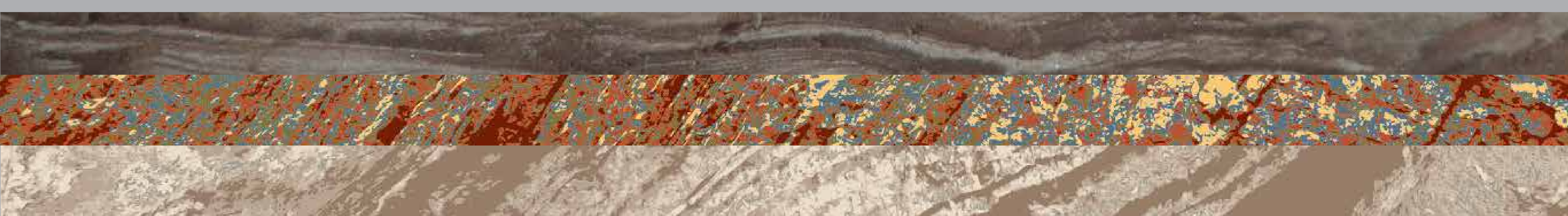
3. Methodology



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.

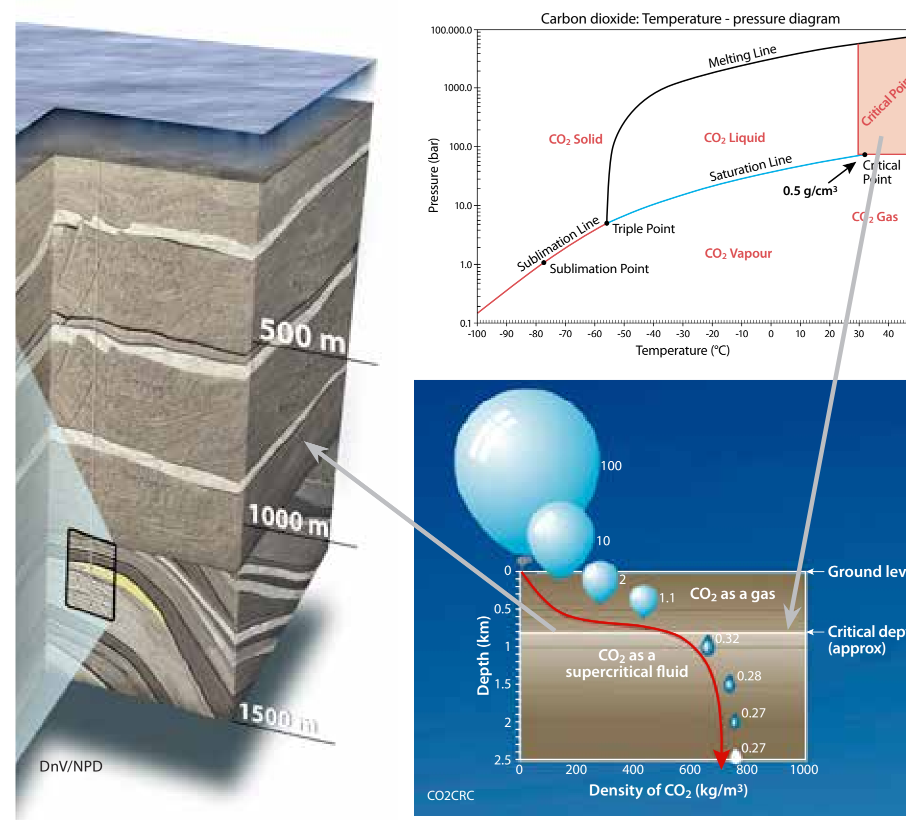
Porosity is a measure of the space in the rock that can be used to store fluids. Permeability is a measure of the rock's ability to allow fluid flow. Permeability is strongly affected by the shape, size and connectivity of the pore spaces in the rock. By contrast, the seals covering the storage formation 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.

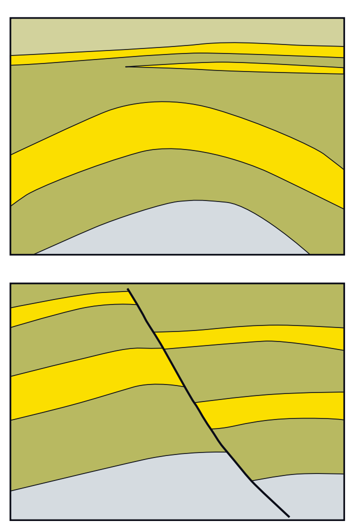
The reservoir is the part of the saline formation that is generally contained within a structural or stratigraphic closure (e.g. an anticline or dome). Therefore it is also able to physically trap and store a concentrated amount of oil and/or gas.

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.

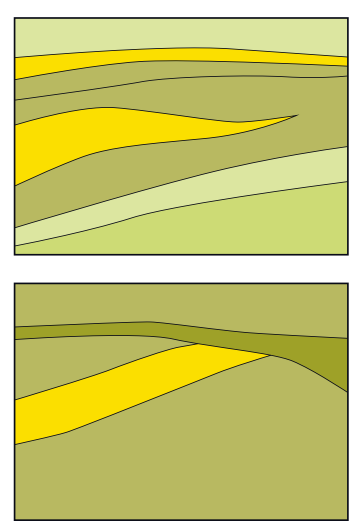
An aquifer is a body of porous and permeable sedimentary rocks where the water in the pore space is in communication throughout. Aquifers may consist of several sedimentary formations and cover large areas. They may be somewhat segmented by faults and by low permeable layers acting as baffles to fluid 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.



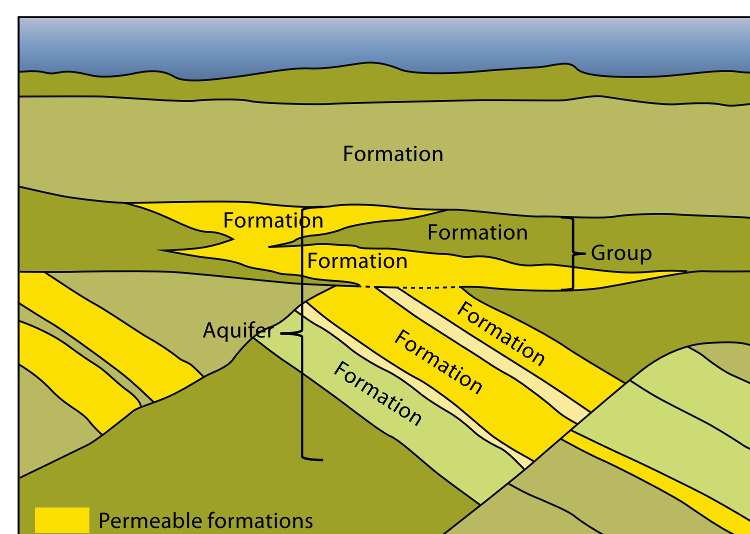
Supercritical fluids behave like gases, in that they can diffuse readily through the pore spaces of solids. But, like liquids, they take up much less space than gases. Supercritical conditions for CO_2 occur at 31.1°C and 7.38 megapascals (MPa), which occur approximately 800 meters below surface level. 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. Methodology

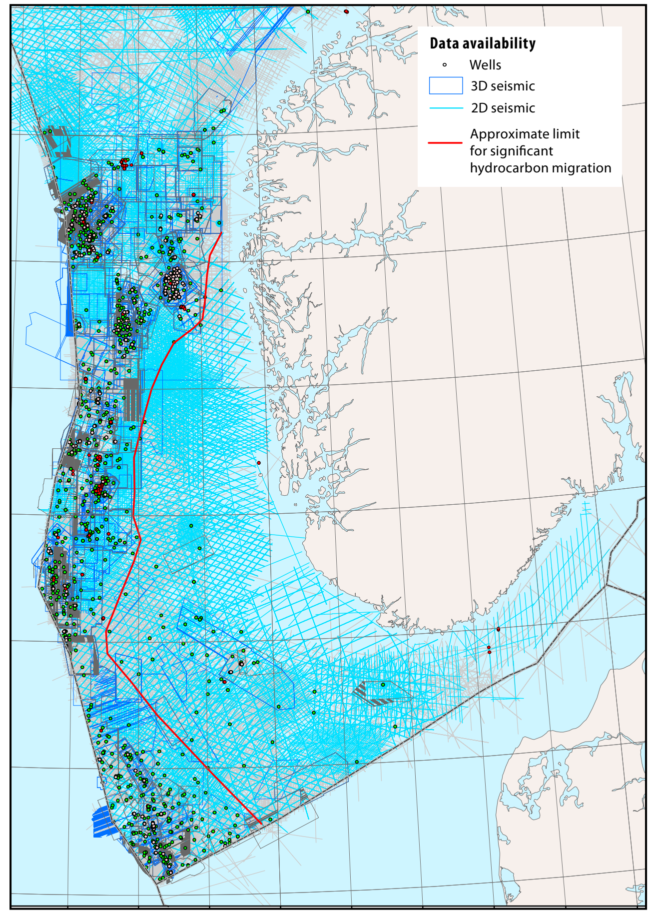
3.2 Data availability

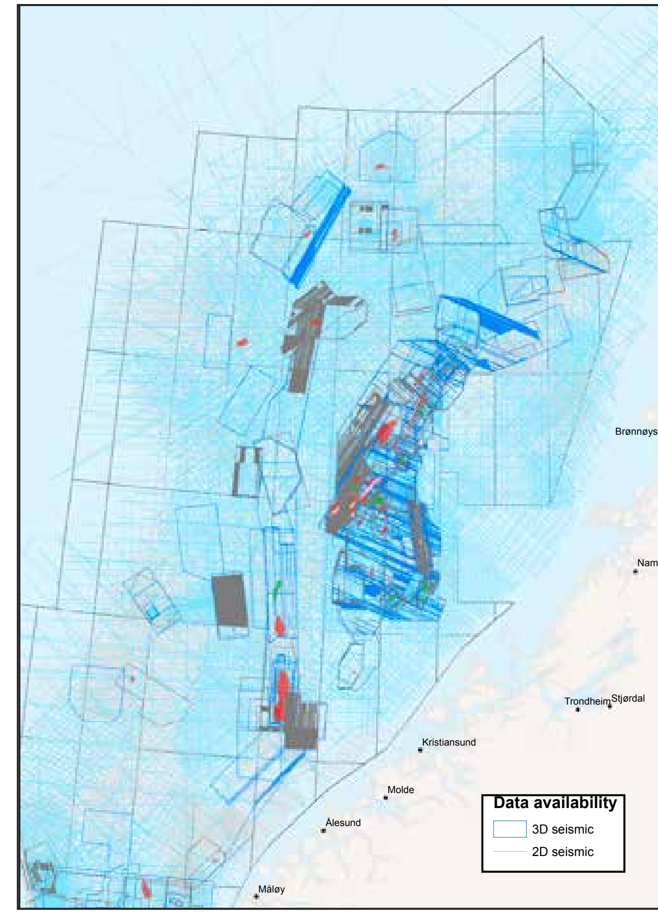
The authorities' access to collected and analysed data is stipulated in law and based on the following statements: "The Norwegian State has the proprietary right to subsea petroleum deposits and the exclusive right to resource management" and "The right to submarine natural resources is vested in the 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".

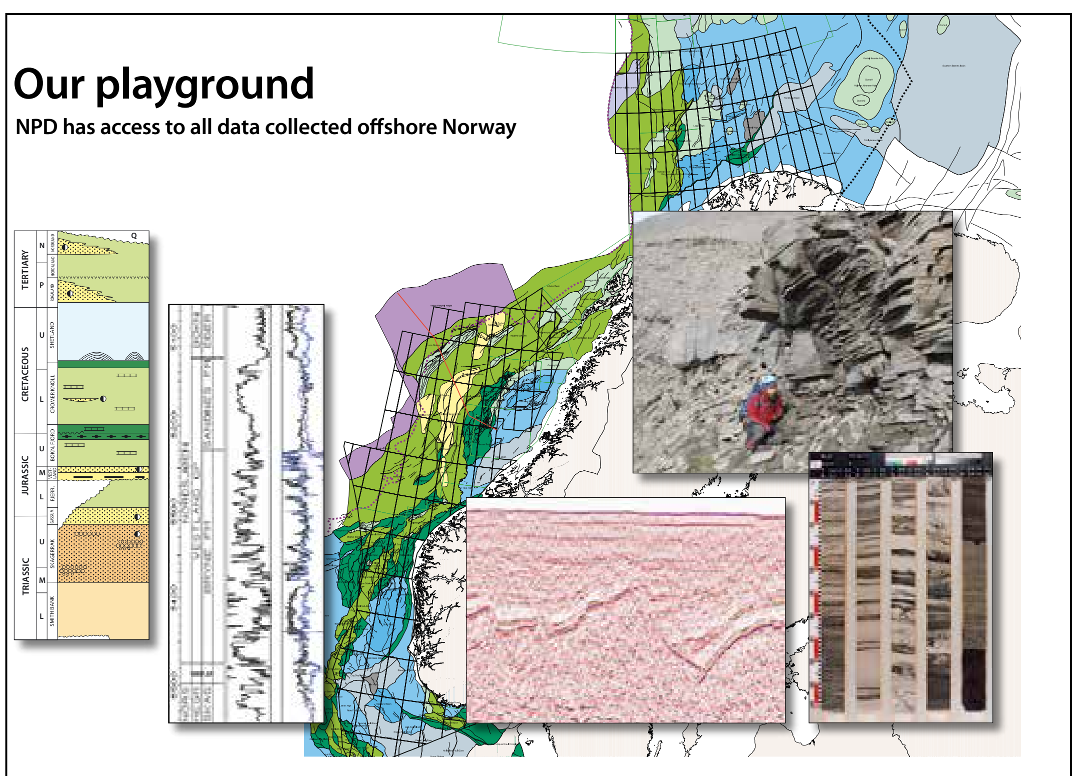
The Norwegian Petroleum Directorate (NPD) has access to all data collected on the NCS and has a national responsibility for the data. The NPD's data, overviews and analyses make up an important fact basis for the oil and gas activities.

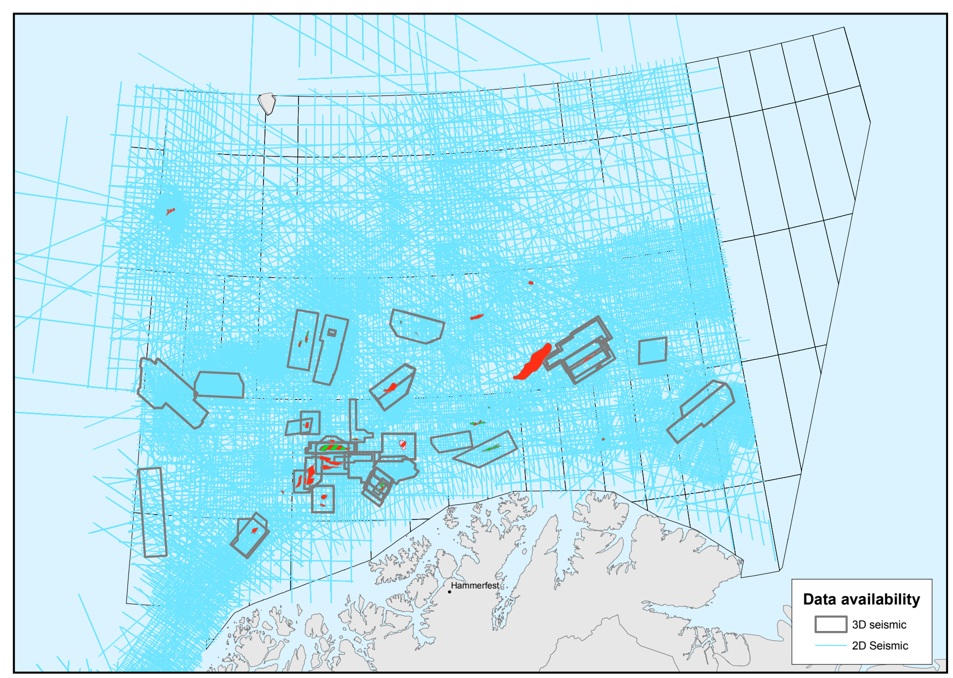
The main objective of these Reporting Requirements from the NPD is to support the efficient exploitation of Norway's hydrocarbon reserves. More than 40 years of petroleum activity has generated a large quantity of data. This covers 2D and 3D data, data from exploration and production wells such as logs, 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/

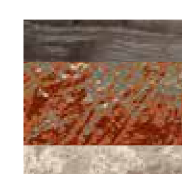








Seismic coverage



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 supercritical 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.

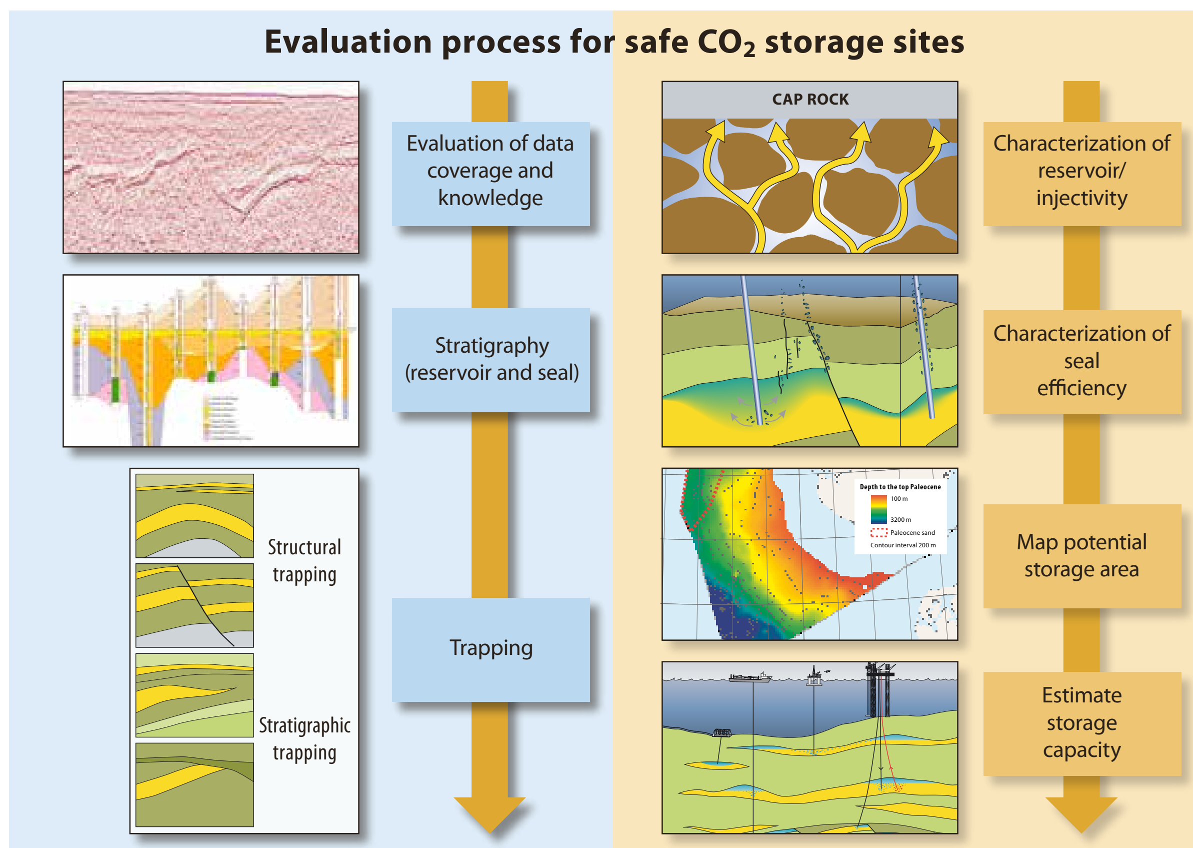
Natural seepage of gas is commonly observed in the hydrocarbon provinces in the Norwegian continental shelf. Such seepage is expected from structures and hydrocarbon source rocks where the pore pressure is close to or exceeds the fracture gradient. Seepage at the sea floor can be recognized by biological 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

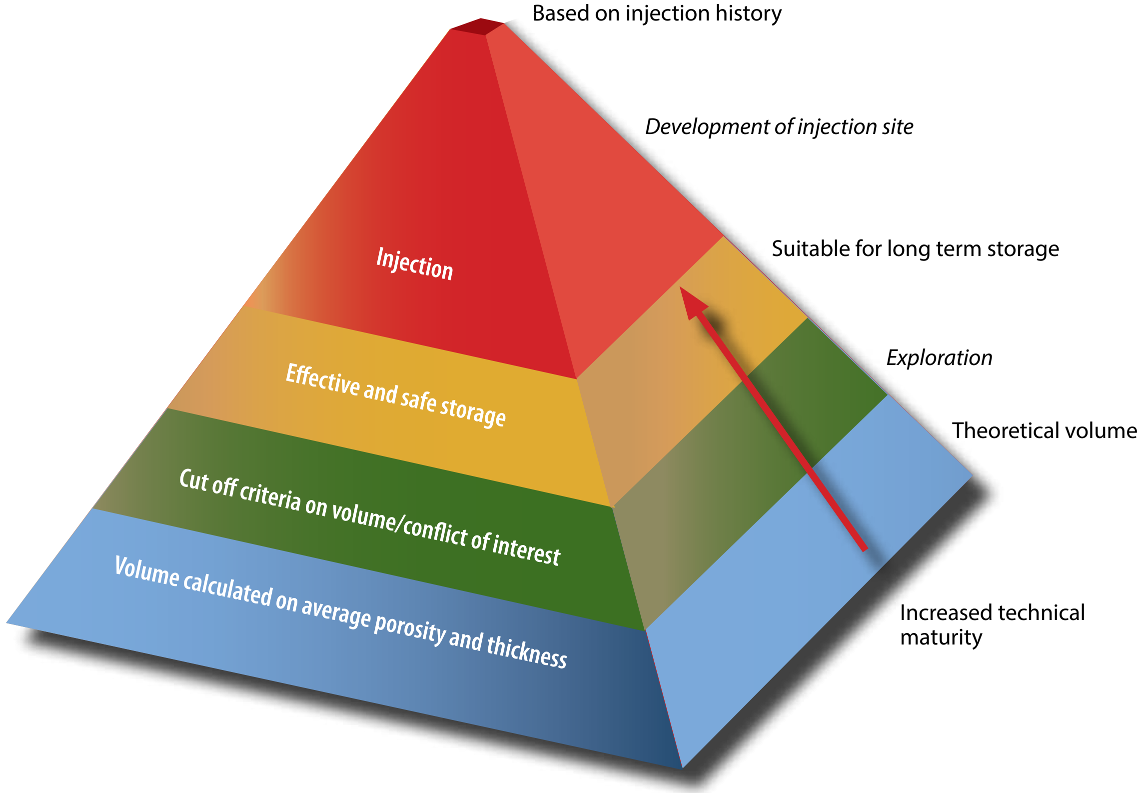
NPD's approach for assessing the suitability of the geological formations for CO_2 storage is summed up in this flowchart. The intention is to identify, in a systematic way, the aquifers and which aquifers are prospective in terms of large-scale storage of CO_2.

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.



3. Methodology

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.

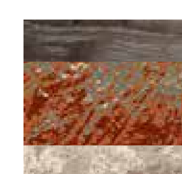
Step 4 is the phase when CO_2 is injected in the reservoir. Throughout the injection period, the injection history is closely evaluated and the experience gained provides further guidance on the reservoirs' ability and capacity to store CO_2.

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.

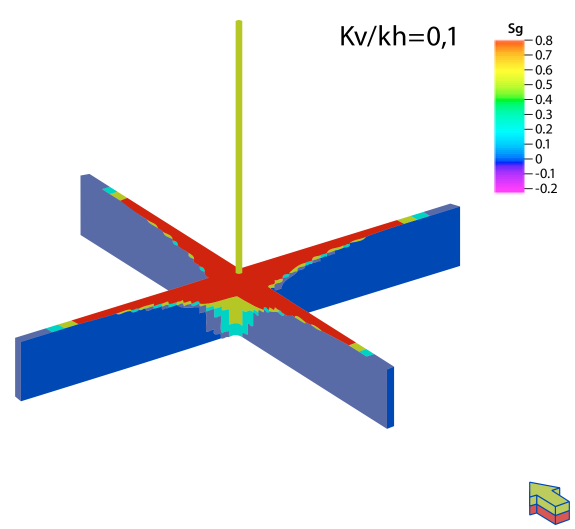
The injection rate will depend on the permeability and how much of the reservoir is exposed to the injection well. The number of wells needed to inject a certain amount of CO_2 will depend on the size of the reservoir and the injectivity.

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.

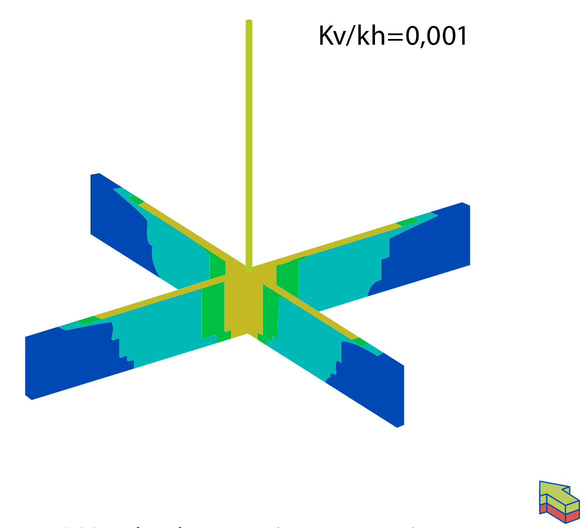
If the reservoir is in communication with a large or open aquifer, the reservoir pressure will stay almost constant during CO_2 injection, as the water will be pushed beyond the boundaries of the reservoir. The CO_2 stored will be the amount injected until it reaches the boundaries. The storage efficiency 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.



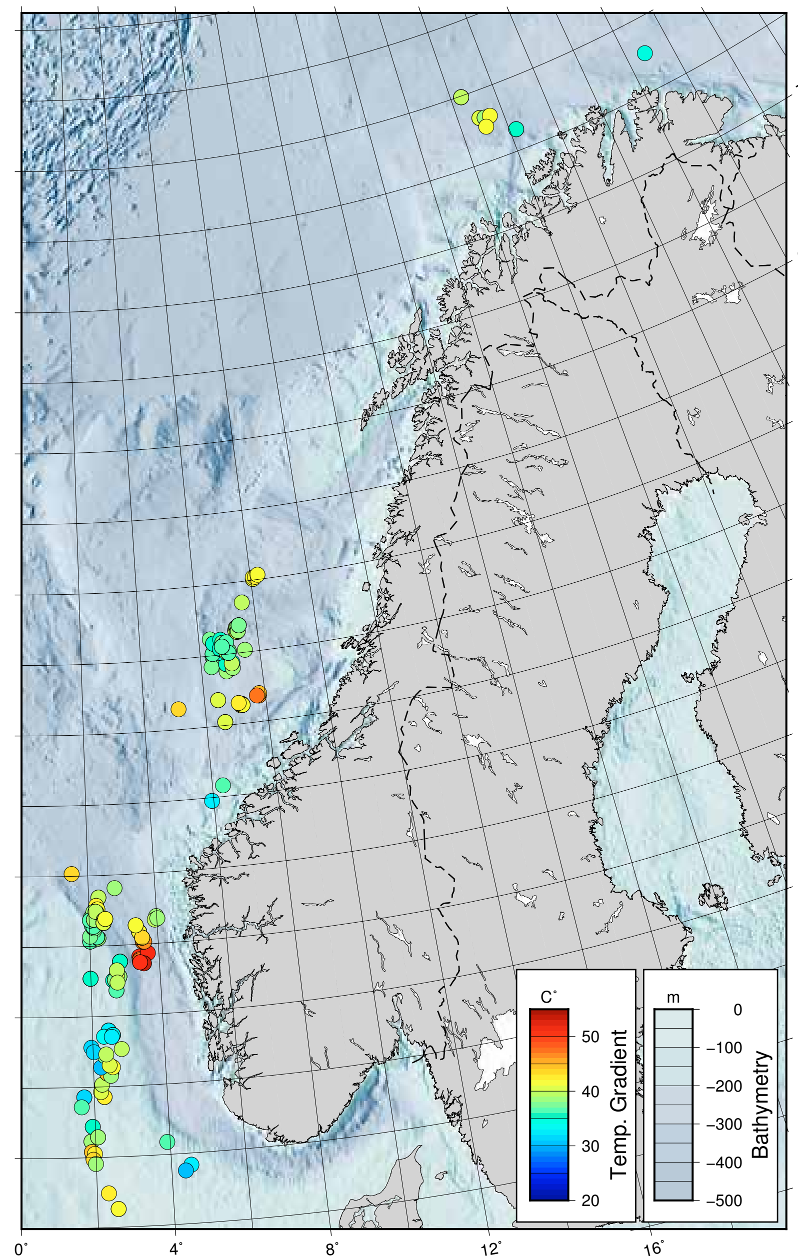
SCO_2 development (open system)



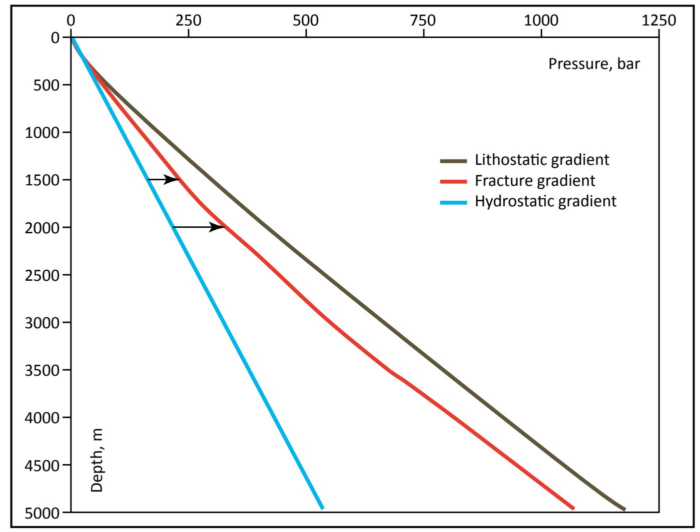
SCO_2 development (open system)

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