CO_2 Storage Liabilities in the North Sea

An Assessment of Risks and Financial Consequences

Summary Report for DECC

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Disclaimer

This report has been prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry. Estimates of CO_2 leakage rates and probabilities should be regarded only as estimates that may change as further information become available. Not only are these CO_2 leakage rates and probabilities estimates based on the information currently available, but they are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. AGR Petroleum Services, TRACS International Consultancy Ltd, Senior CCS Solutions Ltd and their appointed sub-contractors shall have no liability arising out of or related to the use of the report.

Executive Summary

This report was commissioned by DECC to provide a basis for understanding the technical risks and financial consequences of CO_2 leakage from a geological storage site. The main focus was to better understand the probability and scale of contingent liabilities that arise during storage. These liabilities have been identified by companies as a major obstacle to the development and deployment of CCS.

The work has developed estimates of the probability and rates of leakage for each of the most likely leakage pathways. Those estimates are based on available evidence and expert judgement. Leakage risks fall into two broad categories, namely those related to engineered structures which penetrate the storage site (operating and abandoned wells) and those associated with the geological features of the storage site (the integrity of the caprock and faulting.) The emerging conclusions were reviewed by technical experts and then discussed in a workshop of experts from Government, Industry and Academia.

The results indicate that the most probable risk of leakage is associated with wells which had been previously drilled into the geological structure proposed for a storage site and subsequently abandoned. Leakage rates associated with this type of event will normally be extremely low. The largest potential rate of leakage would come from a blowout of an operating well. However, this is likely to result in a relatively small loss of CO_2 because of the relatively short duration before the leak would be remedied.

In view of the high quality of geological structures known to be present in the North Sea, the generic risk of CO_2 leaking through the primary caprock and then through the overburden to reach the seabed is considered negligible. The assessment of the potential for leakage through faults is more problematic and it is not possible to generalise the impact of such an event. While the controlling mechanisms, location and nature of faults are quite well understood, the potential scale and duration of an event resulting in leakage will depend uniquely on the nature and location of the fault. However, given the nature of most faults in the North Sea the generic risk of leakage through the pathway is expected to be very low provided the fault does not extend from the storage site to the seabed. There are few proven technical options for remediating leakage from a fault. Therefore this pathway has the potential to result in the highest amount loss of carbon dioxide. Overall, the risk of experiencing a leak over the anticipated lifetime of a storage site is considered to be very low and the magnitude of any associated CO_2 loss is estimated to be low and manageable through existing and proven corrective measures. The overall financial consequences of leakage are therefore considered to be both definable and manageable.

A number of areas were identified for further work but none that would be expected to materially alter the overall conclusions of the study.

It should be noted that throughout this report estimates of probabilities of leakage and flux rates have been made on the basis of the best available data and expert judgement. These have been reviewed by a selected group of technical experts. These estimates and the findings in this report were then subjected to further review and challenge at a specially convened workshop attended by a range of Government, Industry and Academic parties with an interest in this field.

Table of Contents

1. Introduction

a. Background

The permanent storage of carbon dioxide (CO_2) in the UK must comply with the requirements of the EU CCS Directive[1]. That Directive is intended to ensure environmentally safe storage of CO_2. The purpose of environmentally safe geological storage is permanent containment of CO_2 in such a way as to prevent and, where this is not possible, eliminate as far as possible negative effects and any risk to the environment and human health. The required storage permit may therefore only be issued by the relevant competent authority (the Secretary of State or Scottish Ministers in the UK) where there is no foreseeable risk of leakage.

Storage sites are natural systems. They rely on geological as well as engineered barriers for the containment of carbon dioxide. As such there can be no absolute guarantee of permanent storage. In common with all other environmental licensing arrangements the permitting of carbon dioxide is risk based. Whilst a storage site that is known to have a significant risk of leakage could not be permitted under the Directive, the possibility that leakage may nevertheless take place cannot be completely eliminated.

If leakage were to occur then the released CO_2 would potentially have an impact on the environment and on human health and this could result in unforeseen costs which could in-turn impact on the viability of the storage site and the CCS activity which depends on it. These contingent liabilities are considered by industry to be a significant barrier to demonstration and deployment of CCS. However there are widely varying perceptions about the scale and nature of the these contingent liabilities, and the commercial view tends to contradict the widely held view of technical experts that provided storage sites are carefully selected, controlled and monitored, then carbon dioxide will be permanently stored with virtually no risk of leakage. This report aims to reconcile these views by setting out the potential leakage pathways, the probability of leakage taking place via that route, and the maximum cost of any incident (assumed to be the cost of remediating the leak together with the cost of emissions under the Emissions Trading Scheme).

The Office of Carbon Capture and Storage commissioned this study in order to develop an improved technical understanding of the potential leakage risks (probability, flux and

[1] Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide

duration) and amount, and the options for taking corrective measures to control leakage should it occur. The intention is to improve understanding of the scale of contingent liabilities, which should in turn enable better informed investment decisions as well as judgements to be made about the value and nature of the financial security that has to be posted by the storage site operator under the licensing arrangements..

b. Discussion and underlying Issues

The guiding principles for CO_2 storage regulation, development and implementation are to select, approve and manage sites to prevent leakage. This is embedded within the fundamental requirement of the EU CCS Directive which states that "the purpose of environmentally safe geological storage of CO_2 is permanent containment of CO_2 in such a way as to prevent and, where this is not possible, eliminate as far as possible negative effects and any risk to the environment and human health" (Art. 1). The EU Directive and UK regulatory framework for geological storage are developed on the basis of a risk-based approach for safe storage and leakage.

Evidence from extensive research, operating pilot and demonstration projects and natural (and industrial) analogues around the world provide considerable reassurance that it is possible to store carbon dioxide for long periods, and in the case of natural analogues over geological timescales. This evidence led the IPCC [2] to conclude in 2005 that "with appropriate site selection based on available subsurface information, a monitoring programme to detect problems, a regulatory system and appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health safety and environmental risk of geological storage would be comparable to the risks of current activities such as natural gas storage, EOR and deep underground disposal of acid gas."

In the UK CO_2 geological storage will take place in offshore areas, where public safety risks are further reduced and environmental exposures are low. In addition there is world class subsurface information, geological understanding and oil and gas resources which underpins this confidence about the level of safe storage that may be available.

Carbon dioxide that is stored in accordance with the CCS Directive counts as not emitted for the purpose of the Emissions Trading Scheme. Consequently the relevant allowances need not be surrendered, which in-turn means that allowances either need not be purchased or can be sold at the prevailing market rate. However, if the carbon dioxide subsequently leaks from the storage site then the operator is liable for purchasing the required allowances at the prevailing market rate. This requirement gives rise to contingent liabilities, which must also must be covered by a financial security intended to provide additional reassurance that

[2] IPCC Special Report on Carbon Capture and Storage, Cambridge University Press. 2005

those obligations will be met by the permit holder. They are described in further detail in European Commission Guidance Documents[3].

Whilst these ETS liabilities are not the only obligations that will arise in the event of leakage, the financial consequences under the EU-ETS of unplanned carbon dioxide emissions are potentially very large particularly compared with the commercial opportunity provided by storage. The costs of other impacts, such as the cost of remediation or local environmental damage, and damage to third party interests, are likely to be much smaller and in line with those borne by offshore oil and gas or gas storage activities[4].

The likelihood of a leakage event occurring and the financial consequences of that leak are entirely dependent on the specific circumstances. Additionally, most storage risk assessment methodologies are either qualitative or semi-quantitative in respect of the amount of leakage, and there is limited information available on quantification of risk, comprehensive cases studies, and few published examples of comprehensive probabilistic estimates of leakage. Quantitative approaches are challenging due to very wide ranges in key parameters, multiple methodologies, large technical uncertainty and very low probabilities. This is because quantification of leakage and leakage risk requires better estimation and calibration of:

- probability of leakage,
- leakage rates,
- duration of leakage,
- amount of leakage,
- in some cases these require estimation of areal footprint and dynamic controls,
- how leakage parameter vary according to leakage mechanism/pathway and
- how leakage risk varies with time.

Because there is limited practical experience of leakage (none under a permitting regime designed to prevent leakage, such as in place in Europe), these are emerging areas of research and industry application. This study has reviewed the state of the art, latest developments and applications of the quantitative methods to CO_2 storage.

In making these assessments we are dealing with the compound effect of events which are themselves very low probability. For example in the extremely unlikely event that leakage were to take place, it is extremely unlikely that the financial consequences would be the maximum that could arise if all the carbon dioxide were to be lost from the storage site. In reality corrective measures would be taken (and geological processes would also contribute to trapping some of the injected CO_2 from an early stage). Those measures would have financial consequences, which would cap the financial exposure faced by the storage site

[3] European Commission, 2011. Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide, Guidance Document 4

[4] It is noted that impacts of CO2 release in the marine environment will be much less than from release of equivalent quantities of oil.

operator. The nature and cost of those measures is dependent on the nature of the incident. Existing studies[5] are generic and without assessments of costs or cost-effectiveness to fixing leaks of different types at different stages of the CCS lifecycle. In general terms it is recognised that corrective measures are most likely to be effective during the operational stage of the CCS lifecycle, particularly for leakage via wells. The effectiveness of measures to address geological pathways is less certain.

Results from quantification of leakage risk are key inputs to assessment of Corrective Measures and analysis of Contingent Liabilities. These can be used to help determine the scale of the potential liabilities, potential costs and policy inputs.

c. Scope of Work

The work described in this summary report and the detailed appended reports has been commissioned by OCCS[6] to assist in developing a common understanding of CO_2 leakage and associated liabilities. The intention is to inform storage site developers, the financial sector and others of the general scale of storage liabilities, their financial consequences the cost of possible mitigation options. The objectives of this work were to:

- Develop an improved technical basis for quantitative estimation and assessment of CO_2 leakage risk and leakage quantification (amounts, flux, duration, probabilities).
- Develop expert view on representative parameters for offshore UK North Sea storage (i.e. hazards, leak rate, duration, dynamic controls, probability of leakage) for the four main pathways (faults, caprocks, operating and abandoned wells).

The review focussed on four main possible pathways for potential leakage identified in previous research (Ref EC GD1), which are:

- Abandoned Wells
- Operational Wells
- Caprocks
- Faults and fractures

In each case the major risk of leakage to the biosphere originate with features or structures that penetrate the storage site and which are connected directly or indirectly to the seabed.

For each pathway there was a review of leakage mechanisms and parameters from scientific literature, analogues, modelling, public reports and case studies. The work was split into

[5] EG European Commission 2011. “Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide, Guidance Document 2, Characterisation of the Storage Complex, CO2 Stream Composition, Monitoring and Corrective Measures; IEA GHG Report, 2007: Remediation of Leakage from CO2 storage reservoirs. Report 2007/11

[6] Office of Carbon Capture and Storage in DECC

geological areas (faults and caprocks) and wells for each of which a technical report is available as an Appendix to this summary report. For each of the main pathways the work set out to review develop and estimate representative parameters covering:

- Critical controls on leakage
- Potential leakage rates
- Potential leakage duration
- Potential amount of leakage
- Dynamics of leakage scenarios
- Potential corrective measures & remediation to mitigate leakage
- Variation of risk through storage lifecycle

The participants in the study were:

- AGR Petroleum - Project Management, Wells, Expert Review
- Durham University - Faults, Caprocks, Expert Review
- Senior CCS Solutions Ltd - Summary & Synthesis, Expert Review
- CGSS Australia - Expert Review

The study has been subject to expert review by academic and industry experts; both by peer review of reports and also at a Stakeholder workshop on 20th Match 2012 attended by 25 external experts. These included experts from UK, Netherlands, Norway, Canada and Australia.

2. Well Leakage Pathways

a. Operational Wells

Operational, or active, wells have been defined as all those well types used during the operational phase of the CO_2 storage facility. They include:

- CO_2 injection wells (either active or temporarily suspended pending abandonment)
- Observation wells (used to monitor reservoir pressure and/or fluid movements)
- Water extraction wells (used for pressure maintenance)
- CO_2 injection wells during any infill drilling phases
- CO_2 injection wells undergoing intervention and/or work-over

Estimating the probability of a leak occurring and the likely magnitude or flux of the leak has been largely based on Norwegian data (SINTEF)[7] for well completion reliability and causes of failure.

[7] Assessment of Sustained Well Integrity on the Norwegian Continental Shelf P.Randhol and I.M. Carlsen SINTEF Report 2008

Table 1: Summary, parameters and scenarios for Potential Leakage from Active well

Scenario	Low level leakage	Worse Case Scenario
Scenario	Low level leakage	Blow out on CO2 injection well after failure of initial well control activities.
Probability of Leakage	0.0001 – 0.001	0.00001 – 0.0001
Potential CO2 Leakage Rates	0.1 – 10.0 tonnes / day	5,000 tonnes / day
Duration	0.5 – 20 years (until well abandoned)	3-6 months
Dynamic Controls	Well could be shut in or injection reduced to	Reservoir injection halted until remediation complete to minimise CO2
Potential Amount of Leakage tonnes CO2	18 – 73,000 tonnes	0.45 - 0.9 million tonnes
% CO2 Stored (200Mt case)	0-0.036%	0.225-0.45%
Applicability of Corrective Measures	Conventional well work over with a rig	Relief well drilled at short notice (c. 60 days well + mobilisation)
Variation in Risk through Lifecycle	Injection period; up to closure. Increases as wells age.	Injection period after start of injection; increasing up to closure. Blow out of an infill or injection well is most likely to occur towards end of injection period.
Comments, E.G. Uncertainties	Wells designed for CO2 service	Uncontrolled well release or blowout could occur with shorter durations when initial well control activities are effective (days-3 months). Design flaw due to scarcity of analogues.

The figures presented are best efforts to represent leakage scenarios and risks in the North Sea for a storage scheme with 5 injection wells, 20 year injection period and 200 Million tonnes stored. There are considerable uncertainties involved and the assessment incorporates a high degree of judgement.

A number of key conclusions have been drawn as a result of this work:

- Active CO_2 development wells should be designed and constructed not to leak in active service and will incorporate double barriers.
- Integrity of the double barriers should be regularly monitored and assessed (at least every few months).
- If a single barrier were to fail then it can be detected and repaired in the event that leakage to the biosphere takes place.
- The failure of both barriers at the same time resulting in the loss of well control is very unlikely (ca. 0.00025%/well/year based on comparisons with the oil and gas industry). If such an incident were to take place then:
  -this could result in high flux release of CO_2 over a relatively short space of time (days-months) before the leak is stopped
  -remediation in the worst case would require a relief well to be drilled (taking 3-6 months)

b. Abandoned Wells

Abandoned wells penetrating the storage reservoir pose a risk of leakage because they represent a direct pathway to the surface. Whilst this pathway would have been sealed (by filling with cement) at the time the well was abandoned, leakage could occur for a variety of reasons, including:

- Deterioration of the annular cement and/or casing cement plugs
- Deterioration of pre-existing annular cement bonding around abandoned well casings
- Known or undocumented sections of well that penetrate the proposed storage reservoir formation but which have not been cemented during decommissioning

In assessing a geological structure for its suitability as a storage site abandoned wells will have been assessed to ensure they do not represent an unacceptable risk of leakage, and any necessary remedial work undertaken as a condition of issuing the storage permit. However, record keeping for abandoned wells is not always complete and methods adopted have varied between companies and over time. Often the reservoir formation targeted for CO_2 storage will not have been a target for hydrocarbon production and the well may therefore not have been abandoned to the same standards as would be the case in a hydrocarbon field. If a previously abandoned well does leak then it is likely to prove difficult to repair and, depending on the severity of a particular leak, may require a relief well to be drilled.

Two categories of abandoned wells were considered in this report. Firstly, pre-existing wells which were drilled for the exploration, appraisal or production of hydrocarbons and which were abandoned (as dry holes, discoveries or appraisal wells) prior to the use of the storage site. Secondly, CO_2 injection wells (or related observation / water abstraction wells), which are decommissioned once the storage site is closed.

An important paper by LeGuen[8] has been relied upon for providing probabilities of a variety of potential leakage scenarios.

The following conclusions have been drawn:

<u>1) Previously Abandoned Oil & Gas Wells</u>

- All storage sites will likely have pre-existing abandoned wells in their vicinity although this may not be within the primary or secondary containment zones of the storage complex.
- Saline aquifer structures are likely to have fewer abandoned exploration & appraisal wells. Additionally, depleted oil or gas reservoirs may also have abandoned development wells
- The standard to which wells have been abandoned may be variable and inadequate for CO_2 storage purposes. All abandoned wells will pose a risk to storage integrity and should therefore be investigated and remediated as necessary. Abandonments may have been carried out to lower standards where no hydrocarbon zones were penetrated (i.e. in water zones). However, leakage rates in such circumstances will be low and possibly undetectable.
- The worst case scenario is a total breakdown of all existing cement plugs from an abandoned well that penetrates the storage structure permitting free flow of CO_2 to surface
- Remediation is possible in such circumstances but *in extremis* would require drilling of a relief well.

<u>2) Abandoned CO_2 Injection Wells</u>

- The abandonment design for a previously active CO_2 well will be fit-for-purpose and is considered to present an extremely low risk of leakage.
- In the highly improbable event that an abandoned CO_2 injection well did leak then the same remediation options would be available as for other types of well.

[8] Y. LeGuen et al,2009; A Risk-based Approach for Well Integrity Management Over Long Term in a CO2 Geological Storage Project; SPE 122510

Table 2: Summary, parameters and scenarios for Potential Leakage from Abandoned well

Scenario	Low level leakage via abandoned well	Worse Case: Complete breakdown of abandonment plugs in old well
Probability of Leakage	0.0012 – 0.005	
Potential Leakage Rates (CO2 t/day)	0.60 – 6.00 tonne / day	1,000 tonnes /day
Duration	1 – 100+ years	3-6 months
Dynamic Controls	Manage (reduce) reservoir pressure	All CO2 injection ceases until remediation complete
Potential Amount tonnes CO2	220 – 220,000+ tonnes	90-180,000
% CO2 Stored (200Mt case)	0.0001-0.1+%	0.045-0.09%
Applicability of Corrective Measures	Re-entering abandoned well will be very difficult	Relief Well to intersect the leaking well at or close to the reservoir
Variation in Risk through Lifecycle	Injection period and continues after closure. Abandoned well integrity may deteriorate over long time frames (10's of years but load reduces (plume disperses)	Likely to be encountered during injection period.
Comments, E.G. Uncertainties	Quality of original cement plugging and lack of records for remediation	Original well survey quality leads to an extended and expensive relief well

The figures presented are best efforts to represent leakage scenarios and risks in the North Sea for 200Mt storage case with six abandoned wells and probability of leakage over 100 years. There are considerable uncertainties involved and the assessment incorporates a high degree of judgement.

3. Geological Pathways for Leakage out of Storage Reservoir

a. Caprocks

Storage of CO_2 relies on an extensive and robust caprock or seal. The possibility of movement of CO_2 from the primary storage reservoir into the overlying caprock is one of the main generic hazards or pathways that could lead to eventual leakage out of the storage complex and/or to the atmosphere. A detailed technical review of factors affecting caprock integrity is included as Appendix 2 of this report.

Given the geology of the North Sea migration of carbon dioxide through caprock is likely to be almost impossible for a site that is suitable for permitting under the CCS Directive. The North Sea basin contains oil, condensate and gas trapped in a large variety of reservoirs ranging in age from Devonian to Eocene and including sandstone, limestone, and chalk reservoir rocks. There are numerous extensive caprocks that are known to be effective seals for oil and gas and CO_2, for which the thicknesses are and geology are well known; many of these are 100s to 1000+ m thick. Different seals are present and effective in different regions of the North Sea, but all are likely to be highly effective at containing carbon dioxide. Caprock permeabilities are expected to be very low with abundant structures with a permeability of < 10^{-4} milliDarcies (mD) the level generally accepted as providing a good seal.

Low permeability implies low likelihood of leakage and very low rates of leakage. However, more importantly for CO_2 sealing, low permeability implies that the rock matrix is comprised of very small pore-throat [9]sizes. The interfacial tension between CO_2 and brine within these small pore-throats often results in zero leakage. The process of blockage due to interfacial tension is often referred to as capillary sealing. Capillary sealing can be expected to occur providing the height of CO_2 column underneath a given caprock remains below a critical threshold. From the study of Naylor et al. (2011), it is expected that sustainable CO_2 column heights in Southern North Sea reservoirs are likely to be comparable to the size of gas column heights previously observed.

The above studies assume that the caprock remains intact throughout the surface that is in contact with the carbon dioxide. When CO_2 is injected into a reservoir formation, pore-pressure is expected to increase. This can potentially lead to mechanical failure of the overlying caprock, leading to the development of new fractures and/or the reactivation of existing fractures and faults, all of which can increase caprock permeability. However, this pressure will be subject to regulatory control; if new or reactivated fractures were to occur, then the implications for integrity of the storage site would be similar to if faults existed in the site at the time it was permitted. This is discussed further in the section on fault leakage.

The critical controls on leakage through caprocks include ability to maintain a capillary barrier, caprock permeability and whether or not the CO_2 injection leads to the development of tensile fractures or reactivation of existing faults or fractures. The geological controls on caprock continuity must also be understood to ensure that the caprock is present and continuous across the storage site, and is not absent locally e.g. due to erosion, non-deposition, facies changes, salt withdrawal or permeable injection features. This would all be demonstrated prior to permitting.

[9] In a sedimentary rock made up of small grains and pore spaces, the pore throat is the very small pore space at the point where two grains meet, which connects two larger pore volumes. The number, size and distribution of the pore throats control many of the resistivity, flow and capillary-pressure characteristics of the rock.

Table 3: Summary of Potential Leakage via Primary Caprock

Scenario	Migration through Primary Caprock
Probability of Leakage	Negligible
Potential Leakage Rates (CO2 t/day)	Very low flux rates
Duration	100-1000 years to breakthrough
Dynamic Controls	Largely driven by reservoir pressure.
Potential Amount tonnes CO2	Very low
% CO2 Stored (200Mt case)	N/A
Applicability of Corrective Measures	Stopping injection and possible depressurising of reservoir
Variation in Risk through Lifecycle	Most likely during injection but may not be detected until later.
Comments, E.G. Uncertainties	Continuity of caprock across site is essential.

Providing the caprock is present and capillary seal is maintained, the CO_2 migration or leakage rate through the caprock should be zero. If the capillary seal is overcome CO_2 may enter the caprock and begin to move vertically through the caprock but at very slow rates. One modelling study showed that providing the caprock thickness is greater than 50 m and caprock permeability is less than 0.01 mD (characteristics that are abundant in the North Sea), the CO_2 migration from the reservoir into the caprock after 200 years is unlikely to be greater than 0.001% of the total injected mass. Modelling studies indicate that potential migration rates through the caprock may take 100s or 1000s of years or longer for CO_2 to migrate through the primary caprock formation and reach overlying formations. Consequently the possibility (i.e. risk) of CO_2 migrating though the caprock and overburden to surface is almost impossible.

The leakage mechanisms described above are mostly driven by pressure in the storage site. The formation pressure will be elevated up to the end of injection because carbon dioxide is being introduced into the store, although this will be carefully controlled under the storage permit. Because of this increase in pressure the risk of migration into the caprock and leakage will increase up until the end of injection period. The risk of caprock migration will then decrease once CO_2 injection is stopped and the pressure in the store diminishes.

In view of the high quality caprocks prevailing in the North Sea, the overall generic risk of CO_2 leakage through the primary caprock in North Sea storage sites and then through the overburden to reach the seabed is almost impossible. In addition flux rates are expected to be very very low. Therefore caprock leakage is not considered a material leakage risk in North Sea context, although site specific risk assessment will needed. That assessment will need to address caprock continuity, properties and any potential geochemical impacts of introducing CO_2 to the system. In general terms there will be greater uncertainty about caprock leakage for saline reservoirs reservoirs because there is no pre-existing proof of containment of fluids compared with reservoirs that have naturally contained oil and gas.

b. Faults & fracturing

This section considers potential CO_2 leakage through fault zones and fracturing. These are considered as one of the main potential mechanisms for the movement of CO_2 beyond the boundaries of the storage site. Leakage of CO_2 via a fault or fracture may occur:

- where there is an existing pathway in the form of a fault, fault zone and/or fracture system along which leakage may occur,
- by reactivation of an existing pathway resulting or by fracturing to create a new pathway due to CO_2 injection , or
- due to induced by natural seismicity.

The nature of faulting and fracturing will depend on the specific geological structure, tectonics and structural evolution. While this can be variable at the site specific scale, some important generalised observations can be made for the North Sea. Faults and fractures are prevalent in older and deeper formations in the North Sea, but it is very unusual for them to extend from the depths at which carbon dioxide would be stored through overlying caprock to the surface. This is important as the lack of a direct route substantially reduces the risk of fault leakage. There are local exceptions where faults are present in and offset shallow formations and may reach the surface, for example over salt structures in parts of the North Sea. These may represent a higher risk of leakage, however they are readily detected and sites where such faulting is identified would need additional fault seal assessment to satisfy the requirements for permitting under the CCS Directive.

Faulting is not necessarily a sign of leakage or potential leakage. There are widespread occurrences in the North Sea where there is faulting, but oil and gas has nevertheless remained in the reservoir. These provide evidence that many faults are sealing to oil and gas and by implication other buoyant fluids such as carbon dioxide. Faults, fault zones and fractures have been extensively studied and have been shown to be highly variable in their ability to transmit fluids.

- Faults/fault zones may be transmissive to fluid flow or they may be sealing, and in some cases both on different sections of a fault or at different times.
- Low permeabilities may exist due to mineralisation, the smearing of low permeability rock across the fault plane and where faults offset or penetrate low permeability shale rich formations.

- The permeability of fault zones (which is difficult to measure) may also be highly variable along or up the fault zone. There is evidence for significant permeability and flow anisotropy (i.e. having different flow characteristics in different directions).

- Low permeability faults also have a capillary sealing potential (as with intact caprock). Providing the capillary seal is maintained, the CO_2 leakage rate through the fault should be zero. If the CO_2 plume intersects with a connected fault zone and the capillary seal is broken, CO_2 leakage through the fault zone will be dependent on the fault permeability.

- Representation of fault zone permeabilities and modelling fluid flow (including leakage) through faults is very complex and site specific. Most of this modelling is focused on fluid flow and compartmentalisation of reservoirs with very little on flows through caprocks.

- Modelling of CO_2 flows during leakage via faults is at a very early stage of research and development, with significant uncertainties in general terms and in relation to the applicability of model assumptions to the North Sea.

- A range of natural analogue studies where CO_2 has been observed from faults, fractures and high permeability zones, are discussed in the literature.

A range of CO_2 leakage rates via faults from appropriate natural analogues to storage sites is 0.006 and 0.3 t/yr/m2 [Busch, 2010[10]]. None of these are in the North Sea. Note that these relate to the areal footprint of faults which is seldom documented and likely to be highly variable and site specific. This underlines the need for an assessment of the leakage potential of any fault to be incorporated into any site specific evaluations.

The critical controls on leakage of CO_2 through faults include along and up fault permeability, CO_2 injection induced pressures leading to fault reactivation or fracturing and the presence of pathways connecting the fault through the overburden to the surface. Representative parameters for potential fault leakage in the North Sea have been estimated in this study and are presented in Table 4. For reasons explained above there is a considerable range of variables attached to all aspects of fault leakage, including potential leakage rates. Consequently a very wide range of uncertainty is attached to any generalised prediction of potential leakage rates.

There is similarly little information available that enables a general assessment of the probability of fault leakage since this will be site specific. However, as described above the geological conditions across much of the North Sea seem likely to prevent and mitigate the risks of large scale fault leakage to seabed during CO_2 storage. Fault leakage probability, risk and risk assessment will be highly site specific but the rigorous site selection required by the

[10] The Significance of Caprock Sealing Integrity for CO2 Storage; A.Busch; SPE 139588

permitting arrangements should be used to filter out sites where identifiable faults to seabed with risk of leakage are present.

Table 4: Summary, parameters and scenarios for potential leakage via fault

Scenario	Vertical migration through existing faults - Low flux	Vertical migration through existing faults - Moderate flux	High flux migration through fault activated and enhanced by injection
Probability of Leakage	Not calibated-highly site specific		
Potential Leakage Rates (CO2 t/day)	1-50 t/day	50-250 t/day	1500t/day
Duration	1 – 100 years for low flux; Excludes remediation	1-5 years; includes remediation	1-5 years ; includes remediation
Dynamic Controls	Pressure; episodic or continuous flow; phase behaviour		
Potential Leakage Amount tonnes CO2	0-1.8 Mt (100 year flux); no remediation	0.018-0.46 Mt including remediation	0.55-2.7 Mt including remediation
% CO2 Stored (200Mt case)	0-0.9%	0.0009- 0.23%	0.275-1.37%
Applicability of Corrective Measures	Stopping injection and possible depressurising of reservoir	Stop injection. Pressure management; Possible Relief well(s)	
Variation in Risk through Lifecycle	Critical period is during injection, decreasing risk thereafter.		
Comments, E.G. Uncertainties	Very wide uncertainties for all fault leakage cases, Limiting effects of pressure bleed off – episodic or continuous flow. Uncertain effectiveness of relief wells.		

The figures presented are best efforts to represent leakage scenarios and risks in the North Sea if faults are present. There are considerable uncertainties involved and the assessment incorporates a high degree of judgement.

Potential leakage rates, duration and amount will depend on fault characteristics at the site and any leakage will ultimately be driven by permeability, buoyancy drive and pressure gradient. Further considerations are:

- For closed reservoirs, pressure will decline over time until the store reaches equilibrium with its surroundings. This will be site dependent, but well before this point where the store no longer contains carbon dioxide.
- Fault permeability and pressure gradient are both expected to reduce with reducing pressure. Consequently, CO_2 leakage rates can be expected to reduce with time.

- For open reservoirs in saline aquifers and depleted fields with strong aquifers, natural aquifer drive may lead to sustained reservoir pressures over longer timeframes thereby altering the leakage risk profile relative to time.

- The duration of any fault leakage is another uncertainty in risk assessment. Most of the processes described will results in leakage events, triggered by increasing pressure. These would be expected to reduce over time as pressure drops. Another significant uncertainty is the extent to which fault leakage may be episodic and self-sealing.

- Corrective Measures may reduce the duration of any leakage where higher initial flux occurs.

The timing of potential fault related in the storage lifecycle is more constrained. Leakage of CO_2 through fault zones can only occur once enough time has passed for the CO_2 to intersect a fault zone. The probability of the plume intersecting a fault zone also becomes greater with increasing time as long the plume is expanding. However, the significance of the fault zone as a leakage conduit is driven by the reservoir pressure because faults are expected to be significantly more permeable at critical state (i.e. close to reactivation). The critical time for pressure is during injection. Therefore the risk of fault reactivation decreases once CO_2 injection is stopped. Following CO_2 injection the probability of fault reactivation will mostly be driven by externally induced seismic events (which are very low probability).

There are several options that may be considered for remediation of any fault leakage although these are largely untested and their effectiveness is thus uncertain.

- Faults close to or penetrated by an injection well might be cured using suitably deployed loss control material, similar to techniques used when drilling fault zones in oil and gas wells.

- Pressure control is another option either by ceasing injection allowing pressure to dissipate naturally or by extracting water or CO_2.

- Relief wells might be used but it could be challenging to identify and interest fault leakage zones.

- Reactivation of more remote faults might be controlled by pressure management but could, in the worst possible case, result in a compromised storage site.

4. Synthesis of Findings

a. Overburden pathways

The sections above describe potential leakage pathways from the primary storage reservoir during injection and storage. It is very important to note that the detailed characteristics of a specific site will provide major controls on leakage risk. These will be fully evaluated as part of the permitting process. These will include the number and status of wells, the presence and nature of any faulting at the reservoirs, and the thickness and characteristics of the primary caprocks. The site will also have important characteristics relating to the storage complex and overburden.

In the event that CO_2 is able to move out of the primary reservoir and the secondary containment provided by the storage complex, into faults, caprocks or wells further movement and migration will usually be driven upwards by buoyancy but where it goes and how fast will depend on the nature of potential pathways through the overburden (including through the storage complex). Whether there is leakage out of the storage complex or to the seabed will depend on the presence of pathways through the overburden to the seabed.

In practise such pathways will be very site specific and may be quite tortuous especially where multiple caprock/seal units are present as is often the case in the North Sea. Each successive barrier will reduce the amount of carbon dioxide finding its way to the next, with a resulting dilution and mitigation effect. Secondary reservoirs and seals may also act as effective containment zones and barriers to leakage. The exception will be where there are open wells or fault pathways that extend from the storage site to the seabed. Combinations of pathways connecting wells, faults and permeable reservoirs will be considered as part of the site evaluation, together with possible seals at all levels. The near seabed geological characteristics are also important as these may influence whether there is dispersion or direct flow paths in near seabed sediments. Much work has been done on natural seeps of oil and gas in the North Sea, and while these are limited in extent, they are often highly dispersed. Further review of pre-existing work on seepage controls and distribution may be beneficial. Overburden characteristics and pathways will therefore determine potential for leakage out of Storage Complex to Surface.

b. Storage Options

The generic leakage risks will also depend on the storage options type, notably whether it is an oil or gas field or saline aquifer storage option. The potential risks are compared below.

- In oil and gas fields, there will generally be more abandoned wells (than saline formations), however geological leakage risks will be minimal in view of of the fact that oil and gas has remained trapped for geological timescales and the understanding of controls on trapping. Any faults present will need to be studied to assess connectivity to surface and potential reactivation during CO_2 injection. Reduced risks related to pressure driven leakage mechanisms are envisaged for fields where pressures are depleted.
- Sites in saline formations will usually have fewer abandoned wells, and because of this the risk of leakage from a well should be lower. However it is possible that any pre-existing well will have decommissioned to a lesser standard that an equivalent well in a hydrocarbon field. There may also be poorer records and knowledge retention compared to oil and gas fields. The uncertainty of geological leakage risks will be inherently greater for saline formations than it will be for oil and gas fields. This is because there is no actual evidence of buoyant fluid containment, although many of the geological fundamentals and characteristics could be closely comparable to oil and gas fields. The geological leakage risk will depend on the type of trapping envisaged in the aquifers, with relatively lower risks of leakage in open aquifers than for structures due to greater plume dispersal and residual trapping in open aquifers. It will also depend whether any faults are identifiable, present, and potentially connected to the seabed.

c. Corrective Measures

Corrective measures (CM) are defined in the EU CCS Directive and described further in EC Guidance Document 2. They are actions, measures or activities to correct significant irregularities or leakage (which might be referred to as remediation). Their purpose is to prevent or stop the release of CO_2 from the storage complex so as to ensure the safety and effectiveness of geological storage. Corrective measures are part of the overall risk management process to ensure safe storage and to manage the risks from leakage during the project life cycle.

The general principles for corrective measures should be risk based, specific to the storage site and complex, suitable for use to address leakage or significant irregularities out of the storage complex and any leakage to the surface. They should be linked to monitoring, which should provide triggers for the use of the measures. A condition of the storage permit is that a corrective measures plan needs to be submitted by the operator with the storage permit application and will need to be approved by the regulatory authorities as part of the storage permit.

The type of corrective measure described in Guidance Document 2, includes:

- Limiting CO_2 injection rates or stopping injection 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 for caprock, fault and possibly abandoned well leakage. This type of measure is straightforward to apply at low incremental cost, although disruption to injection may occur which will impact on the business plan for the storage site and the commercial relationship between the emitter and the storage site operator. The effectiveness of this measure 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, close to an identified leakage area. This can be done by removing injected CO_2 from the storage reservoir/plume (actively reducing reservoir pressure) and either controlled venting or re-injection in another site. This would be straightforward provided existing facilities and wells can be used, but again would have a significant impact on the business plan for the storage site.
- Another option is peripheral extraction of formation water or other fluids. This will depend on pinpointing leakage zones and may require new targeted extraction wells. In some cases it may be possible to intersect leakage zones with existing wells, but higher costs and longer timeframes would be incurred if new wells are required.
- 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). The applicability of this approach over extended areas and at the depth of carbon dioxide storage sites is challenging and would be novel application of this technology.
- Increase of pressure in formations upstream of CO_2 leakage, creating an hydraulic barrier in order to stop carbon dioxide migrating towards the vulnerable area (decreasing pressure gradient).
- Well remediation for Active wells. 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. These are likely to be effective, however costs and duration are highly specific to the well situation and may be subject to wide uncertainty levels.
- Well control. Well blow outs can be remediated using standard industry techniques to “kill “the well, which make the well safe by injecting heavy fluids into the borehole and then cementing the well. Alternatively Relief wells may be required, i.e. drilling a new well to interest and plug the leaking well.

- Abandoned wells. Where a previously abandoned well is found to be leaking, a series of steps can be considered. In the North Sea it is likely that it may be very challenging to re-enter an abandoned well because the wellhead and surface casings will have been permanently removed by explosive cutting several metres below the sea floor. The main option for remediation would be a dedicated relief well to intersect, repair and seal off the abandoned well. While challenging and potentially time consuming relief wells have been shown to be effective means of re-entering active or previously abandoned wells.

Relief wells are an important type of corrective measure for several leakage scenarios. A relief well would be a new well drilled using a drill rig from a separate surface location with a deviated trajectory to intersect a leaking well or fault zone at some specified and targeted location in the subsurface. Drilling fluids and cement can then be pumped through the relief well into the leakage zone to seal it off, and/or it may be possible to flow CO_2 or other formation fluids out to reduce formation pressure. In the North Sea these would typically take around 2 months once a rig is on location, at an approximate cost of £25-30 million. The time involved in mobilisation of a suitable rig and any additional surveys to pinpoint leakage zones would also need to be factored in.

d. Leakage Parameters

Tables 1-4 summarise our assessment of representative generic parameter for leakage risk in the North Sea. This is derived from the technical assessments that have been conducted combined with a high degree of judgement where necessary. The quantitative parameters for potential leakage flux, duration and amount are assessed with most confidence for well leakage pathways based on oil industry well engineering and analogue statistics. In contrast, for the reasons explained previously, there is considerable uncertainty for geological leakage rates, particularly in relation to faults.

The duration of leakage estimates shown on Tables 1-4 is based on the assumption that higher flux leakage can be remediated by stopping injection, pressure management or relief wells, etc, and incorporates the time that may be taken to stop leakage. However where leakage flux rates are extremely low, the durations do not assume remediation takes place. In all cases also it is assumed that robust site selection, characterisation and risk assessment is in place and that an adequate monitoring programme is conducted to enable detection of leakage.

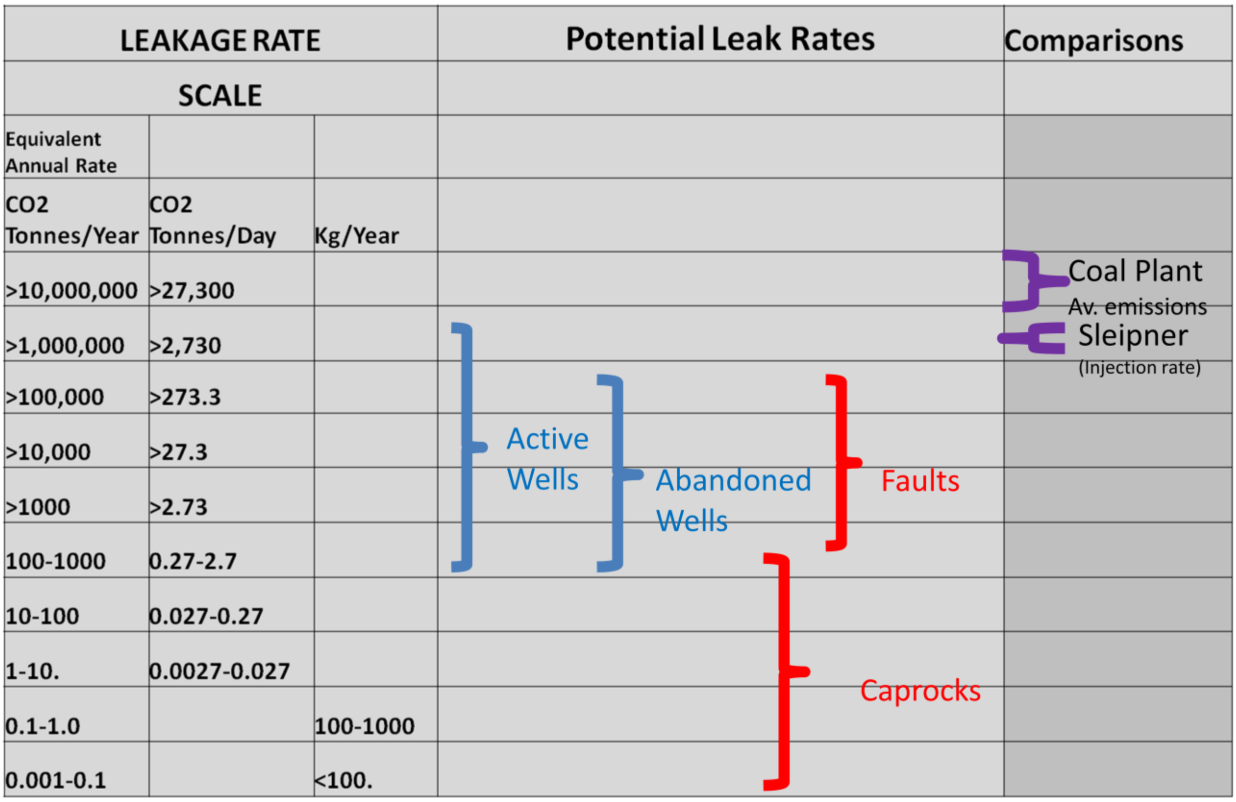

Figure 1: Summary of Potential Leakage Rates for major Hazards

Potential Leakage rates are illustrated in Figure 1 using a standardised scale of CO_2 tonnes/day. This illustrates the wide ranges in uncertainty for estimates of leakage rate. It also shows the highest potential flux rates for leakage (up to ca 5,000 tonnes/day) are for active wells.. Potential leak rates via faults may be up to ca 1500 tonnes/day. For comparison these flux rates, the CO_2 emissions rate for a UK coal power plant is illustrated (up to 60,000 tonnes/day) and the injection rate for the Sleipner CO_2 storage scheme (1 Mt/year or ca 3000 tonnes/day).

Using the estimates of average flux rate and potential leakage duration the total amount of leakage under different scenarios can be estimated and visualised using a simple matrix that has been developed (Figure 2). The colour shading is a traffic light scheme with red/amber/green in relation to total amount of leakage. This is a key parameter for determination of allowances that might need to be surrendered.

All of the scenarios are subject to large uncertainty. But, few of them result in total carbon dioxide releases exceeding 1 million tonnes CO_2 (orange/red shading) over the period of the leak. The worse scenarios are from leakage via faults over periods of many years (up to 2.7 Million tonnes)..

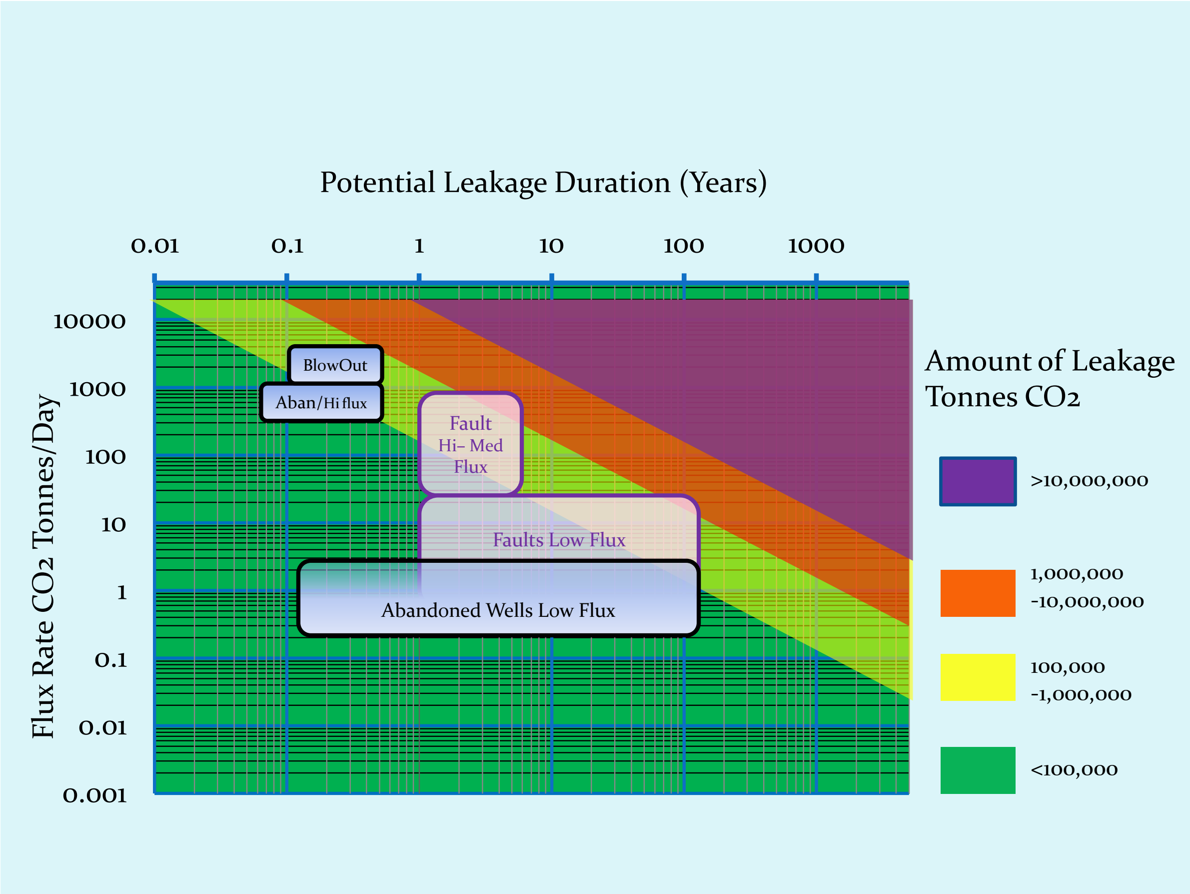

Figure 2: Matrix for Quantification of Potential Leakage showing representative ranges for major Hazards

Probabilities of Leakage

An important part of leakage risk assessment is to assess the probability of an event occurring that leads to leakage. In general terms the probability of leakage occurring is considered extremely low but clearly it is important to discuss this further. A useful framework for categorising leakage probability is shown in Figure 3 from Dodds et al [11]. This illustrates the scale of the probabilities involved. This has a qualitative description together with probability ranges and descriptors. In practice different proprietary methods are likely to be used by Industry.

In this study we have reviewed oil and gas industry frequency statistics for well failures and unintended releases in the North Sea. These have been reassessed for purposes of better understanding probabilities of leakage occurring via abandoned or active wells for representative storage cases in the North Sea.

[11] Evaluation of Risk Assessment Methodologies using In Salah CO$_2$ Storage Project as a Case History, Proceedings of 11th International Conference on Greenhouse Gas Technologies, Amsterdam, 2010, Elsevier

Example Assessment Scale for Probability of Leakage showing North sea examples

B Qualitative Description	Order Magn. Likelihood (annual Freq. or prob. Over a set period)	Basis
A. Certain	1 (or 99.9%)	Certain, or as near to as makes no difference
B. Almost certain	0.2-0.9	One or more incidents of a similar nature has occurred here
C. Highly probable	0.1	A previous incident of a similar nature has occurred here
D. Possible	0.01	Could have occurred already without intervention
E. Unlikely	0.001	Recorded recently elsewhere
F. Very Unlikely	1×10^{-4}	It has happened elsewhere
G. Highly Improbable	1×10^{-5}	Published information exists, but in a slightly different context
H. Almost Impossible	1×10^{-6}	No published information on a similar case

Abandoned Wells (D–F)

Active Wells (F–H)

Ref: Evaluation of Risk Assessment Methodologies using In Salah as a Case History ; Dodds et al, 2010

Figure 3: Assessment Scale for Probability of Leakage

There is virtually no published information on geological leakage probabilities, and it is not considered feasible to quantify this on a generic basis. As a general comment it is often stated that well leakage more of a concern than geological leakage via faults or caprocks in the North Sea (Ref: Amesco, Netherlands, 2007). In the In Salah storage case referenced above the overall risk exposure for wells was higher than any caprock or fault mechanisms. Perhaps it is implicit from these statements that probabilities of leakage will be lower for caprock or fault pathways than for wells.

One related analogue is from natural gas storage for which the UK Health and Safety Executive have assessed the failure rate for a geological failure of the storage cavity in an Underground gas storage facility to be of the order of 10^{-5} failures per well year, or 1 in 100,000 chance of failure per well per year of operation. However this probability relates to slow release of gas at flux rates of the order of 10^{-4} kg/sec (approximately 3.1 tonnes/year) that were considered negligible risk in major hazard terms.

5. Conclusions

Abandoned wells present the most probable source of leakage for many storage sites, including pre-existing exploration, appraisal and any abandoned development wells. Flux rates in the event of any leakage will normally be very low at levels that may not be material. There is a remote possibility of higher flux in event of a loss of well integrity (completed well), however, well leakage can be remediated using industry standard methods, although in extremis a new dedicated relief well might be required in order to stop leakage.

Potential loss of well control from active wells could result in leakage with highest flux rates under blow out scenarios. Based on oil and gas industry experience these would be relatively short in duration, typically between 1 day and 6 months thereby limiting total amount of leakage. Potential flux rates could be up to 5000t/day depending on the nature of the reservoir and the pathway to surface. These can be remediated with oil and gas industry practices, although it may be necessary to drill a dedicated relief well at approximate costs of £25-30million.

Caprock leakage is very unlikely in the UK sector of the North Sea and rates of leakage will be extremely low. This would also mean very long timeframes before breakthrough to seabed. The potential leakage risk and flux rates are unlikely to be material for North Sea sites where caprock presence, thickness and characteristics have been demonstrated.

Fault leakage risk assessment is more uncertain as this is more complex and difficult to generalise and quantify. Fault leakage events may result in the highest amount of leakage of the principle hazards, although this is still a relatively minor proportion (1.5%) of total amount stored. While the controlling mechanisms, location and nature of faults are quite well understood, the potential scale and duration in event of leakage are uncertain, due to uncertainties in horizontal and vertical permeability and transmissivity, pathways to surface and dynamic controls on potential fault leakage. Given the nature of existing faults which generally do not cut to surface there is most concern about reactivation of faults or fractures leading to leakage of finite duration, but overall fault leakage risk is expected to be very low provided no identifiable faults are present between the storage reservoir and seabed. It will be essential to identify and map and assess the connectivity to seabed of any faults at site specific level, and to review any evidence relating to hydrocarbon migration and seabed seepage. The main remediation approach for any fault leakage is likely to be using pressure management although relief wells may be considered if high flux rates occur. Further work is required to assess their likely effectiveness.

Estimates of potential flux rates, duration and total amount of leakage have been presented for different leakage mechanisms with uncertainty ranges. Estimating the probability of leakage on a generic basis is difficult. Indicative probabilities are presented for well leakage cases with probabilities ranging between 0.001-0.00001 for operational wells and 0.001-0.005 for abandoned wells. Lower end probabilities would be attached to higher leakage rates and durations.

The overall leakage risk profile for any site will vary through the CCS/storage life cycle. Because active well, caprock and fault leakage risk should reduce after the end of injection there is expected to be an overall reduction in leakage risk once injection is ended, including a reduction in high consequence events.

Individual risk elements are site specific, in particular faulting and abandoned wells and overburden pathways.

For all sites it will be essential to develop a good geological model and an integrated and combined assessment of potential pathways that might allow leakage to seabed.

6. Potential areas of Further work

The following areas for possible further work relating to CO_2 leakage risk were identified during this review.

1) Further case studies, scenarios or modelling of representative leakage scenarios could be undertaken to better constrain potential leakage and therefore contingent liabilities. Development of and use of probabilistic methods may be beneficial.
2) Further assessment and costing of corrective measures is likely to reduce uncertainties in contingent liabilities. Use of decision trees and case study scenarios may be a useful approach.
3) The overall and site specific understanding of fault leakage mechanisms, leakage prediction and modelling needs to be improved including the following areas:
    - Along and up- fault permeability /conductivity research, prediction and modelling
    - Improved understanding of geomechanics of fault deformation & dynamics of this process.
    - Modelling of fault leakage scenarios
    - Improved understanding of temporal nature of fault leakage – episodic or continuous, and potential leakage duration
    - Site specific fault characterisation to surface, with probabilistic approach, including presence of faults extending to surface; conductivity, detection limits.
    - Review of fault leakage, hydrocarbon systems and migration and shallow oil and gas seepage in UK North Sea

4) Further assessment of near well bore region impacts of exposure on leakage was suggested at the Workshop.
5) Considering what leakage levels may be acceptable in terms of safety, accident hazard and environmental impact and detectability may be beneficial.

Some other areas where further work may be beneficial that were identified in the study (but not related to leakage risk) are:

- Further discussion on Well abandonment standards, regulation and record keeping taking account of anticipated requirements for use of North Sea for CO$_2$ storage. This may include:
    - Does it make sense to upgrade Abandonment standards for UK wells for future storage?
    - Well records. Is there role for stronger regulation/regulatory oversight?
    - Retention of records at abandonment of fields
- Further work on CO$_2$ specific well control implications may be beneficial.

Language, terminology & communication to ensure effective communication between all stakeholders in this area.