Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide

Guidance Document 2

Characterisation of the Storage Complex, CO_2 Stream Composition, Monitoring and Corrective Measures

Climate Action

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Purpose of Guidance Document

This Guidance Document (GD) is part of the following set of Guidance Documents:

- Guidance Document 1: CO2 Storage Life Cycle Risk Management Framework

- Guidance Document 2: Characterisation of the Storage Complex, CO_2 Stream Composition, Monitoring and Corrective Measures

- Guidance Document 3: Criteria for Transfer of Responsibility to the Competent Authority

- Guidance Document 4: Financial Security (Art. 19) and Financial Mechanism (Art. 20)

The purpose of this set of Guidance Documents is to assist stakeholders to implement Directive 2009/31/EC on the geological storage of CO_2 (so-called CCS Directive) in order to promote a coherent implementation of the CCS Directive throughout the European Union (EU). The guidance does not represent an official position of the Commission and is not legally binding. Final judgments concerning the interpretation of the CCS Directive can only be made by the European Court of Justice.

This Guidance Document 2 (GD2) builds on the first Guidance Document (GD1) that has laid out the overarching framework and nomenclature for the entire life cycle of geological storage activities including its phases, main activities and major regulatory milestones. This non-legally binding document provides guidance on:

- Site selection;
- Composition of the CO_2 stream;
- Monitoring;
- Corrective measures.

It is important to recognize that the scientific basis for CCS is evolving, as more information is gained through the ongoing global research and development efforts. Thus, the scientific knowledge-base on issues such as mapping technologies for evaluating storage locations, injection technologies, monitoring technologies, significance of various components in a CO_2 stream, and application of corrective measures will improve over time.

1. Characterisation of the Storage Complex

Geological storage of CO_2 is at an early stage of implementation and practical development. It is based largely on well-established petroleum geology, reservoir engineering practices, and oilfield technology developed over the last 100 years. Currently, there is a limited amount of practical experience in identifying, characterizing, and injecting CO_2 for the purpose of geological storage in underground formations from pilot, demonstration, and a small number of commercial projects. Hence, practices for geological storage will likely evolve as large-scale CO_2 injection projects proceed.

Selecting an appropriate storage site is a crucial first step in improving the viability of a carbon dioxide capture and storage (CCS) project. A key consideration in site selection is the characterisation and assessment of the potential storage complex and surrounding area, so that risks of environmental and human health impacts can be either avoided or reduced. Poor storage site selection can increase financial and environmental risks enormously, and could set back the eventual CCS deployment, as new potential storage complexes and surrounding areas will have to be screened, selected, and characterised (see CO_2 storage life cycle risk management framework elaborated in GD1).

Over the last decade, there have been a number of articles published that describe approaches for assessment ranging in scale from a local site to regional and country assessments. Each have emphasised various aspects of the characterisation process, with some others only describing the technical disciplines and issues that may need to be addressed. Some, such as IEA GHG (2009), have provided prescriptive measures and acceptable ranges in table format of what the authors believe may or may not constitute a favourable or desirable site; e.g. be it onshore or offshore or poor or good reservoir quality.

At this early stage in the evolution of the assessment and development of a potential storage complex and surrounding area, what ultimately is deemed to be a favourable site, provided it has high integrity and will provide a safe and secure outcome, will probably be an interplay of geologicaland commercial aspects. In some instances, sites that may from an engineering perspective present some undesirable features (e.g. poor injectivity) when compared with other sites, might be more commercially viable to develop (albeit with more wells or horizontal wells) than perhaps building a long pipeline to a location with a more technically favourable reservoir interval[1]. Some aspects of a storage site may be able to be 'engineered' to be more favourable; e.g. by 'fraccing' the reservoir to increase injectivity or by the use of smart well designs. Thus, as a site is assessed and modelled, what may appear at a first pass to be a limiting technical aspect, could with engineering intervention, or smart design, prove to be technically and commercially viable. Some technical issues that

[1] Note: Any site chosen must meet the requirements specified in the Directive. The tradeoffs and comparisons discussed here would not affect that obligation.

might now appear to be providing uncertainty for geological storage (e.g. reservoir pressure build up), could evolve with time (through improved technological developments and industrial field scale experience) to become less critical in an assessment process. Thus, reliance on prescriptive measures of the necessary geological characteristics to consider or approve a storage site should be used with caution, and instead a holistic overview should be taken beyond just the local site characteristics and performance measures. Many models and scenarios will have to be developed and considered for any potential storage complex and surrounding area. Each new observation of the deep surface (by drilling and remote imaging) will update, modify and question each previous consideration and assessment.

This uncertainty in the subsurface, both the geological processes and current day conditions, highlights the reason why geological storage – and the characterisation of the potential storage complex and surrounding area as its first step – is where most of the uncertainty and risk lies in any integrated CCS project and where a robust risk management framework is of paramount importance (see Guidance Document (GD) 1).[2]

1.1 Legislative Context

Recital 19 of the CCS Directive notes that the "selection of the appropriate storage site is crucial to ensure that the stored CO_2 will be completely and permanently contained". Furthermore, Article 4 of the CCS Directive notes that:

- The suitability of a geological formation for use as a storage site shall be determined through a characterisation and assessment of the potential storage complex and surrounding area pursuant to the criteria specified in Annex I; and
- A geological formation shall only be selected as a storage site, if under the proposed conditions of use there is no significant risk of leakage, and if no significant environmental or health risks exist.

Annex I of the CCS Directive provides specific criteria for site and storage characterisation, and indicates that the assessment should be done according to best practices at the time of the assessment. In this chapter of the GD2, the best practices as of 2010 are described to provide guidance to the competent authority or authorities (CA or CAs), as well as to the project developers.

1.2 Overview of Approaches that the CA May Need to Consider

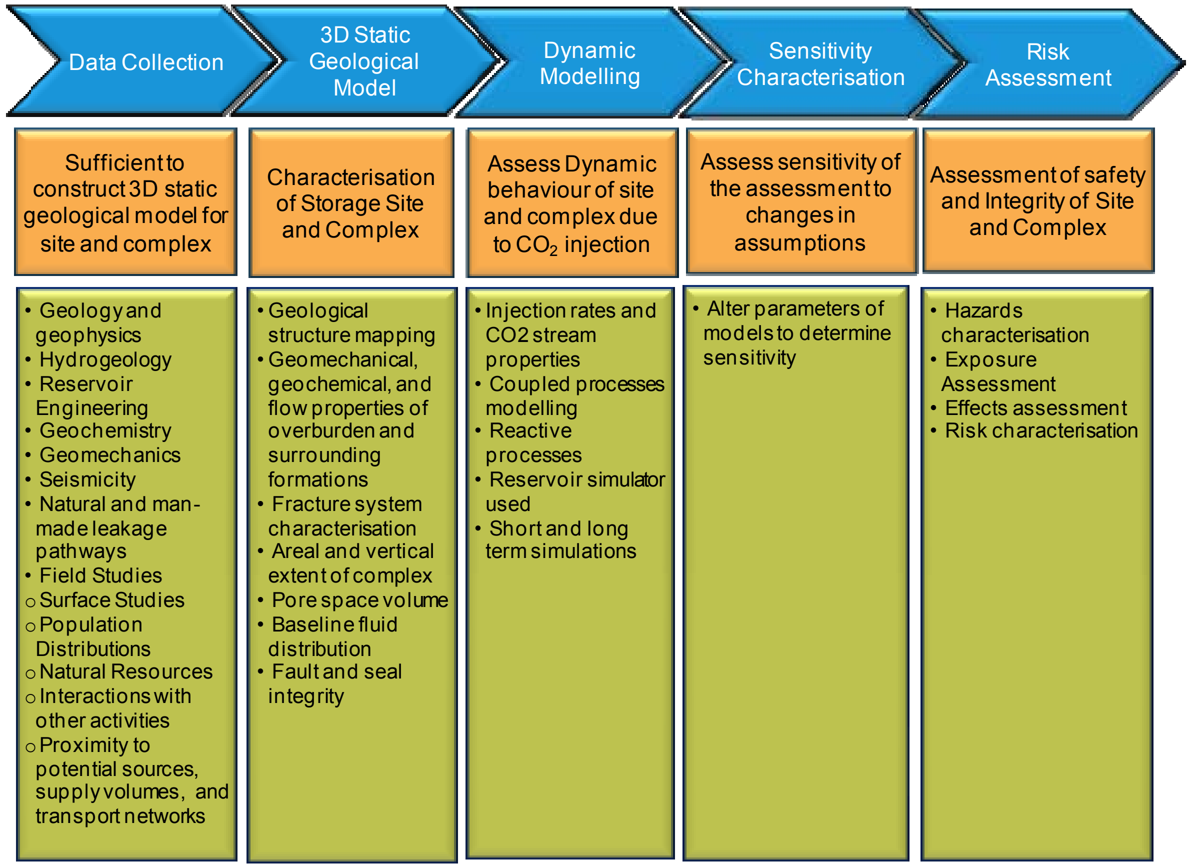
Searching for and "proving" a site for geological storage of CO_2 that will provide high integrity, and be both safe and sustainable for the injection and storage of CO_2,

[2] It is however worth noting that surface facilities (such as pipelines and injection facilities) have to be considered in any risk assessment of any integrated CCS project.

encompasses a variety of technical processes and iterative steps. The key elements of the different steps in the characterisation of the storage site and complex are denoted in Annex I of the CCS Directive, and are schematically shown in Figure 1. Note that the definition of the site and complex is discussed in detail in section 2.5.1. Each step is required to enable the transition between the various phases of the exploration and development cycles of sub-surface assessment, and to reach the levels of uncertainty and proof necessary to identify and prove a site. It should be noted that the risk assessment described in Figure 1 will continue on in the other phases of the project, as described in GD1.

The goal of the characterisation of the storage site and complex is to assess the site's containment, injectivity, capacity, integrity, hydrodynamics, and monitorability in order to ensure safe and permanent storage of CO_2. Note that while monitorability of the storage complex (i.e., the ability for an operator to develop appropriate monitoring plans to meet the CCSD objectives (see chapter 4)) is an important issue and critical for obtaining the storage permit, the operator and the CA should maintain a list of sites dismissed in the site selection process solely because of monitorability. Typically, the sites dismissed from consideration would be basins with good geological integrity, but they may not allow for effective monitoring of the plume. These dismissed sites (solely because of monitorability) could become future storage sites, as monitoring techniques evolve and new advances are made in the future.

Figure 1: Overview of characterisation and assessment of the potential storage complex and surrounding area, based on Annex I of CCS-Directive



Note: Orange boxes refer to "Goals"; Green boxes refer to "Items to be covered in each step"

The site selection process that an operator performs should be understood by the CA, and should be capable of leading to a transparent and informed decision making process. The CA should be confident that the performed characterisation and assessment of the potential storage complex and surrounding area will allow the the development to meet the conditions of the CCS Directive. The process of identifying a site for geological storage will consist of a series of assessments that progressively change scale, commencing with regional assessments, that screen and identify opportunities (known as leads in the oil and gas industry) which are often investigated based on a broad concept of an association of reservoirs, seals and trap types (known as plays in the oil and gas industry). The final identification of a potential storage site will trigger a much more detailed assessment at a specific location (known as a prospect in the oil and gas industry). As required in the CCS Directive, the selection of a storage site will have to be based on a characterisation and assessment of the potential storage complex and surrounding area. As part of the assessment, an operator will also have to document the potential interactions between the CO_2 storage and other sub-surface uses and potential resource conflicts (as discussed below in section 2.6).

In this GD, characterisation of the storage site and the storage complex can be considered to be mostly involved with assessments at different scales. Injection at a specific site will have influence on the storage complex and the surrounding area. A discussion of the extent of the storage complex is given below in section 1.5.1. The same fundamental assessment processes will be required at the scale of a site and a storage complex. Many of the products produced at a regional level in the assessment and exploration processes will be suitable for use in a storage complex assessment (e.g. a regional base seal structure map, seal quality and reservoir characteristics map).

Site Selection Steps

The steps in the site selection assessment process include components such as data collection and analysis, 3D geological modelling, dynamic modelling, sensitivity characterisation, and risk assessment (see Figure 1). Figure 1 is not intended to be an exhaustive work flow diagram that would be performed by operators. For example, items of an engineering, facilities or infrastructure nature (e.g. assessment of and plans for remediation of abandoned wells) are not listed in Figure 1, but should form an integral part of the characterisation and assessment of the potential storage complex and surrounding area in evaluation elements such as leakage pathways. These aspects could be considered on their own in isolation of the geology, but as there is an intimate link between the geology, engineering and development of a storage complex, some pertinent aspects relevant to the CA's consideration of characterisation of a storage complex and surrounding area are included in the following discussions.

To make an informed and knowledgeable decision on a development plan for storage, the CA will need to be conversant with these processes and data types, or have access to expertise (e.g. through an expert technical panel) that will help them review the work that an operator has performed and the development approaches that are contemplated.

This will not only include the expertise and knowledge that has been applied at the modelling and evaluation phases, but also the quality and reliability of the data that has been acquired, and the manner in which it has been acquired.

Pre-existing knowledge and data

The amount of pre-existing data, current knowledge and geological complexity of a site will influence the decision as to what is required to search for, prove, and develop a geological storage site at any given location. As such, some sites and storage types may more rapidly be able to reach levels of proof than others. In addition to the differences related to production versus injection, the amount and type of data and knowledge acquired to prove and develop an oil or gas field, could vary significantly from that required to prove and develop a geological storage site.

The CA may need to consider whether the characterisation and assessment of the storage complex and surrounding area is based on data specifically oriented towards CO_2 storage. Characterisation based primarily on data acquired for the purposes of oil and gas assessment may be incorrectly focussed, as the data may have been acquired in an inappropriate manner or at incorrect geological locations for CO_2 storage (see section 2.3.1).

The CA may need to consider the regulatory processes that are in place for approvals of oil and gas development in a Member State are likely to vary subtly or deviate substantially in different aspects from the assessment and characterisation operations of a CO_2 storage site and complex including the surrounding area. While the technical approaches are mostly similar, the volumes, time frames and approach can be significantly different for large industrial development for geological storage of CO_2.

A good example of the above is that in an oil and gas operation it is possible to prove that the seal works with a single well, by the simple fact that oil or gas has been trapped in an accumulation in a geological structure. For a storage operation, a single well cannot always be definitive, as the seal may be heterogeneous and be different from that single measured location. Often, once a seal is proven to be effective for trapping hydrocarbons, by existence of a hydrocarbon accumulation, an oil or gas operator is unlikely to take core data from the seal in that field. So it is possible that an oil and gas field may have limited physical information on some aspects that are imperative to have physical information on for geological storage. Additionally, the fact that a seal has effectively trapped hydrocarbons (oil or gas (methane)), does not automatically mean that it is effective also for CO_2. It is always prudent to assess the actual seal characteristics in a laboratory before storage commences. However, for an oil or gas reservoir, there may be information from other sources that, in some cases, provide sufficient assurance of the seal properties. In such cases, it may not be necessary have laboratory data on the seal characteristics (implying that cores would have been obtained from the seal layer). In addition, such laboratory testing of seal rock (through drilling) may be very expensive for sub-sea floor saline aquifers (see Glossary for definition).

Irrespective of the storage category (such as depleted oil and gas fields, enhanced hydrocarbon recovery, saline aquifers, and coal seams) for which a characterisation and assessment has been considered, each individual storage site and complex should reach, from prima facie evidence, an approved level of certainty, and ensure that the site will provide high storage integrity, and be both safe and sustainable for the injection and storage of CO_2 as required under the CCS Directive.

Connectivity and Pressure Build-up

If an oil or gas field has commenced operation having achieved a near certainty of a minimum economic field size limit being reached, and as anticipated the reservoir starts with a high production rate and then declines due to a lack of water drive support due to poor reservoir connectivity, then new wells and or water injection can be implemented at that point in time to ensure that the site remains commercial. Predicting the occurrence and timing of connectivity issues is not an easy task without a lot of data and observational information on fluid flow characteristics, which requires substantial characterisation of the reservoir with many wells and repeat seismic data which normally occur during the field development production process. The oil and gas operator can decide at the time of pressure draw down whether to continue with the operations and progressively gain more knowledge about the reservoir as they continue to develop it, or walk away with a given profit.

For storage, however, if there is a pressure build-up due to poor reservoir connectivity or heterogeneity, then more wells can be drilled over time. The storage operator will need to know the reservoir characteristics to a much higher certainty at the start of the operation so as to be able to predict the possibility of pressure build-up, and thus minimise the risk of the longer term commercial and technical viability of a site. Thus, there may need to be more wells drilled at an earlier stage to understand such connectivity issues for storage than would ordinarily occur in an oil and gas field development. This can put financial burden on a storage operator. Furthermore, if the storage operator has to cease injection ahead of the planned time due to unplanned or unknown risks cropping up at a later stage, then there can be a problem with the CO_2 source having to emit CO_2 at potentially an additional cost, as well as the cost involved with a dedicated pipeline that was built and not used for its full life expectancy. Hence, a storage operation is, at the characterisation stage, mostly all a cost with no profit, and thus any high levels of uncertainty could jeopardise long term viability.

The impact of pressure build-up will be a serious issue at a technical level for all storage sites to address and contend with. Each site will need to be assessed individually in terms of local impact on fracture gradients (see Glossary below), but if there is regional hydraulic communication, there will need to be consideration of how the basin pressure system is managed at a regional level. There will always be an option to "engineer the reservoir" at the later stages of characterisation to reduce or avoid any pressure build up that will occur with large scale CO_2 injection across multiple sites in a basin. This can be done by producing formation water from the injection formation,[3] thereby controlling the pressure build up, and transferring that formation water to either be used at the surface facilities if not too saline (e.g. in the power plant or coal mine), or to inject the formation water into a lower or higher stratigraphic units that are not in pressure communication with the target storage formation reservoir,[4] and thereby spreading the pressure increase over a wider volume. The injection site on Barrow Island for the Gorgon project in Australia plans to manage pressure by utilising water production wells, as described above.

[3] Breakthrough of CO_2 to the producer wells can be controlled by positioning the producer well far away from the injection well and in a lower part of the injection zone.

[4] Note that a separate permit may be required to reinject produced water.

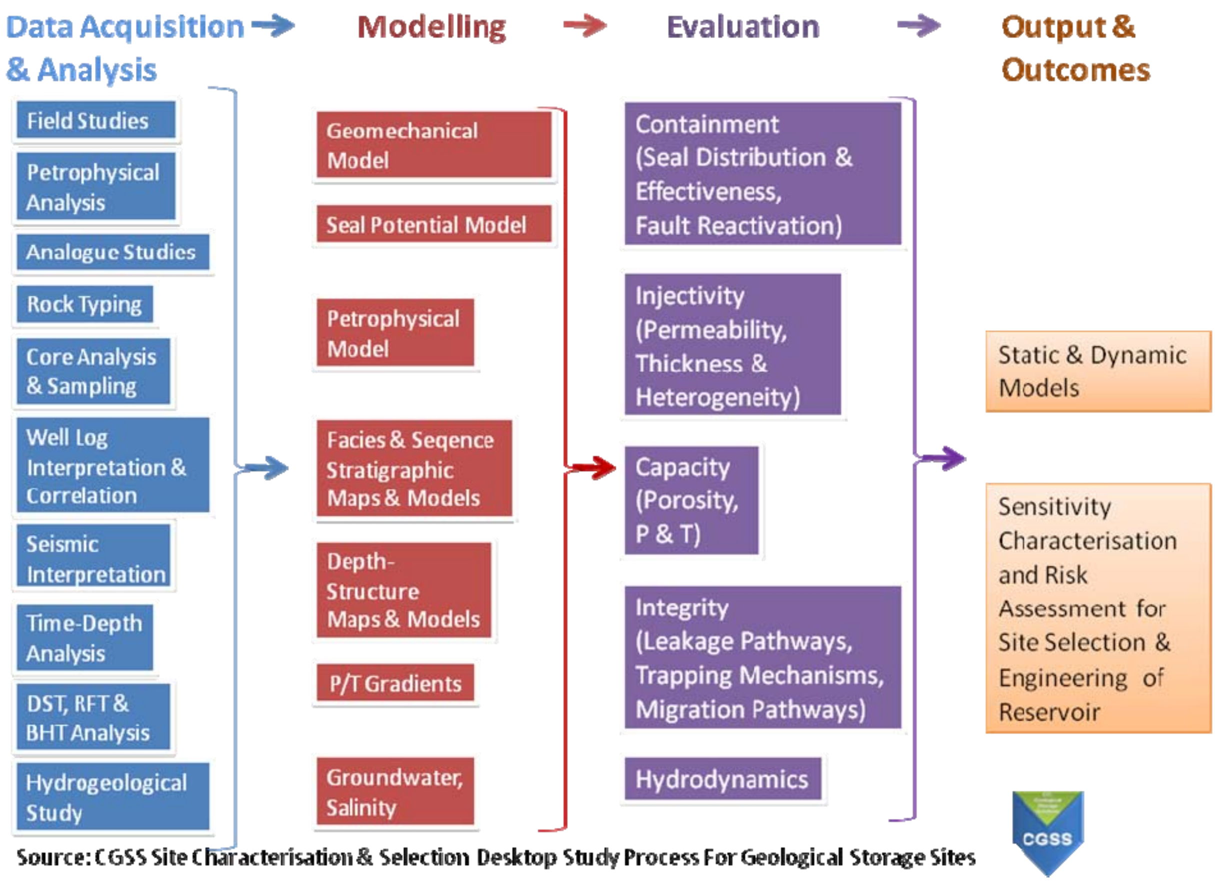
The CA will need to consider the regional impacts of pressure build up both locally and throughout the storage complex when examining the characterisation of the potential complex and surrounding area. Ultimately, if CO_2 storage is deployed at a large scale across a single basin at many sites, it is likely that it will be necessary to implement a basin wide pressure management system.

Emphasis on Storage-focused assessments

The type of examples described above suggests that compared with oil and gas operations, there may be a greater emphasis on the need to acquire, analyse, model and interpret the data for storage operations. The data needs to be accurate enough to allow long term forecasts, but there needs to be allowance in the margins of error or uncertainty in the site and complex characterisation that will allow the operation to proceed and be viable over the long term. This will be necessary for both technical and related commercial reasons, as described above, but also because of the concept of "learn by doing" which the geological storage industry may require.

Figure 2 shows some of the steps that an operator would need to do in order to process the collected data into the geological models and risk assessments, as shown in Figure 1. This figure indicates that there are a lot of interim steps with modelling that are needed to develop an assessment of containment, injectivity, capacity, integrity, and hydrodynamics. There is also significant interdependency of data, modelling and evaluation with geoscientific information. Hence, the CA needs to adequately understand these processes if they are to be comfortable with the decision processes in the site characterisation and selection phases.

Figure 2: Interim steps for evaluating data for obtaining Geological Models



If one, or several of the data types in the data collection and analysis steps are not appropriately acquired or analysed, or there is significant uncertainty as to what the information actually means, then it can have implications throughout the entire process of modelling and evaluation. It can potentially bias the outputs and outcomes of the characterisation process, and then ultimately impact on viability of the mechanisms by which approval decisions have been made, both for the CA and the storage site operator.

The CA will need to focus upon issues associated with the primary data acquisition and analysis for each storage site and complex characterisation so as to be confident in the outcome of the storage site assessment.

Discussion of the various data types and modelling aspects and their characteristics are dealt with specifically in sections 2.6 and 2.7. The EU funded project 'Characterisation of European CO2 storage (SITECHAR)' aims to improve and extend standard site characterisation workflows in Europe. As part of this project, site characterisation workflows are to include assessment of risks and development of monitoring plans necessary to reach the final stage of licensing.[5]

[5] http://cordis.europa.eu/search/index.cfm?fuseaction=proj.document&PJ_LANG=EN&PJ_RCN=11515502&pid=0

1.3 Different storage categories – key issues

There are three principal categories for geological storage of CO_2 that are likely to be implemented at the industrial scale: depleted oil and gas fields, enhanced hydrocarbon (oil and gas) recovery (EHR; EOR and EGR), and saline aquifers, as introduced in section 5.2 of GD1. Each category has its own particular characteristics due to their different trapping mechanisms and geological characteristics. Other options are being examined for storage (e.g. deep unmineable coal, enhanced coal bed methane, basalts, organic rich shales, etc; see Table 3 in GD1), but they are not yet suitable for storage as they do not provide the required injection rates to match industrial deployment, or require much more research and development, or have not reached a proof of concept stage.

The CA will need to be aware of the fact that the technical levels of proof, commerciality, and knowledge required to develop different geological sites for the different storage categories will be highly variable. Thus, the storage permit approval process may need to be flexible, be specific to the site and the storage category, and focus on the specific trapping mechanisms and site development approaches.

Insights and some examples of the differences among the key storage categories are described below.

1.3.1 Depleted Oil and Gas Fields

Oil and gas field development involve the production of hydrocarbons from the deep sub-surface, through the drilling of wells into hydrocarbon accumulations that were previously discovered in a petroleum/gas exploration phase. The hydrocarbons are then produced over a period of approximately 10 to 30+ years, depending on the size of the accumulation and the complexity of the geological characteristics at the site.

Over the life of an oil and gas field, substantial amounts of well and seismic data will be acquired, including reservoir engineering data associated with the fluid flow characteristics of the reservoir interval, and facilities knowledge associated with the operation, management and maintenance of the infrastructure at the site. There may also be a significant amount of information from reservoir modelling for these sites. Thus, these depleted oil and gas fields could provide a good starting point for CO_2 storage characterisation.

However, there may be additional data and knowledge requirements that are needed for CO_2 storage, but are often not a primary concern for hydrocarbon production. For oil and gas fields there will be much less or no emphasis on the evaluation aspects of integrity and containment, and the capacity will focus on the oil or gas reserve volumes, not CO_2 storage pore volume, which are very different concepts requiring different approaches. Although static geological models and dynamic reservoir simulation will be maintained in oil and gas fields, the focus will mostly be on short term, near field aspects, not long term and far field matters (e.g. including migration and leakage pathways). The reservoir engineering information and production data will, however, allow for a history match between the models produced and the actual reservoir field data—such history matching is indeed useful for modelling of CO_2 storage (see section 2.8.3 and GD3).

Furthermore, some of the data from a depleted oil and gas field may have obtained using older technologies. For example, seismic data from oil and gas fields is highly likely to have been acquired prior to the discovery of the field by drilling, and during the production of the field. Most modern fields, including those in most parts of the North Sea, will comprise both two- and three-dimensional (2D and 3D) seismic data, while older abandoned fields may only have 2D seismic data. It is also unlikely that extensive modern seismic data will have been acquired near or at the completion of an old oil and gas fields' life, unless the operator was searching for unrealised hydrocarbon accumulations in or adjacent to the depleting field. Moreover, even if a reasonable seismic data was acquired, there may be water invasion of the field after the end of production. In that case, pressure conditions in the reservoir may have altered substantially from the most recent seismic data set.

Hence, the extent to which the existing petroleum geology and reservoir engineering modelling and evaluation information is relevant will need to be carefully assessed and put into the context of what the intended outputs and outcomes were for the oil and gas field, as it is possible it may have an inappropriate focus or not consider vital aspects of storage (e.g. migration and leakage pathways). It is, therefore, likely that to do a thorough storage site and storage complex characterisation of depleted oil and gas fields will require revisiting or starting afresh for some of the existing data sets and modelling aspects to ensure they have the correct emphasis on storage site issues. For example, in some oil and gas fields, geomechanics may not have been fully accessed, in such cases, a detailed analysis of geomechanics is needed.

The CA may need to be confident that the storage site and storage complex characterisation based on an oil and gas field has gone through an appropriate review process to ensure that data or assessment reports have the correct focus to adequately characterise a storage site and storage complex.

A typical hydrocarbon field may involve many production wells, both as vertical wells, sidetracks off the main wells, and sometimes horizontal or sub-horizontal wells in the reservoir formation. Some large fields, especially those with poor permeability, may contain hundreds of wells, and if a large offshore field, may comprise multiple production platforms. If a well is not compliant to a level that guarantees no likelihood of leakage of potential stored CO_2, it may effectively limit the efficacy of using such fields as storage sites, or introduce high costs to remediate the wells. In some instances, using sidetrack wells for remediation may either be commercially or technically impractical.

During the production and injection of fluids in an oil and gas field development, the rock volume will undergo a change in its pressure regime and there will be significant fluid movement, with possible alteration of the geomechanical, physical and geochemical fabric of the rock, thus altering the sub-surface conditions. Changing these conditions can lead to subsidence or uplift of the neighbouring storage complex. The geomechanical and geochemical conditions and stability of the sub-surface will need to be assessed at the end of the field life, and prior to any reuse of an abandoned field for geological storage.

The CA needs to make sure that the operators are aware in their consideration of a storage site and storage complex characterisation for an abandoned oil and gas field that the data acquired during exploration and production, and/or at the end of the field life, may not accurately represent the current day sub-surface conditions.

Towards the end of the life of an oil and gas field, it is likely to have increased production of water with the hydrocarbons, and if there is pressure reduction in the sub-surface reservoirs, there will be a subsequent reduction in the rate of production of fluids to the surface. This pressure reduction may result in implementation of secondary recovery methods that inject fluids (gas and water) into the reservoir to maintain higher production rates. If the field has been abandoned, prior to being considered for geological storage of CO_2, the condition in which it was abandoned and any maintenance matters associated with wells and infrastructure will need to be carefully investigated.

The CA will need to consider whether the proposed operator has carefully taken into account the way in which depleted oil and gas wells have been managed, maintained, completed and abandoned during their life, based on a petroleum field standard of abandonment. The proposed operator and the CA would have to assess whether those standards are compliant with the requirements of the CCS Directive for CO_2 storage.

The conditions of the abandoned wells should be considered on a case-by-case basis, and if remediation is required, it is important that the potential operator and the CA consider who is responsible for remediation of abandoned wells. Remediation could, for example, be the responsibility of: a) the petroleum operator (unlikely if they are legally approved abandoned wells), b) the storage operator who takes over the field, or c) the MS if they are legally approved abandoned wells. CAs and the potential storage operators will need to carefully consider and have in place a plan detailing how the liability is dealt with for abandoned wells. These issues will need to be resolved before the storage permit is awarded.

Storage of CO_2 in depleted oil and gas fields introduces two aspects which relate to timing. The first is whether the site is already abandoned, and the other is availability, or when will the site be depleted.

If the site has been abandoned, then the data that relates to the field (well completion reports, well logs, engineering data, production data, history matching of the production data, infrastructure plans, reservoir static and dynamic simulation models, etc) may not have been either adequately or completely archived or delivered to the

CA, or be in formats that are not accessible (e.g. in data formats from old software programs that are no longer supported). If the site has changed ownership during the life of the field, then there may also be a loss of corporate knowledge over time as to how the field was developed or how a well was actually completed and maintained.

If a site is nearing depletion, then the operator will be in a phase of nearing a point for abandoning the site. While that timing is mostly predictable based on declining production rates, it can vary depending on the fluctuating commercial value of hydrocarbons; either shortening or extending the field life. Aligning the timing of field abandonment with the availability of a source of CO_2 could be challenging, especially if the field is an offshore platform with high operational and maintenance costs, and perhaps with legal obligations to remediate a site immediately once the petroleum operations cease.

A CA needs to consider the potential to ensure that at, or near abandonment of oil and gas field developments, appropriate archiving of all relevant data and knowledge occurs in collaboration with the existing operator, so as to be able to have the information available at a future date in case geological storage of CO_2 might be considered at the site. Furthermore, such data will have to be transferred to the CA at the time of transfer of responsibility (see GD3).

Bearing in mind the issues raised above, several aspects of site characterisation for depleted oil and gas fields need to be considered that ensure the preservation of all data from a geoscience and engineering viewpoint for exploration, production and abandonment. As raised earlier, the engineering aspects could be considered on their own in isolation of the activities of the geological assessment, but as there is an intimate link between the geology, engineering and development of a site, some pertinent aspects relevant to the CAs consideration of characterisation of a storage site and storage complex and surrounding area (especially potential leakage pathways) are included below.

From a materials, equipment and engineering viewpoint this will include:

- Knowledge of the infrastructure (surface and sub-surface), and materials, and their CO_2 compliance (e.g. cement types, procedures and bonding effectiveness; pipeline and well steel characteristics, etc.);
- Documentation of critical matters associated with well management, development, and maintenance and abandonment procedures (e.g., full details of perforations and patches in the casing in the wells and their adequacy or effectiveness, location and knowledge of equipment lost or abandoned in the well, etc);
- Complete description of the nature, engineering and location of wells drilled and all the approval processes and methods employed (e.g. sidetracks drilled, casing and step-off points, directional drilling data, etc.).

At any sub-surface development facility, there is a risk of well failure through pressure build-up, materials failure, inadequate engineering practices, lack of appropriate supervision or expertise, shortcomings in record keeping and/or poor regulatory oversight, which in a worst case scenario could lead to leakage and/or a blowout with subsequent costly intervention requirements, and could also result in risks to health and safety and environmental damage.

A CA will need to be vigilant in the re-development of an abandoned field for geological storage, providing careful and diligent overview, especially in the development, remediation and re-entry of wells.

From a geoscience perspective, there is a possible flaw in the argument that all depleted oil and gas fields provide assurance for the storage of fluids over a geological timescale as they have already contained oil and gas over a geological timescale. While this is technically correct (Bradshaw et al, 2005) the following needs to be considered for depleted oil and gas fields:

- Many hydrocarbon fields exhibit a leakage signature, and sometimes this is how they are discovered.
    - They may not always be filled with commercial volumes of hydrocarbons, suggesting either not enough hydrocarbons entered the trap to fill it, or it was filled with hydrocarbons and they have in the geological past, or are in current time actively leaking, or
    - They may have spill points within the trap or conduits (faults) or imperfect seals within or intersecting the field, from which oil and gas could be actively leaking, or
    - They may have leaked during periods of tectonic activity long ago. The leakage signature could be the remnants of an "old" leakage event (in the event of a gas leak these are known as a gas chimneys and are often definable from seismic data).
- Many fields only trap oil and not gas (methane), and so the seal needs to be assessed in relation to the storage of CO_2 independently.

Hence, the prior presence of an accumulation of hydrocarbons at a proposed CO_2 storage site, whilst a very positive sign for geological storage considerations for site characterisation, really only means the site has been effective in trapping the volume of and type of fluids they actually contain at the current time. It does not mean that site does not leak hydrocarbons at present or in the past, or would not leak CO_2 if it was stored at the site. However, the converse argument (i.e., if no hydrocarbons are present in a geological trap, it absolutely means the seal is not effective) is not true, as there may not have been any hydrocarbons generated in the sedimentary basin, or hydrocarbons did not migrate into the trap being examined, or that the trap formed after the hydrocarbons were generated and migrated.

In general, the potential operator and the CA will need to assess the prima facie evidence for all aspects of the quality of seals and trapping methods being investigated for each potential storage site and storage complex including surrounding area, be they either oil and gas fields or saline aquifers or other storage categories.

Reliance on a simplistic assumption that hydrocarbons have previously been trapped to prove the effectiveness of the seal will not be a prudent approach to characterisation of a potential storage complex and surrounding area.

1.3.2 Enhanced Hydrocarbon Recovery (EHR)

Enhanced hydrocarbon recovery (EHR), comprising enhanced oil recovery (EOR) and enhanced gas recovery (EGR), will provide opportunities to utilise CO_2 to increase the production of hydrocarbons from what may otherwise be a near depleted hydrocarbon field. It is also possible the EHR may begin to be used at earlier stages than near depletion of a field (e.g. as a cushion gas to maintain pressure and maximise production), but that will come at the risk and cost of having to process potentially co-produced CO_2 during the primary life of the field, rather than at near-depletion stages.

The CCS Directive (recital 20) defines Enhanced Hydrocarbon Recovery (EHR) as the recovery of hydrocarbons in addition to those extracted by water injection or other means. Where EHR is combined with geological storage of CO_2, the provisions of the CCS-Directive apply.

Many of the same advantages and disadvantages and issues associated with depleted oil and gas fields will apply. The only major differences could be that with EHR, there may be a natural transition from a producing hydrocarbon field to storage of CO_2, without the potential period of abandonment and potential loss of data and knowledge that may have happened in a depleted (abandoned) field. As CO_2 has already been injected with EHR, it would be assumed that the wells, materials and infrastructure handling and processing equipment will already be CO_2 compliant, thus saving on costs. However, as the field may not have been originally developed with CO_2 EHR in mind, it will be necessary to fully examine the condition of wells, materials and infrastructure at the site for ongoing long term storage of CO_2.

As for a depleted oil and gas field, there should be production data and a history matching of the produced fluids available, which will allow good predictions as to the reservoir performance for the injection of CO_2. EHR activities of production and injection may have resulted in damage to the reservoirs and seals during production which may lead to geomechanical failure. As many wells may have been converted from hydrocarbon producers to injectors and/or hydrocarbon and CO_2 producers, they will have had a longer life of maintenance and management, and so will need to be thoroughly assessed as to their ongoing suitability for geological storage of CO_2 from a materials and engineering failure perspective. There are examples of CO_2 blow outs due to materials failures in CO_2 EOR fields.

The experience of EOR projects has shown that it is difficult, especially in complex reservoirs, to fully determine the nature and fluid flow characteristics of the hydrocarbon reservoir, leading to inaccurate prediction of the timing of arrival of CO_2 at production wells, resulting in less efficient production of oil through EOR.

Thus, the geological data and modelling information associated with an EHR operation may need to be scrutinised carefully and objectively and on a prima facie basis for any new ongoing operation associated with geological storage of CO_2, to ensure it will provide both a high integrity and long term sustainable site for geological storage of CO_2.

CO_2 EHR fields, the study of the impacts of CO_2 in the subsurface, and the fluid flow characteristics from injection and co-production of CO_2 will provide invaluable experience and knowledge into the geological storage industry. This data set will greatly inform and improve the ways that geological storage site characterisation occurs, and improve the methodology for assessments.

CAs may align themselves to projects associated with CO_2 EHR and use that to benefit and improve the assessment approaches and methodologies of storage in other storage categories.

1.3.3 Saline Aquifers

Geological storage of CO2 in saline aquifers (see Glossary) is considered a key option because of their widespread distribution and large theoretical storage capacity, both in Europe as summarised by the European GESTCO and Geocapacity projects (Christensen,N.P., 2004;Vangkilde-Pederson, T., 2009) and in section 4.2.2 of GD1 and globally (IPCC 2005; Bradshaw and Dance, 2005).

In Europe the Sleipner project in the Norwegian North Sea has provided operating experience of CO2 injection and storage into a saline aquifer since 1996 at a scale of 1 million tonnes CO2 per year. This scheme involves injection into saline aquifers of the Tertiary Utsira Formation at a depth of around 800m subsea (Torp and Gale 2003). There has been extensive data acquisition, monitoring and modelling of the project as a demonstration of CO2 storage. Seismic imaging from repeat 3D seismic surveys has been particularly effective in understanding plume migration and demonstrates effective underground containment (Holloway et al. 2004; Chadwick et al, 2006) .

Unlike geological storage of CO2 in oil and gas fields, where numerous wells, seismic surveys and production history data usually exist, saline aquifers present a different challenge for storage site and storage complex characterisation due to the existence of less well and seismic data and little, if any, production data from the reservoir formation. However, many potential saline aquifer sites are, and will be, adjacent to mature oil and gas provinces with identical or similar geology. In many circumstances, a saline aquifer injection location will be located nearby and down dip from existing oil and gas fields. In parts of Europe saline reservoirs overlie deeper oil or gas fields, such as the Sleipner area and the Southern North Sea. In such circumstances, data from the wells drilled in and around oil and gas fields could provide information on aspects of saline aquifer and be used for the characterisation and assessment of saline aquifer as potential storage site and storage complex.

The characterisation and assessment of a saline aquifer storage site could be difficult because of the lack of data compared to storage in an oil and gas field. However, the saline aquifers normally have much less hazards from pre-existing well penetrations. Such pre-existing wells are widely recognised as being the largest technical risk for leakage of CO_2 from geological storage in oil and gas fields

The large theoretical capacity in saline aquifers combines potential for storage in both “confined” and “unconfined” or open aquifers (Bentham et al, 2005; Chadwick et al, 2006, Geocapacity; 2009). These reflect different trapping mechanisms with different requirements for the characterisation of the storage complex, which the CA will need to take account of. The relevance and importance of these will depend on the geology of the area, and in particular the degree of structuring and the extent of structural trapping that is present.

Storage in confined aquifers incorporates trapping of the buoyant CO2 by structural (e.g. anticlines) and possibly stratigraphic (e.g. sandstone pinchout) features, and is closely analogous to the main trapping mechanisms in hydrocarbon fields. This potential is due to the availability of dry (i.e., empty of hydrocarbons) structures and undrilled geological structures to physically trap CO_2 similar to oil and gas fields. In simple structural traps, volumes and migration pathways of the injected CO2 can be predicted and reservoir models constructed with a higher degree of certainty than in an unconfined aquifer, where the lateral boundaries may be less well defined.

According to Chadwick et al (2006) a key advantage of the structural trap is that migration of free CO2 within the reservoir is tightly constrained and likely to be of limited lateral extent. This is helpful both for estimation of storage capacity and also in risk analysis. The main disadvantage of the structural trap is the possibility, depending on trap geometry and reservoir thickness, of building up a tall, closed vertical column of stored CO2. This will develop large buoyancy forces on the overlying caprock, challenging its capillary and structural integrity. A secondary drawback is the fact that the gas-water contact may be limited to a quite small contact area, thereby restricting CO2 dissolution processes.

The potential storage capacity in such structural traps can be very large in basins where there is extensive and widespread structuring. This has been shown to be well developed in and around the North Sea and in some countries in Europe (GESTCO-Christensen et al, 2004; GEOCAPACITY, 2009). For example structural trapping is well developed in Triassic to Jurassic aged saline aquifers across the UK Southern North Sea, Netherlands, Denmark and Germany. This is related to structural development in these regions formed by movement of the underlying Zechstein salt into pillows and diapirs (Bentham et al, 2005) .

In addition to the storage opportunities within structural traps, in most areas it is expected that there is further capacity in other open or unconfined parts of the saline aquifer formations. This will involve the physico-chemical processes of trapping such as residual gas trapping, mineralisation and dissolution that can occur when the CO_2

is injected down dip along a migration pathway away from any physical trap of a geological structure. This could be down dip from identified structures or into flat lying or dipping unstructured reservoirs that have long distances for migration and/or have reservoirs that produce slow rates of migration. The latter style of trapping, which has been described as migration assisted storage (MAS – Bradshaw et al., 2009, Spencer et al., 2010), can be utilised where modelling indicates that the injected CO_2 will not reach the surface despite not being injected into a geological structure, or which indicates despite being located along a migration pathway from a geological structure, will be trapped physico-chemically before reaching the geological structure.

The distance of migration that is afforded by MAS depends on the basin structure, sub-surface conditions (pressure, temperature, fluid phases, fluids present (oil or gas, fresh or saline formation water), fluid dynamics (e.g. hydrodynamic flow and pressure conditions), reservoir characteristics (porosity, permeability, thickness, heterogeneity), dip of the geological formations, injection rate, well numbers, well engineering (e.g. vertical or horizontal) and if the reservoir has been stimulated (e.g. fractured to stimulate flow). Typical migration distances from modelling where there is continual injection over the life time of a project with >1 $MtCO_2$/year are in the order of tens of kilometres. Larger migration distances could increase the potential for unexpected heterogeneity in the caprock that could potentially lead to leakage. Knowledge from oil, gas and deep ground water migration suggests that when injection ceases for a geological storage project and thus the pressure of the injection process dissipates, and if the dip of the reservoir beds is low, then the likely CO_2 migration rates will be in the order of centimetres/thousand years.[6] During that period, physico-chemical trapping will continually take place, and ultimately the CO_2 will dissolve into the formation water.

While the capacity can be large with MAS trapping in saline aquifers, there are specific issues that need to be addressed in terms of characterisation and assessment:

- a large storage footprint may be involved and therefore it may be required that a large area needs to be mapped in detail to identify potential leakage pathways (particularly faults, but also high permeability sediment stringers in the immediate overburden, or shallow gas occurrences as indicators for previous or ongoing leakage), and also to be monitored(Chadwick et al, 2006).
- Ability to use high resolution seismic data to accurately map the migration pathways in both two-way-time and accurate conversion of travel time to depth so as to assist in the prediction of buoyancy and gravity and how it will influence the migration direction and speed;

[6] See, for example, a) various published models of migration rate of the CO_2 plume away from the wellhead, such as Ennis-King, J, Gibson-Poole, C, Lang, S, and Paterson, L, 2002. Long-term numerical simulation of geological storage of CO_2 in the Petrel Sub-basin: Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies, 1-4 October 2002, Kyoto, Japan; and b) long-term numerical simulation of a portfolio of possible sites for geological storage of carbon dioxide in Australia, such as Ennis-King, J, Bradshaw J, Gibson-Poole C, Hennig A, Lang S, Paterson L, Root R, Sayers J, Spencer L, Streit J, and Undershultz J. Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, September 2004, Vancouver, Canada.

- Use of the correlation of well logs and cores and high resolution seismic data to determine and identify the presence of amplitude anomalies evident on seismic data and to use that to help identify the facies characteristics of the sub-surface seals and reservoirs;
- Identify and predict any variability of the seal and reservoir that may impact on:
  - Rates of fluid flow (e.g. facies variation, permeability and/or lithological changes),
  - Potential leakage pathways (e.g. seal variability),
  - Migration direction (e.g. high permeability streaks, topography of seal-reservoir interface),
  - Pressure build-up (e.g. lithological and stratigraphic variability producing flow barriers),
- Ability to accurately determine the prevailing rock properties through petrophysical and core laboratory assessment and so assist in determining how the rock characteristics will impact on the efficiency of the trapping mechanisms involved with MAS (e.g. determine the likely residual gas saturation)

Many areas of Europe have been assessed in terms of their storage capacity based on the potential storage in open or unconfined saline aquifers. Much of the capacity ascribed to unconfined aquifers can be considered as potential for MAS-based trapping. Given the potentially large capacity in Europe in these situations, there appears to be major potential for MAS-based trapping in saline aquifers in Europe. To date this has largely been described at the regional level, and more detailed assessment and modelling of specific trapping potential will be required.

However, in considering storage in structural closures, it is important that the CA does not accidentally preclude the opportunity and potential in MAS or open/unconfined storage. The reason for this may be that if storage proceeds initially only directly into structural closures, and separate operators wish to access areas down dip of the structural closures at some future date, then CAs may be risk averse of producing a situation whereby CO_2 of two operators could co-mingle, and the legal complication of addressing risk issues and identifying the owners of the liability if leakage occurs could arise.

If an up-dip structure is already filled with CO_2 to a CA's defined maximum reservoir pressure or structural closure height, then down dip injection could increase pressure in the structure, or allow migration of CO_2 toward an already filled structure. This could lead to overfilling of the structure and spillage out of the structure, perhaps resulting in up dip leakage. If, on the other hand, injection is regulated to only occur down dip of structural closures, then MAS will result in substantial volumes of CO_2 being trapped along the migration pathway (normally greatly exceeding the structural trap volume), most CO_2 will never reach the trap, and if any CO_2 is not trapped along the migration pathway it will eventually reach the structural trap and be physically trapped. Down dip injection may also be possible along multiple migration pathways on many sides of the structural closure, leading to even greater potential storage capacity being accessed.

Thus, there is a potential for MAS to increase the potential storage resource that may be available; especially when up dip structures -- that can provide ultimate confidence of both physico-chemical and physical trapping of CO_2 -- are present. Such an approach may provide significant additional capacity potential for CO_2 storage.

The CA needs to understand and take account of all possibilities for saline aquifer storage in any region, including both structural trapping and trapping in open/unconfined aquifers, or MAS. The CA may consider that the manner in which areas for geological storage are planned and released to storage operators will greatly influence the likelihood of accessing the benefits and capacity in unconfined aquifers through MAS. However, an issue for unconfined aquifers/MAS is that horizontal footprint of the CO_2 plume will be much larger than closed structural traps, and more area has to be characterised and assessed for MAS trapping than for structural traps. This could also result in more potential conflicts with other subsurface uses, as discussed below.

1.3.4 Coal Seams

Coal can be used at a technical level for CO_2 injection in either deep unmineable coal seams or for enhanced coal bed methane. Although storage of CO_2 in coal seams will likely only provide a minor contribution to world storage capacity, they may be significant storage option for certain countries. Some of the issues that limit the use of coal include swelling of the coals, poor permeability, and the risk of sterilising coals from future mining.[7] In some cases, coal deposits are not associated with laterally continuous geological formations that will form thick overlying regional seals and thus may represent leakage risks if any CO_2 injected is not adsorbed on the coal matrix or if the liberated methane bypasses the production well interval.[8] However, coal sequences in most European settings are seals rather than reservoirs, and consist predominantly of fine grained rock. Hence, leakage risks from coal-based storage in Europe may not necessarily be higher than in traditional aquifer plays. Hence, a more detailed characterisation of the storage site and storage complex would be needed to make such assessments. Risk of leakage also depends on the mobility of CO_2, and given that coal is chemically reactive, it could better immobilise CO_2 at given pressure conditions

From a CA's viewpoint in Europe, injection into coal seams may provide technical opportunity for CO_2 storage, but the likelihood of matching injection rates to the necessary industrial supply rates is small, particularly for power generation. However, other industrial facilities with small CO_2 output could potentially utilise coal beds as an option. Coal bed methane extraction requires large numbers of wells to extract the methane because of poor permeability in the coal bed. In addition, the wells for extracting coal bed methane needs to have the proper well casing to prevent leakages of CO_2.

[7] See, for example, http://www.coal-seq.com/Proceedings2008/presentations/Frank%20Van%20Bergen_TNO.pdf.

[8] Source: http://www.aph.gov.au/house/committee/scin/geosequestration/subs/sub41attachd.pdf

To extract coal bed methane, it is necessary that water first be produced from the coal so as to depressurise the coal and desorb the methane. It is possible, that if a storage operation is in hydraulic communication with a coal bed methane accumulation and production zone, that the storage operation could raise the reservoir pressure, and impact upon methane production.

The outcome of the coal swelling when CO_2 is injected, may suggest that the technology may not be technically viable over the long term. A significant issue with injection into coal, is that to maximise access to the best permeability, the likely injection targets will have to be shallow, and potentially within the fresh water groundwater zone (~500m). Coals, despite having low permeability, do hold substantial volumes of water, and transmit water into the groundwater system. Thus, potential contamination of the groundwater system needs to be carefully assessed.

If coals are used at an industrial scale for storage of CO_2, CAs will have to consider the increased likelihood of the risk of leakage from the potentially large numbers of wells, and the potential additional risk to contamination of the ground water system. CAs may also need to consider whether there are potential conflict of use issues between coal bed methane operations and CO_2 storage operations due to pressure increase in the reservoir systems that storage operations will produce.

1.3.5 Other Options

As noted in GD1, other options such as injection into basalts and into organic rich shales suffer from very limited permeability and are unlikely to represent major areas for storage of any significant volumes of CO_2[9].

For Europe, and other parts of the world, there are a range of other options that are sometimes put forward for storage of CO_2. Apart from basalts and organic rich shales, others include mineral sequestration (i.e., ex-situ and in-situ carbonation of ultramafic/mafic rocks, including ophiolites), and injection into salt domes, voids from underground coal gasification, and disused mines. Many of these options are yet to reach the proof of concept phase, fail to address fundamental matters associated with the necessary scale of operations that have to be considered, have limited capacity and/or very high costs. Appropriate consideration is required of how such processes scale up technically or commercially to provide opportunity to store at the rates of 1 to 10 $MtCO_2$/year. Until that is proven as possible, then the CAs may wish to consider such options as not being viable and leave them in the academic realm awaiting future results and outcomes to prove their viability.

1.4 Initial Assessment at Regional/Country Level

Art. 4 of the CCS Directive requires that Member States which intend to allow geological storage of CO_2 in their territory undertake an assessment of the storage

[9]Source: http://www.aph.gov.au/house/committee/scin/geosequestration/subs/sub41attachd.pdf

capacity available in parts or in the whole of their territory. Such an assessment can be carried out by allowing exploration on the basis of an exploration permit according to Art. 5 of the CCS Directive. No such exploration shall take place without an exploration permit. Where appropriate, monitoring of injection test may be included in the exploration permit. Procedures for granting an exploration permit must be open to all entities possessing the necessary capacities and permits need to be granted or refused on the basis of objective, published and non-discriminatory criteria. Under the CCS Directive, the term "exploration" refers to an assessment of potential storage complexes by means of activities intruding into the subsurface such as drilling to obtain geological information about strata in the potential storage complex. Exploration might also include injection tests in order to characterise the storage site.

Data generated from assessments at the regional country level can be used to prioritise areas that are more or less suitable for storage. The areas should be ranked based on their prospectivity (see Glossary below), so as not to exclude areas that have little data or uncertain information. This has been the approach in a number of regional and country assessments, be they either deterministic or quantitative approaches (GEOCAPACITIES, GESTCO, CASTOR, Bradshaw et. al., 2002; 2004; 2009). Such studies can develop an ordered list of whether areas have high or low prospectivity, whether they have large or small theoretical storage capacity potential, and what the perceived technical risks are for each region.

In Europe, initial assessment of CO_2 storage capacity at a country, regional or basin level was carried out in several projects supported by the EU Framework Programme, e.g. GEOCAPACITIES, GESTCO and CASTOR. However, these studies do not cover all of Europe and in some Member States they are limited to a few specific regions. Data, methodologies, comparisons and reference estimates generated in these projects can be an important input for the CA's work. This work could be used to assist the development of a more comprehensive assessment of CO_2 storage prospectivity for the next phase of assessment that could be made available to assist industry select potential storage sites for detailed study.

1.5 Screening

The assessment at the basin level will require more specific data than for an initial country or regional level. Such more detailed assessments will similarly identify and prioritise most likely areas to continue future assessment activities. In performing this screening and ranking of regions or basins, a set of selection criteria with appropriate cut-off limits will be required on which the assessment can be made, e.g. basin depth, structural deformation, porosity, permeability, seal and reservoir quality and effectiveness. For each region or basin, the criteria may be adjusted to match the local issues in terms of criteria that reflect the scale and complexity of the storage needs such as distance to source, CO_2 supply volumes, injectivity rate etc. It is often quite important to adequately document the failure cases, so as to alert potential later attempts to re-assess such areas, and to make it apparent as to why they have been dismissed.

Having completed the basin and/or regional scale screening and assessment process, more site specific work will be performed focussed at the local scale and potential prospects where actual CO_2 storage may take place in the sub-surface. This will mean an assessment of the specific rock characteristics at a specific location, thus requiring detailed well and seismic data. The storage complex will need to be considered for the wider implications of the injection and storage proposal, especially in terms of migration and leakage pathways, and hydraulic aspects associated with potential pressure build-up. At this scale, focus will occur on the effectiveness of each individual reservoir and seal, and the distribution and variability of the reservoir/seal pairs in the subsurface. This would in most cases involve exploration activities and thus require an exploration permit according to Article 5 of the CCS Directive.

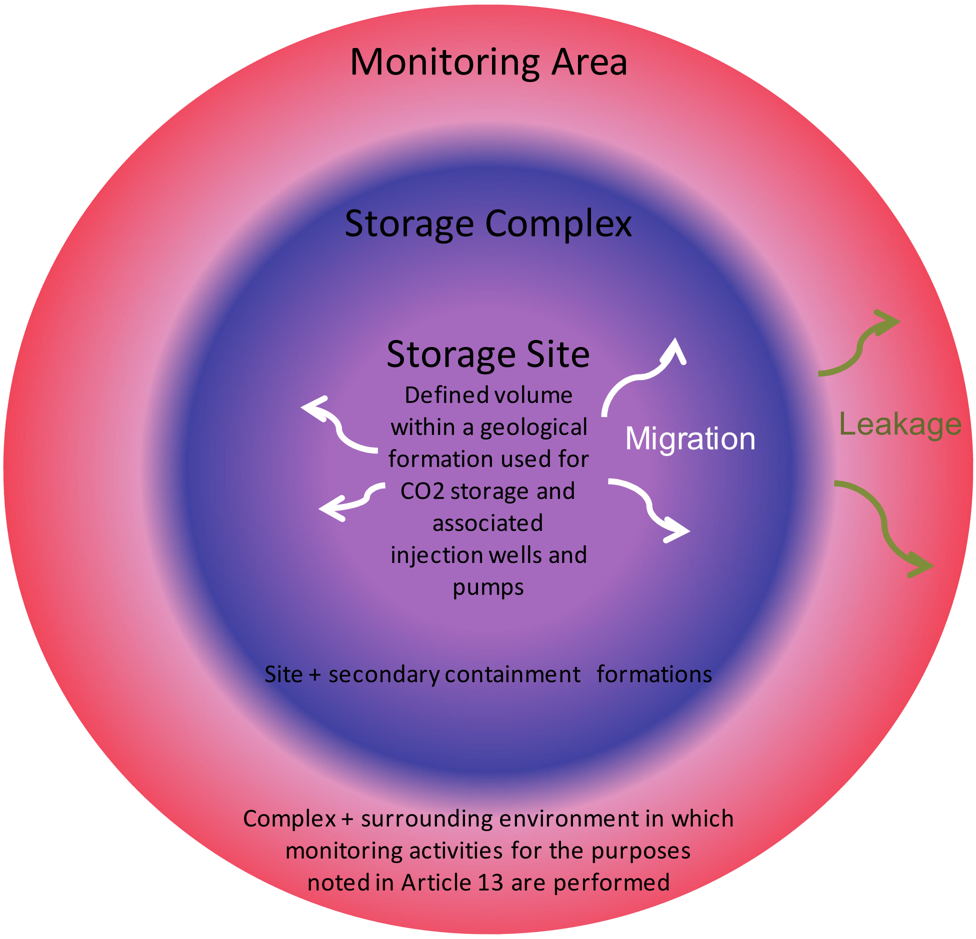
1.5.1 Storage Complex

The CCS Directive describes ‘storage complex’ as:

- “the storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations;”

The definition of the complex is particularly crucial as ‘leakage’ is defined as the release of CO_2 from the storage complex. Given the interlocking definitions of the storage site, storage complex, monitoring area, and leakage in the CCS Directive, Figure 3 provides a schematic indicating the different terms. The diagram below does not necessarily denote spatial or stratigraphic relationships, as the specific definitions for each of these terms will be based on site-specific conditions. It is expected that operator will provide the CA with the specific vertical and areal extent of the geological formation(s) into which injection will take place, as well as defined boundaries of the storage complex. The schematic also indicates migration and any potential leakage; where migration is defined as movement of CO_2 within the complex, and leakage is defined as movement of CO_2 outside the storage complex (and into the monitoring area). As discussed later in Chapter 4, monitoring area will be defined by the monitoring activities that have to take place to meet the monitoring goals given in Article 13.

Figure 3: Schematic defining key terms based on CCS Directive



Questions will arise from the CCSD definition of storage complex related to the time period to be considered and how effects not associated with the actual physical CO_2 plume location (e.g. immediate and widespread pressure effects, or movement of distant formation fluids due to displacement of formation water by CO_2) should be considered as influencing what constitutes the storage complex.

The definition of storage complex certainly includes:

- the immediate surface and sub-surface facilities at the storage site;
- only the targeted seal(s) and reservoir(s), where the CO_2 is physically injected into and is expected to migrate and be stored,
    - i.e. the geological formations which comprise the physically invaded rock volume from the CO_2 plume migration; and
- secondary seal(s) and reservoirs(s) that may contain the CO_2, in case the CO_2 plume migrates beyond the primary seal.

For example, secondary reservoirs could include MAS trapping, such thatif CO_2 could exit out the spill points of structural trap, it can still be trapped by MAS trapping (as discussed above). Thus, the extent of the storage complex may change over time and the specific migration pathways will often only be known for certain from monitoring the injected CO_2. As CO2 dissolves in the formation water,[10] it becomes heavier and could move further down dipinto the basin, and therefore, any associated geological attributes or features of a geological formation where the CO_2 plume may actually reach could also be considered as part of the storage complex. Hence, during the storage permit review and updating process, it is important to allow for changes in the specific boundaries of the storage complex based on science and more updated information gathered through monitoring.

With the above definition in mind, the characterisation and selection process will identify the storage complex, and specific boundaries can be determined by the dynamic reservoir simulation and sensitivity analysis (see below). It is this set of modelling that will identify the extent and timing and impact of CO_2 plume migration, both for the immediate geological region (volume) as well as the distant geological region (volume).

1.6 Data Collection for Characterisation of the Storage Complex and Surrounding Area

One of the most important parts of the CA's role in their consideration of decisions associated with the characterisation of a storage complex and surrounding area will be to assure the quality of the data and the way that it has been collected and analysed. If this is not done, then the relevance of all other elements of the characterisation processes (Figure 2) will be jeopardised. Figure 2 shows how the data and modelling can be used to determine the evaluation of containment, injectivity, capacity, integrity, and hydrodynamics of the site and the storage complex. As suggested in Figure 2, it is important for the CA to carefully consider and focus upon any issues associated with the primary data for each storage complex characterisation. Once that is achieved, and there is confidence with the skill and expertise of the modelling and with the evaluation of the results, then the outcome of the storage complex assessment can be trusted.

1.6.1 Compile and Evaluate Available Existing Data

It is the role of the operator to compile and evaluate the existing data associated with a potential storage site. Data sources of prime use will include information from oil and gas fields, both exploration and production and any deep stratigraphic drilling that has taken place (>100m). Jurisdictions will have different policies as to the release of petroleum data, and they will have different ways of dealing with the different phases from which the data originates (e.g. exploration versus production and reserves data). While there could undoubtedly be sensitivity associated with making information associated with production data from oil and gas fields publicly

[10] Dissolution processes: If the CO_2 plume migrates through MAS trapping processes and some of the CO_2 dissolves into the formation water, it will become denser than the surrounding formation water and will migrate down dip, back into the central deeper parts of the basin.

accessible, this information, relating to the fluid flow characteristics and performance of reservoir systems, is of most value to characterise a storage site. Access to physical core and cuttings material and to digital well log and seismic data may not be as sensitive, but will be essential to make a meaningful storage site characterisation assessment. Where there may be a perceived conflict of use of the sub-surface with the activities of the petroleum operator, obtaining access to non-public petroleum data may be a complex matter to resolve.

The CA will need to consider that in some cases access to essential data from oil and gas exploration operations will facilitate a reliable characterisation and assessment of the potential storage complex and surrounding area. If access to petroleum production data is available in a region nearby to a proposed storage site, and the geology is similar, then a storage operator may be able to make considerable progress to proving the existence of a viable storage site.

1.6.2 Collection of Additional Data and Processing of Site-level Data

The geoscience and engineering disciplines that deal with the subsurface include a comprehensive list of sub-disciplines which are represented within all the different types and elements of each phase of the storage complex characterisation process (see Figures 1 and 2). In terms of geological storage complex characterisation, the integration of these disciplines and the interaction between the individual geoscientists doing the modelling and evaluations are of prime importance to achieving the necessary outputs and outcomes of the characterisation and assessment process.

The data that is necessary to be collected by each of these disciplines is extensive and the methods and approaches by which these are done are highly varied and specialised. As described for the various storage type categories, some sites will require minimal data collection, some will require re-analysis of the data to ensure it has been considered in a relevant manner, and other sites will have no primary data. Some sites will have significant data, but as it was collected for a separate purpose (e.g. oil and gas exploration) the data may not be located correctly from a geological perspective and/or may introduce unintended bias into the assessment. Any data collected from core drills and drill cuts should be maintained by the operator, as such data would need to be transferred to the CA at the time of transfer of responsibility (see GD3).

As specified in Annex I of the CCS Directive sufficient data needs to be accumulated to construct a volumetric and three-dimensional static (3-D)-earth model for the storage site and storage complex, including the caprock, and the surrounding area, including the hydraulically connected areas. This data shall cover at least the intrinsic characteristics of the storage complex that are discussed in the following sub-sections.

1.6.2.1 Geology and Geophysics

These are the two principal geoscience disciplines from which many of the items listed below are derived. These disciplines and the data they require are the essence of all of the analysis in Figure 2. Data associated with geology and geophysics will comprise mostly outcrop and well data associated with rock measurements. The main geophysical data sets will be seismic and other remotely sensed information from geophysical processes. The impact of geology and geophysics and the necessary data sets are described in the sub-disciplines and data sets below.

1.6.2.2 Hydrogeology

Data on hydrogeology (or hydrology) will provide information on the movement and interaction of fluids within the groundwater system. Hydrogeology is a prime data source that links directly to modelling of the pressure and temperature gradients, and groundwater and salinity, which in turn link to the evaluation phases of containment, capacity, integrity and hydrodynamics. Although hydrogeologic techniques can be applied to shallow formation water and deep saline aquifers, on a strict definition hydrogeology may be taken to mean the "shallow" formation water that is usually in the near surface geological formations that comprise the groundwater system (~ < 800m) rather than the deep geological formations within which the formation water is saline. The interface between saline and fresh water can be sharp with a rapid change across a geological boundary, or it can be gradual over 100s of metres of rock interval. The depth at which the interchange between saline and fresh water occurs is basin specific, often depends on whether there are major aquicludes (barriers) that prevent or slow the interaction between the two water types, or whether there are outcropping geological formations that are recharged from meteoric surface waters that penetrate through permeable formations into the deep sub-surface. Meteoric water that has penetrated from the surface into the deep sub-surface formations often has taken millions of years travelling at rates of centimetres per thousand years to reach those regions, indicating that long term slow process of fluid movement occur in such ground water systems.

Hydrogeological studies will be necessary to understand the likely impact of CO_2 leakage into the groundwater system and the preventive or corrective measures that can be considered if that were to occur. Some natural groundwater systems already contain CO_2 in solution due to the natural generation of CO_2 from the deep subsurface during volcanic activity and also from diagenesis and geochemical alteration of the deep rock formations over time. Many naturally occurring gas fields contain high concentrations of CO_2. The natural interactions of the fluids from these regions with the overlying shallow groundwater system provide natural laboratories of the geosphere to allow study and informed estimates of what such interactions may mean for both for short and long term processes. Assessment of such areas could provide valuable and insightful knowledge of the long term impact of geological storage of CO_2 in case of leakage.

1.6.2.3 Reservoir Engineering and Petrophysics

Reservoir engineering encompasses an array of scientific skills (geoscience, chemistry, physics, and mathematics) and data sets that pertain to the assessment of the characteristics and movement of fluids within a deep sub-surface porous medium (reservoir). The term reservoir, from a petroleum reservoir engineering viewpoint, is often considered to mean the porous and permeable rock that contains an accumulation of hydrocarbons, while the porous and permeable rock that contains non-petroleum fluids is considered to be the aquifer. A reservoir engineer will be involved and interested in all the evaluation phases (see Figure 2), but will especially be involved with assessment of injectivity and integrity. Reservoir engineers will work closely with the geoscientists at the development stage of the static geological model and then will be primarily responsible to migrate (upscale) that data and information to build the dynamic reservoir simulation. Having assessed the outcomes of the modelling and evaluation, they will present the options of how to engineer the reservoir to produce the most effective development proposal for the potential storage site.

Petrophysics is the study of rock properties from both physical samples (core and cuttings) and digital measurements (well logs). It includes the physical and chemical properties of the rock and its petrological (mineral composition) characteristics and how these elements impact upon the development of and interaction of fluids in a sub-surface formation. Petrophysics is one of the primary data sources and modelling aspects shown in Figure 2. It links directly into the modelling phases of seal, petrophysics and facies and sequence stratigraphy, which in turn impacts on the evaluation of containment, injectivity, capacity and integrity. The use of petrophysics studies for storage site characterisation is often hampered by the lack of data from appropriate geological locations, due to that the main samples that pre-exist were taken to enhance the knowledge of petroleum exploration issues and not geological storage (e.g. no samples of seal, or no samples of the rock in the water leg of an oil or gas field where the chemistry and rock fabric can be very different). Where this has occurred, reliance has to be made upon well log digital data which makes assumptions of the actual rock characteristics in the intervals from which no physical samples were taken. Sometimes such assumptions are broad or not definitive, and it may be necessary to re-drill wells into the necessary geological intervals so as to take the appropriate samples, specifically, to understand the issues of geological storage. Until extensive exploration cycles commence for geological storage operations, this aspect of bias or inadequacy of petrophysical sampling will be an issue for all storage site characterisation.

1.6.2.4 Geochemistry

Geochemistry is the study of the chemical constituents of rocks at the elemental and mineralogical level. In the context of the characterisation and assessment of potential storage complexes for the geological storage of CO2, it also includes the study of the geochemical composition of the fluids in the rock and their relationship to the rock constituents (e.g. hydro-geochemistry). Geochemistry has an impact on all the evaluation phases in Figure 2, as the assessment of geochemical components is implicit in all of the sampling taken for rock measurements (field studies, petrophysics, rock typing, core analysis and sampling, drill stem testing and repeat formation testing (DST- Drill Stem Testing & RFT-Repeat Formation Testing) analysis and hydrogeological studies).

Geochemistry will prove to be vital in understanding the way that the introduction of the CO_2 stream interacts with the rock and formation water chemistry, causing either precipitation or dissolution of minerals. Geochemical investigation is also used for assessing interactions between the contents in the CO_2 stream and well-bore cement and caprock (see section 3.6). In some instances, the change in chemistry that occurs will result in minerals being entrained and moved along in the fluid flow processes. Some sites will have labile mineralogy that are susceptible to reaction, whilst others will be stable and thus have minimal chemical reactions if any, and others may react but rapidly reach equilibrium perhaps due to buffering of the chemical conditions in the sub-surface. The extent to which and nature of any changes that could occur, will be specific to each storage complex, which is why appropriate sampling and assessment needs to be done for each storage complex. Understanding the geochemistry of a site will benefit from injection tests prior to final approval and use of core samples from the site in laboratory tests that mimic the subsurface conditions. As for the petrophysical sampling, samples from appropriate and key intervals (e.g. the water leg of a petroleum field) will be crucial in producing representative results for storage complex characterisation.

1.6.2.5 Geomechanics

Geomechanics is the study of the mechanical fabric of the rock and how it may respond to physical changes such as changes in the localised reservoir pressure and regional stress regimes. Geomechanics is listed in Figure 2 as a modelling phase that is dependent on data from field studies, core analyses and sampling and seismic interpretation. The geomechanical model impacts principally on the evaluation phase of containment, but also capacity (as prescribed pressure and threshold rock fracture gradients are likely to be required by the CA). The deep sub-surface will have reached equilibrium in terms of the forces that have been applied to the rocks and their geomechanical responses, so any change to prevailing forces may or may not produce a change in the mechanical stability of the rocks. Some geological regions will be very stable and it would take forces of a major nature to produce any reaction, while other areas are critically stressed, and with the introduction of specific circumstances can cause reactivation of pre-existing structural weakness in the deep sub-surface (e.g. faults).

There are many technologies available that can measure the current stress regime and the stress nature of existing faults and to predict what would occur if changes occur. There are also technologies that can be used to accurately monitor and identify when conditions may be reaching a critical state; and thus permit intervention actions. Geomechanics will be an important part of any storage complex characterisation as well as the development plan due to issues like pressure build up and the movement of fluids under pressure into regions that may be critically stressed.

1.6.2.6 Seismicity

Seismicity is the study of the phenomenon of earthquakes that are ruptures in the fabric of the crust of the earth which then causes seismic waves to propagate through rocks.[11] Seismicity is not a discrete element, but will be an important data component and consideration of the geomechanical model. Most earthquakes are caused by the natural dynamic earth crustal forces through plate tectonics and differential forces that exist between and within the oceanic and continental plates. As described for geomechanics, these physical forces and the effects they cause can be measured and monitored with high levels of accuracy using modern technology. There is a world wide array of seismic monitoring stations that allow accurate measurement and location detection of all significant earthquakes, such that their existence and state of crustal stress is well understood and documented. For example, many geological agencies in Europe monitor data from seismometers set up in their countries and this data may be useful for baseline characterisation of seismicity.

In terms of characterisation of a storage complex, the presence of pre-existing faults systems can be identified through acquisition of 2D and 3D seismic reflection data, such that predictions and understanding of the rock fabric through geomechanics can identify if such structural features pose a threat to storage of CO_2. However, there are faults that may not be detectable through seismic measurements, but can affect overall site suitability or optimal well location. There is a considerable practical and technical knowledge of the impact of “induced seismicity” through injection of fluids and changes in overburden and reservoir pressure (e.g. with large dams, mining (subsidence), and oil and gas field activity (subsidence and absidence)) to assist in assessment of the likely risk of induced seismicity for storage complexes.

1.6.2.7 Natural and Man-Made Pathways

Predicting the presence of leakage pathways for potential movement of CO_2 out of the targeted storage formations is the most vital component of any storage site characterisation. It is included explicitly in the integrity evaluation phase in Figure 2, and it links back to every data acquisition and analysis element. Not explicitly listed in the data acquisition and analysis elements are the items which are of engineering, facilities or infrastructure nature but they should form an integral part of the characterisation of a storage complex in the evaluation elements of leakage pathways of a man made nature.

Natural pathways will include geological features that can provide a conduit to overlying and adjacent geological formations outside the targeted storage formation, and potentially the CO_2 could ultimately reach the surface. Such natural pathways will include faults, variation in the seal quality, presence of the seal, and the base seal structure, sandstone intrusions in the caprock, and delineation of the structural trap (e.g. height of a spill point or characteristics of a migration pathway). Predicting faults and their attributes will depend on the quality, type and resolution of seismic data. It will be very rare that any geological data will exist from across a fault plane in the subsurface, so reliance will be on geological inference and geophysical remote sensing methods to define and assign attributes to them. The geomechanical modelling will assist in the prediction of fault behaviour and when combined with well

[11] Note: seismicity should not be confused with “seismic data” which is the term used to describe seismic reflection data that is used in the petroleum industry to study the layers of the earth.

log correlations of adjoining rock types across faults, will help define their sealing potential (e.g., shale or sandstone juxtaposed to shale, or sandstone on sandstone). The size of the offset across a fault will determine whether it can be resolved on seismic (> ~25m) or when combined with the seal thickness can identify the likelihood of breaches of the seal and thus leakage risks. It should be noted that some faults can be sealed and are non-transmissive.

The rock properties that directly determine seal quality can be derived directly from laboratory measurements of geological data, especially core, and as shown in Figure 2 there is a specific seal potential model that is derived from the data acquisition and analysis phases of petrophysical analysis, analogue studies, core analysis and sampling, and DST and RFT analysis. Predicting the seal quality away from a bore hole will be one of the challenges for any storage complex characterisation. At a generic level, some depositional environments, such as marine shales, will provide thick and laterally extensive seals that are of consistent quality, whereas lacustrine shales and mudstones may be more restricted and localised and of a variable quality.

Definition of the structural trap is a fundamental aspect of characterisation of a storage complex, and is a distinct element of the modelling phase in Figure 2 under depth-structure maps and models. This element is dependent on the data acquisition and analysis elements of well log interpretation and correlation seismic interpretation and time-depth analysis. As seismic data is measured in two-way-time and is converted to depth by velocity modelling, variation in the modelled versus the observed can occur, and needs to be considered appropriately in both localised structural traps as well as MAS trapping mechanisms to ensure an accurate representation of the sub-surface is achieved. Incorrect estimates could lead to migration in a different direction, migration at a slower or faster rate (lower or higher dip), or overestimating or underestimating the potential trapping volumes.

The characteristics of the complex vicinity dealt with in the following sub-sections shall be documented and be subject to a risk assessment (see also section 2.1 and GD1).

1.6.2.8 Surface Studies

The nature of the surface (topography) at the storage complex will impact upon how easy it is to develop and manage a storage site, the nature of the data types and data quality that can be acquired, and the cost of access. It will also impact upon appropriateness of different monitoring technologies, likely preventive measures, and the impact of leakage that would occur in a worst case example of surface leakage.

1.6.2.9 Adjacent Population Distributions

The location and concentration of populated areas above and adjacent to the storage site will be an important aspect to consider in the final output and outcome phases of complex characterisation (as shown in Figure 2), particularly for risk assessment and uncertainty analysis. The likelihood of leakage, combined with potential impact will need to be considered by the CA prior to approval of a site. The local terrain (e.g. flat lying, or low lying valleys adjacent to storage sites) should be considered as well in a worst case scenario of a leakage, and whether there is a likelihood for leaking CO_2 to disperse or concentrate. The impact of potential contamination of groundwater from CO_2 leakage should also be considered, which should be deduced from the hydrogeological studies.

There will be a need to examine data in the assessment that identify land holdings and tenure both from a community consultation and access perspective and in terms of assembling information to use in the risk assessment process.

1.6.2.10 Natural Resources

Valuable natural resources in proximity to a potential storage complex have to be documented and the risk linked to the exposure to CO_2 leakage has to be carefully assessed. Valuable natural resources include in particular Natura 2000 areas pursuant to Council Directive 79/409/EEC of 2 April 1979 on the conservation of wild birds and Council Directive 92/43/EEC of 21 May 1992 on the conservation of natural habitats and of wild fauna and flora, potable groundwater and hydrocarbons.

1.6.2.11 Interactions with other Sub-surface Activities

There are a range of potential issues for competition with other sub-surface resource uses that need to be considered. The competition can arise from surface uses, pore-space being used for other purposes, and the potential leakage of CO_2 may affect the usability of other subsurface resources:

- oil and gas field development:
  - the CO_2 plume could contaminate the production of hydrocarbons, thus increasing costs to the operators as they would have to strip off CO_2 and have to allow for changes in the materials of the infrastructure at a facility,
    - conversely, CO_2 injection could increase regional reservoir pressure and actually benefit oil and gas production;
  - the CO_2 plume could reduce the pore space available for natural gas storage reservoirs
- coal bed methane production:
  - the CO_2 plume could contaminate the production of hydrocarbons, thus increasing costs to the operators as they would have to strip off CO_2 and have to allow for changes in the materials of the infrastructure at a facility,
  - CO_2 injection could increase regional reservoir pressure and actually decrease production as the methane can only be produced by producing the formation water to allow it to desorb off the coal,;
- coal mining:
  - CO_2 could sterilise coal mining operations and create unsafe mining conditions;
- Compressed air storage

   - CO_2 could reduce the pore space available for compressed air storage that maybe used in conjunction with wind farms and other power generation;
- groundwater:
   - CO_2 could contaminate groundwater resources;
- underground coal gasification:
   - CO_2 could extinguish underground coal gasification processes or limit development of such operations;
- salt mining:
   - CO_2 could sterilise mining operations by creating unsafe mining conditions;
- geothermal:
   - CO_2 could impact the facilities both at the surface and in the sub-surface thus increasing costs to the operators as they would have to strip off CO_2 and have to allow for changes in the materials of the infrastructure at a facility;
   - CO_2 injection could increase regional reservoir pressure and actually benefit geothermal production operations.

The CA should not require that the operator should check for all of the items listed above, but only those that are relevant for the specific storage complex at the time of the permit application. It will be the final phases of the complex characterisation analysis that any competing uses of sub-surface activities can be identified and an assessment can be made to determine whether there is any likelihood that they pose a conflict of use. The operator should document any such conflicts with other competing uses and include this documentation as part of the storage permit application to the CA. There are monitoring practices and best practices that can be implemented to reduce the likelihood of occurrence of such conflicts. The most effective way to manage such competition will be at the discretion of the CA in the granting of permits to undertake sub-surface activities in close proximity to each other, and/or to insist on agreements between the operators of the various industries as to how they conduct their activities and share information and planning.

1.6.2.12 CO_2 Source: Proximity and Supply Volumes

To search for and prove a site and complex for geological storage of CO_2 is reliant on knowing the likely storage volume and supply rates very early in the selection process. Some sites may be commercially and technically viable at low rates of injection, others will be able to inject at high rates, while some will have large storage capacity and others small. CO_2 source/supply issues will be an important consideration for the size and nature of the trapping mechanisms envisaged at any site. The geological characteristics will determine how suitable any site is to match the required components, and the reservoir properties will determine the numbers of wells and thus commerciality of meeting any CO_2 supply conditions. Changing the CO_2 supply conditions during a site characterisation process may affect the relevancy of the outcome of the exercise, as while a perfectly valid storage site may have been proven, it may not be able to technically or commercially meet the CO_2 supply volumes and rates. Proximity of site to CO_2 source will be an issue in the early stages of CCS deployment. As the CO_2 transport infrastructure develops, the distance that will matter is that between the storage site and the transport network.

1.7 Building the Three-Dimensional Static Geological Earth Model

Building the three-dimensional static geologic earth model is represented as Step 2 in Annex 1 of the CCS Directive. Step 2 consists of using the data collected in Step 1 to construct one or more three-dimensional static geological earth models of the potential storage complex, including the caprock and the hydraulically connected areas and fluids. This should be done using computer reservoir simulators to characterise the complex in terms of:

(a) geological structure of the physical trap;

(b) geomechanical, geochemical and flow properties of the reservoir overburden (caprock, seals, porous and permeable horizons) and surrounding formations;

(c) fracture system characterisation and presence of any human-made pathways;

(d) areal and vertical extent of the storage complex;

(e) pore space volume (including porosity distribution);

(f) baseline fluid distribution;

(g) any other relevant characteristics.

In constructing such models, measured or estimated data for reservoir characterization (e.g., lithofacies, thickness, porosity and permeability) derived from onsite seismic surveys, well logs and cores are needed as discussed in Section 2.6. The amount of actual data that will be needed will depend on the site risk profile and degree of heterogeneity expected given the depositional and structural environment of the storage complex. In any case, it should be understood that data from a few measured locations will have to be extrapolated over the entire complex using geostatistical techniques within the reservoir simulator or in data preparation steps taken before the simulator is employed.

The uncertainty associated with each of the parameters used to build the models shall be assessed, as part of the process of developing the static model. Any error bars (statistical standard errors) associated with extrapolation and contouring shall also be assessed. Thus, the three dimensional static geological model, is a process to describe and attribute the conditions of the geological sub-surface in preparation for simulating the fluid flow performance of the reservoir. Examples of challenges for a modeller:

- Gathering enough site-specific data (if available) from owners of that data or newly acquiring it in a cost-effective manner;
- whether to use analogue models or specific models derived from the actual characteristics of the geology of the site, e.g. to use:
    - specific detailed palaeogeographic maps or approximated maps,
    - real reservoir distribution data (if available) or probabilistically derived distributions of data (from analogues),
- the nature of the model to build in terms of:

- a representation of the “average” conditions,
- a representation of the “high end or low end” conditions,
  - e.g. the CO_2 will bypass low permeability rock and normally follow the very high permeability streaks, which are often not predicted or represented,
- a representation of “all” conditions and run a large number of sensitivity studies,
- how to integrate the various conditions and ranges across a diversity of data types of the geological parameters.

In general, modelling of "high end conditions" would be most helpful in analysis of heterogeneities and long-term phenomena that are difficult to fully forecast (e.g. degradation of the cement of the wells, geochemistry, etc.).

1.7.1 Geological Structure Mapping

Definition of the structure of a storage complex is a fundamental aspect of characterisation of a storage complex, and is a distinct element of the modelling phase in Figure 2. This element is dependent on the data acquisition and analysis elements of well log interpretation and correlation seismic interpretation and time-depth analysis. As seismic data is measured in two-way-time and is converted to depth by velocity modelling, variation in the modelled versus the observed can occur, and needs to be considered appropriately in both localised structural traps as well as MAS trapping mechanisms to ensure an accurate representation of the sub-surface is achieved. Incorrect estimates could lead to migration in a different direction, migration at a slower or faster rate (lower or higher dip), or overestimating or underestimating the potential trapping volumes.

1.7.2 Well Correlation

The correlation of well data is an element of the data acquisition and analysis phase in Figure 2, This element leads directly into the modelling phases of facies and sequence stratigraphic maps and models and of depth-structure maps and models which impact upon all of the evaluation phases. Well correlations attempt to identify the time and spatial relationships between geological sequences in adjacent wells. This is done by examining the core and cuttings, well logs and biostratigraphic data in wells, and integrating with surfaces and attributes that can be identified from seismic data.

The correlation lines that are drawn are attempts to predict which geological sequences were being deposited at the same time as others in neighbouring regions. Laterally in space the geological lithology (e.g. sandstone, shale, limestone) can/will change at any given moment in geological time, thus well log correlations are not straightforward and require skill, experience and interpretive processes and models (sequence stratigraphy) to produce reliable results. The aim of such correlations are to isolate discrete time packages of rock units, which often will form discrete fluid flow units, and which are critical to characterising the storage site and complex for CO_2 injection in the geological model.

If incorrect correlations are made, then the injected CO_2 may flow in unintended directions, or intersect barriers to fluid flow and cause pressure build-up in the reservoir. Similarly, if engineering of the reservoir is required by production of formation water to reduce pressure build up during injection, then it will be essential to locate such pressure management wells in reservoirs that are in actual hydraulic communication with the reservoirs within which the CO_2 has been injected.

1.7.3 Gridding the 3D Model

In the development of the geological model, it is necessary to establish the scale at which the model is processed and utilised in the dynamic reservoir simulation. The gridding of the models can be done at either a coarse or fine scale, depending on the requirements of the outputs and the stage of the modelling in the characterisation process (see Figure 2). At an early stage in the iterative process of reservoir simulations, coarse scaled models can be run, to get an idea of what parameters are going to be sensitive in future models, and so focus attention on ensuring those aspects are as accurate as possible. Generally speaking geologists tend to want to work in fine detail, and engineers then take that information and run much coarser outcomes of the original models. Care needs to be taken in using coarse scaled models for sensitivity analyses, because the effects of coarse grids can be to distort flow rates, travel times and saturation (IEAGHG Modelling Network 2010).

1.7.4 Sedimentological, Petrographical and Porosity/Permeability Data

The data associated with sedimentology, petrography, porosity and permeability will be derived from both direct analysis of physical rock data such as core and cuttings material and from well log derived information. These data are included in Figure 2 in the data acquisition and analysis phases under the elements of field studies, petrophysical analysis, rock typing, core analysis and sampling, and well log interpretation and correlation. They lead into the phase of modelling in the elements of geomechanical model, seal potential model, petrophysical model, facies and sequence stratigraphic maps and models, depth-structure maps and models, and groundwater and salinity. These in turn impact upon every one of the elements in the evaluation phase.

Correlations between the physically derived data of core and cuttings and the digitally extrapolated information from well logs will require calibration for each specific geological interval to determine patterns, trends and relationships. This information can be compared with analogue studies that have more extensive data to produce confidence in the results and interpretations.

1.7.5 Reservoir Heterogeneity / Homogeneity, Continuity, and Fluid Flow Characteristics

The reservoir characteristics that relate to fluid flow properties in terms of the reservoir heterogeneity, homogeneity and continuity are all matters that relate to the effectiveness of the reservoir and are included in the evaluation phase of injectivity (see Figure 2). These aspects are affected by the depositional environments of the rocks and the diagenetic processes that they have been subjected to in the deep sub-surface. If production data exists then fluid flow properties and history matching can help provide calibration of predicted versus observed for all these aspects. How a static geological model is constructed and interpreted in terms of the depositional environments and patterns, and mapping and correlation of the flow units, will affect the fluid flow characterisation. High rates of injection with large volumes of supplied CO_2 will perform more effectively if they are injected into reservoirs that are derived from depositional environments with thick, homogeneous and permeable reservoirs such as beach or aeolian (dune) sands. The depositional environments that produce more heterogeneous reservoir characteristics, such as non-marine fluvial (river) deposits with narrow and thin channel sands, may not be hydraulically interconnected. They will thus be problematic as regards providing good fluid flow properties and could require a large numbers of wells and/or long lateral wells to sustainably achieve high overall injection rates and volumes of stored CO_2.

1.7.6 Seal thickness, Extent and Capacity

The quality of caprocks is the most important element of a site selection process, as if a proponent is unable to prove the containment potential, then approval to perform geological storage at a site is unlikely to be granted. The seal thickness, extent and sealing capacity are shown in Figure 2 in the modelling phase, as the seal potential element. It is dependent on the data acquisition and analysis phases under the elements of petrophysical analysis, analogue studies, core analysis and sampling, and DST and RFT analysis. It directly leads into the evaluation phase element of containment. The characterisation of a seal for site selection will vary depending on the detail and level at which the assessment work is being performed. Usually there will be scarce physical data (e.g. core) of the seal intervals, and thus no quantitative analytical measurements of seal capacity and integrity will be available. Thus, to assess the seal at the exploration phase, qualitative and observational evidence are required to be used (e.g. well logs, well correlations, lithological descriptions, evidence of migrating hydrocarbons above the seal (shows) and analogues). The qualitative approach could include setting a minimum thickness and areal extent for a specific lithology type to identify a potential effective seal, as was done for the Queensland Carbon Dioxide Geological Storage Atlas (Bradshaw et al, 2009). A qualitative assessment based on the absence or presence of hydrocarbons above a seal that contains or contained a hydrocarbon accumulation, thus implying leakage and migration (but perhaps over geological time), can also be used as a guide as to the effectiveness of a seal. Changes in salinity across seal intervals, or evidence to indicate there is no hydraulic communication between overlying reservoir seal pairs, can also be used to qualitatively assess seal characteristics. However, to proceed to a definitive assessment of the seal quality, actual core data from the seal interval will be required to allow capacity and geological integrity estimates to be made for the seal.

1.7.7 Migration Pathways

The mapping of migration pathways and drainage cells (the general areas in which the CO_2 will pool and be stored) will be essential for all saline aquifer storage, as well as to understand the implications of unexpected leakage of CO_2 from a structural trap. The issues associated with migration pathways are discussed in the section on saline aquifers. Migration pathways and drainage cells are included in Figure 2 under the evaluation element of integrity, which draws on all of the elements of the data acquisition and analysis.

A storage fairway is the specific areas of the migration pathways and drainage cells that will contain the CO_2 plume (Bradshaw et al., 2009). The storage fairway is be predicted based on a variety of models and analytical assessments of where injected CO_2 will migrate to and what the fluid flow dynamics and interactions with the reservoir and seal rock will be. The storage fairway lies within the larger drainage cell, and includes the "cylinder" of the CO_2 plume adjacent to the well bore where the CO_2 is injected and the rock that will be invaded by the migrating lenticular tongue of the CO_2 plume along the migration pathway away from the well bore. When calculating potential storage volumes of a reservoir, being able to estimate the likely storage fairway will greatly enhance the reliability of the storage capacity estimate.

1.7.8 Updating the Geological Model

During the various stages of site exploration and development of a storage site, new and more reliable data will be acquired that addresses critical matters associated with a storage complex characterisation. There will be a need to iteratively update and review the geological and reservoir simulation modelling throughout the life of both the characterisation of a storage complex and during its operational phases. As shown in Figure 2, the interdependency of the various phases will mean that any new or updated data will often have impact on results throughout all elements of the complex characterisation process. As that occurs, the static geological model will become more refined, and so will become more accurate in predicting and defining the earth model.

1.7.9 Geomechanics

Assessment of geomechanics in the static geological model will be required to anticipate matters such as reactivation of faults and rock failure in reservoirs or seals. There are a range of technologies that allow prediction of fault reactivation which is dependent on 3D seismic data to define and map the nature of faults and interlinked fault systems. Regional and local stress regimes need to be incorporated as well as examination of the local fracture gradients, and the rock fabric and mineralogy. Physical rock samples will be required to understand the likelihood of failure under changing pressures and stress regimes.

1.7.10 Geochemistry

Changes in the formation water chemistry with the introduction of CO_2 streams could result in precipitation or dissolution of minerals in the rock. Site and complex specific rock and formation water sampling are required to assess each site and complex and to build this into the geological model. As this physical data is often scarce, only idealised examples of small sample sets are usually constructed. To improve prediction of the interaction of rock and formation water geochemistry, models that are ultimately integrated directly with the simulations of the geological model would be desirable. This would assist with assessing the regional impact of changing water chemistry on the various lithological and mineralogical variations in the reservoir and seal across the entire storage complex.

1.8 Characterisation of the Dynamic Behaviour and Sensitivity

The dynamic model of the storage complex simulation will identify the extent and timing and impact of the CO_2 plume migration. A variety of time-step simulations of CO_2 injection in the storage site need to be run to identify all aspects that are relevant for the storage site and complex characterisation. The modelling tools that exist on the market today are very powerful and will allow construction of sophisticated products. Where limited data exists it is possible to produce outputs that appear technically sound but which can be based on very little specific data from a site.

In Annex 1 in Step 3.1 of the CCS Directive, there are a list of factors provided (see Table 1) that will need to be considered for the characterisation of the storage dynamic behaviour. Each of these factors shall be considered for any assessment and characterisation of a storage complex and the simulation of its storage dynamic behaviour. An example of a critical matter that impacts on the actual modelling process and technology which the CA may wish to consider is:

- Coupled models: the linking together of various sub-disciplines and technical impacts into a single dynamic model.

Coupled models are an aspect of critical importance, whether it is geochemistry, geomechanics or fluid flow that is being examined (Ennis-King & Paterson, 2006, Michael et. al., 2008). It is a subject of considerable research and software development activities. Development of coupled models is an attempt to model aspects of the real world to predict and allow for the interdependencies of the sub-surface processes into a single output, rather than deal with them separately and then try to integrate them. With the development of coupled models, it will be important to ground truth the science with field and natural analogue studies as well as to be able to input actual filed data into the modelling, rather than rely on assumptions and estimates.

Described below are other issues that need to be components of and integrated within any storage complex modelling.

Table 1: Characterisation of the storage dynamic behaviour

Factors listed in Annex 1 in Step 3.1 of CCS Directive: Characterisation of the storage dynamic behaviour
At least the following factors shall be considered:
- possible injection rates and CO2 stream properties;
- the efficacy of coupled process modelling (that is, the way various single effects in the simulator(s) interact);
- reactive processes (that is, the way reactions of the injected CO2 with in situ minerals feedback in the model);
- the reservoir simulator used (multiple simulations may be required in order to validate certain findings);
- short and long-term simulations (to establish CO2 fate and behaviour over decades and millennia, including the rate of dissolution of CO2 in water).
The dynamic modelling shall provide insight into:
- pressure and temperature of the storage formation as a function of injection rate and accumulative injection amount over time;
- areal and vertical extent of CO2 vs time;
- the nature of CO2 flow in the reservoir, including phase behaviour;
- CO2 trapping mechanisms and rates (including spill points and lateral and vertical seals);
- secondary containment systems in the overall storage complex;
- storage capacity and pressure gradients in the storage site;
- the risk of fracturing the storage formation(s) and caprock;
- the risk of CO2 entry into the caprock;
- the risk of leakage from the storage site (for example, through abandoned or inadequately sealed wells);
- the rate of migration (in open-ended reservoirs);
- fracture sealing rates;
- changes in formation(s) fluid chemistry and subsequent reactions (for example, pH change, mineral formation) and inclusion of reactive modelling to assess affects;
- displacement of formation fluids;
- increased seismicity and elevation at surface level.

1.8.1 Production History Matching of Fluid Flow Characteristics (Oil and Gas Field)

Access to history matching of produced fluids from oil and gas fields will allow good predictions as to the reservoir performance for the injection of fluids. If there is evidence of compartmentalisation and uneven pressure depletion across the field due to flow barriers and isolated flow units then the storage site characterisation will need to consider the likely efficiency of storage at the site and the approach for well placement and type (horizontal versus vertical). If the proposed storage site is an old field that has been abandoned already, then the final measured reservoir pressures and conditions may not match the current day conditions due to encroachment of water back into the field over time. Unless there is sufficient data for reservoir modelling and sensitivity analyses, updated information will need to be acquired by re-entry or drilling of new wells in order to construct a reliable dynamic reservoir model.

1.8.2 Iterative Approach to Modelling with Multiple Scenarios and Sensitivity Analysis, and Updating with New Data Acquisition

To allow for the large ranges in geoscience data quality and values, the often sparse data sets, and the uncertainty in the interpretations of that data and the analysis, it will be necessary to build dynamic models and produce multiple scenarios with a range of sensitivities in the modelling. It is important to appreciate the way in which the geological dynamic model has been built and whether from a numerical data viewpoint it has been constructed to represent the average, high end, or low end conditions that are predicted at the site. Similarly it will be necessary to take into consideration the uncertainty in the geological interpretations when running sensitivity analysis, such as whether analogue models or specific models derived from the actual characteristics of the geology of the site were used to define the palaeogeography and reservoir and seal distributions.

Another important aspect to consider is the method by which numerical data has been used to populate the model in areas away from well control and the relationship that was used to relate such data to the overarching geological depositional environment characteristics. Understanding these fundamental facets of the reservoir simulation characterisation will assist in determining the level of certainty that should be applied to the output results from the modelling.

When additional or new data is acquired, it may be necessary to revisit aspects of the modelling and evaluation, and then integrate them again into the outputs and outcomes of the geological and reservoir simulation modelling.

1.8.3 Recalibrating modelling based on operational and monitoring data

The CCS Directive requires that data collected from monitoring are collected and interpreted also by comparing the observed results with the behaviour predicted in the dynamic simulation of the 3D model. If there is a significant deviation between the observed and the predicted behaviour, the 3D model shall be recalibrated to reflect the observed behaviour. The following sections address key issues related to this recalibration requirement of the Directive.

The most important measured or estimated data to which the dynamic reservoir simulation model results should be compared are historical pressures throughout the storage complex (see also GD3). These pressure data may be determined by 1) pressure readings at the points of injection from downhole pressure sensors in the injection well or computation of downhole injection pressures from surface pressure gauges, 2) monitoring well pressure sensors in the injection zone and adjacent formations, and 3) pressure changes estimated from land surface deformation measured using satellite imaging or tiltmeters.[12] The first two pressure estimates will be expected to be continuous and have high accuracy but will cover only very specific points in the storage complex. On the other hand, pressure estimated from survey of land surface deformation will likely be periodic and cover large areas albeit

[12] Note that every technology cannot be applied for all sites, this needs to be decided on case by case basis..

with less accuracy than pressure gauges and sensors. However, it should be noted that surface deformation could have multiple sources, not just reservoir pressure, and so repeat surveys may be necessary to identify the source of changes.

The second most important measured data to which the model results should be compared is the location of CO_2 plume as estimated from monitoring wells penetrating the injection zone and remote sensing techniques such as 4-D seismic surveys. However, the applicability of 4-D seismic surveys needs to be assessed for each individual site. Monitoring wells sensors if located in the injection zone could indicate whether the CO_2 plume has reached the monitoring wells at all and, if so, the percent saturation of CO_2 versus native fluids at various points along the height of the injection zone. Similar information could be collected by taking physical samples of reservoir fluids from monitoring wells and bringing them to the surface for analysis. Sensor would record data continuously while the sampling process would be periodic. The location of the plume might also be detectable using seismic surveys or other remote sensing technique (e.g., electrical, electromagnetic, self-potential and gravity surveys). These have the advantage of covering large areas, but will have less accuracy compared to sensors located in or physical samples taken from the injection zone.

The volume of CO_2 injected per time period also will be measured directly and those volumes used in the reservoir simulator in the history matching exercises. Any observed differences in pressures or plume location between the measured/estimate values and the simulated values could come about due to inaccurate representation of the reservoir characteristics or the regional fluid flow dynamics. One possible error will be the representation of reservoir heterogeneity in terms of how porosity and permeability vary laterally and vertically in the injection zone. Effects of heterogeneity may be observed by how effectively the buoyant CO_2 is separated by gravity as it migrates away from the well. If the CO_2 moves quickly to the top of the injection zone then that’s an indication that vertical permeability is high and there is little vertical heterogeneity (i.e. layers of high permeability between layers of low permeability). An indication of lateral heterogeneity is an uneven movement of the CO_2 plume laterally from the injection point, also called “fingering” because the flow pattern looking down from the surface may look like fingers on a hand. An over statement of vertical heterogeneity or an understatement of lateral heterogeneity in the reservoir simulator might lead to an understatement of the area occupied by the plume footprint. Adjustments to representation of the distribution of porosity and permeability in reservoir simulator would bring the simulated pressures and plume location closer to the historical data and improve the accuracy of the long term forecast of conditions at the storage complex.

Pressures that are uniformly higher or lower than expected could indicate that the regional hydrology was not correctly characterized. Regional hydrology will affect how fluids displaced in the injection zone will create pressure gradients at the injection site and over the entire storage complex. The pressure gradient would be expected to show the highest pressures at the point(s) of injection with pressures dropping off as distances increases and eventually coming down to near native pressures. If the reservoir simulator is backcasting lower pressures than actually existed throughout the storage complex, then it is possible that the injection zone is more closed (unable to accept or transmit fluids) than was thought after site characterization was completed. This might indicate that the injectivity and ultimate storage capacity of the site may be lower than expected. On the other hand, measured pressures that are lower than expected throughout the storage complex might indicate that the injection zone is in greater pressure communication with surrounding formations. This could be good thing in that injectivity and capacity might be higher than expected, but it also could indicate that unexpected leakage pathways exist.

Another complicating factor in comparing model results to actual data will be changes in the reservoir characteristics due to geochemical changes, dehydration, dissolution or precipitation of minerals, erosion caused by fluid flows, rock fracturing caused by high pressures, and clogging of pore space by particles in the injected CO_2 stream (from the capture source or picked up in the pipeline or injection zone). These changes could be detected by various methods such as micro seismic monitoring, and analysis of reservoir fluids taken from monitoring well or from occasional side cores taken from injection or monitoring wells. More likely, such changes will be imputed from the historical pressure and flow data and theoretical geochemical models. For example, a reservoir simulation that shows a good history match in the early part of the simulation (i.e., for the period right after injection starts) but has increasing inaccuracy might indicate that reservoir conditions are changing over time.

It should be expected that the actual measured pressure results during the first days of injection could be quite far off from predictions (unless injection test have been run at the well) due to the uncertain performance characteristics of the well completion itself (permeability affects immediately around the perforated borehole or “skin factor”) and unexpected vertical and lateral heterogeneities in the injection zone. For example it would possible for there to exist deviations of 50 percent of more in actual versus measured pressure increases (measured pressure minus native pressure versus predicted pressure minus native pressure at the point of injection and at points further away such as 200 meters and 2,000 meters from the injection point) for a given volume of injected CO_2. However, after the well has operated for several days with substantial injection volumes and the reservoir model has been recalibrated with revised representations for skin factors and heterogeneities in porosity and permeability, then the deviations would be expected to fall.

For example, actual pressure and injected volume data for injection days 1 to 90 could be used to recalibrate the reservoir simulation model to backcast pressure increases for days 91 to 180.[13] Then the actual data for days 1 to 180 could be used for another recalibration to backcast performance from day 181 to day 360, and so on.[14]

[13] A proper simulation could be done only after the actual injection volumes for days 91 to 180 are known, and thus the term “backcast” is used here instead of “forecast”.

[14] The schedule and procedures for recalibration of the reservoir simulation model should be expected to vary from site to site and operator to operator depending on many factors including the schedule by which measured and estimated monitoring data will be collected. Some data will be collected continuously while other data will come from periodic surveys. It is also possible that “partial recalibrations” could be done more often than “full recalibrations” which would require the added data from 4-D seismic, satellite land deformation or other periodic surveys.

A "well behaved" reservoir might be expected to show a relatively fast convergence between actual and backcasted pressures after the first such calibration (i.e., using 90 days of actual data). However, if the reservoir has complex heterogeneities, undergoes physical changes through time, is an area of complex hydrogeology, and is being match against a large number of measured data points, then deviations between actual measurement and backcasted pressure values could be higher and convergence may not occur until several years of operation. The same general points can be made for comparing the location of the CO_2 plume against results of a reservoir simulator except that the actual location of the plume likely will be determined less frequently and with much less accuracy than pressure measurements. Therefore, much wider deviations should be expected.

1.8.4 Storage Capacity, Integrity and Sustainability

The storage capacity, integrity and sustainability of a site are key elements in Figure 2, and they are derived from the evaluation phases of containment and integrity. Almost every element of both the data acquisition and analysis and modelling phases are linked to these evaluation elements. At a pragmatic level these items are dependent, as if the operation of the storage site is such that integrity is threatened (e.g. fracture gradient is close to being exceeded due to pressure build up because of unidentified heterogeneity in the regional reservoir characterisation), then cessation of operations at the injection site will mean that the practical storage capacity and sustainability of the site are much lower than predicted.

Storage capacities are ordinarily estimated at various stages in the assessment, exploration and development cycles as additional and more extensive data and knowledge become available. Early estimates will be largely theoretical, or if good data exists with oil and gas field information then more practical results can be achieved (Bradshaw et al, 2007, Bachu et al, 2007). One of the significant issues for storage capacity calculations is allowing for the potential impact of pressure build up in the estimations (Birkholzer and Zhou, 2009; Birkholzer, et. al, 2009; Van der Meer et al, 2009), and whether a method for "engineering the reservoir" can be employed to ensure that does not happen. It is only once the reservoir simulation phase is reached that more reliable, authoritative and site specific results can be produced for storage capacity, which allow integration of both the gross calculations directly related to the available pore volume with the volume of rock that is likely to be invaded by the CO_2 plume. The reservoir simulation can also provide a temporal assessment to consider over what time frame the invasion and trapping mechanisms will occur, and which trapping mechanisms will dominate at any given moment in time of the plume injection and migration.

The dynamic storage complex simulation model will also identify in space and time the migration pathways, the speed at which the CO_2 plume will move, the phases that it will be in and the impact on the overall integrity of the storage site from the CO_2 injection and plume movement. As discussed earlier, these components (along with others) will help define the "storage complex" that the operator will require for their storage permit proposal.

The sustainability of a site will be defined by the final considerations and implementation of the outputs and outcomes phase in Figure 2, and it is the combined outcome from the static and dynamic models, the assessment of the risks and the measures to avoid them, and the ways in which the reservoir can be engineered to allow the fluid flow and injection processes to be more effective, technically and commercially.

1.9 Risk Assessment

The risk assessment of a geological storage site and complex characterisation will have to draw upon, integrate and evaluate all of the complex characterisation aspects to ensure that an adequate and appropriate assessment has been performed. A detailed description of a risk management framework for the CO_2 storage life cycle is given in GD1. One key element of risk assessment is hazard characterization as outlined in Annex I of the CCS Directive and is discussed in more detail here. Exposure assessment and effects assessment are discussed in more detail in GD1.

1.9.1 Hazard Characterization

Hazard characterisation shall be undertaken by characterising the potential for leakage from the storage complex, as established through dynamic modelling and security characterisation described above. This shall include consideration of, inter alia:

- potential leakage pathways;
- potential magnitude of leakage events for identified leakage pathways (flux rates);
- critical parameters affecting potential leakage (for example maximum reservoir pressure, maximum injection rate, temperature, sensitivity to various assumptions in the static geological Earth model(s));
- secondary effects of storage of CO_2, including displaced formation fluids and new substances created by the storing of CO_2;
- any other factors which could pose a hazard to human health or the environment (for example physical structures associated with the project).

The hazard characterisation shall cover the full range of potential operating conditions to test the security of the storage complex. The primary hazards of geological storage are described in Chapter 5 of GD1, and are not described further here. These hazards include geological leakage, leakages associated with manmade systems and features (i.e., wells and mining activities), and other hazards from the mobilisation of other gases and fluids by CO_2 (e.g. methane). Modelling and sensitivity analysis can be used to create scenarios for the different hazard mechanisms and determine the critical parameters that could result in potential leakage.

Beyond the primary hazards, there are several secondary effects that are described below.

Fault and Seal Integrity

There are different levels of certainty for the technologies available to characterise fault versus seal integrity for geological storage of CO_2, due to the availability of data for each item, and their respective predictive and temporal characteristics.

To proceed to a definitive assessment of the seal quality, actual core data from the seal interval will be required to allow capacity estimates to be made. However, once that is done, then the geological characteristics of that seal may allow it to be widely extrapolated and predictive in terms of its integrity away from the well bore. Shales deposited in a marine environment will provide thick and laterally extensive seals that are of consistent quality, whereas lacustrine shales and mudstones may be more restricted and localised and of a variable quality. Observational evidence of the presence of hydrocarbons above a seal or of salinity changes across a seal will also help determine the effectiveness of a seal. The gross thickness of a seal may indicate from observational evidence that it will have high integrity. Some seal type rocks, classified as unconventional seals (Bradshaw et. al., 2009), may be able to provide thick intervals of effectively bulk low permeability barriers that could act as sponges over geological time and prevent the leakage of CO_2; known as waste zones in the oil and gas industry where hydrocarbons enter but do not migrate through and thus do not accumulate in a reservoir.

Faults however are rarely sampled by drilling and so their integrity becomes largely a modelling and predictive assessment which will rely on seismic data and observational data where it exists e.g. seeps at the surface or hydrocarbon related diagenetic zones (HRDZ) in the surrounding geological strata. To model a fault accurately, 3D seismic data will be required, as well as nearby well data to correlate the lithological data into the fault plane. These correlations will allow an estimation of the likely lithologies that will be juxtaposed across a fault (sandstone on sandstone, sandstone on shale or shale on shale), and thus the likelihood of fluid transmission across the fault. The amount of throw or displacement across a fault in relation to the thickness of an otherwise competent seal will also help determine the integrity of a seal or fault; e.g. if there is 100m of throw on the fault and the seal is 30m thick, then there is a strong likelihood that the fault may have low integrity because the seal will have been breached. Faults may also have low integrity if they have fault gouge along their planar surface (crushed rock from the adjacent lithological layers), which could act as a conduit for fluids to pass up the fault, rather than just horizontally across it.

Often faults in the same area, or on the same structural feature have different characteristics. Faults that are orientated in a perpendicular direction relative to the current day regional stress regime, will be under compression, and may act as seals, whereas those that are parallel to the regional stress regime and under extensional forces may leak. Faults are usually long lived features of weakness in the crust that are reactivated over geological time during various phases of tectonic activity. Over geological time, those phases of tectonic activity will vary in their nature, extent, magnitude and duration, and will most likely alter the characteristics of the fault.

Thus a complication with faults is that they can behave differently over time, or for specific periods of time in the geological record, and it may mean that although a fault leaked at some stage in the past, it does not mean it would leak now. Identifying and proving these aspects is unlikely to be definitive unless high quality data and observational evidence is available.

Local and regional sub-surface pressure buildup

A key secondary effect is the build of local and regional subsurface pressure due to the introduction of additional fluids to the sub-surface. The extent to whether it represents a hazard of any significance will depend on the rock fabric, regional stress regimes, the volume and rate of fluids that are injected, and the fluid flow characteristics of the reservoir. If the reservoir is a closed system, or locally acts as a closed system, then pressure build up is likely to occur if there is industrial scale injection of fluids. If the reservoir is an open system, then the pressure front will propagate from around the injection well bore, and possibly lead to fluid displacement at the edges of the reservoir system. Storage sites could have a regulated maximum pressure increase at the injection site that they cannot exceed. There may also be broader regulations on maximum pressure across the storage complex. If appropriate monitoring systems such as down-hole pressure gauges are installed, then it should be a routine exercise to monitor this aspect, however the long term reliability of such down-hole gauges will need to be considered as a likely risk factor.

The dynamic complex simulation will identify the likelihood of pressure build up based on the geological model, reservoir heterogeneity and fluid flow characteristics. If the model identifies pressure build up as a risk to the sites integrity, then it may be necessary to plan for wells to produce formation water from the reservoir interval and inject it into an overlying geological formation or produce it to the surface. Use of pressure relief wells may become common place in all storage site development plans, and they could be used as a mechanism to control the flow path and direction of the injected CO_2 plume. The production of formation water and its subsequent use or disposal would have to be addressed based on either existing or new regulations.

Geochemical evaluation of new substances

Another secondary effect is the formation of new substances due to the storage of CO_2. Geochemical assessment of both the groundwater and rock matrix (mineralogy) can be used to predict the likely interaction of the rocks and formation water with injected and stored CO_2. This will require sampling of the formation waters and cores of the rock material. Sampling the formation water can often be unreliable so a data validation checks needs to be part of any assessment. Different rock mineralogies and formation water chemistries could lead to varying responses when CO_2 is injected; be it precipitation, dissolution and/or leaching of substances. Natural analogue studies of environments where CO_2 occurs in high concentrations in the sub-surface can provide valuable information as to the likely geochemical interactions that can occur.

Trial injection studies at pilot locations have identified that some minerals can be entrained in the first wave of the CO_2 plume that moves through a rock, leading to the potential to contaminate the formation or ground water, and/or potentially clog up the pores of the rock fabric in the reservoir, thus reducing permeability. Sub-surface regions where CO_2 has moved through the rock matrix can leave tell tale signs of mineralisation behind and can sometimes lead to mineralisation that enhances overlying seal rock mineralogy. Additional geochemical hazards at the groundwater level could include a change of pH and mobilisation of organic hazardous compounds and heavy metals that could be entrained in a groundwater reservoir during leakage.

Further discussion of the hazards of different chemicals formed due to the incidental substances in the CO_2 stream is provided in Chapter 3 of this GD.

1.9.2 Exposure Assessment

Exposure assessment refers to the process of describing the sources and pathways by which a hazard could enter an ecosystem, estimating the magnitude, frequency and duration of exposure to the hazard, and describing the location, number and characteristics of the populations (human or another organism) exposed (see GD1). For geological storage of CO_2, the main mechanisms by which CO_2 will reach and impact upon the ecosystem are well leakage, leakage through faults, and by leakage into the groundwater system. The likelihood of those events occurring and their impact should be an integral part of the risk assessment process described above.

1.9.3 Effects Assessment

Effects assessment refers to the estimation of what happens to humans, other organisms or an entire ecosystem when exposed to a hazard under one or more of the exposure scenarios described in the exposure assessment. Effects can include changes in appearance, activity, health and population size. The effect of the exposure to CO_2 will be dependent on the rate of leakage into the ecosystem. As CO_2 is a naturally occurring non-flammable substance, if low levels of exposure occur than the effects may be minimal or non-eventful. If however large volumes were to be released over a short period of time then the CO_2 may accumulate in low lying areas and cause asphyxiation and related effects for air breathing organisms due to a lack of oxygen. If the CO_2 was released rapidly under pressure, as could occur from a well leakage to the surface, then the rapid pressure and temperature change is likely to cause freezing of the adjacent areas and facilities. Leakage from offshore storage areas would result in CO_2 being released into the ocean waters. Such leakage could affect the marine oceanic ecosystem, including increased mortality and reduced rates of calcification, reproduction, growth, circulatory oxygen supply and mobility (IPCC, 2005).

In addition, the CO_2 streams that will be injected will have other incidental substances, and some of these substances could pose significant effects (see section 3).

1.10 Summary

Sufficient and proper characterization and assessment of the potential storage site, storage complex and surrounding area are the first critical steps in ensuring that a potential storage site has no significant risk of leakage and eliminate as far as possible negative effects and any risks to the environment and human health. The process of identifying a site will consist of a series of assessments that progressively change scale, commencing with regional assessments to basin-scale assessments to more detailed exploration of specific locations. The phases in the site selection assessment process include components such as data collection and analysis, modelling, evaluation, and outputs and outcomes (see Figure 2). There is significant interdependency among the different data elements and interim modelling for assessing containment, integrity, injectivity, capacity, and hydrodynamics. The CA will need to have the capability to understand these processes and data types, or have access to expertise that will help them review the site and complex characterisation and selection analysis that an operator will perform.

The primary storage options are in depleted oil and gas fields, enhanced hydrocarbon recovery, and saline aquifers. Storage in coal beds is a possibility, although its potential is uncertain and requires more analysis. Although there may be existing data (particularly for the oil and gas fields), the CA may need to consider whether the site and complex characterisation is based on data specifically oriented towards CO_2 storage. Characterisation based primarily on data acquired for the purposes of oil and gas assessment may be incorrectly focussed, as the data may have been acquired in an inappropriate manner or at incorrect geological locations for CO_2 storage.

Collection of primary data either through evaluation of existing data or through exploration activities is critical for evaluating the suitability of a particular site and complex. The GD presents the various interlinkages among the different data elements for building 3D static and dynamic geological models of the site and the complex. Sensitivity of the model to different assumptions needs to be considered as well. The modelling and data analysis needs to provide sufficient confidence on the evaluation of containment, injectivity, capacity, integrity, and hydrodynamics of the site and the storage complex. Finally, an assessment of the risks of different hazards through leakage and other secondary effects needs to be conducted, with an assessment of the exposure and effects of the hazards on human population and environment.

1.11 Selected Glossary

- **Depth:** The actual depth to a geological density contrast evident on a seismic reflection line is calculated by interpolating the variable density of rock layers and the variable velocity that sound waves travel through the various overlying rock layers, and computing that with the observed travel time to measure distance or depth; where velocity equals distance divided by time. The calculation of depth from seismic data often will not produce a unique solution due to the large variability of the geological layers in the deep sub-surface. Where available data from well logs can be correlated with seismic data to greatly improve the accuracy seismic interpretations.
- **Drainage cell:** A drainage cell is an area, generally defined from a structural map of a regional reservoir/seal boundary, within which a buoyant fluid (e.g. oil and gas or CO_2), if it migrates, will be contained. It is perhaps most easily thought of as the inverse (subterranean) analogue of the catchment area of a river system, and like a river system can sometimes be composed of several smaller catchments (smaller drainage cells). In the sub-surface the boundaries comprise the structural lows (the axes of synclinal trends e.g. the axis of a large basin can be the basal boundary for several drainage cells) which flank structural highs. Migration, if any, will be up-dip towards the structural high points and away from the synclinal axes. If there are structural closures (e.g. anticlines) along the apex of the associated high trend(s) then a series of spill and fill trappings could occur. If there are no structural closures, then this high trend defines the main focus for migration of buoyant fluid out of the drainage cell. There are gross assumptions made in defining drainage cells, the most important of which are reservoir homogeneity and the lack of significant complicating hydraulic gradients within the reservoir. If basin scale structuring is simple then the drainage cell(s) defined on the base of the regional seal may be sufficient to basically define the gross system. However, if the basin structural and geological history is complex there may be several "stacked" drainage cells (defined at various depths on a series of regional seals), each with a different migration pattern, resulting in potentially complex and tortuous migration pathways.
- **Dry Structure:** A dry structure is a geologically and geophysically defined sub-surface structural feature, such as an anticline or fault bound feature that has been drilled for oil and gas exploration but has been found to contain subcommercial volumes or no oil and gas accumulation, but will contain other fluids (e.g. fresh or saline formation water).
- **Facies Characteristics:** The facies of rocks usually refers to the lithological characteristics and depositional environments in which the sediments were originally deposited – e.g. river channel, beach, offshore bar, lacustrine, lagoonal, etc. High resolution 3D seismic can in some ideal conditions (e.g. offshore in young and shallow rocks; not onshore in deep and old rocks) be highly predictive of both the facies and the rock characteristics.
- **Fracture gradient** is a measure of pressure needed to fracture the rock in relationship to the rock's burial depth.
- **Geological Structure:** A geological structure, or physical trap, is a physical sub-surface feature that has been defined geologically and geophysically and that contains physically trapped fluids. Examples include anticlines, fault blocks and stratigraphic traps.

- **Leakage**: According to Article 3, leakage means any release of CO_2 from the storage complex.
- **Migration**: According to Article 3, migration means the movement of CO_2 within the storage complex.
- **Migration Assisted Storage**: Migration Assisted Storage (Bradshaw et al, 2009) is a trapping mechanism wherein CO_2 trapping occurs through residual trapping of free phase CO_2 as it moves through a geological formation (i.e. away from the injection site up the structure and pressure gradient), even without structural or stratigraphic closure. There are analogues for this in hydrocarbon migration, as oil and gas are trapped in this way as they move between generating formations and reservoirs.
- **Migration Pathway:** A migration pathway is the route along which fluids will permeate and travel within a reservoir and beneath a seal after the fluids have left the well bore. Due to gravity and buoyancy effects, fluids that are less dense than the surrounding fluids will migrate in an upward direction (relative to the structure of the surrounding formations) to the highest part of the reservoir/seal interface. If they intersect an impermeable barrier, such as shale or salt seal, they will move laterally along below that seal within the carrier beds of the reservoir until they are physically confined in a structural trap or stratigraphic trap with vertical or lateral seals, or are trapped physico-chemically.
- **Prospectivity:** A qualitative assessment of the likelihood that a suitable storage location is present in a given area based on the available information and geology. It encapsulates the dynamic and evolving nature of geological assessments where conceptual ideas and uncertainty dominate. Estimates of prospectivity are developed by examining data(where available), examining existing knowledge, applying established conceptual models and, ideally, generating new conceptual models or applying an analogue from a neighbouring basin or some other geologically similar setting. It was defined (for geological storage) in the Intergovernmental Panel on Climate Change Special Report on Carbon Dioxide Capture and Storage (IPCC SRCCS) (Chapter 2: Sources page 94).
- **Saline Aquifer:** The CCS Directive uses the term “saline aquifer” for deep saline formations. In many regions of the world, the technical definition of aquifer refers to a porous rock medium that contains formation water that can be produced to the surface, and often with an economic consideration to the production of the groundwater. Hence the term, saline aquifer, when it refers to deep saline formations, is considered by many geologists to be an incorrect technical term, and for many farmers, the aquifer is their potable groundwater resource. In fields such as petroleum geology, aquifer is sometimes defined as any water bearing portion of a petroleum reservoir. The term actually leads to considerable confusion and public relations problems when groundwater stakeholders mistakenly believe that geological storage of CO_2 is deliberately targeting storage of CO_2 into the potable groundwater system. Thus the term deep saline reservoir or saline formation is often a preferred technical term to use, being described as where formation water is not fresh, hence containing non-potable water, with ranges of (depending on the jurisdiction) approximately >10,000 to >15,000ppm TDS).

  However, in order to maintain congruence with the CCS Directive, the term "saline aquifer" is used in these guidance documents. Conversely and confusingly, petroleum reservoir engineers often use the term reservoir to describe when a porous medium contains hydrocarbons, and use the term aquifer when it does not contain hydrocarbons (be it either fresh or saline) http://www.glossary.oilfield.slb.com/Display.cfm?Term=aquifer. Often geologists refer to reservoir to mean the rock in which the fluid is held, and reservoir engineers use reservoir to describe the fluid within the rock. Thus, the terms associated with aquifer, saline aquifer, reservoir, saline reservoir and saline formations can lead to unwanted confusion and must be clearly defined.

- **Sidetrack:** a sidetrack well is one that is drilled off the main well bore, often substantially parallel to the main well bore, often being used to bypass problem sections encountered in the main well bore, or to step out from the main well bore to reach another target interval, or intersect additional reservoir intervals in the sub-surface. Sidetracks on a petroleum production field, and the way they have been completed and/or abandoned, may represent challenges for remediation to prevent potential leakage pathways for CO_2.
- **Storage Site:** According to the CCS Directive, storage site is a defined volume area within a geological formation used for geological storage of CO_2, and the associated surface and injection facilities.
- **Storage complex:** According to the CCS Directive, storage complex means the storage site and secondary containment formations that have an effect on overall storage integrity and security. See section 1.5.1 for more details.
- **Two-way-time**: Seismic reflection data records the travel time of signals propagated by sound waves in time; milliseconds. The time taken for a sound wave to leave the transmitter at the surface, reflect from a density contrast in the deep sub-surface (such as a shale (seal) to sandstone (reservoir) transition) and then to return to the receptor at the surface, is known as two-way-time or travel time.

1.12 Acronyms

2D	Two dimensional
3D	Three dimensional
BHT	Bottom Hole Temperature
CCS	Carbon Dioxide Capture and Storage
CCS Directive	Directive on the Geological Storage of Carbon Dioxide (2009/31/EC)
CO_2	Carbon dioxide
DST	Drill Stem Testing
e.g.	For example
EGR	Enhanced Gas Recovery
EHR	Enhanced Hydrocarbon Recovery
EOR	Enhanced Oil Recovery
ETS	Emission Trading Scheme
etc.	Et Cetera (Latin: And So Forth)
EU	European Union
GD	Guidance Document
HRDZ	Hydrocarbon related diagenetic zones

i.e.	Id est (Latin: that is)
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
m	Meter
MAS	Migration Assisted Storage
Mt	Mega tonnes
pH	Potential for hydrogen ion concentration
P/T gradient	Pressure / Temperature
RFT	Repeat Formation Testing
SRCCS	Special Report on Carbon Dioxide Capture and Storage
TDS	Total Dissolved Solids
UK	United Kingdom
USA	United States of America

1.13 References

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2. Composition of CO_2 Stream

2.1 Introduction

The CCS Directive requires that the CO_2 stream shall consist overwhelmingly of CO_2. This is to ensure that the CO_2 stream does not negatively affect the integrity of the storage site or transport facilities and to prevent any significant risk to the environment or human health.

2.1.1 Requirements under the CCS Directive

Article 12 of the CCS Directive addresses the criteria for CO_2 streams for geological storage. It notes the following:

- First, a CO_2 stream needs to consist "overwhelmingly of carbon dioxide".
- Second, no *waste or other matter* may be added to the CO_2 stream for the purpose of disposing this waste or other matter underground.
- Third, in addition to CO_2, there are two other types of matter that may be present in the CO_2 stream: (a) incidental substances that are associated with the source (i.e., the CO_2 source, which is dependent on the used feedstock and the industrial process), capture or injection process; (b) trace substances that may be added to assist in monitoring and verification of CO_2 migration.

The CCS Directive requires that concentrations of all incidental and added substances need to be below levels that would:

a. adversely affect the integrity of the storage site or the relevant transport infrastructure;

b. pose a significant risk to the environment or human health; or

c. breach the requirements of applicable EU legislation.

The requirements under points b and c should be interpreted as meaning that the concentration of pollutants regulated under the Integrated Pollution Prevention and Control (IPPC) Directive, the Large Combustion Plants Directive (LCPD) or the Industrial Emissions Directive (IED) shall comply with the limit values and other requirements of those Directives, including concerning the use of Best Available Techniques (BAT).

Member States can accept CO_2 streams for storage only if their composition is analysed, including corrosive substances, and a risk assessment has been carried out indicating that the levels of incidental and trace substances in the CO_2 stream are acceptable, as defined above. In addition, a register of the quantities and properties of the CO_2 streams delivered and injected, including the composition of these streams, needs to be kept.

2.1.2 What is not covered in the Guidance Document

Hazards associated with CO_2 itself are not covered in this Guidance Document, rather the focus is on the other substances in a CO_2 stream. Several references have information about impact of enhanced CO_2 concentrations in ambient air on human health and environment (see, for example, Benson et al., 2002).

2.2 Key Definitions

Article 3 of the CCS Directive defines a ‘CO_2 stream’ as “a flow of substances that results from CO_2 capture processes”. In order to further clarify the meanings of the terms used in the CCS Directive, a set of definitions and explanation is given below:

- *Incidental Substances:* Substances that are present in the CO_2 stream as a result of being (a) naturally in the feedstock (i.e., coal, gas, oil, biomass, coal-biomass mixtures, etc.), (b) picked up in the capture process, or (c) incidentally entrained or intentionally added to prevent hazards during the transportation and injection processes.

- *Added or Tracer Substances*: Substances added to assist in monitoring and verification of CO_2 migration in the storage complex.

2.3 Approach for CA to determine composition of CO_2 stream

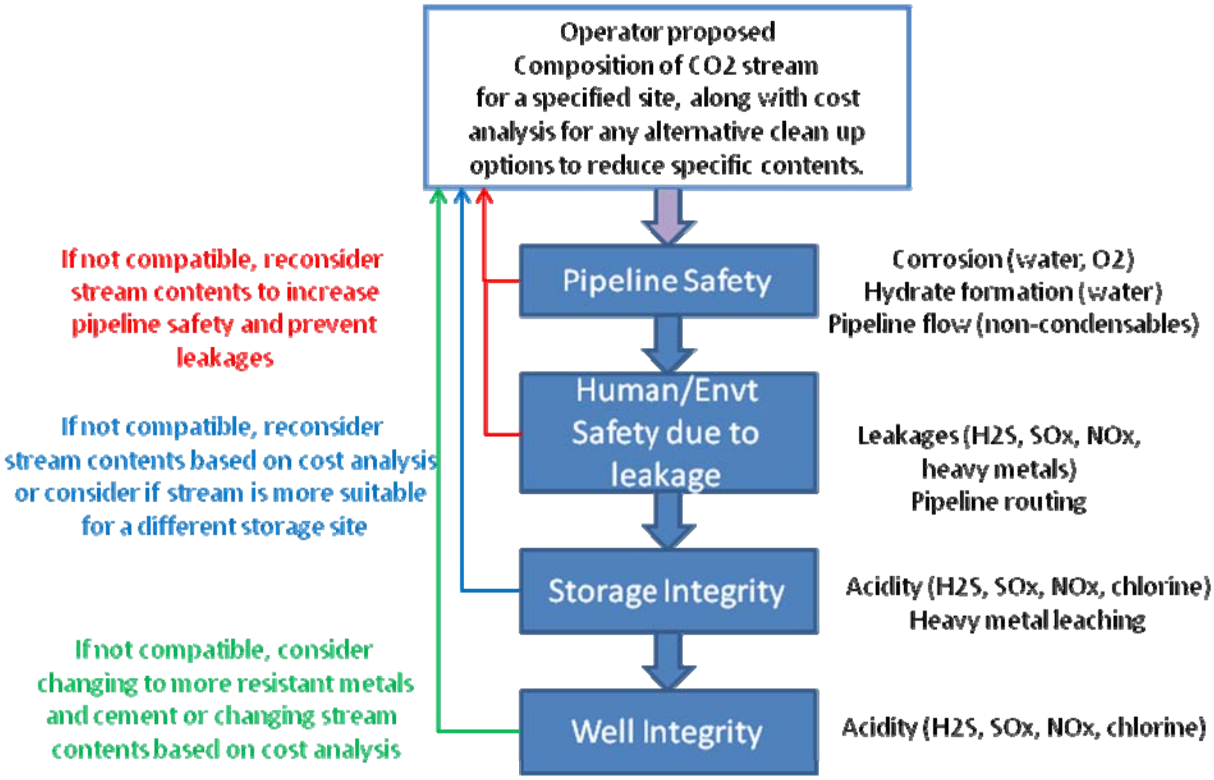
The CA needs to ensure that each operator carries out an analysis of the composition of the CO_2 stream, including corrosive substances, and a risk assessment, including transient concentrations due to start-up or shut-down of capture facilities. If tracer substances are used for monitoring and verifying CO_2 migration, it is important to assess the impacts of such tracers, if any, on storage integrity. Furthermore, operators need to keep a register of the quantities and properties of the CO_2 stream delivered and injected, including the composition of those streams, as required by the CCS Directive. While pipeline operators would likely impose CO_2 stream composition standards to protect the physical integrity and flow characteristics of the pipes, the CA needs to approve the composition of the CO2 stream as it affects pipeline integrity and storage integrity as part of the storage permit.

In determining an acceptable composition of the CO_2 stream, operators and CA could consider optimising the composition for the integrated capture, transport and storage chain. Such an overall optimisation would examine the trade-off between reducing components in a CO_2 stream during the capture process and the impact of such components in the transportation and storage phases while ensuring that the integrity of the storage site and the relevant transport infrastructure is not adversely affected.

However, such integrated approaches may only be applicable for dedicated (short-distance) pipelines.

A proposed chart of activities below in Figure 4 indicates an approach the CA may consider in determining the concentration limits of all incidental and added substances.

Figure 4: Proposed approach for CA to determine an acceptable CO2 stream composition



In case of significant irregularities in the CO_2 stream composition during operation, appropriate corrective measures will have to be undertaken on a case-by-case basis, including an analysis of the causes of the irregularity and impact of the injection of the inappropriate stream into the storage site.

2.4 Composition of CO_2 streams from different processes

The composition of CO_2 streams can vary due to the specific components in the feedstock, the type of process that is used to convert the feedstock into usable energy, the capture process, and any post-capture processing. Furthermore, the amounts and proportions of various components removed from a raw flue gas stream before CO_2 capture (e.g., through de-NO_x and/or desulphurisation processes) will affect the relative concentrations of components remaining in the gas stream.

Removal of air pollutants from a raw flue gas may already be required in order to comply with the Integrated Pollution Prevention and Control (IPPC), LCP and Industrial Emissions Directives. The concentration of incidental substances in most cases can be decreased by adding additional stages of purification (subject to process limits), albeit at higher costs.

The influence of the different kinds of CO_2 capture processes on the composition of the CO_2 stream is discussed below.

Post-combustion capture

Post-combustion capture of CO_2 involves separation of CO_2 from the flue gas stream after combustion of the fuel with air, and the subsequent release of the captured CO_2 into a concentrated CO_2 stream. Post combustion capture systems may be used on systems burning coal, natural gas, oil and biomass. The flue gases coming from direct combustion of coal will contain nitrogen (N_2), oxygen (O_2), water (H_2O), sulphur oxides (SO_X), nitrogen oxides (NO_X), particulates, and chemical compounds containing chlorine (Cl), fluorine (F), mercury, other metals and other trace organic and inorganic chemicals[15,16]. Compared to a flue gas from coal combustion, the flue gas from a gas fired combined cycle plant will contain more H_2O relative to CO_2, and it will have lower concentrations of other components in the flue gas.

In order to operate the capture process economically, many of the substances in the flue gas (especially SO_x and NO_x) will mostly be removed prior to reaching the capture unit to limit degradation of solvents (IPCC, 2005). The requirements of the IPPC, LCP and IE Directives may also constrain the amount of some of these substances in the flue gas. Therefore, the composition of CO_2 stream will nearly be the same regardless of the fossil fuel feedstock used. Furthermore, post-capture processes will, therefore, result in streams that are overwhelmingly carbon dioxide. The 'pure' CO_2 stream after the CO_2 capture process will contain small amounts of nitrogen, oxygen, argon, water and, in some cases, very small amounts of ash, trace metals, SO_2 and NO_x. The specific amount of the incidental substances is dependent on the degree of compression and the number of condensation stages installed.

Pre-combustion capture

In pre-combustion capture, CO_2 or carbon is removed from a gasification stream or a natural gas stream before combustion. The composition of the CO_2 stream depends

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[15] Metals present in CO_2 streams associated with using coal (for any capture process) include mercury (Hg) and other heavy metals present in coal such as Arsenic (As), Selenium (Se), and Cadmium (Cd), antimony (Sb), lead (Pb), chromium (Cr), cobalt (Co), copper (Cu), manganese (Mn), nickel (Ni), vanadium (V), tin (Sn), and zinc (Zn). Other elements include iron (Fe), silicon (Si), aluminium (Al), sodium (Na), potassium (K), calcium (Ca), magnesium (Mg), originating from coal combustion or biomass co-incineration.

[16] Various organic and inorganic residues from post combustion capture processes could include potassium carbonate K_2CO_3 (from Benfield®), monoethanolamine (MEA) and methyldiethylamine (MDEA). The mentioned components (K_2CO_3, MEA, etc.) are not present in flue gas coming from the power plant. These components are only present in the stream after it passes through capture unit. NH_3 may also be present from the DeNOx (SNCR, SCR) plants, and from the Chilled Ammonia capture process.

upon the type of capture process and the type of fossil fuel. The steam reforming process is the most common process used to convert gaseous fuels (such as natural gas, propane, or other light hydrocarbons) to hydrogen, CO_2 and CO. For solid fuels, the gasification process produces a synthetic gas (syngas) containing mostly CO and H_2, which can then be converted to CO_2 using a water-shift reactor. In the reducing atmospheres of pre-combustion processes, the sulphur in the fuel mainly yields hydrogen sulphide (H_2S), although some other compounds such as carbonyl sulphide (COS) are also formed. This is contrary to the oxidizing atmosphere of post-combustion and oxy-fuel processes, where sulphur in the fuel mainly yields SO_X. However, natural gas and propane are mostly sulphur-free except for sulphur-containing odorisers with mercaptans that must be removed from the gas to prevent contamination of the reformer catalyst (NETL, 2002). Thus, the CO_2 product stream from steam reforming is free of sulphur components. Other incidental substances include hydrogen, carbon monoxide, methane, nitrogen, argon, and oxygen.

When liquid or solid fuels are gasified (such as in the integrated gasification combined cycle (IGCC) process), particulates, H_2S, NH_3, COS and HCN are also formed. Pre-combustion capture from the gasification stream (syngas) involves the removal of some fraction of these species prior to combustion in the water-gas shift reactor, followed by cooling stages and acid-gas removal stages. H_2S could be removed together with CO_2 or during pre-treatment[17]. If a purer CO_2 stream is required, then a selective process is required using physical solvents.[18] Nonetheless, H_2S remains a part of the CO_2 stream, and is of the order of 0.01 – 0.6%[19] (dry volume), depending on the sulphur content of the feedstock and the amount of pre-treatment. Other incidental substances include CH_4, C_2+ (hydrocarbons), H_2, CO, and other organic and inorganic residues[20].

Oxy-fuel combustion

In an oxy-fuel combustion process, nearly-pure oxygen is used as the oxidant, instead of air. Flue gas recirculation is needed to keep temperatures on the flue gas side and the water/steam side below slagging and material constraints, making the raw flue gas stream from oxy-fuel combustion predominantly CO_2 and water. Water is typically removed from the stream in a dehydration process; see below.

The amount of incidental substances present in the CO_2 stream is primarily dependent on the type of fossil fuel used in the combustion process. The incidental substances include SO_X, NO_X, HCl and Hg derived from the fuel, and nitrogen, argon and oxygen, derived from the oxygen feed or air leakage into the system. The concentrations of incidental substances in the raw wet flue gas from oxy-fuel combustion are at least 3 to 4 times higher than in conventional air combustion since the combustion products flow volume is 3 to 4 times lower due to the lack of nitrogen

[17] For example, by using a sulfinol process.

[18] For example, by using a Rectisol or Selexol process.

[19] The higher number in the range represents co-capture of H_2S in with CO_2.

[20] Some of these chemicals include methanol (from Rectisol®), N-methyl-2-pyrolidone (NMP, from Purisol®), dimethyl ethers of polyethylene glycol (DMPEG, from Selexol®),and tetrahydrothiophene-1,1-dioxide (Sulfolane, from Sulfinol®).

(coal-air combustion products contain over 70% N_2, while oxy-fuel combustion products contain less than 2% N_2). Meanwhile, the amount of sulphur compounds in the CO_2 stream from oxyfuel combustion is dependent on the amount of sulphur in the coal and the downstream CO_2 processing units employed, which are contingent to the purity specification required for the CO_2 stream. Depending on the sulphur content in coal, a flue gas desulphurisation (FGD) may or may not be used to meet air emission requirements.[21] There can be significant amounts of nitrogen, argon and oxygen (3.7 - 10% dry volume in total) present in the CO_2 stream before any CO_2 processing units, depending on the purity of the oxygen coming from the air separation unit and the leak air flow into the boiler and the downstream ductwork. The amount of nitrogen, argon and oxygen present in the CO_2 stream could be as low as < 0.01% or as high as 15% depending on the CO_2 processing unit employed.

Moisture is another critical component of the stream – prior to drying, water can account for more than 30% of the flue gas volume. After water removal during compression, the CO_2 stream consists of less than 0.1% water (typical for oxyfuel combustion), but about less than 1000 ppm of moisture could also be achieved during compression. However, if a refrigeration cycle and flash column based inert separation process is used to increase the CO_2 content in the stream, then the moisture content from oxyfuel combustion could be required to go down to below 10 ppm.

Also air ingress (tramp air) downstream of the oxy-fuel combustion influences the resulting flue gas composition. About 1% (based on the total mass of flue gas from boiler) of air ingress is reported to yield to about 3-5% decrease in CO_2 concentration (depending on the amount of flue gas recirculation, excess oxygen for combustion and oxygen purity).[22]

CO_2 streams from industrial processes

Broadly, there are three categories of industrial processes that can be distinguished based on their CO_2 concentration in the raw flue gas:

- Low CO_2 concentration (0 to 15%) – This category includes boilers and process heaters in which the CO_2 in the exhaust stream is only from the fuel combustion. The treatment of these emissions is mostly similar to the treatment of emissions from power plants.
- Medium CO_2 concentration (15% to 75%) – Some industrial processes generate CO_2 from non-combustion chemical processes or biological processes Prime examples include cement and lime production, iron and steel production, and fermentation to produce ethanol. These processes may be more amenable to

[21] Furthermore, a FGD could be placed either within the flue gas recycle loop or outside it.

[22] Stanley Santos, IEA GHG R&D Programme: "Development in Carbon Capture Technologies for Power Generation Industry". Presentation at the Institute of Air Quality Management (IAQM) Workshop on CCS, London, UK, 14th November 2007, http://www.ieagreen.org.uk/presentations.html

carbon capture due to their concentrations of CO_2 in flue gas/waste gas streams but they may have other complications, as discussed below.

- High CO_2 concentration (≥75%) – Some industrial processes produce an exhaust stream containing nearly pure CO_2 plus water (e.g., hydrogen and ammonia production and some natural gas processing). Some natural gas streams that contain CO_2 also have H_2S. Depending on what processes are used, the captured waste stream could contain both CO_2 and H_2S or just CO_2.

Some of the industrial processes with their associated raw flue gas CO_2 concentrations are outlined in Table 2 – note that these concentrations do not include a specific CO_2 capture plant. Other industrial processes include lower/varying CO_2 content streams such as from oil sands.

Table 2: Industrial Process CO_2 Concentration in the raw flue gas

CO_2 Concentration	Industrial Category	CO_2 Concentration % Volume (IEA GHG estimates[1], except where noted)
High (≥75%)	Ammonia Process[23]	>90%
	Ethylene Oxide	>90%
	Hydrogen	>80%
	Ethanol	90%
	Natural Gas Processing	>80%
Medium (15% to 75%)	Cement	20%
	Lime[24]	15 -17%
	Iron and Steel	15 - 17%
Low (0 to 15%)	Oil Sands	Main Stack and Boilers 10%, Coker Stack 15%
	Air-based Combustion	3-14%
	Ethylene	12%
	Soda Ash[25]	9-10%

Source: ICF International

While there are only a few capture technologies for electricity generation, the industrial sector has dozens of different combustion applications as well as CO_2-emitting processes that can be considered for capture. This diversity of sources makes capture (and the CO_2 stream composition from these industries) more complex but can also create some opportunities. Unlike power generation from fossil

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[23] CO_2 concentrations associated for ammonia and natural gas processing are based on IPCC, 2005.

[24] CO_2 concentration for the lime industry was estimated based on concentrations from the cement industry since both industries have similar process streams.

[25] CO2 concentrations for soda ash process gas came from US EPA's technical support document for the proposed Greenhouse Gas Mandatory Reporting Rule, specifically from the document for Soda Ash Manufacturing, see, http://www.epa.gov/climatechange/emissions/archived/ghg_tsd.html.

fuels, there are few measured data on the composition of flue gas/waste gas streams from most industrial applications. The composition of CO_2 streams from industrial sources will vary greatly depending on the process and the feedstock used. In many cases, much of the incidental substances are derived from the feedstock itself rather than the industrial process itself. The requirements of the IPPC, LCP and IE Directives will often constrain the amount of air pollutants in the flue gas. Furthermore, some industrial processes include CO_2 capture as part of the standard practice (including ammonia and hydrogen production), and in these cases any incidental substances (such as particulates, SO_x, and NO_x) must be removed in order to prevent the poisoning of catalysts. CO_2 capture from the high concentration category (cement, lime, iron and steel) may utilize oxy-fuel or post-combustion capture processes, such as amine scrubbing, and the incidental substances must be removed to minimize the solvent degradation. The iron and steel industry could also use an in-process capture. Streams from natural gas processing will likely contain methane, non-methane hydrocarbons (C_2+), and H_2S.

Summary of CO_2 stream composition

Based on theoretical calculations, indicative compositions of CO_2 streams generated from the three main capture technologies, as well as a cement plant and process heaters feeding a combined stack at a refinery, are summarized in Table 3It is to be noted that the real behaviour of heavy metals and other trace elements cannot be predicted in a laboratory or from calculations, because coal combustion is conditioned by highly complex processes, such as combustion temperatures, halogen species concentrations, redox conditions, and interaction between different species (Otero-Rey et al., 2003). The capture process used to produce the CO_2 stream is listed in the second row of the table. In these processes, sulphur has been removed as needed to extend the life of the process step which removes CO_2 from the stream; and water has been removed as needed from the CO_2 stream to meet the CO_2 pipeline specification of 0.064% by volume (30 lbs/MMscf). Oxy-fuel combustion has the highest level of contamination for many of these constituents, as the oxy-fuel combustion has no stack emissions. Furthermore, the oxy-fuel system modelled in Table 3 does not have a flue gas desulphurization (FGD) in order to consider a worst case scenario for SO_x in the CO_2 stream. If FGD is included in the oxy-fuel plant, or if the CO_2 were treated, the SO_x concentration in the CO_2 stream would be reduced.

The CO_2 streams captured from coal combustion by all three basic processes can have significant heavy metals content, although most of the heavy metals from coal combustion are typically collected in the fly ash and other waste streams. It is estimated that in post-combustion capture, 87-99% of the heavy metals will be collected in the fly ash and other waste streams, less than 4% in the CO_2 stream, and less than 9% going up the stack. In pre-combustion capture (IGCC process), the heavy metals will mostly be collected in the ash and slag (91-99%), less than 3% in the CO_2 stream, and less than 6% going up the stack. In oxy-fuel processes (with only particulate removal and dehydration purification steps), 88-99% of the heavy metals will be collected in the ash, with less than 12% of the metals could be carried away from the plant in the untreated CO_2 stream.

Table 3: Illustrative Calculated Examples of Composition of CO_2 Streams (after dehydration, but before compression; source: ICF International)

Species	Post-Combustion Capture at Subcritical Pulverized Coal Plant	Pre-Combustion Capture at Coal IGCC Plant	Oxy-fuel Combustion at Supercritical Pulverized Coal Plant	Cement Plant	Refinery Stack
CO_2 source	MEA	Selexol	Stack gas	MEA	MEA
Carbon dioxide, CO_2	99.7%	98.1%	81.8%	99.8%	99.6%
Carbon monoxide, CO		0.13%		1.2 ppmv	
Oxygen, O_2	61 ppmv		3.5%	35 ppmv	121 ppmv
Water, H_2O	640 ppmv	376 ppmv	640 ppmv	640 ppmv	640 ppmv
Ash	11.5 ppm	1.2 ppm	23 ppm	5.7 ppm	
Argon, Ar	22 ppmv	178 ppmv	3.6%	11 ppmv	38 ppmv
Methane, CH_4		112 ppmv		0.026 ppmv	
Nitrogen, as N_2	0.18%	195 ppmv	9.5%	893 ppmv	0.29%
Hydrogen, H_2		1.5%			
Hydrogen sulphide, H_2S		0.17%			7.9 ppmv
Carbonyl sulphide, COS		1.7 ppmv			
Ammonia, NH_3		38 ppmv			
Chlorine, Cl	0.85 ppmv	17.5 ppmv	0.07%	0.41 ppmv	0.4 ppmv
Nitric oxides, as NO_2	1.5 ppmv		0.2%	0.86 ppmv	2.5 ppmv
Sulphur oxides, as SO_2	< 1 ppmv		1.2%	< 0.1 ppmv	1.3 ppmv
Mercury, Hg	0.00069 ppmv	0.000068 ppmv	0.011 ppmv	0.00073 ppmv	
Arsenic, As	0.0055 ppmv	0.0033 ppmv	0.026 ppmv	0.0029 ppmv	
Selenium, Se	0.017 ppmv	0.01 ppmv	0.08 ppmv	0.0088 ppmv	

Notes for table:

- These estimates are based on engineering calculations performed by ICF based on a typical US bituminous coal (Illinois #6) with 2.5% sulphur by weight. The actual amount of substances in a CO_2 stream could vary widely depending on flue gas pre-treatment and capture processes.
- The calculations for the pre-combustion IGCC plant was based on Case 2 scenario analysis in the DOE/NETL-2007/1281 report.
- The calculations for the oxyfuel combustion plant was based on Case 5 scenario analysis in the DOE/NETL-2007/1291 (Revision 2) report.
- The concentrations of mercury, arsenic, and selenium are based on stack gas measurements at a coal-fired power plant in Spain burning a "mixture of two types of coal" (Otero-Rey et al., 2003). However, the concentrations of heavy metals in the CO_2 stream from an IGCC plant may be different than the assumptions in Otero-Rey et al., 2003.

- For post-combustion capture, sulphur was removed as needed for economic operation of the capture step (e.g., to limit amine degradation) from the stream.
- Water was removed from the CO_2 streams to meet US CO_2 pipeline specification of 640 ppm (see below) using glycol-based dehydration. Note that during the compression stage, water, as well as SO_x, NO_x, and Hg, can be removed from the CO_2 stream.[26]
- Heavy metals are typically removed with the particulate matter (fly ash), and therefore more stringent particulate emission standards would further reduce heavy metal content in the CO_2 stream. Furthermore, Hg can be removed during the compression stage along with nitric acid.
- Oxy-fuel combustion has the highest level of contamination for many of these constituents in these examples because ICF assumed for these calculations that the flue gas is not treated except for particle removal by electrostatic precipitation and for water removal to 640ppm. The lack of an FGD allows the sulphur concentration to be high in this calculation; however, this high sulphur content would adversely impact boilers and heat exchangers due to corrosion, and hence a low sulphur coal (<1%) would need to be used to prevent corrosion. If a FGD is included in the oxy-fuel plant, or if the CO_2 were treated after capture, SO_x, HCl, and heavy metal content (e.g., mercury) in the CO_2 stream would be reduced.

The concentrations of all incidental substances can be decreased by adding additional stages of purification. This will result in higher costs of the capture process and affect overall plant efficiency. Furthermore, given that different capture plants will have different compositions of CO_2 streams, it will be important to consider the impact of mixing these streams into the CO_2 pipeline networks, especially when combining CO_2 streams with reducing and oxidising properties. However, at the early stage of CCS development, it is more likely that a distinct CO_2 stream from a particular plant will be linked to an appropriate CO_2 storage site.

2.5 Key concerns of the CO_2 stream composition

An overview of the issues related to the components of a CO_2 stream is provided in the Table 4 below (reproduced from DNV 2010).

[26] Stanley Santos and Jinying Yan, “CO_2 Processing Unit - Challenges in Meeting the Required CO2 Quality”, Presentation at the Oxy-Fuel Combustion Network - 2nd Working Group Meeting on CO2 Quality and other Relevant Issues, September 7th, Cottbus, Germany, 2009..

Table 4: Main issues associated with selected incidental substances of a CO_2 stream (source: DNV, 2010, with modifications)

Component	Health & Safety	Pipeline capacity	Water solubility	Hydrate formation	Materials	Fatigue	Fracture	Corrosion	Operations	Comment
CO_2	√	√	√	√	√	√	√	√	√	Non-flammable, colourless, no odour; low toxicity, heavier than air in the gaseous state
H_2O				√	√	√	√	√	√	Non-toxic; condensable; forms acids with CO_2, NO_x and SO_x, which have a corrosive impact on transport infrastructure
N_2		√	√							Non-toxic; stable
O_2		√	√					√		Non-toxic
H_2S	√	√			√	√	√	√		Flammable, strong odour, extremely toxic at low concentrations
H_2		√	√				√			Flammable, non-condensable at pipeline operating condition; potential impact on transport infrastructure through embrittlement
SO_2	√		√					√		Non-flammable, strong odour, toxic; forms sulphuric acid with water
NO_2	√		√					√		Non-flammable, toxic; forms nitric acid with water
CO	√		√							Flammable, toxic
CH_4+		√	√						√	Odourless, flammable
Amines	√									Potential occupational hazard, with corrosive impact
Glycol	√							√		Potential occupational hazard

As discussed above, the focus in this GD is on how to ensure that incidental substances and trace substances in the CO_2 stream do not adversely affect the integrity of the storage site or the relevant transport infrastructure (corrosion and impact on fluid characteristics), do not pose a significant risk to the environment and human health, and do not breach applicable EU legislation. These aspects are discussed in the following sections.

2.6 Pipeline Impacts

There are three main issues associated with transporting the incidental substances along with the CO_2 stream: corrosion, the risk of gas hydrate formation, and pipeline flow characteristics.

It must also be considered that increasing amount of other components than CO_2 may reduce the transportation capacity of the pipeline, depending on the type, quantity and combination of the components. Indirectly this may have implications on the required pipeline sizing and/or inlet pressure and/or distance between intermediate pump stations.

2.6.1 Corrosion Impacts

Internal corrosion of pipelines can be a major failure mechanism if moisture or oxygen is not sufficiently reduced in the CO_2 stream. In the presence of water, incidental substances, as well as CO_2 itself, can form acids that can corrode pipelines. There are some existing studies on cost comparisons with regard to pipeline materials and integrity for enhanced oil recovery (EOR) (US EPA, 2008a). Acidity and corrosiveness from flue gas components originating from post-combustion capture and oxy-fuel processes (SO_2, SO_3, NO_X, and HCl) will differ substantially from those originating from non- or only partly oxidative processes, such as from pre-combustion capture (CO, H_2, N_2, Ar, H_2S, COS, HCN, etc). SO_2 in the presence of small amount of NO/NO_2 could react with oxygen to form SO_3 and subsequently reacting with water to form highly corrosive H_2SO_4 during compression. SO_3 formed in the boiler in an oxy-fuel process is typically removed in the Direct Contact Cooler that removes HCl and SO_3.

According to the US Department of Transportation's Office of Pipeline Safety, there are no reported pipeline damages caused by internal corrosion, primarily because the water content in the CO_2 stream is controlled before entered into the pipeline.[27] There are also strict procedures in the USA for shutting down the line in case the dehydration system cannot meet the specifications (DNV, 2010, section 5.1).

H_2O concentration limits

Water content in the CO_2 stream should be low enough to ensure that no free water can be formed at any part of the pipeline. Therefore, the expected gas temperatures in the pipelines have to be determined, as the gas temperature defines dew point, which in turn defines how dry the gas has to be. Typical pipeline temperatures are between 8-17^oC and the CO_2 is in liquid form during transport. A sufficient safety margin between the specified water content allowed at the inlet of the pipeline and the water solubility at any location along the pipeline should be specified. For normal operation, a minimum safety factor of two between the specified maximum allowable water content and the calculated minimum water content that may cause water drop within the operational envelope should be specified (DNV, 2010, section 4.8.3). In addition, variations in pipeline conditions, such as during upset conditions when both pressure and temperature may drop significantly, should also be considered in setting the maximum water limit (DNV, 2010, section 4.4.3).

[27] For short dedicated pipelines, one can consider thicker pipelines and different kinds of pipeline materials, instead of dehydrating the stream, as long as pipeline integrity and safety are assured.

Table 5 shows the indicative limits on water content for preventing corrosion, and the CA can use this table to determine the applicable limit in their jurisdiction.

Table 5: Indicative concentration of water to prevent corrosion of pipelines (Source: DYNAMIS, 2007.)

Reference	ppm (by mol)
Kinder Morgan - US pipeline operations (Maximum)	640
Mohitpour et al (2003)	380-640
Odru et al (2006)	50
DYNAMIS	500

Note: The 50ppm is for dehydration of the CO_2 stream using glycol-based dehydration.

The DYNAMIS (2007) project reports that water concentration in a CO_2 pipeline with a good safety margin for avoiding corrosion is 500ppm, although some have argued for full dehydration (at about 50ppm using glycol-based dehydration[28]) or a concentration no more than 60% of the dew point in the worst conditions (Odru et al., 2006). The allowable water content may need to be lower in the presence of other impurities, such as H_2S, O_2 and N_2, as they lower the solubility limit (IPCC, 2005). The CO_2 stream composition could have an impact on the choice of the materials used to build the pipeline and possibly its thickness to ensure that the safety requirements of the CCS Directive are met.

In some plants, the required limitation on water content in the CO_2 pipelines can be met in the acid gas removal stage. In other plants, additional steps must be taken to remove water from the CO_2 stream. If the CO_2 stream is kept well below the critical temperature (31^{o}C) during the compression/pressurization process through the use of multiple compression stages with intercoolers, the liquid water and water vapour can be removed in dehydration units between the compressor stages (DNV, 2010, section 4.8.3). When the CO_2 temperature rises above the critical temperature, the supercritical CO_2 can absorb much more water than liquid CO_2 at lower temperatures. If this occurs, the dehydration units (e.g., glycol dehydrators or molecular sieves) must be installed upstream of the compression stage. In general, the compression train could be designed to remove as much water as possible. Dependent on the cooling water available, a water removal using the knockout drum of the compression train could achieve as low as 600 ppm.[29]

Considerations of water concentration limits for pipeline corrosion is likely sufficient to address corrosion in other infrastructure (pumps, valves, injection tubing).

[28] Note that one can achieve as low as < 5ppm when using a molecular sieve. However, the degradation rate of the molecular sieve binder due to carbonic acid is a concern. This issue could be addressed in future demonstration plants.

[29] Stanley Santos and Jinying Yan, "CO_2 Processing Unit - Challenges in Meeting the Required CO2 Quality", Presentation at the Oxy-Fuel Combustion Network - 2nd Working Group Meeting on CO2 Quality and other Relevant Issues, September 7th, Cottbus, Germany, 2009..

It is important for CO_2 pipelines to consider dehydration processes and water monitoring along the pipeline as part of pipeline design and operation. In some cases, water may be introduced at intermediate compressor stages, even if the input CO_2 stream has minimal water content (DNV, 2010, section 5.1). Therefore, it is important to monitor water content at various segments of the pipeline, depending on the length of the overall pipeline.

O_2 concentration limits

Oxygen in a CO_2 stream can affect both the pipeline in terms of corrosion, as well as injection wells, particularly for EOR. There is considerable uncertainty about the specific impacts of the various concentrations of O_2 in a CO_2 stream, due to lack of fundamental research and development and industrial experience (DYNAMIS, 2007). The combination of H_2S and O_2 further enhances corrosion, but simultaneous presence of H_2S and O_2 is not likely as H_2S is often related to the pre-combustion (IGCC) process in reducing atmospheres where O_2 is not present (DYNAMIS, 2007)[30]. A key concern with O_2 in CO_2 streams used for EOR is that it reacts with oil and can cause overheating of injection equipment (IEA GHG, 2004; DYNAMIS, 2007). DYNAMIS report notes that it can be useful to place oxygen sensors in the injection and production wells for EOR to ensure that these wells do not overheat. However, an early report in 1985 indicated that injection of small amounts of O_2 in EOR applications should not have significant impacts, and the main issue was corrosion (Taber, 1985). Taber (1985) also suggests that flue gas injection with 1-2% oxygen and air injection for in-situ combustion for EOR has taken place without serious corrosion problem, as long as there is sufficient dewatering. However, more research is necessary to assess the impact of O_2 in CO_2 streams for storage.

Currently, most CO_2 pipeline operators in the U.S. allow only a maximum of 10 ppm oxygen, primarily for limiting corrosion. However, given the limited research in this area, the CA may consider limiting O_2 levels in the CO_2 stream on a case-by-case basis, especially for EOR-based streams. The CA may also consider different oxygen concentration levels in the CO_2 streams for non-EOR cases, as long as corrosion considerations and impact on a pipeline network are taken into account.

2.6.2 Risk of hydrate formation

In addition to corrosion, the presence of water in a CO_2 stream can also result in hydrate formation if the temperature is low enough for such hydrates to form. Hydrates form at temperatures higher than the freezing point of water and its solid-like property makes it a danger for pipelines (Carroll, 2003). Hydrates can form in liquids and gases, a; hydrate formation is favoured by low temperatures and high pressure. Hydrates can form not only with CO_2, but also with other incidental substances such as methane, ethane, propane, butane, and hydrogen sulphide; furthermore, free water is not necessarily needed for hydrate formation (Carroll, 2003).

[30] Mixing of CO_2 streams from different sources could result in such combinations leading to greater corrosion potential.

Hydrate formation is typically not a concern for onshore lines due to their relatively high temperatures, but it may be a concern for off-shore pipelines, particularly in the North Sea. In general, the DYNAMIS 2007 report suggests that operators should consider the risk of hydrate formation both in gaseous and liquid CO_2, as well as other incidental substances, in determining the water content of the CO_2 stream. The potential for forming hydrates during commissioning or re-start should also be considered. The DYNAMIS report also does not suggest the use of ammonia for hydrate prevention due to the potential for corrosion and for forming solid ammonium carbonate when reacting with CO_2. Rather, the main strategy for hydrate prevention should be sufficient dewatering of the CO_2 stream.

Furthermore, additional guidance in the DYNAMIS report AP35 "CO_2 Hydrate Formation" notes that:

- Moisture level not exceeding 500 ppm is satisfactory for corrosion purposes and for CO_2 hydrate avoidance under temperature conditions typically found in US.
- A lower, but realistic, standard of 250ppm H_2O is more appropriate for northern North Sea pipeline conditions), even when the CO_2 stream contains some moderate level of common impurities (e.g., about 96% CO_2, 2% N_2, and 2% H_2).
- If choke conditions need to be considered, (defined as down to -2ºC and around 50 bar), then the safe moisture level would have to be reduced to 160ppm.
- If lower temperatures and pressures are foreseen in operational conditions, or further impurities are envisaged, the safe level may need to be further reduced.

2.6.3 Pipeline flow characteristics

Pipeline transportation of CO_2 in the liquid or supercritical regimes is most efficient and economical over long distances, as the friction drop along the pipeline per unit mass of CO_2 is lower compared than transporting the CO_2 as a gas or as a two-phase combination of both liquid and gas (DNV, 2010).[31] The viscosity of supercritical CO_2 is less than that of water.

Getting to the supercritical fluid flow is made more difficult by the presence of non-condensable gases such as hydrogen (H_2), argon (Ar), nitrogen (N_2), oxygen (O_2) and methane (CH_4). CO_2 streams from oxy-fuel plants are most likely to have significant concentrations of Ar, N_2, and O_2 in the CO_2 stream, whereas CO_2 streams from precombustion capture will likely to have more H_2 and CH_4. By diluting the CO_2, the phase change into a supercritical fluid becomes more complex, as higher pressure is needed to convert CO_2 into the supercritical fluid. The presence of hydrogen in the CO_2 stream has the largest effect on the phase equilibrium (DYNAMIS, 2007), which is an issue for CO_2 streams derived from pre-combustion capture. However, it is expected that most of the H_2 in the CO_2 stream will be removed as H_2 is a valuable gas.

[31] In some cases where the CO_2 stream is stored as a gas, gaseous CO_2 transport may be more efficient/feasible for short distances.

The DYNAMIS project suggests a maximum of 4% for all non-condensable gases (such as H_2, Ar, N_2, O_2 and CH_4), whereas existing US pipeline guidelines indicate a maximum of 4% for N_2 and 5% for hydrocarbons, with no specific limits for H_2. The CA may allow the pipeline operator to propose a maximum limit based on economic pipeline operation limitn taking into account the necessary safety considerations.

Recent work has indicated that non-condensable components in the CO_2 stream has significant economic impacts for longer pipelines, and that cost of CO_2 purification can have a significant role for the total cost of CCS, as one needs to balance the cost of purification with other costs (such as storage and transportation).[32]

2.6.4 Existing pipeline limitations on incidental substances

Currently, most of the CO_2 pipelines are being operated in the USA and Canada. In the USA there is approximately 5,800km of existing CO_2 pipelines, that are all operated for EOR. Therefore, the limits placed on CO_2 stream composition is mostly on limiting water content to prevent corrosion and to ensure that the transported fluid's minimum miscible pressure in crude oil will not be so high as to restrict its use for EOR. This includes minimum requirements for CO_2 and maximum limits on nitrogen and hydrocarbons. A pipeline that was built to transport CO_2 for storage in saline reservoirs would not need to meet the standards needed for EOR related for minimum miscibility in oil. Table 6 show the pipeline quality specifications for existing US pipelines.

Table 6: US CO_2 Pipeline Quality Specifications (source: INGAA Foundation, 2008)

Stream Component	Limit	Value	Reason
CO_2	Minimum	95%	Minimum miscible pressure for EOR
Nitrogen	Maximum	4%	Minimum miscible pressure for EOR
Hydrocarbons	Maximum	5%	Minimum miscible pressure for EOR
Water	Maximum	0.064% (640ppmv or 30 lbs/MMscf)	Corrosion
Oxygen	Maximum	0.001% (10ppm)	Corrosion
H_2S	Maximum	0.001-0.02% (10-200ppm)	Safety
Glycol	Maximum	0.0017% (17 ppm, 40 L/million Nm^3, 0.3 gal/MMscf	Operations
Temperature	Maximum	49□C (120 □F)	Materials

[32] J. Yan et al., "Impacts of Non-condensable Components on CCS", Presentation at Working Group on Quality of CO2 Captured from Oxyfuel Combustion Power Plant, 22nd October 2008, Stockholm, Sweden.

2.6.5 Approaches to pipeline routing that reduce potential human health risks from leakage

Pipeline routing will in most cases be covered by existing environmental impact assessment regulations in the Member States. Mostly, issues on pipeline routing for CO_2 streams will be similar to that of hydrocarbons. Since CO_2 is heavier than air, ground topography must be taken into account in the risk assessment (unlike natural gas pipelines but similar to propane pipelines).

2.7 Storage integrity

The CA needs to critically review the issues related to stream composition impacts on geological storage integrity. While some incidental substances can be safely transported in pipelines, they may result in affecting storage integrity. For example, acid gases can be transported safely in pipelines as long as the stream is sufficiently dehydrated, whereas these acid gases could result in reducing storage integrity due to interactions with formation water in the storage site. Of particular importance are the potential deterioration of well-bore cement and other geochemical changes from acid interactions (chemical reactions and mineral dissolution and precipitation, along with related permeability enhancements and clogging effects) with the fluids and rocks in the storage formation and heavy metal contamination of deep saline aquifers.

Czernichowski-Lauriol et al. (2006) has reviewed the literature regarding geochemical interactions between CO_2, formation water, and reservoir rocks. They found that, depending on the nature and scale of the chemical reactions, CO_2 interactions with reservoir rocks and cap rocks may have significant consequences, either beneficial or deleterious, on CO_2 injectivity, storage capacity, sealing efficiency, and long-term safety and stability. Reaction with formation water is expected to trap CO_2 in a solution phase, and in turn, the dissolved CO_2 will react with minerals in the host formation, causing pH buffering, enhanced solubility trapping due to the formation of dissolved bicarbonate ions and complexes. Reaction of the dissolved CO_2 with certain non-carbonate minerals rich in calcium, iron, or magnesium can also trap the CO_2 as a solid carbonate precipitate, essentially immobilising the CO_2 for geological time periods. Mineral reactions result in modification of porosity and permeability of the formation, which can either hinder the injection of CO_2, or aid its migration through the injection zone.

A variety of inorganic acids could be formed when the injected CO_2 stream with its incidental components encounters the fluids in the storage site. These acids can corrode the rocks in the storage complex and affect the geochemistry of the rocks. They can also corrode the cement used for sealing the wells and hence cause leaks over the long term.

Table 7 provides a list of potentially important acids that might be formed from the incidental substances co-injected with the supercritical CO_2 when the CO_2 comes into contact with formation water. Not included in this table are arsenic acid, hydrofluoric acid, hydrogen sulphide, selenic acid, and selenious acid, which are not expected to contribute significantly to the acidity. The strength of the acids is expressed ratio of the equilibrium constant of the acid relative to that of carbonic acid, which is formed by CO_2 interacting with water. The equilibrium constants used to develop the relative acidities shown in Table 7 correspond to 25ºC and atmospheric pressure. Since the pressure and temperature will be much higher in situ, the reaction constants for the formed acids will likely be different in the storage formation, as higher temperatures will typically increase the rate of reaction, while higher pressures can have varied effects.

The volume fraction listed in Table 7 is the upper limit of the concentration of each acid in the CO_2 stream based on near-worst-case assumptions. For example, it assumes that all of the chlorine in the CO_2 stream occurs as HCl, even though it is likely that most of the chlorine will be oxidized and bound with metals during the combustion process (Otero-Rey et al., 2003). The table has been sorted by the concentration of hydrogen ions to identify the potentially most important acids in the CO_2 stream. The most critical acid is hydrochloric acid, which is formed if there is any free form of chlorine present in the CO_2 stream. Sulphurous and sulphuric acid, formed from SO_2 and SO_3 mixed with water, are the next important acids of concern. The contribution of sulphuric acid is about a hundred times less than sulphurous acid, under the assumption that the concentration of SO_3 in the CO_2 stream will typically be about 1% of the concentration of SO_2. Carbonic acid, formed by the combination of CO_2 and water, is a weak acid that contributes little to the volume-weighted acidity of the formation water compared to sulphurous acid and potentially hydrochloric acid if these near-worst-case conditions were to exist. Nitrous acid has a comparable impact as carbonic acid.

The CA should carefully consider potential restriction of the chlorine, SO_x, and NO_x content in the injected stream with a view to prevent potentially high levels of acids that could pose an unacceptable level of risk, subject to geological characteristics of the storage site.

Table 7: Illustrative impact of acids resulting from incidental substances in injected CO_2 stream mixing with formation water (source: calculations by ICF International)

Acid	Formula	Relative acidity	Volume Fraction	Total acidity impact (relative acidity x volume)
Hydrochloric acid	HCl	$2.3x(10)^{14}$	$1.4x(10)^{-3}$	$3.7x(10)^{11}$
Sulphurous acid	H_2SO_3	$3.5x(10)^{4}$	$1.3x(10)^{-2}$	$5.3x(10)^{2}$
Sulphuric acid	H_2SO_4	$2.8x(10)^{4}$	$1.3x(10)^{-4}$	$4.2x(10)^{0}$
Carbonic acid	H_2CO_3	$1.0x(10)^{0}$	$8.8x(10)^{-1}$	$1.0x(10)^{0}$
Nitrous acid	HNO_2	$1.0x(10)^{3}$	$7.2x(10)^{-4}$	$8.2x(10)^{-1}$

Note: The table assumes near-worst-case concentration of HCl, H_2SO_3 and H_2SO_4, as it does not have any treatment of flue gas from oxy-fuel combustion, expect for ash removal and dehydration (see Table 3). The volume fractions also do not include the potential removal of sulphurous, sulphuric, and nitrous acids during the compression stage. Hence, the table presents a worst case scenario for acid production from oxy-fuel flue gases. The total acidity impact gives an upper bound estimate of the concentration of hydrogen ions which might be produced from each acid. The relative acidity is based on calculations under standard conditions and must be corrected to account for pressure and temperature at reservoir conditions—it is expected that the absolute acidity would increase under reservoir conditions due to higher pressure and temperature. Source: Handbook of Chemistry and Physics, 55th edition, 1974-75. See page D-130 and page D-119.

The geomechanical consequences of the chemically-induced changes in fractures and bulk rock petrophysical properties need to be assessed, since they will have an effect on long term storage stability and security. Geochemical reactions are highly site specific, depending on the precise mineralogy, fluid chemistry, pressure and temperature of the host formation. They are also strongly time-dependent, due to the wide range of reaction kinetics, and may also vary based on distance from injection well due to differences in temperature, pressure, and degree mixing with host formation waters. For example, injection of acidic components in rocks that have significant limestone content will lead to some of the acids will be neutralised and the rocks will act as a buffer. However, injection in mostly sandstone-based rocks would mean that there is very little buffer capacity and any formed acids will start attacking the cementitious material and weaken the rocks. On the other hand, buffering by mineral dissolution may significantly reduce the rocks' mechanical strength, increase their permeability, and could be less effective depending on the gas stream velocities and the mass flow of CO_2 injected.

Hence, it is important for operators to conduct geochemical analyses of rocks and the associated fluids (i.e., chemical changes, dissolution, precipitation, and leaching of heavy metals) during the site characterisation phase (covered in Annex I of CCSD), as well as part of monitoring during operation and in the post-closure pre-transfer period.

Operators could also experimentally determine the impact of expected incidental substances on rock samples under simulated reservoir conditions. These tests could then be compared with theoretical expectations based on geochemical modelling as part of the site characterisations. These experimental tests along with modelling may also indicate potential changes to the composition of the CO_2 stream in order to prevent negative impact on storage site integrity. It is to be noted that current understanding of how geochemical tests in the laboratory can be extrapolated to field measurements is still limited. Similarly, geochemical modelling is often subject to great uncertainty due to poor understanding of reaction kinetics and heterogeneity.

Given the geochemical reactions that the CO2 stream would undergo, it is important to recognize that the composition of any leakage from the storage site would be different than the composition of the injected stream.

In addition to changes in geomechanical characteristics of the rocks, the different acids formed will also affect the integrity of wells. Bertos et al. (2004) reviewed accelerated carbonation technology in the treatment of cement-based materials and sequestration of CO_2. They found that certain heavy metals (Pb, Cd, and Ni) increase the susceptibility of cementitious materials to carbonation, i.e., accelerate the deterioration of cement used in injection and monitoring wells at carbon sequestration sites. On the other hand, carbonation has been demonstrated to act positively in the immobilization of heavy metal-contaminated soils and other residues (Bertos et al., 2004).

Similar to the tests conducted on rock samples, it is important to empirically assess and conduct geochemical modelling of the impact of the acids formed from a CO_2 stream on materials used for wells during the operation and post-closure pre-transfer period.

The operator may also want to consider that some incidental substances (e.g., H_2S and SO_x) are more soluble than CO_2, and permeation rates of these substances through the rocks could also be different relative to CO_2. Therefore, there could be variations in concentration of incidental substances at different locations within the CO_2 plume in a storage site. Furthermore, the concentrations of incidental substances from a storage leak may be different than the concentrations in a pipeline leak.

2.8 Health and environmental hazards

In addition to pipeline and storage integrity issues, the CCS Directive requires that the composition of the CO_2 streams do not pose significant risk to the environment or human health. Most of the direct risks arise from short-term sudden leakages from pipelines. The leakage of CO_2 itself can be a major source of health and environmental risks, in addition, the presence of substantial quantities of impurities may affect the potential impacts of a pipeline leak or rupture (IPCC, 2005). Some incidental substances are toxic, such as CO, NO_2, SO_2 and H_2S, and hence it is important to consider limiting the concentration of these substances.

2.8.1 H_2S

H_2S in the CO_2 stream is mostly derived from gasification of coal or from the processing of high H_2S natural gas. Several Member States have already set exposure limits on H_2S exposure levels, as shown in Table 8.

Table 8: Limit Values for H_2S (Source: DYNAMIS)

Hydrogen Sulphide	Time Weighted Average Limit for eight hours		Short Term Exposure Limit (STEL)	
	ppm	mg/m^3	ppm	mg/m^3
Austria	10	15	10	15
Denmark	10	15	20	30
Spain	10	14	15	21
France	5	7	10	14
Sweden	10	14	15	20
Netherlands	10	14	--	--
UK	5	7	10	14
USA (OSHA)	20	--	--	--

Despite the safety risk due to enhanced corrosion in the presence of H_2S, water and oxygen, there may be a net positive effect of having small amounts of H_2S in the CO_2 stream in carbon steel pipes, as it allows the formation of protective compounds on their inner surfaces, increasing resistance against corrosion (DYNAMIS, 2007). On the other hand, H_2S can react with carbon steel pipelines to form a thin film of iron sulphide (if no water is present in the CO_2), which can coat the inside surface of the stainless steel aerial coolers, thus decreasing the heat transfer efficiency (DYNAMIS, 2007). Injection of H_2S in CO_2 streams used for EOR may also have an advantage, as H_2S mixes well with crude oil.

Some CO_2 pipelines in the USA are operated now with only 10ppm of H_2S. The typical limit for H_2S in US natural gas pipelines is 4ppm.[33]

In determining a safety based limit for H_2S, the CA should primarily be concerned about the safety of general public along the pipeline route due to release of any H_2S from pipeline leakages, as well as the safety of workers who will be operating and maintaining the pipeline and pumping stations, where the concentrations of H_2S from leakages could be higher.

2.8.2 SO_X, NO_X

The SO_X and NO_X produced from air-combustion would be removed in post-combustion capture processes in order to achieve the longevity requirements of acid gas removal and amine solvents (Tzimas et al., 2007). According to Hendricks (1994), flue gases that will be sent to amine-based capture should not have more than 10ppm of SO_2. If SO_x and NO_x are not removed from the CO_2 streams from oxy-fuel combustion, oxy-fuel combustion will be the source of most of the SO_x and NO_x. If the oxy-fuel CO_2 streams are cleaned up as suggested by Santos and Haines (2005), then SO_x and NO_x are less of an issue. Most of the SO_2 and SO_3 could be removed during compression prior to entering the downstream CO_2 processing unit depending on the CO_2 specification target. Even without any specific CO_2 processing, a large fraction of the nitrogen and sulphur compounds could be knocked out during compression (depending on the compression design) due to favourable thermodynamic reaction of NO/NO_2 and SO_2 (based on the lead chamber reaction) in the presence of O_2 and H_2O.[34]

When sulphur dioxide is breathed in it can cause immediate irritation in the throat and a sensation of tightness and difficulty in breathing. People with asthma are more sensitive to these health effects and could react to concentrations of SO_2 below 1ppm (DYNAMIS, 2007). NO_2 is a very toxic gas and exposure at low levels may

[33] The DYNAMIS project suggests a 200ppm H_2S limit in the CO2 stream where the maximum concentration of H2S in CO2 is set to such level that the component exceeds its STEL with the same factor as CO2 and reaches its threshold value in the dilution process at the same time as CO2 does. A safety factor of 5 is applied to the maximum concentration limit to reach the recommended value.

[34] White V., et al, 2008: "Purification of oxyfuel derived CO_2", Presentation at the 9th International Conference on Greenhouse gas Control Technologies, 16-20 November 2008, Washington DC.

result in unconsciousness or death. Table 9 and Table 10 show the current exposure limits for SO_2 and NO_2 in various countries. According to DYNAMIS (2007), most countries apply an 8 hour limit value of 25ppm for NO, and STEL are not specified.

The LCP Directive sets limits on SO_2, NO_x and dust emissions from combustion plants with a rated thermal input of 50 MW or more. The actual limits, depend on the thermal capacity and whether it is an existing or new plant.

For large existing plants (>500MWth) firing solid fuels, the SO_2 limit value is 400 mg/Nm^3 and for new plants (>100MWh) the limit is 200 mg/Nm^3 [35,36]. For gaseous fuels[37], the SO_2 limit is the same for existing and new plants and is set to 35 mg/Nm^3 [38].

For existing plants (>500MWth) using solid fuels, the NO_x limit[39] is 500mg/Nm^3 [40]. New plants powered by solid fuels are required to limit NO_x emissions to 400mg/Nm^3 (50-100MWth) and 200mg/Nm^3 (>100MWh)[41]. For natural gas, the limit for new plants is set to 150mg/Nm^3 (50-300MWth) and 100 mg/Nm^3 (>300MWth).[42] There are specific limit values for gas turbines.

These emission limit values set under the LCP Directive apply as the "minimum requirements" for the emissions to the atmosphere, and do not directly apply to the composition of the CO2 stream. In addition, the installations concerned have to comply with the requirements of the IPPC Directive, i.e. permit conditions set by competent authorities have to be based on the Best Available Techniques (BAT), taking into account certain local conditions.

Guidance on what are the BAT for the reduction and control of emissions from various processes is provided in the reference documents on Best Available Techniques (BREF series) adopted and published by the European Commission.[43] These provide a broad view of the ranges of techniques available and their performance (associated emission levels) and applicability.

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[35] Note: The SO_2 limit values for existing plants are calendar monthly mean values, while for new plants are daily mean values.

[36] Note: values apply to a general case. There are separate values for biomass.

[37] Note: values apply to a general case. There are separate values for liquefied gas and low calorific gases from gasification of refinery residues, coke oven gas, blast-furnace gas.

[38] The reference oxygen content, for both the SO_2 and NO_x limits, is 6% for solid fuels and 3% for gaseous fuels, except for gas turbines, the oxygen content can be 15%.

[39] NO_x expressed as NO_2.

[40] Note: The value is set to drop to 200 mg/Nm^3 from 1 Jan 2016.

[41] Note: values apply to a general case. There are separate values for biomass.

[42] For other gases, the limit is the same and equals 200 mg/Nm^3, regardless the plant's capacity. Separately, a new single gas turbine unit (>50MWth) is not allowed to emit more than 50 mg/Nm^3 for natural gas, or 120 mg/Nm^3, if other gaseous fuel is used.

[43] http://eippcb.jrc.es/reference/

Table 9: Eight hour and short term exposure levels for SO_2 (source: DYNAMIS, 2007)

Sulphur dioxide	Time Weighted Average Limit for eight hours		Short Term Exposure Limit (STEL)	
	ppm	mg/m^3	ppm	mg/m^3
Austria	2	5	4	10
Denmark	0.5	1.3	1	2.6
Spain	2	5.3	5	13
France	2	5	5	10
Sweden	2	5		
USA	5	13		

Table 10: Eight hour and short term exposure levels for NO_2 (source: DYNAMIS, 2007)

Nitrogen dioxide	Time Weighted Average Limit for eight hours		Short Term Exposure Limit (STEL)	
	ppm	mg/m^3	ppm	mg/m^3
Austria	3	6	6	12
Denmark	2	4	2	4
Spain	3	5.7	5	9.6
France	-	-	3	6
Sweden	2	4		
Netherlands		0.4		1
UK			5	9.6
USA	-	-	5	9

The limits for SO_x and NO_x should be determined by safety. The content of SO_x, NO_x and HCl in a CO_2 stream depends on the fuel being used, the power plant technology and the technology employed for CO_2 capture. Furthermore, much of the SO_x and NO_x could be removed from the CO_2 stream during compression.[44]

2.8.3 Heavy metal contamination of aquifers

Heavy metals could be present in the CO_2 stream, could be naturally present in the formation waters, or could be leached into the formation water due to acid interactions with rocks containing heavy metals. These heavy metals could then contaminate underground sources of drinking water if there is any leakage from the storage complex, through wells or faults/cracks/weakened caprock.

As discussed in White et al. (2003), Jaffe and Wang (2002) and Wang and Jaffe (2004) have shown that if leaking CO_2 reaches shallow aquifers containing potable water, it could affect water quality by dissolution of trace metals, metalloids, and radionuclides. The results of their geochemical numerical simulations indicate that elevated CO_2 levels in groundwater can amplify the solubilisation of trace metals to the point that undesirable concentrations are reached. They focused on the concentration of Pb in drinking water, with galena (natural mineral form of lead

[44] The DYNAMIS project suggests a 100ppm SO_2 and NO_2 limit in the CO2 stream where the maximum concentration of SO2 and NO2 in CO2 is set to such level that the component exceeds its STEL with the same factor as CO2 and reaches its threshold value in the dilution process at the same time as CO2 does. A safety factor of 5 is applied to the maximum concentration limit to reach the recommended value.

sulphide) as its source. Transport models demonstrate the importance of assessing the areal extent of this CO_2 release, as well as the need to gain a thorough understanding of the key kinetic processes related to CO_2 solubilisation and the dissolution of a trace metal containing mineral phase. These deleterious effects of CO_2 are lessened in drinking water aquifers with a large buffering capacity or high alkalinity.

The CA needs to consider potential effects on underground sources of water from heavy metal contamination due to CO_2 storage. Any significant risks to the environment and human health need to be considered when deciding on the requirements for the composition of the CO_2 stream.

All the constituents in the CO_2 stream (acid gases, as well as heavy metals) could mix with ground water if there is a leak from the pipeline and the risk assessment process needs to consider this issue, as well as dangers from the gases themselves.

2.8.4 Tracer substances for monitoring CO_2

In some cases, tracer substances can be added to the CO2 stream for monitoring and verifying the location and migration of the CO_2 plume. Tracers may also be useful for identifying the source of CO_2 leakages. Broadly, there are two kinds of tracers that can be used: a) natural occurring chemical constituents and b) manmade artificial chemicals. Naturally occurring chemical constituents include stable isotopes of O, H, C, S, and N, noble gases (He, Ne, Ar, Kr, Xe) and their isotopes, and radioactive isotopes (e.g., tritium, ^{14}C, ^{36}Cl, ^{125}I, ^{129}I, ^{131}I). Noble gases and their isotopes can also be added to the CO_2 stream for identification purposes. These natural components in a CO_2 stream can be used to assess fluid origin, migration, and interaction with host rocks along flow paths (GEO-SEQ, 2004). By measuring changes in the concentration ratios of these tracers along the transport pathway, losses (e.g., through diffusion, reaction, or partitioning), and the mechanisms controlling the losses can be investigated (Fisher et al., 2003; McCallum et al., 2005). Assessing isotopic fractions in a leaked CO_2 can also be useful for identifying whether the source of the CO_2 is anthropogenic or biological.

Manmade trace substances include perflurocarbon (PFC) and sulphur hexafluoride (SF_6). Several pilot studies and experimental tests have used PFC tracers and there are good detection capabilities for leakage in both soil gas and the atmosphere (EPA, 2010).

The amount of trace substances to be added to the CO_2 stream will depend on the minimum detectable amount within the medium to be monitored and the probable leakage volumes and dispersion patterns for the relevant leakage pathways. If the CO_2 comes from post-combustion amine capture, the trace amine left in the CO_2 could also help in fingerprinting the CO_2 plume. The- manmade tracers can be detected at levels of a few parts per billion or even parts per trillion (EPA, 2010), and hence only a small amount of them is required to be added.

Naturally occurring isotopes and noble gases do not pose any environmental hazards. However, PFC and SF6 are powerful greenhouse gases themselves, and it is important to prevent spills and leakages of these gases. The potential contamination of sensors, due to spills and equipment leaks, should also be considered (see EPA, 2010). These substances, in small quantities, do not typically pose serious health and environmental impacts—although the operator may want to assess any such impact and submit reports to the CA.

2.8.5 Amines

Amines used in post-combustion CO2 capture can be degraded to different harmful substances such as aldehydes, amides, nitrosamines, and nitramines, some of which have found to be carcinogenic (Låg et al., 2009). Release of these substances to the air, drinking water or the aquatic ecosystems may need to be limited to levels to be determined by the CAs. Where relevant, concentration of these substances shall comply with other requirements as set out in relevant EU legislation, including the Integrated Pollution Prevention and Control (IPPC) Directive, the Large Combustion Plants Directive (LCPD) or the Industrial Emissions Directive (IED).

2.9 Summary

There are several considerations for the CA to be taken into account when deciding on the limits for all incidental and added tracer substances in the CO_2 stream. Requirements for the composition of the CO_2 stream need to ensure that:

- the integrity of neither the storage site nor the relevant transport infrastructure are adversely affected;
- there is no significant risk to the environment or human health; and
- the applicable EU legislation is respected.

Limitations on water and oxygen content of the CO_2 stream is mostly for reducing pipeline corrosion. As for the storage site integrity, the storage site operator and the CA needs to pay particular attention to acid interaction with the geological formation, especially since there will be variance due to site-specific characteristics. The impact of the stream composition on well integrity must also be assessed. In addition, besides the environmental and health risks related to CO_2 itself, potential impacts of all incidental and tracer substances on the environment or human health, for example, due to toxicity need to be considered.

Based on the risk assessment, the CA can determine whether the operator proposed specification of the CO_2 stream composition adequately meets the above criteria.

2.10 Acronyms

Ar	Argon
As	Arsenic
BAT	Best Available Techniques
BREF	Best Available Techniques reference document (under the IPPC Directive and the Industrial Emissions Directive)
˚C	Celsius degree
C_{2+}	Non-methane hydrocarbons
CA or Cas	Competent Authority or Competent Authorities
CCS	Carbon Dioxide Capture and Storage
CCS Directive	Directive on the Geological Storage of Carbon Dioxide (2009/31/EC)
Cd	Cadmium
CH_4	Methane gas
CH_{4+}	Methane ion
CO	Carbon monoxide
CO_2	Carbon dioxide
COS	Carbonyl sulphide
$DeNO_x$	Denitrification (removal of NOx from flue gases)
DNV	Det Norske Veritas
e.g.	For example
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
etc.	Et Cetera (Latin: And So Forth)
˚F	Fahrenheit degree
F	Fluorine
FGD	Flue gas desulphurization
gal.	Gallon
GHG	Greenhouse Gas
H_2	Hydrogen gas
HCl	Hydrogen chloride
HCN	Hydrogen cyanide
Hg	Mercury
H_2O	Water
H_2S	Hydrogen sulphide
H_2SO_3	Sulphurous acid
H_2SO_4	Sulphuric acid
i.e.	Id est (Latin: that is)
IEA	International Energy Agency
IED	Industrial Emissions Directive (2010/75/EU)
IGCC	Integrated gasification combined cycle
INGAA Foundation	Interstate Natural Gas Association of America Foundation
IPCC	Intergovernmental Panel on Climate Change
IPPC	Integrated Pollution Prevention and Control (Directive 2008/1/EC)

km	Kilometer
lbs	Pounds (weight unit)
LCP	Large Combustion Plant (Directive 2001/80/EC)
MDEA	Methyldiethylamine
MEA	Monoethanolamine
mg	Milligram
MMscf	Million standard cubic feet
MWth	Megawatt thermal
N2	Nitrogen gas
NETL	National Energy Technology Laboratory
NH_3	Ammonia
Ni	Nickel
Nm^3	Normal cubic meter
NO	Nitrogen monoxide
NO_2	Nitrogen dioxide
NO_x	Nitrogen oxides
O_2	Oxygen gas
US OSHA	United States Department of Labor - Occupational Safety & Health Administration
Pb	Lead
ppm	Parts per million
ppmv	Parts per million by volume
SCR	Selective Catalytic Reduction
SNCR	Selective Non Catalytic Reduction
SO_2	Sulphur dioxide
SO_3	Sulphur trioxide
SO_x	Sulphur oxides
STEL	Short term exposure limit
UK	United Kingdom
US	of the United States of America
USA	United States of America

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3. Monitoring

3.1 Legislative Context

Monitoring is one of the key activities required by the CCS Directive to ensure the safety of geological storage. The main requirements in the area are stated in Article 13, as follows.

"Member States shall ensure that the operator carries out monitoring of the injection facilities, the storage complex (including where possible the CO_2 plume), and where appropriate the surrounding environment for the purpose of:

a) comparison between the actual and modelled behaviour of CO_2 and formation water, in the storage site;
b) detecting significant irregularities[45];
c) detecting migration of CO_2;
d) detecting leakage of CO_2;
e) detecting significant adverse effects for the surrounding environment, including in particular on drinking water, for human populations, or for users of the surrounding biosphere;
f) assessing the effectiveness of any corrective measures taken pursuant to Article 16;
g) updating the assessment of the safety and integrity of the storage complex in the short- and long-term, including the assessment of whether the stored CO_2 will be completely and permanently contained.

The monitoring shall be based on a monitoring plan designed by the operator pursuant to the requirements laid down in Annex II, including details on the monitoring in accordance with the guidelines established pursuant to Article 14 and Article 23(2) of Directive 2003/87/EC, submitted to and approved by the competent authority pursuant to point 6 of Article 7 and point 5 of Article 9 of this Directive. The plan shall be updated pursuant to the requirements laid down in Annex II and in any case every five years to take account of changes to the assessed risk of leakage, changes to the assessed risks to the environment and human health, new scientific knowledge, and improvements in best available technology. Updated plans shall be re-submitted for approval to the competent authority."

In addition to the CCS Directive, monitoring will also need to meet the requirements under the European Union Emission Trading Scheme (EU ETS) and its Monitoring and Reporting Guidelines (MRG). The MRG are set out in relevant documents (Commission Decision 2007/589/EC on MRG; Commission Decision 2010/345/EU amending Commission Decision 2007/589/EC). In addition to the CCS Directive's requirement to detect leakage, the provisions under the EU ETS require that any leaked emissions that occur from storage activities are quantified and reported in order to determine the allowances that must be surrendered under the EU ETS and

[45] According to Article 3(17) of the CCS Directive "significant irregularity" means any irregularity in the injection or storage operations or in the condition of the storage complex itself, which implies the risk of a leakage or risk to the environment or human health.

to monitor the effectiveness of CO_2 storage as a greenhouse gas (GHG) mitigation technology.

There is further guidance on monitoring in other international legal and regulatory frameworks which have also been taken account of in developing this guidance. These include:

- IPCC Guidelines for National Greenhouse gas Inventories (2006); these consist of a number of steps leading to the inventory and quantification of emission terms during injection and storage of CO_2 for national greenhouse gas inventories.
- OSPAR Guidelines for Risk Assessment and Management of Storage of CO_2 Streams in Geological Formations (2007), which are only applicable for offshore areas.

The monitoring must ensure the effectiveness of any corrective measures (see section 7), and the assessment of the safety and integrity of the storage complex in both the short and long term.

3.2 Approach

In terms of the CO_2 storage life cycle, the initial monitoring plan must be part of the Storage Permit which is approved by the competent authority (CA). The CA is obliged to ensure that the operator monitors the injection facilities, the storage complex (including where possible the CO_2 plume), and where appropriate the surrounding environment during the operational phase and after closure up until transfer of responsibility. Monitoring activities may only be reduced after transfer of responsibility to a level which allows for detection of leakages or significant irregularities. However, if any leakages or significant irregularities are detected, monitoring shall be intensified as required to assess the scale of the problem and the effectiveness of corrective measures.

The CA should ensure that all monitoring activities are based on site specific plans that have been agreed and approved by the competent authorities (CAs) as part of the storage permit based on the requirements laid down in Annex II of the CCS Directive. The monitoring plan shall be updated regularly and at least every five years.

The general principles for the overall approach for monitoring and monitoring plans are:

- Risk based, linked to identified risks from site characterisation and the overall risk assessment;
- Specific to the storage site and complex;

- Sufficiently extensive to cover the storage complex (including where possible the CO_2 plume), migration and behaviour of formation waters and where appropriate the surrounding environment;
- That monitoring is linked to preventive and corrective measures;
- Technology used will be based on the best practice available at the time of design;
- Regular and routine reporting of monitoring data and interpretations of results will take place;
- Monitoring plans will be regularly updated to take account of changes to the assessed risks to the environment and human health, new scientific knowledge, and improvements in best available technology;
- Monitoring activities and plans should be adapted to specific conditions of the offshore marine environment.

Monitoring requirements are in principle risk based and thus depend on the outcome of the risk assessment and identified risks for the specific storage complex.

The starting point for developing and updating any monitoring plans is an adequate characterisation and risk assessment. The general guidance for both risk assessment and site characterisation are covered in GD1 and section 2 of this document. Following the CO_2 storage lifecycle risk framework the risk assessment will result in site-specific criteria for monitoring requirements and may include threshold values for installing preventive or corrective measures. The monitoring plans and activities in turn must be related to preventive and corrective measures.

Monitoring plans should be regularly updated to take account of new information and results from injection, monitoring and site performance data, as well as updates to site characterisation, modelling and risk assessment based on the new data. The review shall also take account of new scientific knowledge, and improvements in best available technology.

A template for the monitoring plan is proposed below, where potential risks, monitoring techniques and mitigation measures are linked together. Regular and routine reporting of monitoring data and interpretations of results is also required by the CCS Directive.

Many technologies are available for monitoring CO_2 storage, which are mostly derived from other sectors and used for other purposes. To date there is limited experience monitoring CO_2 storage projects although new information is being gained from current research and demonstration projects, and new technologies are being developed and/or adapted for use with CO_2 storage.

It is therefore important that the choice of monitoring technology shall be based on best practice available at the time plans are formulated or updated, but not based on what might emerge in the future. The cost effectiveness of specific technologies may be considered when monitoring plans are developed.

3.2.1 Integration with EU ETS Monitoring and Reporting Guidelines

The Monitoring and Reporting Guidelines (MRG) under the ETS Directive (Commission Decision 2007/589/EC and its amendment Commission Decision 2010/345/EU) provide monitoring and reporting guidelines for greenhouse gas emissions from the capture, transport and geological storage of CO_2. The MRG specify how emissions of the CO_2 storage activity have to be accounted for and reported for purposes of the EU ETS (MRG Annexes I (e.g. Section 4.3) and XVIII). The following emission sources at a storage site have to be monitored under the EU ETS:

- Combustion emissions at the injection site;
- Fugitive emissions and emissions from venting at the injection site;
- Emissions from vents and flaring at enhanced hydrocarbon recovery;
- Leakage from the storage reservoir into the water column or atmosphere;

The MRG places emphasis on the verification, accounting and reporting of any emissions (i.e., quantification), the relevant content of which is given below. In the MRG one of the guiding principles is to minimize the uncertainty in the quantification of emissions. Some monitoring methods used for monitoring under the CCS Directive may be suitable for quantification of any emissions resulting from leakage. Furthermore, quantification of any leakage will be useful in assessing the significance of the leakage risk as required under the CCS Directive.

Monitoring activities and plans need to meet the requirements of the CCS Directive should be extended to meet the requirements of the MRG under the EU ETS. It will be more efficient for both the operator and the CA of a storage site to set up and manage monitoring on an integrated basis, covering both CCS and EU ETS issues.

Emissions sources at the injection site and from enhanced hydrocarbon recovery can be monitored using existing approaches from the MRG. Combustion emissions at injection can be monitored with approaches from Annex II (stationary combustion), vented emissions at injection and at enhanced hydrocarbon recovery with approaches from Annex XII (continuous emission measurement) and fugitive emissions at injection by industry best practice. For the MRG formats for monitoring plans already exist at Member State level. This includes industry best practice approaches.

3.2.2 Relationship to preventive and corrective measures

One of the purposes of monitoring is to alert for corrective measures in case of leakages or significant irregularities. Monitoring should also be integrated with the assessment and implementation of preventive measures that can be used to prevent irregularities.

The CCS Directive requires the operator to provide a corrective measures plan at the time of storage permitting, and at the same time as the monitoring plan. The two plans should be developed alongside one another. The corrective measures plan must be produced before any operations largely on modelling exercises performed in the context of site characterization and risk assessment.

The operator is also required to identify and describe preventive measures that can prevent irregularities. These should be included as part of the storage permit application in accordance with Article 7 of the CCS Directive. In practise such preventive measures are expected to include actions that must be taken before CO_2 injection and storage. In addition further preventive measures should be described that might be taken at later stages, including measures that might be taken in response to the results of monitoring, and before any irregularities or leakage occurs that trigger use of corrective measures.

The operator should comment on how models plus forthcoming data from monitoring would be used to identify leakages and significant irregularities – and how preventive and corrective measures might be taken. This will be largely a *site-specific* exercise, based on the aforementioned risk assessment and monitoring plan.

3.2.3 Responsibilities during project phases

The operator is responsible for planning and implementation of monitoring activities during the project development, the operational phase and after closure up until the transfer of responsibility. The operator needs to submit a report to the CA at a frequency to be determined by the CA and at least once a year. This report shall include, among other information, all results from the monitoring, including information on the monitoring technology employed.

CAs are obliged to ensure that the operator monitors the injection facilities, the storage complex (including where possible the CO_2 plume), and where appropriate the surrounding environment during operation and until transfer of responsibility. After the transfer, all monitoring activities are the direct responsibility of the CA. A system of routine and non-routine inspections of all storage complexes (see section 2.5.1 above for a definition) needs to be organised by the CA to ensure compliance with the monitoring requirements until transfer of responsibility.

Pre-injection, injection and post-injection monitoring do not differ in intent or purpose. Risks may be deemed higher in (parts of) the injection phase. The monitoring plan should reflect higher degrees of risk with additional monitoring activity in the initial stages, for example through more frequent monitoring, closer spatial sampling, more extensive sampling and/or different methods.

It may be necessary to gather additional data after storage permitting and before injection starts to provide a pre-injection baseline of the storage complex as a reference to monitoring once injection starts. The gathering of such baseline data may be included in the monitoring plan if it is additional to the data collected for site characterisation, and is discussed further in section 4.4.4. Before injection starts it is of utmost importance to identify all possible baseline data that might be needed throughout the project life cycle including the operations (injection) and post-injection phases, both for planned monitoring as well as for contingency monitoring.

Active and continuous monitoring will take place throughout the injection period, operations phase and after closure up to transfer of responsibility. The amount of monitoring may be reduced after transfer, in view of the decreased level of risk, to a level which allows for detection of leakages or significant irregularities. If any leakages or significant irregularities are detected, monitoring shall be intensified as required to assess the scale of the problem and the effectiveness of corrective measures. As noted above, monitoring after transfer of responsibility is the responsibility of the CA.

3.3 Monitoring Methods

The CCS Directive requires CAs to ensure that monitoring of the injection facilities, storage complex and surrounding environment takes place for the purposes listed in section 4.1 and summarised in the text box below. Annex II of the Directive also specifies that the monitoring plan must in any case include continuous or intermittent monitoring of the following items which should therefore be considered mandatory:

- Fugitive emissions of CO_2 at the injection facility;
- CO_2 volumetric flow at injection wellheads;
- CO_2 pressure and temperature at injection wellheads (to determine mass flow);
- Chemical analysis of the injected material;
- Reservoir temperature and pressure (to determine CO_2 phase behaviour and state).

However the Directive does not specify the measurement methods or technologies that should be considered or used for monitoring. It does, however, provide some general guidance on the technologies that should be considered and used as appropriate (see Annex II of CCS Directive):

- technologies that can detect the presence, location and migration paths of CO_2 in the subsurface and at surface;
- technologies that provide information about pressure-volume behaviour and areal/vertical distribution of CO_2 plume to refine numerical 3D simulation to the 3D geological models of the storage formation;
- technologies that can provide a wide areal spread in order to capture information on any previously undetected potential leakage pathways across the areal dimensions of the complete storage complex and beyond, in the event of significant irregularities or migration of CO_2 out of the storage complex.

The main objectives and purpose of monitoring as described above, are confirming containment of CO_2, alerting for increased leakage risk, identifying leakage if it occurs and significant irregularities, and verifying the CO_2 plume behaviour.

This can be achieved either by measuring the absence of any leakage through direct detection methods, or by verifying indirectly that the CO_2 is behaving as expected in the reservoir based on static and dynamic modelling and updating thereof corroborated by monitoring data. The main challenge for measuring absence of any leakage consists of spatial and temporal coverage of the monitoring method, i.e. "Where and when do we need to monitor in order to be sure that no leakage occurs". The strategy should therefore be based on identified risks.

For the indirect model-based monitoring the emphasis is more on scenario confirmation. As long as predictive models are behaving in agreement with monitoring data, the understanding of both the processes occurring and the behaviour of the storage complex can be considered sufficient. In case of deviations, one should find the causes of the deviations. In the case of significant deviation between the observed and predicted behaviour (as described in 2.8.3) the 3-D model needs to be recalibrated to reflect the observed behaviour as described in Chapter 2 of this GD and in GD3. If, however, the deviations fall well beyond the uncertainty ranges of the predictive models, then additional monitoring and possibly preventive or corrective measures may need to be taken.

It is also important to consider the methods and techniques in relation to the main objectives and different elements of the storage system and monitoring plan at the specific site. Figure 5 provides an overview of possible elements of a monitoring plan, although this is not intended to be prescriptive. The plan's elements, objectives and technologies should be site-specific and risk based; they are also likely to vary through the project life cycle. At present there is no technical measurement which provides a full quantitative analysis of CO_2 leakage from a surface from the size of a underground CO_2 storage pressure plume and therefore a portfolio of methods is likely to be required as appropriate for a specific storage complex. The methods and plan should also cover the formation waters and brine within the storage complex and in surrounding units that may be impacted by injection or leakage.

Figure 5: Monitoring Plan Elements

Operational	Plume	Pathways	Environmental (Leakage)
• Injection Well Control • Pressure & Temperature • Composition • Quantification	• Calibrate Models • Migration • Kinetics • Trapping Mechanisms • Trapping Efficiency • Pressure • Water behaviour	• Caprocks • Faults & Fractures • Wells • Aquifers	• Leak detection • Leak quantification • Emissions/ETS impact • Safety & Environmental impacts

This can be considered in terms of:

- Operational monitoring (which shall meet the mandatory requirements);
- Monitoring the plume which includes:
  - Tracking the injected CO_2 and its movement;
  - water/brine behaviour, properties and movement resulting from CO2 injection;
- Monitoring pathways for potential leakage identified by risk assessment, i.e.:
  - Caprocks;
  - Faults and Fractures;
  - Wells (and well integrity);
  - Overlying aquifers.
- Environmental monitoring for leakage out of the storage complex towards, at or near the surface, on land or offshore:
  - Leak detection;
  - Quantification of leakage;
  - Accounting and quantification of emissions from the storage complex for surrender of emissions trading allowances for any leaked emissions under EU ETS Directive 2003/87/EC;
  - Safety and Environmental impacts.

3.3.1 Summary of Methods for Consideration in Monitoring Plans

The methods, techniques and technologies for monitoring are mostly derived from the oil and gas industry, water industry and environmental monitoring applications. They consist of both proven and developmental technologies, which are being adapted for use in geological storage of CO_2. This must take account of the different fluid/gas properties and differing technical issues.

Although specific experience with different methods for monitoring CO_2 storage is growing, overall there is limited experience, particularly in relation to the wide range of geological and site conditions and storage options across Europe. The applicability and cost of different techniques can vary between onshore and offshore settings, especially in relation to near surface monitoring.

Several reviews of potential monitoring methods and techniques for use with geological storage have been made (IPCC, IEA, ASPEN, and NSBTF). About 60 different methods or techniques have been identified that are potentially applicable for geological storage, which are summarised in Table 11. The table illustrates the large number and ranges of methods that should be considered, however the technologies are at varying stages of development and the list includes some technologies that have yet to be established as suitable for commercial storage projects.

Some monitoring methods need to be deployed using wells. These could use the injection wells for the storage scheme, and may also be dedicated monitoring wells or other wells that penetrate the storage complex. The benefits of any dedicated monitoring well should be assessed by the operator and CA and should take account of the benefit of such monitoring to ensure safe storage weighted against the potential risk of the well penetration of the seal.

The operator and the CA would need to agree upon a defined set of methods as relevant for any particular site based on site specific characteristics and risk assessment. In view of the limited experience to date with CO_2 storage monitoring, the monitoring methods and their applicability, as well as the design of monitoring plans, should take account of best practice and technology status at the time, and any learning and experience from actual storage projects and technology development.

There are a large number of variables that need to be considered by the operator and understood by the CA when assessing different methods:

- The type of method and its suitability for use with CO_2 storage;
- State of development: whether it is proven for use in CO_2 storage and other applications. State of technology development;
- Whether it is a direct or indirect method: e.g. direct measurement of CO_2 concentration in the atmosphere, pH in water etc.; indirect: e.g. remote sensing;
- What medium is investigated: air, water, soils, rock formations, biological indicators;
- Detection limit, accuracy & reproducibility, i.e. the accuracy of single steps, such as accuracy in sample taking, accuracy of the measuring device etc., and the accuracy of the whole method;

- Whether it can be used onshore, offshore or in both settings;
- Site-specific characteristics: the applicability of a monitoring method may depend on site-specific characteristics, such as morphology, mineralogy, depth of the storage site, rock properties, natural plant cover, microclimate, etc.;
- What frequency and spatial distribution is measured: depends on technology type, monitoring locations and the frequency of sampling needed to achieve satisfactory results;
- Cost.

Different methods and techniques are suitable for monitoring as shown in Figure 6.

Figure 6 Different methods and techniques suitable for monitoring

Operational	Plume	Pathways	Environmental Onshore	Environmental Offshore
• **Injection Operations** ◦ Wellhead pressure ◦ Formation pressure and temperature ◦ Injection rate ◦ Microseismicity • **Quantification of CO_2 injected** ◦ Mass flow ◦ Composition and phase	• Pressure and temperature • Geophysics • Well logging (CO_2 saturation) • Surface deformation methods • Tiltmeter • InSAR • Water properties	• **Wells** ◦ Annulus pressure ◦ Corrosion ◦ Cement ◦ Logging ◦ Soil gas • **Caprock** ◦ Formation pressure • **Faults & Fractures** ◦ Microseismicity ◦ Pressure interference • **Aquifers** ◦ Water monitoring ◦ Chemistry	• **Leak Detection** ◦ Sampling and geochemical analysis ◦ Seismic ◦ pressure interference ◦ Soil gas ◦ Vegetation stress ◦ Eddy covariance tower • **Leak Quantification** ◦ Soil gas ◦ Surface gas measurement ◦ … • **Impact: HSE Monitoring** ◦ CO_2 Concentration ◦ Water sampling/analysis ◦ Soils acidity ◦ Surface deformation ◦ Ecosystems surveys	• **Leak Detection** ◦ CO2 flux and concentration monitoring ◦ Water sampling and geochemical analysis ◦ High resolution geophysics ◦ Seismic • **Leak Quantification** ◦ Flux gas measurement ◦ … • **Impact: HSE Monitoring** ◦ CO_2 Concentration ◦ Water sampling/analysis ◦ Ecosystems surveys

Table 11 Summary of Possible Monitoring Methods and Applicability

Category	Method/Technique	Monitoring Application				Onshore/ Offshore		Survey Category	Direct/ Indirect
		Oper.	Plume	Path's	Env.	On	Off	Where Measured	
Operational measurement (Wellhead and Downhole)	Wellhead Pressure and Temperature Measurement	■				■	■	Wells	
	Wellhead flow metering & composition	■				■	■	Wells	Direct
	Downhole Pressure and Temperature Measurement	■				■	■	Wells	
	Casing and Annulus Pressure	■		■		■	■	Wells	
Well Logging	Injection Well Logging (Wireline Logging)	■	■			■	■	Wells	
	Sonic (Acoustic) Logging	■	■			■	■	Wells	
	Cement Bond Log (Ultrasonic Well Logging)	■	■	■		■	■	Wells	
	Pulsed Neutron Capture	■	■			■	■	Wells	
	Density Logging	■	■			■	■	Wells	
	Optical Logging	■	■			■	■	Wells	
	Gamma Ray Logging	■	■			■	■	Wells	
	Resistivity Log	■	■			■	■	Wells	
Well CO2 Sampling	Well sampling & chemical analysis		■			■	■	Wells	Direct
	Tracers		■			■	■	Wells	Direct
Seismic	2-D Seismic Survey		■			■	■	Surface	
	3-D Seismic Multi-component & Timelapse Survey		■			■	■	Surface	
	4-D Seismic Array		■			■	■	Surface	
	Vertical Seismic Profile (VSP)		■			■	■	Wells	
	Cross-Hole Seismic Survey		■			■	■	Wells	
	Microseismic Survey (Passive)		■	■		■	■	Wells	
Shallow High resolution geophysics	Sidescan sonar			■	■		■	Surface	
	Multibeam echo sounding			■	■		■	Surface	
	Shallow 2-D Seismic			■	■	■	■	Surface	
	Bubble stream detection (Sonar)			■	■		■	Surface	
	Boomer / sparker profiling			■	■		■	Surface	
	High resolution acoustic imaging			■	■		■	Surface	
	Ground penetrating radar			■	■		■	Surface	
Gravity Surveying	Time-lapse Gravity		■			■	■	Surface	
	Well gravimetry		■			■	■	Wells	
Electrical and Electromagnetic methods	Land electrical and electromagnetic methods		■			■	??	Surface	
	Induced Polarization		■			■		Surface	
	Spontaneous (Self) Potential		■			■		Surface	
	Airborne EM		■			■		Airborne	
	Magnetotelluric Sounding		■			■	■ ??	Surface	
	Electromagnetic Resistivity		■			■	■	Surface	
	Seabottom electromagnetic (EM)		■			■	■	Surface	
	Permanent borehole Electromagnetic (EM)		■			■	■	Wells	
	Cross-hole Electromagnetic (EM)		■			■	■	Wells	
	Cross-hole Electrical Resistance tomography (ERT)		■			■	■	Wells	
Water Sampling & Geochemistry	Seawater geochemistry				■		■	Seawater	Direct
	Ground-water Monitoring				■	■	■	Wells/water	Direct
	Downhole fluid chemistry				■	■	■	Wells/water	Direct
	Long-term borehole monitoring of pH				■	■	■	Wells/water	Direct
Soil/sediment sampling and Geochemistry	Seabed sampling & gas analysis				■		■	Surface	Direct
	Soil and Vadose Zone Gas Monitoring				■	■		Near surface	Direct
Vegetation imaging	Thermal Hyperspectral Imaging (Satellite)				■	■		Satellite	
	Thermal Hyperspectral Imaging (airborne)				■	■		Airborne	
	Color Infrared (CIR) Transparency Films				■	■		Near surface	
Land surface deformation	Satellite interferometry (InSAR)				■	■		Satellite	
	Tiltmeter				■	■		Surface	
Atmospheric CO2 Flux and Concentration Monitoring	CO_2 Detectors				■	■		Surface	Direct
	Eddy Covariance				■	■		Surface	Direct
	Advanced Leak Detection System				■	■		Surface	Direct
	Laser Systems				■	■		Surface	Direct
	Tracers (Isotopes) in CO2 Samples				■	■	■	Surface	Direct
	Flux Accumulation Chamber				■	■		Surface	Direct
	Bubble stream chemistry				■	■		Surface	Direct
	Portable Infrared gas analysers				■	■	■	Surface	Direct
	Airborne Laser				■	■	■	Surface	Direct
Other	Ecosystems monitoring				■	■	■	Surface	

3.3.2 Monitoring technology & scientific status

The operator and CA should take account of the status of development of the technologies considered and whether it is proven commercial technology, developmental or at the research stage. This should also take account of whether the method and specific techniques is proven for use in CO_2 storage and/or other relevant applications (e.g. oil and gas, hydrology, environmental monitoring, etc).

As mentioned earlier, the design of monitoring plans at the time of the storage permit needs to be based on the best practice and technology status at the time, with any learning and experience from actual storage projects, new scientific knowledge, and improvements in best available technology being incorporated at later stages when the monitoring plan is reviewed.

3.3.3 Overall Monitoring Limitations

Each of the monitoring methods has limitations to its potential application and use in CO_2 storage, and there may be limitations in the applicability of specific methods at any given site.

As a result there will be limitations to the overall monitoring plan that may be deployed at any site. The major limitations are around quantification, accuracy, resolution and the time sampling of specific monitoring in the overall storage life cycle. A review of monitoring limitations from a general perspective has been conducted by the North Sea Basin Task Force (see Box 1).

BOX 1: Limitations of Monitoring – General considerations (NSBTF, 2009, Monitoring Report)

- **Resolution of individual monitoring methods**: Resolution can be translated into the question "what is the smallest amount of CO_2 that can be detected by the method". Resolution generally depends on the instrument specifications, but also on the local environmental circumstances. This question might be stated more exactly based on what is being measured. For example the smallest detectable leaks at the surface could be stated as rate per unit of area per unit of time (micrograms of CO_2 per square meter per second).
- **Accuracy of the individual monitoring methods**: Accuracy can be translated as a follow-up question to the resolution issue "..but what is the uncertainty margin on my measurement". Similar as for resolution, accuracy can be divided into the accuracy of the measurement device and into an accuracy determined by the local environment (i.e. ambient noise, measurement circumstances). As an example, specifications of geophones for acquiring seismic data provide detailed information on the accuracy of the measured signal. However, it makes a large difference if a geophone is placed in a soil with good coupling compared to an unconsolidated environment, where the transfer of the seismic signal to the geophone can be dramatic. And even when the coupling is perfect, the geophones will also pick up local noise for example caused by traffic or industry in the neighbourhood.
- **Parameters measured by the monitoring method**: Most of the currently available monitoring techniques do not measure CO_2 concentrations or fluxes directly, but measure an indirect parameter that can be related to the presence of CO_2 through a model. Such a model will have an additional uncertainty to add to the uncertainty of the quantification. Again seismic data is a good example. The seismic signal picks up differences in density and wave velocity. A model is required to link the seismic signal to CO_2 concentrations.
- **Acquisition pattern deployed by the method (spatial sampling)**: To quantify leakage an integration of measurements over an area of variable is required. Suppose that the first three aspects are perfectly known and that we have a highly accurate method to measure CO_2 directly at the surface with a high resolution, such as a sniffer. This would still not guarantee a proper quantification of leakage over a large area. The sampling density will add another uncertainty on the integral quantification of a leakage.
- **Continuity of the measurements in time (temporal sampling):** Similar as for the spatial sampling, time sampling will add an uncertainty on the quantification of leakage.
- **Separation between background noise,** i.e. CO_2 from other sources, and CO_2 leaking from the storage site. Finally, even if CO_2 could be detected perfectly, this would still demand a distinction between CO_2 leaking from the reservoir and naturally or man-induced background CO_2.

In general, the following should be considered (modified after NSBTF, 2009):

- The techniques that will produce the most accurate results given the circumstances should be used. The appropriate techniques will usually be apparent to specialists.
- There are no sharply defined detection limits for most techniques.
- In the field, their ability to measure the distribution, phase and mass of CO_2 in a subsurface reservoir will be site-specific. It will be determined as much by the geology of the site and surrounding area, and ambient conditions of temperature, pressure and water saturation underground as by the theoretical sensitivity of the techniques or measurement instruments themselves.

- An integrated approach combining different methods is important, with a broad portfolio of methods in the early stage of monitoring.
- There may be benefits in initiating trials of certain techniques in the early stages of monitoring, to establish their suitability at the specific site. Depending on the results, some of these techniques may not be continued.

There are still some key questions requiring further consideration at the general level and for any site by the operator and the CA and as part of any monitoring strategy:

- Which methods are relevant for the specific site?
- What is the resolution of monitoring in detecting leakage?
- How accurately can leakage be quantified?
- What quantity of CO_2 can be resolved in the plume or deep subsurface?
- If continuous monitoring is considered in order to increase time sampling, what shall be the lifespan of the system?

3.3.4 Detection and quantification of leakage and CO_2 plume

Leakage Detection and quantification

Detection and quantification of leakage are important considerations for storage monitoring. There is a specific requirement for quantification of leakage through monitoring if there is actual evidence for leakage. Detection limits and quantification are subject to the limitations of different technologies, their resolution limits their applicability in specific sites and environmental factors, as discussed below.

A key question for quantitative monitoring is of course, to what extent the state-of-the-art technology allows for an accurate quantification. The techniques, methods and approaches will be different for land-based onshore storage sites and offshore sites under the ocean, each of which are described below

<u>Offshore sites</u>

To date there has been no application of shallow subsurface or seabed monitoring specifically for offshore CO_2 storage. However, monitoring of natural gas seepage and its effects on the shallow subsurface and seabed has been undertaken and considered as an analogue for CO_2 seepage (Schroot & Schüttenhelm, 2003a, b).

A monitoring approach for leakage in offshore locations is suggested by the North Sea Basin Task Force (NSBTF, 2009). This suggests adopting a combination of a model-driven approach in combination with a monitoring strategy to estimate the leakage in offshore storage locations for EU ETS purposes. For the North Sea (i.e offshore storage sites) “a sound strategy would be to detect leakage to the surface by geophysical methods like seismic data (detection of gas chimneys) or sea-bottom echo-sounding (detection of pockmarks) and then sample these leakage areas for direct CO_2 detection repeatedly. Based on the sampling profiles an estimate can be made of leakage rates in time for the area. In case of wellbore leakages an additional monitoring program in and around the well is suggested." It would also be possible to monitor offshore injection sites using monitoring wells with pressure, temperature and resistivity sensors located in permeable zones above the cap rock, although the cost effectiveness of this approach will need to be considered.

<u>Onshore</u>

For onshore sites, the strategy, issues and technology options for leakage detection and quantification will be different to offshore sites.

The detection limits of surface monitoring techniques are determined by environmental parameters as well as the sensitivity of the monitoring instruments themselves.

In near-surface systems on land, CO_2 fluxes and concentrations are determined by uptake of CO_2 by plants during photosynthesis, root respiration, microbial respiration in soil, deep natural outgassing of CO_2 and exchange of CO_2 between the soil and atmosphere (Oldenburg & Unger, 2003). Any surface leakage of CO_2 from a man-made CO_2 storage reservoir needs to be distinguished from the variable natural background (Oldenburg & Unger, 2003; Klusman, 2003a, c). Analysis of stable and radiogenic carbon isotope ratios in detected CO_2 can help this process. Most techniques require calibration or comparison with baseline surveys made before injection starts, e.g. to determine background fluxes of CO_2 emissions.

CO_2 Quantification in the Plume

Strategies for monitoring in the deep subsurface have been applied at the Weyburn oil field and Sleipner CO_2 storage site (Wilson & Monea, 2005; Arts et al., 2003; White et al., 2004). Interpretation of 3D seismic surveys repeated at interval of several years has been highly successful in both cases. At Sleipner, which is close to optimum for the technique, detection limit in Utsira Sand is about 2800 tonnes CO_2. At Weyburn, detection limit is about 2500 - 7500 tonnes CO_2.

This shows that deep seismic methods can be used to resolve and quantify CO_2 in the subsurface, although this depends on the target depth (optimum depth of target ca 500-3000 m), reservoir, overburden and rock properties. However, it is also recognised that these methods are unlikely to yield useful information in some circumstances.

In addition, public attitudes to the seismic surveying need to be taken account of and may restrict the frequency of surveying in populated areas. Consequently, the suitability of repeat seismic and its level of resolution will be site specific.

3.3.5 Monitoring methods for pipeline leakage

Computational pipeline monitoring (CPM) is a widely used technique for leak detection, requiring flow, pressure, temperature and other data provided by a SCADA system, and can be divided into four types (DNV, 2010):

- Flow or pressure change;
- Mass or volume balance;
- Dynamic model based system;
- Pressure Point Analysis.

For compositional analysis of the CO_2, gas chromatography can be used. This is the same technology that is used in natural gas transport. Which components need to be measured depends on the specification for purity of CO_2. From the compositional analysis it is possible to measure the density of the gas/fluid. Gas detectors may also be used as part of the risk management strategy for a pipeline. A risk based approach is recommended to determine the need for, and location of, gas (and other) detectors.

Instead of a dew point measurement, experience show that it is more suitable to use a moisture analyzer to measure the water content. There are several choices of moisture analyzers on the market that can be used with CO_2, both contact as well as non-contact.

3.3.6 Monitoring options during post-closure pre-transfer period

In general, the monitoring in the post-closure pre-transfer period would be directed toward providing the data needed to prove that the CO_2 remains contained and that the modelled behaviour conforms to the observed behaviour so the transfer of responsibility may proceed (see GD3). Depending on the specific operational history of the site, one may expect the intensity of the monitoring to be reduced over time as long as the risk assessment indicates that the potential for risk is decreasing. The monitoring method and options will be site specific, and some of the monitoring aims include (Chadwick et al., 2006):

- Verification of the location of the stored CO_2;
- Determining whether the CO_2 mass is seeping into the ocean or atmosphere;
- Meeting local health, safety and environmental (HSE) performance criteria;
- Confirming the accuracy of predictive models; and
- Providing evidence that the system will behave as predicted so that the site may be finally sealed.

As part of assessing containment, it is likely that the following parameters will be monitored: (i) CO_2 plume movement, (ii) reservoir pressure, and (iii) well integrity following abandonment (Chadwick et al, 2006).

3.3.7 Performance Standards

The operator and CA may consider the use of Performance Standards and Key Performance Indicators for the monitoring plan, although these are not specifically required by the CCS Directive. If so these should be designed to meet the aims of the CCS Directive around site safety and containment. These should be developed to help ensure that monitoring meets the specified objectives in the CCS Directive, which are summarised in Section 4.1.

> If developed and used, site specific performance standards should be site specific and they should be based on the geological characterisation, modelling and risk assessment of the specific site and storage complex, and specific risks.

Performance standards and for monitoring should include:

- Targets related to operational, plume, pathways and environmental elements of the plan; These must be aligned with objectives of detecting significant irregularities, leakage or migration under Article 13

- Targets relating to the timing, frequency and accuracy of monitoring plan elements;

- Defining normal, alert and threshold values for key monitoring elements related to identified risk and linked to triggers for preventive or corrective measures, e.g. formation pressure not to exceed fracture pressure of the caprock (that would be expected to result in an irregularity or leakage). Threshold values should be based on site characterisation, modelling and monitoring technology detection characteristics and resolution.

- Establishing a baseline for background emissions. Identified potential leakage pathways and other parameters that will be monitored for environmental performance to detect significant adverse effects on the surrounding environment as required under Article 13 (e.g. water properties, background CO_2 flux) before injection.

It may also prove useful to develop overall performance measures and standards for the entire monitoring scheme in terms that probability is X% of detecting a leak of Y tonnes per year or more within a time periods of Z days or less.

Performance standards should be reassessed periodically and updated to take account of new information.

3.4 Scope and Format of Monitoring Plans

3.4.1 Storage Complex summary

The starting point for developing the monitoring plan is the site characterisation, modelling and risk assessment. The general requirements for both site characterisation and risk assessment are given in the other chapters of this GD. The monitoring plan, in turn, must be related to the corrective measures plan.

The site-specific information in the monitoring plan should include:

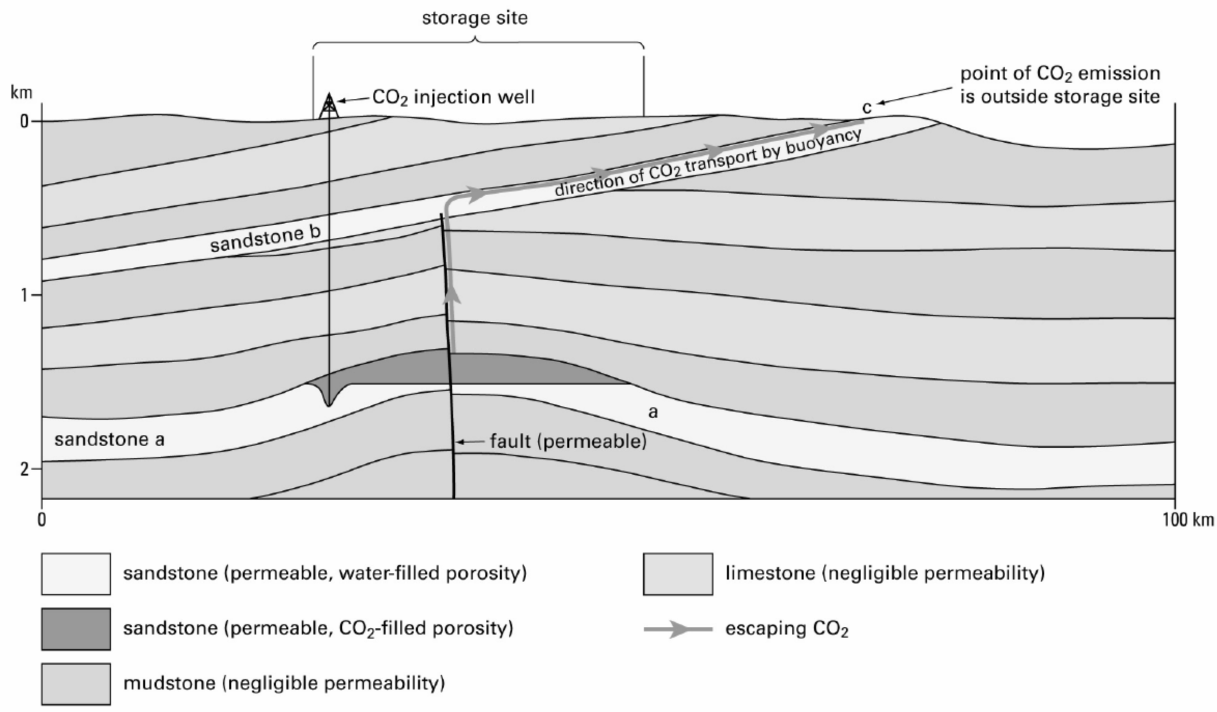
- Location and geographical considerations (e.g. onshore/offshore, local considerations, population centres, land use, potable aquifers, etc.);
- Overview of Site/Complex location and geological characterisation, including reservoir, trapping type;
- Summary of identified risks, including pathways and potential impacts.

3.4.2 Defining the Monitoring Area

The monitoring area should include the injection facilities, the storage complex (including where possible the CO_2 plume), and where appropriate the surrounding environment. The monitoring plan should be based on the geology of the storage complex and the geological framework of the surrounding environment. The site characterisation and modelling and risk assessment should be used to identify features, events and processes that could lead to leakage of CO_2 from the storage complex, and to model potential CO_2 migration and leakage routes and potential fluxes in the case of leakage.

The modelling should be sufficiently extensive to cover possible routes to surface through identified potential pathways for the specific sites, as these may be offset from the injection site (Figure 7). If CO_2 migrates from a storage reservoir (a) via an undetected fault into porous and permeable reservoir rock (b), it may be transported by buoyancy towards the ground surface at point (c). This may result in the emission of CO_2 at the ground surface several kilometres from the site itself at an unknown time in the future. The modelling should also be used to project the extent of potential impacts of CO_2 storage in saline aquifers, such as pressure increases and formation water displacement so that monitoring plans can be developed to address these as necessary. Monitoring should also be considered to detect CO_2 movement into aquifer formations between the main storage reservoir and the surface.

Figure 7: Illustration of potential leakage from a storage site (IPCC)



In some cases, it is possible that different operators working in proximity could have overlapping monitoring footprints or alternative uses of the subsurface. This overlap in monitoring footprints should not, however, extend to the areas where CO_2 plumes can be expected to be observed. Where this occurs, the storage operators and CA should work together to ensure the monitoring plan can be effectively implemented.

3.4.3 Plan Description

A monitoring plan drawn up by the operator must meet the following requirements that are included in the CCS Directive. These requirements are also reflected in the proposed template in Section 3.4.5.

The monitoring plan shall provide details of the monitoring to be deployed at the main stages of the project, including baseline, operational and post-closure monitoring.

The following shall be specified for each phase:

- Parameters monitored;
- Monitoring technology employed and justification for technology choice;
- Monitoring locations and spatial sampling rationale;
- Frequency of application and temporal sampling rationale.

The parameters to be monitored are identified so as to fulfil the purposes of monitoring and risk management at the specific site/complex. The temporal sampling will need to take account of the method and technology used, along with the nature of the medium sampled and type of measurement. Some methods lend themselves to continuous measurement, e.g. pressure sampling in wells or and compositional sampling in air. Other methods, such as direct sampling in water or soil samples and seismic surveying are likely to be episodic in nature.

However, the plan must in any case include continuous or intermittent monitoring of the following items:

- Fugitive emissions of CO_2 at the injection facility;
- CO_2 volumetric flow at injection wellheads;
- CO_2 pressure and temperature at injection wellheads (to determine mass flow);
- Chemical analysis of the injected material;
- Reservoir temperature and pressure (to determine CO_2 phase behaviour and state).

These measurements and related alarms are very important in providing early indications of any anomalous behaviour allowing preventive measures to be taken before any leakage occurs.

The choice of monitoring technology shall be based on best practice available at the time of design. The following options should be considered and may be used as appropriate:

- Technologies that can detect the presence, location and migration paths of CO_2 in the subsurface and at surface;
- Technologies that provide information about pressure-volume behaviour and areal/vertical distribution of CO_2 plume to refine numerical 3D simulation to the 3D geological models of the storage formation established pursuant to Article 4 and Annex I of the CCS Directive;
- Technologies that can provide a wide areal spread in order to capture information on any previously undetected potential leakage pathways across the areal dimensions of the complete storage complex and beyond, in the event of significant irregularities or migration of CO_2 out of the storage complex.
- Techniques for water sampling and analysis. Saline water from the injection zone, reacting to higher pressures and imperfections in the cap rock or well cement, can breach the cap rock endangering shallower drinking water sources and indicating a pathway whereby the CO_2 plume might later escape. Therefore, monitoring the salinity (resistivity), pressure and temperature of fluids above the cap rock to detect such fluid movements may also be appropriate.

Different categories of monitoring can be set out:

- Mandatory monitoring (for all sites). Some parameters to be monitored are mandatory in the CCS Directive. These parameters are important for operational monitoring, and will provide some important and continuous measurements relating to plume behaviour and potential leakage pathways (e.g. formation pressure data).

- Required (site specific) monitoring. This group of site specific monitoring activity is directed to gathering evidence for containment in the reservoir and to demonstrate integrity of seal, fault and wells at the specific site. This will in particular build on the risk assessment during site characterisation in order to respond to site specific risks and uncertainties.

- Optional contingency monitoring. The third category refers to a contingency monitoring system which will only be used in event of irregularities. In the CCS Directive a "significant irregularity" is defined as '…any *irregularity in the injection or storage operations or in the condition of the storage complex itself, which implies the risk of a leakage or risk to the environment or human health*'. Any contingency monitoring is only likely to start some time after injection has started. Contingency monitoring needs to be considered at the very early pre-injection stage based on the risk analysis of "What can go wrong".

3.4.4 Baseline surveys

Baseline monitoring is required to describe the site and complex ahead of any CO_2 injection and storage. These should be considered as an integral part of the initial monitoring plan submitted at the time of storage permitting.

The scope of baseline surveys will depend on the availability and type of data that exists over the specific site, storage complex and surrounding area, including data acquired before and during site characterisation and as part of any environmental impact assessment.

Baseline measurements should be considered as follows:

- Formation gas and fluid characteristics in the storage reservoir, surrounding complex and formations that might be affected by potential leakage, including aquifers;

- Background CO_2 emissions at surface or sea floor;

- Surface and near surface environmental surveys;

- Seabed, surface or near surface baseline surveys to define any pre-existing leakage indicators such as pock marks;

- Ground surface surveying, e.g. where ground movement monitoring is expected to be beneficial and/or in areas of ground movement risk.

3.4.5 Detailed Plan Format

A template for a monitoring plan is proposed (see Table 12 and Table 13) in this section. The first template and part of the plans (Table 12) should include the following:

- Parameters to be monitored (e.g. Column 1): these parameters follow both from the mandatory monitoring obligations as stipulated by the CCS Directive and from the risk assessment. Note, that the latter parameters will be highly site-dependent;

- The technique that will be used to measure the parameter (Column 2): a more detailed description of the technique should be provided outside the table. Especially site specific issues need to be clarified in an accompanying text. Such a description encompasses for example the acquisition parameters;

- The category of monitoring: mandatory, required, contingency (Column 3);

- Temporal frequency of measurement (Column 4);

- Spatial coverage (Column 5) of the data acquisition foreseen in the different phases of the project (pre-injection, injection and post-injection including long-term stewardship after transfer of responsibility). The rationale behind the monitoring strategy should be described in an accompanying text;

- The expected accuracy of the monitoring method and of expected values that indicate normal behaviour;

- Threshold Alert values where predicted normal behaviour stops and where potentially anomalous measurements occur (Column 7): As long as the measured values remain below these threshold values (Threshold 1), no actions are required (green column). If the values exceed the threshold values, specific preventive actions may be defined, the use of which would be contingent on exceeding the alert value. This stage is considered as an increased alert phase, where behaviour starts to deviate from expectations. This could for example lead to recalibration of the models, but when persisting to more stringent measures. The triggering of alerts might also be dependent on how measurements taken at different locations and times corroborate or contradict each other;

- Contingency Values and Actions (Column 8): if the monitoring measurements values exceed the identified threshold coloured red, which would indicate either a significant irregularity or leakage, the highest alert phase starts and immediate actions (or corrective measures) as defined in the second subcolumn of are required.

In the example provided, several parameters have been shown in the template such as injection rate, injected gas composition and fault integrity. Note that more than one monitoring method may be selected for each parameter. At the operator's discretion the table can be further subdivided into to describe the different risks and elements to be monitored (for example operations, caprock, well leakage pathway, plume, etc).

A second table (Table 13) should be prepared by the operator to connect the chosen monitoring methods to the risks identified in the risk assessment and provide a rationale for the choice of the method. This should list the risks identified in the risk assessment analysis. It should relate the chosen monitoring methods to the risks they address, recognising that one method can address more than one risk. It should describe why each method is considered appropriate to address a specific risk from both a technical and a cost-efficiency point of view.

Table 12 Proposed format of monitoring plan template with example information.

Parameter to be monitored*	Technique adopted	Category of monitoring			Project phase and frequency				Location	Normal situation		Alert value		Contingency value (significant irregularity	
		Mandatory	Required	Contingency	Pre-inj	Inj	Post-Inj	Long-term stewardship		Expectation value	Accuracy	> Threshold 1	Action**	> Threshold 2	Contingen measures
Injection rate	Flow meter	x				Cont			Well head						
Pressure	pressure device	x			Baseline data	Cont	Cont	Every year	Well head + Down hole			Larger than hydrostatic pressure	Microseismic monitoring of seal	Larger than fraccing pressure	Stop injec
Temperature	thermometer	x			Baseline data	Cont	Cont	Every year	Well head + Down hole						
Injected gas composition	Gas samples	x				Cont			Well head	Defined %		Allowed fluctuations	Adapt gas composition, reduce injection rate	Above allowed fluctuations	Adapt ga composit stop injec temporar
Fault integrity	Repeated 3D seismic		x		Baseline survey	Order of years, based on modelling	Possible survey after several years	Possible survey after several years	Fault area	No signal changes		Signal change in the seal		Signal change above seal	
	Aqueous chemistry (CO2, pH)		x			roughly yearly									
Well integrity	Annular pressure		x			order of few months			Well bore	t.b.d.		t.b.d.		t.b.d.	
	Wireline Logging		x			order of few months			Well bore	t.b.d.		t.b.d.		t.b.d.	
	Optical Well Logging		x			order of few months			Well bore	t.b.d.		t.b.d.		t.b.d.	
	Cement Bond Logging		x			order of few months			Well bore	t.b.d.		t.b.d.		t.b.d.	Cement
Microseismic monitoring	Geophones behind the casing of a well			x	Baseline data	Cont	(Cont)		Injection well	No events in caprock		Events in the caprock		Large events in the caprock	Stop inje

*Follows from the risk assessment
** t.b.d. by operator examples are updating model additional monitoring
*** t.b.d. by operator, examples are stop injection, back-production, well workover, contingency monitoring

Note: This table is not intended to represent a full monitoring plan, but to show example information to illustrate how the table should function. The numbers and data do not represent real site-specific values.

Table 13 Overview on monitoring methods addressing the risks identified

Risk	Monitoring Methods Used		Rationale for the Choice of Monitoring Method
	No. of monitoring Method	Name of Monitoring Method	Comment: Please explain, why the chosen monitoring method is appropriate for the risk under technical and cost-efficiency considerations
Risk 1	No. 3	Method C	
	No. 5	Method E	
	No. 6	Method F	
Risk 2	No. 1	Method A	
	No. 2.	Method B	
	No. 6.	Method F	
	No.7.	Method G	
Risk 3	……	…….	

3.4.6 Approval of monitoring plans

Monitoring plans should be prepared by the operator and submitted to and approved by the CA. The initial plan should be submitted by the operator as part of the storage permit application. In the case of geological storage under the seabed, monitoring should further be adapted to the specific conditions for the management of CCS in the marine environment. Updates to the plan should be prepared in accordance with section 3.5.6.

In view of the different requirements for approval monitoring plans under the CCS Directive and the ETS Directive (2003/87/EC), the involved CAs should coordinate closely between any different agencies involved and the operator. The CAs involved and key contacts must be regularly communicated to the operator.

Approval of monitoring plans requires close communication between involved CAs in order to avoid unjustified differences in requirements with regards to areas of overlap of the plans. This is especially important for the permit application phase of a storage site to ensure consistency between the monitoring plan requirements under the CCS Directive and the EU ETS Directive.

Where the approval of the two monitoring plans under the CCS and ETS Directives involves different CAs, the case might arise that one CA approves a monitoring plan, while the other requires changes to be made. This might occur due to differences in objectives i.e. a method may suffice for leak detection but be inadequate for leakage measurement.

It is essential to establish good communication channels between the CAs involved with regards to the monitoring plans, and both CAs involved should be contacted in any discussion process. During the permit application process for a storage site, only the CA responsible under the CCS Directive is expected to be involved. However, given that the monitoring plan under the EU ETS is submitted as part of the permit application, a more efficient approach would be to involve the CA responsible for the EU ETS directly in this process at this stage. The two CAs could then agree on potential necessary changes regarding areas of overlap in the monitoring plan and then approach the operator with an agreed request for changes. Any subsequent discussion with the operator should again involve representatives from both CAs. Whenever changes in both monitoring plans occur, which have to be approved by the CA, the same approach could be used.

Guidance for a possible approval process involving two CAs is provided below that could apply either to an initial plan submission for storage permitting or a plan update:

Step 1. The operator submits the monitoring plan either as a part of the storage permit application or as an updated plan.

Step 2. The CA under the CCS Directive contacts the CA under the ETS Directive.

Step 3. Both CAs check the monitoring plan and, in case of full agreement with the content, the process continues with Step 7. Otherwise, the CAs agree on necessary changes to the monitoring plan and the process continues with Step 4.

Step 4. The operator is informed about necessary changes.

Step 5. The operator implements necessary changes to the Monitoring Plan.

Step 6. The operator resubmits the Monitoring plan as part of the storage permit application or update of the related plan. The process continues with Step 2.

Step 7. The monitoring plan is approved by both CAs under the CCS Directive and the ETS Directive.

The CAs should together set up very clear procedures for assessing leakages to coordinate their respective tasks so as to avoid delays. It is recommended that the procedures be documented, stating clearly, who has to provide what information in which format to whom at which point in time.

To improve communication between the contacts of the two CAs and to enhance understanding of the requirements of the two Directives, common training sessions could be held. This would also help build capability.

3.5 Plan Implementation, Reporting and Performance Management

3.5.1 Reporting and Documentation

CCS Directive

According to the CCS Directive the operator has to report the results of the monitoring to the CA at a frequency to be determined by the CA but at least once a year until transfer of responsibility. Monitoring is part of the wider reporting requirements that must include, among other things:

- All results of the monitoring including information on the monitoring technology employed;
- The quantities and characteristics of the CO_2 streams delivered and injected, including composition of those streams, in the reporting period;
- Any other information the CA considers relevant for the purposes of assessing compliance with permit conditions and increasing the knowledge of CO_2 behaviour in the storage site.

Other Reporting Requirements

The Monitoring and Reporting Guidelines under the ETS Directive contain detailed provisions on information to be documented, e.g. previous emission reports and monitoring plan versions, all emissions or data used for emission calculation, but also background information used for cross-checking, information on the justification for the choice of monitoring methods, responsibilities with regards to monitoring, etc. Table 14 shows the generalized requirements for reporting for the CCS Directive, and for the monitoring and reporting activities under the ETS Directive (i.e. ETS MRG).

From an efficiency perspective it seems desirable, that documentation under the CCS Directive and the ETS Directive be combined internally. The CAs should seek to facilitate this where feasible. A combined documentation under the CCS and ETS Directives will also facilitate understanding of overall monitoring during inspections of CAs (required by the CCS Directive) and site visits of the verifier for the EU ETS emission report.

Reporting happens annually both under the EU ETS and the CCS Directive, but not necessarily at the same point in time. Under the EU ETS emission reports have to be verified by an independent party. Deadline for submission of verified emission reports is March 31. It is open to the CA to set the deadline for annual reporting under Art. 14 of the CCS Directive.

For better information and cooperation with regards to the reports, the CA under the CCS Directive could arrange to send a copy of the annual report also to the CA under the ETS Directive, and vice versa. This would of course require the consent of the operator.

Table 14 Comparison of Reporting Requirements

Reporting Requirement	CCS Directive	ETS MRG*
Mass of CO_2 injected during the reporting year	Yes	No
Mass of CO_2 stored during the reporting year	No	No
Cumulative mass of CO_2 stored at the site	Implicit	No
Characterisation of the CO_2 stream (including composition)	Yes	Yes
Monitoring results	Yes	Yes
Characterisation of the proposed storage-site(s)	No	Implicit
Potential leakage pathways	Implicit	No
Source of CO_2 injected and infrastructure used	No	Yes
Leakage	Implicit	Yes
Corrective measures taken	Implicit	Implicit
Modelling updates	Yes	Yes
Fugitive emissions from storage site	Yes	Yes
Third party verification	No	Yes
Environmental impacts (potential)	No	No
Environmental impacts (actual)	Yes	No
Environmental impacts (from potential leakage)	No	No
Environmental impacts (from actual leakage)	Yes	No
Permits issued	No	Yes
Guidelines	No	Yes

* Based on (1) the Commission Decision 2010/345/EC amending Decision 2007/589/EC as regards the inclusion of monitoring and reporting guidelines for greenhouse gas emissions from the capture, transport and geological storage of carbon dioxide, and (2) Commission Decision (2007/589/EC)

3.5.2 Data retention and ownership

There are no specific provisions for data retention and ownership in the CCS Directive but each Member State may choose to develop appropriate policies, laws and regulations concerning who has access to and rights to use the monitoring data and who has the responsibility for the long-term preservation of such data. In general, Article 14(4) of CCSD, encourages CAs to gather and retain all information that the CA considers relevant for the purposes of assessing compliance with storage permit conditions and increasing the knowledge of CO_2 behaviour in the storage site.

The policies regarding ownership and use must balance the project developers' rights to retain proprietary data with the public need for transparency and openness about results, and the social value of pooling of data across sites. The public value of data access in order to accelerate and disseminate learning about storage given the importance of rapid CCS deployment should also be factored in. For example, the CAs could also consider extending the existing practices for data from exploration and production in the oil and gas industry to geological storage data.

Such pooled data could be used to better characterise regional geology, monitor regional effects of injection (e.g., basin-wide pressure build-ups) and develop better monitoring technologies and practices. It is possible that policies could call for some or all of the monitoring data to be treated as confidential business information for a set period of time after it is collected. After that period has expired the data would be made public.

The policies regarding retention of data may consider the obligations of the site operator to retain both raw monitoring data and processed data for specific periods of time. Presumably much of the processed monitoring data will have to be retained to create the operating history that will be needed when responsibility is to be transferred (see GD3). The policies might also address who within the government would retain copies of the monitoring data submitted by the operator during the injection and the post-closure pre-transfer periods. There would also have to be policies regarding the long-term retention of monitoring data after the transfer of responsibility phase.

All such policies might also consider what exact data is to be retained, the format it will be in (including geo-referencing using a consistent GIS standard) and on what media it will be stored and backed-up.

3.5.3 Interpretation of Monitoring Results and Site Performance

According to Annex II of the CCS Directive there are the following requirements:

- The data collected from the monitoring shall be collated *and interpreted*. The observed results shall be compared with the behaviour predicted in dynamic simulation of the 3D models of CO_2 and other fluid movement, pressure, volume and saturation behaviour and geochemical models undertaken in the context of the storage security and site characterisation and used to interpret whether site performance is consistent with predictions and modelling;
- Where there is a significant deviation between the observed and the predicted behaviour, the 3D models shall be recalibrated to reflect the observed behaviour. The recalibration shall be based on the data observations from the monitoring plan, and where necessary to provide confidence in the recalibration assumptions, additional data shall be obtained;

- The risk assessment for the site/complex shall be repeated using the recalibrated model(s) so as to generate new hazard scenarios and flux rates and to revise and update the risk assessment;

- Where new CO_2 sources**,** pathways and flux rates *or observed significant deviations from previous assessments* are identified as a result of history matching and model recalibration, the monitoring plan shall be updated accordingly.

Leakage Events & Significant Irregularities

Where leakage is detected or where significant irregularities that might lead to leakage occur, the operator must immediately inform the CA under the CCS Directive as well as the CA responsible under the ETS Directive. If leakage to atmosphere has occurred, the ETS Directive treats the leakage event as new emission source.

Under the CCS Directive, corrective measures must be implemented immediately and monitoring should be used to prove their effectiveness. The operator is also required to implement the monitoring approach for the quantification of the respective leakage under the EU ETS.

The quantification approach will have been included in the monitoring plan, which then has to be approved by the CA under the EU ETS. This may warrant update in light of any new information concerning the leak.

Quantification will then be carried out according to the monitoring plan and reported annually. The monitoring and reporting guidelines for CCS foresee various options for establishing when a leak started. The operator has to provide evidence of the last point in time leakage was not detected. If this is not possible, reporting of the leakage might be considered for the whole timeframe since injection has started.

After corrective measures have been taken and leakage can no longer be detected the leakage can be deleted as emission source from the EU ETS permit of the storage site.

This process requires clear and fast communication between the two CAs. Not only, must the respective contacts be known, but also guidance must be given about the minimum information to be delivered, and the respective staff members need an appropriate level of training to be able to correctly interpret the information received.

3.5.4 Inspections

Member States are required to establish a system of inspections, which should consist of both routine and non-routine inspections of the storage complex. The purposes of these inspections are to check and promote compliance with the requirements of the CCS Directive and to monitor the effects on the environment and on human health.

The scope and frequency of inspections is clearly laid out in the CCS Directive (Art. 15):

- Inspections should include activities such as visits of the surface installations, including the injection facilities, assessing the injection and monitoring operations carried out by the operator, and checking all relevant records kept by the operator.
- Routine inspections shall be carried out at least once a year until three years after closure and every five years until transfer of responsibility to the CA has occurred. They shall examine the relevant injection and monitoring facilities as well as the full range of relevant effects from the storage complex on the environment and on human health.
- Non-routine inspections shall be carried out:
  - if the CA has been notified or made aware of leakages or significant irregularities pursuant to Article 16(1);
  - if the reports pursuant to Article 14 have shown insufficient compliance with the permit conditions;
  - to investigate serious complaints related to the environment or human health;
  - in other situations where the CA considers this appropriate.
- Following each inspection, the CA shall prepare a report on the results of the inspection. The report shall evaluate compliance with the requirements of the CCS Directive and indicate whether or not further action is necessary. The report shall be communicated to the operator concerned and shall be publicly available in accordance with relevant EU legislation within two months of the inspection.

3.5.5 Evaluation of Performance

The comparison and evaluation of the predicted performance and measured performance of a CO_2 storage project can refer to the performance in terms of:

Safety and environment (CCS Directive);

Effectiveness in emission reduction (ETS MRG); or

Evaluation of performance may be done by the operator, CA and/or an independent third party.

Under the CCS Directive, the evaluation of overall performance is the responsibility of the CA. Evaluation under the CCS Directive refers to the regular evaluation of monitoring data from different reports and the baseline measurement, comparison with predictive models and definition of additional risk management measures during the injection and post-injection stages.

Under the EU ETS and its Monitoring and Reporting Guidelines a competent, independent, accredited verification body or person must ensure that emissions have been monitored in accordance with the guidelines and that the correct emissions data will be reported (European Commission, 2007, Section 10.4 in Annex I).

3.5.6 Updates

The initially installed monitoring system and related procedures need to be updated on the basis of the evaluation and modelling activity, or the results. Monitoring plans must be *updated, at least every five years*, to take into account changes to assessed risk of leakage, impact, new scientific knowledge, and improvements in the best available technology. The CAs may set a more stringent frequency. The plans should also be updated as a matter of urgency in the event of leakage or significant irregularities as changes in monitoring are likely to be required as part of the corrective measures and for the purposes of quantification of leakage.

According to Annex II of the CCS Directive there are the following updating requirements:

- The data collected from the monitoring shall be collated and interpreted. The observed results shall be compared with the behaviour predicted in dynamic 3D modelling undertaken in the context of the security characterisation.

- Where there is a significant deviation between the observed and the predicted behaviour, the modelling shall be recalibrated. Recalibration shall be based on the available monitoring, and where necessary, additional data shall be obtained.
- The geological characterisation and modelling of storage dynamic behaviour of the complex shall be updated using the recalibrated 3D model(s) so as to generate new hazard scenarios and flux rates and to revise and update the risk assessment.
- Where new CO_2 sources**,** pathways and flux rates *or observed significant deviations from previous assessments* are identified, the monitoring plan shall be updated accordingly.

Post-closure monitoring shall be based on the information collected up until closure and updated site characterisation, modelling and risk assessments. The plan must now also provide information needed for the transfer of responsibilities to the CA (long-term stewardship). Especially the site's permanent containment should be indicated, based *on all available evidence*. Post-closure monitoring should also factor in any developments in long-term monitoring methodologies and methods both of which are identified as areas for further research.

3.5.7 Accounting for emissions (including leakage)

Quantification and Accounting for emissions resulting from leakage to atmosphere or to a relevant water column is required under the EU ETS Monitoring and Reporting Guidelines.

EU ETS

The published Monitoring and Reporting Guidelines (MRG) for CCS under the EU ETS describe the method for quantifying potential CO_2 emissions (including leakage) from a storage project.[46] Potential emissions sources for CO_2 emissions from the geological storage of CO_2 include:

- Fuel use at booster stations and other combustion activities such as on-site power plants;
- Venting at injection or at enhanced hydrocarbon recovery operations;
- Fugitive emissions at injection;

[46] The MRG are set out in Commission Decision 2007/589/EC on July 18th, 2007 establishing guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC on MRG and Commission Decision 2010/345/EU on June 8, 2010 amending Commission Decision 2007/589/EC.

- Breakthrough CO_2 from enhanced hydrocarbon recovery operations;
- Leakage from the storage complex.

The amendments to the ETS MRG specify that emissions and release to the water column shall be quantified as follows:

$CO_{2emitted}\ [tCO_2\ ] = \sum L\ CO_2\ [tCO_2/d]$

With summation between boundaries T_{start} and T_{end}, where:

$L\ CO_2$ = Mass of CO_2 emitted or released per calendar day due to the leakage.

For each calendar day for which leakage is monitored it shall be calculated as the average of the mass leaked per hour [tCO_2/h] multiplied by 24. The mass leaked per hour shall be determined according to the provisions in the approved monitoring plan for the storage site and the leakage. For each calendar day prior to commencement of monitoring, the mass leaked per day shall be taken to equal the mass leaked per day for the first day of monitoring.

T_{start} = The latest of:

a. the last date when no emissions or release to the water column from the source under consideration were reported;

b. the date the CO_2 injection started;

c. another date such that there is evidence demonstrating to the satisfaction of the CA that the emission or release to the water column cannot have started before that date.

T_{end} = The date by which corrective measures have been taken and emissions or release to the water column can no longer be detected.

Other methods for quantification of emissions or release into the water column from leakages can be applied if approved by the CA on the basis of providing a higher accuracy than the above approach.

According to the published MRG, the amount of emissions leaked from the storage complex shall be quantified for each of the leakage events *with a maximum overall uncertainty over the reporting period of ±7.5%*. However, in case the overall uncertainty of the applied quantification approach exceeds the value of ±7.5%, an adjustment shall be applied, as follows:

$$CO_{2,Reported}\ [tCO_2] = CO_{2,Quantified}\ [tCO_2] * (1 + (Uncertainty_{System}\ [\%]/100) - 0.075)$$

Where:

$CO_{2,Reported}$=	Amount of CO_2 to be included into the annual emission report with regards to the leakage event in question;
$CO_{2,Quantified}$ =	Amount of CO_2 determined through the used quantification approach for the leakage event in question;
$Uncertainty_{System}$ =	The level of uncertainty which is associated to the quantification approach used for the leakage event in question.

The system uncertainty can be determined by Monte Carlo methods, if the exact steps of quantity determination are formalized. For each of the steps a probability density function (pdf) is proposed for the errors involved. Monte Carlo treatment then yields a pdf for the answers. Hence the overall accuracy = System uncertainty is determined.

3.6 Summary

Monitoring is one of the key activities to ensure the safety of geological storage as required by the CCS Directive and ETS Directive. It is essential to assess whether injected CO_2 is behaving as expected, whether any migration or leakage occurs, and whether any identified leakage is damaging the environment or human health.

CAs are obliged to ensure that the operator monitors the injection facilities, the storage complex (Including where possible the CO_2 plume), and where appropriate the surrounding environment during the operational phase and after closure up until the transfer of responsibility. After that, monitoring is the direct responsibility of the CA, although a reduced level of monitoring activity is required that allows for the detection of leakages or significant irregularities. If they occur, additional monitoring is required to better understand the problem and for the purpose of leakage quantification and emissions reporting, and corrective measures must be implemented.

Monitoring plans must be developed hand in hand with site characterisation, modelling and risk assessment, and also linked to preventive and corrective measures, financial security and financial mechanism (which are discussed further in GD4). The plans should be risk based and site specific. Regular reporting, inspection and oversight is essential and data should be retained for the life of the project and after transfer. Plans should be regularly updated and results of monitoring incorporated back into reassessment of the site characterisation, modelling and risk assessment.

3.7 Acronyms

3D	Three dimensional
CA or CAs	Competent Authority or Competent Authorities
CCS	Carbon Dioxide Capture and Storage
CCS Directive	Directive on the Geological Storage of Carbon Dioxide (2009/31/EC)
CO_2	Carbon dioxide
Cont	Continuous
CPM	Computational pipeline monitoring
DNV	Det Norske Veritas
e.g.	For example
Env.	Environmental
ETS	Emission Trading Scheme
ETS Directive	Directive establishing a scheme for greenhouse gas emission allowance trading within the Community (2003/87/EC)
etc.	Et Cetera (Latin: And So Forth)
EU	European Union
GD	Guidance Document
GHG	Greenhouse gas
GIS	Geographic information system
h	Hour
HSE	Health, Safety and Environment(al)
i.e.	Id est (Latin: that is)
IEA	International Energy Agency
Inj	Injection
InSAR	Interferometric synthetic aperture radar
IPCC	Intergovernmental Panel on Climate Change
m	Meter
MRG	Monitoring and Reporting Guidelines
No.	Number
NSBTF	North Sea Basin Task Force
OSPAR	Oslo/Paris convention (for the Protection of the Marine Environment of the North-East Atlantic)
pdf	Portable document file

pH	Potential for hydrogen ion concentration
SCADA	Supervisory control and data acquisition
t.b.d.	To be determined
tCO_2	Tonnes of carbon dioxide
UK	United Kingdom
USA	United States of America
Vs	versus

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4. Corrective measures

Corrective measures are actions, measures or activities taken to correct significant irregularities or to close leakages in order to prevent or stop the release of CO_2 from the storage complex. They are intended to ensure the safety and effectiveness of geological storage. Corrective measures are part of the overall risk management process that is intended to ensure the safety of geological storage and to manage the risks from leakage during the project life cycle.

The general principles for the overall approach for corrective measures are quite similar to, and closely linked to the risk assessment and monitoring of the complex. Corrective measures should be:

- Risk based; linked to identified risks from site and complex characterisation (and risk assessment) and subject to the limitations of available technologies (as discussed in GD1)

- Specific to the storage site and complex;

- Suitable for use to address leakage or significant irregularities[47] from identified leakage pathways and specific leakage mechanisms out of the storage complex and any leakage to the surface;

- Closely linked to monitoring plans and monitoring (covered in section 4 of this document), which should provide triggers for use of corrective measures by identification of leakage or irregularities;

- Used when there is any leakage or significant irregularities;

A corrective measures plan needs to be submitted by the operator with the storage permit application and will need to be approved by the CA as part of the storage permit. Plans need to be "ready to use" (IEA GHG, 2007) immediately in case of leakage or significant irregularities.

The initial plans will be based on the risks identified for the storage complex, with predicted pathways and scenarios for potential leakage from them based on site characterisation and modelling. The types of risk and pathways would likely be similar to generic types of pathways that are described in GD1, that were primarily either geological pathways (e.g. faults, fractures or caprock absence), manmade pathways (i.e. well bores or old mine workings) or the other types of risk (e.g. groundwater contamination, displaced oil and gas, subsidence). The

[47] As mentioned above, Article 3 of the CCS Directive "significant irregularity" means any irregularity in the injection or storage operations or in the condition of the storage complex itself, which implies the risk of a leakage or risk to the environment or human health.

general locations of many potential pathways can be predicted ahead of any leakage situation, e.g. the location of a major fault or a wellbore. However some potential leakage pathways may not be detectable (e.g. sandstone intrusions) with current technologies at the time of initial risk assessment and corrective measure plans or their locations may be uncertain. If these emerge subsequently, site characterisation, risk assessment, monitoring and corrective measures plans will need to be updated as necessary.

However, the operator and CA should consider that the actual and specific location of any significant irregularity or leakage will usually not be known before it is detected. For example, it may not be known precisely where along the fault, where the caprock is absent or which well and where in the well bore a leak actually is. Nor will the actual pathway between the leak and the surface be known if the flow is not direct (which may be the case as a leak may involve a complex three dimensional problem combining the geology and well pathways).

The corrective measures will ultimately need to be specific to the actual leakage or significant irregularity, taking account of the precise location and nature of the leakage or irregularity, and the specific situation and circumstances in which the leak occurred. Flexibility is required to update and change the plan according to the specific situation.

One vital consideration is early warning and early intervention to detect significant irregularities early and take action through corrective measures to prevent the situation getting worse, and reduce the risk of actual leakage from the storage complex. In the event of leakages or significant irregularities the operator immediately needs to notify the CA and take the necessary corrective measures, including measures related to the protection of human health The CA needs to ensure immediate implementation of correctives measures as a minimum on the basis of the corrective measures plan.

Handling and implementing corrective measures in the event of actual leakage to surface will require rapid and effective interaction between the CA and operator. It will require strong technical expertise in drilling, well engineering and geosciences. Specialist consultants would often be involved in comparable situations in the oil and gas industry. CAs will need to know what expertise exists within their organisations and where and when to draw on external experts.

4.1 Legislative Context

The CCS Directive requires that a corrective measures plan is prepared by the operator and submitted as part of the storage permit application.

Article 16 of the CCS Directive requires that Member States ensure:

- that the operator of the storage site immediately notifies the CA in the event of leakage or significant irregularities and takes the necessary corrective measures including measures to protect human health;
- The corrective measures referred to above shall be taken as a minimum on the basis of a corrective measures plan submitted to and approved by the CA;
- If the operator fails to take the necessary corrective measures, these measures shall be taken by the CA, which shall recover the costs from the operator including by drawing on the financial security pursuant to Article 19 of the CCS Directive.

4.2 Relationship to monitoring and monitoring plan updates

Monitoring and corrective measures are closely interlinked and the plans and activities should be developed by the operator in a holistic manner along with the risk assessment. The CA should seek to ensure close integration between these measures.

The deployment of corrective measures is required in the event of leakages or significant irregularities, and these would usually be detected by monitoring results or the interpretation of monitoring data or inspections. In addition monitoring will be used to assess the effectiveness of corrective measures, and additional monitoring activities may be required in event of any leakage or significant irregularities.

4.3 Responsibilities during project phases

The operator has to develop and hand in a corrective measures plan as part of the storage permit application. As part of this application, the corrective measures plan has to be approved by the respective CA.

Corrective measures may be used at any stage in the life cycle after storage permit award. It is expected that corrective measures will be used mostly during the operations (injection) phase and post-closure pre-transfer phase. After transfer of responsibility, corrective measures may still be required, although the likelihood is reduced from then on as the CO_2 plume is expected to be stable.

Under normal operating conditions (i.e., storage permit has not been withdrawn), in the event of leakages or significant irregularities, the operator has to immediately notify the CA both under the CCS Directive and the ETS Directive and take the necessary corrective measures, including measures related to the protection of human health. Measures approved in the corrective measures plan shall be taken as a minimum.

The CA may, however, at any time require the operator to take the necessary corrective measures, as well as measures related to the protection of human health. These may be additional to or different from those laid out in the corrective measures plan. Moreover, the CA may also at any time take corrective measures by itself.

In circumstances where a storage permit has been withdrawn and the CA is acting as operator, or after transfer of responsibility, then the CA is responsible for taking corrective measures in the event of irregularities or leakage, and maintaining corrective measures plans.

Because the activities involved in corrective measures may be highly specialised and technical, both operators and CAs will need to consider how to access the necessary expertise to implement, review and oversee any corrective measures.

4.4 Corrective Measures Methods

The first step is assessing the corrective measures methods and determining the specific corrective measures for an identified risk in any situation. The nature of the significant irregularity or leakage will dictate the method and type of remediation required (IEA GHG, 2007). This assessment will also need to factor in the impact on secondary containment zones at the complex. It will also need to review whether there is any evidence for accumulation of CO_2 beyond the storage complex.

The main generic leakage pathways and risks were reviewed in the GD1 and can be summarised as follows:

- Geological – Caprock;
- Geological – Faults and fracturing;
- Geological- Overfilling beyond spill point or updip leakage;
- Manmade - Wells and boreholes;
- Manmade pathways associated with Mining activity.
- Other risks (e.g. displacement of methane, groundwater contamination);

To date, there is limited practical experience with use of corrective measures in geological storage of CO_2, although there is experience in well integrity corrections. The methods and approaches are, therefore, based on relevant experience in other sectors including gas storage, oil and gas industry (e.g. well control incidents) and environmental clean up and remediation. The status and learning from other sectors has been reviewed and summarised in several reports (CSLF, 2009; IEAGHG 2007). Any plans and assessments of corrective measures that takes place in the future should be based on the experience available at the time, new scientific knowledge, and improvements in best available technology.

A significant distinction needs to be made between corrective measures that can be applied to the two major types of pathways (1) to the natural, geological system and (2) to the engineered, wellbore system. While corrective measures and repairs to wells are often technically feasible, the effectiveness of corrective measures and potential of restoring the geological system in general is limited. However corrective measures that involve early interventions and modifications to injection operations will usually be beneficial and can provide effective risk management in some circumstances.

In principle, wells can be accessed, allowing tools to be run or operations to be performed in order to repair leakages or significant irregularities of the wellbore and its immediate surroundings. Unlike wells where the location of any anomaly is usually known and pinpointed, geological anomalies are more likely to be three-dimensional problems, of significant vertical and/or lateral extent, and where the precise location of any failure points is uncertain. In addition flaws in the geological system can typically be corrected only when wells are penetrating the affected zone. This seriously reduces the options to repair the geological anomalies, making early detection through monitoring and early intervention important. Hence, it is important to carefully integrate the monitoring plans and activities with the corrective measures. Monitoring should be used to detect anomalies and trigger early corrective measures. The contrast between natural and engineered systems is reflected in the description of corrective measures presented below.

In view of these considerations it is important that irregularities are reported immediately to the CA and that the CA makes sure that early implementation of corrective measures takes place as set out in the CCS Directive.

4.4.1 Summary of Methods – Geological

Where leakage occurs as a result of an unexpected flaw in the geological system, this is most likely to result from caprock failure[48], faults and fracturing, over filling the storage reservoir beyond spill point or up dip leakage as detailed in GD1. The issues may have been identified as risk, or may result from uncertainties in the geological characterisation and modelling. Due to the limited access to the three-dimensional (3D) geological structures at depth, the possibilities to correct or repair the containment capacity of the system usually will be restricted to a general set of measures associated with wells and injection operations management.

Corrective measures can be deployed either to reduce or prevent further leakage or to try to correct and remediate the leakage itself, and any impacts at surface. There are several viable techniques based on stopping the pressure increasing in all or part of the reservoir, or reducing the pressure as follows. Some of the potential measures may also successfully contribute to mitigation of potential ground movement or fluid displacement. The main techniques are:

- Limiting CO_2 injection rates and pressure build-up in specific wells or across the site, either temporarily or permanently. This would reduce pressure build-up in all or part of the reservoir and may be used to address caprock related issues and fracturing. This type of measure is straightforward to apply. Their effectiveness will depend of the specific circumstances, including when and where the intervention occurs and the existing and projected pressure and plume dynamics.

- Reducing the reservoir pressure by extracting CO_2 or water from the storage reservoir or complex. By decreasing the pressure gradient this may help cease or reverse the impacts of faulting, fractures, spill and any migration out of the storage complex. This can be done in a number of ways (Benson, S. & Hepple, R, 2005):
    - Reduction of CO_2 injection pressure (e.g. by using lower injection rate, or more injection wells);
    - Stopping CO_2 injection;
    - Producing back injected CO_2 from the storage reservoir/plume (actively reducing reservoir pressure) and either controlled venting or re-injection in another site;
    - Peripheral extraction of formation water or other fluids;
    - Increase of reservoir capacity and steering CO_2 in favourable directions by hydrofracturing (this would create pathways to

[48] Including capillary failure, absence due to erosion or intrusion features, sandstone lenses, chemical degradation ,fracturing, etc (See GD1 Table 4).

develop and access new compartments of the storage reservoir away from leakage areas; by expanding the storage container, the pressure will decrease).

- Extraction of CO2 at or near an identified leakage point, zone or pathway (in contrast to extraction from storage reservoir). This will depend on pinpointing leakage zones and is likely to require new targeted extraction wells. In some cases it may be possible to intersect leakage zones with existing wells.

- Sealing regions where leakage occurring such as identified fault or caprock leakage pathways in limited areas by injecting low-permeability materials (e.g. foam or grout)49. The applicability of this approach over extended areas and at depth is questionable.

- Increase of pressure in formations upstream of CO_2 leakage, creating an hydraulic barrier (decreasing pressure gradient).

There are other techniques for addressing near surface leakage and CO_2 accumulation (IEA GHG, 2007):

- Accumulation of CO_2 in groundwater can be remediated by pumping the water to surface and aerating to flash the CO_2. The water can either be pumped back underground or re-used, subject to Member State regulations;

- CO_2 leakage into the vadose zone[50]. Large amounts of CO_2 could be removed from the vadose zone using soil vapour extraction technology;

- CO_2 build-up in near surface accumulations. Shallow drilling can be used to access and extract CO_2 in near surface formations and accumulation zones.

CAs should be aware of the status and limitations of different techniques and methods. While several of these measures involve commonly employed practices in oil industry or environmental remediation, some comprise innovative concepts or include expensive operations such as drilling of new wells. The natural geological system contains many heterogeneities and discontinuities. As a result, leakage is not easily undone so that choices to repair are limited and

49 This will only take effect if leakage occurs at spatially very limited areas that can also be reached by wells. Furthermore, the effectiveness will be highly dependent on the nature of the flaw, the lithology, the geological structure and the characteristics of the injected fluid

50 The vadose zone is the shallow layer of unsaturated earth between the land surface and the deepest water table, and includes the capillary fringe. Generally, water in this zone is under less than atmospheric pressure.

rather tend to be directed at mitigation. Furthermore, the effectiveness of all the measures is strongly determined by the site-specific geological system, the nature of the actual leakage or irregularity and the status of the specific method or technique.

These considerations justify the emphasis on a thorough site characterisation during the initial phase of the project to minimize the risk of leakage in the geological system, which is an essential aspect of the storage permitting process that is subject to approval by the CA.

4.4.2 Summary of Methods – Wells

In contrast to the natural geological system, the wellbore system is an engineered structure. Wells or boreholes are drilled and then completed for production or injection operations. A general down-hole well configuration consists of multiple steel casing or tubing (types of pipe used to line the well). In many cases the space between geological formation and the casing, which is called the annulus, is (partly) filled with cement. Injection or production wells often are equipped with injection or production tubing. Abandoned wells should be sealed with cement and mechanical plugs, depending when they date from.

Leakage through operating or abandoned wells (including well bores and boreholes) has been highlighted as a major risk for geological storage projects. This must take account of both the wells used for CO_2 injection and storage and all wells related to other exploration and production activities for oil and gas, water extraction, coal and minerals exploration, etc. Well integrity has been highlighted as one of the major leakage risks, especially for storage in oil and gas storage options where there are pre-existing wells from oil and gas exploration and production activity.

The main leakage reasons that well integrity may be compromised are summarised in a report for IEA GHG (IEA GHG, 2007):

- The well was poorly designed or completed resulting in loss of mechanical integrity allowing CO_2 movement/leakage up the well or well bore; an unanticipated well failure could occur such as parted casing;
- When abandoned the well was inadequately plugged and sealed.

Wells drilled for the purpose of CO_2 storage operations can be designed, completed and abandoned according to requirements applicable to long-term containment. Even previously drilled wells, configured without taking into account future CO_2 storage purposes, can usually be remediated to meet the requirements for geological storage. One problem area is with previously abandoned wells that are no longer accessible.

Use of corrective measures to repair well flaws leading to leakage through or along the wellbore is nothing new. The oil and gas industry holds decades of experience and has many techniques as well as advanced technologies to repair leaks in the various parts of a well. If required, injection tubing and packers can be replaced, leaking casing can be repaired, or cement can be squeezed behind the casing. In the case of a blow-out, standard oil and gas industry techniques are available to 'kill' a well (e.g. injecting heavy mud/weighted brine into the casing).

However the use of these measures with CO_2 storage must also take into consideration that CO_2 is the fluid involved, which may be injected in a supercritical state, and with different phase behaviour.

The section below describes some of the practises associated with corrective measures for remediation of well integrity and well blow outs using standard well service and repair procedures and guidelines should a CO_2 leak occur.

- Loss of Mechanical integrity. The loss of mechanical integrity can lead to internal and external leakage of CO_2 in a number of ways, including leakage of injection tubing, leakage of the casing and leakage behind the casing. Current injection guidelines in other industries require underground injection control program, involving data collection, tests to ensure mechanical integrity and methods for early detection of leakage. There are several techniques that can be used as corrective measures that may include all or some of the following: wellhead repair, packer replacement, tubing repair, squeeze cementing, patching casing, repairing damaged or collapsed casing; wells that are beyond repair should be plugged and abandoned.

- Abandoned wells. Where a previously abandoned well is found to be leaking, a series of steps can be employed to remediate the well. If required, it may be necessary to re-enter and re-plug previously abandoned wells with adequate material.

- Well Blow-outs, which could involve uncontrolled release of CO_2 from a well, could occur during CO_2 injection operations. They could also occur in any new drilling operations that take place into a CO_2 storage reservoir after storage has started (i.e. excluding injection wells drilled before injection starts). Well blow outs can be remediated using standard industry techniques to "kill "the well, which make the well safe by injecting heavy mud into the well bore. In the unlikely event that the actual well head is not accessible a nearby well can be drilled to intercept the casing/wellbore below ground level and to kill the well using the interception well.

4.4.3 Technology status and limitations

CAs should be aware that the status of the technologies that may be used for corrective measure is highly variable. Virtually none of the technologies have yet been used in CO_2 storage applications or environments.

Many of the corrective measures technologies and techniques for wells and well integrity issues are routinely used in the oil and gas industry and in gas storage applications.

Managing injection rates, locations and pressures can be used to manage some of the risks relating to geological leakage pathways and risks. However, many of the other technologies for managing issues related to geological pathways are more novel and also uncertain. The effectiveness of techniques that involve new wells that intersect with plumes or pathways will be highly dependant on being able to identify the target area, which may be difficult in the three dimensional space. Other techniques with extraction of either CO_2 or water are technical plausible but handling the fluids produced and costs will need to be evaluated on a case by case basis.

Some generalised comments can be made:

- Any corrective measures will be highly specific and will need to take account of the nature, flux and location of the leakage or irregularity (in three dimensions), which may be poorly understood especially for geological pathways.
- Gathering further data through monitoring and re-evaluation of site characterisation and modelling will be essential.
- Corrective measures for dealing with leakage or significant irregularities from wells are generally considered feasible using techniques and practises from the oil and gas industry or gas storage.
- Managing injection rates, locations and pressures can be used to manage some of the risks relating to geological leakage pathways and risks.
- Other approaches involving extraction of CO_2 or water may be possible but the fluids produced will need to be handled and the costs may be high.

- The costs of any corrective measures will be highly uncertain and specific to the leakage or irregularity being addressed.

One area under active development targeted at CO_2 storage is advanced materials for wells. An overview of improvements of the isolating capacity of wellbore sealants regarding geological storage of CO_2 is presented by Benge (2008). Efforts directed at enhancement of the Portland cement-based sealing system have focused on reduction of the cement's permeability after curing and decreasing the concentration of materials that react with dissolved or wet CO_2. These materials can be applied in drilling, completion, workover and abandonment operations. Areas under development include the following:

- Reduced cement permeability and reactivity;
- Non-Portland cements;
- Self healing cements and swelling packers.

4.4.4 Life cycle considerations

The initial assessment of corrective measures plan should be prepared by the operator and submitted as part of the storage permit application, for approval by the CA.

Corrective measures may actually be needed and used at any stage in the life cycle after storage permit award. It is expected that corrective measures will be used mostly during the operations (injection) phase and closure and post-closure pre-transfer phases. Corrective measures may still be required and implemented after transfer of responsibility, although the likelihood is reduced from then on as the CO_2 plume is expected to be stable. CAs should recognise that type of corrective measures that can be used may vary through the life cycle phases of any project.

Operational measures relating to injection parameters and rates and using injection wells will only be available during the operations phase and until wells are sealed and abandoned up either at closure or before the transfer of responsibility (see GD3). Measures requiring access through active injection wells will be available during operations but may be increasingly difficult and expensive after the closure milestone, except where monitoring wells continue to be used.

After the transfer of responsibility or the withdrawal of the storage permit, all activities are the direct responsibility of the Member State. After the transfer of responsibility the purpose and aims of corrective measures are similar to earlier stages. However because of the requirements around plume stability and containment for transfer of responsibility, it is expected that there will be little requirement for any corrective measures unless there is unexpected leakage or irregularities.

4.5 Scope and Format of Corrective Measures Plan

Corrective measures plans should be based on the risk assessment, which is in turn site specific and closely related to the site and complex characterisation. At any stage in the life cycle potential and contingent corrective measures should be described for each of the main risks identified. These should take account of the option type, location and whether it is onshore or offshore. There should be linkage between corrective measures and the monitoring plan with triggers and alert thresholds for deployment of corrective measures.

The first requirement for the operator to produce a corrective measures plan is part of the storage permit application and award. The plan developed at this stage has to be developed by the operator based on the pre-injection risk assessment and complex characterisation. This is subject to approval by the CA.

Therefore, the initial proposed corrective measures plan has to be developed by the operator before injection has started. While this should be based on site specific risks, the corrective measures included may inevitably be somewhat generic in nature at this stage, nevertheless it is important that minimum requirements are put in place. This is because the location and nature of leakage mechanisms and pathways may not be pinpointed (e.g. well leakage could be possible from any of one of the wells in an abandoned oil and gas field, from different zones in the wells and via different mechanisms). In addition the viability and cost of corrective measures depends on the nature of the risks and pathways, and there may be few options for corrective measures for certain kinds of risks. In some cases, only very generic measures like reducing reservoir pressure or stopping injection may be proposed.

Close dialogue and interaction between the CA and operator is recommended during the development of corrective measures plans which can further specify the definition and triggers for deployment.

Rapid, open communication and dialogue and interaction between the CA and operator will be essential in any event that corrective measures will need to be deployed.

4.5.1 Plan Description and Format

This section contains an example and possible format for a corrective measures plan (see Table 15 and Table 16). The format is not intended to prescribe measures or to give guidance on the choice of measures. The aim is to enhance transparency and comparability as well as exchange of information between operator and the CA about the risks, monitoring and most suitable corrective measures plan.

The plan might consist of two sections:

- Section 1 could provide an overview of the potential corrective measures that will be used for the risks identified. Threshold values or qualitative circumstances to cover any anomaly, event, leakages or significant irregularities can be stated, which will trigger use of a corrective measure. Furthermore, the monitoring methods used to monitor the effectiveness of a corrective measure are identified together with a cross-reference to the method in the monitoring plan.

- In Section 2 of the plan, each corrective measure would be described in as much detail as possible with regards to the identified risks and their projected location, timeframe needed for implementation and the detailed activities to be carried out. Furthermore, a rationale is included explaining why the corrective measure is appropriate for the risk it is related to.

Table 15: Corrective Measures Plan Section 1 - Overview of Risks & Measures

Risk the measure is related to	Irregularity this measures is related to	Corrective measure	No. of corrective measure	Monitoring method (s)	No. of monitoring method
Comment: Please state the risk(s) as identified in the risk assessment	Comment: Please state the threshold values or qualitative conditions which will trigger this corrective measure			Comment: Please state name and number of the monitoring method(s) used to monitor the effectiveness of the corrective measure, as stated in Table 1	
		Measure A	No. 1	Method D	No. 4
		Measure B	No. 2		

Table 16 Corrective Measures Plan Section 2- Detailed potential corrective measures

Name of Corrective Measure:		Measure A
No. of corrective measure	*Comment: Please state the number of the corrective measure as found in the corrective measures overview table*	No 1
Estimated timeframe needed for implementation	*Comment: Please state how much time the full implementation of the measures is expected to take*	
Detailed description of measure	*Comment: Please state on a detailed technical level, what the measure consists of: What is done where and when?*	
Rationale for the use of the measure	*Comment: Please state why this measure is suited for the risk it is related to*	
Current status of the technique	*Comment on the status of the technique or method, ie. whether proven, commercial, under development, etc*	

4.5.2 Example of a Corrective Measures Plan for Barendrecht Site

In order to illustrate the format, an example is provided for a potential storage site in Barendrecht, The Netherlands (Table 17).

Table 17 Overview of corrective measures and respective monitoring methods used

Risk the measure is related to	Anomaly/Irregularity this measure is related to	Corrective measure	No. of corrective measure	Monitoring method	No. of monitoring method
Comment: Please state the risk(s) as identified in the risk assessment	Comment: Please state the threshold values or qualitative conditions which will trigger this corrective measure			Comment: Please state name and number of the monitoring method(s) used to monitor the effectiveness of the corrective measure, as stated in Table 15	
Injection volume	Too high value	Stop injection until problem solved	1	Flow metering	
CO_2 Stream pollution	Too much non-CO_2 contents	Stop CO_2 intake	2	Gas measurement and Analysis	
Well integrity problem	Too high value	Stop injection and remedy annular pressure problem or abandon	3	Annular Pressure measurement	
Injection well problem	Too high pressure or leakage	Stop Injection and Pancake plug renewal	4	Pressure measurement, CBL	
Plan conformity	Too low injection pressure	Stop Injection and reconsider storage plan and other basic docs.	5	Pressure measurement	
Safe injection	Temperature too close to minimal or maximal value for safe operation.	Injection stop (automatically) and solve surface temperature problem	6	Temperature measurement	
Safety injection	Reservoir P and T differ significantly from predictions	Stop injection and adapt injection conditions to within safety margins	7	SPTG	
Safety injections and warrant against fractures	Injection pressure larger than fraccing conditions	Lower injected volumes and pressures to within safety margins	8	Pressure	
Reservoir aptitude for permanent CO_2 storage	Leakage	Reconsider reservoir modelling and history of CO_2 distribution	9	Gas measurement in monitoring well	
Injection safety	CO_2 surface accumulations	Carry out seismic survey for low depth accumulations if leakage significant.	10	Acoustic measurements concerning tubing	

Risk the measure is related to	Anomaly/Irregularity this measure is related to	Corrective measure	No. of corrective measure	Monitoring method	No. of monitoring method
CO_2 Leakage	CO_2 concentrations in soil	Carry out seismic survey for low depth accumulations if leakage significant; Stop injection and address mitigation and resume injection or abandon. Possibly drill additional monitoring well when an uncontrolled leakage. Possibly produce some CO_2 back to atmosphere to get lower reservoir pressures and leakage volumes.	11	Gas measurement [2D seismic survey + drilling an additional monitoring well]	
Atmospheric leakage of CO_2	High CO_2 concentrations in air.	Stop injection and issue highest alarm	12	Gas measurement at location boundary	

4.6 Plan Implementation, Reporting and Performance Management

4.6.1 Documentation & Reporting

The CCS Directive specifies the need for the operator to submit a corrective measures plan as part of the application for a storage permit which is subject to approval by the CA. The plans should be updated, as appropriate, as part of the storage permit review required under Article 11 of the CCS Directive.

Reporting on corrective measures is also covered by the requirements for reporting of monitoring under the CCS Directive. According to the CCS Directive the operator has to report the results of the monitoring to the CA at a frequency to be determined by the CA but at least once a year until transfer of responsibility (as in Section 4.5.1).

The extent to which corrective measures are reported on in conjunction with reporting of monitoring and storage permit updates will depend whether there have been significant irregularities and leakages and implementation of corrective measures. Where these have occurred, the CA should ensure that reporting of the corrective measures have taken place, and that the operator has met its obligations to assess the effectiveness of corrective measures taken, in accordance with Article 13. It is also desirable that the operator also reports on updates to the corrective measures plans and plan assumptions (i.e. risk, measures and methods).

This information might also be used for the review and update of the corrective measures plan, as appropriate, alongside the review of the storage permit (see also below). For example, if new information provides evidence about specific leakage risks, such as where a CO_2 plume has encountered specific wells or faults without evidence of irregularities, then corrective measures plans could be refined.

The CA should also ensure that the effectiveness of any corrective measures taken during the project life cycle is addressed at the time of Transfer of Responsibility..

4.6.2 Interpretation of Corrective Measures Results and Performance

It is clearly important to assess the effectiveness of any corrective measures that are undertaken to determine what impact they have had on any leakage or significant irregularities. In addition the CCS Directive specifies that monitoring should be used to assess the effectiveness of any corrective measures that are taken.

The operator should integrate this assessment of corrective measures with the assessment of monitoring results which has several requirements as described in section 4 of this GD on Monitoring. In particular the results and performance of corrective measures would need to be reviewed in order to meet the following requirements specified in Annex I of the CCS Directive:

- The risk assessment for the site/complex shall be repeated using the recalibrated 3D model(s) so as to generate new hazard scenarios and flux rates and to revise and update the risk assessment.
- Where new CO_2 sources**,** pathways and flux rates *or observed significant deviations from previous assessments* are identified as a result of history matching and model recalibration, the monitoring plan shall be updated accordingly.

Based on the revised risk assessments and the updated monitoring plans, the corrective measures plans should also be revised accordingly.

4.6.3 Inspections

In the case of leakages or significant irregularities and thus when corrective measures are implemented non-routine inspections shall be carried out by the CA. These non-routine inspections should also assess the effectiveness of the corrective measures implemented.

4.6.4 Updates

Although there are no formal requirements for routine and regular updates to the corrective measures plans in the CCS Directive, they should be updated, as appropriate, as part of the storage permit review required under Art. 11 of the CCS Directive.

Such an update would take account of new information from the project including the results of monitoring and updates to the site characterisation, the assessed risk of leakage, changes to the assessed risks to the environment and human health, new scientific knowledge and improvements in best available technology. With increased knowledge about the storage site, previously identified risks might be considered irrelevant or new risks might emerge for which corrective measures have to be developed. Over the lifetime of a storage site new techniques and technology for corrective measures might emerge or the approach in measures might change.

4.7 Summary

Corrective measures have a crucial role in the risk management of geological storage as they involve activities that can be used to correct significant irregularities or to close leakages in order to prevent or stop the release of CO_2 from the storage complex.

Corrective measures plans must be developed hand in hand with site and complex characterisation, modelling, risk assessment and especially monitoring and other risk mitigation measures. They are also linked to financial security and financial mechanism which may be used to meet the cost of implementing corrective measures.

Initial corrective measures plans need to be submitted with the storage permit application and will need to be approved as part of the storage permit. While based on site specific risks, the corrective measures included may be somewhat generic at this stage because the location and nature of leakage mechanisms and pathways may not be pinpointed. Nevertheless it is important that minimum requirements are put in place. The plans need to be “ready to use” (IEA GHG, 2007) immediately in case of leakage or significant irregularities.

Plans should, as appropriate, be updated as part of the storage permit review to take account of new information from injection and monitoring and any leakage or irregularities. Technology and methods used should be based on the best practice available at the time required and take account of new scientific knowledge and improvements in best available technology. Reporting of corrective measures plans will take place, which will describe the results and effectiveness of the measures used.

Effective techniques for corrective measures relating to well issues are established from oil and gas operations. The options for managing geological issues are more complex and less certain to be effective particularly in the case of significant leakage out of the storage complex. In all cases the effectiveness of all the measures is strongly determined by the site-specific geological system, the nature of the actual leakage or irregularity and the status of the specific method or technique.

The CCS Directive requires the use of corrective measures in the case of leakage or significant irregularities. These should be undertaken immediately by the operator, although the CA must step in if the operator does not take the necessary action.

4.8 Acronyms

2D	Two dimensional
3D	Three dimensional
CA or CAs	Competent Authority or Competent Authorities
CCS	Carbon Dioxide Capture and Storage
CCS Directive	Directive on the Geological Storage of Carbon Dioxide (2009/31/EC)
CO_2	Carbon dioxide
CSLF	Carbon Sequestration Leadership Forum
e.g.	For example
ETS Directive	Directive establishing a scheme for greenhouse gas emission allowance trading within the Community (2003/87/EC)
etc.	Et Cetera (Latin: And So Forth)
EU	European Union
GD	Guidance Document
GHG	Greenhouse gas
i.e.	Id est (Latin: that is)
IEA	International Energy Agency
No.	Number
P	Pressure
T	Temperature
UK	United Kingdom
USA	United States of America

4.9 References

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