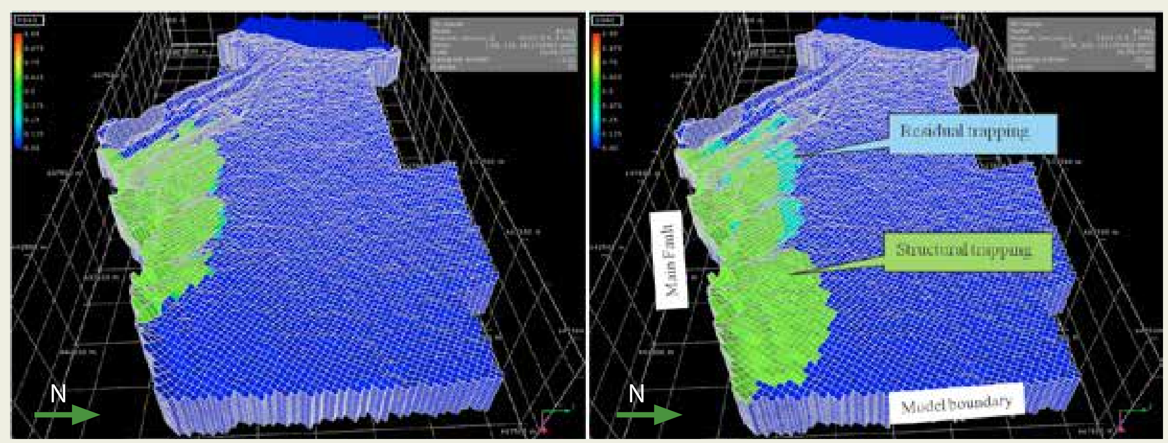
Net/Gross values from 0,97-0,92



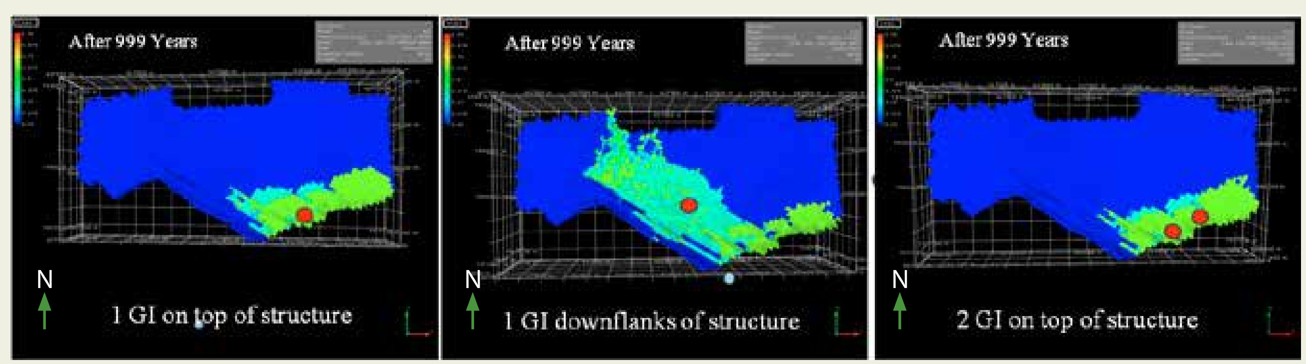
Porosity varies from 20-24 %



Permeability is 1000 mD in the well



Distribution of injected gas (green) after end of injection (50 years), and after 1000 years of storage. North to the right.



Distribution of injected gas (green) after 1000 years of storage, depending on location of injector well.

6.2.2 Prospects

Bjarmeland Platform prospects

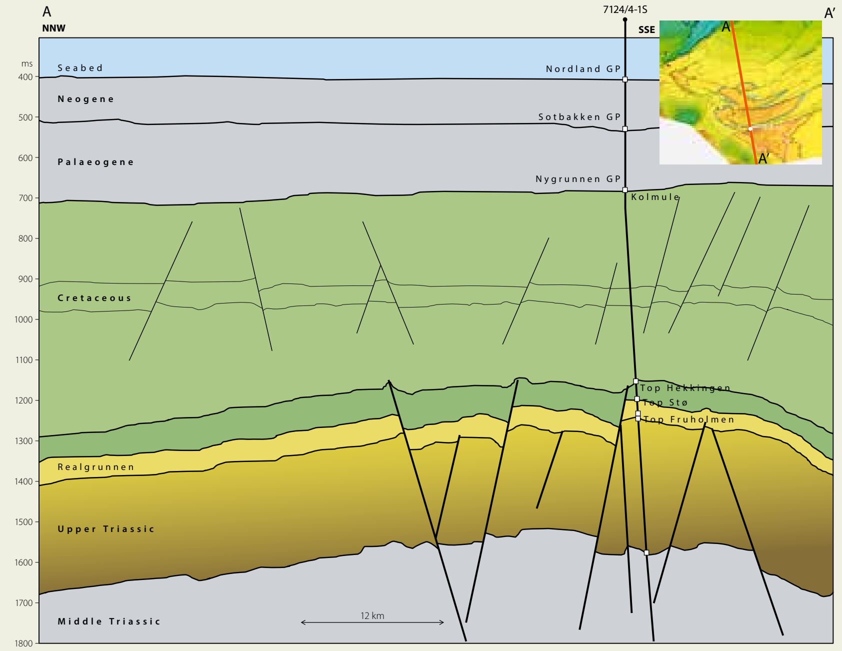
Prospect B is located in the transition zone between the Hammerfest and the Nordkapp Basins, about 70 km north-east of the Goliat Field. It is defined at a NW-SE trending fault block with a structural closure. The main reservoir is in the Stø Formation (Realgrunnen Subgroup). The structure has been drilled by the well 7124/4-1 S, where the Stø Formation was encountered at a depth between 1259 and 1312m. The formation consists of a 52m thick homogeneous unit of mainly fine to medium grained sandstone with good reservoir properties. The well was water-bearing and there are no indications of hydrocarbons. Interpretation of the prospect is based on good 3D seismic data and data from the 7124/4-1S well. The 3D seismic data set does not cover the spill point SE of the structure, which means that the calculated volume is conservative.

The geosection illustrates the geometry of aquifers (yellow) and sealing formations (green). The primary seal is the Hekkingen Formation, and thick Cretaceous shaly sediments act as a secondary sealing layer.

The reservoir quality and storage capacity is summarized and illustrated in the table below. The reservoir properties used in the evaluation are based on the 7124/4-1S well. Prospect B is defined as a half open structure, where the boundary towards the west is structurally closed by a major fault and a graben structure. The structure is segmented by several smaller WSW-ENE trending faults.

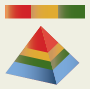
Approximately 50 metres of Hekkingen shale overlie the sand-rich Stø Formation. The faults cutting through the Stø Formation seem to terminate in the Hekkingen shale, hence the seal risk is considered to be relatively low.

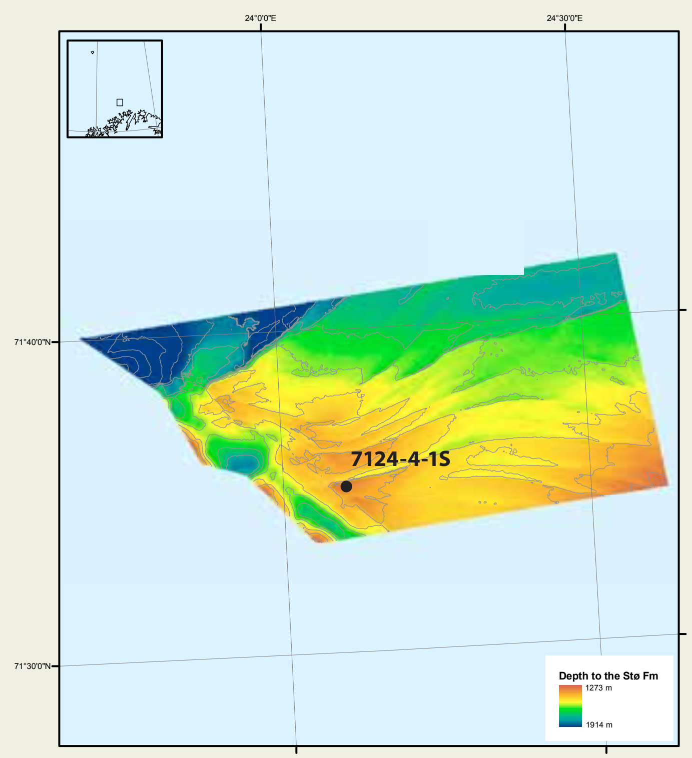
The structure consists of two main segments. If a CO_2 injector is placed in the northern segment, the CO_2 plume can migrate and spill into the structurally higher segment to the south. The calculated CO_2 storage capacity for both segments is 19 Mt based on a constant thickness of the Stø Formation.



NNW-SSE profile showing the geometry of aquifers (yellow) and sealing formations (green) in the simulation model.

Prospect B	
Storage system	Half open
Rock Volume	4.0 Gm^3
Net volume	3.9 Gm^3
Pore volume	900 Mm^3
Average depth	1260 m
Average net/gross	0,98
Average porosity	0,23
Average permeability	500 mD
Storage effeciency	3 %
Storage capacity aquifer	19 Mt
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	



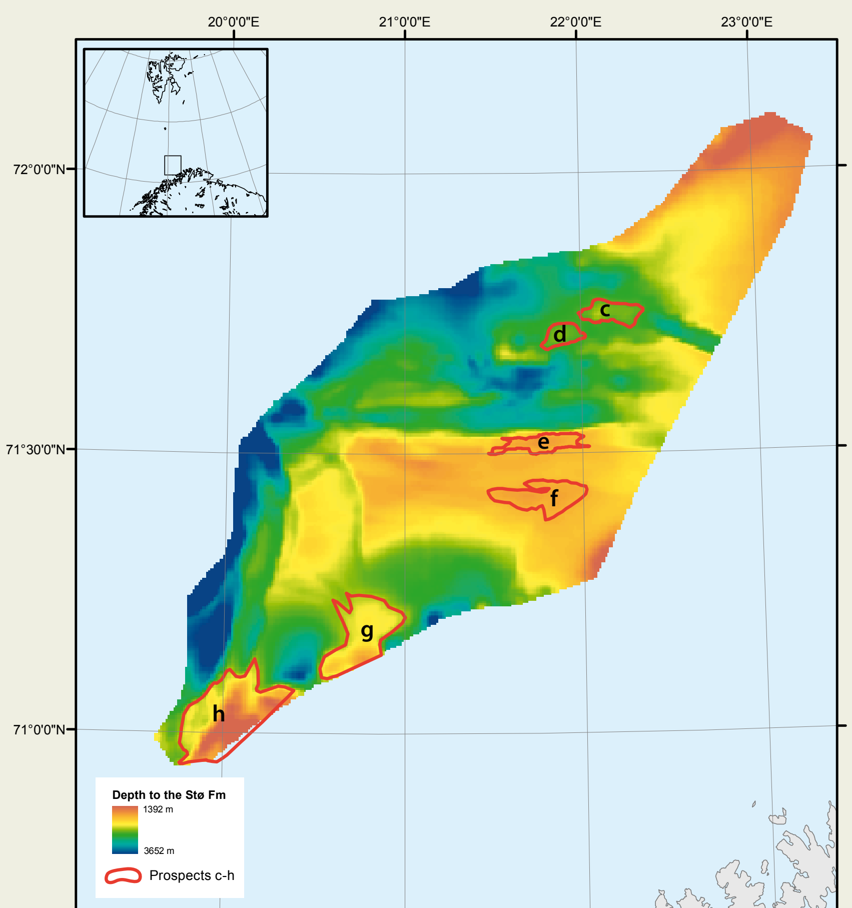


Hammerfest Basin prospects

The Hammerfest Basin aquifer is classified as a half open aquifer, comprising the Tubåen, Nordmela and Stø Formations. The aquifer is bounded by the Troms-Finnmark and Ringvassøy-Loppa Fault Complexes in the south and west, and by the Asterias Fault Complex towards the Loppa High. The permeability is highest in the Stø Formation and lowest in the Nordmela Fm, as reflected in the permeability range in the table. The total aquifer volume is significantly higher than the volume of separate prospects, and the lateral connectivity in the Stø Formation is good. Consequently, the calculation of storage capacity in the Stø Formation in the prospects is in most cases based on the assumption that the pore volume of the trap is the limiting factor.

Prospects C and D

Prospects C and D are structurally defined traps with 4-way closures. No major faults and no signs of gas leakage were observed. The interpretation is based on 2D seismic data with poor coverage; consequently the geometry and size of the structural closures are uncertain. Prospect C has several minor faults cutting through the reservoir. The faults are not believed to offset the primary seal completely, but a lower fractured seal quality is indicated. Well 7122/4-1 was drilled on prospect C and proved a brine filled structure with hydrocarbon shows.

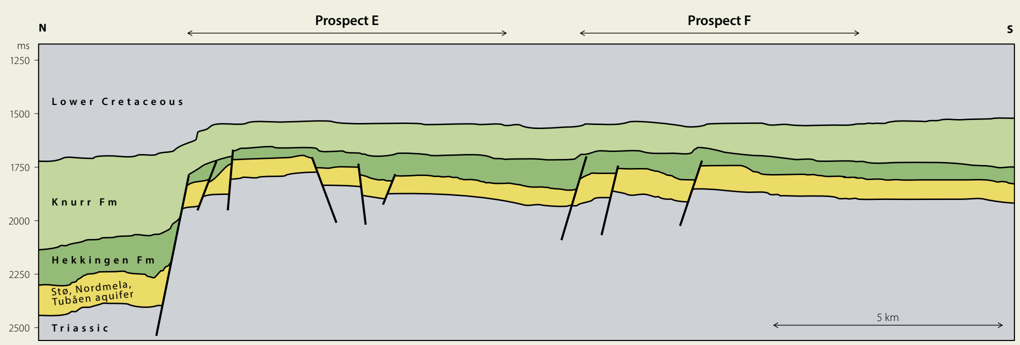


Prospect C	
Storage system	Open
Rock Volume	1.94 Gm^3
Net volume	1.79 Gm^3
Pore volume	280 Mm^3
Average depth	2400 m
Average net/gross	0,92
Average porosity	0,15
Average permeability	1-170 mD
Storage effeciency	10 %
Storage capacity aquifer	19 Mt
Reservoir quality	
capacity	1
injectivity	3
Seal quality	
seal	3
fractured seal	2
wells	3
Data quality	
Maturation	

Prospect D	
Storage system	Open
Rock Volume	1.18 Gm^3
Net volume	1.25 Gm^3
Pore volume	180 Mm^3
Average depth	2400 m
Average net/gross	0,97
Average porosity	0,15
Average permeability	1-150 mD
Storage effeciency	10 %
Storage capacity aquifer	12 Mt
Reservoir quality	
capacity	1
injectivity	3
Seal quality	
seal	3
fractured seal	3
wells	3
Data quality	
Maturation	

Hammerfest Basin prospects

Prospects E and F
Prospects E and F are interpreted as 4-way closures within the greater Albatross area. The closure of prospect E is fault-bounded to the north. The throw of the fault is larger than the thickness of the primary seal; hence the seal quality is rated lower than the neighbouring structure, prospect F. Prospect E was drilled by well 7221/5-3, which encountered brine with hydrocarbon shows in the Stø and Tubåen Formations. Prospect F has not been drilled and is regarded as a hydrocarbon prospect. The closure is partly bounded by faults with small throws. No gas clouds or other signs of gas leakage have been observed in the seismic data. Prospect F can be an interesting candidate for CO_2 storage if water-filled. The storage capacities are based on the volume above spill point. Prospects E and F are located between Snøhvit and Melkøya, only a few km away from the pipeline.



Prospect G
Prospect G is defined as a large structural closure with several culminations. The structure is bounded by the Troms-Finnmark Fault Complex, and a deep spill point depends on a fault seal towards the Triassic rocks in the Troms-Finnmark Platform. Two wells have been drilled within the structural closure, 7120/12-5 was dry, 7120/12-3 was a gas discovery in the Stø Formation. South of the structure, 7120/12-1 encountered brine with hydrocarbon shows, and 7120/12-2 proved gas/condensate. The capacity of the trap is based on the volume above the spill point, but with a low storage efficiency because injected CO_2 plumes must not interfere with the accumulations of natural gas.

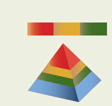
Prospect H
Prospect H is a complex structure with many fault blocks, bounded to the south by the Troms-Finnmark Fault Complex. The volume of the structure is calculated based on a deep spill point which depends on fault seal. The prospect is covered by 3D seismic data, but the seismic data quality is low in large areas due to gas clouds and shallow gas. Within the structure, three wells have been drilled without encountering movable hydrocarbons. 7119/12-4 and 7120/10-1 were dry, while shows were observed in 7119/12-2 throughout the Middle Jurassic to Upper Triassic.

Prospect E	
Storage system	Open
Rock Volume	1.9 Gm^3
Net volume	1.7 Gm^3
Pore volume	290 Mm^3
Average depth	1900 m
Average net/gross	0,86
Average porosity	0,18
Average permeability	2-500 mD
Storage effeciency	10 %
Storage capacity aquifer	20 Mt
Reservoir quality	
capacity	2
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	

Prospect F	
Storage system	Open
Rock Volume	2.3 Gm^3
Net volume	1.9 Gm^3
Pore volume	350 Mm^3
Average depth	1900 m
Average net/gross	0,79
Average porosity	0,19
Average permeability	2-550 mD
Storage effeciency	10 %
Storage capacity aquifer	24 Mt
Reservoir quality	
capacity	2
injectivity	3
Seal quality	
seal	3
fractured seal	3
wells	3
Data quality	
Maturation	

Prospect G	
Storage system	Half open
Rock Volume	17 Gm^3
Net volume	9.9 Gm^3
Pore volume	16 Gm^3
Average depth	2200 m
Average net/gross	0,57
Average porosity	0,17
Average permeability	1-300 mD
Storage effeciency	5 %
Storage capacity aquifer	57 Mt
Reservoir quality	
capacity	2
injectivity	2
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	

Prospect H	
Storage system	Half open
Rock Volume	58 Gm^3
Net volume	29 Gm^3
Pore volume	5.2 Gm^3
Average depth	2100 m
Average net/gross	0,5
Average porosity	0,18
Average permeability	1-600 mD
Storage effeciency	5 %
Storage capacity aquifer	180 Mt
Reservoir quality	
capacity	2
injectivity	2
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	

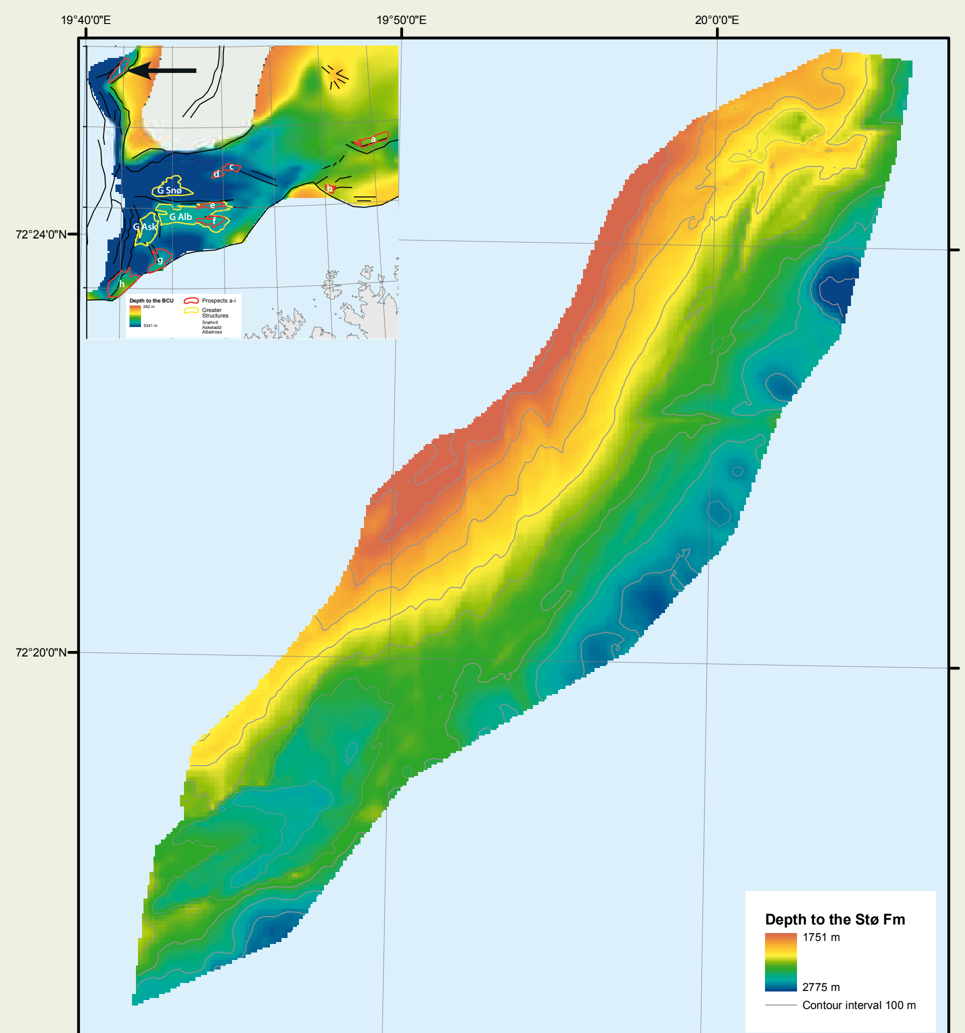


Bjørnøyrenna Fault Complex prospect

The Jurassic aquifer in the Bjørnøyrenna Fault Complex is separated from the Hammerfest Basin by the eroded Loppa High and faults with large throws south of the high. The lithologies and the properties of the formations are similar to the Hammerfest Basin. The area west of the Loppa High is an active petroleum province with several gas clouds, seeps to the sea floor, gas hydrates and recent discoveries of oil and gas. The area is strongly segmented by large faults, and the degree of communication between the rotated fault blocks is not known. Lower Cretaceous sands have developed in some of the fault blocks and communication between segments is possible. One water-bearing closure has been selected as a candidate for CO_2 storage.

Prospect I is located at a closed structure drilled by well 7219/9-1. The geometry of the trap is mapped using 3D seismic data of good quality. The prospect belongs to a fault segment within the Bjørnøyrenna Fault Complex. The Jurassic aquifer formations proved to have good reservoir properties and were water-filled. Shows of residual oil in the well are interpreted as remnants of oil resulting from natural leakage or the water sweep of a hydrocarbon accumulation. There are indications of gas brightening in the fault zone above the crest of the structure. The Fuglen and Hekkingen Formations are eroded at the top of the structure. The main risk for this prospect is considered to be the sealing properties of the cap rock, including the fault and the overlying Lower Cretaceous sedimentary rocks.

Prospect I	
Storage system	closed
Rock Volume	7.7 Gm^3
Net volume	6.9 Gm^3
Pore volume	1.3 Gm^3
Average depth	2100 m
Average net/gross	0,9
Average porosity	0,18
Average permeability	400 mD
Storage effeciency	1 %
Storage capacity aquifer	9 Mt
Reservoir quality	
capacity	2
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	



The location of prospect I is shown by the black arrow in the inset map.

6.2.3 Summary

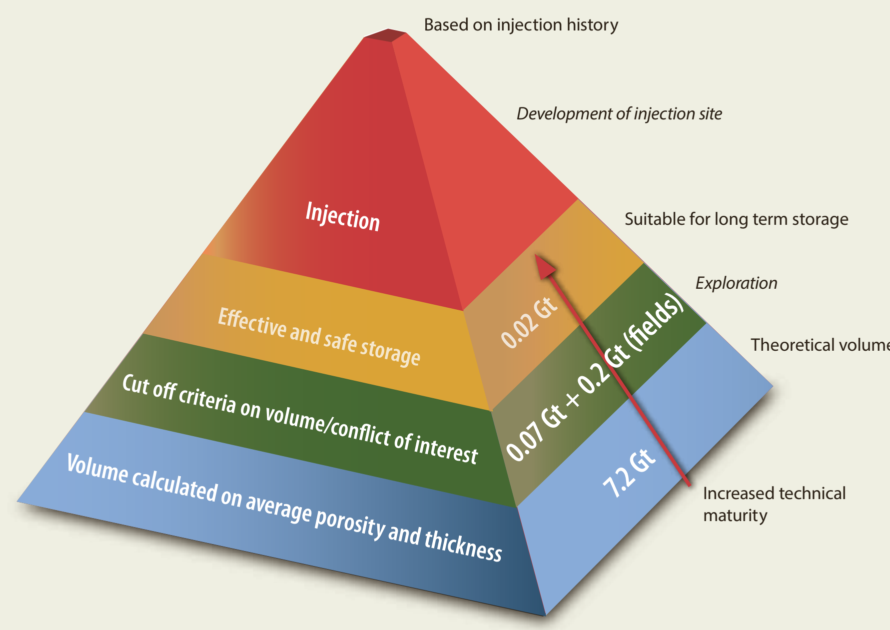
The main results of this study are displayed in the table below and illustrated by the maturation pyramid. The aquifers in the Jurassic Realgrunnen Subgroup are well suited for sequestration, and their storage potential has been quantified. Additional storage in other aquifers is possible. A theoretical storage potential of 7.2 Gt is identified in the regional aquifers. Since some of these areas may have a potential for petroleum exploration and exploitation, the storage potential in the aquifer is classified as immature.

In the near future, the CO_2 available for injection in the Barents Sea is likely to come from natural sources such as CO_2 associated with methane in the gas fields. The evaluation indicates that there is a potential for safe storage of more than 500 Mt CO_2 in structural traps in the southern Barents Sea. Some of these traps are close to the areas of field development and production. The main uncertainties relate to the quality of the seal and to the possibility of encountering hydrocarbons in the traps.

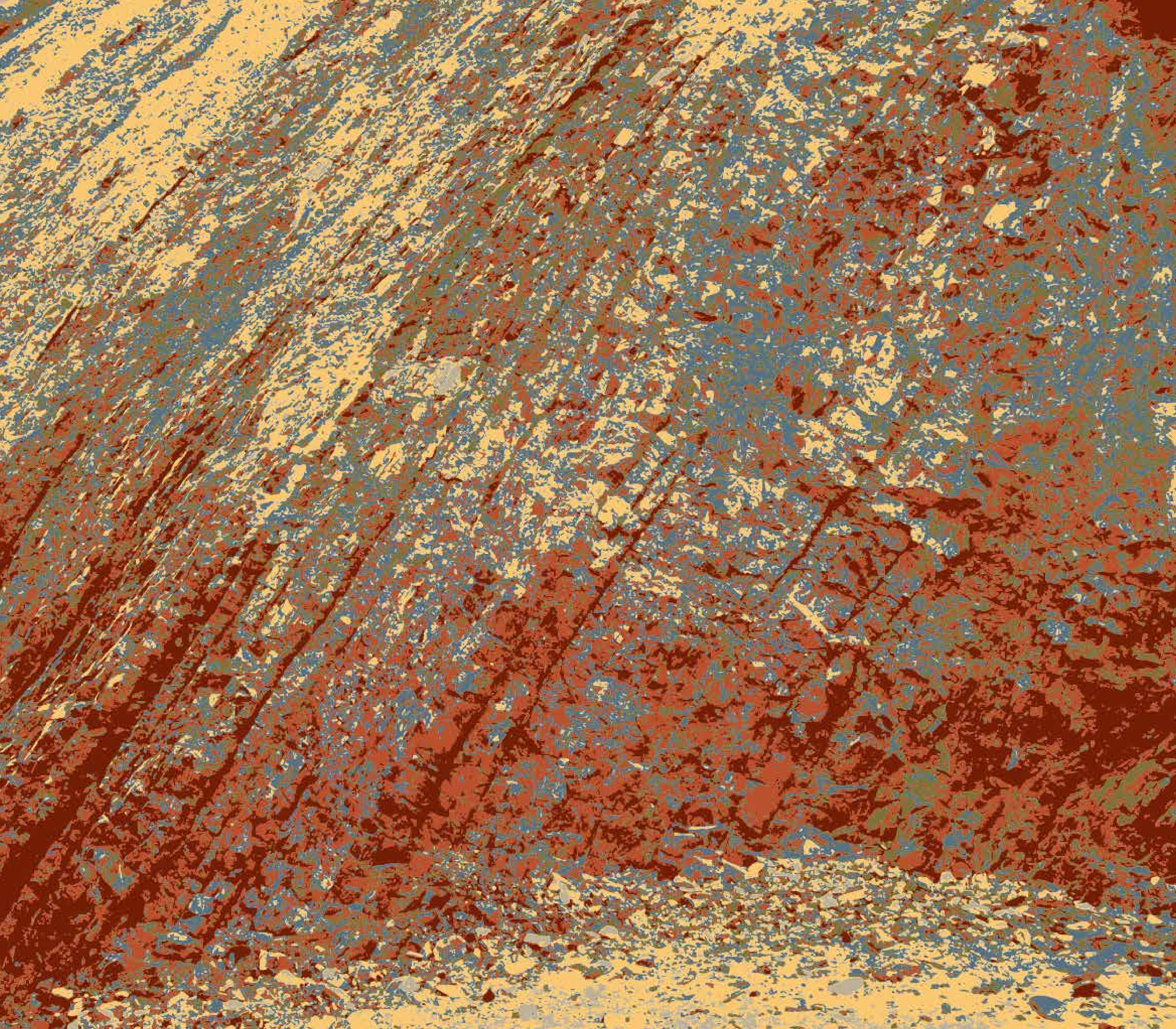
CO_2 injection can be used to mobilize residual oil, which is abundant in the Realgrunnen Subgroup. The potential for such utilization of CO_2 is shown by a simulation study of prospect A. The results indicate that large amounts of CO_2 which can be safely stored in prospects could be dedicated to oil recovery from residual oil and thin oil zones. Analysis of this potential is beyond the scope of this atlas.

Gas production started in the southern Barents Sea in 2007. In the future, when gas-bearing structures are depleted and abandoned, they will have a potential for development as storage sites. A simple calculation revealed a potential of around 200 Mt in four of these structures.

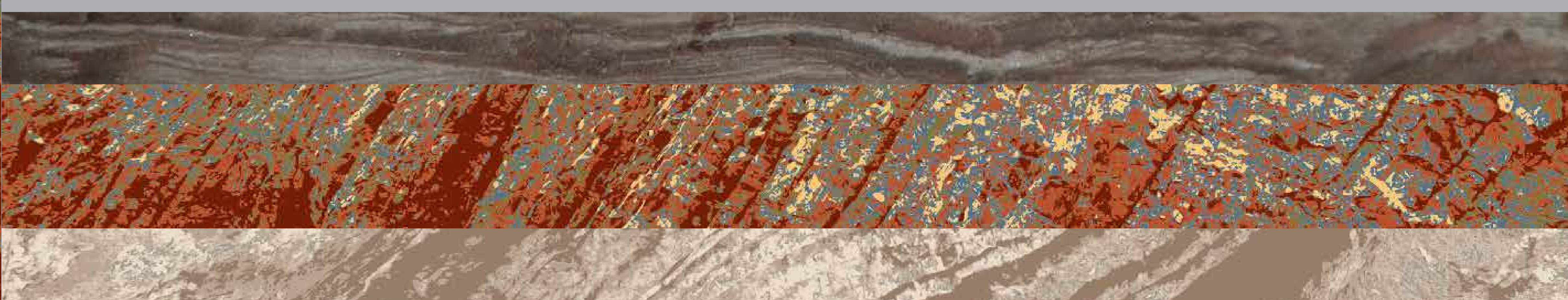
Prospects in structural traps	Avg depth	Bulk volume	Pore volume	Avg K	Open/closed	Storage eff	CO_2 density in reservoir	Storage capacity	Maturity
Unit	*m*	*Gm^3*	*Gm^3*	*mD*		*%*	*kg/m^3*	*Mt*	
BP Aquifer									
A	1525	55	10	500	open	2.50	650	176	
B	1260	4	0.9	500	half open	3	650	19	
HB Aquifer									
C	2400	1.9	0.28	1-170	open	10	700	19	
D	2400	1.2	0.18	1-150	open	10	700	12	
E	1900	1.9	0.29	2-500	open	10	700	20	
F	1900	2.3	0.35	2-550	open	10	700	24	
G	2200	17	1.6	1-300	half open	5	700	57	
H	2100	58	5.2	1-600	open	5	700	183	
BFC Prospect									
I	2100	7.7	1.3	400	closed	1	700	9	
Storage in abandoned fields									
Fields in production								200	
Aquifer volumes									
BP Aquifer	1100	1480	245	5-1000	half open	3	650	4800	
HB Aquifer	2400	1230	120	1-500	half open	3	700	2500	
Greater Snøhvit			4.1						
Greater Askeladd			2.3						
Greater Albatross			5.4						
Snøhvit CO_2 injection									
Snøhvit aquifer 2800	2404-2800	89	6.4	150	half open	2	700	90	
Snøhvit central Stø	2404-2800	6.1	0.68					24	



The UNIS CO_2 well site in Longyearbyen, Svalbard. Photo: Sebastian Sikora.



7. Summary
Storage capacities of The Norwegian Continental Shelf



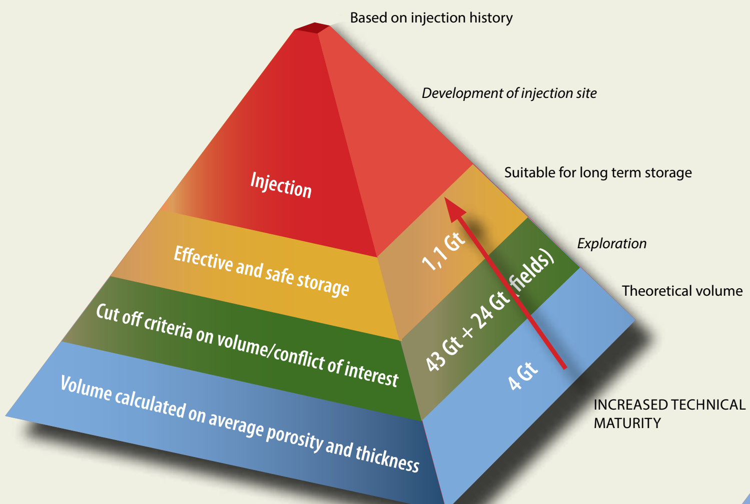
7. Storage capacities of The Norwegian Continental Shelf

An overview of the results of this study are displayed in the table and illustrated by maturation pyramids for the North Sea, Norwegian Sea and southern Barents Sea. All areas have a significant potential for CO_2 storage, but the table shows that the regions are quite different.

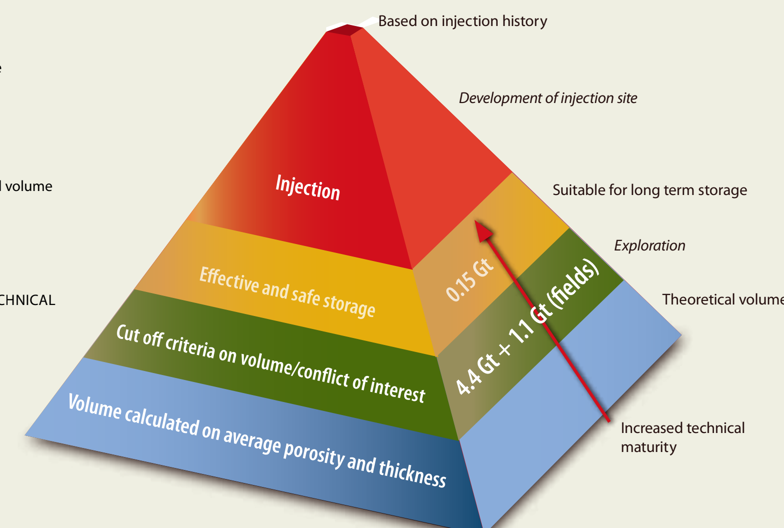
The total storage capacity of the North Sea aquifers is much larger than for the other regions. One reason for this is that in the North Sea there are important aquifers at several stratigraphic levels, while in the Norwegian Sea and Barents Sea, Jurassic formations will be the main target for CO_2 injection.

The injectivity of the studied aquifers and the sealing properties of their cap rocks are considered to be acceptable or good, mainly because poor quality reservoir formations were excluded from the evaluation. Some of these are mentioned in the sections of the geological description.

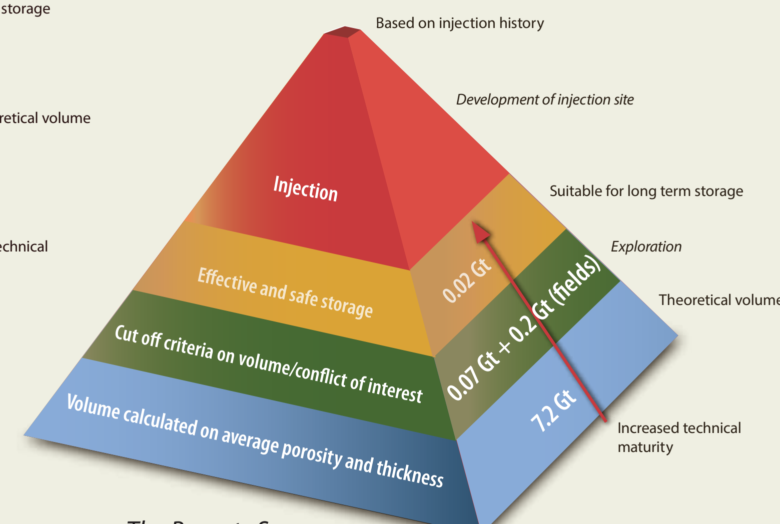
Sealing properties are typically characterized as slightly lower in the Barents Sea than in the other regions. This is discussed in the text and is due to the Cenozoic and Quaternary uplift history and widespread evidence of hydrocarbon seepage.



The North Sea



The Norwegian Sea



The Barents Sea

7. Storage capacities of The Norwegian Continental Shelf

In the North Sea and Norwegian Sea the studied aquifers belong to areas where conflicts of interests with petroleum industry are not very likely. Most of them were characterized to the green level in the maturation pyramid. Due to a geological setting with source rocks at several stratigraphic levels and a complex burial history, most parts of the southern Barents Sea were considered to be of interest for future petroleum exploration, consequently the studied aquifers were classified to belong to the blue level.

A large data base of wells and seismic data has been available for the study. Most areas which have been recently explored by the petroleum industry are covered by 3D seismic data. In general the data coverage of the studied aquifers is more sparse, because they belong to provinces which are less attractive for the petroleum industry. Aquifers with few well penetrations and mainly 2D seismic coverage are characterized with an orange colour in the data quality column. Most likely more data would have to be acquired if such aquifers are selected for maturation of possible storage sites.

In summary, there is more than sufficient storage capacity in the Norwegian Sea and Barents Sea for CO_2 captured from local sources, while the Norwegian North Sea will also have potential to store CO_2 from northern Europe.

Aquifer	Capacity Gt	Injectivity	Seal	Maturity	Data quality
North Sea aquifers					
Utsira and Skade Formations	15,8	3	2		
Bryne and Sandnes Formations	13,6	2	2/3		
Sognefjord Delta East	4,1	3	2/3		
Statfjord Group East	3,6	2	3		
Gassum Formation	2,9	3	2/3		
Farsund Basin	2,3	2	2/3		
Johansen and Cook Formations	1,8	2	3		
Fiskebank Formation	1	3	3		
Norwegian Sea aquifers					
Garn and Ile Formations	0,4	3	3		
Tilje and Åre Formations	4	2	2/3		
Barents Sea aquifers					
Realgrunnen Subgroup, Bjarmeland Platform	4,8	3	2		
Realgrunnen Subgroup, Hammerfest Basin	2,5	3	2		
Evaluated prospects					
North Sea	0,44				
Norwegian Sea	0,17				
Barents Sea	0,52				
Abandoned fields					
North Sea	3				
Producing Fields_2050					
North Sea 2050	10				
North Sea_Troll aquifer	14				
Norwegian Sea	1,1				
Barents Sea	0,2				

8. Storage options with EOR

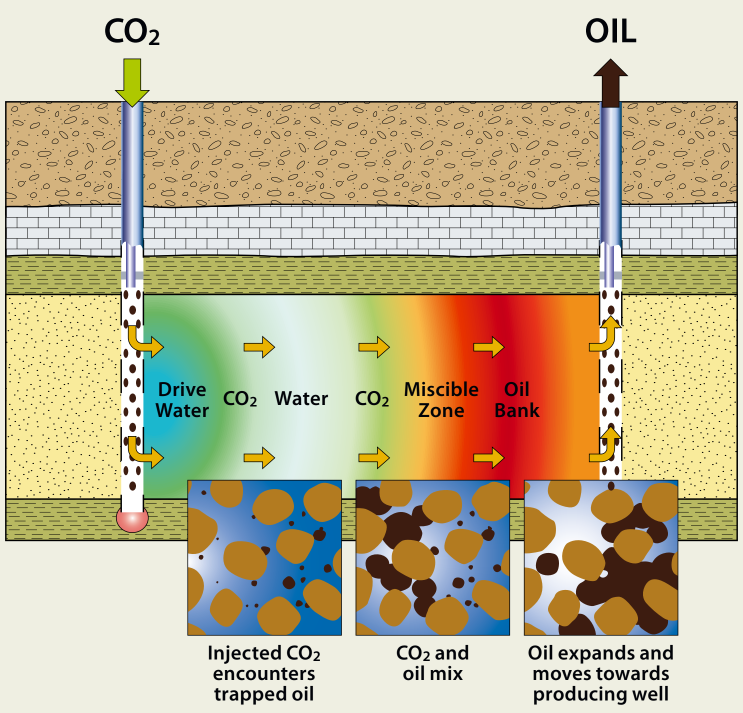
8. Storage options with EOR

Injection of CO_2 in oil fields has for many years been used as a method to enhance oil recovery (EOR), primarily in the United States, where the CO_2 mostly comes from reservoirs with naturally occuring CO_2. CO_2 may also be used to obtain recovery from residual oil zones. The CO_2 injected to enhance recovery is stored in the reservoir but the amount of stored CO_2 is reduced as more and more CO_2 will be recycled after breakthrough in production wells. On the Norwegian shelf, several oil fields have been examined with regard to enhanced recovery through CO_2 injection. Some of the fields have proved to be promising candidates. In the beginning of this century studies carried out by the operator on the Gullfaks Field showed a good potential for increased recovery by CO_2 injection. Studies on the Ekofisk field by ConocoPhillips have shown large reserve potential but with concerns regarding dissolution/compaction. On Haltenbanken the Draugen and Heidrun Fields have been studied but these fields show less EOR potential. For all the fields lack of access to CO_2 has stopped further evaluation.

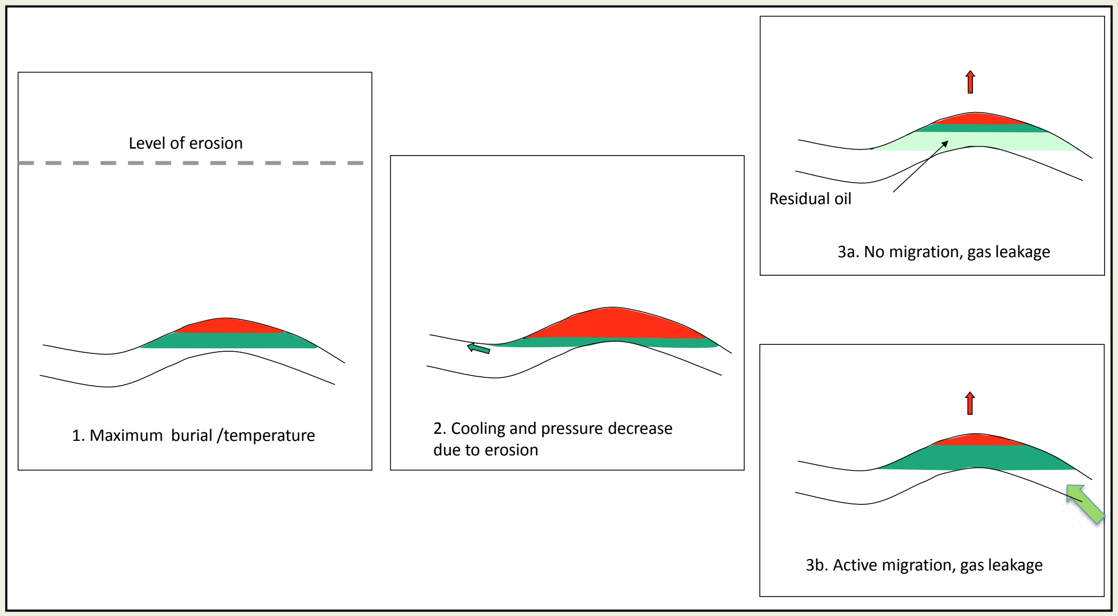
A study carried out by the Norwegian Petroleum Directorate (NPD) in 2005 and updated in 2012 on fields in the North Sea, indicated a large potential for additional oil recovery with an increase in recovery factor varying from 5-12 percent points. These numbers are also confirmed by a study from the BIGCO_2 project (Climit). This study shows an increased oil recovery of more than 370Mt from 19 fields in the North Sea, with an injection of 80Mt/y CO_2.
The amount of stored CO_2 in oilfields is than 1,5 Gt and the amount stored in aquifers is 1,9 Gt CO_2.

The best effect of CO_2 is obtained when CO_2 and oil are miscible in the reservoir. CO_2 also swells the oil, reduces oil viscosity and increases oil density and thereby increase recovery of the oil. CO_2 is soluble in water, can evaporate and extract oil, and it reduces surface tension between oil and water which also help the recovery. The sweep efficiency of CO_2 flooding is not good but can be improved by applying WAG, by alternating injection of CO_2 and water. Using foam with the CO_2 is also a way to help conformance control of the CO_2 movement in the reservoir.

A critical factor in this process is the corrosivity of CO_2 when mixed with water. The CO_2-water mixture will break through in the production wells and reach the process facility. This may cause corrosion in wells and process equipment if not protected. Technological solutions for injection and reproduction of CO_2 have to be improved before this can be a viable method for EOR, especially in older oil fields.



Cross section of a reservoir with CO_2 WAG

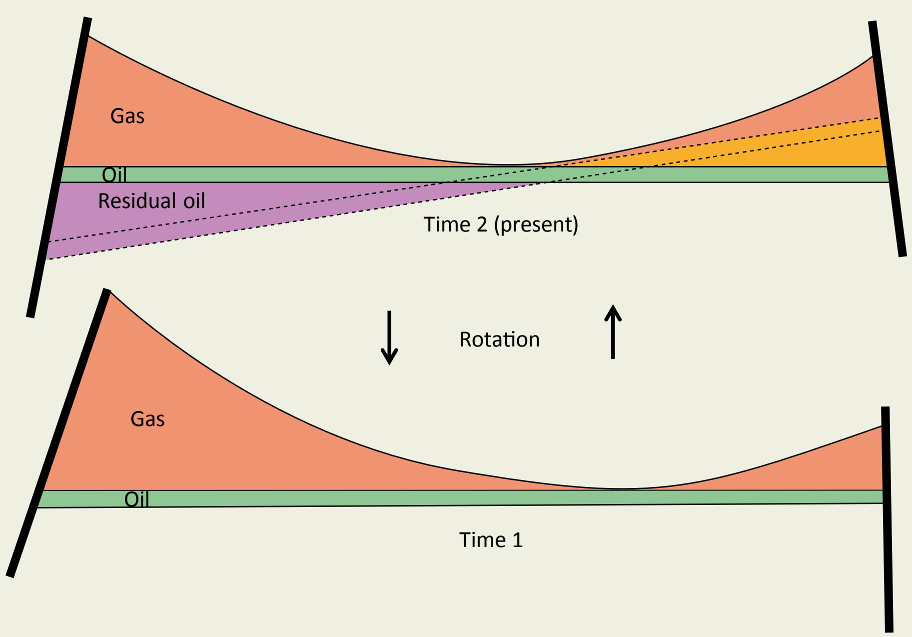


Hypothesis for formation of residual oil zone by natural gas seepage. After maximum burial the rate of seepage of gas is greater than the rate of migration of hydrocarbons into the accumulation. Consequently fluid contacts move upwards. Residual oil (light green) is formed where water replaces oil in the initial oil zone (green).

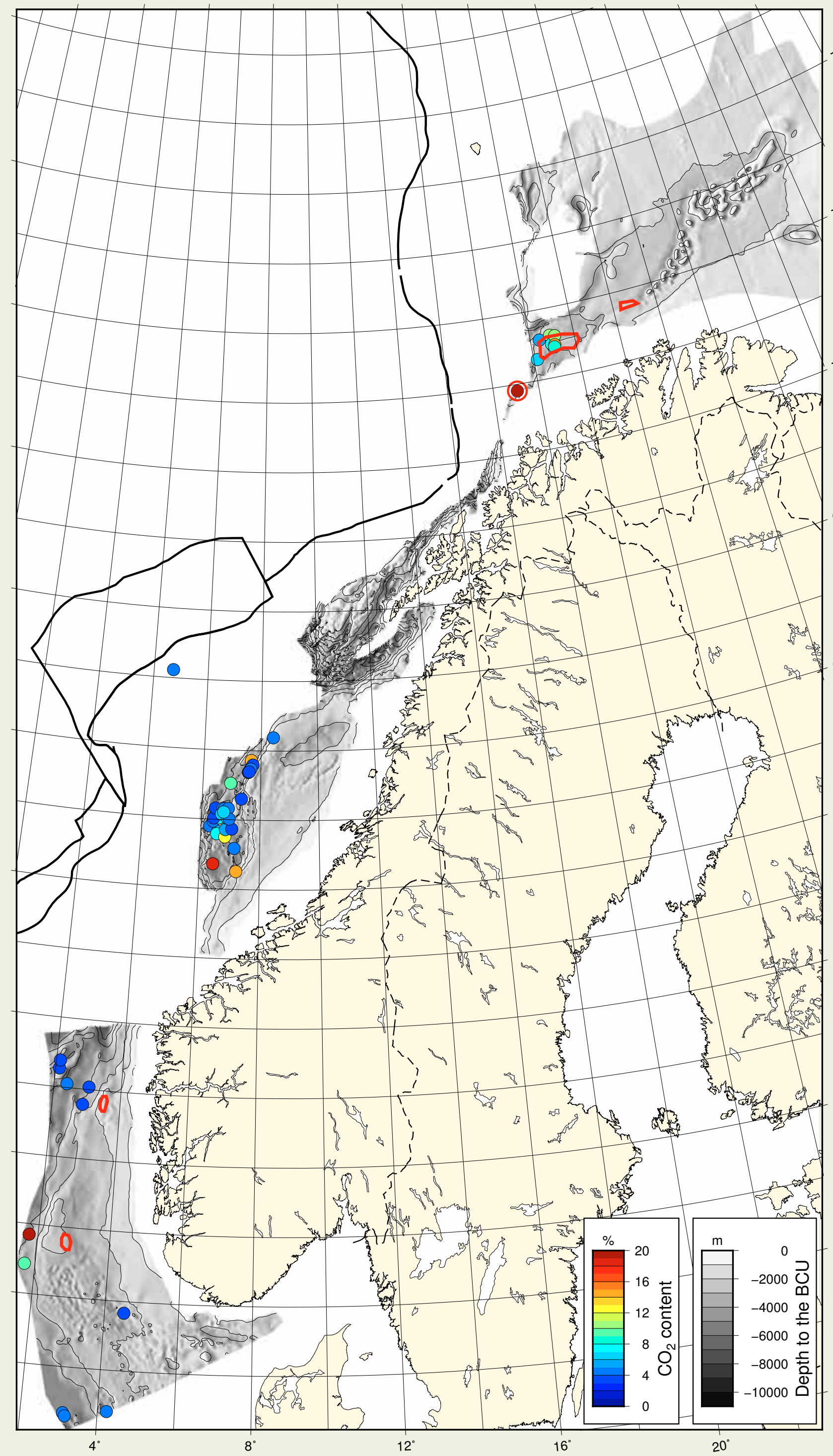
8. Storage options with EOR

Residual oil zones In the late stage of production of an oil field, formation water and injected water will have replaced much of the initial oil. When oil is swept by water, a certain amount of immobile oil will remain. The saturation of this residual oil is typically in the order of 20 %, depending on reservoir properties. Residual oil zones can also form by natural processes. In the Norwegian Continental Shelf, residual oil is common in the Jurassic aquifer of the Hammerfest Basin in the Barents Sea. Significant residual oil zones are also associated with some of the giant oil fields in the North Sea. These zones were formed when oil was redistributed in the trap and water replaced the oil by natural processes. Two common processes which can result in formation of residual oil appear to be tilting of traps and seepage from traps, as shown in the sketches.

Under miscible conditions, CO_2 can be used to mobilize residual oil and make it possible to produce oil from both natural ROZ and ROZs from oil production.



Formation of residual oil zone by rotation of a structural trap with oil and gas. Fluid contacts are controlled by pore pressure and will equilibrate to horizontal surfaces . The pore space where oil is replaced by water will remain with a residual oil saturation (purple zone). There will also be a residual oil saturation in the gas zone (orange zone), but this saturation is much lower than in the water zone. Time 1 – initial trap, Time 2 - rotated trap, dotted lines show the present location of the inital contacts.



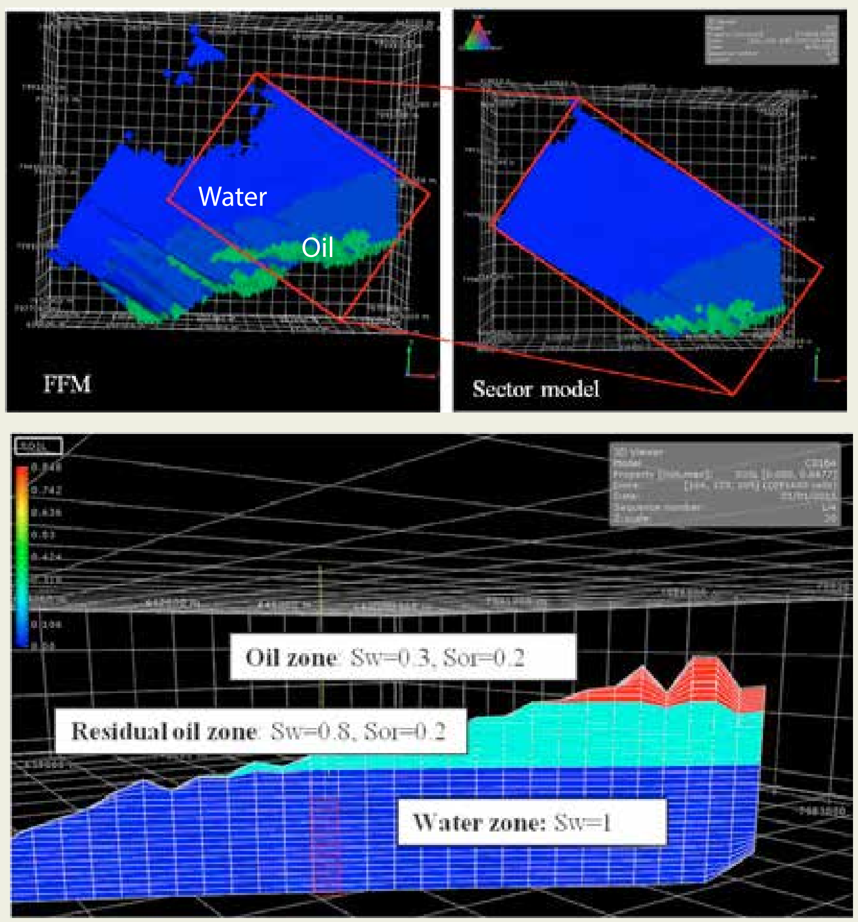
Map of Base Cretaceous unconformity showing location of exploration wells where the measured CO_2 concentration in natural gas exceeds 3 %. 7019/1-1 is marked by a red ring. Residual oil zones are indicated by red lines.

8. Storage options with EOR

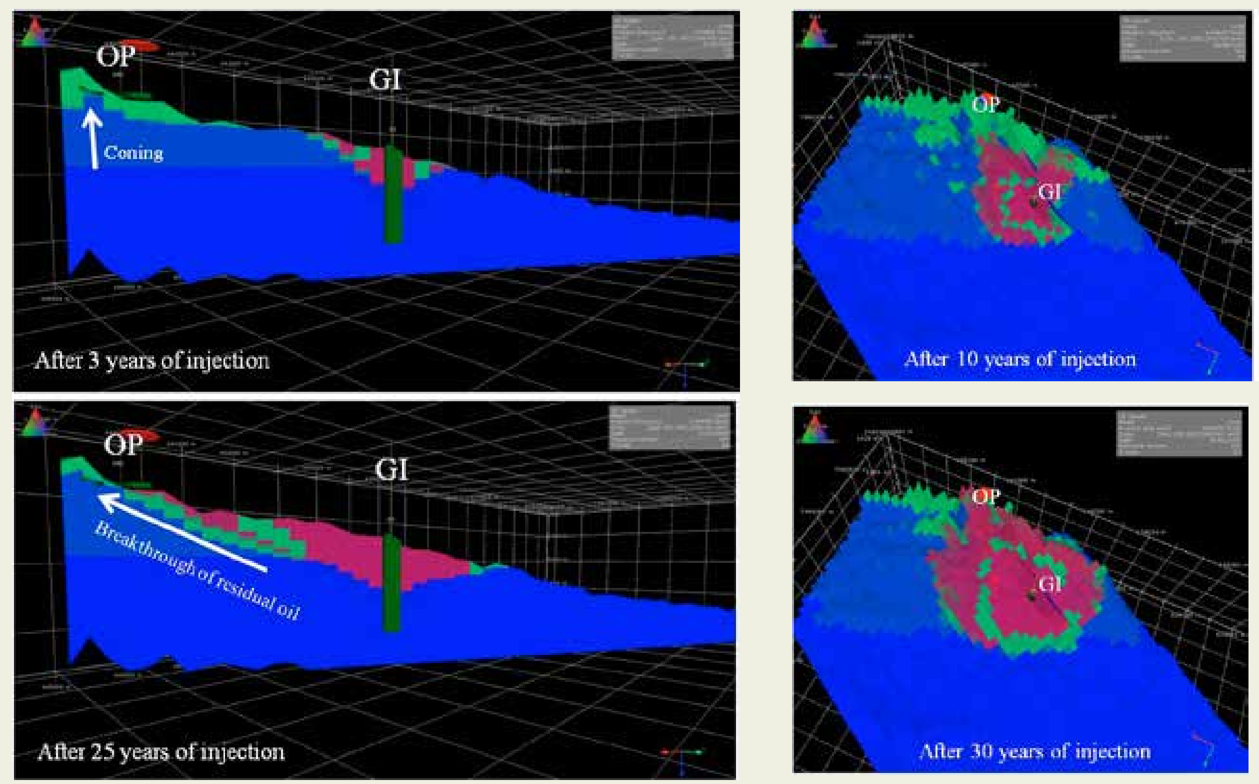
CO_2 flooding will usually be a tertiary process with recovery from residual oil zones after water flooding. Some fields have residual oil below the main oil zone originally in the field, so called paleo oil. In the Barents Sea residual oil or paleo oil have a wide distribution. A simulation study was performed on a structure with residual oil in the southernmost Bjarmeland Platform in the Barents Sea to investigate if some of the residual oil could be produced. Data was obtained from the wells 7125/1-1 and 7125/4-1.

The main oil zone was 1-1,5 m thick in well 7125/1-1 with a 32,5 m residual oil zone below. The study indicated that the main oil zone could be up to 30 m thick in average. Simulation cases were run both on a thin and a thick oil zone.

The oil was produced (well OP in figure below) from the main oil zone while CO_2 was injected down flank (well GI on figure) in the residual oil zone with an injection period of 30 years. Results from the simulation with a 30 m thick main oil zone showed a reduction in oil production when water coned into the producer. However, the oil production increased again when CO_2 together with swept oil from the residual oil zone reached the well.



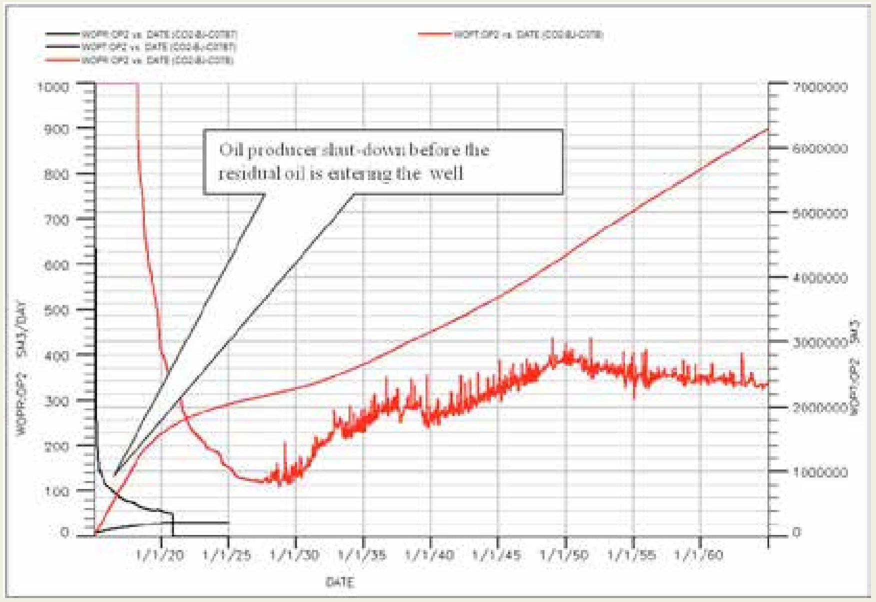
Setup of simulation model, showing the location of the sector model and the distribution of oil and residual oil.



Profiles through the CO_2 injector (GI) and the oil producer (OP), showing distribution of CO_2 (red), oil (green) and water (blue) 3 and 25 years after the injection start. The maps to the right show the distribution of the CO_2 plume. North is down to the left.

With a thin oil zone (3 m thick) the water coned very rapidly into the well and the well died before the the CO_2 and the residual oil reached the well. To optimize recovery from a thin oil zone overlying a residual zone, CO_2 injection should start some years ahead of the production to keep a continuous production and thereby optimize the economics. The input data and the results for both cases are shown in the figures.

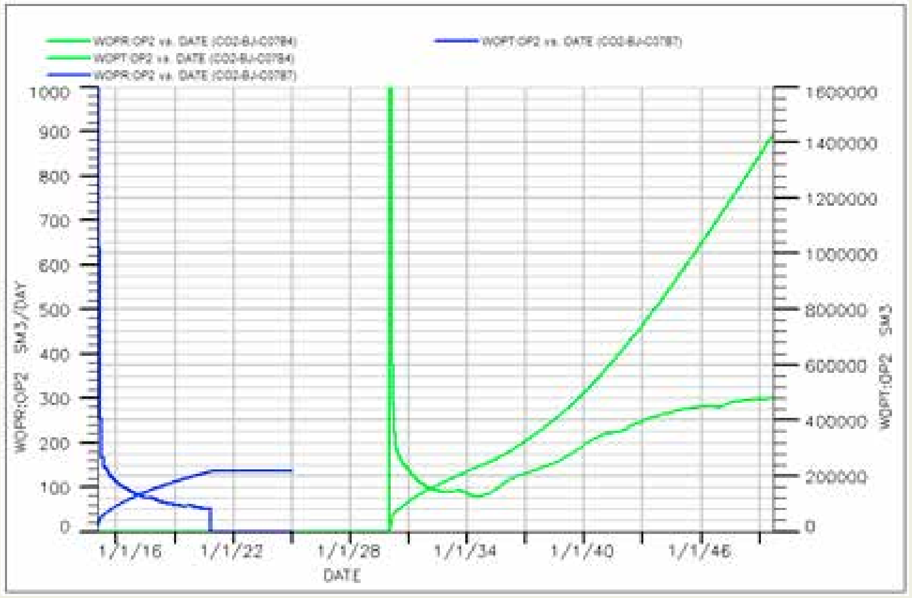
The sector model with a thick oil zone gave a recovery of 6.3 mill Sm^3 including the residual zone. That means a total recovery of 18 %. For the thin oil case the recovery was 4.5 % including the residual zone. It was not easy to distinguish between the main zone and the residual zone recovery in the model. The stored CO_2 in the two cases was 40 and 30 mill tonn respectively. The recovery of oil is to a large degree dependant on the amount of CO_2 injected.



Oil production profiles with sensitivities (Red: basecase model with 30 m oil zone. Black: sensitivity with 3 m oil zone. Oil production and CO_2 injection start 01.01.2015)

Porosity:	22 %
Horizontal Permeability:	900 mD
Kv/Kh :	0.5
N/G:	0.94
So oil zone:	75 %
Sor residual zone:	20 %
Oil density:	0.80
GOR:	66 Sm^3/Sm^3
Max injection pressure:	225 bar
CO_2 injection rate:	1.5 MSm^3/d
OP and CO_2 inj. Start:	01.01.2015
Oil in-place, main structure:	23 MSm^3
Res. oil in-place, main structure:	49 MSm^3
Oil in-place, sector model:	9.7 MSm^3
Res.oil in-place, sector model:	25.3 MSm^3
Results thick oil zone(30 m)	
Oil produced in main and	
residual zone in sector model:	6.3 MSm^3
Recovery factor, sector model	
(main + residual zone):	18 %
CO_2 stored in sector model:	17 Mt

Input data and results.



Oil production starts 15 years after CO_2 injection (Blue: CO_2 injection and oil production startup simultaneously. Green: Delay of production 15 years after CO_2 injection startup.

9. Monitoring

9. Monitoring

Monitoring of injected CO_2 in a storage site is important for two main reasons: Firstly, to see that the CO_2 is contained in the reservoir according to plans and predictions, and secondly, that if there are deviations, to provide data which can be used to update the reserservoir models and support eventual mitigation measures.

A wide range of monitoring technologies have been used by oil and gas industry to track fluid movement in the subsurface. These techniques can easily be adapted to CO_2 storage and monitor the behavior of CO_2 subsurface. For example, repeated seismic surveying provides images of the subsurface, allowing the behavior of the stored CO_2 to be mapped and predicted. Other techniques include pressure and temperature monitoring, down-hole and surface CO_2 sensors and satellite imaging, as well as seabed monitoring. In this chapter we present some of the challenges related to CO_2 storage and some of the available monitoring techniques.

Seal considerations for CO_2 storage — by prof. Per Aagaard, UiO

The main criteria for selecting a site for geological CO_2 storage (IPCC report on Geological CO_2) are adequate CO_2 storage capacity and injectivity, safety and security of storage (i.e., minimization of leakage), and minimal environmental impact. A potential reservoir thus needs a seal or caprock above the reservoir, i.e. physical and/or hydrodynamic barriers that will confine the CO_2 to the reservoir.

Typical rocks forming seals or caprocks offshore in Norway, are sediments like mudstones, shales or fine-grained chalks. The pores are water-filled, while the reservoir beneath may have oil, gas or supercritical CO_2. The seal should prevent the migration of these fluids into the fine-grained caprock. To form an efficient seal, the rock has to have a small pore throat radius, giving them a high capillary pressure. This prevents the migration of fluids like oil and gas or supercritical CO_2 into the caprock, because the capillary pressure is greater than the buoyancy effect.

The capillary sealing is normally sufficient to prevent migration of fluid CO_2 into caprock, and a diffusion of CO_2 dissolved in the pore water of the caprock will also have very limited penetration in time scales of less than thousands of years. But we know from oil and gas reservoirs that caprocks may leak, and seepage of small gas volumes is commonly observed above the big oil and gas fields on the Norwegian shelf. This occurs either through small fractures or faults, which may open up under certain conditions. The seepage process is slow due to a combination of capillary pressures and low permeability in the caprock and the fracture systems. During injection, the caprocks can in particular be affected by: 1) the pressure rise in the storage formation induced by the injection process, and 2) geomechanical and geochemical processes that may affect the integrity and safety of the storage formation. In tectonically active areas, leakage can be induced by earthquakes. This is not an important risk in the North Sea, as recorded earthquake foci are deep-seated.

Fine-grained sediments undergo major changes after their initial deposition as mud. First they are compacted due to the weight of overlying sediments, and later, as the temperature increases with burial depth, chemical reactions also create cement between the sediment grains. Thus there is a transformation from ductile mudstones to more brittle shale or chalk, which mechanically is stronger, but more likely to fracture. Generally, thicker mudstone/shale formations will make better seals, but even rather thin, young sediments have been shown to be effective caprocks. The shallow Peon gas field has a less than 200m thick seal of Pleistocene mud. Several groups are active in research on geomechanics and rock physics of caprock research in Norway under petroleum research programs.

The CO_2 will react with the caprock, and there is considerable concern as to how these processes may affect the seal integrity. In addition, well cement may also deteriorate under reaction with CO_2. There is quite some dedicated research on CO_2 - caprock interaction, both internationally and nationally. In Norway, several research projects are run both under the CLIMIT program (SSC-Ramore) and within the SUCCESS and BIGCCS Centres for Environment-friendly Energy Research (FME).

Monitoring of CO_2 injection and the storage reservoir — by Ola Eiken, Statoil

Monitoring of CO_2 injection as well as acquisition and interpretation of various kinds of well and reservoir data are important for control during the injection period and afterwards. Firstly, monitoring gives feedback to the injection process; it can lead to adjustment of rates, guide well intervention or decisions on new injection wells. In case of unwanted reservoir behaviour, monitoring data can lead to a number of mitigation measures. Furthermore, monitor data are needed to confirm storage reservoir behaviour and are crucial for operating CO_2 quota systems. To obtain public acceptance of a storage site and wide recognition of CCS as a measure to prevent climate change, monitoring will play an important role. Also, predictions of a storage site's long-term behaviour (over hundreds or thousands of years) should be calibrated against monitor data. Finally, public regulations, such as the EU directive 2009/31/EC, Article 13, on the geological storage of carbon dioxide, require monitoring of the storage reservoir.

Monitoring data can be acquired in the injection well(s), in observation wells and by surface measurements. Crucial measurements at the well head are rate, composition and pressure/temperature. Downhole pressure/temperature measurements are of further value, because sensors closer to the reservoir give more accurate responses of pressure build-up during injection and of fall-offs during shut-ins. These can be used to constrain reservoir models and to predict maximum injection rates and storage capacity. Observation wells can, if they penetrate the storage reservoir, give data on pressure build-up and CO_2 breakthrough. This is done by installing various sensors, by logging the reservoir interval regularly and by fluid sampling. Regional pressure development within a basin is of particular importance in large-scale storage. A number of surface measurement techniques can be applied. 4-D seismic has proven most successful on the industry-scale offshore projects of Sleipner and Snøhvit, yielding the geometry of the CO_2 plume with high resolution, while gravimetry has given complementary information on CO_2 in-situ density and dissolution rates in the formation water. Onshore, surface elevation and microseismic data have given valuable information on injection and storage, and these techniques can be extended to offshore applications. Cost is an important aspect of a monitoring program, and subsurface and surface conditions that vary from site to site make a tailor-made plan necessary for each site. Equipment reliability and a system of documentation which works over a time-span of generations are also important for a monitoring program. With a proper monitoring program, a leakage out of the storage complex should be detected long before CO_2 reaches the sea floor or the surface, so that mitigating measures can be implemented.

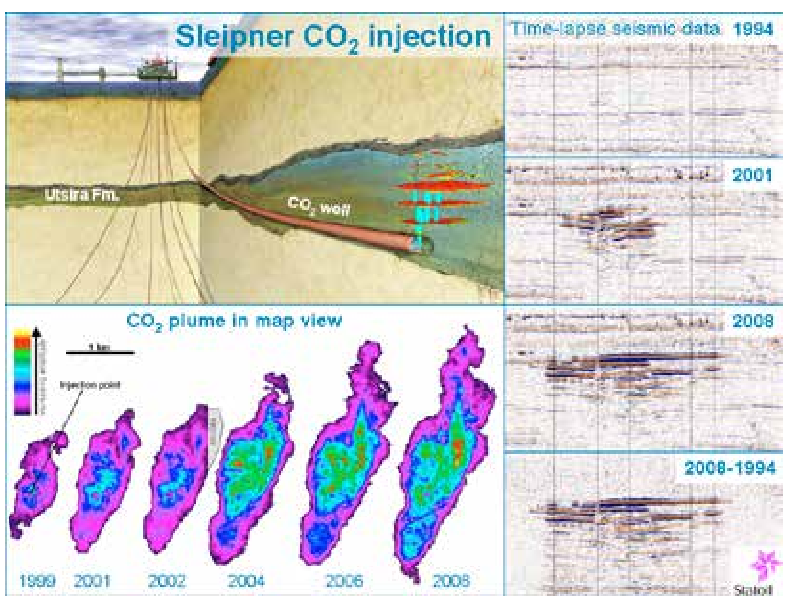


Figure of the Sleipner *CO_2 injection 4-D seismic monitoring. Upper left: sketch of the injection well and storage reservoir. To the right is a seismic section along the long axis of the plume (south-west to north-east) for different vintages and for a time-lapse difference. Note the lack of reflectivity on the seismic difference above the storage formation, showing no signs of leakage. Lower left: Maps of the development through time of cumulative amplitudes for all layers.*
By 2008 the area of the CO_2 plume was about 3 km^2, and it was steadily growing.

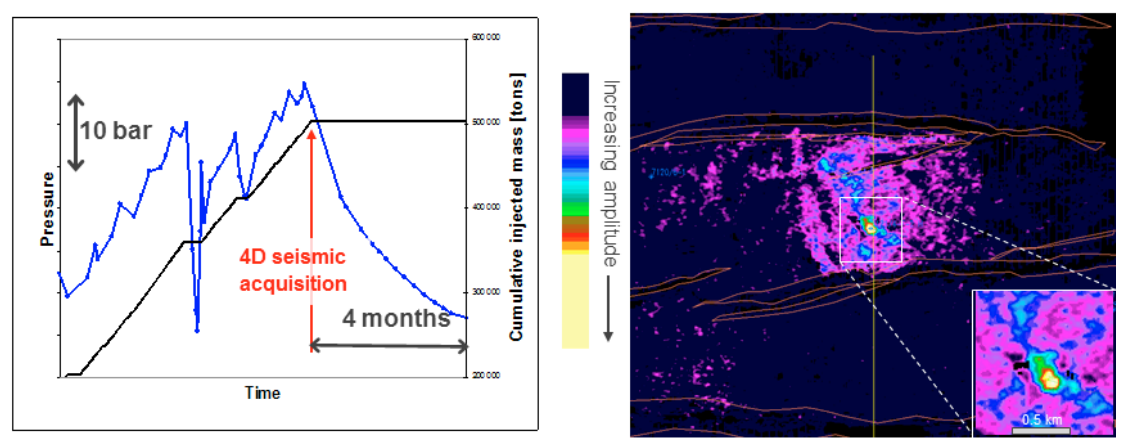


Figure from the Snøhvit *CO_2 injection. Left: Cumulative injection (black line) and estimated bottom-hole pressure (blue line) spanning year 2009, showing pressure increase during periods of injection and pressure fall-off during stops. The timing of a 4-D seismic survey is shown in the figure. Right: A 4D seismic difference amplitude map of the lowest Tubåen Fm. level, showing highest amplitudes close to the injection point, and with decaying amplitudes outwards from the well – falling below the noise level about 1 km away.*

9. Monitoring

Seafloor monitoring of sub-seafloor CO_2-storage sites — by prof. Rolf Birger Pedersen, UiB

A leakage of CO_2 from a storage reservoir can result from a failure during injection or due to a migration of CO_2 from the reservoir to the seafloor along unforeseen pathways for fluid flow. Whereas the first would be detected by instrumentation at the injection sites, monitoring of the seabed may reveal the latter.

The flow of fluids from the subsurface, across the seabed and into the water column has been studied extensively since the late nineteen seventies - when deep-sea hydrothermal venting was first discovered. Since then, the instrumentation and procedures to locate and monitor the flow of fluids (i.e. gases and liquids) from the seafloor has been developed during research investigations both at hot vents and cold seeps. Therefore, when strategies and procedures for monitoring sub-seafloor CO_2 storage sites are being developed today, they are based on over four decades of basic research of natural seafloor fluid-flow systems.

Within the sediments below the seabed, chemical compounds like CO_2 and CH_4 form naturally through microbial activity and sediment diagenesis. There is a natural flux of these and other fluids across the seabed. These fluxes range from widespread and slow diffusion processes, to focused fluid flow at discrete seepage sites. Fluid flow at seepage sites results in distinct topographic, geochemical and biological signatures on the seafloor, as well as chemical and physical imprints in the water column above. Any change in these natural fluid-flow-patterns may indicate the first warning of leakage. Thus the flow of natural, reduced pore water at existing or new seepage sites is expected to be a distinct, initial sign of CO_2 seepage from a subsurface reservoir.

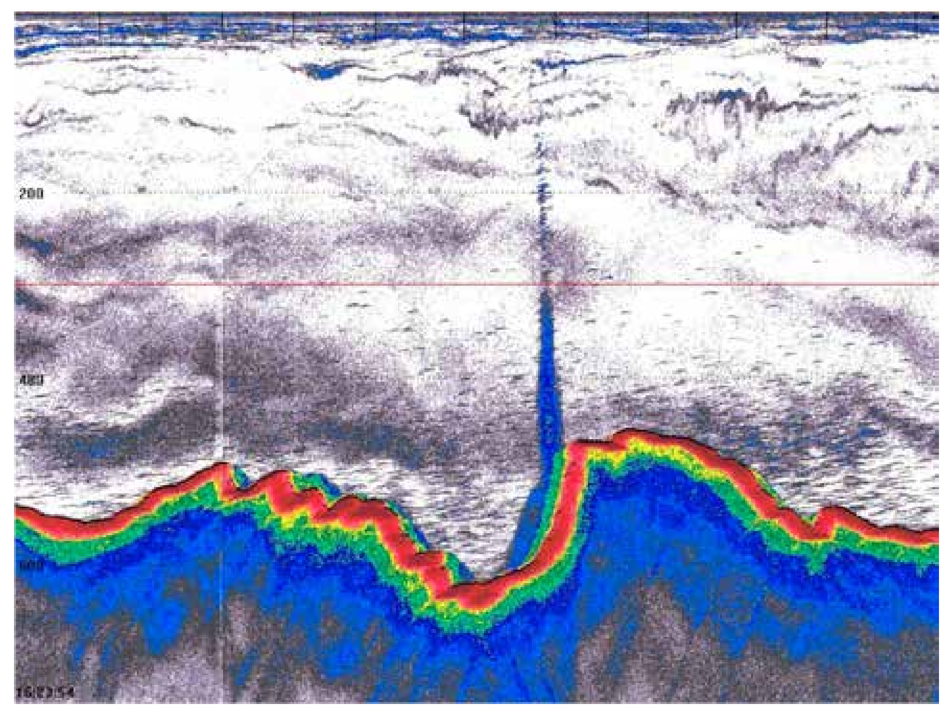
Seafloor monitoring programs are now being designed to detect CO_2 leakages and such early warnings. These schemes include: 1) scanning of the water column with acoustic systems to reveal any changes in the release of gas bubbles from the seafloor; 2) acoustic imaging of the seafloor at ultrahigh resolution to detect topographic changes that might reveal the formation of new fluid escape pathways; 3) imaging of bacterial mats and fauna at seepage sites to document environmental changes related to fluid-flow, and 4) chemical analyses of sea- and pore-water at natural seepage sites to monitor changes in the composition of the fluids emanating from the seafloor.

This monitoring requires advanced instrumentation that is either already available or currently under development. Hull-mounted multi-beam systems that scan the water column while simultaneously mapping the seafloor are now available. With a beam width of five times the water depth, these systems scan large areas in short time spans, detecting even small releases of gas bubbles from the seafloor. Autonomic underwater vehicles (AUV), which can dive for 24 hours and move at speeds of up to four knots at heights of just a few meters above the seafloor, can image the seafloor with side scan sonar systems at 10 cm scale resolution. At such resolutions, the appearance of new fluid flow pathways can be detected by small changes in the seafloor topography.

Where reduced subsurface fluids seep out, microorganisms will colonize the seafloor. They utilize the chemical energy in the fluids and form distinct, white bacterial mats that easily are detected by optical imaging of the seafloor using AUVs and ROVs as platforms for the camera. Today, thousands of images can be geo-referenced and assembled in large photo-mosaics. Repeated seafloor imaging of areas with evidence of fluid flow will be used to monitor the seabed fluid flow regime through the behaviour of microbial colonies and the seafloor biota.

AUVs and ROVs may also carry sensors that directly measure dissolved CO_2 and CH4 in the water just above the seafloor. At present, these sensors lack the sensitivity as well as a rapid enough response time to be effective monitoring tools. Sensors with the needed capability are under development, and in a few years' time they will be available for use in combination with acoustic and optical methods to monitor the state of the seabed fluid flow pattern.

Monitoring of the seafloor at regular intervals with these types of methods will not only be capable of detecting direct CO_2 leakages, but also the subtle changes in the seabed fluid flow pattern that may represent early warnings. If the monitoring reveals anomalies relative to the baseline acquired before the CO_2 injection starts, then special measures should be taken to investigate these areas in more detail. A range of geochemical, geophysical and biological methods is available to examine if the changes are related to leakage from the CO_2-storage reservoir rather than natural variations.

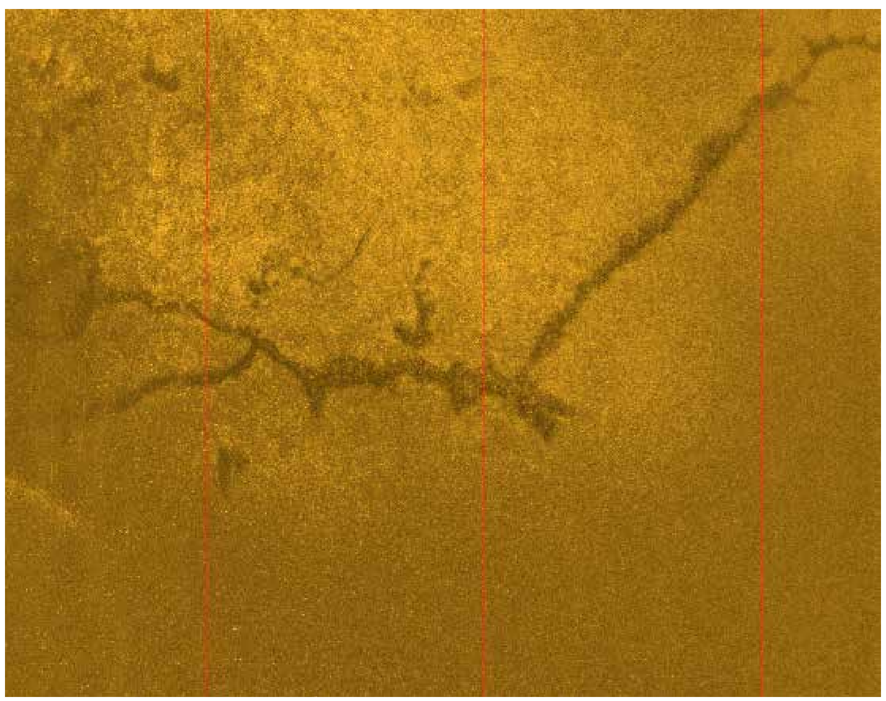


Detection of gas bubbles by echo sounder systems. The figure shows the acoustic signature generated by CO_2 bubbles being naturally released from the Jan Mayen vent fields. The CO2 bubbles are here seen as a blue flare that rises around 500 metres from the seafloor through "clouds" of plankton in the water column.

Seafloor monitoring of sub-seafloor CO_2-storage sites

At such anomalies, a necessary next step may be to place instrumentation on the seabed to obtain time series data. Called seafloor observatories, these instruments are capable of relaying sensor data and images to onshore laboratories via satellite links or fibre optic cable-connections. Seafloor observatories are at the cutting edge of today's marine sciences. Presently, cable based seafloor observatories for basic research are being deployed at natural seabed fluid flow sites in the Pacific. As part of these and other research programs, a range of specialised instrumentation has been developed to monitor natural seabed fluid flow systems. These include: 1) acoustic systems to monitor the flux of gases into the water column; 2) mass spectrometers and chemical sensors to measure fluid components; 3) high-definition camera systems to monitor seafloor biota responses; and 4) broad-band seismometers for detecting cracking events related to subsurface fluid flow. Whereas most of these technologies may be directly transferable to the monitoring of CO_2 storage sites, some may need further development and adaptation.

In conclusion, the know-how and technology developed partly by research on natural seabed fluid flow systems is currently available and can be transferred to the monitoring of CO_2-storage sites. Monitoring schemes can therefore be designed and implemented to document the integrity of these sites, as well as providing early warnings of developing leakage situations from sub-seafloor storage sites.



Detection of seafloor fluid flow structures using side-scan sonar imaging. The image shows a fracture system in the seabed where fluids are slowly seeping out from the subsurface. (Scale: 50 metres between red lines)

Detection of seafloor fluid flow using biologic signatures. The photo mosaic shows white bacterial mats that form a distinct biologic signature of fluid flow across the seabed. (sea star for scale)

Centre for Geobiology

Wells

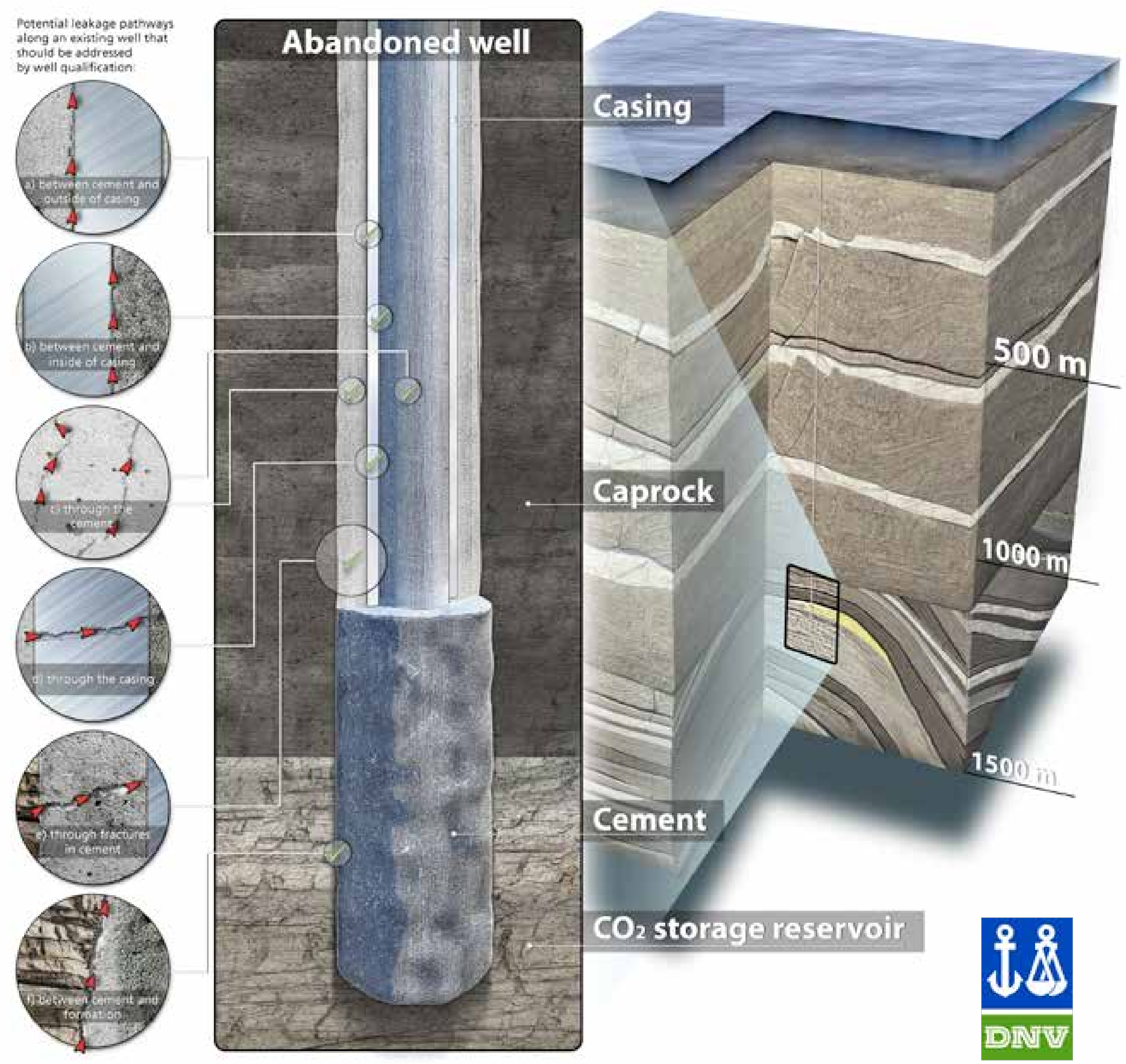
By: The Petroleum Safety Authority Norway

- **A potential CO_2 storage location can be penetrated by a number of adjacent wells that represent potential leakage sources.**
- **Adjacent wells are defined as wells that might be exposed to the injected CO_2. These wells can be abandoned wells as well as production, injection and disposal wells.**
- **Adjacent wells can have well integrity issues that might allow CO_2 to leak into the surroundings.**

There are challenges concerning the design of these adjacent wells, since they were not planned to withstand CO_2. The carbon dioxide in water is called carbonic acid and it is very corrosive to materials such as cement and steel. This situation can over time cause damage to downhole tubulars and mechanical barrier elements and lead to degradation of well integrity.

The general concern regarding CO_2 injection wells is the need of a common recognized industry practice related to design of CO_2 injection wells. This includes qualification of well barrier elements and testing related to CO_2 for medium to long term integrity and low temperatures. A CO_2 resistant design includes considerations related to CO_2 resistant cement, casing, tubing, packers and other exposed downhole and surface equipment.

A common industry practice is also needed concerning plug and abandonment of CO_2 injection wells and adjacent wells.



- **Proposed ISO standard related to CO_2 injection well design and operation.**
- **DNV – "Guideline for risk managment of existing wells at CO_2 geological storage sites" (CO_2WELLS)**

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