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Carbon Capture and Storage

S.J. Friedmann

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Carbon Capture and Sequestration Technologies: Status and Future Deployment

Dr. S. Julio Friedmann
Carbon Management Program Leader
Lawrence Livermore National Laboratory
7000 East Ave, Livermore CA 94550, USA
friedmann2@llnl.gov

Introduction

Carbon capture and sequestration (CCS) is the long-term isolation of carbon dioxide from the atmosphere through physical, chemical, biological, or engineered processes. This includes a range of approaches including soil carbon sequestration (e.g., through no-till farming), terrestrial biomass sequestration (e.g., through planting forests), direct ocean injection of CO_2 either onto the deep seafloor or into the intermediate depths, injection into deep geological formations, or even direct conversion of CO_2 to carbonate minerals. Some of these approaches are considered geoengineering (see the appropriate chapter herein). All are considered in the 2005 special report by the Intergovernmental Panel on Climate Change (IPCC 2005).

Of the range of options available, geological carbon sequestration (GCS) appears to be the most actionable and economic option for major greenhouse gas reduction in the next 10-30 years. The basis for this interest includes several factors:

- The potential capacities are large based on initial estimates. Formal estimates for global storage potential vary substantially, but are likely to be between 800 and 3300 Gt of C (3000 and 10,000 Gt of CO_2), with significant capacity located reasonably near large point sources of the CO_2.
- GCS can begin operations with demonstrated technology. Carbon dioxide has been separated from large point sources for nearly 100 years, and has been injected underground for over 30 years (below).
- Testing of GCS at intermediate scale is feasible. In the US, Canada, and many industrial countries, large CO_2 sources like power plants and refineries lie near prospective storage sites. These plants could be retrofit today and injection begun (while bearing in mind scientific uncertainties and unknowns). Indeed, some have, and three projects described here provide a great deal of information on the operational needs and field implementation of CCS.

Part of this interest comes from several key documents written in the lat three years that provide information on the status, economics, technology, and impact of CCS. These are cited throughout this text and identified as key references at the end of this manuscript.

When coupled with improvements in energy efficiency, renewable energy supplies, and nuclear power, CCS help dramatically reduce current and future emissions (US CCTP 2005, MIT 2007). If CCS is not available as a carbon management option, it will be much more difficult and much more expensive to stabilize atmospheric CO_2 emissions. Recent estimates put the cost of carbon abatement without CCS to be 30-80% higher that if CCS were to be available (Edmonds et al. 2004).

Carbon capture

CCS has two separate but coupled steps. The first is the separation and concentration of CO_2 from industrial flue streams, chiefly power plants. This first step is commonly called ***carbon capture*** and usually includes compression and transportation via pipeline. The second involves the injection of CO_2 as a dense, supercritical (liquid-like) phase into deep geological formations. This step is commonly called ***geological carbon sequestration***, or GCS. In short, the cost for CCS lies mostly in the capture stage. The risk lies mostly in the sequestration stage. Both steps are needed for a successful project.

In the first step, CCS requires the separation of CO_2 from industrial flue streams and concentration to CO_2 purities of 95% or greater (Thambimuthu et al., 2005). This limits compression costs and makes effective and efficient use of available sequestration resource (subsurface pore volume). Currently, three technology pathways exist for commercial CO_2 capture and separation:

- Post-combustion capture: This involves separation of CO_2 from nitrogen, commonly with chemical sorbents (e.g., monoethanolamine (MEA)).
- Pre-combustion capture: This involves conversion of fuel feedstocks (e.g. coal) into syngas via gasification, steam reformation, or partial oxidation and then shifting the syngas chemically to hydrogen and CO_2, and then separating the H_2 from CO_2. Currently, this last step is commonly done with physical sorbents (e.g., Selexol, Rectisol).
- Oxy-firing combustion: This involves combustion of fuels in a pure oxygen or O_2-CO_2 rich environment such that effectively no nitrogen is present in the flue gas. Separation of O_2 from air (N_2) is required and is the main cost element.

Each of these approaches requires substantial power to run the adsorption and air-separation units, raising operating expenses and increasing the amount of CO_2 emissions produced simply to drive the sequestration process. They also require more capital in plant construction and have differing operational costs and energy penalties. At present, each technology pathway appears equally viable from an economic and thermodynamic standpoint (Thambimuthu et al., 2005; Rao et al. 2006; MIT 2007).

Industry has substantial experience with each of these technology pathways, chiefly from operation of hydrogen plants, fertilizer plants, refineries, and natural gas processing facilities. CO_2 has been separated from industrial flue streams at scales much greater than 1 MMt CO_2/y (270,000 t C/y). Similarly, CO_2 has been separated from small-scale power plants, and the technology to scale these operations to plants of 200 MW or greater exists. Large pipelines transport millions of tons of CO_2 hundreds of kilometers, and millions of

tons of CO_2 and other acid gases are compressed and injected into geological formations every year. Thus, a great deal is known about carbon capture, separation, and transportation, and many OECD countries have regulatory frameworks in place to accommodate the permitting of separation facilities and pipelines.

Cost remains an important barrier to wider commercial deployment. However, as the concepts for geological carbon sequestration are proven to be reliable for current power plant technology, improved power plant designs are expected to be able to bring down sequestration costs dramatically. This year, several large pilot projects are testing pre-, post, and oxy-fired combustion tests at the 4-5 MW scale, a necessary precursor to broad commercial deployment. A number of technologies claim to be able to capture and separate CO_2 at \$9-11/ton CO_2, less than half the best available technology. As the results from these and future tests are made public, decision makers and investors will be able to plan better for plant economics and design.

Geological sequestration

A number of geological reservoirs appear to have the potential to store many 100's – 1000's of Gt of CO_2 (Benson and Cook, 2005). The most promising reservoirs are porous and permeable rock bodies at depth (Figure 1).

- *Saline formations* contain brine in their pore volumes, commonly with salinities greater than 10,000 ppm.
- *Depleted oil and gas fields* have some combination of water and hydrocarbons in their pore volumes. In some cases, economic gains can be achieved through enhanced oil recovery or enhanced gas recovery (Stevens, 1999; Oldenburg et al., 2004; Jarrell et al., 2002). Substantial CO_2-enhanced oil recovery already occurs in the US with both natural and anthropogenic CO_2. These fields provide much of the knowledge base we have about the potential issues related to CO_2 sequestration.
- *Deep coal seams*, often called unmineable coal seams, are composed of organic minerals with brines and gases in their pore and fracture volumes that can preferentially adsorb and bind CO_2 as well as store it in pores and minor fractures.

Because of their large storage potential and broad distribution, it is likely that most geological sequestration will occur in saline formations. However, initial projects have been proposed for depleted oil and gas fields, accompanying enhanced oil recovery, due to the high density and quality of subsurface data and the potential for economic return. Although there remains some economic potential for enhanced coal bed methane recovery much less is known about this style of sequestration (Benson & Cook, 2005; MIT, 2007, NPC 2007, US DOE 2007a). Even less is known about sequestration in basalts. As such, many workers are not convinced of the economic viability of sequestration projects in coal, basalts, or oil shales given today's technology and understanding (US DOE 2007b).

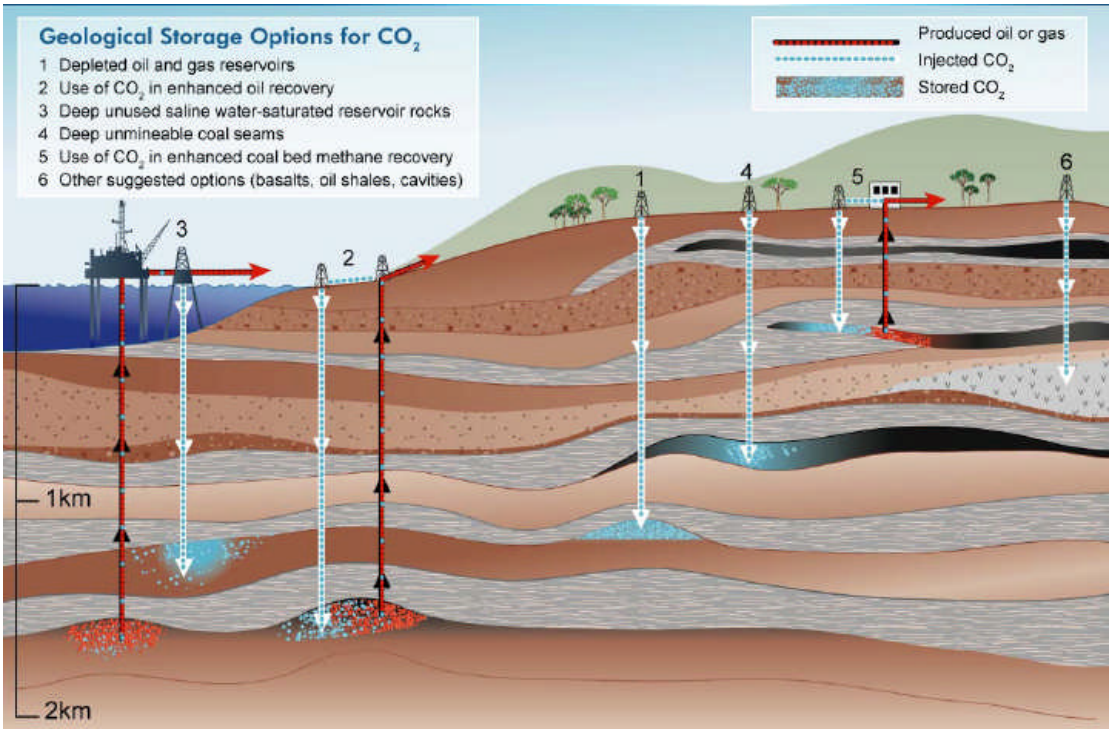

Figure 1: Options for storing CO_2 in underground geological formations. After Benson and Cook (2005).

Storage of large CO_2 volumes in geological formations requires that the CO_2 be relatively dense, so that storage capacity is efficiently used. Given typical geothermal gradients and hydrostatic loads, CO_2 is likely to be in a **supercritical** state at most target sites greater than 800 m depth (e.g., Bachu, 2000). At the likely range of injection pressures and temperatures for most projects, CO_2 would be buoyant and gravitational forces would push CO_2 upward from the injection point.

Consequently, trapping mechanisms are needed to store CO_2 effectively. For depleted oil and gas fields or for saline formations, CO_2 storage mechanisms are reasonably well defined and understood (Figure 2). CO_2 sequestration targets will require *physical barriers* to CO_2 migration out of the crust to the surface. These barriers will commonly take the form of impermeable layers (e.g., shales, evaporites) overlying the sequestration target. This storage mechanism is highly or directly analogous to that of hydrocarbon trapping, natural gas storage, and natural CO_2 accumulations. At the pore scale, *capillary forces* can immobilize a substantial fraction of a dispersed CO_2 bubble, commonly measured to be between 5 and 25% of the CO_2-bearing pore volume. The volume of CO_2 trapped as a residual phase is highly sensitive to pore geometry, and consequently is difficult to predict; however, standard techniques can measure residual phase trapping directly in the laboratory with rock samples.

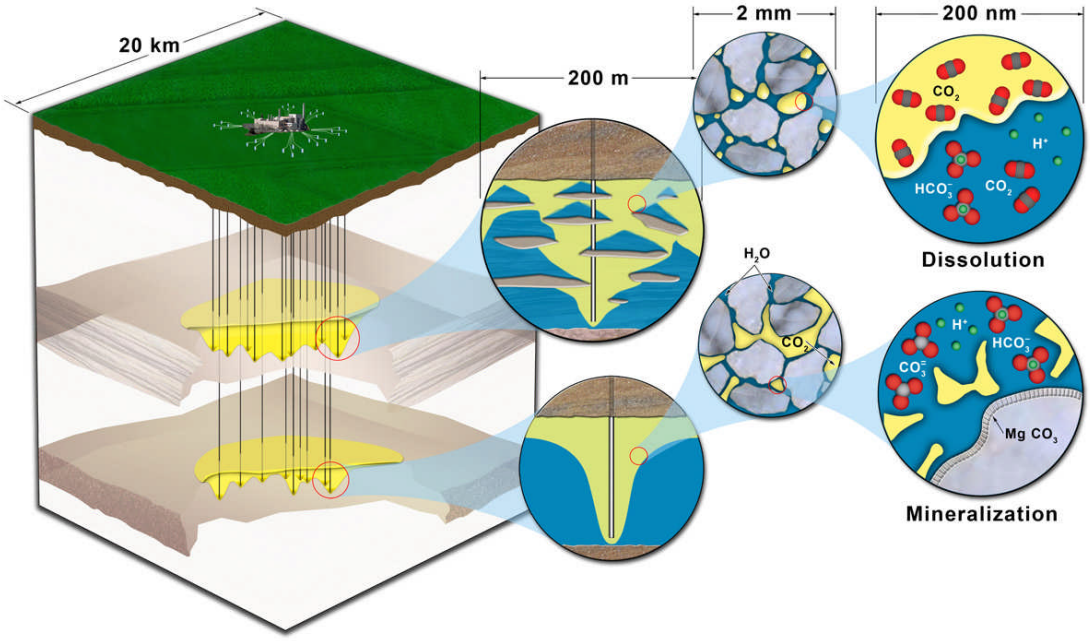

Figure 2: Schematic diagram of large injection at 10 years time illustrating the main storage mechanisms. All CO_2 plumes (yellow) are trapped beneath impermeable shales (not shown). The upper unit is heterogeneous with a low net percent usable porosity, whereas the lower unit is homogeneous. Central insets show CO_2 as a mobile phase (lower) and as a trapped residual phase (upper). Right insets show CO_2 dissolution (upper) and CO_2 mineralization (lower). After MIT (2007).

Once in the pore volume, the CO_2 will *dissolve* into other pore fluids, including hydrocarbon species (oil and gas) or brines. Depending on the fluid composition and reservoir condition, this may occur rapidly (seconds to minutes) or over a period of tens to hundreds of years. Once dissolved, the CO_2–bearing brines are denser than the original brines, and so the strong buoyant forces of free-phase gas are replaced by small downward forces. Over longer time scales (hundreds to thousands of years) the dissolved CO_2 may react with minerals in the rock volume to *dissolve or precipitate* new carbonate minerals. For the majority of the rock volume and major minerals, this process is slow, and may take hundreds to thousands of years to achieve substantial storage volumes. Precipitation of carbonate minerals permanently binds CO_2 in the subsurface; dissolution of minerals generally traps CO_2 as an ionic species (usually bicarbonate) in the pore fluid.

Although substantial work remains to characterize and quantify these mechanisms, the current level of understanding can be used today to develop estimates of the percentage of CO_2 that can be stored over some period of time. Confidence in these estimates is bolstered by studies of hydrocarbon systems, natural gas storage operations, hazardous waste injection, and CO_2-enhanced oil recovery (CO2-EOR). In the case of EOR, CO_2 has been injected underground for over 30 years. Current evaluations of CCS effectiveness based on our current understanding of trapping mechanisms estimate that more than 99.9% of injected CO_2 can be reliably stored over 100 years, and it is likely that 99% of CO_2 can be reliably stored for 1000 years (Benson and Cook 2005). While

these estimates are predicated on the assumption of careful siting and due diligence before injection, it reflects the view that the crust contains sites that are generally well configured to store CO_2 effectively.

Large-scale commercial deployment

In order to achieve substantial GHG reductions, geological storage needs to be deployed at a large scale (Friedmann, 2006), there must be minimal leakage from the underground storage reservoirs back to the atmosphere, and there must be minimal impact on other uses of the subsurface environment and the resources it contains. The issue of scale dominates deployment of GCS (Pacala & Socolow 2004; Edmonds et al. 2004; McFarland 2004; US CCTP 2005). These volumes would have geological carbon sequestration, providing 25-75 Gt C over 50 years, or 15-43% of emissions reduction needed to stabilize atmospheric CO_2 levels at 550 ppm (Pacala and Socolow 2004).

Today there are three well-established large-scale injection projects with an ambitious scientific program that includes monitoring and verification (Table 1): Sleipner in Norway (Arts et al., 2004), Weyburn in Canada (Wilson and Monea 2004), and In Salah in Algeria (Riddiford et al. 2004). Each project has injected CO_2 at the rate of ~1 MM tons/y (~280,000 t C/y). Each project has had a substantial supporting science program or anticipates one. Substantial information can be found on each project in the literature, and summaries can be found in Benson and Cook (2005).

Table 1: Current and pending large CO_2 injection projects

Site	Location	Reservoir class	Reservoir type	Permeability	Seal type	Start date*
Sleipner	Norway	Offshore Saline Fm.	Deep-water Sandstone	V. high	Thick shale	1996
Weyburn	Canada	Onshore EOR	Ramp carbonate	Moderate	Evaporate	2000
In Salah	Algeria	Onshore Sandstone	Fluvial/tidal sandstone	Low	Thick shale	2004
FutureGen	US	Onshore Saline Fm.	Fluvial sandstone or shelf carbonate	Moderate	Thick shales or evaporites	2012
ZeroGen	Australia	Onshore EOR/Saline	Fluvial/deltaic sandstone	Low-moderate	Shale	2011
Snohvit	Norway	Offshore Saline Fm.	Fluvial sandstone	Moderate	Shale/evap.	2008
DF1/Miller	UK	Offshore EOR	Deep-water sandstone	Moderate - high	Thick shale	2011
DF2/Carson	US	Onshore EOR	Deep-water sandstone	Moderate - high	Thick shale	2012
Latrobe Valley/ Monash	Australia	Offshore EOR/Saline	Fluvial/deltaic sandstone	High	Thin and thick shales	2011
Gorgon	Australia	Offshore Saline Fm	Deep-water sandstone	Moderate	Thick shales	2009

Hauten/ Draugen	Norway	Onshore/ Offshore Saline Fm.	Deep-water sandstone	High – V. high	Thick shales	2010
Phase III Regional Partnerships	US	Varying, but mostly Saline Fm.	Varying	Varying	Varying	2010

* = *date of first injection or planned first injection of CO_2*

These projects have sampled a wide array of geology (Table 3) with varying trapping mechanisms, injection depths, reservoir types, and injectivity. Each of these projects appears to have ample injectivity and capacity for success, and none has detected CO_2 leakage of any significance. In addition to the three sequestration projects, many industrial applications have injected large volumes of CO_2 into the subsurface. EOR operations in W. Texas, New Mexico, Colorado, Wyoming, Oklahoma, Mississippi, Trinidad, Canada, and Turkey have individual injection programs as large as 3 MM t CO_2/y (~820,000 t C/y) and cumulative anthropogenic emission injections of ~10 MM t CO_2/y (2.7 MM t C/t) (Kuuskraa et al., 2006). It should be said that the monitoring and verification program at each site varies substantially (MIT 2007). In many EOR projects, there is almost no monitoring beyond that required for CO_2 flood operations (Jarrell et al 2002).

A significant number of large-scale injection projects are expected to begin within the next five years, which will provide dynamic new opportunities to design and implement and test new monitoring strategies (Table 3). These projects will sample a substantial range of geology and on a global basis will be able to provide the opportunity to learn about the scientific, technical, and operational concerns. This list will be out of date when it is published – new projects are being announced at an astonishing rate.

Science and technology status

As discussed above, the knowledge of trapping mechanisms and the successes of the three large projects provide substantial information. These are augmented by studies of naturally occurring CO_2 systems, (IEA GHG 2005), natural gas storage facilities, hazardous waste disposal, acid gas injection, and CO_2 -EOR (Benson & Cook 2005). This knowledge provides a firm foundation for commercial action and a nacent foundation for the development of regulation, standards, and legal frameworks for sequestration (Wilson et al., 2003). GCS itself, however, drives study into specific technical and scientific challenges associated with the central elements of site characterization, selection, operation, and monitoring (US DOE 2007a; Wilson et al. 2007). Forward investigation around these topics will enhance the technical and operation understanding of commercial GCS.

Monitoring and Verification (M&V)

Monitoring and verification must detect and track CO_2 in the deep subsurface near injection targets, in the shallow subsurface, and above ground. Monitoring and verification studies are a chief focus of many applied research efforts. The US Department of Energy has defined M&V technology development, testing, and deployment as a key element to their technology roadmap (US DOE, 2007a), and one

new European Union program (CO2ReMoVe) has allocated €20 million for monitoring and verification. Some form of M&V will be required at commercial sites, but the extent of monitoring required by regulators, operators, or financiers remains uncertain. Many geophysical and geochemical methods are sufficiently well understood for them to be used to make reasonable performance predictions at candidate storage sites (Benson et al. 2004; Burton et al. 2007). Testing which of these approaches will be the most valuable for a given geological environment remains to be determined.

Key science and technology gaps

Despite the tremendous amount of applied and basic knowledge, there remain both cross-cutting and-site specific topics for investigation (Friedmann 2007b). From an applied perspective, the National Energy Technology Laboratory has written and annual plan to identify and address key technology gaps (US DOE 2007a). Conversely, a recent report by the US DOE Office of Science (US DOE 2007b) is meant to be focus on a set of basic science gaps and questions. While these documents are not meant to be comprehensive, they accurately reflect the current state of knowledge and potential to continue scientific investigations in GCS.

Deployment Challenges

Despite the current gaps in sequestration science and technology, commercial projects have begun and are ready to proceed with confidence in their success. Today, we know enough to safely and effectively execute key tasks around single large-scale injection projects:

- Characterize a site
- Design and operate the project
- Monitor the CO2 injection
- Mitigate problems that might arise
- Close and abandon the project

Although this knowledge is currently being brought to bear on specific injection projects around the world, greater scientific understanding is required to develop tools, regulations, and standards for deployment of multiple million ton injections in thousands of wells nationwide and worldwide across a range of geological settings. This affects both sides of the deployment rubric over the project life cycle (Friedmann 2007a; Wilson et al. 2007). Potential operators must execute a set of tasks to prepare for and execute injection permitting and operation. Similarly, potential regulators, investors, insurers, and public stakeholders require information to make decisions. Part of the challenge is to provide a technical basis for each set of actors to make decisions concerning the minimal amount of information needed to serve all stakeholders (Friedmann 2007a; Burton 2007).

While many possible goals and terms may be pursued in site characterization, it is difficult to imagine the success of a large-scale injection project without knowledge of three parameters. These are *injectivity*, *capacity*, and *effectiveness* (Friedmann 2006). In general terms, injectivity and capacity may be estimated by conventional means, such as special core analysis, regional and local structural and stratigraphic mapping, and simple multi-phase fluid flow simulations. However, there are n explicit standard measures of effectiveness. Ultimately, characterizations must rely on estimates of geomechanical

integrity, hydrodynamic stability, and seal continuity for the rock system, fault system, and well system (Streit and Hillis 2004; Hovorka et al. 2006; Chiaramonte et al. 2006; Burton et al. 2007).

Given this complexity, it is not broadly accepted today what terms constitute effective storage. The FutureGen project's request for proposals (FutureGen Alliance 2006) laid out a set of minimum criteria for acceptance. These criteria are based on expert opinion, laboratory experimentation, analog studies, and simulations. However, there is no empirical data set from multiple geological carbon sequestration deployments that provide a standard for characterization of site effectiveness.

Hazards Assessment and Risk Management

Supercritical CO_2 is buoyant and will seek the earth's surface; therefore, CO_2 injection carries the possibility of leakage. Importantly, CO_2 leakage risk will not be uniform across all sites, thus CO_2 storage sites will have to demonstrate minimal risk potential in their site characterization plans (Bradshaw et al. 2004). Based on analogous experience in CO_2 injection such as acid gas disposal and enhanced oil recovery, these risks appear to be less than those of current oil and gas operations (Benson and Cook 2005).

The direct hazards associated with geologic sequestration fall into three distinct categories:

- hazards associated with the release of the carbon dioxide to the earth surface
- hazards associated with release into groundwater and subsequent degradation
- hazards associated with earth movement caused by the injection process itself.

The hazards themselves in turn are associated with failure mechanisms and triggers (Table 2). Potential triggering of events associated with these hazards could lead to undesired consequences. As such, it is an important goal to identify and understand these hazards in order to avoid triggering hazard events. Identification and characterization of these hazards is the critical first step to managing the risks at a site. They also serve as the basis for a quantitative probabilistic risk assessment (PRA). A robust PRA cannot be made today due to substantial scientific and technical gaps. However, the hazards associated with a site can be identified, mapped, characterized, and parameterized sufficiently to avoid failure or (alternatively) avoid selecting a bad site.

Table 2: CCS-Related Earth & Atmospheric Hazards (after Friedmann 2007a)

Atmospheric release hazards	Groundwater degradation hazard	Crustal deformation hazards
Well leakage	Well leakage	Well failure
Fault leakage	Fault leakage	Fault slip/leakage
Caprock leakage	Caprock leakage	Caprock failure
Pipeline/operational leakage		
	Water displacement and far-field saline intrusion	Induced seismicity

		Subsidence/tilt

Development of Standards and Protocols

Understanding risk requires understanding the controlling parameters in the geological environment elected for the sequestration sites. The risk elements described so far for earth and atmospheric hazards suggests the need to systematically rank, quantify, and respond to those potential hazards. **Protocols** will be developed to inform operators and regulators on preparing and opening a site, and will serve as the basis for operational standards. Planning for operation geological carbon sequestration will be based on scientific studies (Wilson et al. 2007). It is crucial that these studies occur in the context of large projects (Friedmann 2006; MIT 2007). ***The development of these protocols based on studies at large-scale injection projects should be the highest priority of any decarbonization strategy for most OECD countries***.

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