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De-Risking CCS

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List of Acronyms

Acronym	Definition
ALARP	as low as reasonably possible
AoR	Area of review
ATSL	Adaptative traffic light system
AoR	Area of Review
BECCS	Bio-Energy with Carbon Capture and Storage
CCS	Carbon capture, utilization, and storage
CO_2	Carbon dioxide
CSEM	controlled-source electromagnetic
DAC	Direct Air Capture
DAS	Distributed acoustic sensing
DOE	United States Department of Energy
ECBM	enhanced coal-bed methane
EOR	Enhanced oil recovery
EPA	United States Environmental Protection Agency
ESR	Emotionally self referent
ERT	electrical resistance tomography
FEPs	Features, events, and processes
IC	Institutional control
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D Program
IPCC	Intergovernmental Panel on Climate Change
LUC	Land use control
MCA	multi-criteria assessment
MVA	Monitoring, Verification, and Accounting
NETL	National Energy Technology Laboratory
NRAP	National Risk Assessment Partnership
PACE	Property assessed clean energy
PHMSA	Pipeline and Hazardous Materials Safety Administration
PISC	Post-injection site care
PMI	Project Management Institute
PMP	Project Management Professional
ppm	Parts per million
PV	photovoltaic
SPUD	Start production unit date
SRF	screening and ranking framework
SWIFT	Structured "What-If' Techniques
TD	Total depth
TLS	Traffic light system
UIC	Underground injection control
USDW	Underground source of drinking water
USEA	United States Energy Association
USGS	United States Geological Survey

Acronym	Definition
VEF	Vulnerability evaluation framework
VSP	Vertical seismic profile

Executive Summary

Carbon capture and storage (CCS) is gaining attention on a national and global scale, in large part due to the November 2021 passage of the Bipartisan Infrastructure Law, which allocated $12.1 billion in federal funds to CCS as part of the national effort to achieve President Biden's decarbonization goals. This was part of the larger climate package because scientists across the globe agree that efforts to prevent the rapid warming of the Earth due to excessive carbon dioxide (CO_2) buildup in the atmosphere will not be successful without CCS. As a result, commercial-scale CO_2 sources that want to develop CCS projects face risk in many parts of developing, permitting, and executing a project.

This new exposure for the technology, components of which have been in use for nearly a century and a half, along with increased regulation around the emissions of CO_2, has brought with it significant interest by industry in including CCS into their business portfolios. But while those who have worked in the CCS space, or with the technology, for decades know it to be a proven technology with the potential to stem some of the worst effects from climate change, those who are just learning about the technology – and who are being asked to commit resources to finance or ensure CCS projects – still have a lot of questions. Some of the key gaps in the critical path toward CCS deployment are the technical gaps that have not been sufficiently studied. Those wishing to explore CCS will need to be aware of risks associated with development of an integrated CCS program, especially with a series of sequential phases of development: Integrated CCS Pre-Feasibility, Storage Complex Feasibility, Site Characterization, and Permitting and Construction.

To assist stakeholders address these risks, this report is organized into seven sections:

1) Introduction: Describes the purpose and scope of the work and this report.
2) Planning for Risk: Describes best practices for organizing CCS project risks and methods for evaluating the risks.
3) Applying the Bowtie method to common CCS risks: Applies the Bowtie Method of Risk Assessment to discuss commonly cited risks related to CCS projects – CO_2 leakage, induced seismicity, and public acceptance.
4) Applying the perspective of the Insurance / Re-insurance Industry: Summarizes the information learned from listening sessions covering the de-risking of CCS projects conducted with stakeholders representing subsurface, business, insurance and financing, and outreach expertise.
5) Summary of the De-Risking Workshop: Summarizes the De-Risking Workshop held as part of this project on September 8, 2022 at the offices of USEA in Washington, D.C.
6) Emerging Technologies: Discusses the background and current challenges for emerging technologies related to CCS – Direct Air Capture (DAC), Bio-Energy with CCS (BECCS), Reforestation/Afforestation, Enhanced Weathering, and Blue Hydrogen.
7) Conclusions: Summarizes the information found under this effort and presents a path forward for additional work.

Planning for Risk: Risk planning is an integral part of the management of any project. Best practices for CCS project risk management are available in the Department of Energy's National

Energy Technology Laboratory (DOE/NETL) 2017 report titled *Risk Management and Simulation for Geologic Storage Projects.* Major themes from this report are discussed and put into context with tools available from the Project Managements Institute (PMI). In addition, three classes of Risk Analysis – Qualitative, Semi-Quantitative, and Quantitative – are also discussed. Finally, risk mitigation options and monitoring, verification, and analysis (MVA) methods are also explored.

Applying the Bowtie Method: The Bowtie Method for Qualitative Risk Assessment is a seven-step approach to evaluating a single hazard and involves identifying seven factors: (1) the hazard, (2) possible causes of the hazard, (3) possible consequences of the hazard, (4) possible controls to prevent the hazard, (5) possible recovery mechanisms to mitigate the consequences of the hazard, (6) possible threats to the controls and recovery mechanisms, and (7) possible controls for the threats to the controls and recovery mechanisms. The Bowtie Method was applied to three commonly cited examples of risks related to CCS projects – CO_2 leakage, induced seismicity, and public acceptance.

Applying the Perspective of the Insurance / Re-insurance Industries and *Summary of the De-Risking Workshop:* Given the importance of the Insurance / Re-insurance industry to the success of CCS, a multi-phase outreach program was utilized to identify key issues of interest to insurers/re-insurers. The goal of this was to identify the questions and concerns of stakeholders in the finance and insurance and re-insurance industries relative to CCS and its de-risking. To get these answers, the research team relied on in-person virtual interviews, either one-on-one or in small groups, with subject matter experts within the CCS, oil and gas, finance and insurance, geology, risk management, and research fields. Four questions were asked of each interviewee:

1) What are the most important issues to consider when de-risking CCS?
2) What assurances are needed to ensure the risk is acceptable?
3) What are the gaps in understanding CCS risks from your point of view?
4) What has not been asked that is important to consider relative to de-risking CCS projects now and/or in the future?

By posing four standardized questions to every participant, as well as follow-up questions prompted by their responses and participating in a more free-flowing conversation about de-risking CCS, the research team was able to quickly find common themes and several key takeaways relative to de-risking CCS for the insurance, re-insurance, and finance industries. They include:

- Implementation of CCS requires consideration of issues related to storage site selection, permitting and the approval process for Class VI wells, and long-term liability/project close-out uncertainties.
- Effective enablers in de-risking potential CCS projects include modeling the strides made by the ethanol industry; helping diminish the risk profile of the project by demonstrating that the site is well-characterized, well-operated, and well-managed; and fixing permitting delays and pitfalls.
- Gaps in understanding CCS risks include legislative aspects (state and federal) and public perception relative to technology and induced seismicity.

When asked an open-ended question about additional considerations regarding de-risking CCS, participants' feedback focused largely on three items: long-term liability issues, how monitoring protocols will be managed and enforced, and possible sources of funding for CCS projects, especially when 45Q expires. Identifying the major points of concern for financing and insuring CCS is the first step in the process of de-risking the technology. While the feedback received from participants outlined many issues to explore from a technical perspective, the two main themes repeated throughout the discussions were education and trust.

Emerging technologies: Specialized risks for each technology were identified and considered. Examples of these risks include the following:

- DAC – New technology, economics, revenue streams.
- BECCS – Land use changes/competition, power markets/revenue.
- Reforestation/afforestation – Permanence/reversal, fires, pests, maintenance.
- Weathering – Feed supply issues, reaction kinetics.
- Blue hydrogen – Market dynamics, lifecycle analysis (LCA).

Conclusions: Development of a CCS risk assessment requires a broad range of capabilities and expertise and the participation of entities that can provide a business framework across the entire CCS value chain. In addition to technical experts, CO_2 source and supply companies, pipeline developers, storage and enhanced oil recovery (EOR) site operators, and financial investors are needed to make these projects work. As the project develops, these team members may become host sites, equity partners, technical consultants, advisors, or stakeholders. The objective of the expert engagement, conducted in this project through the listening sessions and De-Risk Workshop, was to develop a base of knowledge that translates technical information to a wider audience so these non-technical stakeholders can understand the risks posed by CCS projects. Risk assessment efforts should be site-specific, ongoing, and iterative to ensure that the risk of CCS projects is reduced through practical experience.

1.0 Introduction

The United States Energy Association (USEA) is a nonprofit, apolitical, non-lobbying organization which works with the US Department of Energy (DOE) in sponsored efforts to advance energy information and knowledge across the world. USEA's mission has two pillars of equal importance. USEA serves as a resource by convening energy stakeholders to share policy, scientific, and technological information to foster the advancement of the entire energy sector. Internationally, USEA promotes energy development by expanding access to safe, affordable, sustainable, and environmentally acceptable energy in partnership with the US Government. Through its Consensus Program, a cooperative agreement with DOE's Office of Fossil Energy and Carbon Management, USEA commissioned a series of tasks to better understand issues surrounding de-risking CCS, particularly as they relate to the finance and insurance/reinsurance industries. The project team, led by Battelle, used information about CCS development throughout the US and world to research potential CCS project concerns insurance and re-insurance companies will need addressed in order to cover CCS projects.

High level risk topics were discussed with several well-known professionals from different industries. During the first two quarters of 2022, the project team organized various individual and larger group sessions to engage with influential and knowledgeable stakeholders in CCS industries including oil and gas, insurance, industrial CO_2 emitters, and electric power, along with key figures from CCS research and the Battelle team. The goal of the listening sessions was to encourage informal dialogue regarding the concerns amongst these diverse stakeholders relative to de-risking CCS. The research and the strategies established with the panels of experts were visualized in a holistic way, addressing risks present in practically all stages of CCS implementation, including planning and site characterization, construction, operations and maintenance, and post-injection site care (PISC) and site closure.

The scope is to research information that insurance and re-insurance companies will need to cover CCS projects. This report discusses risks specific to CCS projects: CO_2 leakage, induced seismicity, and public opposition. While these risks are not the only risks arising from a CCS project, they are sufficiently novel in that they present the most unknowns to the insurance and financing industries. This project provides a framework for the types of discussions that must be had with stakeholders along the entire CCS lifespan and the concerns that must be addressed through this dialog.

2.0 Planning for Risk

Planning for risk in a CCS project requires three steps: (1) providing the context for the risk assessment, (2) determining the most appropriate method(s) for assessing risk, and (3) establishing appropriate risk monitoring and management protocols. Section 2.0 is intended to discuss important factors to establish the context of a CCS project, provide assessment types and examples, and show risk planning requirements. Proper risk management gives project decision-makers confidence that the possible negative outcomes of a project are appropriately assessed and managed, increasing the chance of the project meeting its technical goals. Four concepts must be fully understood by all parties involved in establishing risk probabilities:

- Definitions of risk probability and severity. Define project- and location-specific risk.
- Probability and severity matrix. Use the results of these assessments to prioritize risks.
- Reporting. Project the risk management process to determine how these risks are documented, analyzed, and communicated.
- Tracking. Determine how risk activities will be recorded and how risk management processes will be audited.

2.1 Context for Risk Management

A risk assessment must be specific to the area where the project is sited, consider the operational parameters, and evaluate surface receptors like human populations, ecosystems, land use, and current industrial or mineral operations. This includes identifying the internal and external factors that could impact project risk. Internal factors include the project team, contractors, internal stakeholders, such as corporate management, as well as factors like organizational culture and capabilities (DOE/NETL, 2017). External factors include external stakeholders, such as regulators and the public, as well as trends and circumstances in the policy, regulatory, environmental, and economic setting. These analyses should be revisited at the beginning of each stage of the development of a site and referred to as project management.

The International Organization for Standardization (2018) provides a framework for risk assessment that involves three steps: Risk Identification, Risk Analysis, and Risk Evaluation. Risk Identification defines, through methods like literature reviews, theoretical analysis, or expert opinion, the potential cause of a system's risks. Risk Analysis uses this information to determine the likelihood and frequency of an identified risk, characterize its consequences, assess vulnerability and potential exposure of stakeholders, and develop a risk matrix that helps evaluate risks. Risk evaluation is then conducted to determine if the risks are tolerable or acceptable. Risk Management results can then be used to prioritize risk mitigation measures, monitoring, and further evaluation.

Then, based on adequate methodologies, a robust and reliable framework that allows for the evaluation of both consequences and uncertainties in each of the phases of the project can be established. DOE/NETL provides a series of best practices manuals related to CCS project planning and implementation. DOE/NETL (2017), *Risk Management and Simulation for Geologic Storage Projects*, provides a tailored approach for risk identification and management for CCS projects. The process involves several important steps (Figure 1):

Establishing the context for risk management. The purpose and applicability of the risk assessment must be established.

Integrate and communicate risks. Develop a deeper understanding of potential project risks through a four-step, iterative process of Risk Analysis and Assessment:

Risk identification*.* Project- and site-specific information is used to determine the possible risk assessment with implementation.

Risk characterization. Risk characterization involves three steps: (1) determine likelihood; (2) determine the severity of an individual risk event; and (3) multiply the two to determine risk. This can be done quantitatively, semi-quantitatively, or qualitatively.

Risk ranking/prioritization. Determine the highest project- and location-specific risks.

Risk Mitigation Plan*.* Determine the most appropriate ways to address the risk through monitoring, control, and mitigation.

Implementation of Risk Management Process. Communicate risks with relevant stakeholders and organize and plan relevant activities.

Monitor/Update/Iterate. Implement best practices for updating plans in response to project risks, including project design, site factors, and risk characterization (DOE/NETL, 2017; Hurtado et al., 2021).

Figure 1. Risk Management Process (from DOE/NETL, 2017).

Additionally, there are risks that can only be recognized after they have occurred. This requires each project to have sufficient project consistency, the ability for the project to change in response to external information, clearly defined project goals, the ability for the project team to report safety concerns, review of warning signs and risk indications, and two-way communication with relevant stakeholders. Experiential learning could also help mitigate these unknown risks. This is enhanced through information sharing between projects. This requires a suitable methodology and schedule for the review of risks for an individual project, a willingness to share information between projects, and an inclination of project managers to accept and apply outside information to their projects.

Once the risks have been identified, it will be necessary to assign values to each of the identified failure scenarios (probability) and to the impacts on each initially defined objective (impact function). The total risk of the system will be the sum of the probability of each scenario by its impact function.

For risk assessments to be consistent and meaningful, the application of appropriate methodologies in the evaluation of probability and severity is essential. Assessment methodologies can be divided into two broad categories: qualitative and quantitative. Technological maturity or gaps in knowledge in the evolution of disturbed natural systems, as well as the project phase, determine the nature of the assessment to be used (Hurtado et al., 2021).

Risk assessments can be enhanced using different tools approved by the Project Management Institute (PMI). Project Manager Professional (PMP) experts can provide the expertise to decide which method or tool is the most appropriate given each project based on three main factors:

- *Project complexity.* Is a robust risk approach demanded by high levels of innovation, new technology, commercial arrangements, interfaces, or external dependencies that increase project complexity? Or is the project simple enough that a reduced risk process will suffice?
- *Project importance.* How strategically important is the project? Is the level of risk increased for this project because it aims to produce breakthrough opportunities, addresses significant blocks to organizational performance, or involves major product innovation?
- *Development approach.* Does the project follow a waterfall approach, where risk processes are sequential, or does the project follow an agile approach, where risk is addressed at the start of each project sequence and iteratively during execution?

Risks of integrated CCS projects and shared infrastructure must also be considered. Specific issues that may result from this integration can include risk assessment boundaries, stakeholder and responsible party identification, and compounding risks from multiple operations. These issues are beyond the scope of component- or project-specific risk assessments, and therefore beyond the purview of a single project manager. As a result, a holistic, integrated risk assessment may be necessary to capture all possible risks, receptors, and mitigating factors.

2.2 Risk Assessment Methods

Risk monitoring uses agreed-upon risk response protocols, risk identification processes, new risks analysis, and evaluating risk process effectiveness throughout the project. The benefit of this process is that it enables project decisions to be based on current information about overall project risk exposure as well as individual project risks (DOE/NETL, 2017). Risk management can be accomplished through quantitative, semi-quantitative, or quantitative assessments. Qualitative assessments are used when specific, quantitative information on relevant project risks does not exist. These analyses are completed by assigning qualitative likelihood (e.g., very likely, possible, rare, etc.) and severity (negligible, moderate, catastrophic, etc.) values by subject matter experts. Qualitative approaches are useful for identifying unacceptable risks and ranking the magnitude of individual project risks. Quantitative tools can be used to classify and evaluate important risks in more detail (Mulcahy, 2018).

2.2.1 Qualitative Risk Assessment

The most common qualitative methods are probability/severity matrices and bowtie risk assessments. The current report focuses on these methods. Additional methods include vulnerability evaluation framework (VEF), structured “what-if’ techniques (SWIFT), multi-criteria assessment (MCA), and selection and classification framework or screening and ranking framework (SRF) (Hurtado et al., 2021).

Performing a qualitative risk analysis is the process of prioritizing individual project risks for further analysis or action by assessing their probability of occurrence and the severity of an impact. The process can focus efforts on high-priority risks and can be performed throughout the project.

After the analysis phase, the risk evaluation phase can be considered through the severity of consequences of risk materialization (PMI, 2021). This was previously identified in the risk analysis phase and the probabilities associated with said materialization could be estimated and based on adequate methodologies. This would establish a robust and reliable framework that allows the evaluation of both consequences and uncertainties in each of the phases of the project. Most projects focus only on risks that are uncertain future events that may or may not occur.

- *Variability risk.* Uncertainty exists about some key characteristics of a planned event or activity or decision.
- *Ambiguity risk.* Uncertainty exists about what might happen in the future. Areas of the project where imperfect knowledge might affect the project’s ability to achieve its objectives.

Several methods can be used to perform a qualitative risk assessment. The basis of such assessments is a comprehensive and transparent database of features, events, and processes (FEPs) that are relevant to the behavior of CO_2 in geological storage systems (Quintessa, 2014). The database includes around 200 FEPs in a hierarchical structure, with individual FEPs grouped into eight categories. Each FEP has a text description and an associated discussion of its relevance to long-term performance and safety. Key references from the published literature are included together with hyperlinks to other relevant sources of information.

- Assessment basis factors (e.g., purpose of assessment, endpoints, spatial parameters, timescale, assumptions on storage and future human actions, and models and data),
- Related to external factors (e.g., external receptors, external events affecting storage, etc.),
- CO_2 storage (e.g., scheduling, operational constraints, storage verification, etc.),
- CO_2 properties (e.g., CO_2 behavior, CO_2 interactions in the subsurface, and CO_2 transport, etc.),
- Geosphere considerations (e.g., reservoir properties, fractures/faults, mechanical properties, etc.),
- Legacy well considerations (e.g., construction and materials, seals and abandonment, and orphan wells),
- Near-surface environments (e.g., terrestrial environments, human behavior, etc.), and
- Impacts (e.g., impacts on groundwater, impacts on soil and sediments, etc.).

Once each relevant FEP is identified using site specific information, risks are ranked and discriminated using expert judgment. These FEPs are assigned the following:

A likelihood value, for example:

1 = Rare, 2 = Unlikely, 3 = Possible, 4 = Likely, and 5 = Certain

A severity value, for example:

1 = negligible impact, 2 = minor impact, 3 = moderate impact, 4 = major impact, 5 = catastrophic).

Once these values are assigned, Risk is found by multiplying the Likelihood value by the Severity Value. The resulting values can then be assigned qualitative risk, for example:

1 – 3 = Low, 4 – 7 = Moderate, 8 – 13 = High, 14 – 25 = Extreme

This method allows for the organization of expert inputs to determine the relative importance of risks identified by each FEP.

The surface and subsurface vulnerabilities of an integrated CCS project were defined using a FEPs approach like that defined by Battelle (2020) for capture and transport and Quintessa (2014) for storage operations; this includes the following issues:

- Capture: Construction risks, security, weather-related events, and other risks identified by the project team.
- Transport: Construction risks, security, CO_2 leaks (operational failures/leaks/damage), public opposition, weather-related events, and other risks identified by the project team.
- Storage: construction risks, security, CO_2 leakage (operational failures/loss of containment/damage), induced seismicity, public opposition, and other risks identified by the project team.

Another qualitative risk assessment method is the Bowtie process outlined by Alizadeh & Moshashaei (2015). The process, which allows for the identification of the hazard, potential causes, potential consequences, controls, and recovery methods, involves seven steps outlined below and shown in Figure 2:

1) *Identify the bowtie hazard.* Hazards are the things that could cause harm. Events cause the release of hazard (topline event).
2) *Assess the threats.* Issues that could cause events.
3) *Assess the consequences.* Outcomes of the topline event.
4) *Control.* Protective measures to prevent threats from releasing hazard. Reduce risk to as low as reasonably possible (ALARP).
5) *Recovery Controls.* Technical, operational, and organizational methods to limit consequences of a topline event.
6) *Identify threat to controls.* Issues that affect the reliability of the control.
7) *Identify the controls for the threats to controls.* Controls to protect controls.

Section 3.0 presents an example of how the Bowtie method can be used to organize risks, risk mitigation, and recovery mechanisms in a typical CCS project.

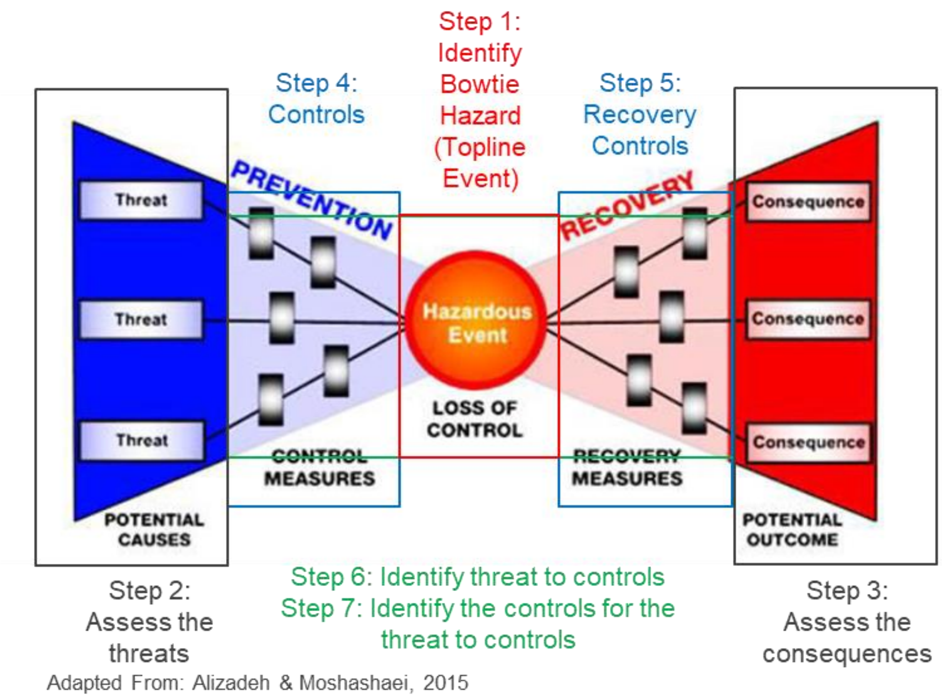


Figure 2. Work Performed and Outcomes by Task.

2.2.2 Semi-Quantitative Analysis

Semi-quantitative analyses can be used to show risk when certain quantifiable factors can be used to estimate risk. For instance, the leakage potential from existing boreholes can be found using leakage proxies, features of the well that were used to determine the relative likelihood of a leakage event (see Battelle [2020] for more information on the process). This semi-quantitative method combined methods originally developed by Hnottevange-Telleen et al. (2009) and Tucker et al. (2013) in a similar approach as that used by Battelle (2018). The likelihood of leakage is determined using equations first developed by Bachu and Watson (2008) that are modified to account for well leakage criteria. The modification of the equations is described by Duguid et al. (2017) and implemented by Battelle (2018). The method uses a series of equations and fitting parameters that relate the likelihood proxy of leakage criteria (Equation 1), defined above, to leakage likelihood (Equation 2) using an apparent age. Apparent age is determined using the likelihood proxy data with site-specific fitting parameters (Equation 3). Although the equations are designed to simulate the likelihood of leakage of CO_2, they were also used to simulate the likelihood of brine leakage. This simplified the process because only one set of equations is needed to simulate leakage.

$Likelihood\ Proxy = \frac{\Sigma_{i=1}^{n}}{5n}$ Equation 1.

where n is the number of applicable likelihood criteria, the likelihood proxy is calculated using only those likelihood criteria that were applicable. For example, if a well was not plugged, the “plug date” and “plug cement” categories were not counted in n.

$Leakage\ Likelihood = Ce^{N*Apparent\ Date}$ Equation 2.

$Apparrent\ Date = M * Likelihood\ Proxy + B$ Equation 3.

- *Surface.* This scenario involves leakage of CO_2 or brine to the ground surface.

- *USDW.* This scenario involves leakage of CO_2 or brine to an underground source of drinking water (USDW).
- *Caprock.* This scenario involves the movement of CO_2 through the caprock to formations overlying the CO_2 storage reservoir but underlying the lowest USDW.

Battelle (2020) used several leakage proxies to estimate the possibility of CO_2 leakage from the reservoir to one of the identified receptors:

- *Location.* The location (e.g., withing CO_2 plume or within pressure front) puts chemical and physical stressors on the well not caught in other portions of the evaluation.
- *Well Type.* Well type is an important consideration because the primary purpose of the well (i.e., oil and gas production, injection, etc.) will dictate the stresses put on the well during their operational lifetimes.
- *Well Status.* Well status is an important consideration because of the likelihood of the well being monitored during operations (producing or injecting) versus periods of dormancy (inactive or plugged and abandoned).
- *Start Production Unit Date (SPUD).* SPUD dictates the amount of time that the wellbore has been exposed to potentially corrosive fluids in the subsurface as well as the well construction standards and methods in use at the time.
- *Formation at total depth (TD).* The formation at TD dictates the formations of interest that are penetrated by the borehole. In addition to creating pathways from the reservoir with CO_2 and brine, the depth of the borehole also dictates the total surface area of the well that is exposed to the subsurface that could potentially leak.
- *Well Construction.* The individual casings and cement used could affect the risk. In general, likelihood criteria described are representative of a single, distinct feature of the well. Production casing cement, well treatment, and plug cement, however, each have two criteria to describe their likelihood of leakage: cement volume and cement placement.
- *Treatment.* Two treatment factors can be considered: treatment type and treatment interval. For wells with more than one treatment, a conservative approach should be used to determine the risk. Treatment type is important because treatments could introduce higher permeability channels that could short-circuit well protections, particularly for hydraulic fracturing. In addition to treatment type, the formation treated would affect the likelihood of leakage. Formations treated (from deepest to shallowest) could include the reservoir, the baffle between the reservoir and primary caprock, the primary caprock, the baffle between the primary and secondary caprock, the secondary caprock, or a formation above the storage complex. No treatment is also an option.

2.2.3 Quantitative Analysis

A quantitative risk analysis is the numerical analysis of the combined effect of individual project risks. This process quantifies overall project risk exposure and can also provide additional quantitative risk information to support risk response planning (PMI, 2021). A quantitative analysis can be completed if there is sufficient information to determine the probability of an event occurring and the cost of the consequence of that event. Koornneef et al. (2011) report that risk assessments are difficult for the non-engineered portions of CO_2 storage projects because of a lack of empirical data and methodological standards. Chen et al. (2020) report a method for using monitoring data to improve the quality of quantitative risk assessments.

Quantitative risk assessments conducted using site-specific data exist (e.g., Pawar et al., 2015). The DOE has developed models to estimate the likelihood and amount of CO_2 leakage using site-specific storage complex information as part of the National Risk Assessment Partnership (NRAP) (Pawar et al., 2016).

Duguid et al. (2022) describe a quantitative risk assessment for CO_2 transport via pipeline. The authors used incident and accident data from the Pipeline and Hazardous Materials Safety Administration (PHMSA) to determine the likelihood and severity of CO_2 pipelines accidents and compared them to accidents at natural gas and other hazardous liquid pipelines. The average risk of operations of CO_2 pipelines per mile is lower than any of the other pipelines. The median risk of operations of CO_2 pipelines per mile is lower than gas transmission/gathering and non-CO_2 hazardous liquid pipelines and only slightly higher than gas distribution pipelines.

2.3 Adequate Risk Mitigation Planning

Once risks have been identified and ranked, adequate project planning is an important part of risk mitigation. Monitoring, verification, and accounting (MVA) plans must be developed both for risk analysis and subsequent mitigation measures (Hurtado et al., 2021). The performance of a CO_2 injection well can be confirmed by monitoring. This confirms safe operations and helps update the iterative risk assessment. The risk assessment allows for the identification of the most important elements affecting the behavior of the CO_2 storage system and guiding mitigation or corrective measures as needed. A CCS risk assessment requires that the possible leakage pathways might breach a CO_2 storage facility and the operational activities that may lead to induced seismicity are well understood. In addition, mitigation tools to prevent these issues and remediation measures in the event of CO_2 leakage or induced seismicity must be selected using site-specific and project-specific information. These issues are considered using the Bowtie Method for risk assessment in Section 3.0.

Project-specific MVA plans are developed using a three-step process.

> *Stage 1: Define MVA Goals.* The first stage in the preparation of a site-specific MVA plan is to compare the risks identified qualitatively, semi-quantitively, and quantitatively (See Section 2.1) with the high-level project goals, performance targets, and regulations. This analysis and reservoir management must be tailored to site-specific needs to ensure successful project operation.

> *Stage 2: Define measurement techniques.* Measurement techniques and safeguards for monitoring targets are identified in the next stage. Each active safeguard has a sensor for parameter measurement, decision logic to respond to the measurement output, and a control response to mitigate risk and inform the project operator.

> *Stage 3: Determine measurement tools.* A wide variety of tools and techniques are available for monitoring CO_2 stored in deep subsurface geologic storage sites, as well as conducting surveillance in the event of leakage. Tools have been designed for monitoring in the atmosphere, at or near the ground surface, and in the subsurface.

Additional considerations for risk mitigation planning for CCS projects include the following:

- Scheduling and planning individual projects expected as part of the concept.
- Pre-closure and post-closure administrative controls, which can be used to prevent impacts to the storage complex during and after site operations.

- Operational and post-injection monitoring, which must be established to ensure safety, seal integrity, storage permanence, and plume stability.
- Quality control measures, which must be considered to ensure that project safety and recordkeeping measures are followed.
- After site closure, CO_2 reversibility of injected CO_2 may be needed to produce oil and gas resources or as a future source of CO_2.
- Remedial actions needed to remediate damage caused by lost CO_2.
- Over-pressuring, or exceeding the maximum allowable pressure, can cause fractures and provide pathways for CO_2 migration.
- Records and markers must be used to memorialize the project and remain available and visible for future stakeholders.
- As large volumes of monitoring data are acquired using diverse monitoring approaches, a major challenge has been finding ways to streamline and optimize data processing and data integration.

3.0 Applying the Bowtie Method

The Bowtie method for risk assessment (see Section 2.2.1) was applied in general by accounting for three Bowtie hazards (Top-Line Events) that must be considered by all CCS projects: CO_2 leakage, induced seismicity, and public opposition. These top-line events were selected because they are sufficiently unique to CCS as to not be directly encountered by the insurance and financing industries in most other contexts. This analysis is intended to show that each of these topline events has been identified through project experience and has available control and recovery mechanisms.

3.1 Step 1. Identify the Bowtie Hazard (Top-Line Event)

The first part of the process is to identify the top-line events or hazards. This defines what could go wrong with a CCS project. As part of this project, three distinct Bowtie hazards were identified: CO_2 leakage, induced seismicity, and public acceptance of CCS projects. Additional top-line events associated with integrated CCS projects, like well construction, construction safety, heavy industry, etc., are more commonly dealt with and are therefore not referenced within this document.

3.1.1 CO_2 Leakage

Sudden releases of CO_2 outside of the storage complex can lead to potential hazards to human health or the environment if CO_2 reaches groundwater, surface water, or ambient air. In addition, these releases, as well as smaller, longer-term releases can affect project efficacy and project economics. The success of CCS projects depends upon ensuring in-situ entrapment of CO_2 in the geological formations indefinitely. Naturally existing sealing formations above the storage formation provide the main entrapment mechanism. However, without careful project siting, sealing formations may allow CO_2 leakage.

3.1.2 Induced Seismicity

Induced seismicity refers to injection-induced earthquakes. Understanding the potential mechanisms and receptors of induced seismicity is critical to developing mitigation and recovery options. CCS differs from other energy technologies in that it involves continuous CO_2 injection at high rates under pressure for long periods of time, and it is purposely intended for permanent storage (no fluid withdrawal). Given that the potential magnitude of an induced seismic event correlates strongly with the fault rupture area, which in turn relates to the magnitude of pore pressure change and the rock volume in which it exists, large-scale CCS may have the potential for causing significant induced seismicity.

3.1.3 Public Opposition

Public perception of CCS can be crucial, and research interest in this topic has been growing. For this research, a compilation of various methodologies and factors that were considered important in relation to the perception of society about CCS projects was created. New energy technologies often face skepticism or opposition. Acceptance is not guaranteed and depends on many factors.

3.2 Step 2. Identify Potential Causes (Threats)

CO_2 leakage out of the storage complex could occur via faults/fractures or along wellbores, which can lead to three of the main causes of loss of safe behavior in the CO_2 storage complex:

- The loss of the reservoir's integrity.
- The existence of fractures and/or faults that could constitute possible pathways for CO_2 leakage.
- The loss of the well integrity.

3.2.1 Causes of CO_2 Leaks

The primary mechanisms that may have impacts on the migration of a CO_2 plume include:

- Pressure gradient and natural hydraulic gradient,
- Buoyancy due to the density differences between CO_2 and formation fluids,
- Phase trapping and diffusion,
- Dispersion and fingering due to the reservoir heterogeneities and mobility contrast between CO_2 and formation fluids,
- CO_2 solubility into the resident fluid,
- Adsorption of CO_2 by organic materials, and
- Mineralization or mineral transformations (Hills et al., 2020).

CO_2 is a supercritical fluid at depths greater than 800m (Bachu, 2001). Supercritical CO_2 has a bulk compressibility higher than water and its viscosity is reduced 10 times (Espinoza and Santamarina, 2011). Thus, soon after the injection, as the plume migrates away from the wellbore, buoyancy force pushes CO_2 upward until it is immobilized by the capillary or structural (faults and caprock) traps. CO_2 can also be dissolved in formation water depending on the pressure, temperature, and salinity level. Geochemical reactions, combined with pressure increases from continuous injection, can decrease the capillary entry pressure and initiate leakage pathways. CO_2 leakage can then occur due to the following:

- A discontinuity or compartmentalization of the geological storage formation, therefore leading to a significant increase of the pressure in the injection well.
- An unexpected fluid flow within the reservoir, e.g., the spread of the CO_2 plume beyond the desired region, such as a fault/fracture zone or discharge point, or the migration of the CO_2 plume through the cap rock.
- The creation or reactivation of faults and/or fractures in the reservoir, or in the cap rock, caused by stress changes during CO_2 injection, since the stress path has a deep effect on stress dynamics and fracturing/faulting when injecting into a depleted reservoir.

Leakage Pathways

<u>Caprock and vertical migration.</u> Free CO_2 can find its way out of a storage site due to several mechanisms (Figure 3). First, CO_2 may migrate due to changes in pressure during injection. During the injection, pressure builds up around the injection site and fractures can be initiated once the injection pressure exceeds the minimum principal stress. In the long term, regional pressure changes the state of in-situ stresses and permanent geomechanical issues, such as vertical uplift (Shi and Durucan, 2009; Tillner et al., 2014; Zhu et al., 2015), fault reactivations, and caprock integrity can be observed.

In saline aquifers, pressure buildup can be more catastrophic since, unlike depleted reservoirs, aquifers are holding a hydrostatic pressure and may not have a huge pressure margin to rely on. Thus, active CO_2 reservoir pressure management is the key for a successful injection operation, particularly in aquifers (Buscheck et al., 2012). It is also crucial to analyze poorly-oriented faults and fractures crossing the reservoir and caprock. Thus, it is important to ensure that CO_2 can be immobilized by active trapping mechanisms in a storage site.

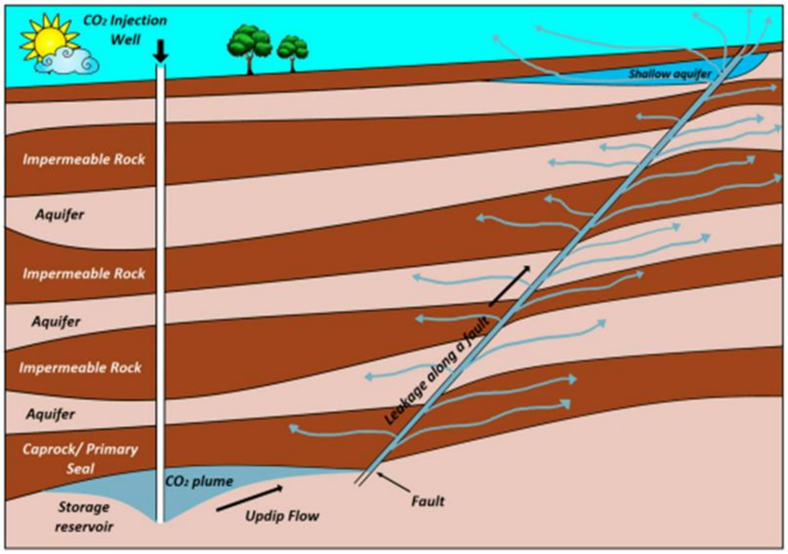


Figure 3. Pathways for CO_2 migration for a possible leakage through faults (Adapted from Bachu and Celia, 2013).

During the injection, CO_2 migrates laterally away from the injection well (due to viscous force) and then starts to migrate vertically towards the top of the reservoir because of the buoyancy force. Factors affecting the vertical migration of CO_2 have been studied by many researchers. It has been reported that CO_2 solubility decreases the vertical migration, but the rate of migration depends on the vertical permeability (Yu et al., 2020). The extent of the vertical flow also has a direct relationship with the injection rate where the horizontal migration would be greater at a lower injection rate.

Faults. Numerous processes are involved to induce a fault, including plate motions, folding, gravitational sliding, volcanic intrusion, crustal unloading, and fluid injection/withdrawal. It is typically assumed that faults are impermeable because of the shale gouge or clay smear, but many faults are membrane or capillary seals (Yielding, 2015). For a membrane seal, leakage will start when the buoyancy pressure of injected CO_2 becomes larger than the capillary entry pressure of the rocks dominated in a fault zone. Once the leakage is initiated, there are two likely scenarios:

- There is a permeable formation on the other side of a fault that will receive CO_2 and release the pressure from the fault's surface causing across-fault leakage.
- Faults are juxtaposed against an impermeable formation, CO_2 will accumulate inside the fault surface and reactivation will be triggered once the maximum shear strength of the fault is reached (Umar et al., 2019).

Wellbores. Many pathways may become a conduit for the migration and seepage of CO_2 from a storage site (Figure 4). Active or abandoned wells in a storage site can be a potential leakage path for CO_2. (Zhang and Bachu, 2011). Drilling, production, and abandonment operation of the wells used for CO_2 storage have a drastic effect on the well integrity. It should be noted that CO_2 storage wells must act as a secure barrier against the leakage for centuries. Prior to CO_2

injection and during the operation and abandonment phases, well integrity can be affected by faulty well completion or chemical and mechanical stresses.

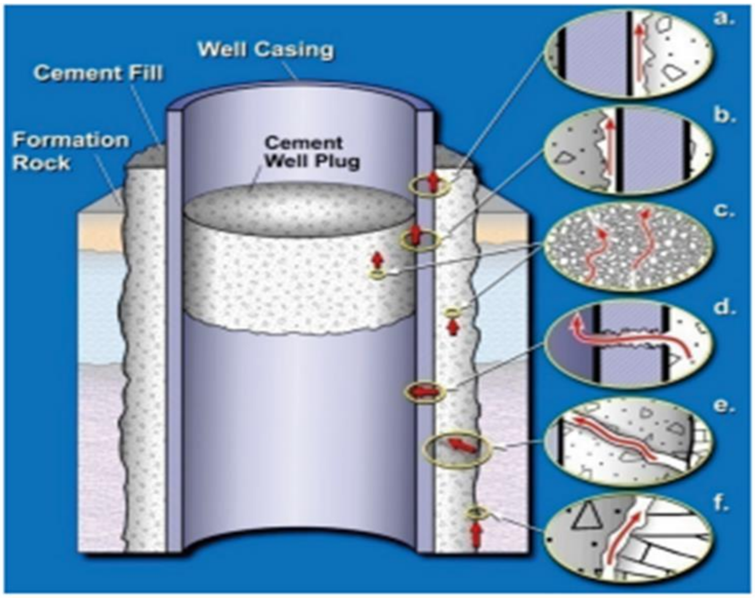


Figure 4. Possible Leakage (red arrows) Pathways in an Abandoned Well (Gasda et al., 2004).

Legacy sites with many wellbore penetrations may also need to be used. In these circumstances, the ability to continuously focus on the complex world of risk analysis from a holistic approach (quantitative and qualitative), following the procedures of the most recognized institutions and organizations of national and international reference, such as the case of PMI or Quintessa organization, will lead to the consolidation and in a certain way, guarantee more precise risk models that work based on the success of projects in their life cycle, and therefore an economic and financial boost to the entire industry from the banking and insurance sectors. The IEA Greenhouse Gas R&D Program (IEAGHG) released a report on "Long Term Integrity of CO_2 Storage-Well Abandonment" discussing the analysis of potential factors contributing to CO_2 leakage from an injection (IEA, 2009). According to this report, 98% of leakages are observed in abandoned cased wells with a poor cement job.

3.2.2 Causes of Induced Seismicity

Natural induced seismicity is a potential operational issue that must be managed. Pre-operational testing is a key factor for operating within safe parameters that can help mitigate any potential natural seismicity. The balance of injection and withdrawal of fluids is critical to understanding the potential for induced seismicity with respect to energy technology development projects. Induced seismicity may occur whenever conditions in the subsurface are altered in such a way that stresses acting on a preexisting fault reach the breaking point for slip. If stresses in a rock formation are near the critical stress for fault rupture, theory predicts and experience demonstrates, that relatively modest changes of pore fluid pressures can induce seismicity (Figure 5).

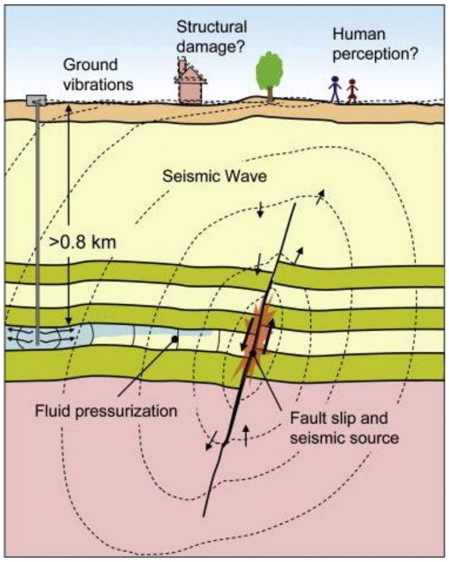


Figure 5. Loss of integrity Schema (Source: Hurtado et al., 2021).

Injection of fluid in rocks causes an increase of the pore pressure and also modifies the state of the stress (Hsieh, 1996; National Research Council [NRC], 1990). Generally, induced earthquakes are not damaging, but if preexisting stress conditions or the elevated pore fluid pressures are sufficiently high over a large fault area, then earthquakes with enough magnitude or intensity to cause damage can potentially occur. Two basic questions must be answered to determine the severity of any potential damage:

- What is the magnitude of the pore pressure change?
- What is the extent of the volume of rock where the pore pressure is modified in any significant manner?

The magnitude of the induced pore pressure increases and the extent of the region of pore pressure change depend on the rate of fluid injection and total volume injected, the fluid viscosity, and two hydraulic properties of the rock (intrinsic permeability and storage coefficient) (Figure 6).

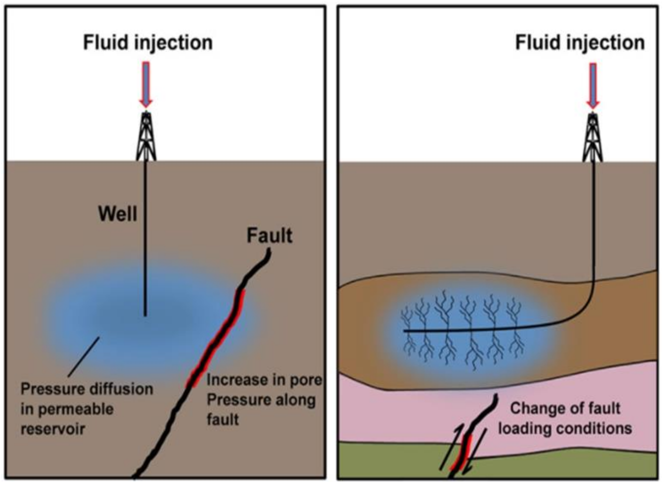


Figure 6. Stress changes due to fluid injection scenarios (Adapted from DOE/NETL, 2017).

Shallow earthquakes result from slip (movement) along a preexisting fault. Two critical questions concerning such earthquakes are:

- Which factors are responsible for the initiation of a seismic event?
- Which factors control the magnitude of the event?

Many factors are important in the relationship between human activity and induced seismicity: the depth, rate, and net volume of injected or extracted fluids, bottom-hole pressure, permeability of the relevant geologic layers, locations and properties of faults, and crustal stress conditions. Another important factor to consider in evaluating the potential for an energy project to induce felt seismic events is the variation in volume from technology to technology, and the variation in net volume over time. Evaluation of production facilities for large-scale CCS thus requires a complete presentation of the risk of induced seismicity and a comprehensive monitoring plan including bottom-hole pressures and time response to different injection regimes.

Table 1 summarizes methods that can be used to determine the likelihood of a seismic event. Column B indicates methods that must be developed to estimate probabilities (“P”) for various aspects of an induced seismic event, which is shown in Column A. These four aspects include the probability of generating an earthquake of M > 2.0, the probability of shaking being felt at the surface, the probability of different strengths of shaking from an earthquake, and the probability that the earthquake shaking will affect structures and people.

Table 1. Likelihood of hazard and risk assessments. Source: DOE/NETL (2017).

A. Probability (P) Needed	B. Method	C. Technology Dependent?	D. Region Dependent?	E. Depth Dependent?
1A. P [Generate magnitude ≥ 2[(a)] earthquakes]	1B. Statistical	1C. Yes, depends on factors such as volume, pressure, rate, and depth	1D. Yes, tectonically active versus stable region	1E. Yes, large earthquakes usually not induced near surface
2A. P [Shaking felt at surface]	2B. Analytical/ Statistical	2C. Yes, depends on magnitude distribution and maximum magnitude	2D. Yes, depends on earthquake properties	2E. Yes, deeper induced earthquakes may not be felt
3A. P [Strength of shaking]	3B. Analytical	3C. Yes, depends on maximum magnitude	3D. Yes, depends on the earthquake properties	3E. Yes, shallow
4A. P [Structures and people affected]	4B. Analytical	4C. No	4D. Yes, depends on the structural strength and tolerance for shaking	4E. Yes, deeper earthquake, if felt at the surface, may affect a larger area.

Notes: (a) Magnitude 2.0 earthquakes are minor earthquakes that can be felt slightly but cause no damage.

3.2.3 Causes of Public Opposition

Over the last decade, a diverse body of articles has been published on public perception of CCS. The technology acceptance framework by Huijts et al. (2012) is a useful tool for structuring the various results. Table 2 summarizes the most important findings for each variable in the framework.

Table 2. Main Findings of Public Acceptance Studies of CCS (Quoted from L'Orange Segio et al., 2014).

Concept	Main Findings
Acceptance	• Most important predictors are perceived risks, perceived benefits, and trust • Aspects and consequences of technology itself play a role, but the influence is limited • Social context of project site is influential
Experience	• Case studies point to the importance of prior experience with fossil fuel or other industries for acceptance • Little research, worth exploring more
Knowledge	• The public's mental models and misconceptions about CCS are understood well enough to produce meaningful information materials • Pre-existing knowledge and information about CCS influence acceptance, but the impact is limited
Trust	• Important predictor of acceptance • Most trusted are area researchers and non-governmental organizations, least trusted are industry stakeholders • Trust can be enhanced through fair procedures, honest communications, and collaboration of multiple stakeholders
Fairness	• Case studies point to the importance of both procedural and distributed fairness • Little research, worth exploring more
Affect	• Positive and negative affect are two different dimensions • Affectively loaded messages are more persuasive; their content might be different from expert messages
Perceived costs	• Costs are seen as a major disadvantage of CCS
Perceived risks	• Potential risks that the public sees are quite well understood • Most important perceived risks are CO_2 leakage and induced seismicity • Perceived risks are one of the best predictors of public acceptance
Perceived benefits	• Single best predictor for public acceptance • Perceived benefits are influenced by trust • Important for concrete projects to identify local benefits
Outcome efficacy	• Low perceived outcome efficacy prevents protest, even if acceptance is low
Problem perception	• General agreement that climate change is real, only small portion of deniers • Tends to have positive effect on benefit perception, negative effect on risk perception
Energy context	• People want to discuss CCS within the broader context of alternatives • Evaluation in context tends to be more positive than in isolation
Interference with nature	• Seems to be an important predictor for risk perception, benefit perception, and acceptance • More research needed to clarify role.

3.3 Step 3. Identify Potential Outcomes (Consequence)

The risks associated with long-term carbon storage can broadly be categorized as local, regional, and global environmental effects arising from the release of stored CO_2 to the atmosphere. If leaks do occur, a number of hazards exist:

1) Potential hazards to human health and safety.
2) Hazards to groundwater from CO_2 leakage and brine displacement.

3) Hazards to the natural environment.
4) Release of co-contaminants.
5) Financial losses due to lost project revenue, damaged or stranded assets, voluntary recovery efforts, and litigation.

3.3.1 Consequences of CO_2 Leaks

Impact to Human Health. Although CO_2 is generally regarded as safe and non-toxic, exposure to high concentrations can be harmful and even fatal. Ambient atmospheric concentrations of CO_2 are currently about 400 parts per million (ppm). Humans can tolerate increased concentrations with no physiological effects for exposures up to 1% CO_2 (10,000 ppm). Beyond this, CO_2 can act as an asphyxiant. Examples of possible leakage scenarios are classified as low or high consequence based on the amount of CO_2 or brine released to the receptor.

Impacts to human health could also occur as the result of impacts to USDWs. Pressurization of reservoir could cause the release of brine into USDWs or surface environments. In addition, CO_2 leakage into USDWs or freshwater and marine environments could cause geochemical changes in these systems. CO_2 and water form carbonic acid. At high enough ionic activities, these acids can significantly reduce the pH of an aquifer or aquatic environment. Changes in pH and other geochemical changes can lead to several adverse effects:

- Mobilization of heavy metals. Naturally occurring heavy metals in CO_2 storage formations and USDW formations can be mobilized. Some of these metals (e.g., arsenic, mercury, and lead) are hazardous to human health and environmental receptors.
- Stress on aquatic ecosystems. Changes in water chemistry, including pH, dissolved oxygen, and major and minor ions can stress aquatic receptors, including benthic creatures, filter feeders, fish, and mammals.
- Formation alterations. Geochemical changes can alter USDW properties, leading to increased total dissolved solids, increased or decreased aquifer yields, etc.
- Dissolution of CO_2 and transformation of minerals. The dissolution of CO_2 and transformation of minerals can be affected by pressure and temperature conditions due to their impact on the mass of minerals and the aqueous species involved in the equilibrium reactions. They can also accelerate the chemical reactions, develop fractures, or reactivate faults.

Impacts to the Surface and Existing Natural Resource Extraction. Leaked CO_2 can cause the deformation of the land surface if the pressure on the land surface is altered. In addition, the presence of CO_2 in the subsurface or the migration of CO_2 out of the reservoir to other subsurface or surface environments can affect future land use or natural resource extraction. These changes may present opportunities for additional resource extraction (e.g., enhanced oil recovery [EOR] and enhanced coal-bed methane [ECBM]) or impede extraction (e.g., inhibited recovery through formation changes or hazards presented by the presence of CO_2). These may result in financial impacts or reduced access to natural resources. The most important point is choosing the right method to evaluate and build the metrics.

Costs of CO_2 Leakage. Battelle (2020) determined the costs of finding and fixing leaks CO_2 leaks in CCS projects using the following cost categories: Mitigations costs, interruptions to operations, legal costs, and erosion of public trust.

Mitigation costs. The costs of mitigating damage caused by CO_2 leaks can include finding and fixing the leak, short- and long-term remediation, and technical remedies for the leak. These are discussed further in Section 3.4.2.1.

Operations interruption costs. Includes the cost of downtime or reduced operational capacity due to the need to find and fix a leak. The cost of downtime is variable based on the leak details. For instance, Battelle (2018) assumed 25% loss in operational capacity and includes costs related to “take-or-pay” contract mechanisms of \$20/t CO_2 and lost revenue from carbon storage credits, referred to as Climate Program Compensation (U.S. EPA, 2001).

Legal costs. Includes all costs associated with legal expertise needed to address stakeholder claims.

Erosion of public trust. Public relations costs may be associated with a CO_2 leak. CO_2 leaks can erode public trust and require some efforts to ensure the public that the science if sound and that the fix worked.

3.3.2 Consequences of Induced Seismicity

Seismic risk is formally evaluated based on a combination of the seismic hazard, level of the exposure of the population and built environment of the seismic hazard, and the vulnerability to shaking of the buildings and infrastructure within the risk area. Induced seismicity from CCS is currently difficult to accurately assess. With only a few small-scale commercial projects overseas and several small-scale demonstration projects under way in the US, few data are available to evaluate the induced seismicity potential of this technology.

Risk exists to those structures only if the shaking is minor, moderate, or larger. Factors that should be considered for risk include location of faults, location of infrastructure that can be damaged, and net changes to subsurface pore pressure caused by the energy project. These net changes involve the volume and pressure of fluids injected or extracted, the duration of injection and extraction, and the number of wells involved in the project. Two spatial aspects of risk analysis are important to consider in the context of induced seismicity:

- Multiple structures that can be damaged. A single well that induces earthquakes large enough to cause damage at the surface may damage multiple structures at the surface.
- Multiple well locations. The risk associated with induced seismicity must be evaluated in terms of the sources of human activities. The spatial distribution for an entire industry project (e.g., underground injection of CO_2) may be very large, and a risk analysis of the entire project would be necessary.

3.3.3 Consequences of Public Opposition

During project siting, public acceptance is a key feature of successful project implementation. Public opposition could occur as the result of pressure from local, state, or national non-governmental organizations or citizen groups. Public opposition to a project could complicate the development through project delays, project cancellation, or delays in technology implementation. Incidents of CO_2 leakage, induced seismicity, or other operational failures could lead to public opposition during project operations.

3.4 Steps 4-7. Control Measures and Recovery Measures and Threats and Protections for These Measures

Recognizing the risks involved in oil and gas reservoir storage, risk mitigation activities are essential. The Intergovernmental Panel on Climate Change (IPCC) has recommended the following interrelated development and management practices:

- Careful site selection, including performance and risk assessment and socio-economic and environmental factors.
- Monitoring to provide assurance that the storage project is performing as expected and to provide early warning in the event that it begins to leak.
- Effective regulatory oversight.
- Implementation of remediation measures to eliminate or limit the causes and impact of leakage.

3.4.1 Control Measures

CO_2 Leakage and Induced Seismicity Control Measures. Characterization*.* Per Environmental Protection Agency (EPA) Underground Injection Control (UIC) Class VI regulations (§146.87 – Logging, sampling, and testing prior to injection well operation) provides well characterization requirements prior to injection well operation. These characterization requirements are designed to ensure the geologic conditions of the storage complex are understood and that all associated injection and monitoring wells are of sound integrity. Geologic characteristics that must be understood include formation type, depth, permeability, porosity, and storage efficiency. Once the formation type has been identified, the depth of the candidate site should be estimated. As the depth of the storage site increases, the probability that CO_2 will remain in its supercritical state increases. CO_2 stored in its supercritical state occupies less volume than in the gaseous phase, thus ensuring a more efficient use of storage capacity.

The capacity of a rock to allow fluids to flow through it is called permeability. In other words, fluids can easily migrate through permeable formations but will be stopped or trapped by impermeable rocks. The storage site should be overlain by an impermeable layer of rock to confine the CO_2 and prevent its migration to freshwater resources or back to the atmosphere. Thus, the permeability of the overlying formation should be estimated when evaluating a potential risk into the storage site.

Two formation properties – porosity (a measure of the void spaces in a rock) and permeability (the capacity of a rock to transmit fluids through interconnected pores on a microscopic scale) – must be understood to determine the potential for injection. Trends in porosity and permeability in reservoirs can be determined by researching the depositional environment. Both porosity and permeability (generation, magnitude, and distribution) differ considerably between igneous, metamorphic, and sedimentary (clastic and carbonate) reservoirs. Secondary (diagenetic) changes can create or destroy the original porosity and permeability or create barriers to fluid flow. In some cases, the secondary porosity considerably increases the porosity of the rock matrix and is the primary mechanism for fluid storage and fluid flow. The performance of CO_2 injection into a geological formation can be predicted by estimating the storage efficiency. Storage efficiency is defined as the percentage of pore spaces that are accessible to and can thus hold the free-phase CO_2.

CO_2 storage also requires a sealing formation or caprock. The capability of a caprock to confine CO_2 is controlled by many parameters ranging from capillary sealing pressure to lateral continuity, thickness, ductile/brittle behavior, and presence of fractures or faults (Vavra et al., 1992) (Figure 7). Sealing potential is defined as the capacity of a caprock to maintain its strength against the migration of fluid during or after fluid injection. Leakage through caprock can take place in two ways:

- Through interconnected pore space.
- Through initiation of new factures or reactivation of preexisting fractures.

The factors controlling the capillary pressure, on these occasions, are pore throat size, CO_2-water interfacial tension and surface wettability of rock. Surface wettability, on the other hand, can be determined experimentally in a laboratory setting.

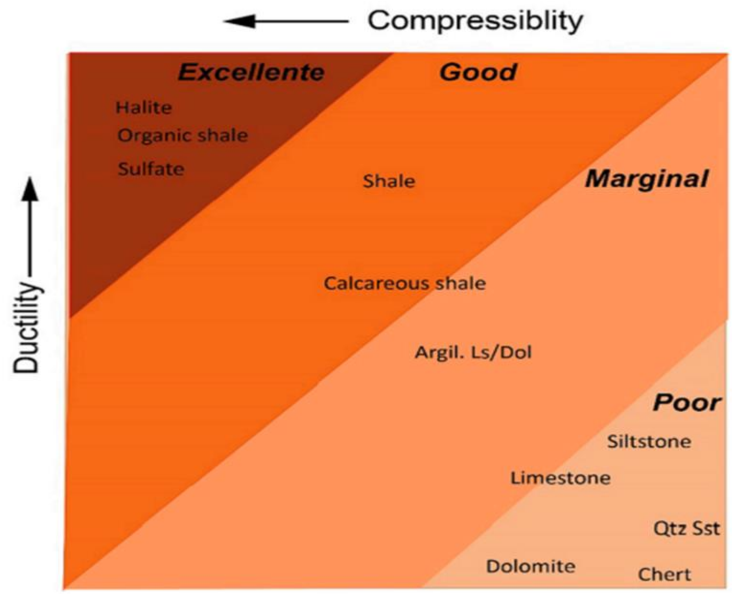


Figure 7. Sealing Behavior of Different Rocks Based on the Compressibility and Ductility Factors (Kivior et al., 2002).

<u>Safety assessment of a CO_2 storage site.</u> Given the complexity of geological storage sites a risk management/assessment guideline is essential to ensure that CO_2 leakage can be minimized during and after injection (Table 3). Certain steps that need to be taken to assess the suitability of a geological medium for possible CO_2 storage and possible management strategies recommended are initial screening (Phase 1), reservoir characterization (Phase 2), operational aspects (Phase 3), monitoring (Phase 4), and remediation strategies (Phase 5).

Table 3. Screening Criterion for Selection of Global Depleted Gas Reservoirs (Raza et al., 2016).

Parameters	Positive Indicators	Cautionary Indicators	Indication of Aspect
CO_2 source and total storage capacity	Total capacity of reservoir estimated to be much larger than the total amount produced from the CO_2 source	Total capacity of reservoir estimated to be similar or less than the total amount of produced from the CO_2 source	Storage potential
Depth	>800 m	800 m > depth > 2000 m	Storage potential
CO_2 density	High	Low	Storage potential
Porosity	>20%	<10%	Storage potential Capillary trapping

Table 3 (continued). Screening Criterion for Selection of Global Depleted Gas Reservoirs (Raza et al., 2016).

Parameters		Positive Indicators	Cautionary Indicators	Indication of Aspect
Thickness (net)		>> 50m	<20 m	Storage potential Injectivity
Permeability (near-wellbore)		>100 mD	10-100 mD	Injectivity
Well type		Horizontal well with or without hydraulic fracture	Vertical well without hydraulic fracture	Injectivity
Type of minerals		Ca-, Mg-, or Fe-rich framework minerals such as feldspars, clays, micas, and Fe-oxides	Fast reacting carbonated minerals	Injectivity/mineral trapping
Residual gas/water saturation		Less	High	Injectivity
Pore throat size distribution		Less heterogeneous	High heterogeneous	Injectivity and trapping
Salinity		Low	High	Solubility trapping
Temperature		Low temperature gradient	High temperature gradient	Solubility trapping
Pressure		Under pressure	Overpressure	Solubility trapping
Gravity number		Less	High	Capillary trapping
Rock type		Quartz rich sandstones and carbonates	Highly stress sensitive carbonates	Capillary trapping
Rock wettability		Strong water wet	Less water wet or oil-wet	Capillary trapping
Interfacial tension		High	Low	Capillary trapping
Hydraulic integrity	Res. Type	Reservoir without compaction/aquifer support Have not experienced any injection in the past Less fault and fractures	Res. With compaction/aquifer support Have experience any injection in past More faults and fractures	Containment
	Well loc. & condition	Good completion condition and away from faults and fractures	Poor completion and near to faults and fractures	Injectivity
Seal Capacity – CO_2 column height		Capillary entry pressure much greater than buoyancy force to maximum produced CO_2 column height	Capillary entry pressure similar to buoyancy force of maximum produced CO_2 column height	Containment
Seal geometry – Lateral continuity		Un-faulted	Laterally variable faults	Containment
Seal geometry – thickness		>100 m	<20 m	Containment
Hydraulic integrity: Seal		Presence of mineral and stress characterization data of seal	Absence of mineral and stress characterization data of seal	Containment
Distance between CO_2 emissions and target medium		<300 km	>300 km	Transportation cost

Control Measures for CO_2 Leakage. Monitoring. Per EPA UIC Class VI regulations (40 CFR 146.90 – Testing and Monitoring Requirements), the owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic storage project is operating as permitted and is not endangering USDWs. Typical monitoring plans include components for monitoring the CO_2 plume and water/brine behavior, detecting potential release pathways, quantifying releases, and meeting regulatory requirements (European Commission, 2011). CO_2 leakage is monitored through several technologies. These technologies, detailed in Appendix A, include the following:

- **Atmospheric monitoring:** Monitoring CO_2 in the atmosphere to determine if there is a leak from the storage complex.
- **Remote sensing:** Determining CO_2 leakage through changes in the land surface.
- **CO_2 leakage-induced environmental responses:** Analyzing CO_2 leakage through changes in environmental receptors like vegetation stress, fertilization, or mineral formation and alteration.

- **Near-surface monitoring:** Monitoring geochemical changes in soil or groundwater to determine impacts from leaking CO_2.

- **Subsurface Monitoring:** Subsurface monitoring can be accomplished by subsurface monitoring wells often in conjunction with seismic geophysical methods.

- **Seismic geophysical methods:** Timelapse vertical seismic profiles (VSPs), crosswell seismic in boreholes, and distributed acoustic sensing (DAS) are methods of seismic geophysical methods. Some seismic geophysical methods can lead to time-lapse (4D) data collection.

- **Gravity methods:** Determining the presence of CO_2 using high-precision gravity measurements.

- **Electrical methods:** Using the contrast between the electrical conductivity of CO_2 and water to determine the location of CO_2.

Well Construction and Rehabilitation. Wellbores that penetrate the storage complex and caprock can be rehabilitated through well workovers, plugging or re-plugging and abandonment of wells, or monitoring approaches adapted to monitor areas near potentially compromised boreholes.

Well Design. To prevent the contamination of USDWs and the atmosphere, wells are constructed to prevent the movement of fluids within or along the wellbore. Several barriers are common to all modern wells: Surface casings, annular cement, and cement plugs (for plugging and abandonment). These factors can be used to help prioritize the well rehabilitation and monitoring.

Surface Casing. Surface casing is the barrier between the borehole and the well in the upper part of the well. The surface casing is required to protect USDWs and should be cemented back to the surface. Because the surface hole is not drilled to the storage formation, it does not affect the caprock but could protect from the release to a USDW or surface. If the surface casing cement reaches the surface, the surface casing is considered responsive.

Production Casing. Production casing is the barrier between the reservoir and caprock formation and the well. The production casing must be cemented to prevent migration of fluids between formations.

- Production cement terminates in surface casing. The production cement is the cement between the borehole and the well in the lower part of the well. Production cement that extends into the surface casing means that, ideally, there is a portion of the well without a cement barrier.
- Production cement as percent of column. A column of cement must be sufficiently thick to prevent flow between units. Cement that covers a certain percentage of the borehole is more likely to be an effective barrier and to prevent flow in micro-annuli and cracks in the cement.

Well Plugging. When abandoning a well, it is necessary to install cement plugs at specific points in the wellbore. The amount and integrity of the cement used can be:

- Well Plug – Percentage of column. The percentage of the well column that is plugged is equated to the amount of the casing that is sealed internally. Because most wells are not entirely plugged with cement, 20% was chosen as the most efficient seal possible.
- Well Plug – Difference between TD and bottom of plug. The difference between the bottom of the last plug and the total depth is used as a proxy for the empty space between the bottom of the well and the deepest plug. For most wells that penetrate the reservoir or caprock, the bottom of the well is at or near a formation of interest.

<u>Operational Constraints.</u> Project operational constraints are required to prevent the leakage of CO_2, damage to reservoir or caprock formations, or induced seismicity during and after injection. Specifically, 40 CFR §146.88 requires that “injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s)” to prevent damage to the formation.

<u>Plume Stabilization.</u> Over time, the CO_2 plume and pressure front stabilize naturally. Natural stabilization of a CO_2 saturation plume and pressure front occur through trapping mechanisms. Through trapping, CO_2 is kept in place through one of four mechanisms: stratigraphic traps, residual traps, solubility traps, or mineral traps. The storage mechanism, along with the sweep efficiency, relative permeability, CO_2 viscosity, water viscosity, and density determine the performance and success of the storage process.

Carefully choosing a site to ensure that it efficiently traps the CO_2 at a cost-effective manner for a long duration of time. Thus, the first step of any CO_2 storage project is the exploration phase, whereby the ideal storage site is identified and selected. The choice of the appropriate storage site depends on several factors, including the maximum amount of CO_2 to be stored, CO_2 temperature, CO_2 pressure and chemical properties, the source of the captured CO_2, and its mode of transportation. It is also important to consider the duration of operation of the CCS project. Thus, these factors should be clearly identified before the beginning of the exploration phase.

The CCS project operator should also identify the risk evaluation criteria that will be used to rank the candidate storage sites. The evaluation criteria FEPs must consider the technical elements as fluids, chemicals, and geological features but also could include economic, regulatory, and technical considerations.

<u>Stratigraphic/Structural Traps.</u> Trapping mechanisms are primarily stratigraphic or structural depending on the physical processes by which they isolate an area or formation (Figure 8). Stratigraphic traps are the result of lithology (rock type) changes. Structural traps can be divided into three forms: anticline trap, fault trap, and salt dome traps.

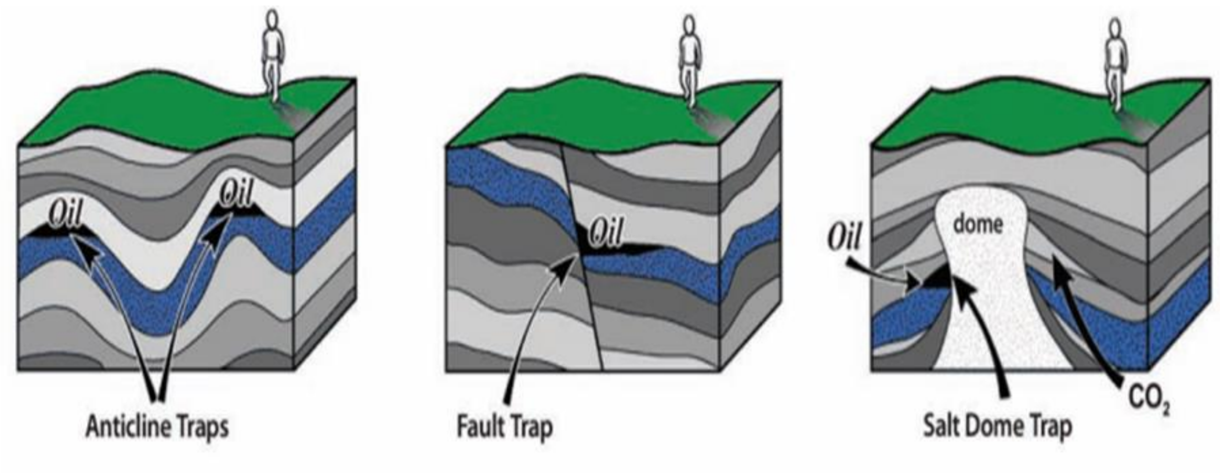


Figure 8. Structural Traps, Including Anticline Traps (left), Fault Traps (center), and Salt Domes (right). (Modified from Petroleum Research Institution, 2008.)

Post-closure mitigation controls. Future human actions that could affect CO_2 containment are external factors that are difficult to predict. FEPs related to future human actions include the motivation and knowledge of future human activities, changes in political and cultural institutions, developments in technology, future oil and gas drilling and mineral extraction, water management, and explosions or crashes. In addition, the presence of CO_2 may influence future activities. Ensuring future human actions do not affect system containment requires documentation of project activities and restrictions of future activities that might affect containment. This can be accomplished through recordkeeping, and consideration of land use controls/institutional controls (LUCs/ICs) to prevent any activities that would affect the storage complex.

3.4.1.4 Induced Seismicity Control Measures

Induced Seismicity Mitigation Plan. A plan should be in place before any injection operations begin (DOE/NETL, 2021). The framework of the plan should be based on Traffic Light System (TLS) protocol, which is a risk management tool (Figure 9). One of its purposes is communicate the status of the project, and it specifies predefined actions that should occur to attempt to prevent large magnitude induced events. It also prompts the operator to consider changes to the operations if a concerning trend of seismic activity has been observed. TLS will typically apply to three or more response levels, shown in Figure 9.

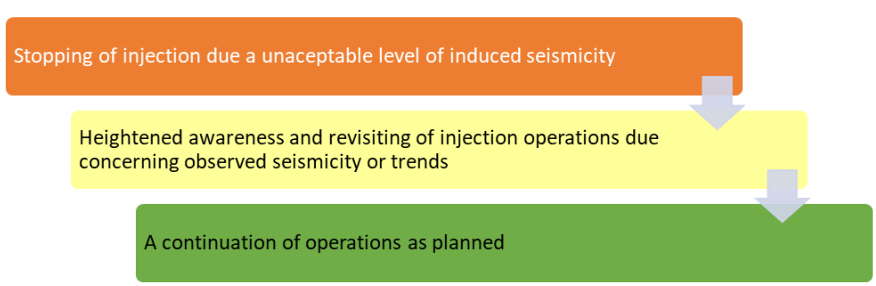


Figure 9. TLS Levels (DOE/NETL, 2021).

An adaptative traffic light system (ATSL) is another method, fully probabilistic, that incorporates new data on the fly, to update geomechanical and seismic forecasting models, and integrate hazards and risk calculation. This is not only for past observations of seismicity but can produce projections of seismicity based on the actual or project injection and production rates on the reservoir (Figure 10). In both TLS and ATLS, the threshold criteria determining when an increase in response level is necessary should be defined in such a way that they allow effective intervention to prevent the traffic light from reaching the highest response level, requiring a full stop of the operation.

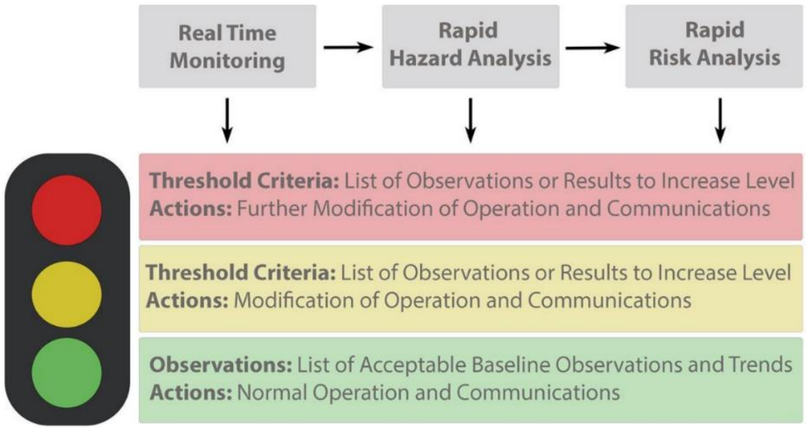


Figure 10. Example of adaptative traffic light system DOE/NETL (2021).

The use of a traffic light control system. The protocols described refer to a "traffic light" control system for responding to an instance of induced seismicity. Such a system, although rarely employed in energy technology projects with active cases of induced seismicity, allows for low levels of seismicity but adds additional monitoring and mitigation requirements when seismic events are of sufficient intensity to result in a concern for public health and safety.

Seismic event magnitude alone is generally insufficient as the only criterion because of the nature of attenuation (absorption or loss of energy) with increasing distance from an event location to a sensitive receptor site. Zoback (2012) provides a summary of a TLS for the purpose of managing potential induced seismicity from wastewater disposal.

Table 4. Primary elements of a protocol for addressing induced seismicity in Enhanced Geothermal Systems (EGS) Technologies, Source: DOE/NETL (2012).

Cat. Of Essential Activities	Preparation Stage	Drilling Stage	Stimulation Stage	Operations Stage	Completion Stage
Initial screening to determine the feasibility of the ESG project	Assess the local hazard potential from natural seismicity; the local, state, and federal regulations; the nearness of the project population centers; the probable magnitude of induced events; and the probable risks of potential damage from both natural and induced events. If the proposed ESG project appears to be feasible based on this initial screening assessment, then the essential activities of the ESG project listed below are recommended to proceed in the manner described within each of the five sequential stages of project development as identified herein.				
Public and regulatory communi-cations	Identify the local people and organizations to meet with. Hold initial public meeting, explain the planned project, identify their concerns.	Meet with and inform the public, regulators, and media as to the drilling schedule. Upon completion, meet and explain the drilling results.	Meet with and inform the public, regulators, and media as to the stimulation schedule and results.	Meet with and inform the public, regulators, and media as to the operational schedule and results.	Meet with and inform the public, regulators, and media as to the project completion.
Criteria for ground vibration and noise	Install ground motion and noise monitoring instruments.	Report to the public, regulators, and media the monitoring results.			

Table 4 (continued). Primary elements of a protocol for addressing induced seismicity in Enhanced Geothermal Systems (EGS) Technologies.

<table>
<tr><th>Cat. Of Essential Activities</th><th>Preparation Stage</th><th>Drilling Stage</th><th>Stimulation Stage</th><th>Operations Stage</th><th>Completion Stage</th></tr>
<tr><td>Seismic monitoring</td><td>Determine areal size and sensitivity needed for local array. Install and operate seismic recording array and allow timely public access to results.</td><td>Continue to monitor the seismicity recorded and publicly report the results.</td><td colspan="2">Add and/or reposition array’s seismometers as needed to follow and characterize induced events.</td><td>Continue to record and report induced seismicity as long as needed to describe local conditions.</td></tr>
<tr><td>Hazard assessment</td><td>Evaluate the potential additional hazards to be expected from the locally induced seismicity.</td><td colspan="3">Review and reassess the potential for damage based on local observations.</td><td>Report to the public, regulators, and media on the actual results experienced.</td></tr>
<tr><td>Risk assessment</td><td>Develop a probabilistic risk analysis to estimate the probability of risk (monetary loss) to be expected.</td><td colspan="3">Revise the risk assessment as appropriate based on any physical damage, nuisance, and/or economic losses attributed to the project operations.</td><td>Report to the public, regulators, and media on the actual results experienced.</td></tr>
<tr><td>Direct mitigation plans</td><td>Develop a plan to control the level and impact of locally-induced seismicity.</td><td colspan="3">If needed, implement the control system to cause the drilling stimulation, or continuing operations to be temporarily reduced or suspended until the level of the locally-induced seismicity has been returned to an acceptable level, as determined by the regulatory agencies.</td><td>Report to the public, regulators, and media on the actual results experienced.</td></tr>
<tr><td>Indirect mitigation plans</td><td colspan="5">Provide local jobs, support local community facilities, and provide compensation if appropriate. Continue indirect mitigation activities as long as needed.</td></tr>
</table>

Existing induced seismicity checklists and protocols. Checklists can be convenient tools for government authorities and operators to discuss and assess the potential to trigger seismic events through injection, and to aid in determining if a seismic event is or was induced. Two checklists, one to address each of these two circumstances—the potential for induced seismicity and the determination of the cause of a felt event—can be helpful (Table 5 and Table 6, respectively). The checklists recommend a list of 10 “yes” or “no” questions to quantify “whether a proposed injection project is likely to induce a nearby earthquake” and a list of seven similar questions to quantify “whether an ongoing injection project has induced an earthquake.”

Table 5. Potential for induced seismicity checklist. Source: DOE/NETL (2017).

Question	No Apparent Risk (Yes / No)	Clear Risk (Yes / NO)
Background Seismicity		
Are large earthquakes magnitude (M > 5.5) known in region? (within several hundred km)		
Are earthquakes known near the injection site? (within 20 km)		
Is the rate of activity near the injection site (within 20 km) high?		
Local Geology		
Are the faults mapped within 20 km of the site?		
If so, are these faults known to be active?		
Is the site near (within several hundred km of) tectonically active features?		
State of Stress		
Do stress measurements in the region suggest rock is close to failure?		

Table 5 (continued). Potential for induced seismicity checklist.

Question	No Apparent Risk (Yes / No)	Clear Risk (Yes / NO)
Injection Practices		
Are (proposed) injection practices sufficient for failure?		
If injection has been ongoing at the site, is injection correlated with the occurrence of earthquakes?		
Are nearby injection wells associated with earthquakes?		
TOTAL YES ANSWERS		

Table 6. Checklist for the Potential Cause of Induced Seismicity. Source: DOE/NETL (2017)

Question	Earthquakes Clearly NOT Induced (Yes / No)	Earthquakes Clearly Induced (Yes / NO)
Background seismicity: Is this event the first known earthquake(s) of this character in the region?		
Temporal correlation: Is there a clear correlation between injection and seismicity?		
Spatial correlation		
Is the epicenter near wells? (within 5 km)		
Do some earthquakes occur at or near injection depths?		
If not, are there known geologic structures that may channel flow to sites of earthquakes?		
Injection practices		
Are the changes in fluid pressure at well bottoms sufficient to encourage seismicity?		
Are the changes in fluids pressure at hypo central location sufficient to encourage seismicity?		
TOTAL YES ANSWERS		

Preliminary risk classification of site-specific seismic risk can be completed using the process defined by DOE/NETL (2021) (Figure 11). The assessment involves classifying the potential seismic risk into one of four categories: Very Low, Low, Medium, or High. These risk classifications are based on local, state, and federal law; geologic setting; regional seismicity estimates; the presence of potential impacted features or populations; the magnitude of potential impacts; local risk tolerance; and planned operations. The expected seismic risk is used to determine the amount of analysis that is required to confirm operational safety prior to proceeding with site-specific characterization for a CCS project. For instance, a site classified as Very Low will need minimal pre-screening work for induced seismicity. Sites with Low risk may require some additional analysis but can generally proceed. Medium risk site may need to be abandoned unless there are compelling data to show that the site can proceed. High risk of induced seismicity should preclude the site from development.

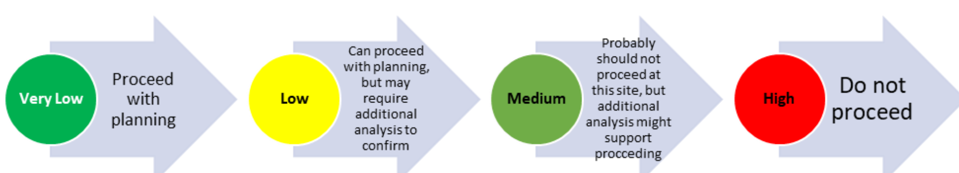


Figure 11. Preliminary Classification of Site-specific Seismic Risk (From DOE/NETL [2021]).

Did Injection Induce the Observed Earthquake(s). The list of seven questions (Table 6) from Davis and Frohlich (1993) evaluates four factors related to possible cause: background seismicity, temporal correlation, spatial correlation, and injection practices.

Expert Panel. An expert panel should be formed to provide evidence-based information and recommendation pertaining to the induced seismicity risk posed by the project. Subject matter experts have proven successful, particularly in the presence of substantial epistemic uncertainties, such as a greenfield site and investigating the potential for induced seismicity (Trutnevyte and Azevedo, 2018).

3.4.1.5 Public Engagement

L'Orange Segio et al. (2014) conducted a literature review of public acceptance on CCS projects. The results of the studies that included the US are summarized in Table 7. These studies represent an array of qualitative and quantitative approaches related to outreach and public opposition. The literature surveyed found several themes. CCS was not a preferred option for addressing climate change in two of the studies (Fleishman et al., 2010; Palmgen et al., 2004 in a study of 126 individuals), although Fleishman et al. (2010) found that technologies with CCS were preferred to the same technology without CCS. The respondents in these studies favored energy efficiency and efficacy of energy storage. Palmgren et al. (2004) further found that CCS was the least favored option for addressing climate change. Two studies found that CCS remained largely unknown (Carley et al., 2012; Reiner et al., 2006), meaning that public outreach may be an effective way to educate project stakeholders.

Effective stakeholder engagement for CCS involves early communication, knowledge about the community (social context), a focus on local benefits, and using effective and appropriate modes and fora for communication (Ashworth et al., 2012). Knowledge of the community is a particularly important component of outreach. Sharing additional information about safeguards for the technology could help to allay fears. For instance, Palmgren et al. (2004), who found that CCS was the least favored mitigation option, found that many respondents in a different survey of 18 non-technical respondents perceived high risk, negative consequences, and were uncertain about costs. They also wanted to see CCS in a broader context with other mitigating technologies, work that has been done by the Intergovernmental Panel on Climate Change (IPCC) in the years since the study was conducted (IPCC, 2022).

An understanding of the communities targeted by outreach efforts will also help tailor effective messages to address individual concerns. For instance, Carley et al. (2012) found that people who are more politically conservative were less likely to support CCS. Having a message of economic development may be the best tactic to reach these people. In contrast, Palmgren et al. (2004) found that people who were for environmental protection had a negative view of CCS. Stressing the safety mechanisms (e.g., the controls discussed in this document) combined with a message supporting economic development in a carbon constrained way may be a more effective message for these individuals. The authors explicitly state that the message of continued fossil fuel use was not compelling to their respondents; however, it may be compelling to the conservative respondents of Carley et al. (2012).

Public acceptance can be fostered through and effective outreach program. Witte (2021) provides an outreach strategy that organizes an outreach strategy by answering three key questions: (1) Who should communicate, (2) what should be communicated, and (3) how to communicate (Figure 12). The authors recommend that a person of trust and a qualified project team should communicate with the entire community on a case-by-case basis and include business associations, trade unions, and other business stakeholders. Issues related to CCS should be tailored to the affected communities. This will require analysis on what the concerns of the communities are and how a CCS project could help address those concerns.

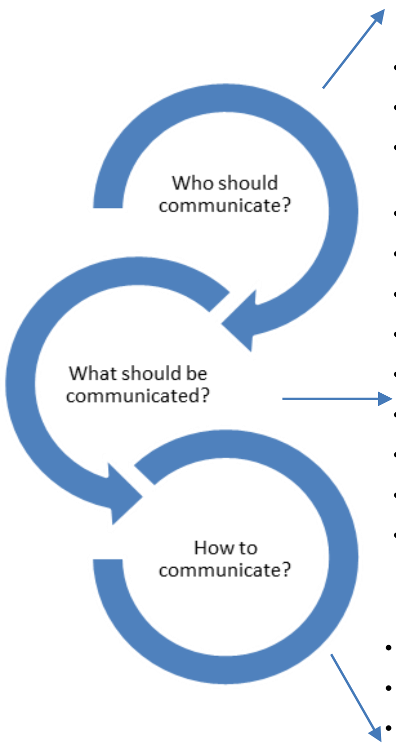
Communication strategies will also need to be developed to ensure that all relevant stakeholders are reached.

Table 7. Literature Review of Qualitative and Quantitative Risk Assessments (From L'Orange Segio et al., 2014) (Note: One of the US studies reviewed was not included but what has been included is representative of the US responses).

Type of Study	Citation	Assessment Details	Summary of Results[1]
Qualitative, includes US	Ashworth et al., 2012	The authors interviewed stakeholders in case studies in Australia, Netherlands, and the US	Critical success factors for projects: alignment of government and development team; communications expert; consideration of social context and ability to adapt to changing social context Components of effective stakeholder communication: timing (early); knowing the community; identifying local benefits; use of appropriate information channels; social context
	Fleishman et al., 2010	The authors provided workshops that included "homework" with residents of the Greater Pittsburgh Metropolitan area. Participants were recruited through community organizations	Participants favored energy efficiency over other low-carbon alternatives Technologies with CCS preferred over their counterparts without CCS Preferences were stable, rankings did not change after group discussions
	Palmgren et al., 2004 (Study 1)	The authors conducted face-to-face interviews with a "convenience sample" of 18 non-technical respondents	Problem perception: most agree that global warming is a problem Perceived risks/costs: costs, efficacy, unforeseen negative consequences Desire to consider CCS in broader set of options
	Wong-Parodi and Ray, 2009	The authors conducted two focus group interviews from communities potentially affected by CCS, one that included people with high incomes and one that included people with low incomes	Primarily negative attitudes towards hosting CCS site Perceived risks/costs: catastrophic leak; induced seismicity; technical risks might change the nature of the town (e.g., reduce property values) Poorer community felt resigned and powerless Sense of empowerment influenced by past experiences Industry-caused environmental damage
Quantitative, includes US	Carley et al., 2012	The authors conducted a phone and mail survey that included "random digit dialing with stratification" (L'Orange Segio et al., 2014).	Knowledge: 80% have not heard of CCS More positive view of CCS if respondent believes human activities contribute to climate change, supports expanded use of low-carbon electricity sources, holds egalitarian world view More negative view of CCS if respondent is a political conservative
	Palmgren et al., 2004 (Study 2)	The authors conducted a closed-survey of 126 individuals	CCS is least favored mitigation option; respondents want efficacy of storage better demonstrated Possibility for continued use of fossil fuels not seen as compelling argument Higher pro-environmental values associated with lower acceptance of CCS
	Reiner et al., 2006	The authors conducted a survey of online panels and random samples	Knowledge/problem perception: Climate change recognized as problem; CCS mostly unknown Similar preferences across countries for how national energy agencies should allocate funding Information on cost and environmental impact of renewable energy technologies decreased support for renewable

1. Quoted verbatim from L'Orange Segio et al. (2014).

- Persons of trust Persons within the scope of their respective expertise
- Qualified project team
- Entire community of interest (to be defined on a case-by-case basis)
- Inclusion of new players, e.g., business and trade associations, companies along the entire value chain



- CCUS narrative embedded in the overall context of sustainability
- Urgency to combat climate change
- Framing of CCUS as environmental technology (where there is no alternative)
- Discussion of alternative technologies
- Integration into norms and values of society
- Costs in the context of the overall energy transition
- Economic advantages and disadvantages
- Set economic consequences in relation to ecological ones
- Infrastructure challenges/use of existing infrastructure
- Presentation of project experiences incl. risk analyses
- Integration into current political context
- Liabilities/standards/regulatory framework/security Role of CCUS for global economy/international cooperation

- Develop an empowerment and communication strategy and plan
- Take into account the main principles of public participation
- Meaningful voice during decision-making processes
- Establish continuity in communication
- Fairness/greatest possible transparency/inclusion of all/neutral/clear/high quality
- Creation of problem-oriented knowledge,
- Include local needs and contexts/site characterization.
- Consider community compensation
- Use of classic media, such as brochures, local media

Figure 12. Communication and Participation in Three Steps (Source: Modified from Witte [2021]).

3.4.2 Recovery Measures

3.4.2.1 CO_2 Leakage Recovery Measures

CO_2 flow diversion. The principle of remediation of CO_2 leakage by CO_2 flow diversion towards close compartments from the CO_2 storage reservoir through hydraulic fractures or deviated wellbores requires the creation of a pathway for fluid migration between the CO_2 storage reservoir and the leaky and neighboring compartments, since the CO_2 reservoir and neighboring compartments are originally not connected. In this sense, compartmentalized saline aquifers or gas reservoirs represent geological settings potentially suitable for remediation by flow diversion.

In the case of relevant CO_2 leakages from geologic storage, pressure relief can be achieved by diverting CO_2 from the CO_2 storage complex to non-connected parts of the reservoir, or to adjacent aquifers and/or reservoirs. This fluid migration can be performed by hydraulic fracturing (fracking) across a sealing fault that separates adjacent compartments, or also by drilling a well.

Fault sealants. The oil and gas industry generally uses different techniques to reduce the flow rate of a given fluid or to maximize oil or gas recovery by injecting fluids with specific properties. Some of these methods could be adapted to reduce or interrupt CO_2 flowing through fractures or faults. One example of this technology is the injection of polymer gel to seal the fault that diverts the flow within the reservoir.

Correcting the Loss of Well Integrity. Measures to mitigate or correct the loss of well integrity in case of CO_2 escape are well documented and are informed by best-practices of the oil and gas industry. This best-practice portfolio of remediation technologies can also be applicable to CO_2 injection wells. New developments and emerging technologies should also be considered, including gels, smart cement, and polymer resins.

Find and fix a leak. The process for finding and fixing a leak includes identifying the possible area of the leak, conducting a screening survey to identify the location (e.g., Light Detection and Ranging [LiDAR]), conducting geochemical sampling and pressure testing at wells in the survey (for the purposes of this analysis, it was assumed ten wells would need to be sampled and tested to identify the leaky well), conducting groundwater sampling to determine potential impacts to USDWs, and fixing the leaky well using a workover rig.

Environmental remediation. Short- or long-term environmental remediation based on EPA-derived costs. Includes accumulated CO_2 extraction, pressure management systems, surface leakage remediation, and groundwater remediation.

Technical remedies for damages. Includes costs related to remedying nearby activities affected by the leak, including groundwater resources or subsurface mining.

3.4.2.2 Induced Seismicity Recovery Mechanisms

Once seismic activity has been introduced above a threshold, there is only a limited range of possible operational procedures that may be able to mitigate further seismicity. The operator can modify the injection operation by reducing the injection rates or volume, stopping injection altogether, producing from the injection well, or producing fluid elsewhere with the goal of reducing the pressure at a location (i.e., active pressure management) (DOE/NETL, 2021). The efficiency of active pressure management is an area of ongoing research (Kroll et al., 2020).

Early Evaluation Period. The first year of injection operations should be considered an early evaluation period. During the early evaluation period, the seismogenic and hydrologic behavior of the target reservoir and underlying basement units should be analyzed to calibrate, verify, and update the pre-injection models and parameters (DOE/NETL, 2021). During this critical time, the relative changes in pressure and stress may be at their greatest, therefore, it is suggested that injection operations should be gradually increased and that any increases in the planned injection rate be recommended by the expert panel, which should be empowered to recommend a slowing or halting of injection to the regulator if hazardous conditions warrant it.

Seismic PISC. During PISC. monitoring and other actions are needed to ensure that any USDW is not endangered. Subject matter experts may recommend implementing a seismic PISC which may have a duration that is different from the requirements of the induced seismicity mitigation plan. During the seismic PISC, seismic monitoring, the outreach and communications program, and the implementation of the Induced Seismic Mitigation Plan should continue, maintaining and adequate number of monitoring stations and reviewing the procedures.

Liability and Insurance. Liability and compensation coverage for damages caused by induced earthquakes should be included in the Induced Seismicity Mitigation Plan as a last means of indirect mitigation. Such indirect mitigation has been used in geologic storage projects in the past (Giardini, 2009). Having an insurance and compensation plan in place prior to operation may significantly increase public acceptance for a subsurface injection project. Operators should be sufficiently covered or demonstrate sufficient assets to self-insure against damages from induced seismicity. Insurance coverage for potential losses at the median annual exceedance probability of 0.0001 or greater have been suggested for geologic storage (Wiemer et al., 2017). The amount of coverage should be reevaluated annually. An induced event could occur due to the sum of all injection operations in its vicinity.

3.4.2.3 Public Acceptance Recovery Mechanisms

Regardless of the issue, should a situation out of the norm for the drilling, injection operations, and closing of a CCS site come to pass, it will be necessary to initiate a Crisis Communications Plan to ensure operators manage the situation effectively while not eroding public trust. The Crisis Communications Plan should be created as part of the initial project planning and should include these specific elements:

- Identified Crisis Communications Team, with defined roles, including appointed community liaison, media spokesperson, appointed contacts for each company involved in the project, subject matter experts, and their contact information. (Some organizations will elect to use all internal staffing for this team, while others will elect to use outside agencies for assistance.) Regardless, it is imperative that those directly involved with the project and the community relations aspects of the project are on the team to provide continuity to the public and guide anyone less familiar with the project area. If an outside agency is elected, their cooperation should be secured in advance of the project commencing and they should be regularly updated on the progress of the project so that they are familiar with it should their skills be called upon for crisis communications.
- Outlined protocols for crisis response including possible crisis-triggering scenarios, expected outcomes, and solutions; pre-determined locations for communications briefings; method of and schedules for communications with local leaders, officials, media, the public, etc.
- Contact information for community leaders, emergency response groups (local, regional, state, country), environmental remediation authorities, regulatory officials, local media, etc.
- Media matrix for the affected area.
- Background information on all companies involved in the project (Fact Sheets, etc.) along with safety records, each company’s crisis communications plan, any maps or graphics that can help the media explain the situation to the public, etc.
- Digital templates of media alerts, press releases and talking points to be used to facilitate quick, thorough, and transparent communications with the public.

The most crucial element of any crisis is timing – and it is no different in crisis communications. The longer a situation goes unaddressed and unresolved, the worse it tends to get. By having a plan at the ready, compiled, and agreed upon and a Crisis Communications Team familiar with their roles in a crisis prior to a project launch, the better prepared the project team is to manage the crisis situation from a public perception angle. Public communications should be quick, accurate, and ongoing until the situation is resolved. Post crisis, public communications should continue through any following investigations, sharing damage estimates, identified causes, remediation efforts, and plans relative to continued operations. Any issues related to misinformation, whether through the media or other groups, should be addressed immediately and publicly if necessary. While a crisis is never ideal, planning for one can help preserve a project should one arise. Public trust takes time to gain but can be lost in an instant. By communicating in a timely and transparent fashion, public confidence in a project is less likely to be eroded due to a crisis.

4.0 Applying the Perspective of the Insurance / Re-insurance Industry

During the first two quarters of 2022, Battelle organized various individual and larger group listening sessions to engage with influential and knowledgeable stakeholders in CCS industries including oil and gas, insurance, industrial CO_2 emitters, and electric power, along with key figures from CCS research and the Battelle team. The goal of the listening sessions was to encourage informal dialogue regarding the concerns amongst these diverse stakeholders relative to de-risking CCS.

The feedback garnered from these meetings helped inform the project team on existing research concentration and provided recommendations for additional direction for the research to be conducted to ensure that the most pressing concerns relative to insuring and financing carbon storage projects were addressed. This was a valuable opportunity to establish USEA's thought leadership and engagement with relevant industry stakeholders to help identify key bottlenecks to the implementation of CCS.

This part summarizes the highlights of these discussions and some preliminary topics slated for further research, as well as a general overview of the proceedings following the workshop/listening sessions.

Questions posed:

1) What are the most important issues to consider when de-risking CCS?
2) What assurances are needed to ensure the risk is acceptable?
3) What are the gaps in understanding CCS risks from your point of view?
4) What has not been asked that is important to consider relative to de-risking CCS projects now and/or in the future?

4.1 What Are the Most Important Issues to Consider When De-risking CCS?

Implementation of CCS requires consideration of issues related to the following broad areas:

- Storage site selection
- Permitting and approval process for Class VI wells
- Long term liability/project close-out uncertainty

The participants agreed on the need for a robust risk management plan to transparently demonstrate the risks identified, their relevance, risk ranking of the acceptance factors, and appropriate mechanisms in place for safety and integrity of operations related to all components of a CCS project.

Available scientific data suggest that CCS is safe and is presented as an effective approach to mitigate anthropogenic CO_2 emissions globally. In order to successfully deploy this technology widely, the participants collectively emphasized the critical issue of storage site selection and the need for appropriate assessment of site-specific risk profiles as part of the detailed characterization efforts during project development. Detailed site characterization would address relevant issues of concern raised by the participants, such as injection and containment integrity of the subsurface system of interest. Some other issues that the participants noted were:

- Identify and plan for site accessibility related constraints which would feature in the project execution. This includes cost/availability considerations of engineering procurement contractors for construction of surface equipment/facilities.
- Evaluate and plan for legislative issues related to land access, such as securing lease or ownership for pore space rights as these vary state-to-state.

A significant uncertainty is related to the permitting and approval process for Class VI wells. This can be partially mitigated with the support of sound technical understanding gained from the implementation of robust site characterization efforts. Participants discussed the following issues related to the permitting process as critical to de-risking CCS:

- Does the historical performance of the entities/organizations responsible reflect a track record for safety and integrity? Have they demonstrated sufficient understanding of the proposed site in the permit application? The rigor applied for site selection is critical for successful permitting and lays the foundation for proposed operating and monitoring plans. For example, the types, locations, and frequencies of technologies applied for monitoring the plume and pressure at a given site would be specific to its geologic and structural considerations.
- Transparency in the considerations is required to demonstrate that the applicant is doing everything practical to present and manage potential project risks. This, in turn, establishes confidence in the proposed risk management strategies and would be effective in addressing uncertainties related to operations and monitoring in relatively complex systems, such as fractured reservoirs.

Underwriting risk is all about trust. Another critical uncertainty relates to the close-out considerations of the potential CCS projects. The relationship of insurance and re-insurance companies with organizations that own risk establishes trust in the demonstrated expertise and plans that reasonable measures are in place to actively mitigate the potential risks being underwritten. The participants indicated the following additional issues/concerns that need to be considered to de-risk potential projects:

- Lack of existing projects to corroborate the projected long-term dynamics of CO_2 in the subsurface. EPA has established good practices and policies to evaluate Class VI wells but has not benefitted from many experiences to show the realized behavior and impacts of CO_2 in different geologic formations
- Uncertainty of PISC/site closure causes much hesitation by potential investors. Tax equity partners and other project investors realistically do not want the ongoing risk of civil suits and associated financial uncertainty while too many issues related to long-term liability remain unresolved across the US.
- What happens at closeout? One possible scenario is that at the end of 12 years, all of the investors are gone, but closeout would be accomplished through reserves. Negotiations would include considerations for how much reserves will be needed to complete closeout. This involves building financial models to estimate what bucket of reserves would be required and fits into an actuarial table of “How much is the potential exposure to liability past closeout?”.
- Legal and contractual issues related to ownership were brought up by participants. Clarity on aspects such as ‘Who owns the CCS project?’, ‘Who owns the carbon once it’s in the ground?’, and ‘Is it owned by the company that created the CO_2 or does ownership transfer to the capturer or the people putting it in the ground?’ become vital should there ever be an issue of migration/contamination that brings in regulatory action.

It would also be helpful if speciation could determine the source and assign penalties, typically in clean-up situations. Guidance on the impacts of occurrence of potential risk events on the awarded carbon credits is also required.

Plant operators or emitters typically hire different consultants to evaluate and design different components of a CCS project, but it is critical to look at it as a whole and not segmented to avoid bottlenecking issues close to implementation. The participants had varied opinions on if the CCS industry should be considered analogous to the oil and gas industry.

- While all issues of concern have come up via the project experiences thus far, there is a need to help prioritize the investors' concerns. Early-stage investment was the second highest risk i.e., efforts in starting a site that will not ultimately work. While CCS is significantly less risky than oil and gas operations, the work done to get to the permitting stage is the associated reassurance for this risk concern.
- Some participants discussed how CCS can be similar to the oil and gas industry. They highlighted similar construction considerations and due diligence requirements for drillers and workers. Contractual risks, operating, and managing regulatory and legal risks are long tried and true underwriting decisions that insurance companies are well-versed with.
- On the other hand, some participants felt that the CCS industry differs from oil and gas operations, due to the associated commercial risks (not enough commercial-scale projects, so still a new industry), and political and regulatory risks due to uncertainties with the government policies and public opinion on seismicity risks.
- The comparison with other established industries is important, but CCS projects could feature these different risks in different levels. Hence, a robust risk management plan is required to understand the level of different risks, and quantify them, for example, ranking the acceptance factors of the risks and their relevance. One example of different risks on different levels is the management of existing brine injection wells in potential CO_2 storage sites versus those in oil fields.

CCS projects are still an emerging technology and, hence, require the previously stated issues related to pipelines, storage site characterization, and capture to be evaluated to show competence and that there are appropriate mechanisms in place for the safety and integrity of operations. The participants also noted that public opposition is not necessarily a go/no-go decision-maker. Community engagement with these projects, from the early conceptual and feasibility determination phases, would greatly benefit these potential projects.

4.2 What Assurances Are Needed to Ensure the Risk Is Acceptable?

The following assurances are effective enablers in de-risking potential CCS projects:

- Implementation efforts by ethanol are great gateway industries.
- Demonstrate that the site is well-characterized, well-operated, and well-managed, which would result in diminished risk profiles. Integrated risk assessment and transparency is vital.
- Successful permitting would play a key role for financial insurance.

The key assurance in de-risking CCS projects comes from the site-specific data that is collected and evaluated as part of the UIC permit application. Much of these data are outlined in the permit requisition and enables significant reduction in the technical project risks. This includes assurances related to:

- Improved understanding of the sub-surface integrity to ensure that the cap rock seal is not compromised.
- Design and implementation of an informed monitoring program and appropriate surface infrastructure.
- Understanding the integrity of the wellbore casing and that of existing wellbores to determine required mitigation efforts (e.g., upgrading orphan wells) to avoid potential leakage pathways.

Data uncertainty could vary depending on onshore versus offshore projects as it is possible that there is higher paucity of data that increases uncertainty. For example, legacy oil and gas wells would reduce geologic uncertainty to establish storage capacity. The reservoir characterization efforts need to incorporate variable importance analysis to target reducing critical uncertainties that affect CO_2 dynamics in the subsurface. The participants noted that while there does not seem to be an added risk onshore versus offshore, the data paucity would need to be addressed for both environments to ensure the modelling is more representative.

- As part of the permitting process, there are activities related to data collection, characterization, and numerical evaluation of technical performance for a given site that form the basis for safety and efficacy of the reservoir and analysis of risks. Participants indicated that while presenting the risk scenarios and their likelihood would be relevant to the insurance and reinsurance companies, the technical background would also provide beneficial assurances in ensuring their understanding and alignment with the project developers. Delays of permitting are important to internal rates of return.
- As part of the risk assessment, quantitative methodologies exist that can enable strong risk analysis. For example, Baker Hughes has a quantitative risk assessment that allows them to look at different input parameters and how they vary by percentage. Understanding the risks and consequences, even in the form of a probability log register, would inform potential mitigation approaches and evaluation of worst-case scenarios. Assigning financial values to this would be beneficial to provide required assurances to the insurance and reinsurance industries. Participants commented that overall, there are a lot of great programs and methods to approach the issues the industry is facing, but the analysis needs to appropriately consider the regulatory situation, and resource, cost, and time intensiveness of these methods to avoid “paralysis by analysis.”

Due diligence and project planning are essential to provide required assurances to de-risk potential CCS projects. Participants noted the following assurances related to this, including:

- Quality and quantity of the site-specific data.
- Choice of commercial tools/software to work the data and the reputation of these companies (software owners) in the industry.
- Range of potential models (probabilistic or deterministic) and sensitive analysis of relevant scenarios.
- Purchasing the land or appropriate approaches to ensure land access rights.
- Risk management should exist through the entire project cycle. No two sites are equal, and easy sites with non-complicated geology, deep porous and permeable reservoirs, thick and extensive cap rock, no fractures, or tectonically active areas are ideal. Considerations such as benefits for the community, other development advantages, infrastructure, training, education, and national sequestration center pilots are equally important assurances for making a strong case for smooth project execution. The transparency and information shared during the consultations, participation, and

decision-making, in combination with the reputation and stakeholder opinion of the project developer, help establish trust with the insurance and reinsurance industries to engage in projects. These include the key milestones of permitting as well as surface issues, lands rights, surface environmental issues, and environmental justice.

Many issues of concern, such as long-term liability and ownership, are contractual issues that can be worked out between the parties during project development to avoid bottlenecks during implementation. Risks related to issues concerning unintended consequences were brought up by some participants that would need assurances. This was for assigning responsibility between different parties in light of the argument that 'What happens if we find out 10 years down the road that what we thought was [effective], isn't, what happens then?' Risks related to issues concerning unintended consequences might need to be mitigated with additional assurances to become acceptable. CCS can be looked at through the lens of a landfill rather than oil production operations, as it relates to permanent disposal, even if the contents are not inherently dangerous. Scenario evaluation within the area of review as part of the risk assessment would directly address this risk.

- Permitting is a key action for financial insurance.
- Reputation for the technical teams is important.
- Permitting timing is a competency that companies need to follow through with. Our experience does put us in a position to obtain permits to get it through. Does putting the project in our hands create a more expedient, reliable process?

Participants indicated that the situation currently faced by the CCS industry is possibly less about specific projects than the industry overall. Insurance companies do not want to underwrite unprofitable businesses. Consider the analog of the cyber insurance industry, which has seen a recent spike in purchases since 2016 (Government Accountability Office [GAO], 2021). Insurance companies grow more confident with industries and technologies over time, especially when they can see a history of successful project completions. Time will be the key factor in the process of de-risking CCS. As project developers demonstrate effective management of the portfolio of risks, a well-run industry will see the price in insurance decrease. Generally, insurers are good at pricing the risk over time. The participants noted that:

- The organization's reputation will be an important component and good backup data showing a successful track record will help insurance companies commit to the business. Reliability is also necessary to assure investors that the organization will be involved with the project from start to finish.
- CCS is a well-regulated industry where safety, operations, and risk management are part of regulatory requirements. While this helps with assurances, many insurance and reinsurance companies are new to this market and this lack of history or relationship with the organizations is a factor that must be addressed.
- Large self-funded projects need engineering and operational expertise. Funding mechanisms other than including operational developers, tax equity developers, and tax equity investors. An organization's needs are dependent on the organization type, e.g., tax equity investors would wait for the developers to figure out/get project components in place.

4.3 What Are the Gaps in Understanding CCS Risks from Your Point of View?

The participants discussed the following key gaps in understanding CCS risks:

- Legislative clarity, or lack thereof, is a major gap.

- Public perception relative to technology tied to induced seismicity concerns, which are highly manageable and predictable.

Issues identified include the following:

- There are limited data from legacy wells to help settle fears.
- Monitoring once injection is complete – who owns the risk and for how long?
- Mitigating the risk of the existing structures in the subsurface. US Geological Survey (USGS) is working on mapping orphan wells, but sometimes the data are incomplete or only available on a county-by-county basis, so the process is time-consuming, and the uncertainty should be high into the risk models.
- It is necessary to more closely study the impact of CO_2 injection in brine reservoirs.
- There is a perception that “pore space” purchase equals drilling activity but that isn’t the case.
- Due diligence in permitting for Class VI wells.
- In general, there are some geomechanical issues relative to not enough data about caprocks and reservoirs. There is a need for more geomechanical modeling in CCS projects, and core tests done on caprocks.
- From a financial standpoint, there are several questions relative to paying for projects when 45Q expires. Some possibilities explored include a carbon tax and power generation. How will shifting the burden of costs from the developer to the citizen impact low-income homes?
- What’s the long-term business case that can be made for a CCS project?
- The relative lack of knowledge that the general public has about CCS must be addressed. The acronym CCS is not top of mind with people in many instances, the term carbon capture evokes ideas of carbon offsets and carbon credits, not the process of geologic sequestration. CCS needs a good public relations campaign to help make people understand what it is.
- Additional education is needed to adequately inform people about the options related to CCS.
- Many opportunities involving CCS go beyond just disposal; however, they are either misunderstood or unknown to many people.
- There is a lack of historical data and uncertainty about plume movements.
- Lawmakers need to be educated about CCS and there needs to be more advocacy for specific legislation relative to CCS.
- Pore space is a factor to consider, as developers are developing a site, that is one of the factors that will come in addition to “is this geologically and technically possible?” We have to ask, “can we acquire pore space?”. Involving experts on pore space access would be prudent because often companies do not know where to drill because they don’t know about land rights.
- Instead of saying ‘best space geologically,’ ‘which one works best’ should be the phrase we use, one example should be considered by emissions and emitter and proximity to them versus what makes sense geologically.

- Because there are a lot of unknowns at the beginning of a project, it is difficult to create a realistic budget until you have made a sizeable investment in drilling a characterization well. Sometimes it is difficult to get funding under those circumstances because companies do not fully understand the technical, policy, and capabilities in data confidences.
- Uncertainties in interactions between fluids in the reservoirs.
- The lack of history. There are a lot of projections being made by a lot of different experts and organizations and sometimes the information they share is conflicting – how does an organization determine who to listen to and follow?

4.4 What Has Not Been Asked that Is Important to Consider Relative to De-risking CCS Projects Now and/or in the Future?

The key takeaways on additional considerations relative to CCS project risks based on the responses from the participants included the following aspects:

- What are the long-term liability issues associated with CCS and how will it be managed?
- What is in place to keep people from perpetually injecting versus closing the well and initiating a monitoring protocol?
- Could funding for CCS projects could be managed similar to the Property Assessed Clean Energy (PACE) program?[1]

Issues identified include the following:

- It is important to understand how CO_2 wells are integrated with other disposal wells.
- Administrative miscommunications between government agencies confuse developers.
- What impact will public opposition have on CCS? How do you manage a situation when a landowner agrees to a pipeline but changes their mind? Or how do you address entire co-ops of farmers who oppose siting pipelines on their property? There are organizations that are concerned that supporting a CCS project will damage their brand due to possible public opposition. There is a need for better education of not just finance and insurance folks, but the public in general about what CCS is and why it is necessary. There is a need for technical education, but too much education creates competitors, which industry will not support. In the first phase of the project, good education on the process would help get finance and insurance people on board.
- There is a market for ethanol-grade CO_2, but the costs of capture get more difficult to manage when you are dealing with CO_2 from other industrial enterprises. Currently, the only option is more tax credits. The costs are getting in the way of innovation.

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[1] According to the US Department of Energy, the PACE program is:
The property assessed clean energy (PACE) model is an innovative mechanism for financing energy efficiency and renewable energy improvements on private property. PACE programs exist for:

1. Commercial properties (commonly referred to as Commercial PACE or C-PACE).
2. Residential properties (commonly referred to as Residential PACE or R-PACE).
3. Commercial and residential PACE programs share a common foundation. PACE programs allow a property owner to finance the up-front cost of energy or other eligible improvements on a property and then pay the costs back over time through a voluntary assessment. The unique characteristic of PACE assessments is that the assessment is attached to the property rather than an individual.
4. At long-term capture, there needs to be a mechanism to pay for carbon capture production that doesn't come out of a company's bottom-line or going through a credit line. Either adding Carbon Capture to PACE or creating a similar program might be the method to fund it.

- People underestimate the importance of relationships and trust. Trust is extremely important, and it is something that is built over time. Company culture, safety, and mindset are also important when establishing trust and building a relationship.

4.5 Anticipated Financing Needs and Strategies

The enhancements to the government incentives, for example the Section 45Q tax credits, is a positive development to help support the financing of CCS projects. As has been demonstrated in the wind and solar energy sector, the use of federal tax incentives has created a thriving market for development and investment in such projects using innovative tax equity structures. A similar market for CCS projects could very well develop first for EOR-supported opportunities and then for saline storage projects as reductions in the cost for capture technologies accelerates. Potential strategies would include identifying potential equity sponsors who could maximize the use of the federal tax credits, commercial bank lenders, and capital market debt financing alternatives. As the acceptance of CCS projects increases, and after more technical education for stakeholders and financial sponsors and insurance companies get involved, more potential equity and debt financing options may be available.

5.0 Summary of De-Risking Workshop

On September 8, 2022, Battelle and the USEA hosted a workshop titled *Paving the Way for the Insurance and Finance Industries through De-Risking CCS*. The workshop included a series of presentations and workshops from a select group of expert panelists on risk in CCS. This section provides a summary of some of the main ideas in certain presentations of the experts in the field. Notes from five different presentations and panel discussions conducted as part of the workshop are presented in this section. Slides presented at the workshop are also provided in Appendix B.

5.1 Monetizing Risk/Managing Risk/Identifying a Path Forward for Financial Assurance

Speaker: Chiara Trabucchi (Industrial Economics, Incorporated)

It is possible to determine the dollar amounts and circumstances that need to be managed to minimize the financial risks associated with CCS projects. This information can be used to create a financial structure that recognizes the site-specific nature of each project's risk profile. Valuation parameters can be tailored to each project's risk profile to reflect the site-specific variables.

5.2 Understanding Risk in CCS: Panel Discussion #1

Panelists: Sue Hovorka (Texas Bureau of Economic Geology), Christine Ehlig-Economides (University of Houston), Matt Flannery (Stratum Resrevoir), and Adam Seitchik (Battelle)

- Thus far, very secure sites have been developed; however, large scale CCS deployment will require more uncertain sites.
- Existing wellbores may prove to be leakage pathways for CO_2 or brine, but because these wells will generally be identified as part of the Class VI process, they are unlikely to be lower risk. The oil and gas industry provides experience and datasets that can help reduce this risk.
- The confining interval, or sealing formation, presents a unique factor for CCS. In the context of oil and gas, the presence of oil or gas implies that presence of a geologic trap. As a result, characterization of the confining interval is generally not needed.
- One of the most challenging topics is the compatibility of the injection fluids (resident fluids and CO_2). In petroleum fields, the fluids in place have been in contact with the formation for thousands or millions of years and have reached chemical equilibrium. Injecting CO_2 into the subsurface may affect the equilibrium and may lead to precipitation of solids, dissolution, and mineralogical changes.
- Reducing uncertainty and risk in a CCS project can be accomplished with more data.

5.3 Risk Mitigation Opportunities: Panel Discussion #2

Panelists: Jeff Erikson (Global CCS Institute), James Mackey (OGCI Climate Investments, LLP), and Sasha Mackler (Summit Power Group)

- Risk perception and risk tolerance may affect public acceptance. Even if geologic investigations suggest project safety, the risk perception and risk tolerance of a community may be an impediment to public acceptance. The perceived health and safety risks may lead to opposition and project delays.

- The largest deployment issue for CCS is pipelines. Public acceptance of CO_2 pipelines may face opposition due to "Not-in-my-Backyard" (NIMBY) protests and opposition to industry. Public engagement is needed to build public acceptance.
- One of the panelists suggested a financial, legal, and insurance issues of CCS should be addressed in a joint industry report. The Secretary of Energy can request a central report from the federal advisory committee.

5.4 Project Implementation Case Studies: Lessons Learned from Projects on the Ground: Panel Discussion #3

Panelists: Jackie Gerst (Carbonvert), Brian Hill (Crescent Resource Innovation, Inc.), and Nalin Gupta (Wabash Valley Resources)

- The US current has 876,000 subsurface injection wells. Any question that asked about CCS, should also be asked about these activities. Existing injection wells do not require subsurface property rights, but the current assumption is that CO_2 does. The insurance industry that exists for all those wells including radioactive disposal wells but not carbon dioxide.
- Contractual requirements for operations may be difficult to meet in some situations, particularly if a system experiences unexpectedly long delays or has high percent capture requirements. Multiple sources can mitigate these risks but requires more capital and operating expenses.

5.5 Applying and Accepting Risk in CCS for the Insurance/Re-Insurance and Finance Industries: Panel Discussion #4

Panelists: Fred Eames (Hunton Andrews Kurth, LLP), Dan McGarvey (Marsh's US Power and Renewable Energy), and Gary Price (Battelle)

Cultural perception will be an important component of the implementation of CCS. Several different entities interested in participating in a CCS project will need to go through performance evaluations.

6.0 Emerging Technologies

This section presents emerging CO_2 removal technologies that are opportunistic to achieve CCS implementation and the specialized operational risks that must be managed to enable their commercial implementation. They range from technologies that enhance naturally occurring processes, nature-, and technology-based solutions. This section describes the following technologies that are in the early technology readiness levels: (1) direct air capture (DAC), (2) bioenergy with carbon capture and storage (BECCS), (3) reforestation/afforestation, (4) enhanced weathering, and (5) blue/green hydrogen. These emerging technologies are important because they have the potential to support a faster transition by offsetting emissions from certain sectors, such as aviation and heavy industry, which are difficult to decarbonize.

IEA (2020) recommends three policy initiatives to support the development of emerging technologies: (1) large-scale demonstration facilitated by government support, (2) corporate initiatives to support carbon reduction, and (3) CO_2 pricing initiatives.

6.1 Direct Air Capture

6.1.1 Background

DAC refers to technologies that can extract CO_2 from the ambient air at any desired location. This CO_2 can then be permanently stored in deep geological formations to achieve negative emissions or it can be utilized as a source for synthetic hydrocarbon products. DAC has the flexibility of being a location-independent source of CO_2 and can operate anywhere where renewable energy (such as solar photovoltaic [PV], wind, or geothermal) can be found or installed without the need for arable land. It also has a much smaller physical footprint than bio-based approaches. There are currently a handful of companies actively designing and demonstrating different DAC technologies in North America and Europe.

Breyer et al. (2019) stated that DAC with CCS is an important pathway to effectively defer the CO_2 emissions from diffused emission sources comprising the transportation sector. While the American Physical Society reported on the feasibility of DAC in 2011 (Socolow et al., 2011), its widespread adoption has been hindered by associated high costs and substantial energy input requirements. A 1 Mt of CO_2 per year large-scale DAC facility for CO_2-EOR is being developed in the US through a Carbon Engineering and Occidental Petroleum partnership in Texas with 19 small-scale operational DAC plants existing worldwide (IEA, 2020).

6.1.2 Current Challenges

DAC holds the general risks associated with new technology scale up and implementation. The cost of capture for DAC is currently higher than for point-source CO_2 capture as capture cost increases with dilution. Current DAC capture costs exceed $100 up to $1,000/tonne (IEA, 2020). The authors state that the following are needed to evaluate the viability of DAC:

- Appropriate lifecycle assessment methodologies (i.e., cradle-to-grave) and regulations.
- Source assessments under “strict sustainability criteria” for potential utilization applications.
- Studies on the impact of DAC on energy systems.

It is important to identify potential revenue streams in further opportunities for utilizing dilute CO_2 streams as feedstock, such as biomass production via microalgae cultivation. As the technology is being implemented across different applications, the economics of DAC can be less burdensome. For example, Lackner (2013) suggests that the energy requirements may not be as demanding as initial estimates if it is implemented for CO_2 capture from flue gas due to less stringent capture requirements with a capture rate of ~50% for DAC compared to 80 to 90% or more for flue gas capture. DAC (with CCS) powered by solar and wind electricity would be potentially net negative carbon dioxide removal (CDR) technology. In addition, design efficiencies, such as using renewable power or using waste heat for CO_2 recovery can improve impact of system (IEA, 2020).

6.2 Bioenergy with Carbon Capture and Storage

6.2.1 Background

Bioenergy with CCS involves biological capture of atmospheric carbon by photosynthetic processes. The electricity or heat production from these bioenergy sources when combined with CCS is referred to as BECCS. It is projected to be among the top three bridge technologies that are negative emissions pathways in terms of its technical potential.

6.2.2 Current Challenges

There is currently no international market for biomass due to its low energy density characteristics, but its utilization is mostly local (viz. cooking and heating applications in rural areas) (Pour, 2019). The profitable market for the product (i.e., bioenergy) includes biofuels such as ethanol and biodiesel. Supportive policies exist in the US that have enabled viability of the domestic bioenergy market.

Some of the main challenges that need to be overcome include sustainability and affordability of the source of bioenergy. Land availability limitations resulting from the competition of the dedicated energy crop with other potential crops is another challenge of BECCS. The high investment and operations and maintenance costs of BECCS impacts its economic viability in the power markets. Kemper (2015) estimated the levelized cost of electricity production through BECCS to be between $70 and 230 / MWh.

The long-term prospects of this land intensive technology, along with many of its perceived impacts, are dependent on the details of the system. In addition, using feedstocks such as agricultural waste would limit competition with other land uses, thus ensuring thoughtful implementation of BECCS to achieve net negative emissions. The project structure and regulatory aspects would play a significant role in working to alleviate the current barriers to entry in a sustainable manner. Impact assessment studies and appropriate field-based life cycle assessments are recommended to determine areas and appropriate combinations of land use, energy needs, economics, and feedstocks to support BECCS.

6.3 Reforestation/Afforestation

6.3.1 Background

Reforestation and afforestation involve planting trees (or allowing trees to regrow) on land that had recently or not recently been covered with forest, respectively. These processes remove atmospheric CO_2 via photosynthesis as trees grow and thus store this carbon. Reforestation/afforestation can promote and protect biodiversity by ensuring diverse native species are considered.

6.3.2 Current Challenges

Reforestation/afforestation is one of the few pathways that is already practiced and hence ready for large-scale implementation. The annual rate of CO_2 sequestration is dependent on the amount of land devoted to reforestation and afforestation with approximate breakeven costs of between -$40 and $10 per tonne of CO_2 utilized (Hepburn et al., 2019). The key risks are related to permanence/reversal if the forests are disturbed or destroyed due to humans, fires, and pests, all of which would result in the undesired release of the stored carbon in addition to erosion of soil health. Land management and policy support will thus be needed for maintenance and monitoring of CCS by these techniques as well as to govern allocation between land for forestation and other uses such as agriculture.

6.4 Enhanced Weathering

6.4.1 Background

CO_2 removal through rock weathering is a natural geochemical process. Enhanced weathering seeks to accelerate weathering reactions of minerals that consume CO_2 when they dissolve and thus contribute to CCS. It aims to mitigate climate change by providing co-benefits for food security (Beerling, 2017; Beerling et al., 2018).

6.4.2 Current Challenges

While there have been some field trials with basalt on agricultural lands in the US and a few countries around the world, much work in this area is theoretical in the form of modeling studies and needs validation.

Enhanced weathering requires validation as an effective and consequential means for CCS relative to the benefits of technologies such as DAC and storage in geologic formations to allow for its large-scale implementation. The key concerns to be addressed concern feed supply issues and reaction kinetics. These revolve around the effort and energy required to mine, distribute, and manage the minerals required for enhanced reactions, the energy requirements for the silicate reactions, the extremely slow reaction kinetics compared to carbonate minerals, and the need to manage potential ecosystem impacts. Future steps are recommended to focus on feasibility assessments and pilot-scale studies in potential field settings integrated with detailed environmental modeling to study technology viability and accelerate wide-scale technology deployment.

6.5 Blue/Green Hydrogen

6.5.1 Background

Hydrogen is being considered to decarbonize heavy transportation sectors and for energy storage applications given its versatility. The source used for the production of this hydrogen brings about a color-coded classification such as gray hydrogen, blue hydrogen, and green hydrogen. Blue hydrogen is the hydrogen produced from fossil fuels (natural gas) where the CO_2 is captured and stored or utilized while green hydrogen is emissions-free with the hydrogen produced from the electrolysis of water using renewable energy sources.

6.5.2 Implementation Limitations/Current Risks

One of the main benefits of hydrogen power is that it has multiple uses and can satisfy the energy needs for all sectors, including passenger vehicles and long-distance travel (e.g., shipping and airlines), distributed energy production, residential and commercial heating, and industry fuels (DOE, 2020). Several studies have investigated the potential future demand for hydrogen.

Clean hydrogen production currently costs $5 per kilogram. The DOE envisions three primary pathways to reduce this cost to $1 by:

- Improving the efficiency, durability, and manufacturing volume of electrolyzers.
- Improving pyrolysis, which generates solid carbon, not carbon dioxide as a byproduct.
- “Advanced pathways” for hydrogen production such as photoelectrochemical approach, where sunlight and specialized semiconductors are used to break water into sunlight and hydrogen.

Ongoing and proposed research to tackle these technological advancements would help achieve the DOE’s Hydrogen Shot. Balancing the hydrogen production costs (blue versus green) with the market dynamics is critical to its large-scale implementation. Appropriate lifecycle assessment methodologies would also shed light on the economics of these technologies and enable development of viable implementation plans to achieve these decarbonization goals.

7.0 Conclusions

The primary objective of this report is to communicate possible risk, consequences, mitigation opportunities, and recovery mechanisms for CCS projects, geared toward the insurance/re-insurance and finance industries. As the CCS industry matures, experience will continue to inform the risks. Better analysis, detailed characterization, and final permitting and construction will all help to mature the industry leading to reduced surface, subsurface, and business uncertainties.

A high-level overview of risk definition and risk mitigation are provided in this report. This process is critical and provides a rigorous analytical framework for identifying and characterizing pertinent risks; proactively developing methodologies to mitigate the impacts from any unacceptable risks; and integrating risk management with project management, design, and implementation. Risk is assessed by estimating the probability of an event that results in adverse impact and quantifying the magnitude of those adverse impacts or consequences. The risk management overview presents the concepts and steps involved in developing a qualitative and quantitative evaluation of the impact these risks could pose to human health, safety, the environment, and the operation of a storage project.

Development of a CCS risk assessments complex requires a broad range of capabilities and expertise, as well as participation of entities which can provide a business framework across the entire CCS value chain. In addition to technical experts, CO_2 source and supply companies, pipeline developers, storage and EOR site operators, and financial investors are needed to make these projects work. As the project evolves through development stages, these team members may become host sites, equity partners, technical consultants, advisors, or stakeholders. The objective of the expert engagement, conducted in this project through the listening sessions and De-Risk Workshop, was to develop a base of knowledge that translates technical information to a wider audience so these non-technical stakeholders can understand the risks posed by CCS projects. Risk assessment efforts should be site-specific, ongoing, and iterative to ensure that the risk of CCS projects is reduced through practical experience. This project provides a framework for the types of discussions that must be had with stakeholders along the entire CCS lifespan and the concerns that must be addressed through this dialog.

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Appendices

Appendix A – Examples of Monitoring Technologies for CCS Projects

Each CO_2 injection project has its own set of priorities, risks, monitoring targets, and requirements for project success. A site-specific, risk-based monitoring plan is designed to mitigate negative impacts and reduce uncertainties by iterative application of monitoring and risk analysis.

Identifying potential risks during site characterization, baseline, or subsequent monitoring operations allows targeted actions to mitigate risk impacts or to prevent their occurrence.

It is well known the existence of a wide variety of methods for mitigating and/or correcting the possible effects of CO_2 leakages from a CCS project. It has also been demonstrated that mitigation or correction techniques are more effective close to the source of the CO_2 escape rather than near the surface, where the detection of CO_2 is more difficult since it tends to be dispersed.

Several CO_2 monitoring approaches are available. Their efficacy and adaptability depend on site-specific conditions. A summary of available monitoring approaches is provided below.

Atmospheric monitoring could play an important role in assuring the public that the injected CO_2 remains in the subsurface. Atmospheric CO_2 levels are impacted by numerous environmental factors, such as seasonal variance, topography, and ecosystem performance (plants, animals, and organisms), as well as other activities emitting to the atmosphere, such as stationary or mobile CO_2 sources. Therefore, atmospheric monitoring protocols likely require detailed evaluation to spatially and statistically characterize the sources of variability, as well as any potential signal from migration of stored CO_2. This characterization, prior to CO_2 injection, is called the baseline.

For geologic storage applications, several field deployable monitoring techniques have been developed in recent years for detecting and quantifying atmospheric CO_2 emissions above injection sites, wellheads, and abandoned well sites. These tools are intended to provide assurance or demonstrate that CO_2 from underground storage is not being released to the atmosphere, and if it is, to allow for quantification and mitigation. Three of the atmospheric monitoring approaches include optical CO_2 sensors, atmospheric tracers, and eddy covariance flux measurement.

Remote sensing for CO_2 leakage detection refers to methods that provide information about features on the Earth's surface without direct contact, using the electromagnetic spectrum. Remote sensing monitoring techniques are considered superior to other monitoring methods for CCS projects over the long term because of their non-destructive nature compared to most other monitoring methods, range of spatial and temporal coverage (Navalgund et al., 2007), and ability to access unreachable terrain. Based on what feature is intended to be monitored (CO_2 or proxy) at a CCS site, remote sensing techniques can be further categorized into direct and indirect. Examples of remote sensing technologies for CO_2 leakage detection include ground-, air-, and space-based monitors (Figure 13).

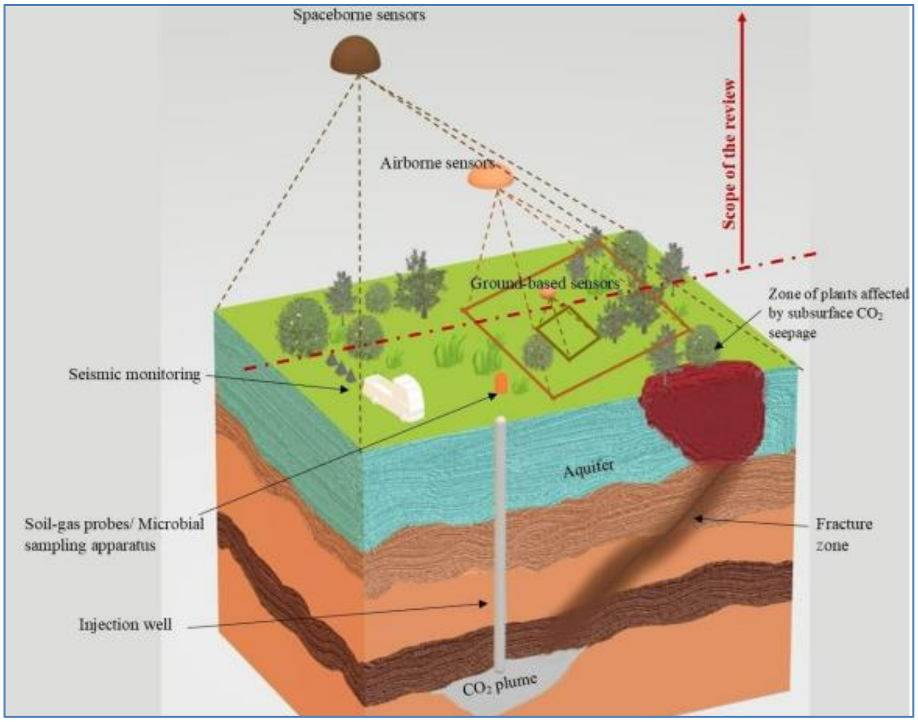

Figure 13. Remote Sensing for CO_2 Leakage Detection (from Raval, 2022).

CO_2 leakage-induced environmental responses, such as the response of vegetation and the formation and alteration of minerals on the surface due to increased subsurface CO_2 concentrations, are the two main environmental responses studied using optical remote sensing. The reasons behind such responses are:

- CO_2 induced vegetation stress – Oxygen displacement in the soil from CO_2 leakage affects chlorophyll content, cell structure, and root water absorption. This reduction in root water absorption results in water accumulation in the subsurface, which will further reduce the oxygen concentration in the ground and exacerbate the stress (Raval, 2022).
- CO_2 induced fertilization – Subsurface leakage can result in localized high atmospheric CO_2 concentration when openings such as abandoned wells are available. If this atmospheric CO_2 concentration is within the threshold limit, it improves plant health by acting as a fertilizer.
- CO_2 induced mineral formation and alteration – An acidic environment created in the soil due to CO_2 leakage has the potential to alter minerals. An example of mineral alteration is red bleaching (reduction of Iron [III] oxide). An acidic environment can also result in formation of minerals such as calcite in the longer term.

Near-surface monitoring can also be used to track CO_2 leaks. Geochemical tools are discussed that identify and quantify possible migration of CO_2 from the subsurface into the vadose zone and shallow groundwater sources. EPA emphasizes the need for careful planning of near-surface monitoring. Monitoring frequency and spatial distribution of groundwater or soil-gas monitoring points must be decided to describe how the proposed monitoring will yield useful information in compliance with standards. In addition, an accurate baseline must be established so that future measurements may be compared with ambient conditions.

Subsurface monitoring of CO_2 storage projects has several objectives, including monitoring the evolution of the dense phase CO_2 plume, assessing the area of elevated pressure caused by injection, and determining that both pressure and CO_2 are within the expected and acceptable areas and migrating in a way that does not damage resources or the integrity of the storage complex. Deep subsurface monitoring is carried out using an extensive range of tools. Some access the subsurface via wells and can probe an area around the well in high resolution; other tools are deployed at the surface and use geophysical properties to measure fluid and rock properties at a distance. Additionally, combined instruments can be deployed, using two or more wells (crosswell) or one or more wells and the surface.

Seismic geophysical methods. Seismic technologies have benefited from many decades of development, testing, and optimization for the petroleum industry (Figure 14). As a result, these technologies are highly advanced and are used for reservoir characterization, and in some cases, reservoir fluid monitoring in producing oil and gas fields. Seismic monitoring strategies include surface seismic, borehole seismic, and passive seismic techniques. Surface seismic surveys utilize surface sources to generate downward-propagating elastic waves. These waves travel into the earth and are reflected back to the surface at layer boundaries, and velocity and waveform are changed by acoustic impedance properties of the rock-fluid system:

- Time-lapse vertical seismic profiles (VSPs) provide vertical resolution that allows detection of reservoir properties such as fluid saturation changes caused by injection or production activities relatively near the borehole containing the receivers.
- Crosswell seismic is a borehole approach that uses a seismic source located in one well and a receiver array located in an adjacent well
- Distributed acoustic sensing (DAS) is a relatively recent development in the use of fiberoptic cable for measurement of ground motion. Through Rayleigh scattering, light transmitted down the cable will continuously backscatter or “echo” light so that it can be sensed.

Time-lapse (4D) seismic data acquisition can be a useful tool to track the migration of CO_2 and characterize the flow dynamics of a reservoir over time (Li et al., 2021). Azuma et al. (2014) pointed out that if the quantitative relationship between the seismic attenuation and CO_2 saturation can be well established, seismic method can become the most reliable method of CO_2 monitoring.

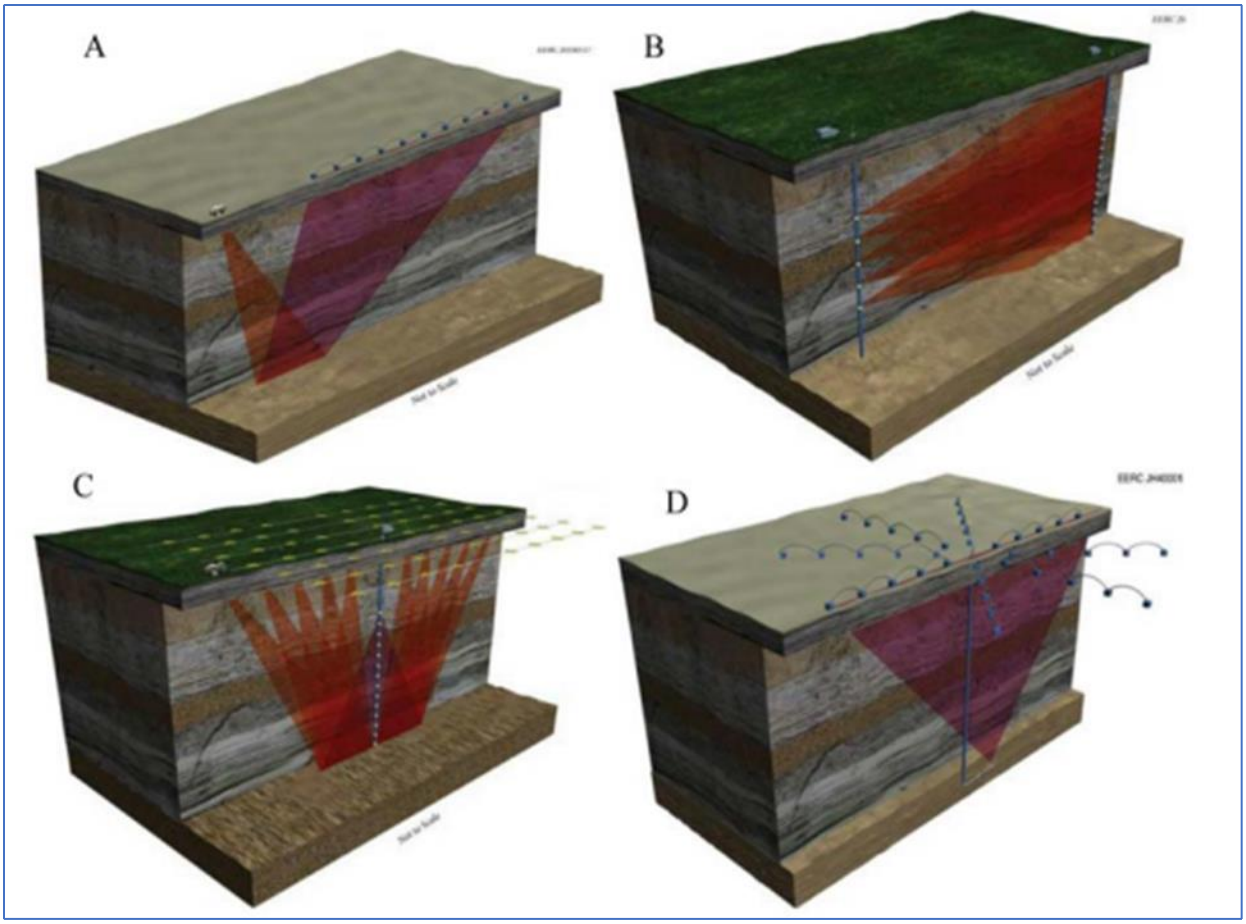

Figure 14. Schematics of Various Seismic Monitoring Techniques: (A) 2-D Surface Seismic, (B) Crosswell Seismic, (C) 3-D VSP, (D) Surface-Based Microseismic (from Hamling et al., 2011).

Gravity methods. High-precision gravity measurements can be used to detect changes in density caused by CO_2 injection into a storage reservoir. This is because CO_2 is less dense than the formation fluid that it displaces in the reservoir. A change in the vertical gravity gradient may also indicate a change in reservoir pressure (DOE/NETL, 2020). CO_2 detection thresholds are site-specific, but, as a general rule, deeper reservoirs are less suitable for gravity monitoring.

Electrical methods. Electrical methods can be used to detect the conductivity contrast between CO_2 (less conductive) and saline water (more conductive) in a geologic formation. Specific electrical techniques that have been tested to monitor CO_2 include electrical resistance tomography (ERT), electromagnetic tomography, and controlled-source electromagnetic (CSEM) surveys. ERT and Electromagnetic can provide a three-dimensional image of the resistivity distribution of the storage reservoir. In time-lapse mode, these techniques can be used to map the spatial extent of an undissolved CO_2 plume in a saline reservoir to monitor changes in fluid saturation and to track plume migration.

Appendix B – Examples of Slides Presented at the De-Risking Workshop

Definition of Environmental Justice

Per the Environmental Protection Agency (EPA), EJ is

"the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies."

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3

How EJ Affects Industry Development and Operations?

- **NEPA and/or Title VI affect most regulators and their decisions including permitting, siting and enforcement.**
- **SEC is establishing new ESG disclosure requirements**
- **Informed companies are better positioned to manage the potential risks:**
  - Legal
  - Financial
  - Reputational

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8

Legal Basis for EJ

- **EJ Communities rely on the following constitutional and statutory provisions to advance their concerns**
  - Due Process Clause
  - Equal Protection Clause
  - National Environmental Policy Act (NEPA)
  - Title VI of the 1964 Civil Right Act
  - State statutes, regulations and Constitutions

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Benefits to Clients of Proactively Addressing EJ Concerns

- Maintains client's status as an industry leader
- Bolsters record of environmental compliance
- Builds relationships with community and customers
- Transparency is favored by regulators (and courts)

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Examples of Federal Covered Benefits

I. Financial Assistance including grants, credit, guarantees or direct spending/benefits
II. Direct Payments or benefits to individuals
III. Federal procurement benefits (acquisition of goods and services for the Federal Government's use)
IV. Programmatic Federal staffing costs
V. Other Investments as determined by OMB

Calculating Benefits:

- Agencies must assess programs and deliver methodology for calculating benefits (including metrics) by 12/17/21.
- Agencies must ensure public participation and meaningful involvement of community stakeholders and consider Title VI implications of LEP when drafting their methodologies

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Instructive Legal Cases

Vecinos para el Bienestar de la Comunidad Costera v. Fed. Energy Regul. Comm'n, 6 F.4th 1321 (D.C. Cir. 2021)

- Residents, environmental groups, and nearby city petitioned for review of decisions by FERC authorizing construction and operation of three liquefied natural gas (LNG) export terminals on shores of shipping channel in Texas and construction and operation of two 135-mile pipelines that would carry LNG to one of those terminals.
- When conducting an environmental justice analysis, an agency's delineation of the area potentially affected by the project must be "reasonable and adequately explained," and include "a rational connection between the facts found and the decision made."
- FERC has offered no "rational connection between the facts found and the decision made," the court finds its decision to analyze the projects' impacts only on communities in census blocks within two miles of the project sites to be arbitrary.
- Cases was remanded without vacatur and project proponents were given the opportunity to cure

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WHAT STARTS HERE CHANGES THE WORLD

Geologic Storage Background Relevant to Insurance/Bonding

Susan Hovorka
Gulf Coast Carbon Center
Bureau of Economic Geology
Jackson School of Geosciences
The University of Texas at Austin

Paving the way for Insurance and Finance Industries through De-risking CCUS
USEA/Battelle workshop, Washington DC 9/8/2022

BUREAU OF ECONOMIC GEOLOGY — TEXAS Geosciences, The University of Texas at Austin, Jackson School of Geosciences — GCCC GULF COAST CARBON CENTER

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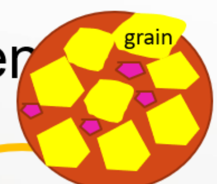
WHAT STARTS HERE CHANGES THE WORLD

Meanings of Storage Permanen



- Isolation from atmosphere
  - ~~Leakage of 1% per year all CO_2 lost in 100 years~~
- Slow vs Catastrophic leakage

- Value
  - How long counts as permanent?
- ~~Lifecyle~~
  - ~~Net carbon balance of activities~~
  - ~~In comparison to catch-and-release~~ – Cycling and recycling carbon as synthetic fuel
  - ~~Relationship of CCS to EOR~~

How Do We Assure Storage Permanence?

1. Policy approaches:

   Penalty: Performance bond or pool to assure against risk of future loss

   Reward: Governmental assumption of risk after closure

2. Long term monitoring

   – Surveillance to assure no escape

May have some use, but not the key assurance

3. Is the Key....

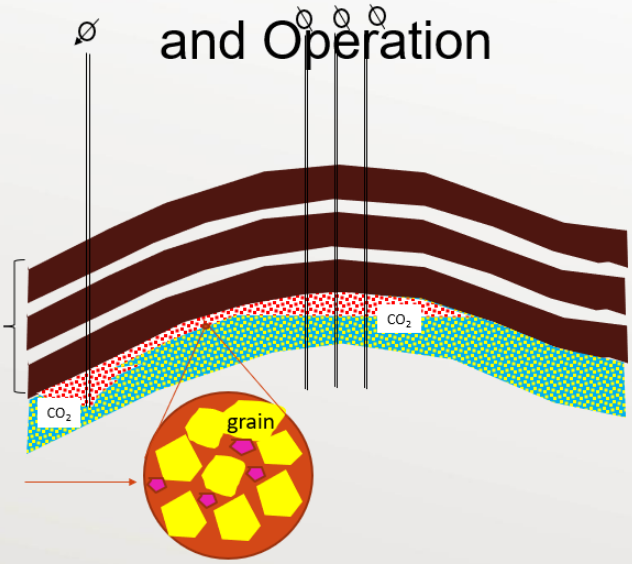
WHAT STARTS HERE CHANGES THE WORLD

Most of the Permanence is in the Site Selection and Operation

Site selection

Confining system

Porous media performance in accepting & retaining CO_2



Operation

Managed injection to match to the storage resource – total mass and rate

Maintain well integrity in terms of isolation

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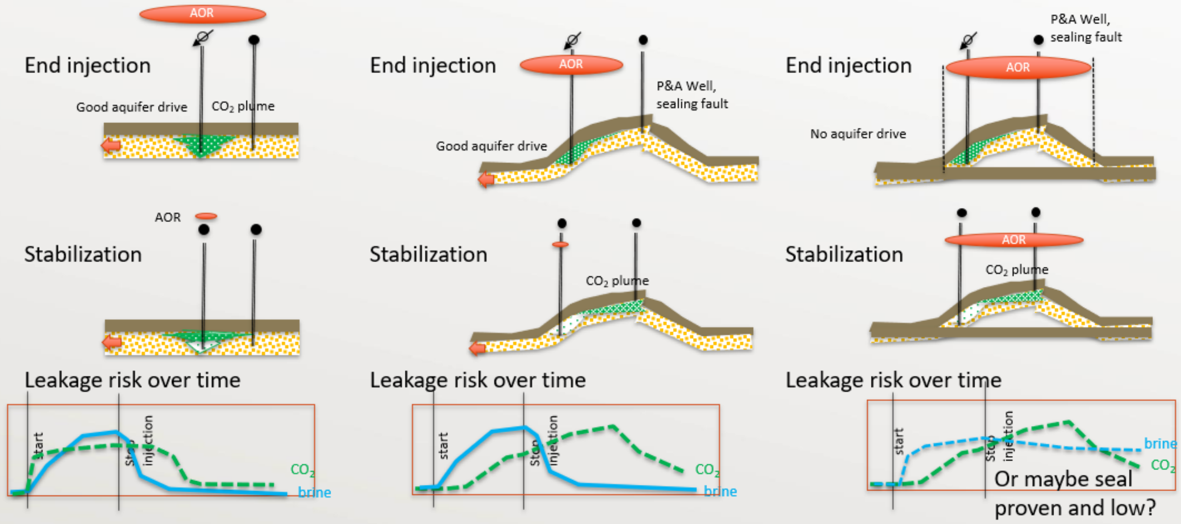
WHAT STARTS HERE CHANGES THE WORLD

Risk Cases – huge variability



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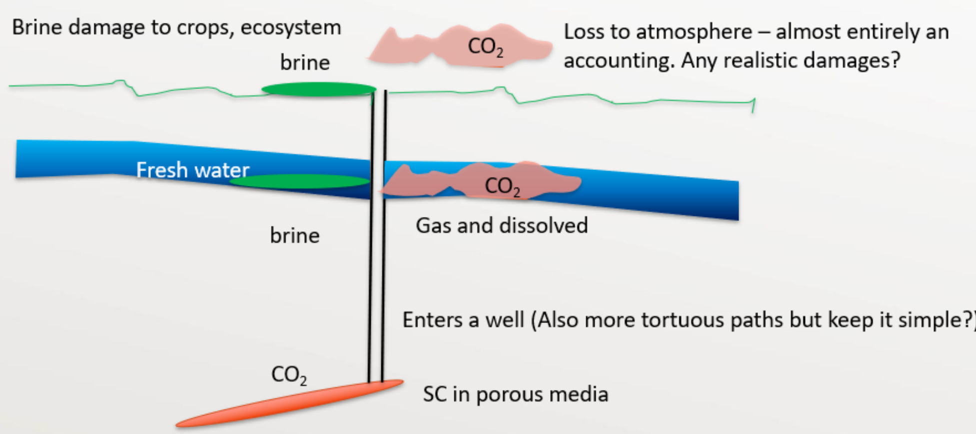
WHAT STARTS HERE CHANGES THE WORLD

Impacts of storage failure



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WHAT STARTS HERE CHANGES THE WORLD

Pragmatic cost of failure

- Use the physically-calibrated model cases to create arrays of failures
  - Slow leakage - wells, over inject capacity
  - Delayed leakage - long flow paths with eventual leakage
  - Blow outs – with and without management
- From this, quantify impacts
  - Loss of CO_2 to atmosphere and reversal of credits
  - Damage to resource (freshwater, land or ocean ecosystem)
  - Cost of mitigation – well repair
  - Damages to life or infrastructure
- Practical input to policy
  - Reversals, buffer pools, duration and value of monitoring, reduce commercial uncertainty

STRATUM RESERVOIR

De-Risking the Subsurface for Sequestration Projects

Conceptual Similarities to Petroleum Projects

- Commodity: Injectable Pore Volume ↔ Recoverable Reserve Volumes
- Development Strategy: Storage Type ↔ Play Type
- Production Strategy: Injection Rates ↔ Production Rates
- Trap: Confining Interval ↔ Sealing Formation

  Storage Interval ↔ Reservoir

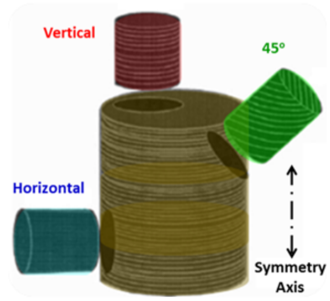
Conceptual Differences from Petroleum Projects

- Pressure Increase vs Pressure Decline
- Compatibility of Fluids and Rocks
- Plume Migration

De-Risking the Subsurface for Sequestration Projects

Risk Mitigation

- Reduce uncertainty where possible.
  Quantify irreducible uncertainty.
- Subsurface permitting requirements are similar (EPA, ISO, EU).
  Porosity, Permeability, Saturations, Geomechanics,
  Fluid and Rock Geochemistry, Phase Behavior,
  Capillary Pressure, Structure, Density, etc.
- Probability Distributions of Properties: P10, P50, P90.
  Critical Risk Maps, Data Driven vs Model Driven Decisions.



- Tailored sampling & analysis program that satisfies the permitting requirements:
  - **Site Screening** and **Evaluation**
  - **Volumetrics** and Performance
  - **Monitoring,** Reporting, and **Verification (M**RV**)**
    Environmental, Social, and Governance (**E**SG)