PAYNE INSTITUTE COMMENTARY SERIES: **COMMENTARY**

Geological Storage: Risks and Operational Risk Mitigation

By Brad Handler, Anna Littlefield and Felix Ayaburi

The use of Carbon Capture and Storage (CCS) as a climate mitigation tool envisions the permanent underground storage of CO_2. The prospects for large scale adoption of geological storage has raised concerns regarding the risks — of property damage, environmental degradation, and to human health— if stored CO_2 were to leak to the surface or into shallow water resources.

This concern under-appreciates the degree to which the industry and regulators are able to mitigate the risk of leakage or damages. Decades of scientific study of the subsurface are being applied to the subsurface assessment and approval of proposed storage sites. Monitoring techniques are applied before, during, and after injection to ensure that the CO_2 plume is developing and migrating as expected and remains contained within the injection interval. While physical 'trapping' of the CO_2 in the subsurface is the primary containment mechanism, post-injection pressure dissipation and other natural processes such as solubility trapping and CO_2 mineralization lessen the risk of leakage over time.

CCS is also often characterized as being unproven, which does not do justice to its history. As of last year, there were over 40 CCS projects with geological storage (including field tests) that had either completed injections or for which injections are ongoing. This operating history has been very supportive of the ability to select subsurface conditions that can contain injected CO_2. Further, within the United States, operators have been injecting CO_2 into the subsurface for enhanced oil recovery (EOR) since the 1980s. While the goal of permanent storage is unique to CCS, the experience and learnings from EOR operations translates to CCS projects.

Although current regulations, which bring to bear this understanding of the subsurface, can go a long way to mitigating the risks of leakage, appropriate management of CCS projects during operations is also critical. This allows for a separate but related risk — the viability of the developer/operator. This "business" risk is exacerbated by the landscape of proposed developers (a new breed of which lack operating history), how they are raising funds, and their reliance on government subsidy (and presumably for many, carbon finance).

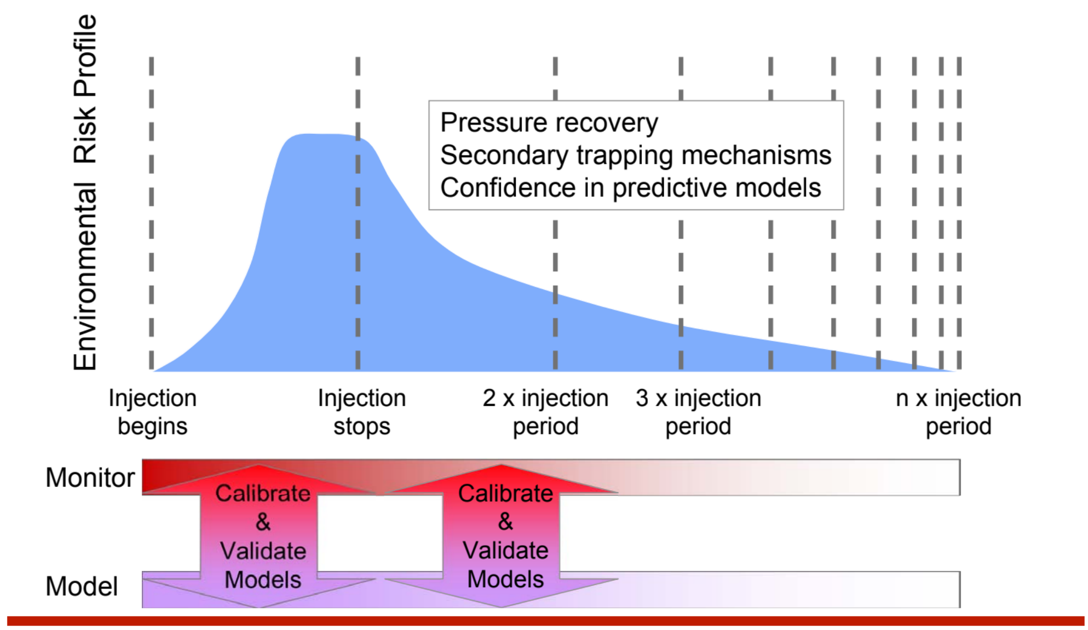
This paper discusses the risks for third parties (i.e. not for the developers) associated with geological storage of CO_2. The risks are segmented across the various phases of the storage lifecycle — construction, injection, post-injection/site care (PISC), and Long Term Stewardship (LTS). Within each section, the paper describes engineering- and operational-related steps that are being taken by operators and regulators to mitigate such risks, i.e. related to site selection, well design, injection conditions, monitoring, and well closure.

A companion paper outlines the risk mitigation options that can be taken to address the business-related/financial viability risks during the operating phases of a CCS project. Another paper considers risk mitigation specifically during the LTS phase and the idea of releasing the operator from such responsibilities and liability. The series concludes with observations about how project developers, the insurance industry and government can help catalyze more CCS projects.

THE LEAKAGE RISK PROFILE OVER TIME

Although this paper addresses several risks, arguably the most pressing is the potential for stored CO_2 to migrate away from its designated area, as this presents potential for third party and environmental damage. It has been determined that the risk of leakage across geological storage sites peaks during the latter stages of the injection period as CO_2 volumes and pressures build. The risk holds roughly steady until injection ends. When injection stops, pressures are expected to decrease over time with continued migration of the plume, solution trapping and (to a lesser degree) mineralization of the stored CO_2. Thus the risk of leakage is expected to decline materially over the ensuing decades (see Exhibit 1).

Exhibit 1: Risk Profile Curve for CCS Sites



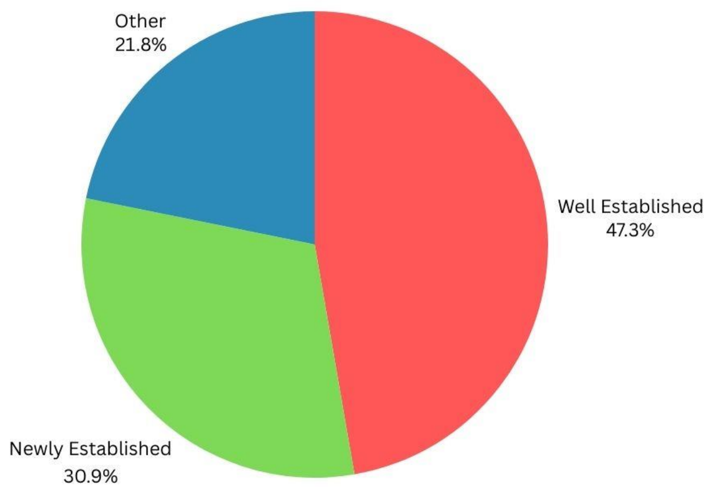
Source: Sally Benson, Stanford University, Global Climate & Energy Project (2007)

RISKS STEMMING FROM THE BUSINESS ENTITY (THE PROJECT DEVELOPER)

A CCS project developer earns revenues, in the form of tax credits and potentially carbon credits, during the injection period. Meanwhile the developer incurs the costs associated with (capture/acquisition of the CO_2 and) injection, debt service, royalties to landowners, and, particularly for smaller developers, providing Financial Assurance to the U.S. Environmental Protection Agency (EPA).

Currently, there is a diverse landscape of CCS project developers, with companies of varying sizes, focus/specialty, operational capacity, and history of successful project execution. This includes start-ups with no "other" assets, (i.e. its assets relate only to the proposed CCS activities) and limited operating experience up through oil supermajors and other large industrial behemoths with significant resources. Of the 113 EPA-tracked projects that are characterized as "capture", "full chain", "transport" or "storage", 35 (31%) can be considered as having developers that are "new" entities, i.e. companies (including all the companies within a consortia) without meaningful operating history (in any activity, see Exhibit 2). All else equal, these CCS start-ups raise questions about financial viability given that a developer/operator has responsibilities that last more than fifty years.

Exhibit 2: Categorizing U.S. Geological Storage Project Developers



Source: IEA (2024), CCUS Projects Database

To mitigate operational risk, permit applications submitted to the EPA or the states, require evidence of Financial Assurance (FA), which is designed to backstop safe site closure, proper plugging and abandoning of injection and monitoring wellbores, restoration of the site to its original state, and remediation of any environmental damages, for example in the event of leakage of stored CO_2. (FA is discussed in more detail in the *Financial Risk Mitigation* companion paper.)

OPERATIONAL PHASES RISK REVIEW

Construction Phase

CCS projects are large scale, multi-faceted engineering & construction projects. For geologic storage, operators must construct a CO_2 injection well and subsurface monitoring wells. Well construction involves a series of carefully sequenced tasks, executed by teams with diverse expertise and utilizing specialized equipment, often provided by various companies/contractors. Throughout the construction phase, developers must navigate the risks of schedule delays, cost overruns, and accidents that could result in injuries or damage to equipment and property. These risks are exacerbated by project management complexity.

Yet these risks are consistent with those performed routinely in hundreds of active oil and gas well operations across the U.S. As such, the financial and insurance industries are adept/experienced at evaluating and "pricing" these risks into supporting insurance, lending and other products.

Injection Phase

During the injection period, there remains risk of equipment damage and bodily injury at the injection (well) site, although the risk of such incidents is lower than during construction as there are fewer people present on site and fewer crews coordinating activities.

Instead, greater risk (at least for third parties) relates to the CO_2 plume and its containment in the subsurface[1]. The first risk in this vein is that CO_2 migrates outside the anticipated containment area, laterally or vertically. Lateral migration could occur due to unanticipated reservoir heterogeneity, or insufficient capacity in the modelled plume area. Vertical migration is more problematic and could occur through the caprock along unmapped or reactivated faults, or along improperly plugged and abandoned wellbores. The potential damages that might occur or liability that might be incurred include:

- Property, the developer's or that owned by third parties
- Environmental, for example if agricultural resources or drinking water is affected
- Trespass, if the CO_2 is determined to have migrated to an area to which a different owner owns the rights
- Forfeiture of the revenue or tax credits that were based on that "lost" CO_2

Concerns regarding CO_2 leakage stem in part from an experience at the In Salah project in Algeria in 2007 during which it stored CO_2 was known to have experience unanticipated lateral migration. Operations were suspended in 2007 and resumed in 2009.

The second risk is of (induced) seismicity during injection. In other words, there is risk that the injection of CO_2 creates seismic events that, if strong enough, could result in property damage (the developer's or third parties'), bodily injury, or environmental liability. This concern stems largely from the experience in the U.S. with disposal wells, into which are injected large volumes of "wastewater" produced through hydraulic fracturing of oil and gas wells. Operations of such disposal wells has demonstrated that nearby fault lines can be re-activated, potentially leading to seismic events that can pose a threat to safety and property[2].

To minimize both risks, the project developer takes several steps, many of which are mandated by regulators.

Subsurface Evaluation

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[1] This section ignores the business risk to the developer that it cannot inject as much CO_2 as intended. This risk, which for example is playing out currently in Chevron's Gorgon CCS project, impacts the developer's ability to earn revenues on the project.

[2] It is worth noting that there is other historical experience with induced seismicity. In one example, the Gallen deep geothermal project in Switzerland was terminated in 2013 due to a magnitude 3.5 seismic event. The event was attributed to deep drilling in fault-controlled regions, which exacerbated dormant faults. Additionally, an unexpected gas reservoir was encountered which posed challenges to well stability and safety

Subsurface evaluation is undertaken as part of the EPA's Underground Injection Control (UIC) Class VI well program application process. Injection location and depth are selected based on the suitability of the reservoir, the overlying seal/caprock, and the overall basin setting that will ensure permanent containment. Suitability is determined based on extensive data collection, analysis, and a final geomodel that represents the closest approximation of subsurface conditions, including any faults or fractures within the Area of Review (AOR), and predicts the geometry of the CO_2 plume as well as any geochemical reactions that might occur upon injection.

Similarly, as it relates to hydrogeology, the vertical and lateral limits of all underground sources of drinking water (USDWs) and their positions relative to the injection zone(s) must be included. Baseline geochemical data on fluid- and solid-phase geochemistry of all USDWs, must detail pre-injection monitoring results (natural baseline geochemistry) as well as planned sampling/testing of geochemical analytes during and after injection. These shallow monitoring procedures are implemented to ensure that no environmental degradation occurs in the event of a CO_2 leak.

"Man-Made" Risks/Operational Controls

Class VI guidelines for a CO_2 injection well include elements that address the "man-made" risks — specifically concerns related to CO_2 handling and risk of leakage. To offer just two examples:

- The prescribed metallurgy of the casing is far more corrosion resistant (because CO_2 is more corrosive than hydrocarbons).
- When the injection well is plugged when injections are to be stopped, it is mandated that the entire annulus surrounding the wellbore be sealed with (corrosion-resistant) cement. This differs from oil & gas operations, for which only (hydrocarbon-bearing) sections of the subsurface must have a cement barrier applied.

During injection operations, the developer/operator monitors subsurface pressures to ensure that fracture gradient is not exceeded, and that the injection reservoir is able to handle the anticipated rates and volumes of CO_2[3]. Operators are also responsible for monitoring across the Area of Review (AOR), which includes not only the CO_2 plume, but also the pressure front (pressures increase outside the extent of the CO_2 plume as brine is displaced in the reservoir).

Post Injection/Site Care (PISC) Phase

At the end of the injection period, the developer plugs the injection well. As noted above, EPA Class VI regulations include taking additional steps to limit the risk of CO_2 leaking to the surface along the wellbore or annulus. In the PISC phase, activity at the site is limited to monitoring for CO_2 leakage. Thus operational risks that were present during the construction or injection phases become immaterial.

The duration of the PISC phase is variable and site specific. The EPA mandates 50 years, after which time operators are no longer required to maintain FA; as is discussed in the LTS phase

[3] Experience with wastewater disposal wells has shown that effective management of the rate and pressure of injection can mitigate against the risk of earthquakes associated with wastewater disposal wells.

companion paper, U.S. states have set different time frames to release project developers from their obligations.

During the PISC phase, it is presumed that the principal risks are the potential for CO_2 leakage and, related, the operator's ability to continue requisite monitoring activities. As is noted above, it is believed that the volumes of CO_2 that are at risk of leakage continues to decline through this period.

Long Term Stewardship Phase

Upon satisfactory performance of the stored CO_2 during the PISC phase, the site can be "closed." Site closure marks the beginning of the Long Term Stewardship (LTS). Functionally, operations during the LTS phase are limited to some periodic monitoring of the site for leakage; given the risk of leakage is expected to continue to decline over time, as discussed above, such monitoring can presumably be less frequent than during PISC.

Rather, defining an LTS phase sets the basis to consider the potential for the responsibilities related to monitoring — and to assuming any liability should it arise — to be held by a party other than the developer. In other words, it has been contemplated that the developer would hand off responsibility (and ownership) to a public or quasi-public entity after the PISC phase/site closure. This idea will be considered further in the *Long Term Stewardship* companion paper in this series.

ABOUT THE AUTHORS

Brad Handler
Payne Institute Program Manager, Sustainable Finance Lab, and Researcher

Brad Handler is a researcher and heads the Payne Institute's Sustainable Finance Lab. He is also the Principal and Founder of Energy Transition Research LLC. He has recently had articles published in the Financial Times, Washington Post, Nasdaq.com, Petroleum Economist, Transition Economist, WorldOil, POWER Magazine, The Conversation and The Hill. Brad is a former Wall Street Equity Research Analyst with 20 years' experience covering the Oilfield Services & Drilling (OFS) sector at firms including Jefferies and Credit Suisse. He has an M.B.A from the Kellogg School of Management at Northwestern University and a B.A. in Economics from Johns Hopkins University.

Anna Littlefield
Payne Institute CCUS Program Manager and Research Associate
PhD Student, Geology and Geological Engineering, Colorado School of Mines

Anna Littlefield is the Program Manager for Carbon Capture Utilization and Sequestration for the Payne Institute at the Colorado School of Mines. As a current PhD student in the Mines geology department, her research focuses on the geochemical impacts of injecting CO2 into the subsurface as well as the overlap of geotechnical considerations with policymaking. Anna joins the Payne Institute with 8 years' experience in the oil and gas industry, where she worked development, appraisal, exploration, new ventures, and carbon sequestration projects. Her academic background is in hydrogeology with an M.S. in geology from Texas A&M University, and a B.S. in geology from Appalachian State University. Anna is passionate about addressing both the societal and technical challenges of the energy transition and applying her experience to advance this effort.

Felix Ayaburi
PhD Student, Operations Research with Engineering, Colorado School of Mines

Felix Ayaburi is a Ph.D. Student in Operations Research with Engineering at the Colorado School of Mines. He holds an MS in Mineral and Energy Economics from the same institution. His research interests include the application of optimization methods in underground mine planning, electric vehicle deployment and responsible sourced gas.

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