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Recent Advances in Risk Assessment and Risk Management of Geologic CO_2 Storage

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Abstract

This paper gives an overview of the advances made in the field of risk assessment and risk management of geologic CO_2 storage (GCS) since the publication of the IPCC Special Report on Carbon Capture and Storage in 2005. Development and operation of a wide range of demonstration projects coupled with development of new regulations for safe injection and storage of CO_2 has led to development and deployment of a range of risk assessment approaches. New methods and tools have been developed for quantitative and qualitative risk assessment. These methods have been integrated effectively with monitoring and mitigation techniques and deployed in the field for small-scale field tests as well as large-scale commercial projects. An important development has been improved definition of risks, which can be broadly classed as site performance risks, long-term containment risks, public perception risks and market risks. Considerable experience has now been gained on understanding and managing site performance risks. Targeted research on containment risks and induced seismicity risks has led to improved understanding of parameters and processes influencing these risks as well as identifying key uncertainties that need to be targeted. Finally, significant progress has been made to effectively integrate communication strategies with risk management approaches to increase stakeholder confidence in effectiveness of deployed risk management approaches to manage risks.

1. Introduction

The 2005 Intergovernmental Panel on Climate Change's Special Report on Carbon Capture and Storage (IPCC, 2005) discussed in detail the topics of risk management, risk assessment and remediation at geologic CO_2 storage (GCS) sites. The report classified GCS site risk assessment as the process of identifying and quantifying potential risks caused by the subsurface injection of CO_2, where risk is defined as the product of the probability of an event happening and the consequences of the event. Further, GCS risk management process was defined as the application of a structured risk assessment approach to quantify risks by taking into account stakeholder input and context, to modify the GCS operations to remove excess risks and to identify and implement appropriate monitoring and

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intervention strategies to manage the remaining risks. Since the publication of the IPCC report, the field of GCS risk management and risk assessment has advanced significantly.

In 2009 the IEAGHG study on risk assessment (IEAGHG, 2009) demonstrated a risk assessment and management framework (Figure 1) aimed at maintaining the terms regulatory authorities use, have consistency between different regulatory agencies as well as different disciplines (engineering, ecological, human health and behavioural risk assessment) and illustrate the iterative nature of the process as data are collected and knowledge improves during the project phases. In this context risk source assessment is primarily utilized at the site selection and storage licensing stage; exposure assessment is considered during licensing, monitoring and verification and for the development of mitigation plans; and the effects and risk characterization steps are utilized in mature storage site monitoring and verification and the development of mitigation plans.

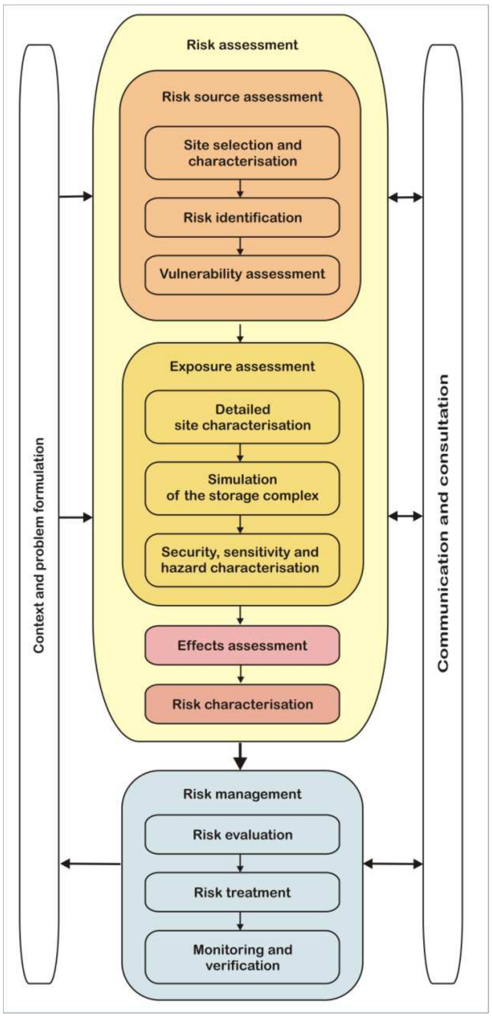

Figure 1. IEAGHG recommended risk assessment, management and communication framework for CO_2 storage projects (IEAGHG, 2009).

This framework, originally presented at the IEAGHG CO_2 Storage Risk Assessment Network meeting in 2007 was largely implemented with the introduction of the EC Directive for CO_2 storage projects (EC, 2009a; EC, 2011) and its risk assessment process which identified hazard characterisation, exposure assessment, effects assessment and risk characterisation as essential steps and specifically required an assessment of the sources of uncertainty and evaluation of the possibilities to reduce uncertainty.

In addition to the IEAGHG study, multiple other guidance documents on field deployment of GCS technology have described risk assessment and risk management approaches, including the CSLF Risk Assessment Task Force's Risk Assessment Standards and Procedures report (CSLF, 2009), World Resource Institute's CCS Guidelines (WRI, 2009), US DOE's Best Practices Manual on Risk Analysis and Simulations (US DOE, 2011), DNV's guidelines (DNV, 2010a; DNV, 2010b; DNV, 2012).

The various risk assessment and risk management approaches have further matured through actual applications to field projects as well as research studies focused on better understanding and predicting GCS risks. Over the last decade, more than 45 field projects ranging from small-scale pilot tests injecting a few hundred tonnes of CO_2 to large-scale tests injecting over a million tonnes have been undertaken in all parts of the world including in North America, Australia, Asia, Brazil, Algeria and the European Union (Cook et al. 2014). Several commercial projects, including the Quest and Boundary Dam projects in Canada and the Gorgon project in Australia, have either recently become operational or will be operational by 2016 (GCCSI, 2015). The multitude of field projects have employed some form of risk assessment (qualitative, semi-quantitative and/or quantitative) and developed risk management strategies as required by the overseeing regulatory agencies. Development of regulations for CO_2 injection and storage operations such as OSPAR (2007), EU Directive on GCS (EC, 2009c), US EPA's Class VI rule (EPA, 2011), and Alberta's CCS regulatory framework (2013) have provided guidance on regulatory requirements for safe operations and risk management of GCS projects.

The 2005 IPCC report focused extensively on containment risks associated with CO_2 and brine leakage through various mechanisms and pathways, including, wellbores. Additionally, risks associated with induced seismicity were also discussed. Experience from various field projects to date shows that the overall GCS risks can be broadened beyond the containment risks based on various stakeholder interests and classified as follows:

- Site performance risks: risks to successful operation of field projects, primarily that of insufficient capacity or injectivity, during appraisal and injection stages.
- Containment risks: risks to effective containment of CO_2 during injection and post-injection (storage) period.
- Public perception risks: risks to public acceptance of field projects.
- Market failure risks: financial risks to deployment or execution of field projects with feedback from site performance, containment and public perception risks.

Over the last 10 years, public policy has mainly driven the development of demonstration and industrial scale projects. The policy-makers and public concerns have focused on long-term CO_2 containment risks to ensure the effectiveness of GCS as a greenhouse gas emissions abatement technology. On the other hand, the field operators are principally interested in having effective methods for reducing the CO_2 footprint of either their own operations or of their products and have focused on site performance risks coupled with market failure risks. In practice, field projects need to develop a balance between site performance risks, market risks, and long-term containment risks.

Overall, GCS risk assessment has enormously benefitted from the experience gained in analogous disciplines. The main concept borrowed in the early days was that of a systematic approach for identification of the Features, Events and Processes (FEPs) relevant to long-term performance of geological repositories as a first step towards risks identification (Espie, 2004; Benson, 2002; Wildenborg et al., 2004; Savage et al., 2004). While a few early studies have used approaches such as inference logic for probabilistic risk assessment (Wildenborg, 2001; Lewis, 2002; Wo et al. 2005; Larsen et al., 2007), the majority of the early work on GCS risk assessment dealt with conceptual and descriptive risk characterization. Benson (2007) introduced the concept of risk profiles (Figure 2) to communicate the evolution of environmental risks at a GCS site.

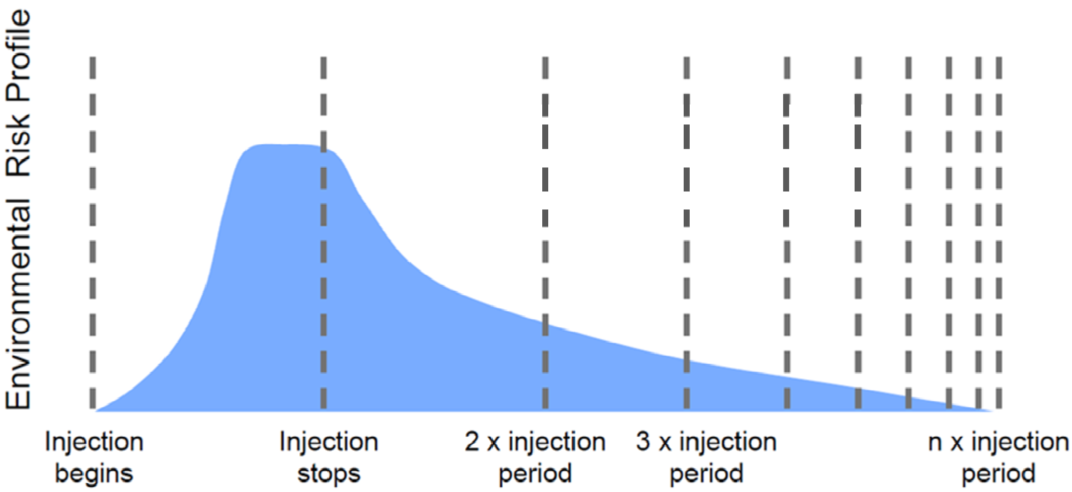

Figure 2: Schematic risk profile for a CO_2 storage project. (Benson, 2007)

Even though it was qualitative in nature, the risk profile concept has become extremely effective in communicating how environmental risks evolve during various stages of a GCS site. However, it has also become increasingly apparent that decision makers need meaningful quantitative indicators, such as potential CO_2 and brine leakage rates and volumes or CO_2 concentrations outside primary storage formation due to possible leakage.

Quantifying such site-specific risk profiles requires forecasting the time-dependent evolution of a GCS site by taking full account of the physical processes, conditions and parameters in modelling of leak paths, rates and volumes. Given that the geologic systems are inherently heterogeneous (variable) and uncertain, probabilistic risk assessment approaches can be used to determine the variability in computed risk profiles. The input parameter distributions used in the modelling need to be determined rigorously through a transparent process including expert elicitation to ensure stakeholder confidence. The time-dependent GCS site performance predictions can be used to determine probabilities of an event happening. Computation of risk requires quantification of impact as well (risk is product of probability and consequence), which can be challenging as impacts may not be valued the same by various stakeholders. Additionally, the full effects of alterations in the assumptions in models and parameters on the estimated risks need to be demonstrated through uncertainty quantification. Developing approaches to quantify the risk profiles conceptualized in Figure 2 has been the subject of risk assessment studies carried out in recent times including within efforts such as US DOE's National Risk Assessment Partnership-NRAP (Pawar, et al. 2014).

There are uncertainties in almost all aspects of a GCS project including site characterization, field operations, post-injection site care, and post-closure activities. The uncertainties can be associated with parameters, processes, models or scenarios. The inherent variability at a GCS site is known as aleatoric uncertainty. Lack of knowledge due to limited characterization data is known as epistemic uncertainty. Epistemic uncertainties can be reduced through data collection efforts as part of site characterization, field operation and monitoring activities (Figure 3). On the other hand, aleatoric uncertainties cannot be completely eliminated and can be retained through post-closure phase. It is also possible that characterization data can lead to an increase in uncertainty.

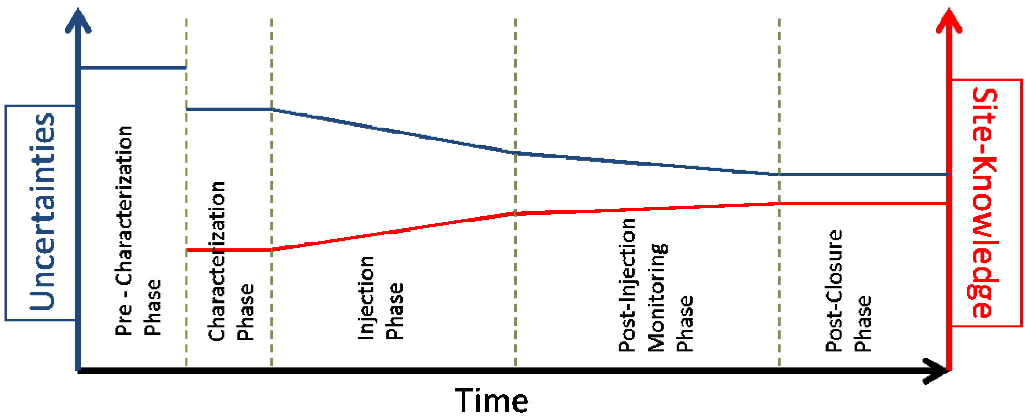

Figure 3. Qualitative illustration of the level of uncertainties over time at GCS sites.

The time scale that the risk assessment needs to concern is of critical importance and has varied in various projects. For example, the FutureGen risk assessment used a time period of 5000 years (FutureGen, 2007) while the Otway risk assessment used 1000 years (IEAGHG, 2013a). There is still no consensus about what constitutes an appropriate time scale for risks at a geologic carbon storage site.

This review article focuses on developments in several key areas of GCS risk assessment and risk management over the last 10 years. The aim of the article is not to provide an exhaustive overview of all the developments over this time period. We give an overview of advances related to containment risks primarily focusing on leakage through wellbores and faults, advances in understanding of impacts of induced seismicity, advances made in risk assessment approaches and their applications to field projects, site performance risks and their management through two specific storage field examples, advances in market failure risk analysis, advances in risk management practices and finally effective communication strategies to address public acceptance risks.

2. Containment risks: Advances in risk assessment of leakage pathways

Potential leakage pathways, including imperfectly sealed or degraded wells, discontinuous or failed caprocks and transmissive faults impact three risk category areas: containment, site performance and public perception. Successful and safe drilling of injection and monitoring wells is one of the most costly and crucial aspects of the performance phase of a CO_2 project. Containment of CO_2 and brine in the subsurface is essential to the success of the entire sequestration operation and depends on ensuring that wells in the storage complex are not conduits for escaping fluids, that the caprock provides complete closure of the storage reservoir, and that faults, if present, are neither permeable pathways nor activated by CO_2 injection. Wells are among the most visible and obvious targets of concern for the public and a focus of fears ranging from blowouts to drinking water contamination to possible damage of the surface environment.

Of these three risk categories (containment, site performance and public perception), most CO_2 sequestration research has focused on evaluating containment risks. Short and long-term performance risks are real and important, and are already active areas of research and investment within the oil and gas industry, which is highly motivated in the development of effective drilling and completion technologies as well as ensuring long-term performance of CO_2 injection. However, much work remains to be done to disentangle the public's association of drill rigs with catastrophic oil and gas accidents (i.e., the Macondo exploration well blowout in the Gulf of Mexico) and the lower hazard operations of drilling into depleted oil and gas fields and saline reservoirs. In addition, the CO_2 storage community needs further development of methods of formalizing and demonstrating to the public an effective regulatory environment governing the safe drilling and operation of wells for the injection of CO_2.

CO_2 is naturally the focus of much of the risk assessment work on containment. However, the IPCC report recognized the displacement of brine during CO_2 injection as an important risk. One of the key developments during the past 10 years has been the increased recognition of the potential impact of brine migration due to CO_2 injection including on ground water resources (e.g., Birkholzer et al. 2009; Keating et al. 2013). This stems in part from work that indicates that the impact of CO_2 contamination on groundwater chemistry is generally moderate, particularly in high-quality drinking water aquifers, whereas migration of high-salinity brine into drinking water aquifers would have a deleterious consequence.

2.1. Well Integrity

Well integrity is a broad subject encompassing the drilling, operation and abandonment of wells. The drilling phase includes low frequency but high impact risks of blowouts as well as the more common but lower impact risks associated with field operations (spills from trucks, pipelines, waste pits, etc.). The operational phase (including injecting/producing fluids, monitoring, etc.) has perhaps the lowest risk for the wells completed as part of the project, as the wells are safely completed to modern standards and their behavior is or can be actively measured and monitored for problems. Nonetheless, operating wells could compromise containment. The most challenging phase in risk assessment is abandonment as the well is generally no longer observable and assessing its integrity is a matter of review of records and inferring the quality of the abandonment process. For the injection and post-injection monitoring and post-closure phases, it has been found useful to separate leakage events into acute and chronic classes (corresponding to high and low flow rates; FutureGen, 2007). The rationale is that high flow-rate events will be readily observed and therefore remediated in a short period of time, whereas, low flow-rate events may go undetected for an extended period and could remain unmitigated (FutureGen, 2007).

Well integrity studies usually make a distinction between wells constructed for the specific purpose of injecting and monitoring CO_2 and legacy wells that exist within the area-of-review in either an operational or abandoned state (Viswanathan et al. 2008; Oldenburg et al. 2009). It is generally assumed that purpose-built wells offer significantly less risk for reasons that include the likelihood of greater regulatory oversight and public scrutiny and the use of completion materials (specialty cement and steel casing) that are more chemically compatible with CO_2. Legacy wells, on the other hand, were not built with CO_2 containment in mind; could be sufficiently old that there is little confidence in the quality of construction or abandonment practices; and may exist in large numbers, particularly when depleted oil and gas fields are used for CO_2 storage (e.g., Gasda et al. 2004). Most research for well integrity in CCS has therefore focused on these legacy wells. Examples of risk assessment studies that focused on well integrity include Zhou et al. (2005), Viswanathan et al. (2008), Le Guen et al. (2011), Nicot et al. (2013), Jordan et al. (2015), and Bai et al. (2015).

Since the IPCC report, the approach to risk assessment of operational and abandoned wells has been separated into distinct tasks including determining the number of wells in the area-of-review; estimating the frequency with which these wells could be expected to develop leaks; and evaluating the permeability of these pathways. Subsequent numerical simulations are used to calculate the amount of fluid that could leak based on the permeability and the injection reservoir conditions (e.g., Jordan et al. 2015; Viswanathan et al. 2008). The number of wells (or well density) is highly site-specific and not easy to generalize (Carey 2013). On the other hand, site-specific data that includes well locations is often readily available.

Significant progress has been made in understanding the frequency of well integrity problems since the IPCC report. The primary sources of information have been studies of natural gas storage projects and the records obtained from regulatory agencies on the frequency of sustained casing pressure (SCP) events and failed mechanical integrity tests (MITs). Experience from the natural gas storage community is summarized by IEA Greenhouse R&D Programme (2006), which provided estimates of rates of 2.0×10^{-5}

per well-year based on 12 well-based incidents of gas discharge occurring among 634 facilities over the course of 40 years.

SCP incidents reflect migration of fluids within the nested set of steel casings. They do not demonstrate leakage outside the well, nor is the source of the leaks identified. In many cases, SCP originates from intrusion of shallow gas into the well and does not reflect losses from the reservoir. Nevertheless, SCP records have been used to estimate the frequency with which well components fail and thus provides at least an upper bound on possible rates of well failure. Watson and Bachu (2007, 2008) examined records from across the Alberta province in Canada and found SCP rates of 3.9%. Davies et al. (2014) recently completed a comprehensive assessment of the available data for observations of SCP and related gas migration outside of wells. The rates of incidents varied widely from 1.9-75% of the wells in a given field. The EPA's Underground Injection Control program provides additional statistics on failures of various components of the well identified through mechanical integrity test (MIT) reports. Reporting by Lustgarten (2012) found MIT failure rates varying from 1-10% among US states. Data on rates of well integrity failures could be used as input to a site screening process to identify problematic geologic settings or well construction processes that may indicate a poor CO_2 sequestration site.

The statistics available in these reports do not capture impacts (e.g. the amount and extent of groundwater contaminated or volumes of fluid leaked) or even indicate that emissions to the environment have occurred. As emphasized by King and King (2013), wells are constructed with multiple barriers and the failure of any single component (e.g., a leak in the production tubing) does not necessarily translate to the escape of fluids to the environment. For example, Kell (2011) found that 0.1% and 0.02% of wells in Ohio and Texas, respectively, were associated with groundwater contamination events, a rate much lower than SCP or MIT reports. It must also be noted that in certain fields there could be a common cause of failure related to complex geology or the specific well design, and fields with a high SCP rate or suspected poor zonal isolation would be unlikely to gain regulatory approval for CO_2 storage.

Risk assessment approaches for wellbore integrity in GCS (e.g., Viswanathan et al. 2008, Stauffer et al. 2009, Oldenburg, et al. 2009; Bai et al. 2015) have used permeability as a key quantitative measure of the potential consequences of well leakage, where permeability around the well is used to quantify the amount of CO_2 or brine that could migrate along damaged wells. Measured permeability values for the wellbore environment are quite rare. Crow et al. (2010), Gasda et al. (2011) and Hawkes et al. (2014) provide direct measures of the permeability of an approximately 3-m section of the annulus outside the casing. Measured values for wells were generally low (from 0.01 to 5 mD). However, there are cases where permeability testing has indicated the absence of competent cement and thus high permeability over a short interval (Duguid et al. 2014). Tao et al. (2011) have used observations of SCP to estimate permeabilities of 18 leaking wells and found values of 0.02-3 mD with one well yielding a best-estimate value of 100 mD. We note that intact Portland cement has a permeability in the micro-Darcy range making it generally a very effective seal.

Despite early concerns, a significant body of research suggests that while supercritical CO_2 is reactive with wellbore materials, it does not necessarily lead to a degradation of wellbore integrity. Carey et al.

(2007) showed that an ordinary Portland cement from a well with 30 years operational history at a CO_2-EOR field had evidence of CO_2 migration but that the cement maintained an annular barrier. Experimental studies by Kutchko et al. (2007) showed a similar resilience of Portland cement to exposure to CO_2. Although the current United States EPA (US-EPA) Class VI CO_2-sequestration regulations require "CO_2-resistant" cement, evidence from the field and experiments suggests that ordinary Portland cement is adequate to maintain wellbore integrity. The situation for ordinary (mild) steel casing is more complicated: where it is protected by Portland cement, corrosion rates are slow; where it is directly exposed to supercritical CO_2 and water/brine, corrosion rates are rapid (as great as 20 mm/year) (Han et al. 2011 and Choi et al. 2013). Corrosion of steel can short-circuit the leakage paths by allowing fluids to enter into the well annulus and flow easily toward the surface. However, at that point, another defect must allow the fluids to escape back to outside the casing. Several studies have found that wellbore systems (both cement and steel) can self-heal due to swelling and precipitation reactions or mechanical deformation (see Carey 2013 for a review). All of these considerations suggest that properly completed wells will not be damaged simply by exposure to supercritical CO_2 or CO_2-bearing solutions. As with any engineered system, we do not have observations that extend over long periods of time. Modern well construction began at the start of the 20th century and the oldest CO_2-exposed wells are about 60 years in age. As a result of this, wells are still considered more likely leak paths than geological features and absorb a significant proportion of the monitoring effort in any GCS project.

2.2. Caprock Integrity

Risk assessment of caprock integrity is similar to wellbore integrity in the sense that the inherent properties of good-quality caprock (typically shale or evaporites; e.g., Grunau 1987) are more than adequate to isolate CO_2 in the subsurface. Risk assessment then involves determining whether such caprock properties are present across the project area and whether the planned injection operation can be conducted without damaging the caprock. Literature from the oil and gas industry provides basic guidelines for assessing the quality of a potential caprock for the initial assessment of site suitability (Downey 1984; Biddle and Wielchowsky 1994; Cartwright et al. 2007). This involves both laboratory and field investigations.

Low permeability and high capillary entry pressures are two key, laboratory-measured attributes of good caprock. Field evaluation is necessary to demonstrate that prior tectonic and reservoir operations have not damaged either the caprock seal or the wells (e.g., Hawkes et al. 2005; Sibson 2003). In any case, many researchers emphasize that ductility is necessary to limit the possibility of the existence of transmissive fracture systems (e.g., Ingram and Urai 1999; Rutqvist 2012). Finally, the geometry of the caprock system must be determined (e.g., through seismic surveys) to prove closure and containment of buoyant fluids. This may be difficult to establish where faults provide part of the closure that may be either transmissive or sealing (e.g., Dewhurst et al. 1999).

Caprock can be damaged by injection operations. The likelihood of fracturing depends on the tectonic environment (compressional, extensional, or strike-slip), the magnitude of the differential stress, and the amount and orientation of brittle fracture features (Sibson 2003). Hawkes et al. (2005) describe mechanisms involving activation of faults in the reservoir that extend into the caprock as one of the principal risks. They do not regard stresses induced in the caprock by inflation of the reservoir as a likely mechanism for fault generation. They do recognize the potential for induced shear failure at the reservoir-caprock interface (which may have a particularly deleterious impact on wellbore systems) and the potential for hydraulic fractures to grow out of the reservoir and into the caprock.

Some research (e.g. Ingram and Urai, 1999; Hermanrud and Bols, 2002) concludes that high pore-pressure in the reservoir can generate hydraulic fractures in the shale caprock. These describe overpressured oil and gas reservoirs where hydrocarbon has leaked through dilational fractures that developed in the caprock. Interestingly, these fractures re-seal once the reservoir returns to a normally pressured state, as reflected in the coincidence between measured leak-off pressures and pore pressure (e.g., Hermanrud and Bols, 2002). In order to prevent these fractures, many authors suggest limiting the injection pressure to values below the minimum stress (Hawkes et al. 2005). Minimum stress measurements can be obtained by mini-fracs and other downhole methods which should allow management of injection pressures below those that induce tensile fractures. However, Sibson (2003) considers this type of extensional fracture to be likely only at relatively low differential stress conditions and emphasizes the potential for activation of existing faults as a more significant caprock risk.

The focus of most GCS risk assessment studies on caprock has been on geomechanical analyses of fault generation or reactivation (Hawkes et al. 2005; Bildstein et al. 2009; Rohmer and Bouc 2010; Smith et al. 2011; Goodarzi et al. 2012; Verdon et al. 2013; White et al. 2014) but the consequences of a caprock failure (i.e., permeability and flow of CO_2 through a fault) are relatively poorly known. On top of this, the evolution of fault zone permeability and other properties with induced slip is weakly understood and a key focus of current research (e.g. Gugliemli et al. 2008). Some studies, for example, Gutierrez et al. (2000), suggest that fault permeability in mudstone may decrease with increasing deformation which would limit CO_2 leakage. Recent experiments by Carey et al. (in press) provide quantitative measures of permeability of fractured shale that can help bound permeability of damaged caprock. In addition, Rutqvist et al. (2007) show how pressure monitoring can reveal very clear responses in reservoirs where fault activation has occurred, potentially limiting consequences of fault activation.

3. Containment risks: Advances in induced seismicity risk assessment

It has long been recognized that increasing fluid pressure in the subsurface can potentially reactivate faults, generally with associated seismic events or possibly as aseismic faulting (with no detectable seismicity). In light of this, GCS projects have generally recognized fault behavior as a key concern to be addressed in the project design and risk management plan (e.g. Chiaramonte et al. 2014).

In the past decade, growing attention has been paid to induced seismicity—reflecting increased understanding of both the site performance and public perception risks. It should be noted, however, that much of this attention has resulted from recent experience outside the CO_2 storage sector. In the United States, for example, the shale oil and gas boom has led to a substantial increase in the volume of waste fluids disposed through deep injection wells. This has in some cases led to a noticeable rise in the frequency of induced earthquakes, including in area which have a low natural earthquake hazard (Ellsworth 2012, National Research Council 2013). In Europe and Australia, a few geothermal projects have induced modest seismic events, heightening public awareness of the issue (Deichmann and

Giardini 2009, Baisch et al. 2006). To date, field observations of induced seismicity at CO_2 storage projects are quite limited. Microseismicity (here defined as $M \leq 2.0$) has been recorded at several sites where sensitive microseismic arrays are deployed—notably the Weyburn-Midale Project (Verdon et al. 2011), the Illinois Basic Decatur Project (Coueslan et al. 2013; Kaven et al. 2014), and the In Salah Project (Goertz-Allmann et al. 2014). Recent work by Gan and Frohlich (2013) also suggests a likely connection between CO_2-enhanced oil recovery operations in Texas and several >M3 events. As new demonstration and commercial CO_2 projects commence operation, empirical experience with this issue will likely grow.

In a widely discussed article, Zoback and Gorelick (2012) suggested that induced seismicity will prove to be a major stumbling block for geologic CO_2 storage technology, particularly if deployed at the gigatonne scale. This concern centers not so much on the seismicity itself, but rather the potential for caprock seals to be compromised by reactivated faults. This work has prompted a healthy and rigorous debate in the scientific community, with arguments on all sides as to what impact induced seismicity will have on future storage projects (e.g. Juanes et al. 2012; Villarasa and Carrera, 2015). This is a complex and multi-faceted topic, and a detailed discussion of the issue is beyond the scope of this work. Three general points, however, are worth mentioning here. First, seismic risks are inherently site- and project-specific, and are best evaluated on a case-by-case basis. Second, quantitative risk assessment tools—the focus of this review paper—can provide a rational basis for deciding whether risks are acceptably low and can be safely managed at a given project. Third, issues of public perception are likely to be as important, if not more important, than the technical risk itself.

There are several categories of hazard and risk associated with induced seismicity (White and Foxall, 2014). The obvious risk is that ground motion resulting from induced earthquakes could lead to significant structural damage, though fairly large magnitudes, typically greater than M4-M5, are required to cause damage unless particularly fragile structures are located near the event. However, magnitude and distance from the earthquake source alone are insufficient to determine damage potential because seismic ground motion at the Earth's surface is highly site-specific and structural fragility varies widely in different parts of the world. A more likely risk is that smaller but more frequent felt events will constitute a nuisance to nearby populations by causing annoyance or alarm and minor cosmetic damage. A general guideline is that an M2+ event that occurs at a typical reservoir depth of a few kilometers is likely to be felt by a nearby observer, but this is highly dependent on the specific site characteristics. With respect to the damage and nuisance risks, the foundation for induced seismicity risk assessment methods is a significant body of experience dealing with natural (tectonic) seismic hazards. In particular, Probabilistic Seismic Hazard Assessment (PSHA) and Probabilistic Seismic Risk Assessment (PSRA) methods are mature and widely used in the natural hazard and structural engineering communities. Of course, these methods are under constant development as the community recognizes inherent challenges and limitations to current approaches (e.g. Field et al., 2015).

While the overall PSRA framework may be adapted from natural hazards to induced hazards, certain underlying differences must be addressed. Several research groups are pursuing work in this direction, adapting the PSRA framework to better fit our technical understanding of induced events. These differences may be best discussed by considering the major components of a typical PSRA:

1. Source characterization and seismic event occurrence rates
2. Ground motion prediction
3. Hazard estimation
4. Structure and community vulnerability
5. Risk estimation

The first step is to identify potential seismic sources—e.g. individual faults or volumetric regions within which seismic event occurrence is assumed to be homogeneous. For each source, one then estimates the average frequencies of occurrence of seismic events of different magnitudes (i.e. levels of natural seismicity). For induced seismicity, this first step is more challenging. Since most induced events take place on small faults and fractures. Furthermore, unlike natural seismicity, one does not have a long historical record of seismic events with which to constrain appropriate seismic event recurrence relationships. Finally, and most importantly, individual events are tightly connected to evolving pore pressure and stress perturbations in the subsurface. This introduces strong time- and space-dependencies in the statistics of induced seismicity occurrence. Significant research has focused on connecting seismicity with the fluid injection and/or withdrawal process (e.g., National Research Council, 2013; IEAGHG 2013, McGarr 2014). Some authors have adopted an empirical or semi-empirical approach to this problem, using the measured seismicity and injection rate at a given site to continuously update a short-term forecast of event frequency (Bachmann et al. 2011, 2012; Mena et al. 2013; Shapiro et al. 2007, 2010). This work builds on similar approaches being applied to model naturally-occurring earthquake aftershock sequences (Gerstenberger et al. 2005). Recent work has also explored simulation-based approaches (Baisch et al. 2009, 2010; McClure and Horne 2011; Cappa and Rutqvist 2012; Foxall et al. 2013; Rinaldi et al. 2014), though gathering sufficient characterization data to make such models useful remains an ongoing challenge.

Assuming an understanding of seismic sources, the next step is to quantify ground motions that may be expected at a given surface location. Conventional PSHA employs empirical ground motion prediction equations (GMPEs) derived from regressions on worldwide strong motion data (e.g. Ambrahamson and Shedlock, 1997; Abrahamson et al. 2008; Bozorgnia et al. 2014). Existing GMPEs typically do not extend to magnitudes below M4.5 and even then are poorly constrained for the smallest events and short distances (e.g. Bommer et al. 2006). The NGA-West1 database, for example, includes events down to M4.5, while the latest NGA-West2 database (and associated GMPEs) has been expanded to include events down to M3.0 (Bozorgnia et al. 2014). Douglas et al. (2013) recently developed GMPEs specifically for magnitudes less than M3.5 and short distances, based on data from six geothermal areas. Microearthquake seismograms from small earthquakes can also be used as empirical Green's functions for site-specific, physics-based synthesis of ground motion due to larger events (e.g. Hutching et al. 2007; Hutchings and Wu 1990). Simulation-based techniques have also been widely developed for ground motion prediction (e.g. Graves and Pitarka, 2010), and are being applied to induced seismicity hazard estimation (e.g., Foxall et al., 2013). Nevertheless, effective strategies for developing site-specific ground motion estimates, particularly prior to injection, remain an important research goal.

Using this information, a ground motion hazard curve for a specific location and time period may then be developed. This function quantifies the probability of exceeding a certain ground motion velocity or acceleration threshold within a specific time period. Rigorously developed uncertainty bounds are an essential part of a hazard curve, since both estimation of earthquake frequencies and ground motion prediction are inherently subject to large uncertainties. The hazard curve may then be convolved with a vulnerability function—representing the probability of damage resulting from a given ground motion level—to arrive at a risk estimate.

As mentioned earlier, for induced seismicity the definition of "damage" must be considered broadly. Methods for establishing building and infrastructure vulnerability functions have been developed by the structural engineering community (e.g. Federal Emergency Management Agency, 2015). Again, large uncertainties remain in the vulnerability estimation. In practice, earthquake losses are often estimated as an average for different structure types, with the caveat that nominally similar buildings may respond quite differently to a seismic event.

Methods for developing "nuisance" fragility functions, to quantify the public's response to induced events, are less well developed, but some work is available. The effects of felt but non-damaging ground motions have been studied in the mining and construction industries, leading to the development of standardized acceptability criteria (Dowding, 1996). Majer et al. (2012) recommended that these criteria be included in best-practices guidelines for induced seismicity at geothermal sites. Risk assessments at GCS sites could also benefit from these recommendations. A community's reaction may also depend on the rate of natural seismicity in the area, which will impact both seismic design standards and general experience with earthquakes.

In summary, conventional PSRA methodologies provide a solid and rational foundation for performing seismic risk assessments at carbon storage sites. While the overall framework is sound, a number of important gaps and uncertainties exist when adapting individual components to the nuances of fluid injection operations. The research community is making good progress on these issues, however, and one may hope that tools for performing dependable seismic risk assessments would become broadly accessible in the near future.

4. Advances in Risk Assessment Approaches

The area of quantitative risk assessment and probabilistic modeling for CO_2 storage sites was in a nascent stage at the time IPCC report on CCS was published. At that time, most of the approaches applied in the field were qualitative and were based on FEPs/Scenario analysis. Over the past decade, the risk assessment approaches have evolved significantly, some drawing from expertise within the oil and gas industry and from assessment techniques developed within the field of nuclear waste disposal. Both, the qualitative and quantitative risk assessment approaches have evolved and have been applied to field projects (Table 5, NETL, 2011). The qualitative approaches have focused extensively on expert elicitation, risk register and bow-tie diagrams (Hnottavange-Tellen, 2015; Gerstenberger et al. 2013; Tucker et al. 2013; Polson et al. 2012). Semi-quantitative and quantitative approaches have utilized approaches based on expert elicitation combined with risk matrix (e.g. Schlumberger's Carbon Workflow, Hnottavange-Tellen et al. 2009), evidence support logic (e.g. CO2TESLA, Metcalfe et al., 2013a, Tucker et al., 2013) and Bayesian networks (Gerstenberger et al., 2015). Expert elicitation has been an important aspect of GCS risk assessment and has been used to elicit hazards, processes, their probabilities as well as parameters and their probability distributions. Performance assessment models based on systems modeling approach that provide the ability to simulate dynamic evolution for the entire GCS system (CO_2-PENS by Stauffer et al., 2009, Certification Framework by Oldenburg et al. 2009, QPAC-CO_2 by Metcalfe et al. 2013b) or parts of it such as wellbores (Viswanathan et al. 2008; Meyer et al., 2009, LeNeveu, 2008) have also been developed and applied to field projects (Metcalfe et al. 2013b, Dodds et al., 2011, Le Guen et al., 2011).

The approaches mentioned above can be applied at various stages of risk assessment from pre-selection to post-closure. Approaches such as Bayesian Network, CO2TESLA, CO_2-PENS, CF and QPAC-CO_2 have been developed for probabilistic risk assessment applications. While there have been a few examples of the application of models for quantitative risk assessment, the models that are used to predict the behavior of the engineered natural system at a CO_2 storage site are in need of additional validation and verification. Relatively few full-scale field sites have had data collected that can be used to validate such models, and it is very unlikely that a full-scale systems model (reservoir to groundwater) will ever have a full suite of data collected at a field site to validate it. Nonetheless, models for individual components of the CO_2 storage system can be potentially validated based on targeted measurements.

4.1. NRAP example of Quantitative Risk Assessment approach

One example of a quantitative risk assessment (QRA) approach that allows application of probabilistic approaches to take into account uncertainties on both spatial and temporal scales is being developed within US DOE's NRAP program (Pawar et al. 2014) for application to evaluating long-term containment risks. The NRAP approach builds upon the CO_2-PENS systems model (Stauffer et al. 2009) through an Integrated Assessment Modeling (IAM) approach to simulate long-term performance of a CO_2 storage site. In this approach a GCS site is represented as a collective system of components such as reservoirs, wells, faults, and groundwater aquifers. Reduced order models (ROMs) are developed to capture the CO_2 and brine movement and resulting processes/interactions within each of the components (Shahkarami et al, 2014, Oladyshkin et al, 2011). ROMs are typically developed from results of detailed process model simulations with Monte Carlo variation of input parameters for each of the systems components and are verified against the process model results. They could be developed from field data if there were sufficient data from a carbon storage site, but that is generally not the case, which is also why it is difficult to validate ROMs. Properly developed ROMs not only capture the underlying complex physical interactions but also have the advantage of being computationally efficient. Ultimately, the ROMs are brought together in an IAM approach in a manner that effectively captures the connectivity of all the system components. Coupled process models can be used to demonstrate validity of coupling multiple ROMs into an IAM framework to identify conditions under which the loose coupling of ROMs could fail to reproduce suitable results (Houseworth et al, 2013). However, while different pieces of a systems model can be verified and validated with process models and/or field data, the validation of a complete IAM with field data has not been done to date due to a lack of appropriate data for each component. Even if such data did exist, it would be a very complicated process to validate any single IAM due to all of the uncertainties present in the geologic system, and it is likely not necessary, as much confidence in the models can be gained from validation of individual components and verification of the integrated models by model to model comparison. The IAM can be used to simulate time-dependent performance of CO_2 and brine movement through various parts of a GCS site from injection to post-closure. The IAM is characterized by fast computational times and provides the ability to use it in a Monte Carlo simulation approach, where tens or hundreds of thousands of realizations of the total system performance can be performed in a relatively short time period (on the order of few hours to 1 day). The Monte Carlo simulations can be performed by sampling over a range of uncertain parameters each of which can be represented using statistical distributions. Results of the Monte Carlo simulations can be used to develop probabilities associated with CO_2 and/or brine movement out of primary storage reservoir and their impacts as part of quantifying risks. This approach also allows one to probe the uncertainties within the system and to identify which geologic or operational properties have the highest contribution (influence) to risk, whether they be properties of the reservoir, wellbores, groundwater, etc.

NRAP uses a similar approach to investigate the risks or hazards of induced seismic events (Foxall, et al, 2013). In this case, a background catalog of seismic sequences is needed. Process models are used to predict pressure and stress changes due to injection, and a catalog of seismic events is probabilistically determined based on the interactions between faults and the pressure plume resulting from injection. Seismic hazard is then forecasted based on a combination of the background and induced event seismic catalogs, which creates a new frequency-magnitude relationship for seismic events due to CO_2 injection. Similar to the IAM approach, this approach also allows for sampling multiple uncertain parameters during probabilistic calculations.

4.2. Data needs for Probabilistic Risk Assessment

In most risk assessment approaches for GCS, there is significant variability and uncertainty in the subsurface parameters used in the calculations. This presents a significant challenge for many GCS projects deployed in saline reservoirs, particularly ones which are not associated with previous hydrocarbon exploration or production, as relatively few characterization data are available for these sites. The number of uncertain parameters that represent a GCS system can be large. In general, only a smaller subset of these uncertain parameters is needed for probabilistic assessment, as many parameters have a relatively small impact on the overall performance of a GCS site. Sensitivity analyses can be used to identify which parameters may have an impact on performance of various components such as reservoir, wellbore, etc. (Bromhal et al, 2014; Wainwright et al, 2014).

The type of data needed to predict the overall risks depends on what risks the assessment is meant to address. Data for parameters such as reservoir permeability, porosity, thickness, and depth will be central to almost all of the risk assessments. The cost of acquiring data during a CO_2 storage project will likely be greater for a saline aquifer than for a hydrocarbon reservoir which have been previously explored and will likely have more characterization data available at the outset compared to a typical saline aquifer. On the other hand, a number of these basins can have geologic analogs where data may already be available due to hydrocarbon exploration and production. However, when it comes to other parts of the containment system such as wellbores or faults, data for failure rates, permeability statistics and fracture densities are not widely available and much more difficult to collect (as mentioned in Section 2). The semi-quantitative/quantitative risk assessment approaches give the ability to specify values of uncertain parameters as probability density functions (pdfs) which can be determined using available data or based on *a priori* knowledge as part of the expert elicitation process. Approaches such as CO2TESLA (Metcalfe et al, 2013) and BN (Gersterberger et al., 2015) also allow for incorporation of uncertainty associated with the confidence in knowledge of parameter pdfs. The scarcity of appropriate data makes it even more important to use the available data in the most efficient way and to estimate the uncertainty associated with the model predictions. In recent years stochastically based methodologies have been developed for this purpose (Korre et al., 2007; Grimstad et al, 2009; Shi et al, 2014; Govindan et al, 2014).

Ultimately, the probabilistic risk analysis can identify which uncertain parameters have the largest influence on risk and whether additional data collection should be performed to reduce the uncertainty so as to better constrain the risks. This can also help inform decision makers about acceptable range of uncertainties for a particular project.

While our capabilities to quantify risks for GCS have improved significantly since the release of the IPCC report, there is still a great deal of uncertainty, some of which we can handle well, and others of which are more challenging. Reservoirs can be characterized as they have traditionally been in the oil and gas industry, with the recognition that CO_2 storage projects might well start with a higher level of subsurface uncertainty than many hydrocarbon projects, but this will be compensated for by the significant and mandatory monitoring with highest intensity in the areas with the high level of uncertainty. Subsurface uncertainty such as pinch outs or sealing faults too close to a well has the potential to introduce performance risk and hence affect the economics of an injection project. Improved techniques to identify such features in advance could help reduce uncertainties and improve risk estimation.

Our capability to assess leakage risks, and particularly induced seismic risks, remain highly uncertain due to a lack of comprehensive data on potential leakage pathways, stress fields, fault locations and fault properties. There is also very little data on potential leakage properties of wells. While faults and fractures are generally unlikely to provide a leakage pathway all the way from the injection reservoir to the surface, their transport characteristics are very uncertain, and our ability to locate the faults, especially those with small offsets (< 10m), is limited. For induced seismicity risks, in-situ stress measurements at the storage site may be poorly constrained. Future research is therefore needed to improve methods for characterizing CO_2 storage systems, especially overburden sequences and the geomechanical properties of sealing rock systems.

4.3. Examples of Risk Assessment Applications

The application of risk assessment techniques to field projects has evolved over the last 10 years, partly by necessity as risk management processes have been implemented on the growing number of CO_2 storage projects at pilot, demonstration and commercial scale internationally. The applications of risk assessment techniques have ranged from characterization of leakage or containment risk to site performance risks. We provide a few examples to demonstrate applications of different types of risk assessment techniques. We give two examples of containment risk assessment, one for a pilot test (CO2CRC Otway Project) and another for an industrial scale project (In Salah CO_2 Storage Project). As mentioned earlier, there are multiple other examples of applications of risk assessment to a range of field projects (e.g. Hnottavange-Telleen, 2015, Metcalfe et al., 2013a, Metcalfe et al., 2013b).

4.3.1. Application of the RISQUE Method for Leakage Risk Assessment – CO2CRC Otway Project Stage 1 Example

The Risk Identification and Strategy using Quantitative Evaluation (RISQUE) method, developed by Bowden et al 2001, has been applied to many CO_2 storage examples including various sites in Australia (Bowden and Rigg, 2004), the CO2CRC Otway Stage 1 Project (Watson, 2014), the In Salah CO_2 Storage Project (Dodds et al, 2011) and the Weyburn-Midale Project (Bowden et al, 2013). RISQUE is a quantitative risk technique, based on the judgment of a panel of experts, which provides a transparent process allowing any stakeholders to simply yet measurably understand the risks in a CO_2 injection process.

An illustration of the RISQUE risk assessment process is the application to the CO2CRC Otway Project Stage 1. In 2008, the Otway Project produced from a natural CO_2-rich gas field, transported via a 2km pipeline, injected and stored into a depleted Naylor gas reservoir in the onshore Otway Basin, south east Australia. The 25 – 30m thick Cretaceous Waarre C Sandstone reservoir is a fault bounded (3 sides) structural trap, overlain by a ~300 thick mudstone seal. These bounding faults terminate within the overlying mudstone, preventing migration into the overlying aquifers. Due to the recent depletion of the pre-existing gas Naylor gas field, the structure was also pressure depleted.

The Otway Project combined the proprietary RISQUE method with CO2CRC's own research using a technique where specific risk categories were populated with quantitative risk parameters (Bowden &Rigg, 2004; Streit& Watson 2004). While CCS was considered to be a new application for RISQUE, the project benefitted by having a risk tool and methodology that met industry standards. In workshops facilitated by experienced risk assessment professionals, the range of static properties in the identified leakage mechanisms (e.g. faults, wells) and associated uncertainties were compared to the uncertainties in modelled dynamic changes invoked in the subsurface due to CO_2 injection and various CO_2 leakage scenarios. The overall question assessed in the workshops was 'could injected CO_2 leak out of the defined storage container?' To add quantification to the assessment, the project team established leakage limits at less than the likely retention suggested by the IPCC (IPCC, 2005). Therefore the acceptable leakage limit was set at 1% total volume stored over 1,000 years. This allowed the ranking of the Otway Project to be compared to other projects. The process of quantification of containment risks was to systematically define each risk on the following basis:

- Likelihood of leakage occurrence (0–1 represented at a log scale);
- Impact in terms of leakage rate (tonnes CO_2 per year);
- Duration of leakage (time that the event would be active).

Two containment risk assessments were performed for the Otway Stage 1 Project. The 2005 assessment was performed to assess project viability and gauge the data needs from the planned CRC-1 injection well. The 2007 risk assessment was performed after the CRC-1 well was drilled to incorporate additional data and interpretations and to prepare the Project for final approvals. The results of the two containment assessments of the Otway Project containment risk performed in 2005 and 2007 are shown in Figure 4 and Figure 5, respectively.

Overall the RISQUE method assessed the containment risk as low for the Otway Project, with each identified risk within the threshold targets and considered acceptable on this basis. The outputs and recommendations from the RISQUE method led to further targeted geological characterisation and dynamic modelling and drove the optimisation of the Project's monitoring program to ensure containment.

This risk application was essential in progressing the project as it: 1) provided a structure for integrating a diversity of data sources and site characterization steps; 2) provided regulators with a high level of confidence in the rigor of the evaluation process; and 3) provided the community a transparent process so that they themselves could easily judge that the project would be undertaken in a safe manner. Few other injection projects have documented the risk assessment process in such detail. The experience at Otway has shown the importance of ensuring that a rigorous and well-documented risk assessment process is followed.

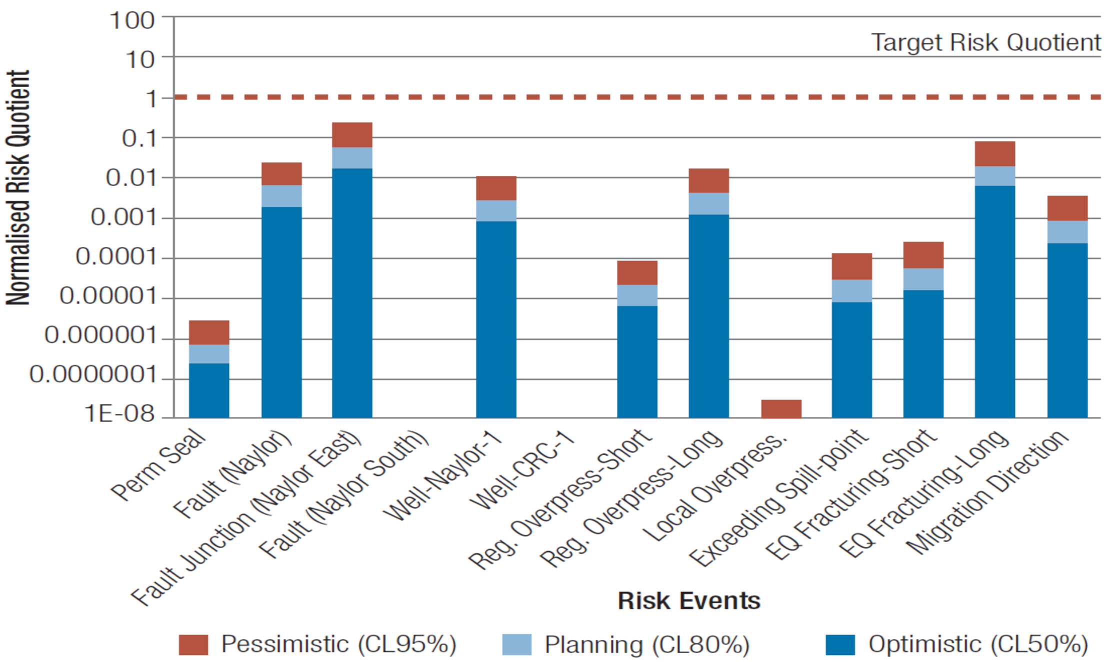

Figure 4. 2005 RISQUE output for the Otway Project, showing the assessment before the new CRC-1 injector well was drilled and interpreted (Watson, 2014).

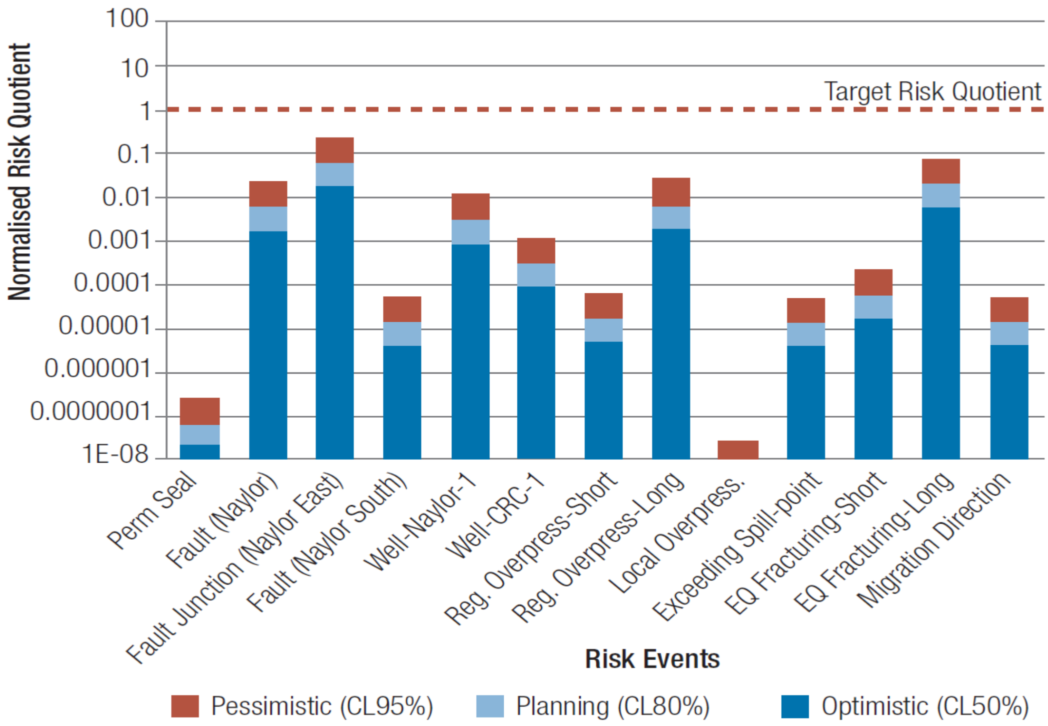

Figure 5.2007 RISQUE output for the CO2CRC Otway Project Stage 1. Each risk is plotted as a quotient on a log axis relative to the Target Risk Quotient. An optimistic, planning and pessimistic quotient is provided for each risk to representing input uncertainty (Watson, 2014). The risk quotient is determined as a function of probability and impact relative to an acceptable leakage limit of 1% leakage over 1,000 years.

4.3.2. Leakage Risk Assessment Applications to In Salah

From 2004 to 2011, 3.86Mt of CO_2, separated from produced In Salah gas fields, was injected into the water leg of the Krechba gas reservoir in the southern Sahara desert in Algeria. The ~20m thick Carboniferous C10.2 reservoir is sealed by ~950m of carboniferous mudstones, topped by a ~5m anhydrite cement. Overlying this is a mixed Cretaceous sandstone and mudstone sequence, which is the regional potable aquifer (Ringrose et al, 2013).

The joint industry operators carried out extensive analyses of the Krechba system including several risk assessment efforts. The long injection history at Krechba, and associated characterisation, modelling, and monitoring data provided a test-bed for evaluating various risk assessment approaches. These risk assessments included the RISQUE method (Dodds et al, 2011), the certification framework (Oldenburg et al, 2011) and a temporal risk analysis (Dodds et al, 2011); examples of the latter two are discussed here in detail.

The Certification Framework (CF) is a risk-based process, developed for the CO_2 Capture Project (CCP; http://www.co2captureproject.org), to assist in certifying sites for CO_2 storage. The purpose of the CF is to provide a framework for the various project stakeholders to analyse leakage risk in geologic CO_2

storage in a simple and transparent way and to certify start-up and decommissioning of geologic CO_2 storage sites (Oldenburg et al, 2009). CF simplifies the storage system into the leakage source, leakage mechanisms (faults and wells), and compartments of leakage impact (e.g. underground source of drinking water). A product of the probability of leakage and impacts to compartments is calculated using an underlying catalogue for CO_2 flux and leakage risk is determined against a pre-determined threshold (Figure 6).

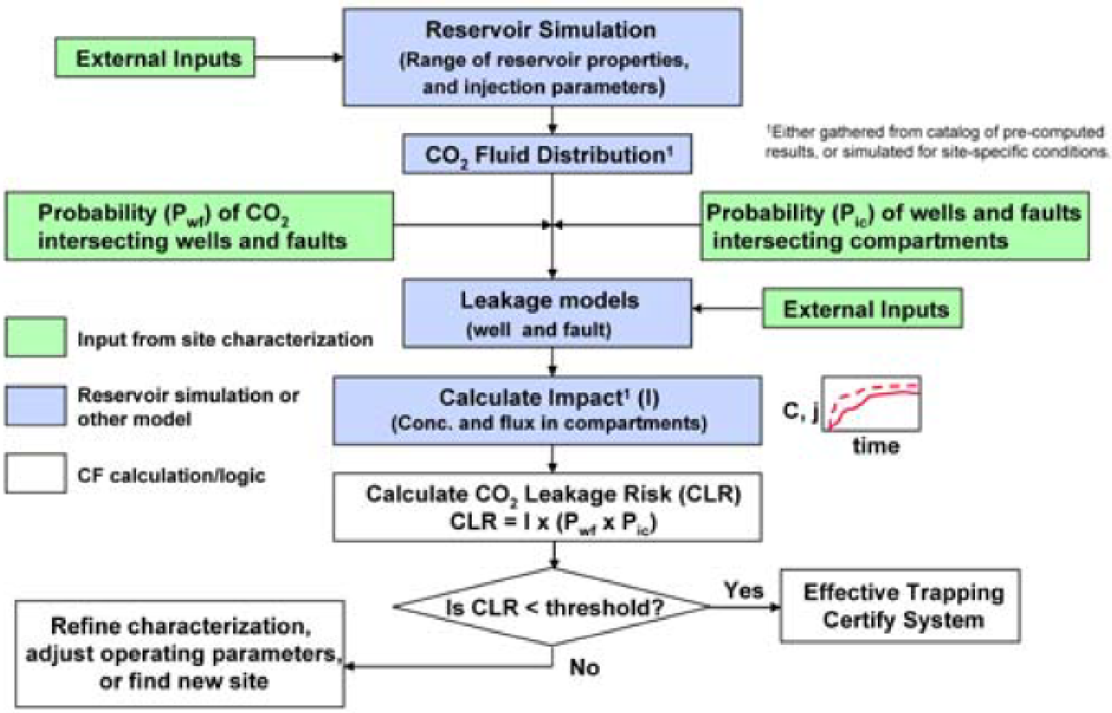

Figure 6.Flow chart for the CF approach (Oldenburg et al, 2011)

The CF was applied to the In Salah CO_2 storage project datasets at three different states of knowledge: pre-injection stage, at start of injection around mid-2004, and four years into injection in September 2008 (Oldenburg et al, 2011). This example refers to the 2008 state of knowledge. The CF utilises likelihood terminology in a similar manner to the RISQUE method, then expresses the outputs in a qualitative sense.

The CF analysis defined differing temporal periods of the storage system according to production timing of the Krechba gas field, as CO_2 migration into the gas cap during the planned ~20 year production period was undesired, while after production migrating CO_2 could utilise this pore space without adverse impact. The CF determined that the risk of CO_2 leakage into the gas cap during the production period was low. The CF also assessed leakage via wells, faults/fractures, defining both an upper and lower boundary to the system. This vertical leakage was determined with a risk range from *de minimis* to low. The method correctly highlighted a relatively higher CO_2 risk by well leakage, which was subsequently confirmed when CO_2 breakthrough was observed at the nearby KB-5 well in 2007 (Ringrose et al, 2009). The method also identified a higher risk of vertical leakage into the caprock than initially estimated, following analysis of new seismic data, satellite data and dynamic/geomechanical models (Ringrose et al, 2013). Based on these CF output recommendations were made to regularly assess the integrity of legacy wells KB-2, 4 and 8, and to limit injection pressure (Oldenburg et al, 2011).

A new risk assessment technique was also developed and applied to In Salah to assess the temporal and spatial changes in risk across the CO_2 storage project (Dodds et al, 2011). As mentioned in the Introduction, the concept of a temporal risk profile has been considered by other groups internationally (Benson, 2007, Pawar et al., 2014) to assist in understanding not only the level of leakage risks, but how these risks are increasing/decreasing in time and space. Knowing the temporal and spatial distribution of risk allows for optimization in the development and execution of storage system monitoring and risk management.

The QRTT (Quantitative Risk Through Time) technique, an internal BP methodology, was used at In Salah to evaluate the relationship between the risk mechanisms for CO_2 loss (derived in a similar manner as a RISQUE) and the stochastically forecasted, changing dynamics of the storage system (i.e. formation pressure, fluid chemistry) (Dodds et al, 2011). The In Salah QRTT analysis examined the risks along three migration pathways, identifying mechanisms for CO_2 leakage (risk mechanisms) from the three points of injection (spatially and temporally) until 1,000 years after the end of injection. The QRTT analysis utilized the 2008 URS RISQUE risk assessment outputs as a starting point for the temporal analysis, assuming that the likelihoods for relevant risks were judged at the maximum likely pressures that each risk mechanism would experience.

The In Salah CO_2 Storage Project's temporal risk analysis output shows a series of risk curves for overall temporal risk, fault/fracture (overburden integrity) risk, well integrity and lateral migration (Figure 7).

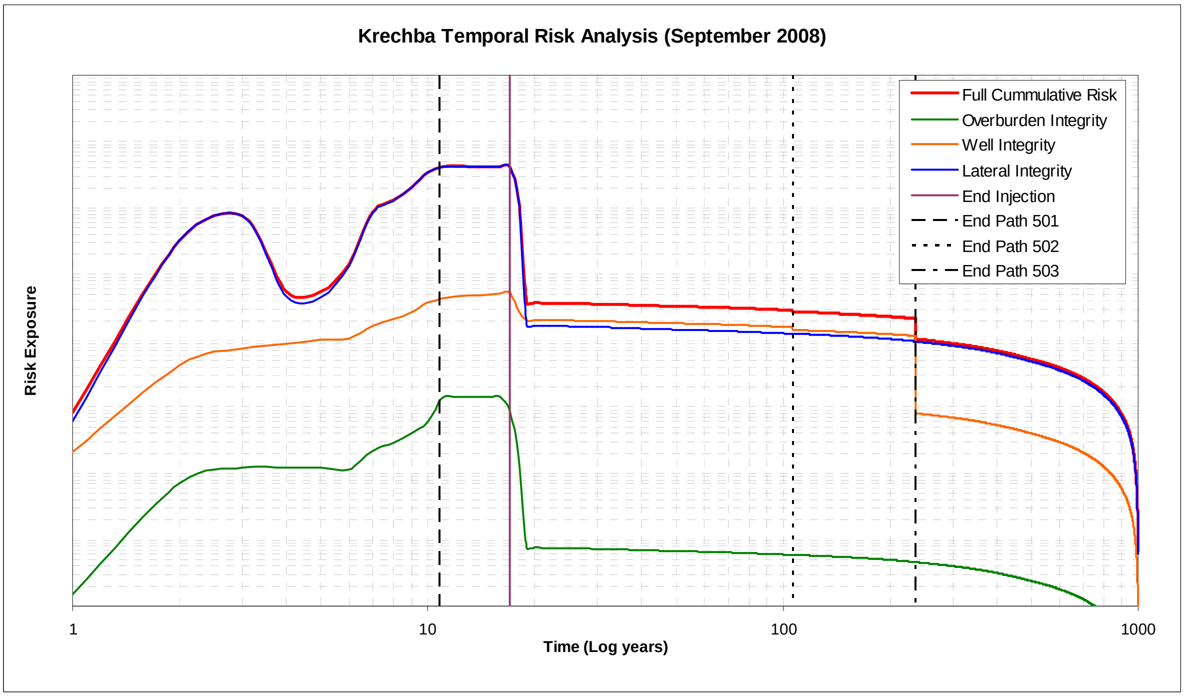

Figure 7.Full quantitative temporal risk profile for the In Salah Storage Project (risk exposure and time axis in log scale). Vertical lines represent end of lateral migration paths from each injector well and end of injection (Dodds et al, 2011).

The temporal risk output successfully determined that heightened project leakage risk occurs during the injection phase. The majority of risk is a consequence of the high injection pressure relative to the low permeability and small pressure window of operation for the In Salah Project. Seeing maximum risk in the operational stages of a project is an ideal scenario, as the ability to respond to risk is easiest when all wells are still accessible, and facilities and expertise are at hand to manage any required activity.

5. Site Performance Risks

The multiple field projects undertaken over the last 20 years have highlighted that site performance risks need to be addressed to ensure a successful GCS operation. Ultimately, successful CO_2 storage requires successful well operations, and a successful well operation requires a degree of flexibility and attention to details of the formation properties in the vicinity of the injection wells. Well operations, including modifications to the initial well plan, should be regarded as important mitigation measures used to contain and reduce the set of risks identified at the outset of any project. Two critical GCS site performance risk criteria include injectivity and capacity. Injectivity refers to the ability of a particular injection well to deliver CO_2 into the storage formation (controlling the injection rate) while capacity refers to the available volume for CO_2 storage (limiting the cumulative injection total). Injectivity can most simply be defined by the injectivity index, II_{CO2}, where

$$II_{CO2} = q/(P_{wi} - P_{res})$$

where, q is the flow rate,
P_{wi} is the injection well pressure,
P_{res} is a reference far field reservoir pressure

Additional terms can be added for wellbore effects, usually defined as a 'skin' factor. However, due to the compressibility of CO_2, pressure gradients within the wellbore, and multi-phase flow processes this simple relationship may be difficult to apply and a more advanced treatment of CO_2 injectivity is usually required, such as the pseudo-pressure method proposed by Al-Hussainy et al. (1966), where:

$II_{CO2} = q/[m(P_{fhbp}) - m(P_{res})]$, where $m(P)$ is the integral of pressure along the injection interval.

More generally, the limits on injection rate can be grouped into wellbore effects (e.g. pore-clogging, formation damage and fractures), near-wellbore reservoir heterogeneities (e.g. stratigraphic barriers or faults within a few 100m of the well) and far-field reservoir effects (such as formation continuity and pressure communication with other rock formations). Multi-phase flow effects may add further complexity, requiring reservoir simulation of flow dynamics at the near-wellbore and far-field scales.

The CO_2 storage capacity of a given rock formation is defined in terms of rock volume (V_b), net-to-gross ratio (N/G) which is the proportion of gross rock volume formed by the reservoir, porosity (ϕ), and fluid density ($\rho_{CO2}^{(P,T)}$), most commonly using a form of the following equation:

$M_{CO2} = V_b \times N/G \times \phi \times \rho_{CO2}^{(P,T)} \times E$

where, E is an efficiency factor, typically in the range of 0.01 to 0.05.

In a pure aquifer storage system with closed boundaries and without fluid extraction, the pressure increase due to CO_2 injection is proportional to the amount injected and the product of compressibility and the storage aquifer volume in pressure communication. Without fluid extraction the capacity is limited by the following factors:

- Compressibility of water
- Compressibility of the formation
- The volume of formation and water in pressure communication with the injector
- The difference between the hydrostatic pressure and the caprock formation breakdown pressure or fault transmission pressure.

The capacity of a formation to store CO_2 can be greatly increased by extracting formation fluids: either by the production of hydrocarbons, or explicit brine extraction. Extraction relieves the pressure, countering the fact that water has a low compressibility, and could increase the efficiency by up to an order of magnitude. The limiting factor turns from pressure to the time of CO_2 breakthrough at the water production wells and subsequent shut in, akin to managing the conformance in a CO_2-EOR operation.

For example, the Gorgon project on Barrow Island in Australia intends to extract water simultaneously with CO_2 injection. The Peterhead/Goldeneye CCS project in the North Sea intends to benefit from the underpressure in a depleted gas field, caused by six years of gas production.

The basic definitions of capacity and injectivity mentioned above, while valid for simple cases, belie a more complex relationship between the two which are in fact closely interrelated in practice. In simple terms, with an unlimited number of injection and production wells one might be able to utilize the estimated formation capacity, but with a limited number of injection wells the actual CO_2 storage capacity will be limited by both the actual achieved injection rates and the reservoir architecture controlling the overall storage capacity. For a heterogeneous reservoir system, lateral and vertical heterogeneities and flow barriers may lead to further limitations on injectivity and capacity compared to the case where uniform rock properties are assumed.

The majority of the promising prospective sites for CO_2 storage are saline aquifers, where limited data is available and the lack of field operational experience limits our ability to estimate injectivity and capacity. One approach to address this issue, before appraisal injection data becomes available, is based on the premise that individual geological formations and their characteristics can be assessed on the basis of their depositional and tectonic setting and, if available, the reservoir/site history of nearby hydrocarbon exploration and/or production systems. Although reservoir properties of potential storage formations typically exhibit large spatial and temporal heterogeneity, there is some structure to this variability which can be characterised using spatial modelling methods. Combining this with stochastic storage reservoir modelling and injection scenario analysis provides the opportunity to develop key performance indicators specific to the CO_2 storage formation systems considered (Korre et al., 2013). Key performance indicators, such as the Period of Sustained Injection (PSI) and the Fraction of Capacity Utilised (FCU), may be used to select an appropriate CO_2 storage site. Optimisation studies that take into account storage site design constraints, such as the number and locations of injection wells, the maximum allowable bottom-hole pressure and well-rate allocation, could be used to estimate optimal storage capacity while minimising risks of unwanted CO_2 migration (Cameron and Durlofsky, 2012; Babaei et al., 2014a, b).

5.1. Site Performance Management Case Studies

The complex interplay between the factors controlling injectivity and capacity are nicely illustrated by the injection history observed at the Sleipner and Snøhvit projects offshore Norway. At Sleipner, initial problems with injectivity into the relatively unconsolidated Utsira sand formation were resolved by re-perforating the injection interval and installing sand and gravel packs (Hansen et al. 2005), leading to a well completion set-up (Figure 8) that has enabled steady injection of CO_2 for over 18 years. Following this initial well operation, CO_2 injection at Sleipner has not been limited by injectivity, and most of the focus has been on monitoring and modelling the CO_2 plume development in order to understand the long-term storage capacity. The 20-year operational history of this injection well also builds confidence in the durability of a well system specifically designed to handle CO_2.

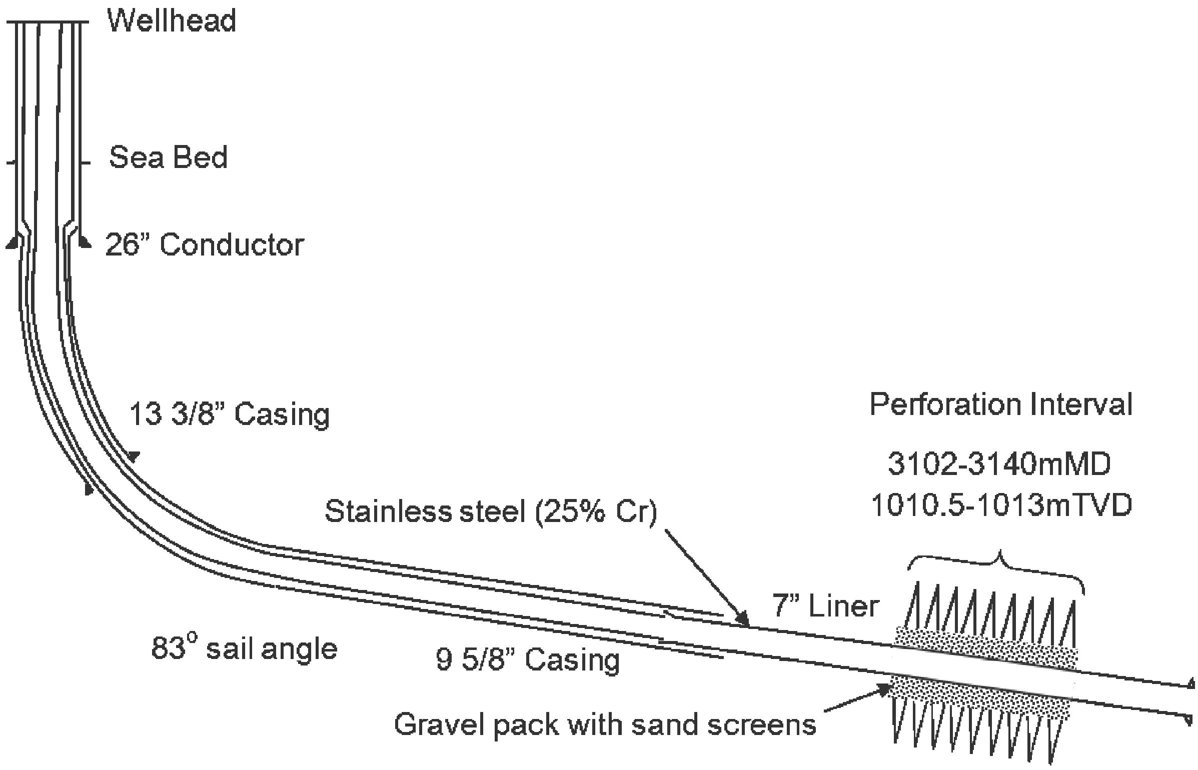

Figure 8. Summary of the Sleipner CO_2 injection well completion set-up, after the re-perforation operation (redrawn from Hansen et al, 2005).

Well performance was a key factor at the Snøhvit CO_2 injection site in the Barents Sea. Two main factors gave rise to higher than expected pressures in the injection well: a near-wellbore effect and a more far-field reservoir heterogeneity effect. Note that the injection well design included a downhole pressure and temperature gauge deployed at the casing shoe c. 800m above the injection interval, allowing for detailed analysis and interpretation of the injection pressure history (Figure 9).

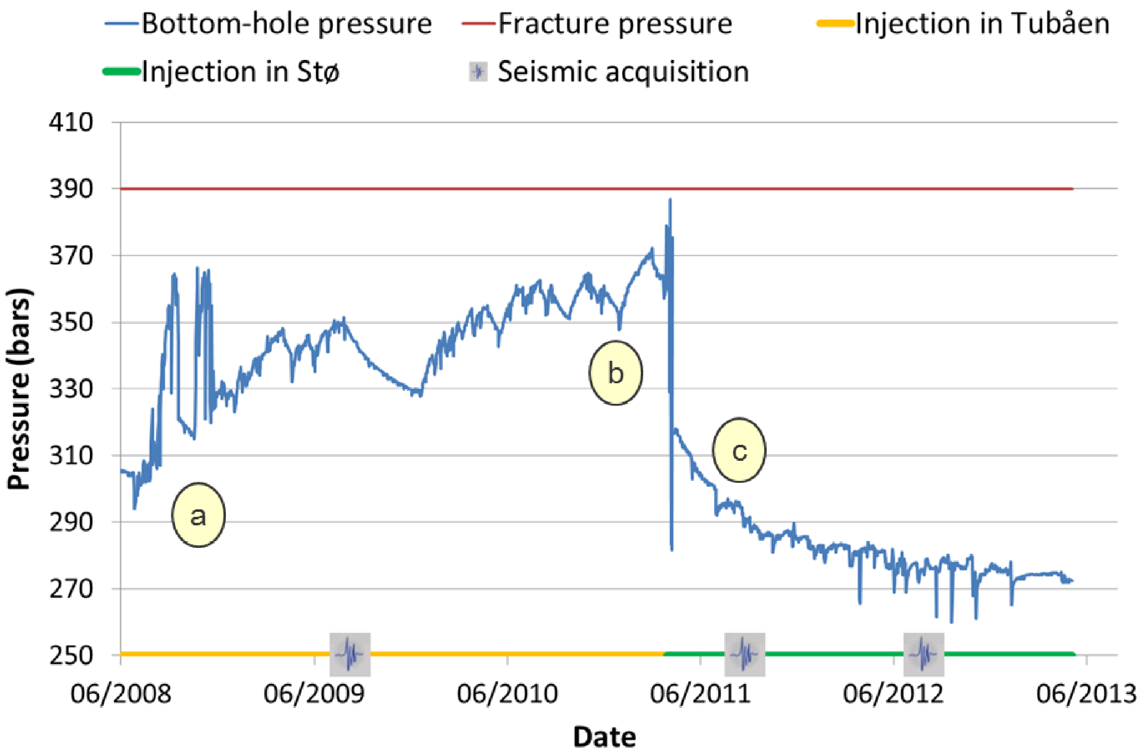

Figure 9. Pressure history at the Snøhvit CO_2 storage site (2008 to 2013) with time-lapse seismic acquisition surveys. Three main features of the injection pressure history are: a) early rise in pressure due to near-wellbore effects related to salt drop-out, b) a gradual rising trend in pressure due to geological flow barriers in the Tubåen Formation, and c) pressure decline to a new stable level following well intervention and diversion of the injection into the overlying Stø Formation.

Injection started in June 2008 via a vertical well with three injection intervals in the fluvial Tubåen Formation at a depth of 2600m. During the first 6 months of injection the flowing bottom-hole pressure rose by 40-50 bars over the expected injection pressure. This pressure rise was interpreted as a near-wellbore effect, and resolved by adding minor amounts of a Methyl-ethylene-glycol (MEG) solution to the injection stream (Hansen et al, 2013). The pressure rise during this initial period was probably due to salt drop-out caused by the interaction of dry-CO_2 with formation brine, although pore-clogging by fines migration may also have been a factor. The addition of MEG modified the dissolution-precipitation reaction, reducing the pore-clogging effects. As the injection continued and the CO_2-brine front extended outwards into the formation these near-well effects became less important and the need for chemical treatments was reduced. The second pressure trend seen in the Snøhvit data was the gradual pressure rise over the first 3 years of injection. This was interpreted as being due to the presence of reservoir barriers in the region around the injection well, although it was initially unclear what these barriers might be. The decision to acquire the first time-lapse seismic survey in 2009 (Eiken et al. 2011), in order to understand the CO_2 distribution in the reservoir, proved very successful and showed that two main reservoir factors were at play:

- Stratification: The seismic amplitude-change data showed that most of the CO_2 was entering the lower of the 3 perforated intervals (Hansen et al. 2013, Grude et al. 2013)

- Barriers: fluvial channel architecture and fault compartments were also evident on the time-lapse seismic data, strengthening the argument that reservoir barriers were causing the gradual pressure rise (Osdal et al., 2014).

Analysis of the pressure time series data (Hansen et al. 2013, Chiaramonte et al. 2014) identified the presence of two partial pressure barriers around the injection well, one at around 500m and a second at around 3000 m . The first is probably a channel-margin stratigraphic barrier, while the second is more likely to be a fault. Using this integrated analysis of pressure gauge data and time-lapse seismic data, the Snøhvit operations team planned and executed a well intervention operation in 2011, leading to an improved injection solution utilizing the overlying shallow marine Stø Formation (Osdal et al. 2014). Injection well pressures have now stabilized using the modified injection plan.

5.2 Summary of site performance risks

These operational examples of CO_2 injection history provide an important basis for developing best practices for managing site performance risks. It is clear that guidelines for CO_2 injection well management should include the following:

- Appreciation of the interaction of wellbore, near-wellbore and reservoir factors in controlling the actual injection performance;

- The initial injection well completion plan may often need to be revised and improved to respond to actual formation properties (i.e. injection wells need back-up solutions or alternative injection options);

- Down-hole pressure gauge data is vital for injection well management and should be prioritized wherever possible;

- Integrated use of monitoring data (geophysical and downhole) with advanced analysis of actual reservoir performance, allows injection strategies to be adjusted and optimized to the *in situ* reservoir conditions.

In terms of risk management for CO_2 storage projects during the transition from appraisal to the deployment and operational stages, this integrated analysis of wellbore, near-wellbore and reservoir factors is vital. A flexible and proactive injection well management plan should allow for individual risk factors to be mitigated and minimized during the initial stages of the storage operation.

6. Market Failure Risk

In the previous sections we have explored the technical risks including containment and site performance risks. In addition to these, successful deployment of GCS projects necessitates assessment of market failure for prospective developers. By their very nature storage projects carry significant exposure to counterparty risk. This has been discussed by the Zero Emissions Platform (ZEP) in their recent report of Transport and Storage business models (ZEP, 2014). A storage developer has to have confidence that there will be an income stream sufficient to cover the project investments and commitments: these are likely to include up to a decade of exploration and appraisal prior to injection, and the approximately two decades of post closure stewardship needed to prove that the CO_2 remains contained and that the modelled behavior conforms to the observed behavior (EC, 2009 b, c).

In a market where there is a well-established growth trajectory as the power and manufacturing industries decarbonize, the storage developer can be confident of filling the site capacity should they develop it in the right location. At the present time there is no evidence for an established growth trajectory; therefore storage developers are not emerging, and similarly large emitters do not have the confidence that storage will develop if they were to invest in CO_2 capture technology. The main exceptions are in areas of North America where there is an established market for CO_2 via CO_2 EOR projects and in Norway where there is a sufficiently high CO_2 emissions tax in place.

When considering CO_2 storage opportunities and associated risks from the market point of view, it is necessary to take into account the view point of different stakeholders. The developer, site owner, regulator, finance and insurance industry all have the option to support or not support the financial investment decision (FID) for a CO_2 storage project. Their perception of CO_2 storage project risks is indeed quite different.

For the CO_2 storage site developer, the stage-gate process used to establish that a positive FID can be made requires an iterative assessment of technical and economic risks at an increasing level of confidence while progressing development plans from the *identify and assess* stage-gate, through *analysis of options* and the *optimization of preferred plan,* which leads to FID. The site owner perceives risks in a similar process and is additionally sensitive to how risk and uncertainty affect how their portfolio of sites is utilized and is likely to perform on the longer time-horizon. For regulators, environmental and related risks are the priority; while for the finance and insurance industry, risk is perceived in terms of technical and legal due-diligence.

Technical risks discussed previously with respect to demonstration projects affect the CO_2 storage capacity, CO_2 injection rate, monitoring plan and post injection care plan, all of which affect costs significantly and need to be considered for FID. Additionally, infrastructure requirements which include different site development concepts, modification of existing or building up new injection platforms, subsea injection development, modification of existing production facilities for injection, or drilling new injection wells, may considerably change the capital and operational expenditures (CAPEX and OPEX) of CO_2 storage projects. Overlain on these choices are injection strategy aspects, such as injection rate, number of injection wells and injection duration, which affect costs dramatically. Finally, other key financial factors such as the CO_2 market price, bid payment fees, interest rate, inflation rate also play an important role in the storage costs (Figure 10), in turn affecting CO_2 storage project risks. Recent work, (Korre et al., 2014) is focusing efforts to establish how these risks and associated uncertainties relate to economic and market risks.

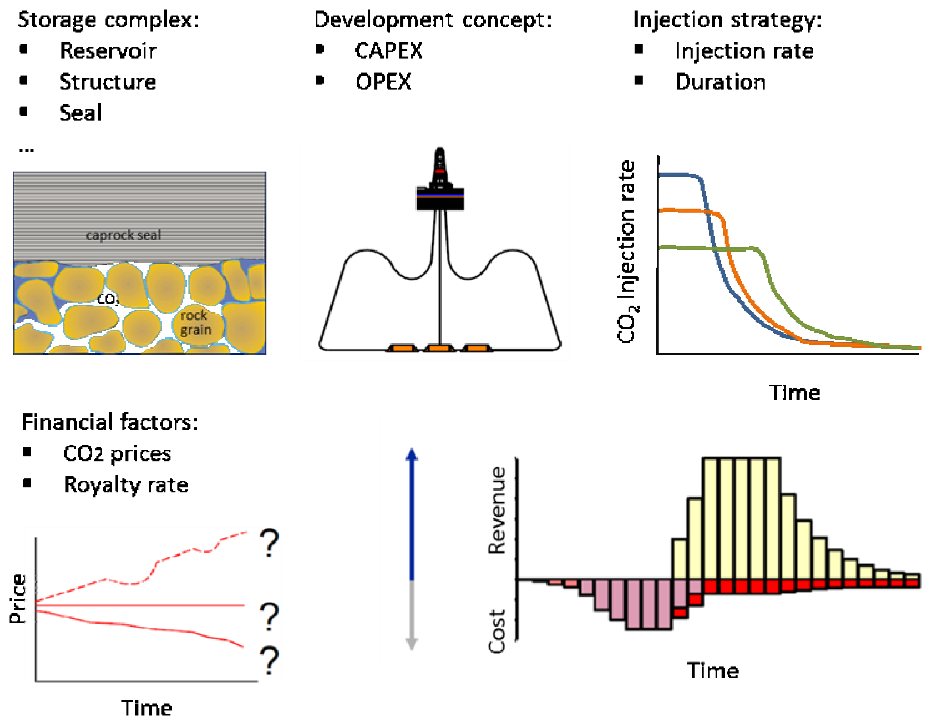

Figure 10. Key drivers of CO_2 storage cost uncertainty (Korre et al. 2014).

7. Risk Management

Risk management includes not only assessment of risks but also development of monitoring and mitigation strategies to minimize risks (IPCC, 2005). Risk management is an iterative process where estimated risks are updated based on monitoring data, advances in fundamental scientific understanding or changes in regulations and updated risk estimates are used to assess re-deployment of monitoring and mitigation strategies. An effective risk management approach also requires effective methods to communicate risks to the wider stakeholder group including, the regulatory authorities responsible for permitting.

In recent years, a number of field projects, especially the Quest and Peterhead/Goldeneye projects, have adopted bow-tie analysis. The benefits of using the bow-tie analysis for risk management have been realised by organisations world-wide across a variety of business sectors and the method has been in widespread use since the mid-1990s.

The bow tie method starts by identifying the “top level event”– in the case of CCS this is often leakage from the storage reservoir; though a project might make multiple bow-ties, one for induced seismicity, another for brine migration , and yet another for leakage to the surface etc. The method then identifies threats – for example, injection pressure. Finally it looks at the barriers – why will the injection pressure not cause a leak? with potential barriers, because there is a competent caprock with a measured fracture initiation pressure; because the injection pressure will be limited to below the fracture pressure; because the fault movement pressure has been determined to be below the pressure limit; because there is a secondary storage formation and another caprock; because there is microseismic monitoring which if triggered will cause the operators to stop injecting (a monitoring and correction barrier), to name a few.

The analysis repeats this for the right hand side as well. Suppose a leak takes place (say from a well), what are the barriers to stop it harming workers on the offshore platform? Barriers could be detectors and alarms to ensure that people will not enter the area; separation distances of accommodation from wells. These barriers exist to militate against the final consequence taking place. This analysis is done for all identified threats and mitigation paths, all barriers are explored.

A schematic bow-tie is shown in Figure 11 with the dark boxes indicating barriers also called controls or safeguards. First, there are passive safeguards that are always present from the start of injection and do not need to be activated at the appropriate moment. These passive safeguards exist in two forms: geological barriers identified during site characterisation (e.g. caprock) and engineered barriers identified during engineering concept selections (e.g. well casing and cementation). Second, engineered active safeguards may be brought into service in response to some indication of a potential upset condition in order to make the site safe.

Engineered active safeguards are composed of:

- A sensor (monitoring technology) capable of detecting changes with sufficient sensitivity and reliability to provide an early indication that some form of intervention is required.

- Some decision logic to interpret the sensor data and select the most appropriate form of intervention.

- A control response capable of effective intervention to ensure continuing storage performance or to control the effects of any potential loss of storage performance. Effective control responses may include re-distributing CO_2injection amongst the existing wells to allow one well to reduce the rate and pressure of injection, alternatively an injection well may be abandoned and a replacement drilled elsewhere.

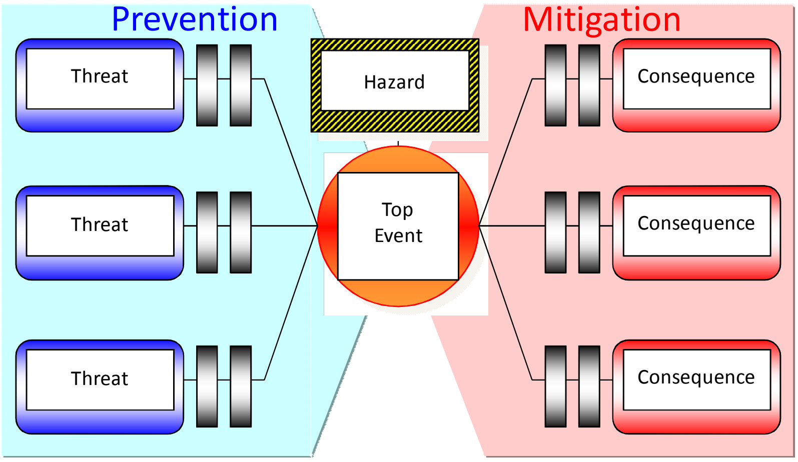

Figure 11. Schematic of a bow-tie diagram. The threat is on the left while the black bars indicate barriers to the top level event. On the right hand side again the black bars are barriers against escalation having the ability to stop the ultimate consequence from taking place.

This combination of a sensor, decision logic and a control response is the mechanism for additional risk mitigation provided by monitoring and mitigation. Figure 12 shows a schematic of the Quest project bow-tie diagram (Bourne et al., 2014). A similar approach adopted for the Goldeneye CO_2 offshore store in the North Sea is described by Tucker et al. (2013).

Experience at the In Salah project has illustrated that through the integration of data from a wide array of monitoring sources and the iterative improvement of coupled flow and geomechanical storage system models (Vasco et al., 2010; Bissel, et al., 2011; Shi et al, 2012; Gemmer et al., 2012;

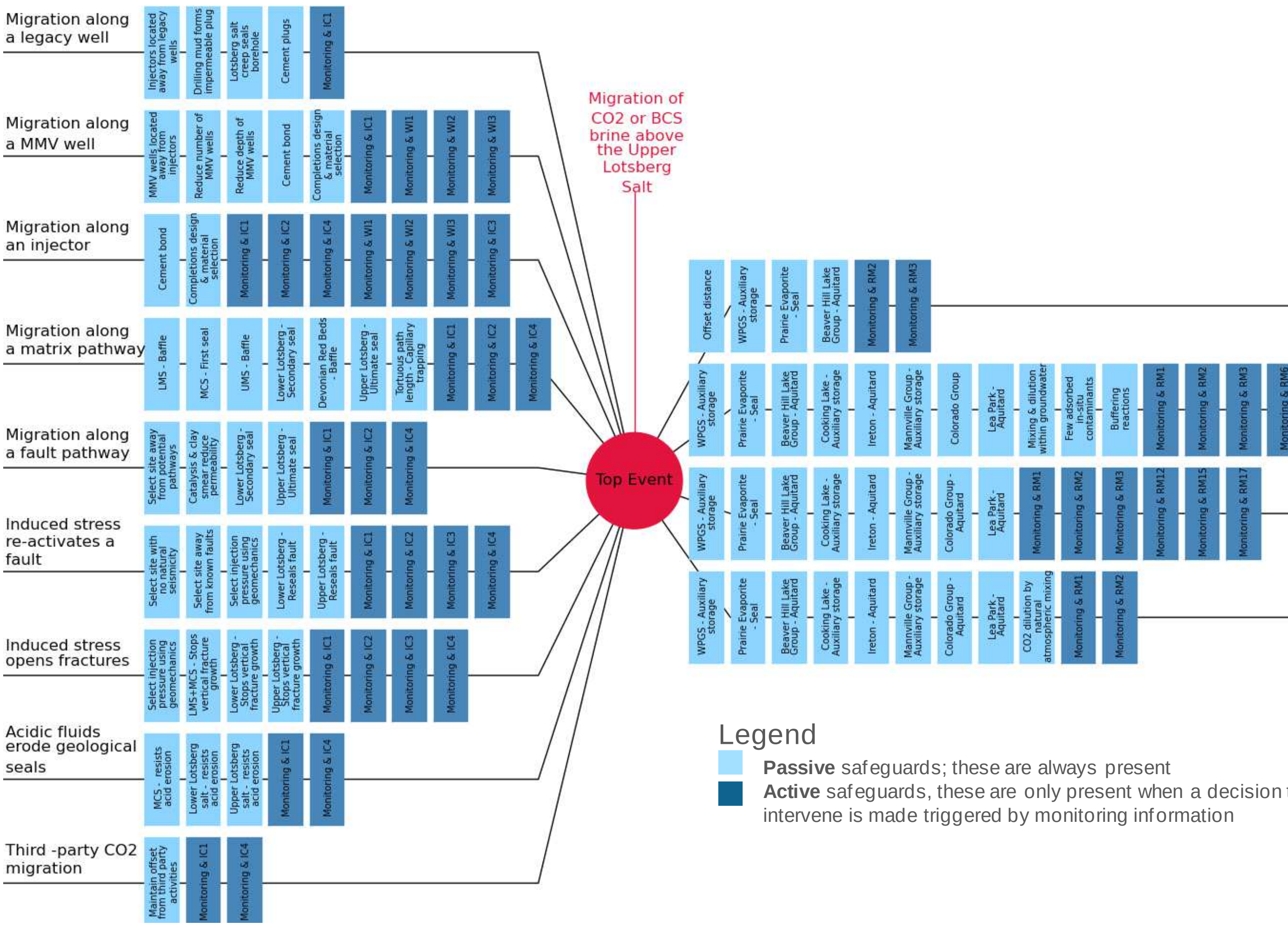

Figure 12. Summary of the safeguards in place to reduce the likelihood (left side) and consequence (right side) of any unexpected loss of containment at the Quest CO_2 storage site. The additional active safeguards are control measures triggered by monitoring.

White et al. 2014; de la Torre Guzman et al. 2014), it is possible to develop a detailed understanding of injectivity, flow and pressure behaviour during CO_2 storage operations. Such analysis can be used to assess the performance of fault and/or fracture zones that may be present in storage systems, deduce their transmissibility (de la Torre Guzman et al. 2014), and ultimately evaluate their role in controlling appropriate risk management strategies.

Experience from the offshore CO_2 injection projects at Sleipner and Snøhvit also demonstrates the value of integrated monitoring and mitigation measures to reduce and manage risks during the operational phases. While the risk assessment and monitoring approaches and their integration and deployment through field projects has evolved over the last decade, the demonstration of mitigation approaches has been limited beyond those mentioned in the context of site operations. Imbus et al. (2013) provide an overview of various approaches that can be used to mitigate leakage at GCS site, though they do mention that the effectiveness of these approaches needs to be tested in field projects. Additionally, there has not been much work on the evaluation of the effectiveness of different mitigation strategies for given conditions, or to address the consequences of mitigation actions. For example, production of brine from a storage formation can reduce leakage risks by reducing pressure and CO_2 plume sizes to a well-contained area, but introduce additional risks caused by the handling of the brine in surface facilities. Field tests can be potentially carried out at a site where leakage has been detected or controlled release experiments to help address several of these issues.

8. How do we rank severity of risks to projects today?

Recent work has indicated that the probability of releases of CO_2 via a geological pathway in a properly characterized and permitted store is extremely low (Senior and Jewell, 2012). The probability of release via a wellbore conduit, while also extremely low, is estimated to be higher than the geological pathway. This leads projects to the conclusion that they must concentrate additional monitoring safeguards at the wells.

A key point in GCS that is sometimes overlooked is that no CO_2 storage should be permitted without significant characterization and regulatory scrutiny. This means that storage site candidates with even a small chance of CO_2 leakage are unlikely to be permitted and that monitoring will always be mandated for residual areas of risk, and injection parameters will be set in such a manner that risk will be minimized. The Snøhvit project is a case in point. Injection pressures were monitored and the injection plan was modified as a result of increased pressure buildup.

Over the past decade at least 50 million tonnes of CO_2 have been injected into the subsurface in monitored CO_2 storage projects throughout the world. The operational risks that have materialized have been more related to injection performance and the effectiveness of monitoring installations. Rigorous risk assessment, characterization and risk management required as part of the permitting process has given confidence in developing projects that have very low containment risks.

9. Communication

Effective communication is an integral part of effective risk management. As mentioned in the Introduction, the stakeholder group interested in deployment of GCS is extremely diverse and includes policy makers, public, industry, and regulators. While the GCS field projects executed to date do have to take into account the public perception risk (acceptance of the project), no documented GCS risk assessment application exists where the public perception risk has been explicitly addressed as part of a structured risk assessment approach. On the other hand, the field projects have recognized this risk and have engaged in extensive outreach efforts as part of the risk management approach. An effective communication approach needs to demonstrate how the risk assessment approach has effectively taken into account various stakeholder concerns during the assessment process, how the uncertainties have been handled, what impact uncertainties have on risks, and how risk is managed via monitoring and mitigation actions. Addressing public perception has been an important element of various international CO_2 sequestration efforts, including US DOE's CO_2 Sequestration Regional Partnership program which has resulted in a Best Practice Manual for public outreach and education for CO_2 storage projects (US DOE, 2013). Greenberg et al. (2011) demonstrate how effective integration of risk assessment, communication strategies and project management can be used to manage not only project risks but also public perception risks.

10. Conclusions & Path Forward

Significant progress has been made in the risk assessment and risk management practices applied to GCS. The progress has been facilitated by development of regulations and over 45 international field projects. The experience with field projects has demonstrated that site performance risks and market failure risks need to be addressed to assure successful field projects and application of GCS technology at large-scale. Targeted research focused on issues related to major risk concerns such as leakage pathways and induced seismicity has helped to lower uncertainties associated with them. While it has been recognized that the probability of high risk events such as "well blowout" or "catastrophic caprock failure" is extremely low, there has been a rather limited effort to quantifying these probabilities. The FutureGen EIS application (FutureGen, 2007) has estimated the frequency of an eruptive event to be vanishingly remote (probability of $< 10^{-6}$ per 5000 years).

Over the last 10 years, the need for effective approaches for quantitative risk assessment has become increasingly apparent which has led to development of multiple quantitative risk assessment approaches, tools and their field applications. Even though the timescales for risk assessment have varied they have been of the order of 1000 years and have ranged between 1000 – 5000 years. There is still no consensus about what constitutes an appropriate time scale for risks at a geologic carbon storage site. Additionally, methods such as the Bow-Tie approach have been deployed to manage risks in large scale GCS projects, including, the Quest project. In addition to technical advances, tremendous progress has also been made to improve communications with GCS stakeholders in the context of development of field projects.

As we move forward multiple issues need to be addressed to improve overall risk management of GCS projects and remove barriers associated with large-scale GCS deployment. These include wider applications of quantitative risk assessment approaches and tools in order to improve and enhance their applicability, to validate their risk estimates, to increase their comprehensiveness and most importantly, to increase stakeholder confidence in their applicability. Additionally, further targeted research studies are needed to reduce uncertainties in critical parameters that influence key leakage risks and induced seismicity risks. It is also necessary to test effectiveness of risk management approaches integrating risk assessment with monitoring and mitigation. Further field testing to determine the effectiveness of mitigation and intervention approaches is a critical need that should be addressed to gain confidence in applicability of these approaches. Finally, even though significant advances have been made in communication with stakeholders, there is a need to further develop effective communication strategies to gain stakeholder confidence in the effectiveness of risk management approaches to minimize risks and acceptance of wide-scale deployment of GCS technology.

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