Deep Geological Storage of CO_2 on the UK Continental Shelf: Containment Certainty

Supplementary Note B: Geological Leakage Risks

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1. Introduction

This document provides additional technical information that underpins our assessment of the containment certainty of deep geological storage of CO_2 in offshore sites on the UK continental shelf (UKCS). The aim of this document is to present a thorough explanation and justification of the key findings and conclusions of the main report (Daniels *et al.* 2023), and is aimed at a technically experienced geoscience audience.

Many studies and pilot projects to date have concluded that geological storage of CO_2 in suitably selected and assessed sites is safe, and that there is very high certainty that a very high proportion of the injected CO_2 will remain within the storage site for the foreseeable future. Since containment certainty is extremely high, its corollary, “risk of leakage” is extremely low; however, it is not zero. This appendix focuses on the geological aspects that contribute to the non-zero risk of CO_2 leakage.

1.1 Document layout

- Sections 1 and 2 of this report focus on general aspects of geological storage risk.
- Sections 3 to 6 each describe an overall category of geological leakage pathway in more detail.
- The quantitative results of our assessment of leakage rates and leakage probabilities are given in Sections 7 and 8, respectively.
- Section 9 collates our combined leakage rates and probabilities in comparison with other published and unpublished assessments.

1.2 Overall assessment of containment certainty

There are various different categories of potential leakage pathway along which CO_2 may be lost from a storage site. To assess the risk of leakage from each of these types of pathway we need to consider the following:

- The probability that leakage will occur via a given type of pathway.
- The range of leakage rates for that type of pathway.
- The typical duration of leaks of this kind. This is heavily influenced by the time taken for a site operator to identify a leak, and the mitigation methods that the operator might use to contain the leak to prevent further loss of CO_2.

To estimate the magnitude of a leakage event (in the unlikely event that one should occur), we need to consider the leakage rate and the duration.

Risked leakage volumes are a product of the leakage magnitude and the probability that that class of leakage pathway or leakage event will occur.

1.3 Conventions used

In this study we consider the rate of fluid flow (including **leakage rate of CO_2**) to be the amount of fluid moving over a specified time. In the scientific literature, values of flow rate are presented in a range of formats: to allow comparison we have converted all rates so they can be presented in metric tonnes per annum (tpa).

We use **fluid flux** to mean the amount of fluid that flows across a given area in a specified time, and for comparative purposes we express all fluxes as metric tonnes per square metre per annum.

Where amounts of fluid are provided as volumes, we have converted to mass at standard conditions of 1 ATM pressure and 0°C, using the ideal gas constant corresponding to the type of gas, where needed.

In this study we assume an arbitrary threshold leakage rate of one tonne per day to distinguish between very minor low-rate escape (here termed “seeps”) and higher-rate leaks.

For convenience, we consider probabilities to be effectively ‘negligible’ when they are smaller than 0.00003% (i.e. a likelihood of less than 1 in 3.3 million).

Punctuated leakage events of short duration (such as leakage from a well that is subsequently remediated, detailed in Supplementary Notes C and D) are typically expressed as probabilities of leakage per year per well. More protracted leakages (typically smaller magnitude events occurring over longer time periods) are generally expressed as the probability of occurrence over the whole lifespan of a storage period, including the period during CO_2 injection, plus a specified post-injection period typically of long duration.

1.4 Site-specific vs. generic leakage probabilities

There is a wide range of geological factors that determine the suitability of a potential site for CO_2 storage. Because these factors can vary significantly between different areas, an extensive and detailed geological characterisation and risk assessment must always be carried out for every prospective storage site. In the UK this is strictly controlled by a permitting process managed by the North Sea Transition Authority (NSTA, https://www.nstauthority.co.uk/the-move-to-net-zero/carbon-capture-and-storage/).

The risks of geological leakage derived for a specific site will be applicable to that site only, and cannot be applied to other storage sites where geological conditions may be markedly different. While specific site appraisals will always be required, there is nevertheless also a need for a more generic assessment of likely ranges of leakage probabilities, rates, and durations, to support the regulatory and fiscal frameworks necessary for development of CCS in the UK and beyond. In this study we derive general ranges of leakage probabilities and rates by collating data from a number of different site appraisals, and a range of additional geological data sources, described in more detail below.

Our assessments of leakage risk aim to provide current best estimates for “reasonable worst case” leakage events for typical prospective offshore CO_2 storage sites on the UKCS. An important premise in our study is that potential storage sites that contain unacceptably high leakage risks will not be granted a storage permit by the UK regulators. Geological leakage scenarios may exist that have leakage magnitudes outside the ranges that we have derived, however we consider the probability of such events to be negligible for permitted sites on the UKCS. Our ranges of values of leakage risk need to be re-assessed before they are applicable to areas beyond the UKCS with contrasting geology or different site permitting regulations.

In our general assessment of leakage risks we provide ranges of values for leakage probability and leakage rates. The extents of these ranges reflect two factors; firstly, that there is significant variability in the geology between different permittable sites on the UKCS, and secondly, that there is still some scientific uncertainty in many detailed aspects of the geological processes that influence CO_2 storage.

1.5 Qualitative comparison of risks in different types of storage site

This section includes overall comments on geological storage sites, including a qualitative comparison of depleted oil and gas field stores, fully or partially confined, and open saline aquifer stores (see Table 1 and Table 2).

In general, the geology of saline aquifers makes them no more prone to leak than depleted oil and gas fields. However, assessed geological risks are usually lower for depleted fields than for saline aquifer sites because depleted fields have already demonstrated a high degree of containment over millions of years (assessed risk in saline aquifers will also be reduced if dynamic data indicate different pressure regimes in the reservoir and overburden). Furthermore, extensive data and knowledge accrued during hydrocarbon exploration, development and production will provide a greater level of sub-surface characterisation than is available for most prospective saline aquifer sites, and this gives improved understanding of how the injected CO_2 is likely to behave. Nevertheless, some risk of leakage remains for depleted UKCS oil and gas fields (even those that were ‘filled-to-spill’ prior to production), particularly for fields that remain in the hydrocarbon generating window today. It is possible that some pathways have been leaking (albeit at low flow rates) over geological time, with lost hydrocarbons continuously replenished (re-charged) by freshly generated oil or gas. Small leakage volumes would be unlikely to have been detected prior to field development, and the pressure depletion during production may have prevented further leakage.

In confined sites (depleted fields and fully or partially confined saline aquifers), uncertainty will usually be highest at the start of injection and will then typically reduce with time (although any erroneous assumptions in modelling the site could mean the risk profile increases). In contrast, in open saline aquifer sites uncertainty does not diminish with time in the same way, because the plume continues to migrate after injection has stopped, and therefore may come into contact with additional geological features that could represent further potential leakage pathways.

Geological Leakage Pathway	Comments	Depleted field site	Saline aquifer: fully or partially confined site	Saline aquifer: open site
Seal	Evidence of different fluid regimes across the seal would reduce risk. Seal has largely been proven over geological time for a depleted field (in fill-to-spill fields must have either not leaked at all or been replenished implying low leakage rates).	Negligible risk	May have lower risk than 'open' site. Equivalent risk to open site per unit area	May have higher risk than confined site (if plume continues to migrate across larger area after injection)
Faults/ fractures	Faults can be sealing or transmissive. Behaviour will be broadly known for a depleted field (though low leak rates could be undetected).	Lower risk	Higher risk	Higher risk
Induced faults/ fractures	This risk links to knowledge of the fracture pressure/reactivation pressure for the seal and knowledge of pressure transmission within the reservoir.	Lower risk	May be higher, depends on changes in storage site pressure	May be higher, depends on changes in storage site pressure
Gas pipes/ chimneys	Gas phase is visible in seismic data whilst active (any leak via gas chimney containing CO_2 or natural gas). Sub-seismic chimneys will be less visible.	Lower risk	Higher risk	Higher risk
Lateral migration	Highest confidence in structural closure with significant relief. Presence of free natural gas could increase buoyancy, leading to increased lateral migration.	Lower (might be higher if CO_2 plume mixes with residual natural gas)	Lower risk	Higher risk than confined site (if plume continues to migrate across larger area after injection)

Table 1. Overall qualitative comparison of relative risks between different types of storage site

Geological anomaly or mechanism	Depleted field	Saline aquifer	Mitigation
Pressure transmission / dissipation	Lower risk (lower uncertainty at start of operations)	Higher risk	Slower injection, more injection wells (might also require brine production).
Reservoir efficiency (e.g. bypassing porosity by high perm streaks)	Low but not zero (different buoyancy and viscosity than hydrocarbons)	Higher	Change injection intervals/rates/revise injection strategy.
Induced seismicity	May be slightly lower	May be slightly higher	*In extremis* cease injection. Set by regulator.
Compartmentalisation of the reservoir	Extremely low risk	Higher risk	Could require more wells to be drilled, or site to be closed.

Table 2. Non-leakage issues that may have an impact on the operational lifespan of a site (that could require mitigation including permanent cessation of injection)

2. Migration of the CO_2 plume

Understanding the migration path of the injected CO_2 plume is a critical part of the assessment of leakage risk for any storage site; it constrains the earliest time that CO_2 will be in the vicinity of specific potential flow pathways, and therefore directly influences the reasonable worst case duration times for leakage events in this study. For open saline aquifer sites, prediction of the plume migration path should also provide confidence that CO_2 will not migrate laterally beyond the limits of the storage complex.

Since plume migration predictions are derived from numerical modelling based on the interpreted geology of the storage complex, there must always be some inherent uncertainty on the validity of the modelling outputs. This emphasises the importance of both careful geological characterisation of the storage complex prior to CO_2 injection, and ongoing monitoring of the site throughout its entire operational period in order to detect significant irregularities in storage site performance. Case studies of real-world CCS sites such as Sleipner and In Salah are important because they show that storage site performance does not always match pre-injection modelling, and that monitoring results can be used to iteratively improve modelling, and to improve confidence in long-term predictions of site behaviour. Experience demonstrates that unexpected behaviour of CO_2 in the subsurface can be identified from monitoring data which enables site models to be updated and mitigation actions to be taken early where needed, long before a resultant CO_2 leak to surface could occur.

In this report, leakage probabilities and reasonable worst case leak magnitudes assume that there is a regulatory permitting process in place to ensure that prospective site operators have robust static and dynamic models and comprehensive MMV (measurement, monitoring and verification) plans in place. Risks could be significantly different for regions beyond the UKCS with contrasting regulations, or for the UKCS in the unlikely event that the current regulatory framework were weakened.

3. Leakage through caprocks

In this report we use the terms “top seal” and “caprock” synonymously. In general, the term “seal” implies “top seal”, unless otherwise stated or clear from the context. This section addresses potential leakage through continuous, intact caprock, and leakage that could arise due to lateral variability in seal quality. Leakage via discontinuities such as faults, fractures, and other seal by-pass features is considered separately in later sections.

Prior to permitting of a CO_2 storage site, considerable effort will be placed on characterisation of the seal. This is particularly important for saline aquifer sites (since sealing capability over geological time will generally be unproven). However, sites in depleted oil and gas field may also need significant work to improve understanding of seal properties, as less focus may have been placed on the seal during hydrocarbon exploration (compared with other elements of the hydrocarbon system).

To confirm the sealing capability (“seal quality”) of a caprock, it is necessary to assess the thickness of the caprock unit, its lateral continuity across the entire storage site, its geomechanical properties, any geochemical response to CO_2, and the likelihood of caprock heterogeneity; i.e. the possibility that seal quality decreases laterally (or vertically) away from the sampled sections of the caprock. Kaldi *et al.* (in IEAGHG 2011) express these parameters in terms of the “Seal Potential”, which is a function of:

- Seal Capacity (the calculated column height of CO_2 that can be supported by the capillary properties of the caprock, derived from laboratory testing of rock samples of the seal lithology).
- Seal Geometry (areal extent, thickness, and lateral continuity of the caprock, derived from interpretation of seismic and well data).
- Seal Integrity (brittleness of the caprocks, based on geomechanical analysis; Ingram & Urai 1999).

The effectiveness of typical seals found in the UKCS, and the extremely low likelihood of CO_2 leakage through intact seals is thoroughly addressed by Mathias 2012a, with much supporting evidence from Hildenbrand *et al.* 2004, Busch *et al.* 2008, 2010, Angeli *et al.* 2009, Underschultz 2009, Shukla *et al.* 2010, Wollenweber *et al.* 2010, IEAGHG 2011, Deflandre *et al.* 2013, Kaldi *et al.* 2013, Gasda *et al.* 2017, Harrington *et al.* 2018a, 2018b, and many others.

3.1 Leakage mechanisms through intact caprock

The two main mechanisms of leakage through intact caprock are molecular diffusion and capillary membrane breakthrough (see comprehensive descriptions in IEAGHG 2011 and Mathias 2012a). Rates of molecular diffusion are governed by the effective diffusion coefficient of a given caprock, and are usually derived from laboratory-based diffusion experiments (Busch *et al.* 2008, 2010). CO_2 capillary breakthrough pressures are estimated from experimental testing of caprock samples, for example using mercury injection (e.g. Hildenbrand *et al.* 2004, Li *et al.* 2005, Angeli *et al.* 2009, Wollenweber *et al.* 2010).

3.2 Leakage due to lateral variability in seal quality

Although data derived from boreholes that penetrate the seal can provide very important constraints on seal properties, in areas further away from the borehole(s) there is a risk of reduction in seal quality due to lateral facies changes. Resultant changes in lithology might lead to an increase in grainsize (with greater porosity and permeability, and larger pore throat sizes), and/or a change in geomechanical properties, such as a decrease in plasticity (increase in brittleness) of the seal.

In depleted oil and gas fields, the risk of high leakage rates is inherently extremely low (negligible). For saline aquifer sites, because much is already known about the likely continuity of the main sealing units around the UKCS, the risk of poor seal quality is also generally low, however a residual risk remains. An important factor is that lateral heterogeneity in seal quality may not be easily detectable in seismic data. A relevant line of evidence related to the risk of poor-quality seals is provided by analysis of unsuccessful hydrocarbon exploration drilling (including Schofield 2016, Mathieu 2018, Quirk & Archer 2020a, 2020b). Risk could be greatly mitigated by suitable pressure data from the storage complex, and further sampling and testing of seal units from additional wells that are more widely distributed across the potential storage site.

3.3 Leakage amounts and leakage rates through caprock

There is a strong scientific consensus that the risk of leakage of injected CO_2 through a good quality, intact caprock is extremely low, and for most UKCS storage sites this risk will be negligible. This section shows that although some types of caprock will eventually allow a low rate of gas escape, there is very high confidence of storage containment because background leakage of this type is a *very* slow geological process (measured over geological rather than human timescales).

Some lithologies (e.g. some evaporites) exhibit such low permeabilities that leakage amounts would be undetectable, and inconsequential even across the whole area of a storage complex and over considerable geological time. Fine-grained clastic rocks (mudstones, shales) can have somewhat higher permeabilities. For example, typical gas fluxes due to molecular diffusion range between 10^{-4} and 10^{-7} tonnes per square metre per year, while those for capillary flow are 10^{-3} to 10^{-4} tonnes per square metre per year (Krooss & Leythaeuser 1996). This shows that the amount of gas moving through a large area of intact caprock can eventually be significant, as demonstrated by estimates of natural methane leakage through intact caprock (Hovland *et al.* 1993, Clayton & Dando 1996, Judd *et al.* 2002). Although flux rates of gas escape are very low, the large areas over which ongoing background leakage is occurring means that overall annual flow rates are large (Judd *et al.* 2002 estimate the total annual methane loss from the UKCS to be between 1.2 and 3.5 million tonnes per annum; note this includes both biogenic and thermogenic gas, and includes leakage via a combination of pathways). However, the critical factor is that seepage rates through typical intact caprocks and overlying strata are so low that even if this type of leakage occurs, there will be a time delay of thousands to millions of years before CO_2 that is injected now could first start to reach the seabed surface. Busch *et al.* 2010 modelled the time needed for CO_2 to migrate by molecular diffusion through shale caprock with an effective diffusion coefficient of 10^{-10} m^2s^{-1}, porosity of 0.1, and top reservoir at 2000m depth. Applying this method to our ‘typical’ UKCS sites, and retaining similar conservative values for the effective diffusion coefficient and porosity, it would take over a million years for CO_2 to reach the seabed.

In summary, although containment certainty of injected CO_2 is high over human timescales, an important corollary is that many basins (including parts of UKCS) show evidence for ongoing escape of natural gasses; these includes both shallow biogenic methane, and also deeper thermogenic methane (presumably with associated naturally occurring CO_2 in some locations) that began its extremely slowly migration through the caprock and overburden tens or hundreds of millions of years ago.

High rates of leakage due to lateral variability in seal quality are precluded in depleted oil and gas fields. In saline aquifer sites potential leakage rates could conceivably be somewhat higher, because although flux rates are likely to remain relatively low, the areal extent over which leakage may occur could be several square kilometres per storage site. Relative risk is lower in fully or partially confined than open saline aquifer sites (Table 1).

3.4 Possible damage to caprock during depletion of an oil & gas reservoir.

It has been suggested that oil and gas fields may experience depletion-induced damage during production (Zoback & Zinke 2002, Streit & Hillis 2004). This is of importance because it could potentially compromise the integrity of fault and caprock seals, and therefore imply an increased probability of leakage and increased leakage rates, irrespective of the fact that containment certainty can be assumed prior to field development. In this regard, the conclusion of Manzocchi *et al.* (2010) is important:

> *“failure of intra-reservoir sealing faults can occur during a reservoir depressurization via a water-drive mechanism, but contrary to anecdotal reports, published examples of production-induced seal failure are elusive.”*

4. Leakage via faults and fractures

Faults and fractures provide potential leakage pathways from the storage reservoir because they can (though generally do not) have permeabilities that are several orders of magnitude higher than the surrounding matrix of the caprock. Assessment of the leakage risk due to faults and fractures can be challenging, because of the inherent complexity and heterogeneity of many fault zones, and because fluid flow can sometimes be influenced by a background network of small-scale faults and fractures that are below the resolution of seismic data.

4.1 Leakage mechanisms related to fault zones

The potential for fluid to flow along a fault zone (laterally and up/down dip), or across the fault zone, is dependent on the 3D displacement profile of the fault, and the properties of fault rocks within the fault zone. Leakage along or across a fault can occur by the following mechanisms:

- Juxtaposition leakage, typically constrained by juxtaposition analysis of each fault (Allan 1989, Knipe 1997, Bretan *et al.* 2011, Yielding *et al.* 2011).
- Membrane leakage, controlled by the capillary threshold pressure of the fault rocks (Manzocchi *et al.* 2010), and typically evaluated stochastically using estimates of shale gouge ratio (SGR) as a proxy for the height of the fluid column that the fault is likely to contain (Yielding *et al.* 1997, Yielding 2002).
- Reactivation of existing faults, and the initiation of new faults and fractures (this is considered later in a separate section).

4.2 Probability of leakage via fault zones

Assessment of the probability of leakage across faults is done on a site-specific basis. An important requirement for quantitative appraisal is that the quality of seismic data needs to be good enough across the full extent of the storage complex for faults to be mapped in sufficient detail to evaluate juxtaposition and calculate SGR for all mapped faults.

The likelihood of significant fault leakage is very much reduced in depleted oil and gas field sites (compared with saline aquifer sites). Not only has containment over geological time been proven, but there will often be greater understanding of the geomechanical properties of the caprock and reservoir, and production history data provides key constraints on reservoir compartmentalisation and response of the reservoir to changing pressure (e.g. Clarke *et al.* 2017). The probabilities that we provide for fault leakage in depleted oil and gas field stores assume that the CO_2 storage site operator has access to the original geoscience analyses and field production data, and has a full history-matched model for the site. The absence of such data is likely to increase the uncertainty of the site appraisal during the CCS permitting process.

The greater probabilities of fault leakage inferred for saline aquifer sites reflect both the lack of proven fluid containment over geological time, and the increased uncertainty about geological properties of the reservoir and caprock. An important exception is when there is data available to show clearly contrasting pressure regimes between the saline aquifer and the overburden/underburden. In the absence of data from the proposed storage complex, effective characterisation of seals through surveys and core testing would help to reduce this uncertainty.

4.3 Leakage rates and amounts via faults and fractures

Constraints on likely ranges of reasonable worst-case leakage rates for faults and fractures are based on data collated from the following categories of analyses:

- Naturally occurring CO_2 seeps (Rogie *et al.* 2000, Faulkner & Rutter 2001, Pearce *et al.* 2002, 2004, Lewicki *et al.* 2007, Busch *et al.* 2010, Chiodini *et al.* 2010, Burnside *et al.* 2013, Nickschick *et al.* 2015, Bond *et al.* 2017, Roberts *et al.* 2018, Miocic *et al.* 2019).
    - As well as providing evidence of possible leakage rates, natural CO_2 repositories demonstrate that CO_2 can be stored successfully in the sub-surface over geological time, even when faulted (e.g. Yielding *et al.* 2011, Burnside *et al.* 2013, Miocic *et al.* 2019).
    - Reported leakage rates from natural CO_2 stores range between a few tonnes to several hundred thousand tonnes per annum. High rates of reported leakage are all from tectonically and/or volcanically active regions, and are not representative of geological conditions in the UKCS.
    - Measured flow amounts at localised gas vents on a fault zone are typically given as a leakage flux. Because fault zones are typically heterogeneous, care is needed when upscaling measurements from individual point source leaks to the entire length of the fault zone. Another source of uncertainty is that leakage rates in some faults may be intermittent, or vary with season (e.g. Jones & Burtell 1996, Klusman 2003).
    - Further work is needed to study suitable outcrop analogues where CO_2 has (or may have) interacted with faults, fault rocks, and faulting processes (e.g. Rushton *et al.* 2020).
- CO_2 leakage experiments (Lewicki *et al.* 2010, Roberts *et al.* 2018).
- Calculated gas leakage rates via faults inferred for hydrocarbon basins (Watson *et al.* 2008, Evans 2008, Keeley 2008, Smeraglia *et al.* 2022).
- General rates of fluid flow estimated for faults (Eichhubl & Boles 2000, Wilkins & Naruk 2007).

- Numerical modelling of fault zones (Moretti 1998, Chang *et al.* 2008, Scandpower 2010, 2012, Preuss 2011, Nakajima *et al.* 2014).
    - Care is needed in applying the results from modelling of fault zones. Simplistic models that assign very high permeabilities (e.g. 1000 mD) to the full fault damage zone and along the entire length of a fault are unlikely to be representative of real fault zones, and can result in unrealistically high rates and fluxes (e.g. Chang *et al.* 2008, Scandpower 2012).

4.4 Sub-seismic fault and fracture networks

The risk of leakage on a sub-seismic network of faults and fractures is difficult to assess. In depleted oil and gas fields, and sites with thick evaporitic seals, the risk is likely to be very low, and maximum likely leakage rates are constrained by the proven containment of hydrocarbons prior to production. In saline aquifer sites with shale caprocks, the geological and geomechanical uncertainties are higher, and leakage risk may be greater.

There is a danger that leakage risk via fracture networks will be underestimated, perhaps in part because small-scale fractures are hard to detect and characterise in the sub-surface, and also because of an erroneous assumption that dilational fractures will sufficiently reseal under compression to prevent fluid flow. In reality, fracture surface morphology (roughness), small asperities, and fracture bridges (Laubach *et al.* 2004a, 2004b) can all cause fracture permeability to be retained.

While much published work exists on the characterisation of naturally fractured reservoirs (e.g. Nelson 2001), there has been much less focus on natural fracture systems in fine grained clastic rocks, though shale gas exploration has led to a new research impetus in recent years (e.g. Ferrill *et al.* 2014, Gale *et al.* 2014, Imber *et al.* 2014, Petrie *et al.* 2014). Further work is needed to characterise natural fracture systems and evaluate their impact on seal quality in mudstones and shales.

Estimation of the abundance (spatial intensity) and size (length, height, damage zone width, throw) of sub-seismic scale faults generally uses published scaling relationships (e.g. Childs *et al.* 1990, Torabi & Berg 2011). Scandpower 2010, 2012 use this approach applied to CCS site appraisal. Prediction of flow magnitudes using Discrete Fracture Network (DFN) modelling can also capture the multiscale flow behaviour in connected fracture systems (e.g. Iding & Ringrose 2010). Recently, the EU-funded DETECT project has addressed the risk of CO_2 leakage via fractures in the caprock using a multi-disciplinary and multiscale approach (Dean *et al.* 2020), and has set a new benchmark standard in the assessment of leakage via the fault and fracture network (Snippe *et al.* 2021).

Production data from the shale gas industry can provide useful constraint on possible flow rates though fine grained clastic caprocks. Obviously considerable care is needed, since the overall engineering aim of maximum gas flux in a shale gas production environment is diametrically opposite to the maximum containment security required in CCS (for example, enhanced flow rates are achieved through the use of proppants and high reservoir pressures). Nevertheless, shale gas production data can provide upper limits on likely maximum flow rates via fractures. There is extensive literature related to shale gas; useful papers with production data include: Valko 2009, Warpinski *et al.* 2009, Kennedy *et al.* 2012, Patzek *et al.* 2013, Shelley *et al.* 2013, Walton & McLennan 2013, Alarifi 2021a, 2021b, Wachtmeister *et al.* 2021, (and many others). It is important to emphasise that production from some "shale gas" reservoirs is from fine-grained tight sandstones (rather than very fine-grained clay-rich shales typical of the best seals), which would not likely to be accepted as viable caprocks in a prospective CO_2 storage site for the UKCS.

4.5 Induced faulting and fracturing

The risks outlined above are associated with leakage via pre-existing static (seismically inactive) faults and fractures. Ongoing CO_2 injection into a storage site leads to increasing reservoir pressure, which if unchecked would eventually reduce the frictional strength of existing faults sufficiently to cause them to reactivate (Hubbert & Rubey 1959, Sibson 1994), or would exceed the effective tensile strength of the intact rock causing new fractures to form.

4.5.1 Reactivation of existing faults

The probability that existing faults (or fractures) will reactivate is generally likely to be lower for depleted oil and gas field stores than for saline aquifer stores, provided that reservoir pressures during CO_2 injection are kept well within the original pre-production pressure in the reservoir. The assessment of the likelihood of reactivation requires careful geomechanical analysis of the storage site lithologies (Streit & Hillis 2004, Rutqvist *et al.* 2007, 2008, 2012, Rinaldi *et al.* 2014). Risk of reactivation can be evaluated using slip tendency (fault stability) analysis (Morris *et al.* 1996). Examples of this approach applied to shales and/or CO_2 storage sites include Williams *et al.* 2016, 2018, Gamboa *et al.* 2019, and Nantanoi *et al.* 2022. There is greater uncertainty over transmission of pressure within saline aquifer storage sites (that do not have historical production data).

Likely amounts and rates of leakage due to fault reactivation are difficult to assess. Reactivation might cause isolated leakage events (periodic 'belching' on the fault; see the fault-valve concept of Sibson 1990), or could change the permeability structure of the fault zone by opening new, more long-lived leakage pathways. Leakage volumes could be represented in site-specific assessments as single amounts (as we have used in this study), or as a multiplier of the leakage risk evaluated for pre-existing faults in the site.

4.5.2 Initiation of new fractures

The probability of inducing new faults and fractures should generally be low, particularly in well-monitored depleted oil and gas field stores in which comprehensive geomechanical analysis has been carried out, and where reservoir pressure is kept below pre-production levels. In all situations care is needed to ensure that reservoir pressure is well within the effective tensile strength of the caprock to avoid generation of hydraulic fractures. Although likelihood of occurrence is low given design and monitoring to ensure the site remains below fracture initiation pressure, the potential impact of hydraulic fractures in fine grained clastic caprocks can be significant (Ringrose *et al.* 2013). Fisher & Warpinski 2011, Davies *et al.* 2012, 2013, and Lacazette & Geiser 2013 have described data from micro-seismic monitoring that shows induced fracturing can elicit a response several hundred metres vertically above (and below) the active well (taken to be associated with fracture initiation, propagation, and/or slip). Careful monitoring of pressure in the storage site also needs to ensure that unexpected localised pressure build-up does not occur due to compartmentalisation of the reservoir (e.g. Castelletto *et al.* 2013).

4.5.3 Induced seismicity

Reaction of existing faults or initiation of new fractures may be accompanied by minor seismic activity, of which larger events may be detectable with local micro-seismic monitoring. This is extremely useful for effective site management, as it gives advance warning of potential significant irregularities in storage site performance (e.g. In Salah CCS site, Ringrose *et al.* 2013). Aspects of induced seismicity associated with CO_2 storage are addressed by Nicol *et al.* 2011, Mazzoldi *et al.* 2012, Kaldi *et al.* 2013, White & Foxall 2016, and others. Issues raised by Zoback & Gorelick 2012, 2015 have elicited rebuttals from the CO_2 GeoNet 2012 and Vilarrasa & Carrera 2015 in relation to storage sites in Europe (and UK), however may have relevance for other regulatory jurisdictions.

5. Leakage via other seal bypass systems

Cartwright *et al.* (2007) presented a classification scheme for a range of features that collectively represent ways in which the containment capability of a seal may be bypassed. These include a class of sub-vertical chimney-like features that have been recognised in 3D seismic in many basins, including the UKCS, and which are interpreted to be gas escape pipes. They occur across a wide range of scales (Robinson *et al.* 2021), including examples in outcrop that would be below seismic resolution, though can be over 1km in height and tens to hundreds of metres wide (Løseth *et al.* 2001, 2011, Davies *et al.* 2012. 2013). Where they reach the seabed, they are commonly associated with pockmarks (Judd *et al.* 1994, Judd, 2001, Judd & Hovland 2007, Callow *et al.* 2021). Similar features have been observed that developed as a consequence of a controlled CO_2 release experiment in the shallow sub-surface, 100km south-east of the Goldeneye complex in the UK North Sea (Roche *et al.* 2021). Gas chimneys have been observed in the reservoir and overburden at the Sleipner CCS site, and have been invoked during history-matching of the reservoir behaviour (Williams & Chadwick 2018). There is no evidence for CO_2 leakage from the reservoir at Sleipner.

Although we treat them here as a separate category for risking purposes, there can be an intimate association between gas chimneys and faults (see Fig.3 of Sibson 1994), and the margins of many chimneys are defined as a set of polygonal faults (Cartwright *et al.* 2007).

Probability of moderate or high leakage via gas chimneys is very low for depleted oil and gas fields, and for saline aquifer stores with good quality seismic data (i.e. any permittable site on the UKCS). The main risk is of very low amounts of leakage via poorly imaged sub-seismic scale features. Methane leakage rates estimated from bubble streams observed in North Sea pockmarks, reported by Hovland & Judd 1992, Clayton & Dando 1996, Judd & Hovland 2007, Evans 2008, and Li *et al.* 2020, range from less than a tonne to over 2,500 tonnes per annum. At present we treat the rate of 45,000 tonnes per annum reported by Tkeshelashvili *et al.* 1997 from a pockmark in the Black Sea as an outlier that requires further confirmation.

6. Irregularities in lateral plume migration

Lateral plume migration refers to migration of CO_2 laterally along the storage formation (rather than vertically) and for open sites could lead to the plume migrating beyond the confines of the storage complex (depending on the structure of the site). This risk will be site-specific, relating not just to geological factors but also to the decision by the operator (and agreed with the regulator) on the location of the boundaries of the storage complex. To lead to a leak to atmosphere lateral migration would require migration from the storage complex and then to surface, usually requiring combined pathways to leak to seabed.

Migration of the CO_2 plume is most uncertain at the start of operations, leading to quite large ranges in possible extent by the end of injection (Pawar *et al.* 2017). Jackson & Krevor 2020 note that unpredicted and rapid plume elongation has been observed in five out of six reviewed subsurface CO_2 storage projects due to uncertainty in fluid thermophysical properties, poorly imaged topography, or centimetre-to-metre scale heterogeneities. Monitoring during injection will inform the model, reducing the potential uncertainties in the range of plume extent as injection progresses (e.g. Dance *et al.* 2019). Cavanagh 2013, when discussing the CO_2 plume at Sleipner, provides evidence on the short time over which the modelled plume behaviour aligned with actual observed plume behaviour. The plume is predicted to stabilise 'very quickly after injection ceases' rather than decades or centuries afterwards.

The risk of lateral migration, like other risks, is site specific. The probability of CO_2 migrating beyond the boundaries of the storage complex within an open aquifer storage site is higher than for a confined site (Jackson & Krevor 2020), because in an open site the plume could continue to migrate after injection ceases. In open sites there is typically also a poorer understanding of pressures and connectivity in the reservoir. Lateral migration rates link to the balance of viscous (injection) versus capillary forces (Sarris & Gravanis 2019). Rates of migration will vary significantly between sites (at Sleipner, Chadwick *et al.* 2008 report a rate of lateral plume migration of one metre per day). Leakage rates to surface that involve lateral migration beyond the pre-defined storage complex could be limited by any secondary potential leakage pathway encountered.

Lateral migration is impacted by aquifer topology, porosity, permeability contrasts, overall permeability, injection rate (Jackson & Krevor 2020, Dance *et al.* 2019), the length of well over which injection occurs, well orientation, fluid salinity (Al-Khdheeawi *et al.* 2017) and even the presence of natural gas (Ghanbari *et al.* 2020). Additionally and significantly, lateral migration rates and the time over which this risk remains high are linked to the extent and transmissivity of the connected aquifer (Pawar *et al.* 2017).

7. Overall leakage rates

7.1 Data sources used for assessment of leakage rates and fluxes

The wide range of documented methods and data types used to constrain the range of potential leakage rates and fluxes are described earlier in Sections 3 to 6 for the different geological leakage pathways.

7.2 Assessment of leakage rates: Results

Our overall assessments of reasonable worst-case ranges of generic leakage rates (in tonnes per day and tonnes per annum) for UKCS depleted oil and gas field stores, and for saline aquifer stores, are given in Table 3.

Explanatory notes for Table 3:

a. Leakage rates given here are for generic CCS sites on the UKCS, and assume a robust permitting process.
b. Probabilities for saline aquifers refer to a partially or fully confined (rather than open) site.
c. Capillary flow and diffusion are very slow processes in fine-grained clastic lithologies. Some leakage might start to occur over geological time (after thousands to millions of years for a 100m thick shale), but not over shorter timespans. Rates for evaporite seals are generally even slower. Conversely, leakage rates in poor quality seals can be significantly higher.
d. These flow rates are based on seal quality (in 100-400m caprock) deteriorating laterally such that permeability is 10^{-17} to 10^{-16} m^2 (10^{-2} to 10^{-1} mD). Informed by Hou *et al.* 2012. Based on Darcy flow equation, and assumes 20% of gas will leak through the caprock; i.e. the caprock seal has changed laterally to become the equivalent of a (very) poor quality reservoir with low-end 'recovery factor'.
e. These are very large fault zones typically located at or near active plate margins - and hence not applicable for UKCS. (This does not imply that the UKCS is seismically quiescent; there are natural earthquakes, both onshore and offshore, however frequency and magnitude are much lower than at active plate margins).
f. All analogue examples of observed very high fluid fluxes (CO_2 or CH_4) are from volcanic and/or tectonically active regions.
g. Fault zones large enough to have potential juxtaposition leakage, as well as risk of fault membrane leakage, plus enhanced damage zone permeability.
h. Maximum leakage rate capped because of proven containment of hydrocarbon field.

i. Size of these faults is much smaller than the overall size of a storage structure, but is potentially big enough for the damage zone to extend through a moderately thick seal. Lower risk of juxtaposition leakage.

j. Negligible consequence as isolated features, but could collectively enhance permeability as a connected network of small-scale faults/fractures, and/or serve to connect larger faults or other higher permeability features.

k. Induced faulting/fracturing refers to initiation of new fractures within the caprock (not specifically the reservoir). Problems with induced faults/fractures are only likely to arise if the pressure response during injection is highly unexpected. The likelihood of this for depleted fields should be very low as long as the storage operator has the original hydrocarbon production data (including history matched production models).

l. Inherently higher risk for saline aquifers than depleted fields because the pressure transmission within a saline aquifer store is more uncertain than within a depleted field store (particularly prior to CO_2 injection), and because less is generally known about the geomechanical properties of both the reservoir and the seal over the full extent of the storage site in a saline aquifer. Additional risk will arise if reservoir pressures are permitted to rise above original fluid pressures,

m. Leakage caused by increased fluid pressure on critically stressed fractures. Could be accompanied by likely low-magnitude seismicity. Would not necessarily cause major increase in long-term leakage rates; might initially cause localised short-lived episodic escape ('burps') via faults.

n. Induced hydraulic fractures. Not likely in depleted fields unless pressure response is not as anticipated for CO_2 injection. In worst case hydraulic fractures could be hundreds of metres high and hence cut the entire thickness of caprock, though initially this would be localised at structural highs and flow rates are likely to be low (this risk highlights the importance of site monitoring).

o. There is higher risk for an aquifer than a depleted field store that baffles will unexpectedly focus the plume into localised compartments and hence cause pressure to increase within that compartment.

p. Understanding of the importance of gas chimneys as seal bypass features has increased over the last 15 years. Good 3D seismic is a major help to recognise their presence and to quantify diameter and depth.

q. Most chimneys described from UKCS are likely to be towards the lower end of this range, particularly for depleted oil and gas fields.

r. Risk of lateral migration is extremely site-specific, and generic risks are poorly constrained. Only part of the risk is technical, also links to the definition of the storage complex as agreed with the regulator. Indicative leakage rates shown here are simply based on averaged values of the other types of leakage pathways for the site.

Pathway Type	Leak mechanism / category		Context of probability estimate [a]	Depleted Oil & Gas Fields			
				Leak rate (tonnes/day)		Leak rate (tonnes/year)	
				max	min	max	min
Through caprock	diffusion		10x10m area, after 1,000,000 years [c]	2.74E-06	2.74E-08	1.00E-03	1.00E-05
	capillary flow through intact caprock		10x10m area, after 1000 years [c]	2.74E-05	2.74E-09	1.00E-02	1.00E-06
	lateral variability in seal quality		1x1km area, after 100 years [d]	4.30E+01	4.30E+00	1.57E+04	1.57E+03
Faults (and fractures)	major tectonically / volcanically active fault zone [e]		per fault zone	5.48E+03	2.74E+01	2.00E+06 [f]	1.00E+04
	large block-bounding fault zone [g]		per fault zone	2.74E+00 [h]	2.74E+00	1.00E+03 [h]	1.00E+03
	map-scale faults [i]	seep	per fault zone	1.00E+00	2.74E-01	3.65E+02	1.00E+02
		minor		2.74E+00 [h]	1.00E+00	1.00E+03 [h]	3.65E+02
	sub-seismic scale faults & fracture network [j]	seep	per site	1.00E+00	2.74E-02	3.65E+02	1.00E+01
		minor		2.74E+00 [h]	1.00E+00	1.00E+03 [h]	3.65E+02
Induced faulting / fracturing [k]	reactivation of pre-existing faults [m]	seep	per site	1.00E+00	2.74E-01	3.65E+02	1.00E+02
		minor		2.74E+01	1.00E+00	1.00E+04	3.65E+02
	initiation of new faults/fractures [n]	seep	per site	1.00E+00	2.74E-01	3.65E+02	1.00E+02
		minor		2.74E+01	1.00E+00	1.00E+04	3.65E+02
Gas chimneys / pipes [p]		seep	per site [q]	1.00E+00	1.00E-01	3.65E+02	3.65E+01
		minor		2.74E+00 [h]	1.00E+00	1.00E+03 [h]	3.65E+02
Lateral migration [r]		seep	combined per site/ per feature.	1.00E+00	2.74E-02	3.65E+02	1.00E+01
		minor		2.74E+01	1.00E+00	1.00E+04	3.65E+02

Pathway Type	Leak mechanism / category		Context of probability estimate [a]	Saline Aquifers [b]			
				Leak rate (tonne/day)		Leak rate (tonnes/year)	
				max	min	max	min
Through caprock	diffusion		10x10m area, after 1,000,000 years [c]	2.74E-06	2.74E-08	1.00E-03	1.00E-05
	capillary flow through intact caprock		10x10m area, after 1000 years [c]	2.74E-05	2.74E-09	1.00E-02	1.00E-06
	lateral variability in seal quality		1x1km area, after 100 years [d]	4.30E+01	4.30E+00	1.57E+04	1.57E+03
Faults (and fractures)	major tectonically / volcanically active fault zone [e]		per fault zone	5.48E+03	2.74E+01	2.00E+06 [f]	1.00E+04
	large block-bounding fault zone [g]		per fault zone	1.37E+03	2.74E+00	5.00E+05	1.00E+03
	map-scale faults [i]	seep	per fault zone	1.00E+00	2.74E-01	3.65E+02	1.00E+02
		minor		2.74E+01	1.00E+00	1.00E+04	3.65E+02
	sub-seismic scale faults & fracture network [j]	seep	per site	1.00E+00	2.74E-02	3.65E+02	1.00E+01
		minor		2.74E+01	1.00E+00	1.00E+04	3.65E+02
Induced faulting / fracturing [l]	reactivation of pre-existing faults [m]	seep	per site	1.00E+00	2.74E-01	3.65E+02	1.00E+02
		minor		2.74E+01	1.00E+00	1.00E+04	3.65E+02
	initiation of new faults/fractures [n]	seep	per site [o]	1.00E+00	2.74E-01	3.65E+02	1.00E+02
		minor		2.74E+01	1.00E+00	1.00E+04	3.65E+02
Gas chimneys / pipes [p]		seep	per site	1.00E+00	1.00E-01	3.65E+02	3.65E+01
		minor		8.22E+00	1.00E+00	3.00E+03	3.65E+02
Lateral migration [r]		seep	combined per site/ per feature.	1.00E+00	2.74E-02	3.65E+02	1.00E+01
		minor		2.74E+01	1.00E+00	1.00E+04	3.65E+02

Table 3. Estimated ranges of generic reasonable worst-case leakage rates for UKCS depleted oil and gas fields and partially or fully confined saline aquifer sites. (Letters in the upper-right corner of cells refer to separate notes in the text)

7.3 Collation of analogous leakage rate data

A comparison of leakage rates from a variety of types of evidence from different geological scenarios is given in Figure 1. Section 2.1 of Roberts *et al.* 2018 includes a relevant discussion on the difficulty of comparison between flow rate and flux, and the challenges of conversion between the different units variously used for either.

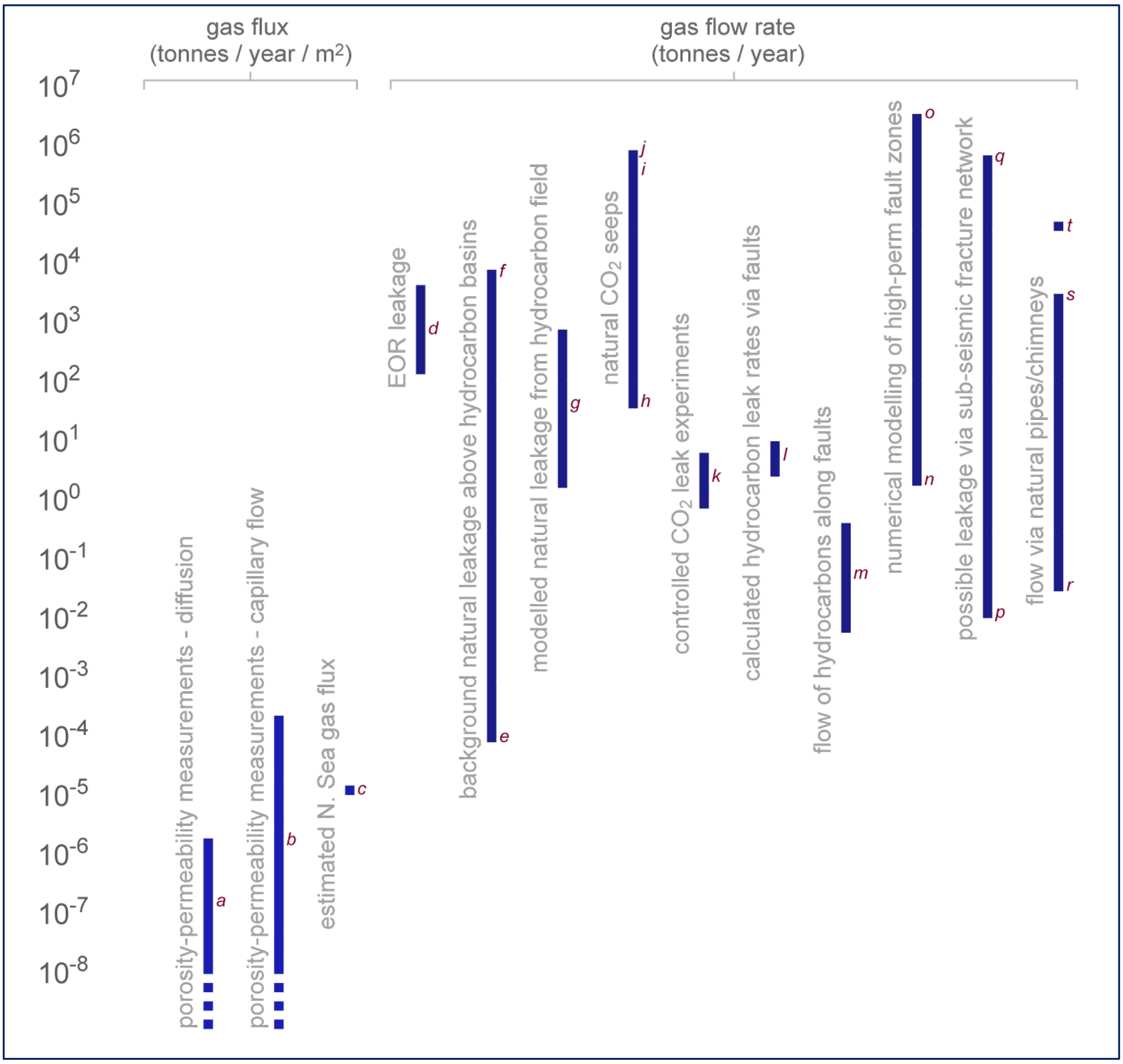

Figure 1. Collation of representative leakage rate data (log-scale). Letters next to range bars refer to explanatory notes given in the main text

Explanatory notes for Figure 1:

a. Krooss & Leythaeuser 1996; Busch *et al.* 2010.

b. Hildenbrand *et al.* 2004.

c. Bozec *et al.* 2005.

d. Klusman 2003; Stenhouse 2009; Roberts *et al.* 2018.

e. Judd *et al.* 2002.
f. Hovland *et al.* 1993.
g. Smith *et al.* 1971 in Table 4 of Evans 2008.
h. Roberts *et al.* 2018.
i. Lewicki *et al.* 2007; DECC2012 (Jewell & Senior 2012; Mathias 2012b).
j. Chiodini *et al.* 2010; Roberts *et al.* 2018.
k. Roberts *et al.* 2018.
l. Watson *et al.* 2008; Keeley 2008.
m. Wilkins & Naruk 2007.
n. Scandpower 2010.
o. Scandpower 2012 (extreme rate, very low probability).
p. Scandpower 2010.
q. Scandpower 2012 (extreme rate, very low probability).
r. Clayton & Dando 1996.
s. Li *et al.* 2020.
t. Judd & Hovland 2007; Tkeshelashvili *et al.* 1997.

8. Overall leakage probabilities

There are no reported leaks to surface from any current or former CCS project. These engineering successes to date are re-assuring, though not yet numerous enough to provide a robust statistical basis to assess probabilities of leakage for future CCS sites. Instead, a wide range of different types of indirect geological evidence is typically used to inform risk assessment. Significant uncertainty still exists in how best to apply these different data, and consequently, evaluations of leakage probabilities are often reached through consensus by a panel of experts. Much scope remains for important research in many aspects of geological storage of CO_2, including increased cross-disciplinary collaboration between geoscientists and statisticians.

8.1 Data sources used for assessment of leakage probabilities

For this report, our assessment of the probabilities that loss of CO_2 could occur by the various geological leakage pathways is based on our interpretation and application of the following data sources:

- Published case studies of appraisals of potential and actual CCS sites, e.g.:
    - Latrobe Valley storage assessment (Hooper *et al.* 2005).
    - Potential sites in USA evaluated within the FutureGen Project (FutureGen 2007).
    - Gorgon, Australia (Flett *et al.* 2009, https://australia.chevron.com/our-businesses/gorgon-project).
    - Sleipner, Norwegian N. Sea (e.g. Chadwick et al, 2010, 2019, Furre *et al.* 2017).
    - In Salah, Algeria (e.g. Oldenburg *et al.* 2011, Ringrose *et al.* 2013).
    - CASSEM project (Smith *et al.* 2011).
    - Weyburn-Midale project (Bowden *et al.* 2013).
    - Otway project (Cook *et al.* 2013, Dance *et al.* 2019).
    - Johansen Fm., below Troll field, Norwegian N. Sea (ZEP2019, Hoydalsvik *et al.* 2021).
    - Captain Fairway, North Sea (DETECT project, including Dean *et al.* 2020, Snippe *et al.* 2021).
- Appraisals of detailed geological characterisation of proposed CCS sites on the UKCS; (mostly unpublished). Published examples include outputs from the UKSAP project and “Key Knowledge Deliverables” documents released via GOV.UK:
    - UK Storage Appraisal Project (UKSAP, https://www.eti.co.uk/programmes/carbon-capture-storage/uk-storage-appraisal-project/, https://www.co2stored.co.uk).

  - Peterhead (Goldeneye) & White Rose (Endurance): https://www.gov.uk/government/publications/carbon-capture-and-storage-knowledge-sharing-technical-subsurface-and-well-engineering.
  - Longannet (Goldeneye): https://webarchive.nationalarchives.gov.uk/20121217154246/https://www.decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/feed/scottish_power/abstract/abstract.aspx
  - Kingsnorth (Hewett): https://webarchive.nationalarchives.gov.uk/ukgwa/20121217153852/https://www.decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/feed/e_on_feed_/e_on_feed_.aspx
  - Additional CCS Key Knowledge Deliverable documents from 8 Rivers, Acorn, C-Capture, HyNet, NEP/NZT, Tigre, and TERC, recently published at: https://www.gov.uk/government/collections/carbon-capture-and-storage-knowledge-sharing.

- Published and unpublished ranges of leakage probabilities based on expert panel decisions, e.g.:
  - Unpublished: Scandpower 2010, 2012.
  - Published: Jewell & Senior 2012, Alcalde 2018, ZEP 2019.

- Meta-studies of containment security in analogous geological scenarios:
  - Natural CO_2 repositories (e.g. Lewicki *et al.* 2006, 2007, Stenhouse 2009, Miocic *et al.* 2016, Roberts *et al.* 2018).
  - Gas storage (e.g. Benson *et al.* 2002, IEAGHG 2006, Keeley 2008, Evans 2008, 2009, Watson *et al.* 2008, Bruno *et al.* 2014, Evans & Schultz 2017, Schultz & Evans 2020, Schultz *et al.* 2020).
  - Hydrocarbon accumulation, exploration & production (e.g. Clarke & Cleverly 1991, Evans *et al.* 2003, Judd & Hovland 2007, Schofield 2016, Mathieu 2018, Goffey & Gluyas 2020, Quirk & Archer 2020a, 2020b, NSTA https://www.nstauthority.co.uk/data-centre/).

- General repositories of CCS-related information; e.g.:
  - Intergovernmental Panel on Climate Change (IPCC, https://www.ipcc.ch/)
  - IEA Greenhouse Gas R&D Programme (IEAGHG, https://ieaghg.org/)
  - Gassnova (Norwegian state enterprise for CCS, https://gassnova.no).

8.2 Assessment of leakage probabilities: Results

Our overall assessment of the range of reasonable worst-case leakage probabilities for generic UKCS storage sites in depleted oil and gas fields and partially or fully confined saline aquifers are given in Table 4.

Pathway Type	Leak mechanism / category		Context of probability estimate [a]	Depleted Oil & Gas Fields: Probability of occurrence		Saline Aquifers [b]: Probability of occurrence	
				max	min	max	min
Through caprock [c]	diffusion		after 1,000,000 years [d]	negligible for UKCS		negligible for UKCS	
	capillary flow through intact caprock		after 1,000 years [d]	negligible for UKCS		negligible for UKCS	
	lateral variability in seal quality		after 100 years [e]	negligible for UKCS [f]		5.00E-03 [g]	5.00E-04 [g]
Faults (and fractures)	major tectonically / volcanically active fault zone [h]		per fault zone	negligible for UKCS		negligible for UKCS	
	large block-bounding fault zone [i]		per fault zone	1.00E-04 [j]	1.00E-05	1.00E-03 [k]	5.00E-04
	map-scale faults [l]	seep	per fault zone [m]	1.00E-03	2.74E-04	1.00E-02	5.23E-03
		minor		2.74E-04	1.00E-04	5.23E-03 [n]	1.00E-03
	sub-seismic scale faults & fracture network [o]	seep	per site [p]	2.50E-03	2.02E-04	1.25E-02	3.35E-03
		minor		2.02E-04	1.00E-04	3.35E-03	1.00E-03
Induced faulting / fracturing [q]	reactivation of pre-existing faults [r]	seep	per site [s]	1.00E-03	5.23E-04	1.00E-02	5.23E-03
		minor		5.23E-04	1.00E-04	5.23E-03	1.00E-03
	initiation of new faults/fractures [t]	seep	per site [u]	1.00E-03	5.23E-04	1.00E-02	5.23E-03
		minor		5.23E-04	1.00E-04	5.23E-03	1.00E-03
Gas chimneys / pipes [v]		seep	per site [w]	2.50E-03	2.66E-04	1.00E-02	3.00E-03
		minor		2.66E-04	1.00E-04	3.00E-03	1.00E-03
Lateral migration [x]		seep	combined per site/ per feature. [y]	2.67E-03	6.30E-04	1.75E-02	5.40E-03
		minor		6.30E-04	1.70E-04	5.40E-03	1.83E-03

Table 4. Estimated ranges of generic reasonable worst-case leakage probabilities for UKCS depleted oil and gas field stores and partially or fully confined saline aquifers. (Letters in the upper-right corner of cells refer to separate notes in the text)

Explanatory notes for Table 4:

a. Probabilities given here are for CCS sites on the UKCS, and assume a robust permitting process. Probabilities are estimates of the likelihood of occurrence of leakage via the specified type of leakage pathway during a period of 25 years of CO_2 injection followed by 100 years of storage.

b. Probabilities refer to a partially or fully confined (rather than open) saline aquifer site.

c. Assumes that the permitting process has involved careful appraisal of seal quality (seal integrity, capacity, and geometry).

d. Capillary flow and diffusion are very slow processes in fine-grained clastic lithologies. Some leakage might start to occur over geological time (after thousands to millions of years for a 100m thick shale), but not over shorter timespans. Rates for evaporite seals are generally even slower. Conversely, leakage rates in poor quality seals can be significantly higher, though such sites would not be expected to be granted a storage permit.

e. For any leakage to occur on human (rather than geological) timescales, the plume would need to reach an area in which there is a connected pathway with high permeability (at least 10^{-2} mD, i.e. much greater than a typical seal), through the entire thickness of the caprock. We have derived a likelihood of this occurrence by inference from analysis of unsuccessful wells drilled for hydrocarbon exploration (Mathieu 2018; see below).

f. Extremely low probability for depleted fields because of proven containment capability prior to hydrocarbon production.

g. Particularly important that seal quality is adequately demonstrated prior to permitting for aquifer sites.

h. These are very large fault zones typically located at or near active plate margins - and hence not applicable for UKCS. (This does not imply that the UKCS is seismically quiescent; there are natural earthquakes, both onshore and offshore, however frequency and magnitude are much lower than at active plate margins).

i. Fault zones large enough to have potential juxtaposition leakage, as well as risk of fault membrane leakage, plus enhanced damage zone permeability.

j. Large leakage pathways on faults are extremely unlikely for depleted fields, as fault seal sufficient to contain hydrocarbons is already proven.

k. Underlying probabilities may be larger - but higher-risk sites are very unlikely to be granted a permit for UKCS.

l. Size of these faults is much smaller than the overall size of a storage structure, but is potentially big enough for the damage zone to extend through a moderately thick seal. Lower risk of juxtaposition leakage.

m. Many prospective sites may have a number of faults of this size; many are likely to be sealed, of those that do leak, most are likely to have low flow rates, and residual trapping might capture a proportion of CO_2.

n. Faults should be visible on seismic, and if there is an associated significant risk of leakage the site would be unlikely to be granted a storage permit for UKCS.

o. Negligible consequence as isolated features, but could collectively enhance permeability as a connected network of small-scale faults/fractures, and/or serve to connect larger faults or other higher permeability features.

p. Risk is higher for saline aquifer stores because less will generally be known about the geomechanical attributes of the seal. There is a possibility that a depleted field could originally have had undetected low-volume leakage, (particularly before or during early stages of production, before reservoir pressure dropped), although this would indicate that any future leakage via the same pathway would also have a similarly low rate.

q. Induced faulting/fracturing refers to initiation of new fractures within the caprock (not specifically the reservoir). Problems with induced faults/fractures are only likely to arise if the pressure response during injection is highly unexpected. The likelihood of this for depleted field stores should be very low as long as the storage operator has the original hydrocarbon production data (including history matched production models).

r. Leakage caused by increased fluid pressure on critically stressed fractures. Could be accompanied by seismicity. Would not necessarily cause major increase in long-term leakage rates; might initially cause localised short-lived episodic escape ('burps').

s. Lower likelihood in depleted fields because pressure regime should be well understood from original oil & gas production.

t. Induced hydraulic fractures. Not likely in depleted fields unless pressure response is not as anticipated for CO_2 injection. In worse case hydraulic fractures could be hundreds of metres high and hence cut entire thickness of caprock, though initially this would be localised at structural highs and flow rates would likely to be low (this risk highlights the importance of site monitoring).

u. Risk greatest in the vicinity of structural highs, and in parts of the sites that may be less well characterised (i.e. where risk of compartmentalisation is highest).

v. Understanding of the importance of gas chimneys as seal bypass features has increased over the last 15 years. Good 3D seismic is a major help to recognise their presence and to quantify diameter and depth.

w. High-rate leakage from large features has very low probability, as sites with features visible on seismic are likely to have been identified (particularly for depleted fields). However, minor leakage on smaller features (including sub-seismic scale) could occur, especially when ongoing injection causes reservoir pressure to increase.

x. Probability (and consequence) of lateral migration is extremely site-specific, and generic risks are poorly constrained. Only part of the risk is technical, but also links to the definition of the storage complex as agreed with the regulator. Indicative probabilities shown here are based on averaged values of the other types of leakage pathways.

y. There is a risk that plume migration will not be as anticipated based on pre-injection reservoir models (particularly for open saline aquifer sites which are not represented here).

8.3 Comparison with other assessments of leakage probabilities

In this section we compare our probabilities (Table 4) with those produced earlier by other workers. Meta-data for the previous studies are shown in Table 5. Comparison of probabilities are given in Figure 2 (grouped by study) and Figure 3 (grouped by leakage pathway).

The various studies used here were produced by different groups of workers, using different methodologies, in contrasting geological settings and/or regulatory environments. Most, but not all, were produced in the context of risk assessment for CO_2 storage. To produce the comparison of probabilities in we have 'mapped' previous leakage probabilities from each study to the closest type of leakage pathway in our evaluation. Inevitably, this has involved a varying degree of subjective judgement, and it is important to emphasise that there is scope to reinterpret the use of legacy data in this way.

In addition to previous studies of leakage probabilities for CCS, we have also considered the implications of studies of unsuccessful wells drilled for hydrocarbon exploration (Mathieu 2018), and statistics of leakage incidents from underground gas storage facilities (Schulz *et al.* 2020, based on earlier studies of Evans 2008, 2009, Evans & Schultz 2017, and Schultz & Evans 2020).

Prospects with wells that were drilled that had seal issues identified as risks prior to drilling are assumed not to be suitable CO_2 storage site candidates. Data presented by Mathieu (2018) from wells drilled in the UK Central North Sea over a 10 year period suggest that 2 of the 98 drilled wells were unsuccessful due to top seal issues that had not been identified as significant risk elements prior to drilling[1]. While this proportion is relatively high, it is important to emphasise that: (1) it is likely that in most cases the seal quality issues could be identified and characterised in detail once the well was drilled (i.e. if the well had been drilled as part of a site appraisal for CCS, the well results would indicate that the site was not suitable for CO_2 storage), (2) these wells were drilled in the context of "high-risk/high-reward" hydrocarbon exploration in which the typical likelihood of success was ca. 30% (i.e. this is an entirely different premise compared with the containment certainty required for CCS), and (3) evaluation of potential UKCS areas for CO_2 storage will tend to favour sites where the reservoir is overlain by a well-known regional seal (in contrast to hydrocarbon exploration, where local, less well-understood seals might be present in structures that were deemed to be valid targets for drilling).

[1] Note: 20% of wells were unsuccessful due to any type of seal issue that had not been identified prior to drilling. 2% of these were related to top seal; for the remaining 18% of unsuccessful wells, prior to drilling either the operators did not identify the geometry of the site correctly, or the properties of any lateral or bottom seals or faults critical to ensuring the site was contained were not correctly assessed. The detailed characterisation and stringent permitting process for UK CCS is likely to identify all such risks. Whilst samples of the caprock might not be available for every site, samples from nearby wells and a regional understanding of the caprock will be necessary, alongside evidence of characteristics such as fluid isolation across the seal (for example, differing fluid salinities or pressure gradients) to prove the seal and reduce the risk associated with the geometry of the storage site (as recommended in EU 2011).

Aspect	This study	Schultz et al 2020	ZEP 2019	Mathieu 2018	DECC 2012	Scandpower 2012	Oldenburg et al 2011	Scandpower 2010	FutureGen 2007	Hooper et al 2005
Nature of study	Estimation of generic leakage risks for potential UKCS CCS sites	Statistical analysis of historic leakage incidents in underground gas storage sites (in multiple countries)	Estimation of generic leakage risks for potential North Sea CCS sites	Appraisal of unsuccessful UKCS wells drilled for hydrocarbon exploration & production (E&P)	Estimation of generic leakage risks for potential UKCS CCS sites	Appraisal of site-specific leakage risks (Johansen Fm. below Troll field, Norwegian North Sea)	Leakage risk assessment (In Salah CCS site, Algeria)	Appraisal of site-specific leakage risks (Utsira Fm. in Utsira Syd, Norwegian North Sea)	Leakage risk assessment for four potential onshore CCS sites in USA (Jewett, Odessa, Mattoon, Tuscola)	Appraisal of site-specific leakage risks (Latrobe Valley & Gippsland Basin, Australia)
Storage (or other) scenario	Depleted Fields & Confined Saline Aquifers	Underground Gas Storage (UGS)	Saline Aquifers (& Depleted Fields)	Hydrocarbon E&P	Depleted Fields & Saline Aquifers	Unconfined Saline Aquifer	Saline Aquifer	Unconfined Saline Aquifer	Saline Aquifers	Depleted Fields
Generic or specific probabilities	Generic	(UGS not CCS)	Generic	(E&P not CCS)	N/A	Specific	Specific	Specific	Specific	Specific
Basis for probability estimates	Expert consensus	Leakage statistics	Expert consensus	Statistics from UK regulator	Expert consensus	Expert consensus	Academic study	Expert consensus	Unattributed government report	Expert consensus
Plotted in Figs. 2 & 3	Yes	Yes	Yes	No	No	Yes	Yes	Yes	Yes	Yes
Include leakage rates tied to probabilities	Yes	No	Yes	N/A	N/A	Yes	No	Yes	Yes	Yes
Plotted in Fig. 4	Yes	(Yes)	Yes	No	No	Yes	No	Yes	Yes	Yes

Table 5. Overview of the main studies with quantitative leakage risk data used in this report

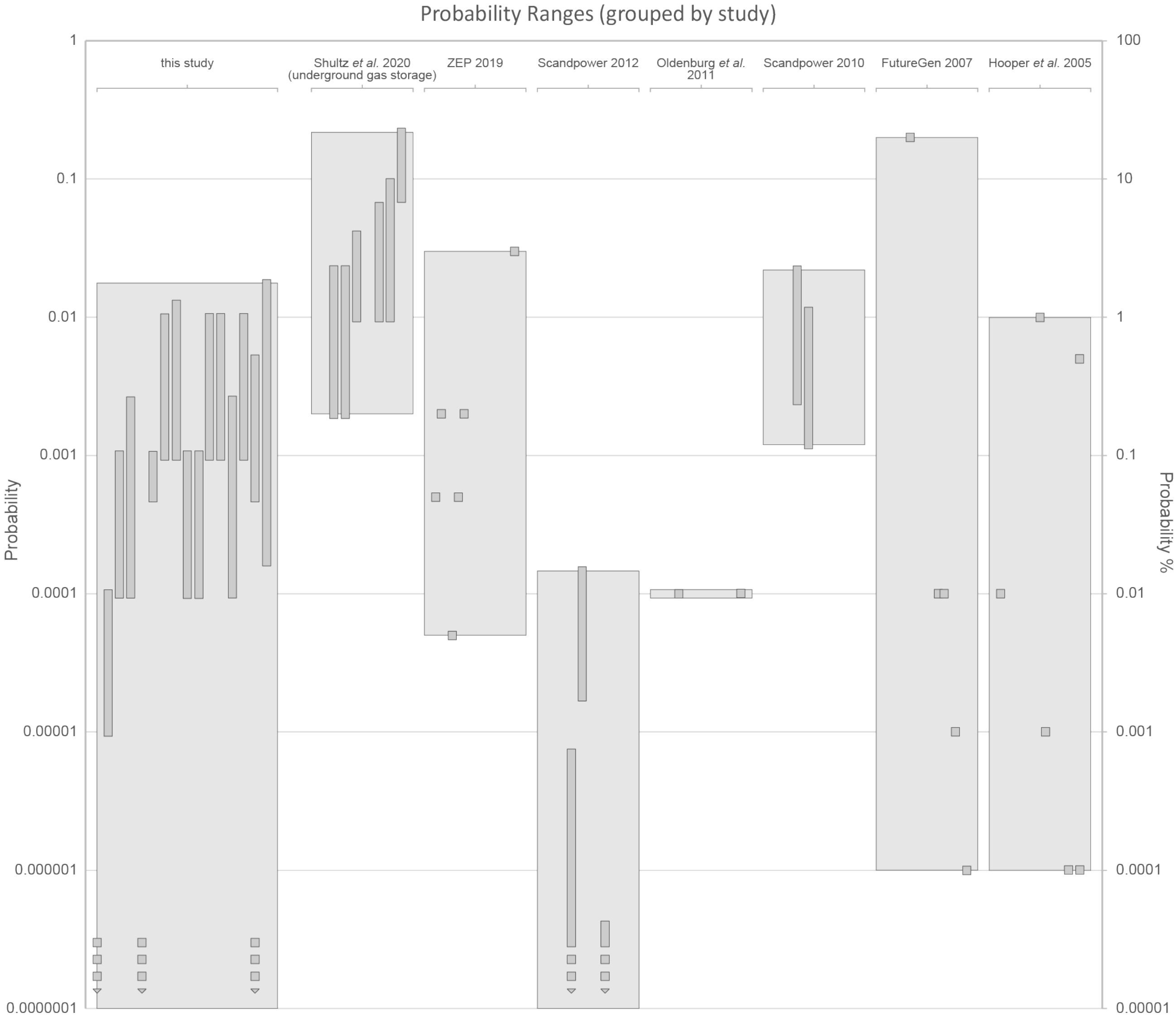

Figure 2. Overall comparison of leakage probabilities relative to previous studies

Reported incidents related to leakage from underground gas storage (UGS) sites in USA (Schulz *et al.* 2020) may provide insight on the likelihood of leakage via geological pathways in CCS sites. Leakage incidents are characterised according to the severity of the event, and span a period of eight decades. Leakage probabilities from Schulz *et al.* (2020) are very likely to represent an upper limit on the corresponding risk for UKCS CCS because: (1) many of the reported incidents are rates at a low-level ('nuisance') severity that didn't involve significant loss of gas from the store; (2) UGS usually involves many cycles of gas injection and removal, which may change the geomechanical response of the reservoir and increase the likelihood of failure; (3) the US regulatory framework for UGS at the time when previous incidents occurred was less stringent than current UK regulations for CCS (Schultz *et al.* 2020), with minimal monitoring in most states; (4) natural gas sites may be substantially shallower than CO_2 storage sites.

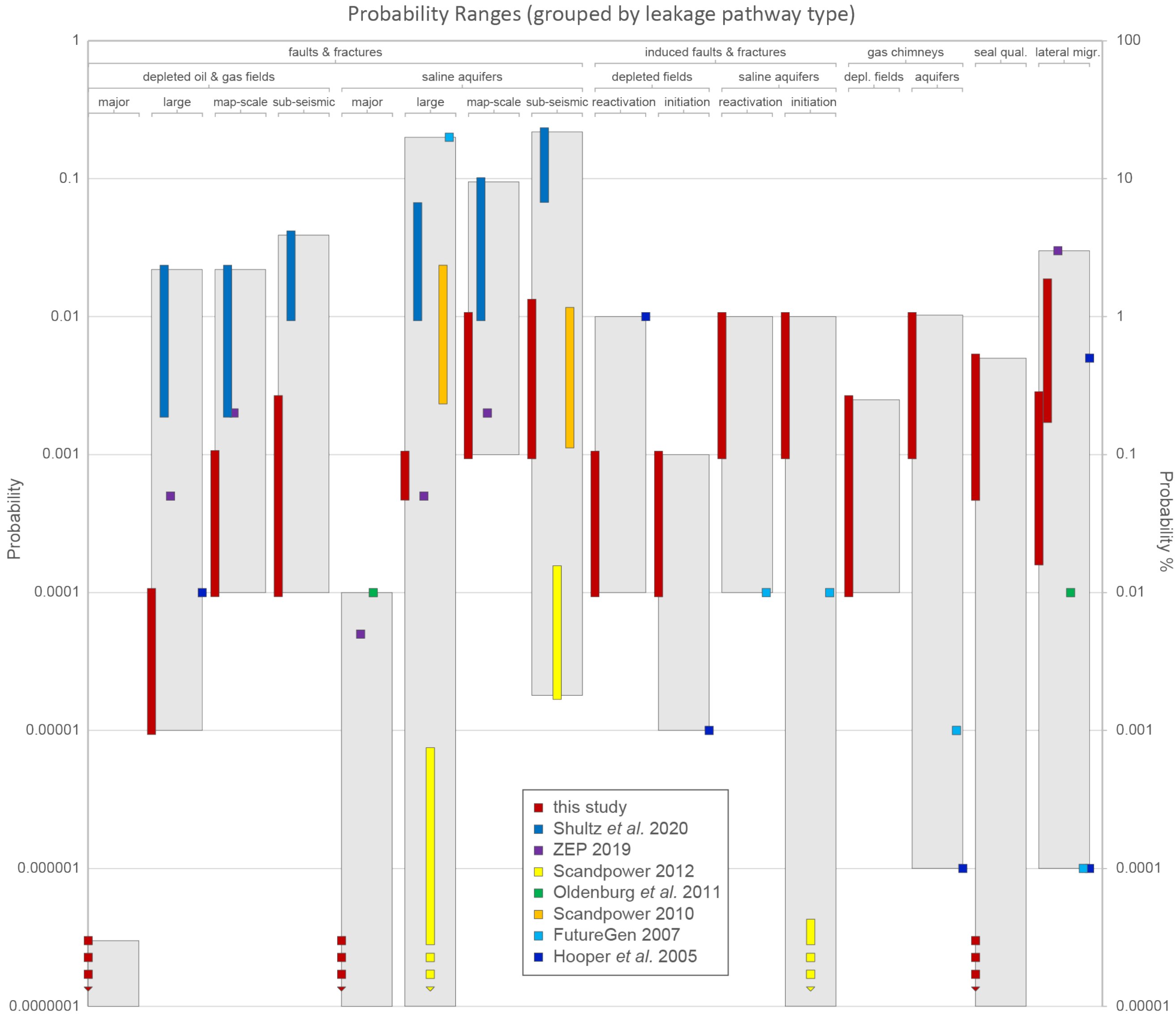

Figure 3. Overall comparison of leakage probabilities relative to previous studies, grouped by leakage pathway

9. Combined probabilities and leakage rates

Our derived ranges of leakage probabilities relative to leakage rates, in comparison with previous studies, are combined in Figure 4.

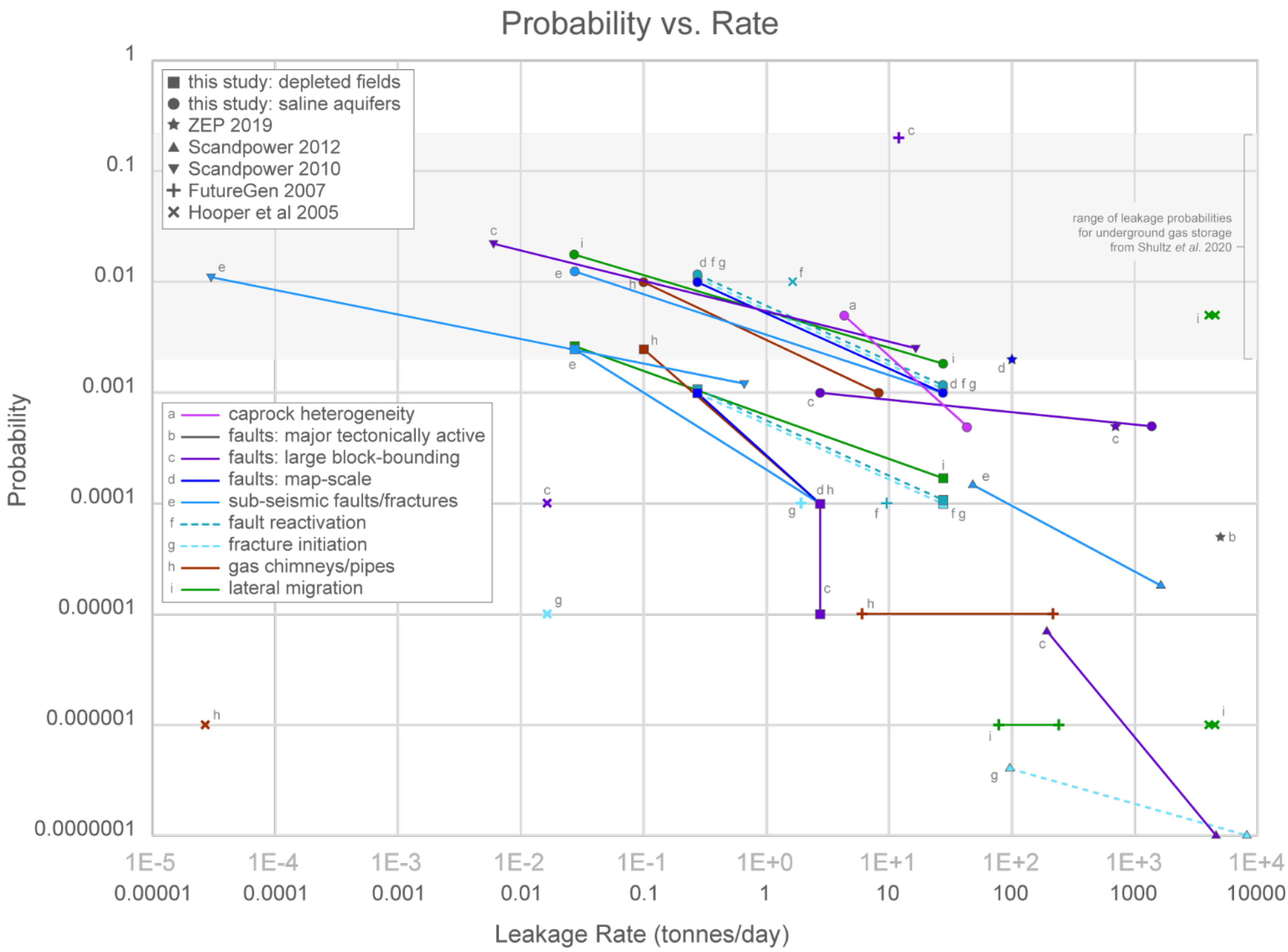

Figure 4. Leakage probabilities plotted against leakage rates for comparison between this and previous studies

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