Plains $CO_2$ Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

# PCOR PARTNERSHIP STORAGE PROJECT RISK MANAGEMENT: INTEGRATING GUIDANCE DOCUMENTS, REGULATORY REQUIREMENTS, FINANCIAL INCENTIVES, AND BEST PRACTICES

**Plains $CO_2$ Reduction Partnership**
**Task 2 – Deliverable 7**

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## EERC DISCLAIMER



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# PCOR PARTNERSHIP STORAGE PROJECT RISK MANAGEMENT: INTEGRATING GUIDANCE DOCUMENTS, REGULATORY REQUIREMENTS, FINANCIAL INCENTIVES, AND BEST PRACTICES

## EXECUTIVE SUMMARY

Risk management for a geologic carbon dioxide ($CO_2$) storage project (hereafter "storage project") addresses a set of risk scenarios that are identified for a project. The risk scenarios comprise a chain of circumstances that has the potential to occur and produce a negative impact on a component or objective of the project. In this context, risk is expressed in terms of the severity of the consequences (negative impacts) produced by the occurrence of a risk scenario and the associated likelihood of its occurrence (chance of a scenario happening, described using general terms or mathematically by specifying a probability of occurrence over a given period). Many of the risk scenarios for storage projects relate to storage permanence and the potential consequences that could negatively impact the commercial, safe, or long-term containment of $CO_2$.

There is no one-size-fits-all risk management approach for storage projects. Instead, risk management is about having a detailed process in place, adhering to that process throughout the project life cycle, and adapting the process depending on site-specific conditions, applicable regulatory requirements, and any additional requirements imposed by pursuing one or more financial incentive programs. This document represents a culmination of risk management experience gained by the Plains $CO_2$ Reduction (PCOR) Partnership since 2003, presented here as a recommended risk management process that can be used or, if warranted, readily adapted by most storage project developers to satisfy their risk management needs. The sections of the document include the following components of risk management applied to storage projects:

- Section 2.0 provides an overview of existing guidance documents for storage projects and summarizes the common elements that should be incorporated into the risk management process.

- Section 3.0 outlines federal regulatory requirements and highlights distinguishing characteristics of specific state-level requirements that could affect project risk management planning for states within the PCOR Partnership region.

- Section 4.0 summarizes additional risk management requirements imposed on project developers if they choose to pursue certain financial incentive programs. This document discusses two programs: 1) qualifying the stored $CO_2$ for a tax credit under Section 45Q of the Internal Revenue Code (Section 45Q credit), and 2) the California Air Resources

Board Low Carbon Fuel Standard for ethanol producers who capture and store $CO_2$ from their ethanol plants and sell the resulting lower-carbon ethanol in a low-carbon-fuel market for a premium price.

- Sections 5.0–8.0 integrate nearly two decades of risk management experience within the PCOR Partnership, comprising storage project development activities guidance documents, regulatory permit applications and hearings, and interactions with authorities responsible for managing financial incentive programs, into a recommended risk management process (Section 5.0), guidance for establishing the context of the risk assessment (Section 6.0), risk assessment technical approach with examples (Section 7.0), and discussion of risk treatment options (Section 8.0).

- Section 9.0 provides a review of the PCOR Partnership risk management experience, highlighting key aspects in the evolution of risk assessment for past and present storage projects.

This document encompasses the current body of knowledge and best practices for applying a standardized risk management approach for storage projects. These best practices will continue to evolve and be refined over time as commercialization of the $CO_2$ storage industry proceeds.

# PCOR PARTNERSHIP STORAGE PROJECT RISK MANAGEMENT: INTEGRATING GUIDANCE DOCUMENTS, REGULATORY REQUIREMENTS, FINANCIAL INCENTIVES, AND BEST PRACTICES

## 1.0 BACKGROUND AND OBJECTIVES

### 1.1 Geological Carbon Storage and Risk Management

Carbon capture and storage (CCS) is a process that captures carbon dioxide ($CO_2$) from an anthropogenic point source, preventing its release to the atmosphere, and injects the captured $CO_2$ via one or more injection wells into a deep geologic reservoir for permanent storage. CCS is a key technology option to mitigate $CO_2$ emissions while allowing the full range of economic and societal benefits to be realized from the continued use of fossil fuels. The Plains $CO_2$ Reduction (PCOR) Partnership, funded by the U.S. Department of Energy (DOE), the North Dakota Industrial Commission (NDIC) Oil and Gas Research Program and Lignite Research Program, and participating member organizations, is accelerating the deployment of CCS in the PCOR Partnership region. The PCOR Partnership region covers the central interior of North America and includes ten U.S. states (Alaska, Iowa, Minnesota, Missouri, Montana, Nebraska, North Dakota, South Dakota, Wisconsin, and Wyoming) and four Canadian provinces (Alberta, British Columbia, Manitoba, and Saskatchewan). The Energy & Environmental Research Center (EERC) at the University of North Dakota leads the PCOR Partnership, with support from the University of Wyoming and the University of Alaska Fairbanks.

Risk management for a geologic $CO_2$ storage project (hereafter "storage project") addresses a set of risk scenarios that are identified for a project. The risk scenarios comprise a chain of circumstances that has the potential to occur and produce a negative impact on a component or objective of the project. In this context, risk is expressed in terms of the severity of consequences (negative impacts) produced by the occurrence of a risk scenario and the associated likelihood of its occurrence (chance of a scenario happening, described using general terms or mathematically by specifying a probability of occurrence over a given period) (International Organization for Standardization, 2017). Many of the risk scenarios for storage projects relate to storage permanence and the potential consequences that could negatively impact the commercial, safe, or long-term containment of $CO_2$.

There are several important characteristics of storage projects to consider when executing a risk management process. First, risk management applied to storage projects is a type of systems analysis that integrates several disciplines including geology, geophysics, reservoir engineering, and other engineering fields to understand and evaluate the operation of the storage system. Second, risk management applied to storage projects requires a three-dimensional (3D)

understanding of the subsurface characteristics and the movement of fluids (formation water and $CO_2$) and pressure in the subsurface in response to $CO_2$ injection. Third, the projection of this 3D understanding of the subsurface onto a two-dimensional (2D) plane at the surface of the earth is also required because the boundaries of the $CO_2$ volume and elevated pressure in the subsurface inform decision-making about surface landowner concerns and the areas needed for monitoring the storage project. Lastly, risk scenarios describe possible future events and consequences. Both physics-based models and inputs from subject matter experts are needed to evaluate these potential events and consequences based on a given set of inputs.

### *1.1.1 Key Physical Zones of the Subsurface*

Figure 1-1 illustrates and defines some of the key physical subsurface zones of a storage project that are necessary for understanding the remainder of this document. Definitions of the components were adapted from the International Organization for Standardization (ISO) (2017) or were based on project experience within the PCOR Partnership region. The stratigraphy (layers of geologic units) and relative thicknesses of each geologic unit are generalized from storage projects located in North Dakota, and individual geologic members are grouped to simplify the stratigraphy into hydrostratigraphic units with similar hydrologic characteristics related to fluid flow. As shown in Figure 1-1, two important systems – the storage unit and the confining system – consist of combinations of several of the individual subsurface components. The storage complex includes the storage unit (N), primary seal (M), dissipation interval (L), and additional seals (K). In some circumstances, the storage complex may also include the lower confining layer (O). The confining system (Q) refers to a group of formations overlying the storage unit that exhibits low permeability and/or high capillary entry pressure (e.g., a clay-rich shale or mudstone) that impede the upward migration of fluid(s). In the figure, the confining system includes the primary seal, dissipation interval, and additional seals.

Additional information regarding some of the zones in Figure 1-1 is provided below:

- Many of the technologies used to monitor the storage project are limited to either the surface/near surface or the deep subsurface.

- The legacy wellbores shown in Figure 1-1 extend down to the lowermost underground source of drinking water (USDW) (four wells), the dissipation interval, or the storage unit; however, depending on the storage project location, all three scenarios are possible.

- A USDW is an aquifer or a part of an aquifer that is currently used as a drinking water source. A USDW may also be groundwater needed as a drinking water source in the future. The lowermost USDW plays a particularly important role in the risk management process since the Safe Drinking Water Act (SDWA) establishes requirements and provisions for the Underground Injection Control (UIC) Program, and the regulations for CCS fall under the Class VI rule of the UIC Program – Wells Used for Geologic Sequestration of $CO_2$. The Class VI rule requirements are designed to protect USDWs. (See Section 3.0 Regulatory Requirements for additional details).

**A** **Biosphere:** Realm of living organisms including the atmosphere, on the ground surface, in soils, in oceans and seas, and in surface waters such as rivers and lakes. To distinguish the biosphere from the geosphere, this document limits biosphere to the soils (vadose zone), ground surface, rivers, other bodies of water on land, and the atmosphere and does not include the lowermost USDW.

**B** **Geosphere**: Solid earth below the ground surface and bottom of rivers and other bodies of water on land and below the sea bottom offshore. This document limits the geosphere to the strata above the additional seals and to the ground surface, which encompasses the lowermost USDW.

**C** **Near Surface:** Biosphere and the geosphere down to the base of the lowermost USDW.

**D** **Deep Subsurface:** Geosphere below the base of the lowermost USDW.

**E** **Ground Surface/Vadose Zone:** The ground surface refers to the surface of the ground at the well site, which follows the topography of the land area surrounding the storage project. The vadose zone refers to the portion of the earth between the ground surface and the water table, where the soil pores are filled with air, not water. The vadose zone is only a few feet thick, which is not distinguishable at the scale of the figure.

**WELLS**

**F** **Legacy Wellbores:** One or more preexisting wells within the area of review of a storage project that were drilled for a different purpose than $CO_2$ injection or monitoring of the respective storage project.

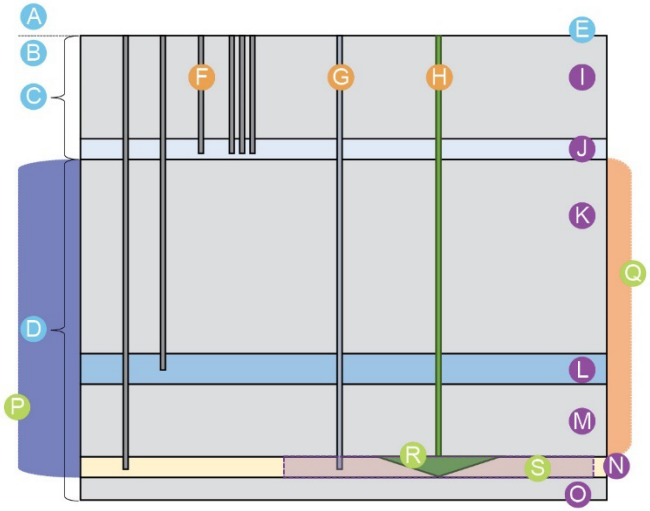
**G** **Monitoring Well:** One or more wells drilled to acquire measurements of the deep subsurface of the respective storage project.

**H** **Injection Well:** One or more wells drilled to deliver $CO_2$ to the storage unit.

**I** **Overlying Units to Ground Surface:** Multiple geologic layers between the top of the lowermost USDW and the ground surface, which may include additional groundwater aquifers along with intervals of low-permeability units.

**J** **Lowermost USDW:** A USDW is defined in the Code of Federal Regulations (40 CFR 144.3) as an aquifer or its portion: (a)(1) which supplies any public water system; or (2) which contains a sufficient quantity of ground water to supply a public water system; and (i) currently supplies drinking water for human consumption; or (ii) contains fewer than 10,000 mg/L total dissolved solids (TDS); and (b) which is not an exempted aquifer.

**K** **Additional Seals:** Geologic unit or set of geologic units that effectively restricts migration of fluids in the sedimentary succession between the primary seal(s) and the lowermost USDW.




**L** **Dissipation Interval:** A saline aquifer (contains greater than 10,000 mg/L TDS or is not a USDW) between the primary seal and the lowermost USDW with hydrogeologic properties sufficient to attenuate $CO_2$ or formation fluid migration along an unidentified leakage pathway through the confining system.

**M** **Primary Seal:** A continuous geologic unit (known in reservoir engineering as cap rock and in hydrogeology as an aquitard or aquiclude) above a storage unit that is part of a storage complex and effectively restricts migration of fluids out of the storage unit and leakage out of the storage complex.

**N** **Storage Unit:** The geologic stratum (or strata) into which $CO_2$ is injected for the purpose of storage.

**O** **Lower Confining Layer:** A continuous geologic unit (known in reservoir engineering as cap rock and in hydrogeology as aquitard or aquiclude) below a storage unit.

**P** **Storage Complex:** A subsurface geologic system extending vertically to comprise storage unit(s) and identified seal(s) and extending laterally to the defined limits of the $CO_2$ storage project. In the figure, the storage complex includes the storage unit, primary seal, dissipation interval, and additional seals.

**Q** **Confining System:** A group of formations overlying the storage unit that exhibits low permeability and/or high capillary entry pressure (e.g., a clay-rich shale or mudstone) such that it impedes the upward migration of fluid(s). In the figure, the confining system includes the primary seal, dissipation interval, and additional seals.

**R** **$CO_2$ Plume:** The region within the storage unit where $CO_2$ is present in a separate phase (supercritical fluid). In the figure, the green triangular polygon shows the extent of the $CO_2$ plume within the storage unit.

**S** **Pressure Buildup Extent:** The region within the storage unit where pressure buildup has occurred, where pressure buildup refers to the increase in storage unit pressure above hydrostatic pressure – the initial pressure in the storage unit prior to $CO_2$ injection.

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Figure 1-1. Illustration of the subsurface showing some of the key physical components for risk management applied to a storage project.

- Some of the subsurface components may be referred to using different terms. The more common of these synonyms are as follows:

    1. The primary seal is sometimes called the "primary confining layer" or "cap rock."

    2. Additional seals are sometimes called the "secondary confining layer" or, depending on the site-specific stratigraphy and number of additional seals, the "tertiary confining layer."

    3. The dissipation interval is sometimes referred to as a "thief zone" because vertically migrating fluid would be lost to this saline formation, thereby decreasing, or nearly eliminating, vertical fluid migration above the saline aquifer to the USDW.

    4. The storage unit is sometimes referred to as the "storage reservoir" or "sequestration zone."

Lastly, in addition to the subsurface components identified in Figure 1-1, two other important features of the subsurface that are identified are the $CO_2$ plume (R) and the extent of the pressure buildup (S). The $CO_2$ plume refers to the region within the storage unit where $CO_2$ is present in a separate phase (supercritical fluid), which is sometimes referred to as the "free-phase $CO_2$ plume." The extent of the $CO_2$ plume within the storage unit is represented in the figure by a green triangular polygon. The pressure buildup extent refers to the region within the storage unit where pressure buildup has occurred, referring to the increase in storage unit pressure above the initial pressure in the storage unit prior to $CO_2$ injection. The pressure buildup extent is represented in Figure 1-1 by the light red shaded area within layer N.

Paramount to successfully applying the risk management process to storage projects is ensuring that each of the key physical zones of the subsurface have been sufficiently characterized such that the resulting conceptual model and predictive modeling of $CO_2$ and pressure in the storage unit can adequately evaluate the risk scenarios.

### *1.1.2 Key Physical Components of the Surface*

Figure 1-2 shows the projection of the 3D subsurface features from Figure 1-1 onto a 2D plane at the surface of the earth. An important surface component is the delineation of the area of review (AOR), which is defined as the region surrounding the storage project where USDWs may be endangered by the injection activity (40 Code of Federal Regulations [CFR] 146.84 and North Dakota Administrative Code [NDAC] Section 43-05-01-05.1 Area of review and corrective action). U.S. Environmental Protection Agency (EPA) guidance for delineation of the AOR includes several computational methods for estimating the pressure buildup in the storage unit in response to $CO_2$ injection and the resultant areal extent of pressure buildup above a "critical pressure" that could potentially drive higher-salinity formation fluids from the storage unit up an open conduit to the lowermost USDW (U.S. Environmental Protection Agency, 2013a). In Figure 1-2, the extent of the AOR is shown as a smaller area than the extent of the pressure buildup, which is intended to illustrate that only the portion of the pressure buildup that exceeds the critical

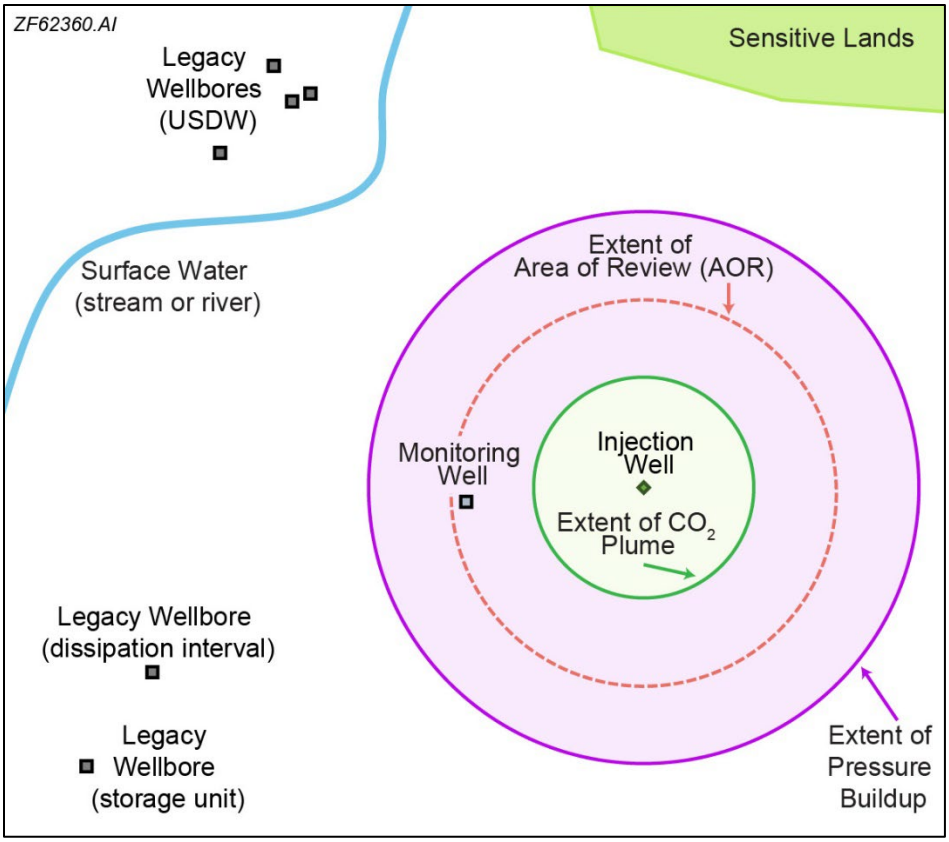


Figure 1-2. Illustration of the surface showing some of the key physical components for risk management applied to a storage project.

pressure is included as part of the AOR. In some circumstances, the AOR extent may be only slightly larger than the $CO_2$ plume extent; however, each storage project has unique site-specific conditions that will determine the delineation of the AOR. That said, the smallest AOR extent for any site will be no less than the $CO_2$ plume extent. The delineation of the AOR is a major technical component for storage projects and plays a critical role in the risk management process.

As shown in Figure 1-2, the legacy wellbores that are completed in the USDW are in the upper left-hand corner of the map, while the legacy wellbores that are completed in the dissipation interval and the storage unit are in the lower left-hand corner of the map. This hypothetical spatial arrangement of legacy wellbores is meant to illustrate one potential scenario—many different legacy wellbore configurations can occur and the spatial relationships between the legacy wellbore completion depths (e.g., USDW, dissipation interval, or storage unit) and distances from the $CO_2$ plume and AOR affect the risk scenarios.

Lastly, Figure 1-2 shows two other surface features: i) surface water (stream or river) and ii) sensitive lands (e.g., wetlands or conservation areas). The spatial relationships between surface features like surface water or sensitive lands and distances from the $CO_2$ plume and AOR are incorporated into the project risk scenarios.

Evaluating risk scenarios related to the interplay of the $CO_2$ plume, AOR, and legacy wellbores with surface features is an important part of applying the risk management process to storage projects.

### *1.1.3 Storage Project Life Cycle*

A geologic storage project will advance through a series of phases over the course of its life cycle: site screening, feasibility, design, construction/operation, and closure/postclosure. Four technical elements are commonly included, to varying degrees, during each of these phases of storage project development: i) site characterization; ii) modeling and simulation; iii) risk assessment; and iv) monitoring, verification, and accounting (MVA). Each of these technical elements plays a key role in gathering and assessing site-specific data that provide a fundamental understanding of the storage system and its performance. While each of the four technical elements independently provides useful data, integrating them through an adaptive management approach (AMA) yields a more streamlined, fit-for-purpose strategy for the commercial deployment of a storage project (Figure 1-3). Key to this integration, which now represents a best practice, are feedback loops that allow the results of each element to inform the others (Ayash and others, 2016). These feedback loops are present and evolve as the storage project progresses through its life cycle. Applying the AMA when implementing the risk management process for storage projects is particularly important because of the long-term nature of these projects, which may operate for 30 years or longer, resulting in the risk management process being repeated over time. This iterative process enables the evaluation of potential risk scenarios that may evolve from changing site conditions, changing site plans or designs, evolving operational activities, and/or policy and regulatory developments. Thus, using the AMA, the risk management process is one that is repeated from project inception (site screening) through the project closure/postclosure phases.

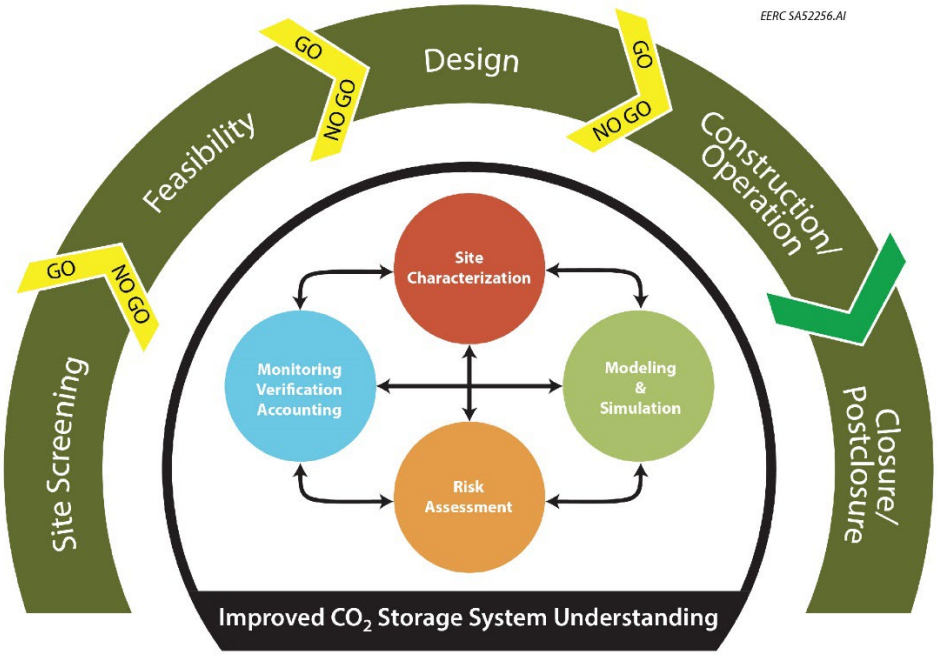


Figure 1-3. The PCOR Partnership's AMA to storage project development.

### *1.1.4 Risk Management Resources*

There are several resources available to assist storage project developers with the risk management process. For example, many guidance documents, international standards, and best practices manuals (hereafter "guidance documents") have been developed from DOE, industry, and international experience. These guidance documents provide recommendations for risk management and example applications for storage projects. Several of these guidance documents are discussed in Section 2.0 – Guidance Documents.

As expected, regulations drive many of the risk management practices. In the United States, these regulations are enforced by EPA, which regulates the construction, operation, permitting, and closure of injection wells used to place fluids underground for storage. However, there are also state-specific regulations depending on the location of the storage project and the status of Class VI primacy within a state. Regulatory requirements for risk management are discussed in Section 3.0 – Regulatory Requirements.

For sites capturing and storing $CO_2$ in a storage unit, the risk management requirements for permitting one or more injection wells are embodied in EPA or state-specific regulations. However, site developers wishing to receive a tax credit for the stored $CO_2$ may have additional risk management requirements to qualify the stored $CO_2$ for this credit. In other scenarios, for example, ethanol producers who capture and store $CO_2$ from their ethanol plants (ethanol produced with CCS), there are additional financial incentives— namely, selling the lower-carbon ethanol in a low-carbon fuel market for a premium price relative to other ethanol producers who are not using CCS. Qualifying ethanol produced with CCS for these low-carbon fuel markets brings additional risk management requirements. The additional risk management requirements for storage projects to secure financial incentives are discussed in Section 4.0 – Financial Incentive Programs.

## 1.2 Objectives

There is no one-size-fits-all risk management approach for storage projects. Instead, risk management is about having a detailed process in place, adhering to that process throughout the project life cycle, and adapting the process depending on site-specific conditions, applicable regulatory requirements, and any additional requirements imposed by pursuing one or more financial incentive programs. With this understanding, the objectives of this document are to:

- Provide an overview of existing guidance documents that discuss risk management for storage projects and summarize the common elements that should be incorporated into the risk management process.

- Outline federal regulatory requirements for risk management and highlight distinguishing characteristics of specific state-level requirements that could affect project planning.

- Summarize additional risk management requirements imposed on project developers if they choose to pursue one or more financial incentive programs for their stored $CO_2$ or the lower-carbon-intensity products that they produce concurrently with CCS. This

document limits the second case to ethanol production with CCS and low-carbon fuel markets.

- Integrate nearly two decades of risk management experience within the PCOR Partnership, comprising storage project development activities, guidance documents, regulatory permit applications and hearings, and interactions with authorities responsible for managing financial incentive programs, into a recommended risk management process that can be used or, if warranted, readily adapted by most storage project developers to satisfy their risk management needs.

In addition to Section 2.0 (Guidance Documents), Section 3.0 (Regulatory Requirements), and Section 4.0 (Financial Incentive Programs), which were referenced earlier, Section 5.0 provides a recommended risk management process, followed by key aspects of establishing the context for storage project risk assessments (Section 6.0), conducting a risk assessment (Section 7.0), and identifying risk treatment alternatives (Section 8.0). Section 9.0 discusses some of the PCOR Partnership risk assessment experience, including risk assessment lessons learned across different projects, states, and regulatory settings.

## 2.0 GUIDANCE DOCUMENTS

There are several guidance documents available to support the risk management process for storage projects. These guidance documents compile expertise into a set of best practices or consistent processes within a risk management framework. Guidance documents do not have the force and effect of law and are not meant to bind the user. In contrast, regulatory requirements are federal or state laws that must be followed (see Section 3.0 Regulatory Requirements). Nevertheless, guidance documents provide helpful information that users can incorporate into their respective storage project(s). Appendix A briefly summarizes six guidance documents relevant to the risk management process for storage projects and a set of EPA guidance documents for storage projects:

- ISO 31000 (2009): *Risk Management – Principles and Guidelines*

- Canadian Standards Association (CSA) (2012): *Z741-12 – Geological Storage of Carbon Dioxide*

- Azzolina and others (2017): *PCOR Partnership Best Practices Manual for Subsurface Technical Risk Assessment of Geologic $CO_2$ Storage Projects*

- National Energy Technology Laboratory (NETL) (2017): *Risk Management and Simulation for Geologic Storage Projects*

- International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) Technical Report (2018): *IEAGHG Modelling and Risk Management Combined Network Meeting, June 18–22, 2018*

- ISO 27914 (2017): *Carbon Dioxide Capture, Transportation, and Geological Storage — Geological Storage*

- Set of EPA final Class VI guidance documents to assist UIC program directors in implementing the Class VI program and Class VI well owners or operators in complying with the Class VI regulations (U.S. Environmental Protection Agency, 2022d)

There are numerous guidance documents, peer-reviewed publications, and industry reports that address the topic of risk management in general and risk management applied to storage projects specifically. The preceding set of guidance documents is by no means an exhaustive list; however, they are representative of the core body of knowledge around this topic and provide a basis for the approach presented in the current document for risk management applied to storage projects. The common themes from these guidance documents that are incorporated into this document include as follows:

- **Risk management process:** The ISO 31000 risk management process, as further detailed in CSA Z741-12 and ISO 27914, provides a valid risk management process for storage projects that includes establishing the context, risk assessment (risk identification, risk analysis, and risk evaluation), and risk treatment. Section 5.0 (Risk Management Process) expands on this topic.

- **Establish the context:** Establishing the context for a risk assessment for storage projects can benefit from i) establishing a functional model of the storage project that identifies key features like the storage unit, confining strata, geochemical and geomechanical properties of the storage unit, and existing wellbores and ii) establishing risk criteria – risk likelihood, risk severity, and risk criticality-scoring matrices that incorporate stakeholder feedback. Section 6.0 (Establish the Context) expands on this topic.

- **Risk assessment:** The risk assessment process includes risk identification, risk analysis, and risk evaluation. Many of the identified risk scenarios emphasize the importance of the AOR and potential risks to the endangerment of USDWs and include a common set of storage system performance risk categories that should be considered for storage projects: i) storage capacity, ii) injectivity, iii) vertical and lateral containment of subsurface fluids (e.g., $CO_2$, formation brines, and/or oil), and iv) induced seismicity. The risk analysis and evaluation heavily rely on geologic modeling and reservoir simulations, along with supplemental computational modeling tools, to provide quantitative or semiquantitative results to inform the risk scoring. However, expert judgment is often a significant part of the risk-scoring process. Section 7.0 (Risk Assessment) expands on these themes.

- **Risk treatment:** A risk treatment plan should be developed for each identified risk scenario that has not been eliminated from further evaluation. The goal of the risk treatment plan is to ensure that risk is reduced to and maintained at an acceptable level. Section 8.0 (Risk Treatment) expands on this theme.

## 3.0 REGULATORY REQUIREMENTS

In the United States, EPA regulates the construction, operation, permitting, and closure of injection wells used to place fluids underground for storage. The federal regulations for the UIC program are found in Title 40 of the CFR (Parts 124, 144, 145, 146, and 147). The SDWA establishes requirements and provisions for the UIC program. Regulations for CCS fall under the Class VI rule of the UIC program – Wells Used for Geologic Sequestration of $CO_2$.

Two states—North Dakota and Wyoming—have primary enforcement authority (recognized by EPA) under the SDWA to implement a UIC program for Class VI injection wells located within their states, except within Indian lands. The remaining 48 states must work with EPA to permit Class VI injection wells. The remainder of this section describes risk management regulatory requirements under EPA and state-specific risk management requirements for North Dakota and Wyoming.

### 3.1 EPA

As previously described, there is no stand-alone risk management guidance document and, therefore, no prescriptive risk management process recommended by EPA. Similarly, there is no prescriptive risk management process under 40 CFR Parts 124, 144, 145, 146, and 147. However, the term "risk" is mentioned throughout the code in the context of the risk of endangerment to USDWs. Therefore, risk scenarios are contained within the permitting requirements and are adequately addressed through EPA's regulatory approach that outlines the minimum technical criteria for the following:

A. Site characterization
B. AOR and corrective action
C. Injection well construction
D. Class VI injection depth waivers and use of aquifer exemptions for geologic storage
E. Injection well operation
F. Testing and monitoring
G. Recordkeeping and reporting
H. Well plugging, postinjection site care (PISC), and site closure
I. Financial responsibility
J. Emergency and remedial response

Within the EPA Class VI permit application outline (U.S. Environmental Protection Agency, 2022b) and checklist (U.S. Environmental Protection Agency, 2022a), the term "risk" is specifically mentioned in several sections:

- **Seismic history, seismic sources, and seismic risk:** Information must be provided on seismic history and the presence and depths of seismic sources and seismic risk to understand the potential for seismicity, inform a seismic monitoring program, and support the development of an emergency and remedial response plan that is appropriate to the potential frequency and magnitude of seismic events in the region (U.S. Environmental

Protection Agency, 2022b). EPA refers the reader to Section 2.3.7 of the geologic site characterization guidance (U.S. Environmental Protection Agency, 2013b).

- **$CO_2$ plume and pressure front tracking:** A plan must be developed to track the $CO_2$ plume and pressure front to identify potential risks to USDWs, verify modeled predictions of the project behavior, and inform reevaluations of the AOR (U.S. Environmental Protection Agency, 2022b). EPA refers the reader to Section 5 of the testing and monitoring guidance (U.S. Environmental Protection Agency, 2013c).

- **Alternative PISC time frame:** If approval of a shorter PISC time frame than the 50-year default is sought, site-specific data and evidence must be provided to show that the project will no longer pose a risk of endangerment to USDWs at the end of the proposed PISC time frame (U.S. Environmental Protection Agency, 2022b). EPA refers the reader to Section 3.2.2 of the well-plugging, PISC, and site closure guidance (U.S. Environmental Protection Agency, 2016).

- **Monitoring well-plugging and site closure plan:** Descriptions must be provided on how all monitoring wells will be plugged and site closure and site restoration activities will be performed so that the project will not pose a risk of endangerment to USDWs after closure (U.S. Environmental Protection Agency, 2022b). EPA refers the reader to Sections 2 and 4 of the well-plugging, PISC, and site closure guidance (U.S. Environmental Protection Agency, 2016).

- **Emergency and remedial response plan:** The plan must demonstrate that appropriate and timely responses will be taken to protect USDWs from endangerment should an emergency event occur during the construction, operation, and postinjection phases of the project. This information will satisfy the requirements of 40 CFR 146.82(a)(19) and 146.94 (U.S. Environmental Protection Agency, 2022b). EPA refers the reader to the Class VI project plan development guidance (U.S. Environmental Protection Agency, 2012).

Therefore, the primary risk categories included under 40 CFR Parts 124, 144, 145, 146, and 147 and in the EPA Class VI permit application include seismic risk and the risk of endangerment to USDWs, with emphasis on the AOR, corrective action, and testing and monitoring.[1] These themes are also embedded within many of the EPA final Class VI guidance documents.

Additional reference to risks to USDWs are found in the final Class VI rule under "II. Background 3. What are the unique risks to USDWs associated with GS (geologic storage)?" These unique risks include the following:

[1] In this context, "corrective action" refers to the use of director-approved methods to ensure that wells within the AOR do not serve as conduits for the movement of fluids into USDWs, where "director" refers to the person responsible for permitting, implementation, and compliance of the UIC program. For UIC programs administered by EPA, the director is the EPA regional administrator or their delegate; for UIC programs in primacy states (North Dakota and Wyoming), the director is the person responsible for permitting, implementation, and compliance of the state, territorial, or Indian UIC program.

- **Large $CO_2$ injection volumes:** Storage projects are expected to inject large volumes of $CO_2$, larger than are typically injected in other well classes regulated through the UIC program.

- **The buoyant and mobile nature of the injectate ($CO_2$):** Supercritical $CO_2$ in the subsurface is buoyant and thus would tend to flow upward if it were to encounter a migration pathway such as a fault, fracture, or improperly constructed or plugged well.

- **The potential presence of impurities in the $CO_2$ stream and its corrosivity in the presence of water:** When $CO_2$ mixes with formation fluids, a percentage of it will dissolve. The resulting aqueous mixture of $CO_2$ and water can be corrosive (carbonic acid).

In addition, in the final Class VI rule under "IV. Cost Analysis Risks Table IV-1 – Relative Risk of Regulatory Components for Selected Regulatory Alternative Versus the Current Regulations," EPA explains how the injection well construction requirements are increased relative to the baseline requirements under the UIC program, with the following incremental requirements: i) construct and cement wells with casing, tubing, and packer that meet American Petroleum Institute (API) or ASTM International standards and are compatible with $CO_2$ and ii) cemented surface casing (base of the lowermost USDW to surface) and long-string casing (cemented from injection zone to surface) must be compatible with fluids with which they may be expected to come into contact.

As of the date of this report, 29 Class VI wells have initiated the EPA Class VI permitting process in EPA Region 5 (seven wells), Region 6 (14 wells), and Region 9 (eight wells); however, only two of the Class VI well permits are active (both associated with Archer Daniels Midland in Macon County, Illinois), 26 are listed as pending, and one has withdrawn its application (U.S. Environmental Protection Agency, 2022c). The term "risk" does not appear in either of the Archer Daniels Midland permits (Permit Number: IL-115-6A-0002 [Facility Name: CCS#1] or Permit Number: IL-115-6A-0001 [Facility Name: CCS#2]). However, the permits clearly state that the objective is to prevent the movement of fluids into or between USDWs or into any unauthorized zones consistent with the requirements at 40 CFR 146.86(a).

Since EPA does not provide specific requirements for risk management, it is up to applicants to use their own risk management methods. The generalized language of 40 CFR Parts 124, 144, 145, 146, and 147 allows applicants to exercise flexibility in their means and methods of demonstrating the safe and effective storage of $CO_2$ within a storage unit and thereby effectively manage seismic risk and the risk of endangerment to USDWs.

### 3.2 North Dakota

On April 24, 2018, EPA approved an application from the state of North Dakota under the SDWA to enforce a UIC program for Class VI injection wells located within the state, except within Indian lands. EPA will continue to administer all well classes within Indian lands. As a result of this action, in the state of North Dakota, Class VI injection wells and the associated

storage facility[2] permit (SFP) for the storage project are managed under the North Dakota Century Code (NDCC) (Chapter 38-22, Carbon Dioxide Underground Storage) and the NDAC (Chapter 43-05-01, Geologic Storage of Carbon Dioxide). The North Dakota program was required to be equivalent to or more stringent than the EPA Class VI program to be granted primary enforcement authority (primacy).

Like the EPA Class VI rule in 40 CFR Parts 124, 144, 145, 146, and 147, there is no prescriptive risk management process under NDCC Chapter 38-22 or NDAC Chapter 43-05-01, which therefore allows applicants to exercise flexibility in their means and methods of demonstrating the safe and effective storage of $CO_2$ within a storage unit. Risk scenarios are contained within the broader permitting requirements and are adequately addressed through North Dakota's regulatory approach, which outlines an expanded list of minimum technical criteria equivalent to or more stringent than the EPA Class VI program.

The concepts of seismic risk and the risk of endangerment to USDWs, which are a focus of EPA's Class VI regulations, are implicit in the requirements under NDAC Chapter 43-05-01, and the term "project-specific risk assessment" is mentioned in specific places within NDAC Chapter 43-05-01. Examples of where risk is addressed in North Dakota's regulations include the following:

- **43-05-01-05(b)(3). Storage facility permit:** A technical evaluation of the proposed storage facility must be conducted, which includes a broad set of geologic and hydrogeologic evaluations that are like the site-screening, selection, and characterization recommendations under ISO 27914 (International Organization for Standardization, 2017) and the EPA Class VI program under 40 CFR "A. Site Characterization." These evaluation requirements are aimed at demonstrating the safe and effective storage of $CO_2$ within a storage unit and thereby effectively managing seismic risk and the risk of endangerment to USDWs.

- **43-05-01-05.1. Area of review and corrective action:** The AOR and corrective action requirements are aimed at managing the risk of endangerment to USDWs and are like the EPA Class VI program under 40 CFR "B. AOR and Corrective Action."

- **43-05-01-09.1. Financial responsibility:** The commission[3] shall take into account project-specific risk assessments, projected timing of activities (e.g., PISC), and interest accumulation in determining whether sufficient funds are available to carry out the required activities.

- **43-05-01-11.4. Testing and monitoring requirements:** Design of surface air and soil gas monitoring must be based on potential risks to USDWs within the AOR, which is like EPA Class VI program under 40 CFR "F. Testing and Monitoring."

[2] In North Dakota, "storage facility" refers to the reservoir, underground equipment, and surface facilities and equipment used or proposed to be used in a geologic storage operation (NDCC Section 38-22-02 Definitions).
[3] In NDAC Chapter 43-05-01, "commission" refers to NDIC.

- **43-05-01-17. Storage facility fees:** The commission shall take into account project-specific risk assessments, projected timing of activities (e.g., PISC), and interest accumulation in determining whether sufficient funds are available to carry out the required activities.

- **43-05-01-19. Postinjection site care and facility closure:** Before project completion, the storage operator shall provide a final assessment of the stored $CO_2$'s location, characteristics, and its future movement and location within the storage unit. The storage project operator shall submit the final assessment to the commission within 90 days of completing all PISC and facility closure requirements. The final assessment must include an assessment of the funds in the $CO_2$ storage facility trust fund to ensure that sufficient funds are available to carry out the required activities on the date on which they may occur, taking into account project-specific risk assessments, projected timing of activities (e.g., PISC), and interest accumulation in the trust fund. These PISC and facility closure requirements are like EPA Class VI program under 40 CFR "H. Well Plugging, Post-Injection Site Care (PISC), and Site Closure."

As of the date of this report, four $CO_2$ SFPs have been requested in the state of North Dakota, with three of them approved (Department of Mineral Resources, 2022):

1. Red Trail Energy, LLC (RTE) ethanol facility targeting the Broom Creek Formation in Stark County, North Dakota (Case No. 28848, Order No. 31453 – Approved October 2021).

2. Minnkota Power Cooperative, Inc. (Minnkota) Milton R. Young Station targeting the Broom Creek Formation in Oliver County, North Dakota (Case No. 29029, Order No. 31583 – Approved January 2022).

3. Minnkota Milton R. Young Station targeting the Deadwood Formation in Oliver County, North Dakota (Case No. 29032, Order No. 31586 – Approved January 2022).

4. Dakota Gasification Company Great Plains Synfuels Plant, targeting the Broom Creek Formation in Mercer County, North Dakota (requested June 2022 – Pending).

Throughout the permitting process for Case Nos. 28848, 29029, and 29032, including the comment periods and SFP hearings before the commission, the applicants addressed multiple questions related to seismic risk, the risk of endangerment to USDWs, and other risks related to storage permanence (risk of potential $CO_2$ containment failures). Consequently, although there is no risk management section in the permit applications, it is incumbent on the applicant to proactively identify these risk scenarios through a risk management process.

### 3.3 Wyoming

Wyoming Department of Environmental Quality (WDEQ) regulations under the Class VI rule address risk management and related issues. WDEQ filed its application with EPA for Class VI primacy on January 31, 2018, with approval granted on October 9, 2020. WDEQ

published its final Class VI regulations on October 5, 2021: *Water Quality Rules and Regulations Chapter 24: Class VI Injection Wells and Facilities Underground Injection Control Program* (Wyoming Department of Environmental Quality, 2021). The Wyoming program was required to be equivalent to or more stringent than the EPA Class VI program to be granted primacy.

Because WDEQ's Class VI regulations are a component of Wyoming's comprehensive statutory and regulatory regime for CCS, risk management is best understood in the context of that entire regime. On March 11, 2022, the Wyoming Legislature passed Senate File 0047 (SF47), an act relating to the "long-term stewardship of $CO_2$" in geologic storage, which was signed into law on March 21, 2022. Although this law sits outside of Wyoming's Class VI regulatory program, it directs that the WDEQ "environmental quality council and the Wyoming oil and gas conservation commission shall promulgate all rules necessary to implement the provisions of this act" (35-11-320, 5b); therefore, SF47 provides additional context for managing CCS risks in the state.

Wyoming's Class VI regulatory program divides storage projects into several time-sequence phases that, individually and collectively, can last decades. These phases are analogous to the AMA for developing storage projects, and typically include 1) siting/design (which can last one year or more), 2) operations/$CO_2$ injections (which can last several decades), 3) closure and postclosure (which is now at least 20 years under SF47; this period is also sometimes known as the PISC period), and 4) long-term stewardship (which lasts for an indefinite period of time thereafter). SF47 focuses on the long-term stewardship phase.

Consistent with the Class VI rule, WDEQ's Class VI regulations require proactive identification and management of risks throughout the storage project phases, with all data and permittee actions requiring approval by WDEQ. The focus of the Class VI program is on risk management in the AOR, which must be delineated based on computational modeling that meets stringent regulatory requirements, then, if needed, corrective action to address areas of concern must be conducted within the AOR. These intertwined actions take the form of an "AOR and corrective action plan" that must be initially proposed, maintained, reviewed, and updated at least every 2 years during the project's operational life and at least every 5 years during the PISC period (until site closure) (Wyoming Department of Environmental Quality, 2021, 13. Area of Review Delineation and Corrective Action).

Class VI wells must meet minimum siting criteria to ensure that $CO_2$ injections occur in areas with a "suitable geologic system" that comprises 1) "an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the [$CO_2$] stream and 2) confining zones that are free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected [$CO_2$] stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zones or causing non-transmissive faults to become transmissive" (Wyoming Department of Environmental Quality, 2021, 12. Minimum Criteria for Siting Class VI Wells).

Wyoming's Class VI regulations also require the owner/operator to prepare and maintain numerous plans, each of which, in turn, is designed to manage project risks. Those plans include the following:

- "[AOR] and corrective action plan" discussed above

- Testing and monitoring plan (Wyoming Department of Environmental Quality, 2021, 20. Testing and Monitoring Requirements)

- Injection and monitoring well-plugging plan (Wyoming Department of Environmental Quality, 2021, 23. Injection Well-Plugging)

- PISC and site closure plan (Wyoming Department of Environmental Quality, 2021, 24. Post-Injection Site Care and Site Closure)

- Emergency and remedial response plan (Wyoming Department of Environmental Quality, 2021, 25. Emergency and Remedial Response)

Financially, storage project risks are managed through financial responsibility obligations that are borne by the owner/operator of the Class VI well. WDEQ's Class VI regulations state that "owners or operators of Class VI wells shall establish, demonstrate, and maintain financial responsibility for all applicable phases of the geologic sequestration project, including complete site reclamation in the event of default" (Wyoming Department of Environmental Quality, 2021, 26. Financial Responsibility).

Financial responsibility, in turn, is based on a financial assurance cost estimate that the Class VI owner/operator must prepare and update. The regulations impose stringent requirements regarding how that estimate is to be prepared and what it is to include. Under WDEQ's Class VI regulations, financial responsibility must address 1) performing corrective action, 2) plugging injection wells, 3) PISC and site closure, 4) testing and monitoring, and 5) emergency and remedial response. Financial responsibility also must consider the following events: 1) contamination of underground sources of water, including USDWs; 2) mineral rights infringement; 3) single large-volume release of $CO_2$ that impacts human health and safety or that causes ecological damage; 4) low-level leakage of $CO_2$ to the surface that impacts human health and safety or that causes ecological damage; 5) storage rights infringement; 6) property and infrastructure damage, including changes to surface topography and structures; 7) entrained containment releases of contaminants other than $CO_2$; 8) accidents and unplanned events; 9) well capping and permitted abandonment; and 10) removal of aboveground facilities and site reclamation (Wyoming Department of Environmental Quality, 2021, 26. Financial Responsibility).

WDEQ's Class VI regulations additionally require owners/operators to "consider" a "risk activity table" when making these financial assurance cost estimates. The risk activity table is provided in Appendix A of WDEQ's Chapter 24 and is reproduced in Table B-1 of Appendix B of this document.

The owner/operator of the Class VI well must post, maintain, and update as necessary an appropriate qualifying financial instrument(s) in an amount sufficient to cover the amount(s) specified in the financial assurance cost estimate. In addition to addressing financial responsibility as discussed above, WDEQ's Class VI regulations separately require owners/operators to obtain and maintain "public liability insurance" that meets certain minimum coverage requirements until

WDEQ "certifies that plume stabilization has been achieved" (Wyoming Department of Environmental Quality, 2021, 26. Financial Responsibility).

SF47 adds to Wyoming's existing statutory and regulatory regime for CCS/CCUS (carbon capture, utilization, and storage) by creating a framework for the long-term stewardship of $CO_2$ in geologic storage. SF47 amends several provisions of prior Wyoming CCS/CCUS laws. The substantive provisions of SF47 take effect on July 1, 2023. SF47 also authorizes both WDEQ and the Wyoming Oil and Gas Conservation Commission to take whatever actions are necessary, including issuing and/or amending regulations to implement the law. WDEQ has since stated publicly that it does not believe that it needs to engage in additional rulemaking to implement SF47.

As of the date of this report, four Class VI applications have been requested in the state of Wyoming, with all of them under review (Department of Environmental Quality, 2022):

1. North Shore Exploration and Production, LLC, under project Painter Reservoir CCS1; targeted reservoir is the Nugget Formation.

2. Frontier Carbon Solutions, LLC, under project Sweetwater Carbon Storage Hub, Permit No. 2022-242, Facility ID No. WYS-037-00262; targeted reservoir is the Nugget Formation.

3. Frontier Carbon Solutions, LLC, under project Sweetwater Carbon Storage Hub, Permit No. 2022-243, Facility ID No. WYS-037-00263; targeted reservoir is the Nugget Formation.

4. Frontier Carbon Solutions, LLC, under project Sweetwater Carbon Storage Hub, Permit No. 2022-244, Facility ID No. WYS-023-00205; targeted reservoir is the Nugget Formation.

### 3.4 Regulatory Requirements Summary

Two states—North Dakota and Wyoming—have primacy (recognized by EPA) under the SDWA to implement a UIC program for Class VI injection wells located within their states, except within Indian lands. The remaining 48 states must work with EPA to permit Class VI injection wells. There are no prescriptive risk management requirements under EPA (40 CFR Parts 124, 144, 145, 146, and 147) and North Dakota (NDCC Chapter 38-22 or NDAC Chapter 43-05-01), which therefore allows applicants to exercise flexibility in their means and methods of demonstrating the safe and effective storage of $CO_2$ within a storage unit and thereby effectively manage seismic risk and the risk of endangerment to USDWs. However, risk scenarios are contained within the broader permitting requirements and are adequately addressed in both EPA and North Dakota regulatory approaches. In contrast, there are prescriptive risk management requirements under WDEQ's Class VI regulations in the risk activity table that is provided in Appendix A of WDEQ's Chapter 24 (Wyoming Department of Environmental Quality, 2021), which is reproduced in Table B-1 of Appendix B of this document.

## 4.0 FINANCIAL INCENTIVE PROGRAMS

As described in Section 1.0, CCS is a process that captures $CO_2$ from an anthropogenic point source, preventing its release to the atmosphere, and injects the captured $CO_2$ via one or more injection wells into a deep geologic reservoir for permanent storage. Therefore, CCS reduces industrial $CO_2$ emissions and is one approach in a portfolio of potential GHG reduction strategies. Financial incentive programs currently exist to encourage CCS deployment and thereby accelerate GHG emission reductions. This section describes additional risk management requirements site developers may need to conduct to qualify their storage projects for two types of financial incentive programs.

The first financial incentive under consideration here is a tax credit under the Internal Revenue Service (IRS), in accordance with Section 704(b) of the Internal Revenue Code, and the credit for carbon oxide[4] sequestration under Section 45Q of the Internal Revenue Code (Section 45Q credit).

The second financial incentive program is for ethanol producers who capture and store $CO_2$ from their ethanol plants (ethanol produced with CCS) and sell the lower-carbon ethanol in a low-carbon fuel market for a premium price relative to other ethanol producers who are not using CCS.[5] Currently, the only low-carbon fuel market for ethanol produced with CCS is the California Air Resources Board (CARB) Low Carbon Fuel Standard (LCFS). While several other U.S. states and Canadian provinces have maintained existing low-carbon fuel programs for ethanol, they have not yet incorporated specific CCS policy.

### 4.1. Section 45Q Credit

#### *4.1.1 Section 45Q*

The Section 45Q credit is a performance-based tax credit incentivizing CCS under Title 26 of the Internal Revenue Code. The original Section 45Q credit was enacted by the Energy Improvement and Extension Act of 2008. The Bipartisan Budget Act of 2018, enacted on February 9, 2018, substantially modified the Section 45Q credit to increase over time, expanded the credit to include other carbon oxides, and eliminated the previous 75-million-tonne cap. Section 45Q generally allows a credit of an amount per tonne of qualified carbon oxide captured by the taxpayer that is i) disposed of in secure geological storage, ii) used as a tertiary injectant in a qualified enhanced oil recovery (EOR) or enhanced natural gas recovery project and disposed of in secure geological storage, or iii) utilized in certain ways described in Section 45Q(f)(5). Section 45Q credit for EOR and $CO_2$ utilization is beyond the scope of this document. The amount of the Section 45Q credit depends on the date the carbon capture equipment is placed in service and whether the qualified carbon oxide is disposed of in secure storage. To qualify for the Section 45Q credit, IRS requires an approved monitoring, reporting, and verification (MRV) plan under EPA Greenhouse Gas Reporting Program (GHGRP) Subpart Resource Recovery (RR).

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[4] "Carbon oxide" can refer to any of the three oxides of carbon: $CO_2$, carbon monoxide, and carbon suboxide.

[5] There are multiple types of transportation fuels to which the LCFS applies under Barclays Official California Code of Regulations (CCR Title 17 Section 95482. Fuels Subject to Regulation); however, this document focuses exclusively on ethanol low-carbon fuel markets.

### *4.1.2 EPA GHGRP Subpart RR*

MRV plan requirements are provided in Title 40 Chapter I Subchapter C Part 98.448. This program has been established for over a decade, with numerous approved plans available for reference on EPA's website (www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide). For example, two of the North Dakota storage projects described in Section 3.2 have approved MRV plans, namely RTE's and Minnkota's. Decisions for all EPA-approved MRV plans may be found on the Subpart RR – Geologic Sequestration of Carbon Dioxide website (www.epa.gov/ghgreporting/subpart-rr-geologic-sequestration-carbon-dioxide).

An MRV plan proposed to EPA must include i) delineation of the maximum and active monitoring areas, ii) identification of potential surface leakage pathways within the maximum monitoring area, iii) strategy for detecting and quantifying any surface leakage of $CO_2$ as well as establishing baselines for monitoring $CO_2$ surface leakage, and iv) summary of how site-specific variables will be calculated using the mass balance equation (Leroux and others, 2021).

Because the North Dakota and Wyoming programs were required to be equivalent to or more stringent than the EPA Class VI program to be granted primacy, most of the geologic characterization and monitoring requirements under GHGRP Subpart RR are identical to the regulatory requirements under North Dakota and Wyoming programs (Leroux and others, 2021).

Like the regulatory requirements under the Class VI rule, the contents of the MRV plan focus on the risk of endangerment to USDWs and the resultant monitoring area delineation, testing, and monitoring requirements to effectively manage potential risk scenarios. Even if storage project operators can permit their Class VI wells or storage facilities without conducting a risk assessment, to successfully qualify for the Section 45Q credit, operators will need to conduct some type of risk-based justification for their MRV plans. Therefore, risk management is implicit in the MRV plan and, by extension, necessary for obtaining the Section 45Q credit.

## 4.2 CARB LCFS

In January 2019, CARB adopted the CCS protocol under LCFS to include CCS processes within "pathway certification" of carbon intensity (CI) values, i.e., the means for acquiring credits through the LCFS carbon market (hereafter "LCFS CCS protocol") (Leroux and others, 2021).

The first step in obtaining a CCS-inclusive pathway is CCS permanence certification, as detailed in the LCFS CCS protocol (CARB, 2018). The certification resembles the EPA Class VI program, North Dakota, and Wyoming regulations, as the foundation for the LCFS CCS protocol was the EPA Class VI program. However, the LCFS CCS protocol contains significant additions. The application process involves the following components:

1) Approval of third-party reviewers
2) Development of application documentation
3) Third-party review and certification of the completed application
4) LCFS evaluation of the certified application package
5) LCFS Tier 2 pathway application for unconventional fuel production

Some of the CCS permanence certification requirements differ from the requirements of the EPA Class VI program, North Dakota, and/or Wyoming regulations, the details of which are beyond the scope of the current document but are captured in Leroux and others (2021). However, with respect to risk management, the LCFS CCS protocol requires a site-based risk assessment and risk management plan (RMP) under Section I (Site Sequestration Certification) of the application package.

Site sequestration certification under the LCFS CCS protocol requires the storage project operator to complete a site-based risk assessment that quantifies the risk of $CO_2$ leakage over 100 years postinjection, describes the potential pathways for leaks or migration of $CO_2$ out of the storage unit, and describes the potential risk scenarios that could occur as a result. The results of the risk assessment must be used to inform the design of the testing and monitoring plan. At a minimum, the risk assessment must examine leakage risk and the scenarios in the emergency and remedial response plan.

Storage permanence is the first part of the site-based risk assessment. The LCFS CCS protocol requires that only sites in which the fraction of $CO_2$ retained in the storage unit is very likely (greater than 90% probability of occurrence) to exceed 99% over 100 years postinjection will be eligible to receive permanence certification. Specific risk tools are not listed in the LCFS CCS protocol, which provides applicants with flexibility in their means and methods for demonstrating storage permanence.

The storage project operator must also develop and submit a RMP that documents the results of the risk analysis. The RMP must summarize the activities evaluated for risk, what those risks are, how they are ranked, and the steps the storage project operator will take to manage, monitor, avoid, or minimize those risks. Any risk scenarios identified as important but not included in the emergency and remedial response plan must be included in the RMP.

The LCFS CCS protocol prescribes the risk criteria and risk classification methods that must be used in the RMP. Risk likelihood (probability of occurrence during a 100-year period) must be scored with categories of <1% (low), 1%–5% (medium), and >5% (high). The severity of potential consequences if the risk scenario were to occur must be scored with categories of "insubstantial," "substantial," or "catastrophic." Table 4-1 shows the LCFS CCS protocol risk scenario classification matrix, which must be used to classify each risk scenario as "low risk," "medium risk," or "high risk." Neither the risk likelihood nor the risk severity by itself are sufficient to classify the risk scenario. Instead, the combination of likelihood and severity defines the risk scenario classification. For example, if a risk scenario is determined to have a likelihood of <1% and an insubstantial severity, then the risk would be classified as low (green cell in the lower left-hand corner of the risk scenario classification matrix in Table 4-1). Alternatively, if a risk scenario is determined to have a likelihood of >5% and a substantial severity, then the risk would be classified as high (red cell in the middle of the top row of the risk scenario classification matrix in Table 4-1). Thus the interaction between risk likelihood and severity determines the classification, and risk classifications increase from the lower left to the upper right in Table 4-1. The LCFS CCS protocol mandates that any risk scenario classified as high must be mitigated to medium risk or low risk prior to application submittal.

**Table 4-1. Risk Scenario Classification Matrix Showing the Risk Likelihood Scale in the Left-Most Column and the Risk Severity Scale along the Top Row (adapted from Table 1 of the LCFS CCS protocol [California Air Resources Board, 2018]).**

| | Insubstantial | Substantial | Catastrophic |
|---|---|---|---|
| **>5%** | Medium risk | High risk | High risk |
| **1%–5%** | Low risk | Medium risk | High risk |
| **<1%** | Low risk | Medium risk | Medium risk |

### 4.3 Financial Incentive Programs Summary

Financial incentive programs currently exist to incentivize CCS deployment and thereby accelerate GHG emission reductions. For storage project operators to qualify for the Section 45Q credit, IRS requires an approved MRV plan under EPA GHGRP Subpart RR. Formal approval of the submitted MRV plan occurs when the technical review is satisfactory and EPA issues a final decision to the operator. Like the regulatory requirements under the Class VI rule, the contents of the MRV plan focus on the risk of endangerment to USDWs and the resultant monitoring area delineation, testing, and monitoring requirements to effectively manage potential risk scenarios. Therefore, risk management is implicit in the MRV plan requirements and, by extension, necessary for obtaining Section 45Q credit.

For ethanol producers who intend to sell the lower-carbon ethanol produced with CCS in the CARB LCFS, the risk management requirements established in the LCFS CCS protocol are prescriptive and require the storage project operator to complete a site-based risk assessment and RMP. These risk management requirements can significantly increase the scope of work for a storage project and should therefore be factored into project planning.

## 5.0 RISK MANAGEMENT PROCESS

The risk management process is a structured and systematic technique for managing the risks of a storage project that is implemented at each stage of a project's life cycle. It includes both an assessment of the risks as well as the development of monitoring and mitigation strategies to minimize the risks. An effective management framework comprises five primary elements: 1) establish the context, 2) risk assessment, 3) risk treatment, 4) communication and consultation, and 5) monitoring and critical analysis. Figure 5-1 illustrates the integration of these five main components of the risk management process. This document focuses on Elements 1–3; Elements 4 and 5 are beyond the scope of the current document. Each of these components is described in further detail in their respective sections of the document.

Risk assessment is at the core of the risk management process (blue box in Figure 5-1). It is an iterative process of identifying, analyzing, and evaluating individual project risk scenarios, which enables storage project developers to proactively plan and implement mitigation strategies, as needed, to address individual risk scenarios (Ayash and others, 2016). Each iteration through the risk management process shown in Figure 5-1 adds additional information that further informs the risk assessment until each of the identified risk scenarios is adequately assessed.

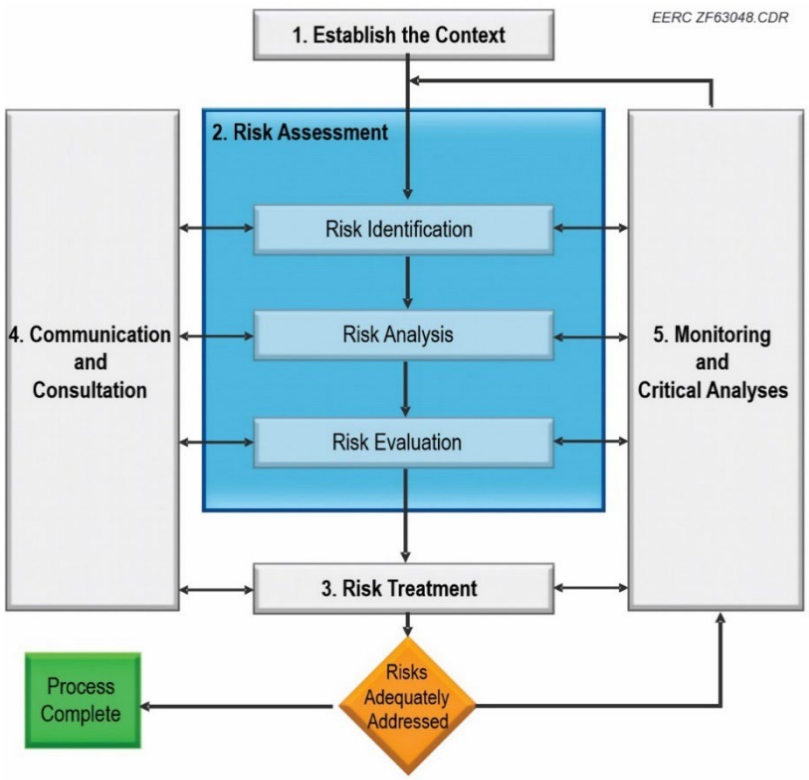


Figure 5-1. Primary elements of the risk management process (adapted from ISO 31000 [2009] and ISO 27914 [2017]).

A storage project risk is the combination of the severity of consequences (negative impacts) of an event and the associated likelihood of its occurrence (Azzolina and others, 2017). Project risks can be assessed and prioritized using qualitative, semiquantitative, or quantitative frameworks based on expert panel judgment or models. Risk assessments are typically conducted in coordination with subject matter experts and the storage project development/management team (hereafter referred to as the "risk team") through a series of meetings and workgroup sessions over a period of months or years. Therefore, multiple iterations of the risk assessment are performed over time during the execution of the risk management process. General guidelines for the risk management process are presented in ISO 31000 (2009), ISO 27914 (2017), and Azzolina and others (2017). Sections 6.0–8.0 provide more detail on several components of the risk management process in Figure 5-1.

## 6.0 ESTABLISH THE CONTEXT

Establishing the context of the risk assessment is the first step in a risk management process (top box in Figure 5-1). The context articulates the risk assessment goals and objectives and sets the scope (i.e., activities and boundaries) and risk criteria (i.e., the thresholds for defining the significance of a risk) of the process, considering both the internal and external environments that may influence assessments or impact stakeholder perceptions of risk. The primary stakeholders of a storage project typically include the public, regulators, project developers, project managers, and subject matter experts. As indicated in Figure 6-1, the stakeholder areas of interest can be classified into four broad categories: 1) component of the storage project, 2) project stage, 3) risk category, and 4) risk metric.

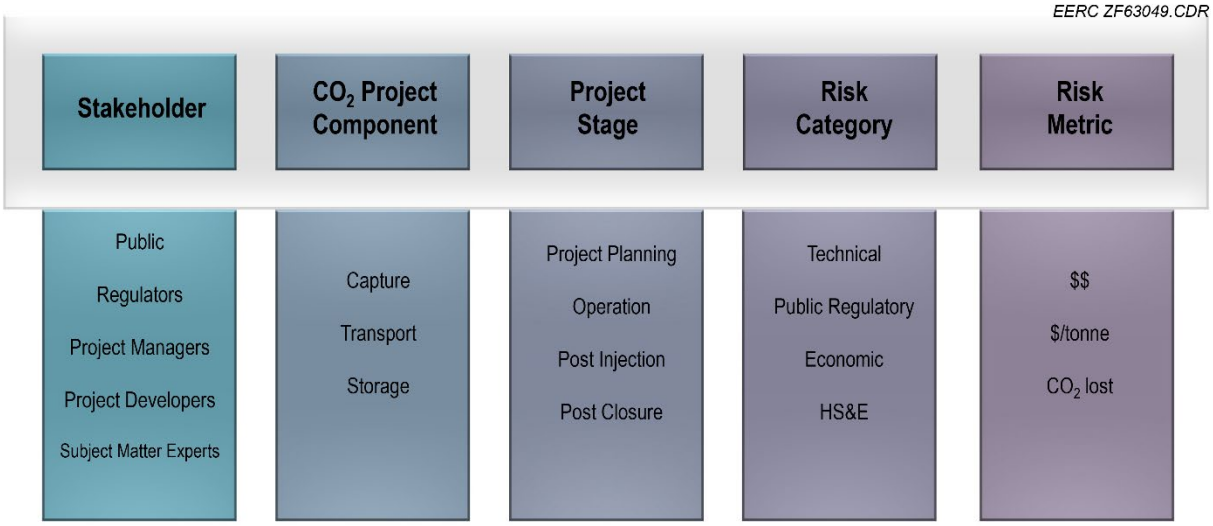


Figure 6-1. Overview of stakeholder areas of interest for consideration when establishing the context of the risk assessment. Different stakeholders will have different concerns driven by project component of interest, lifecycle stage of the component, risk category of interest, and risk metrics that will be used (adapted from Gerstenberger and others, 2013).

ISO 27914 (2017) recommends that the following topics be considered when establishing the context for a storage project risk assessment:

- Natural environment and hazards
- Regional natural resources and activities
- Infrastructure and facilities
- Social, political, and economic context

- Policy, legal, and regulatory environment
- Industry-recommended practices pertaining to effective risk management
- Project operator and subcontractors, their respective functions, responsibilities and accountabilities, and the relationships between their respective systems for risk management
- The state of knowledge of and uncertainty about each aspect of the project, including storage systems components, storage plans, socio-political environment, etc.
- Project scale and duration, project phases, decision points, and respective time scales

As a project evolves through time, the risk assessment context may also need to evolve to ensure that it reflects the most current project details.

The remainder of this section addresses two prominent aspects of establishing the risk assessment context: i) the development of a functional model of the storage project and ii) the definition of the risk criteria.

### 6.1 Functional Model of the Storage Project

A functional model of the storage project defines the storage system boundaries, the system components that will be evaluated in the risk assessment, and the functions of these components. The purpose of the functional model is to allow for the intricacy of the storage unit and overlying formations to be reduced to a set of components about which the stakeholders can formulate judgments regarding the underlying potential risk causes, their associated likelihood, and the severity of their impacts on the performance of the storage system. Figure 6-2 provides a generic depiction (block diagram) of a typical storage project, showing the storage complex (lower confining layer, storage unit, primary seal, dissipation interval, and additional seals), lowermost USDW, and surface. Depending on the distance between the storage unit and basement rock, the CARB LCFS CCS protocol may require the storage project operator to identify and characterize additional dissipation interval(s) below the storage complex to limit the extent of downward overpressure propagation and lower the potential for induced seismicity within formations beneath the storage unit. The risk assessment is focused on evaluating the containment of the injected $CO_2$ stream in the storage unit and the potential for $CO_2$ or formation fluids to migrate from the storage unit to receptors such as the lowermost USDW, surface water, and biosphere. Potential pathways for fluids to migrate from the storage unit to the overlying formations include injection well(s), monitoring well(s), plugged and abandoned (P&A) wells, other wells, or faults/fractures, as indicated by the vertical arrows in the figure. Subject matter experts can use the functional model to trace failure modes across the different geologic units and to describe risk scenarios that could affect storage permanence and environmental receptors like the lowermost USDW, surface water, or biosphere.

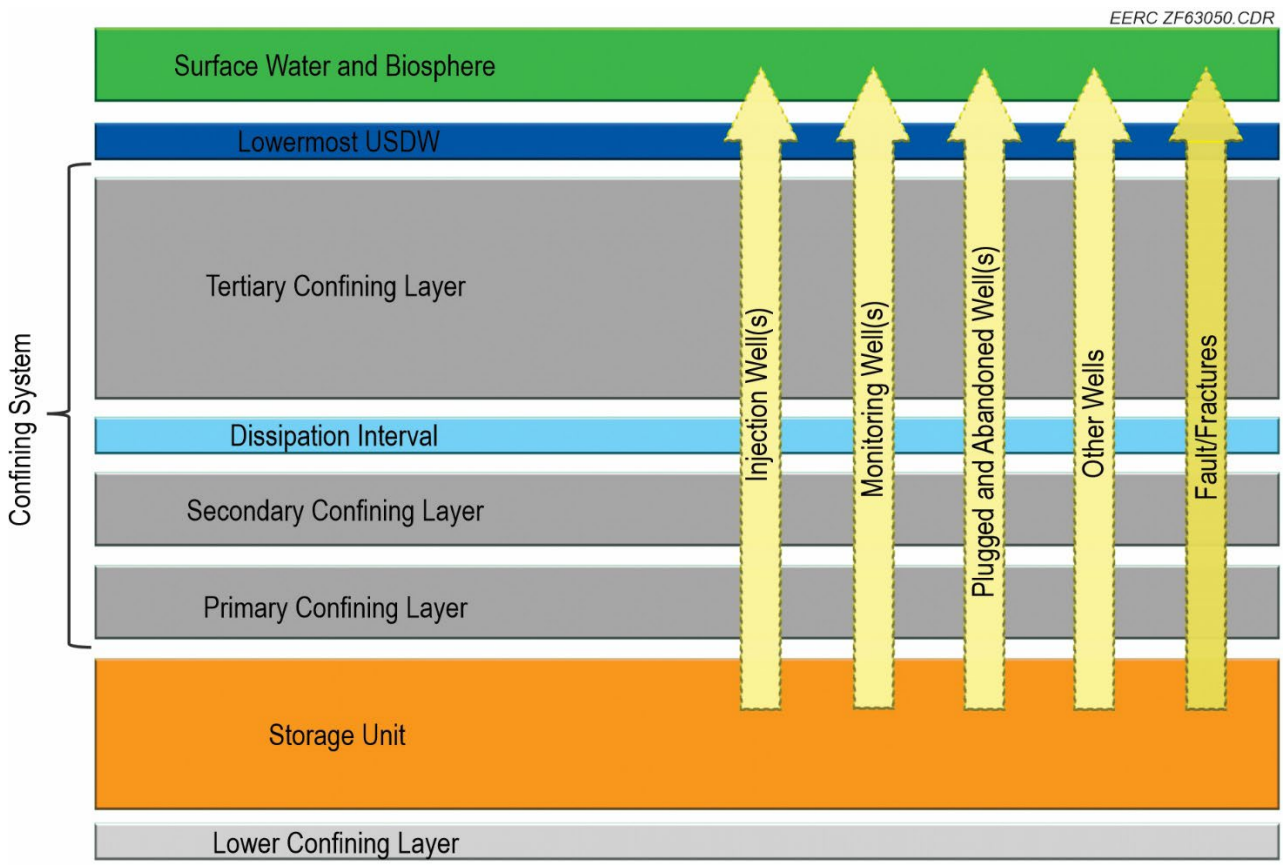


Figure 6-2. Generic depiction of a functional model of a storage project, which includes the storage unit, multiple confining layers (e.g., lower, primary, secondary, and tertiary confining layers), a dissipation interval, the lowermost USDW, and the surface as well as various features (e.g., wells, faults, or fractures) that may be present and provide fluid migration pathways from the storage unit to the overlying storage system components.

## 6.2 Definition of Risk Criteria

Risk criteria for the evaluation of individual risk scenarios include i) the likelihood of occurrence and ii) the severity of potential consequences should the risk scenario occur (International Organization for Standardization, 2017). When establishing the context for the risk assessment, these criteria are developed by integrating the best available knowledge and scientific reasoning and are presented as standardized scales, the discretization of which reflect the nature of the potential risks and the availability of sufficient data to foresee differences in their likelihood of occurrence and subsequent severity. Specific examples of risk likelihood and risk severity scores are provided in Sections 7.3.1 and 7.3.2, respectively.

Neither the likelihood nor severity of a risk scenario, by itself, is sufficient to classify the risk scenario. Rather, the classification of a risk scenario is based on its criticality, which is a relative measure of the frequency of occurrence and its consequences, i.e., the joint distribution of

likelihood and severity (U.S. Department of Defense, 1949, 1980). The criticality score is used to rank risk scenarios and identify those that may require some form of treatment. Therefore, in addition to developing the risk likelihood and risk severity scales, when establishing the context for the risk assessment, one or more methods for evaluating the risk criticality are developed based on project-specific risk tolerances or regulatory requirements. Specific examples of evaluating risk criticality are provided in Section 7.3.3.

### 6.3 Summary

After establishing the context for the risk assessment, the risk team should have a clear understanding of the risk assessment objectives and scope (i.e., activities and project boundaries), a well-developed functional model of the storage project, and risk criteria—risk likelihood and risk severity scores, in addition to one or more methods for evaluating risk criticality. At this point, the risk team is ready to conduct the risk assessment with the appropriate project stakeholders.

## 7.0 RISK ASSESSMENT

Risk assessment is the overall process of risk identification, risk analysis, and risk evaluation as illustrated in the blue box of Figure 5-1. The risk assessment allows the ranking of potential risk scenarios in accordance with their criticality scores (i.e., the combination of their risk likelihood and risk severity scores) and serves as a basis for designing risk-based monitoring programs as well as targeting risk scenarios, if warranted, for treatment. As previously discussed, iterative rounds of risk assessments are performed over the life cycle of a storage project, each of which is better informed than the previous one with new information. This AMA produces increasingly better risk assessments that are better able to evaluate the risk scenarios of interest. The outcome of the completed risk assessment paves the way for evaluating the acceptability of the identified risk scenarios and evaluating appropriate means to treat all risks that are deemed unacceptable.

### 7.1 Risk Identification

Risk identification is the process of recognizing and describing risk scenarios, which is achieved through facilitated meetings with subject matter experts. These meetings are guided by the results of several site characterization studies accompanied by several seed questions that are designed to obtain and combine the opinion of various experts (Gerstenberger and others, 2013).

Over the course of conducting multiple storage project risk assessments throughout the PCOR Partnership Program, a common set of primary technical risks have been identified which include the following:

- **Storage capacity:** The ability of the storage unit to store the designed target mass of injected $CO_2$ over the project duration (e.g., 50 million tonnes [Mt] over 25 years).

- **Injectivity:** The ability of the storage unit to accept the designed target mass of injected $CO_2$ at rates that can be achieved without fracturing the formation (e.g., 2 Mt per year for 25 years).

- **Vertical and lateral containment of subsurface fluids (e.g., $CO_2$, formation brines, and/or oil):** The permanent storage of $CO_2$ and affected fluids within a storage unit.

- **Induced seismicity:** The ability of the storage unit to store the designed target mass of injected $CO_2$ without causing minor earthquakes or tremors from subsurface injection of fluids.

At a minimum, these risk categories should be addressed for all storage projects. In addition, the risk identification should consider the requirements of the following guidance or regulatory requirements, if applicable to the project:

- **CSA Z741-12 (2012):** These standards recommend that the storage project operator perform a comprehensive risk identification process that i) considers all features, events, and processes (FEPs) relevant to the identification of scenarios that can carry significant risk and ii) documents in a traceable and consistent manner in which FEPs have been considered.

- **ISO 27914 (2017):** The elements of concern identified in this guidance include human health and safety, the environment, and system performance (e.g., injectivity, containment, and service reliability).

- **WDEQ Chapter 24:** For storage projects located in the state of Wyoming, WDEQ's Class VI regulations require owners/operators to consider the risk activity table when making financial assurance cost estimates. The risk activity table is provided in Appendix A of WDEQ's Chapter 24 (Table B-1), which includes risks related to i) mineral rights infringement (trespass), ii) water quality contamination, iii) single large-volume $CO_2$ release to the surface—asphyxiation/health/ecological, iv) low-level $CO_2$ release to surface—ecological damage due to low-level releases—potential asphyxiation of human or ecological receptors, v) storage rights infringement ($CO_2$ or other entrained contaminant gases)—form of mineral rights infringement, vi) modified surface topography (subsidence or uplift) resulting in property/infrastructure damage, vii) entrained contaminant (non-$CO_2$) releases, and viii) accidents/unplanned events (typical insurable events).

- **EPA GHGRP Subpart RR:** For storage projects intending to qualify the stored $CO_2$ for a tax credit under the IRS Section 45Q credit, MRV plan requirements provided in Title 40 Chapter I Subchapter C Part 98.448 require i) delineation of the maximum and active monitoring areas and ii) identification of potential surface leakage pathways within the maximum monitoring area.

- **CARB (2018):** For ethanol producers who capture and store $CO_2$ from their ethanol plants (ethanol produced with CCS) and intend to sell the lower-carbon ethanol in a low-carbon fuel market, the CARB LCFS CCS protocol requires that a site-based risk assessment be conducted that, at a minimum, examines i) leakage risk and ii) the scenarios in the emergency and remedial response plan as well as any other risks that could be reasonably anticipated.

At the initiation of the storage project, the risk identification process begins with a preliminary list of potential storage-related risks assembled from a basic understanding of the functional model of the storage project combined with existing databases of potential FEPs associated with the geological storage of $CO_2$ (e.g., Quintessa, 2014). At this stage, the internal and external stakeholders further develop this preliminary list of risks by examining the functional model of the storage project and available data from any previous site characterization studies to perform a failure modes and effects analysis (FMEA). The FMEA describes how the risk scenarios would occur (i.e., what would have to fail and what would be the cause of the failure [failure modes] and what would be the effect of such a failure). The FMEA results can be cross-referenced with existing databases for other storage projects to develop a comprehensive list of failure modes and causes (Azzolina and others, 2017). ISO 27914 identifies a set of criteria for the identification of the threats that should be addressed for a storage project (Table 7-1). In addition, ISO 27914 recommends that the risk identification should assess the biosphere and economic resources in the geosphere that could be affected by $CO_2$ injection operations.

**Table 7-1. Criteria Description for the Identification of Threats for a Storage Project (International Organization for Standardization, 2017)**

| No. | Criteria Description |
|---|---|
| **1** | The site has sufficient capacity to accept required $CO_2$ injection volumes. |
| **2** | The site has sufficient injectivity to allow $CO_2$ injection at required rates. |
| **3** | The site will provide long-term containment, i.e., prevention of leakage at rates or in a total mass sufficient to cause an adverse impact or greater than limits set by local regulations or license terms. |
| **4** | The $CO_2$ injection operations will not lead to seismicity or earth deformation sufficient to cause an adverse impact. |
| **5** | Modeling and cost-effective monitoring are feasible and:<br>a) Allow timely implementation of appropriate risk treatment.<br>b) Provide confidence that the storage site is suitable for continued $CO_2$ injection operations.<br>c) Ensure that related criteria for site closure will be met. |
| **6** | The project operational procedures ensure operational safety and environmental protection, i.e., avoidance of impacts to health, safety, and the environment stemming from construction and operation of wells and the project surface infrastructure and from project interactions with nonproject human activities local to the project site and surrounding area. |

### *7.1.1 Recommended Site Characterization Studies*

Site characterization studies of the storage unit and other site features are required to support a storage project risk assessment. ISO 27914 provides a set of recommended characterization studies for the storage unit and confining strata (primary seal and additional seals) in addition to recommendations for geochemical, geomechanical, and well characterization. Review of storage project site characterization studies relative to these recommendations should be incorporated into the risk identification as part of the assessment of completeness about whether the necessary information was collected to adequately conduct the risk analysis. The functional model of the storage project can be used to provide a cross-reference to ensure that the recommended characterization studies have been completed for each of the major system components (See Figure 6-2). Some of these recommended site characterization studies may not be applicable to all storage projects as site-specific conditions dictate the level of site characterization studies needed

to satisfy the permitting requirements and the risk assessment. In addition, storage projects that are early in their development life cycle may not generate all the site characterization data described below; therefore, the completeness review must also consider the current phase of project development relative to the site-screening, feasibility, design, construction/operation, and closure/postclosure phases.

##### *7.1.1.1 Storage Unit*

The storage unit is the reservoir into which the $CO_2$ stream is injected for geologic sequestration. ISO 27914 recommends characterizing the storage unit to provide a reasonable estimate of capacity and injectivity and to manage risk. Characterization of the storage unit is intended to be completed prior to injection of any $CO_2$ (International Organization for Standardization, 2017). The ISO 27914-recommended storage unit characterization includes the following elements:

- Determination of the extent of the storage unit and establishment of its boundaries, including identification and characterization of fault zones and structural features that could affect containment.
- Mapping of the geometry of the storage unit and evaluation of its distance to subcrops or outcrops.
- Identification of the presence and size of known local traps in the storage unit and evaluation of large-scale vertical and horizontal stratigraphic heterogeneity of the storage unit.
- Evaluation of the spatial distribution of porosity and permeability in the storage unit.
- Development of 3D geologic models of the storage unit.
- Estimation of wettability, relative permeability, and capillary pressure for $CO_2$ and the fluids present in the storage unit.
- Evaluation of the temperature distribution in the storage unit prior to injection of the $CO_2$ stream.
- Evaluation of the initial pressure distribution in the storage unit prior to injection of the $CO_2$ stream.

##### *7.1.1.2 Sealing Formations*

ISO 27914 recommends characterizing the primary seal and additional seals (confining strata) that are part of the confining system to provide adequate confidence in the containment of the stored $CO_2$ (International Organization for Standardization, 2017). ISO 27914 recommended that characterization of the primary seal includes the following elements:

- Determination of the stratigraphy, lithology, thickness, and lateral continuity of the primary seal.

- Evaluation of primary seal integrity, including porosity and permeability, and testing where possible, and assessment of seal mineralogy to determine the suitability for containment of the $CO_2$.

- Identification of potential leakage pathways, such as fractures, faults, and wells, and their potential to transmit fluids.

- Estimation of the capillary entry (displacement) pressure for $CO_2$.

- Evaluation of the pressure distribution in the porous and permeable unit immediately overlying the primary seal (dissipation interval), located above the storage unit and below the additional seals.

ISO 27914 recommends characterization for additional seals that are part of the confining system and includes the following elements:

- Identification of overlying permeable strata and additional seals that are present between the storage unit and other subsurface resources.

- Characterization of the permeable strata, where present, within the storage unit and in the overlying sedimentary succession in terms of the flow and composition of formation fluids and geomechanical properties.

- Characterization of the additional seals, mainly in terms of their geometry and lithology.

##### *7.1.1.3 Geochemical Characterization*

ISO 27914 recommends characterizing the chemical composition of the $CO_2$ stream proposed for injection and of the fluids in the storage unit. In addition, ISO 27914 recommends characterizing the mineralogy of the rocks in the i) storage unit, ii) primary seal, and iii) most proximate permeable units immediately overlying the storage unit and primary seal (i.e., dissipation interval) (International Organization for Standardization, 2017). The recommended baseline geochemical characterization efforts include the following elements:

- The $CO_2$ stream composition and its variability.

- The major, minor, and trace mineralogical components of the rocks in the storage unit and primary seal.

- The composition of and variability in the composition of formation fluids, including dissolved gases in the storage unit.

- Additional baseline sampling of the geosphere and biosphere based on the anticipated geochemical reactions in the subsurface.

#### *7.1.1.4 Geomechanical Characterization*

ISO 27914 recommends geomechanical characterization of the i) storage unit, ii) primary seal, and iii) overburden (International Organization for Standardization, 2017). The recommended baseline geomechanical characterization efforts include the following elements:

- Evaluation of the natural seismicity and tectonic activity of the region where the storage unit is to be located. The available information related to seismicity and tectonic activities should be collected and analyzed.

- Characterization of the in situ stress regime (magnitude and orientation of principal stresses). Knowledge of the in situ stress regime in combination with the geomechanical modeling procedures should be used to assess the maximum $CO_2$ injection pressure limits.

- Determination of rock mechanical properties of both storage unit and primary seal, which include:
  - Strength and deformation mechanical properties according to the observed material behavior of the rock of interest (e.g., Poisson's ratio and Young's modulus).
  - Thermal properties (e.g., thermal expansion coefficient, specific heat capacity, and thermal conductivity).
  - The attributes (e.g., orientation, spacing, roughness, aperture, infilling, and mineralization) of weak planes and any discontinuities (e.g., bedding and natural fractures and faults).
  - Estimation of the fracture extension (propagation) pressure.

- Development of a mechanical earth model (MEM) (geologic model populated with geomechanical properties) that includes an adequately detailed representation of the storage unit and primary confining layer and a simplified representation of the overlying sedimentary strata. The geometry of the MEM should be based on the spatial distribution of strata, fractures, and faults as represented in the geologic model of the project. Its constituents should be populated with the mechanical properties and in situ stresses that have been gathered.

As previously noted, some of these recommended geomechanical characterization studies may not be applicable to all storage projects as site-specific conditions dictate the level of site characterization studies needed to satisfy the permitting requirements and the risk assessment. For example, storage projects with adequate storage capacity relative to the planned $CO_2$ injection rate may not affect the subsurface stress regime to the extent that a MEM is necessary to properly characterize geomechanical risk.

#### *7.1.1.5 Well Characterization*

ISO 27914 states that characterization of wells is a principal tool in identifying, remediating, and managing well leakage risk and therefore recommends a characterization of the legacy wells that could affect the storage project within the AOR. An evaluation should determine if the legacy wells within the AOR have sufficient isolation to prevent formation fluids or injected $CO_2$ from vertically migrating outside of the storage unit into USDWs and/or to the surface and if corrective action is necessary (International Organization for Standardization, 2017). The recommended evaluation of legacy wells as a potential leakage pathway entails:

- Identification of the wells that penetrate the storage unit within the AOR.
- A determination of the status (exploration, producing, injecting, suspended, or abandoned) and ownership of the wells within the AOR.
- Characterization of the population of legacy wells by vintage, construction type, and type and extent of mechanical defect and identification of problematic wells, if any.
- An evaluation of the potential of the wells to leak and an identification of the wells that need observation and/or immediate remediation.
- Identification of wells within the AOR that penetrate shallower horizons above the storage unit or adjacent structures (including use of surveys to locate old, unrecorded wellbores) and their status and characteristics.
- Identification of wells that have inadequate or no available plugging records to assess the integrity of the plugs to seal during $CO_2$ storage.
- Determination of the chemical composition of well materials that will come into contact with $CO_2$ and/or a $CO_2$-charged fluid.

### ***7.1.2 Risk Identification Output***

#### *7.1.2.1 Risk Scenario Descriptions*

Following a review of the functional model of the storage project and site characterization studies that have been completed or targeted for completion, depending on the life cycle stage of the project, the risk team can describe the risk scenarios. The risk team can build on the preliminary list of potential storage-related risks, tailoring the risk scenarios in accordance with the available site-specific information. Risk identification is often done through facilitated meetings with subject matter experts using multiple tools and techniques to elicit their responses.

The details of these tools and techniques are beyond the scope of the current document; however, examples of them are provided in a Project Management Institute guidance document (Project Management Institute, 2021).

An important aspect of the risk scenarios is creating a detailed risk description, sometimes called a "risk statement," which should conform to the following format (Project Management Institute, 2021):

> "If < EVENT > happens, then there is a risk < CONSEQUENCE > that the project could be impacted < IMPACT >."

For example, the paragraph below provides an example risk description for a risk scenario about injectivity of the storage unit, identifying the event, consequence, and impact:

> Because of unanticipated geologic characteristics of the storage unit, the injectivity of the storage unit around the injection well is lower than expected from site characterization data, modeling, and simulation <EVENT> and leads to pressure buildup in response to $CO_2$ injection exceeding the expected pressure response <CONSEQUENCE> requiring a lower $CO_2$ injection rate to avoid exceeding the maximum bottomhole pressure constraint specified in the permit <IMPACT>.

Each risk scenario description should capture the event, consequence, and impact, as shown in the above example. Clear risk scenario descriptions are necessary for the risk team to perform the risk analysis and reduce the chance of ambiguity among the different stakeholders who may interpret the risk scenario differently if the description does not clearly identify the event, consequence, and impact.

#### *7.1.2.2 Reconciling Multiple Failure Causes*

For many storage project risk assessments, different risk scenarios can result from a single failure mode, which can, in turn, be attributed to multiple system failures. Azzolina and others (2017) provided an example risk identification outcome with multiple failure causes related to containment (vertical fluid migration). As shown in Figure 7-1, the risk scenarios were subdivided based on how the vertical fluid migration occurred from the storage unit to the overlying formations (via P&A wells, injection wells, or producing wells), the different fluids that migrated ($CO_2$, formation water, or oil), the impact zone or receptor of the fluid (atmosphere or groundwater aquifer), and the location of the wells from which the migration occurred (wells within the active project area, wells beyond the active project area, updip wells, or downdip wells). Using this approach, one "parent risk scenario" produced many "child risk scenarios" after all the permutations were defined. Consequently, this degree of resolution in the risk scenarios resulted in a relatively large number of individual risks. At the time of the initial risk assessment, the risk team believed that the risk likelihood scores for the different failure causes could be different and, therefore, justified separating the risks into these more granular, specific risk scenarios. In subsequent risk assessment updates, however, the risk team incorporated new information from the operational phase of the project and recognized that parsing the parent risks was not necessary as it created risk scenarios that could not be distinguished from each other during the risk analysis (i.e., the failure causes could not be distinguished based on likelihood of occurrence). Accordingly, during the next risk assessment update, the risk scenarios were consolidated at the fluid type without adding the specificity of the impact zone or the location of the wells of concern (i.e., three

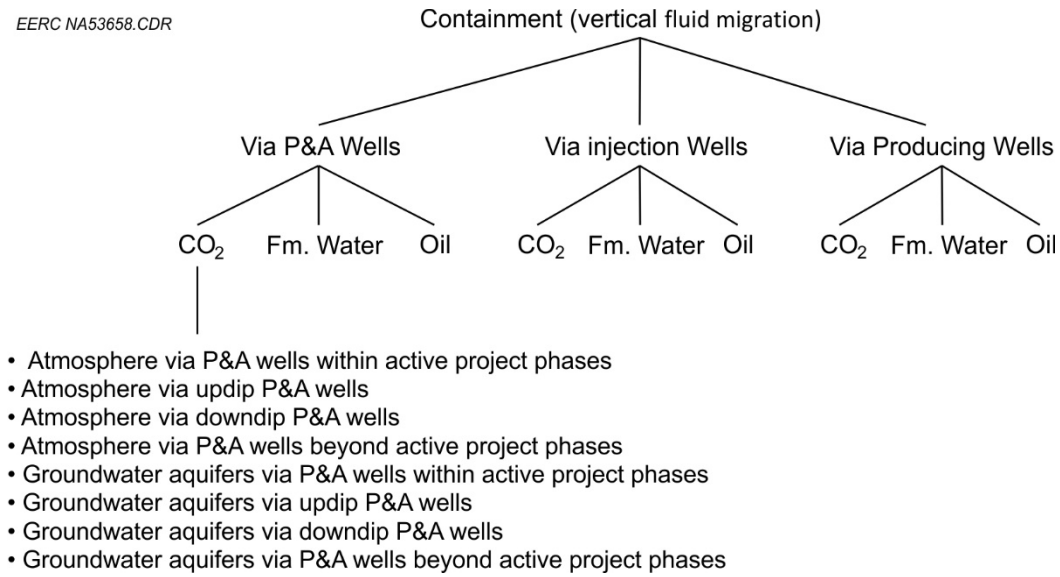


Figure 7-1. Example hierarchical tree illustrating how one risk, in this case containment (vertical fluid migration), can be separated into multiple individual risks when different failure causes, fluids, impact zones, and well locations are included.

risk scenarios each under "Via P&A Wells," "Via Injection Wells," and "Via Producing Wells"). This level of specificity of the risk assessment was believed to be sufficient to adequately assess the risks at this phase of the project.

This example illustrates the need for storage site characterization data and the input of an expert work group to adequately identify the site-specific risk scenarios. It also demonstrates how risk scenarios evolve throughout the different phases of a storage project life cycle and how data collection over a project life cycle is important to the risk assessment process. In this example, the project team initially adopted a granular risk identification process that led to multiple permutations, which were later consolidated into fewer risk scenarios following the collection of actual operational data.

### *7.1.3 Project Risk Register*

The results of risk identification should be recorded in a project risk register in a consistent manner so that risk assessments are comparable over time. For each recorded risk scenario, CSA (2012) and ISO 27914 (2017) recommend that the risk register include the following information:

- A description of the risk scenario
- A description of the risk controls to prevent or mitigate the risk scenarios
- A description of the assessed effectiveness of each risk control.

- The designated risk owner and the persons responsible for actions associated with execution of the risk controls.

- A schedule for timely execution of the risk controls

- The estimated residual risk for each relevant element of concern and a description of the basis or rationale for the risk evaluation

Each entry in the risk register is generally assigned a risk number or some other unique identifier that will be tracked over the project life cycle. As previously discussed, each risk scenario description should capture the event, consequence, and impact. In the context of storage projects, risk controls refer to preventative systems that are in place to reduce the likelihood of a risk scenario (i.e., preventing the risk scenario from occurring) or mitigation measures in place to limit the consequences (i.e., lower the severity of the risk scenario should it occur). This portion of the risk register is not completed until after the risk analysis and evaluation. The risk owner is typically the storage project developer; however, unique situations may arise where a different party is responsible for one or more risk scenarios. Lastly, residual risk refers to the remaining risk after accounting for the impact of risk controls (i.e., inherent risk minus the impact of risk controls). This portion of the risk register is also not completed until after the risk analysis and evaluation. The risk register is the primary output from the risk identification step.

### 7.2 Risk Analysis

For each risk scenario described in the risk register, the risk team must then conduct a risk analysis, comprising a technical evaluation that integrates the best available knowledge and scientific reasoning to determine the i) risk likelihood (the probability that a risk scenario will occur over a specified time frame) and ii) the risk severity of potential consequences (the impact of the risk scenario on one or more criteria) (International Organization for Standardization, 2017). The risk analysis should conform to the risk-scoring guidelines outlined by the appropriate governing body, which would have been identified during establishing the context of the risk assessment (see Section 6.2).

The risk analysis can be one of the most time-consuming and challenging elements of the risk management process because it integrates several disciplines like geology, geophysics, reservoir engineering, and other engineering fields to understand and evaluate the operation of the storage system. Therefore, all available project data must be identified and analyzed to support the risk analysis; for example, published local or regional data sets, rock core samples and associated laboratory measurements, well log measurements, downhole testing (e.g., injection test), 3D seismic surveys, geologic models, reservoir simulations, or any other activity that was conducted as part of the storage project development in support of the Class VI permitting process.

As reiterated throughout this document, multiple rounds of risk assessments are performed over the life cycle of a storage project, each of which is better informed than the previous one with new information. Risk analysis is highly dependent on the level of knowledge of a system; the better known a system, the better understanding of the risk scenarios. In the early phases of storage project development, many of the storage system components are not well-characterized, i.e., there

is uncertainty in the project understanding of the storage system. Consequently, the level of risk can be higher in the early phases of project development. As the project progresses along the development pathway, additional site characterization data are collected, models are constructed, and reservoir simulations are executed; thus the storage system components are better characterized, reducing uncertainty and generally reducing risk (Carpenter and others, 2011).

The nature of the risk analysis should be commensurate with the level of system knowledge. Risk analysis methodologies are broadly classified in two main groups: semiquantitative and quantitative. Semiquantitative risk analysis methods do not necessarily provide numerical results and therefore describe risk likelihood and severity using qualitative terms. A qualitative risk analysis is generally conducted through elicitation of expert judgments from subject matter experts, which can be subjective and prone to bias and variation (Morgan and Henrion, 1990; Kahneman and others, 2022). Methods for eliciting expert judgments are beyond the scope of the current document; however, the risk team facilitating the risk analysis should be aware of the challenges and make every effort to minimize bias and quantify the variation among experts. When there is a lack of data and/or specified knowledge, semiquantitative risk analysis may be sufficient and more effective. In contrast, quantitative risk analysis methods are generally used in well-known systems where the level of uncertainty is lower, and their outputs are more quantitative measures of risk likelihood and severity (Condor and others, 2011). A tiered approach is recommended for the risk analysis, beginning with a semiquantitative risk analysis and then progressing toward quantitative risk analysis as the level of system knowledge improves. Additional details about semiquantitative and quantitative methods are discussed below.

### *7.2.1 Semiquantitative Risk Analysis*

Two of the more popular techniques that have been published for semiquantitative risk analysis are i) FEP (Savage and others, 2004) and ii) vulnerability evaluation framework (VEF) (U.S. Environmental Protection Agency, 2008).

The FEP method utilizes a generic FEP database that has been developed for the geologic storage of $CO_2$ (e.g., Quintessa, 2014). Features are physical characteristics and elements of a site, such as wellbores, subsurface faults, primary seals, or storage units. Events are relatively short-term or discrete events that will or may happen, such as well drilling, injection pressure increases, pipeline ruptures, or seismic events. Processes can be physical and/or chemical such as geomechanical or geochemical processes and multiphase flow behavior. Processes are relatively long-term or ongoing events or actions, such as gravity-driven $CO_2$ movement, regulatory compliance, or residual saturation trapping of $CO_2$ (Condor and others, 2011; National Energy Technology Laboratory, 2017; Patil and others, 2021). Risk analysis approaches using the FEP method develop "assessment models," which are interactions among the FEPs for different risk scenarios that the risk team can use to qualitatively assess each risk scenario. Essentially, the assessment models link important project FEPs and the risk scenarios through which individual or combinations of FEPs could result in adverse impacts to the project. FEP analysis therefore provides a structured approach for the systematic review of a storage project. These assessments can then be used in future risk analysis with more quantitative models.

The vulnerability assessment incorporated in the VEF was developed to systematically identify those conditions that could increase the potential for adverse impacts from geologic storage, regardless of likelihood. The VEF identifies attributes of storage systems that may lead to increased vulnerability to adverse impacts, identifies potential impact categories, and provides a series of decision support flowcharts that are organized, systematic approaches to assess the attributes and impacts. Figure 7-2 shows the VEF conceptual model. These attributes and impact categories were carefully selected by EPA as the key factors of storage systems to be included in a vulnerability evaluation. The system first is characterized in terms of the injected $CO_2$ stream, the confining system, the injection zone (storage unit), and a series of geologic attributes that could influence (i.e., increase or decrease) the vulnerability of the storage system to unanticipated migration, leakage, and undesirable pressure changes (first column). Next, an approach is then provided for defining the spatial area that should be evaluated for adverse impacts associated with unanticipated migration, leakage, or undesirable pressure changes (middle column). Lastly, potential impact categories and associated key receptors are then identified, including human health and welfare, atmosphere, ecosystems, groundwater and surface water, and the geosphere (last column) (U.S. Environmental Protection Agency, 2008).

There are other methods for semiquantitative risk analysis beyond the FEP and VEF methods described here. The common characteristics across these methods are i) they are best applied when there is a lack of data and/or specified knowledge and ii) they do not necessarily provide numerical results such as risk likelihood or risk severity scores and instead use qualitative statements to analyze the risk scenarios.

Many of the risk assessments conducted for early storage projects in the PCOR Partnership region were semiquantitative in nature, relying on the VEF method or similar methods to elicit expert judgment about the storage system, given the state of knowledge about the project. Semiquantitative risk analysis can serve as the basis for a more quantitative risk analysis, and several of the storage projects progressed through their development life cycle and therefore evolved from semiquantitative to more quantitative risk analysis methods.

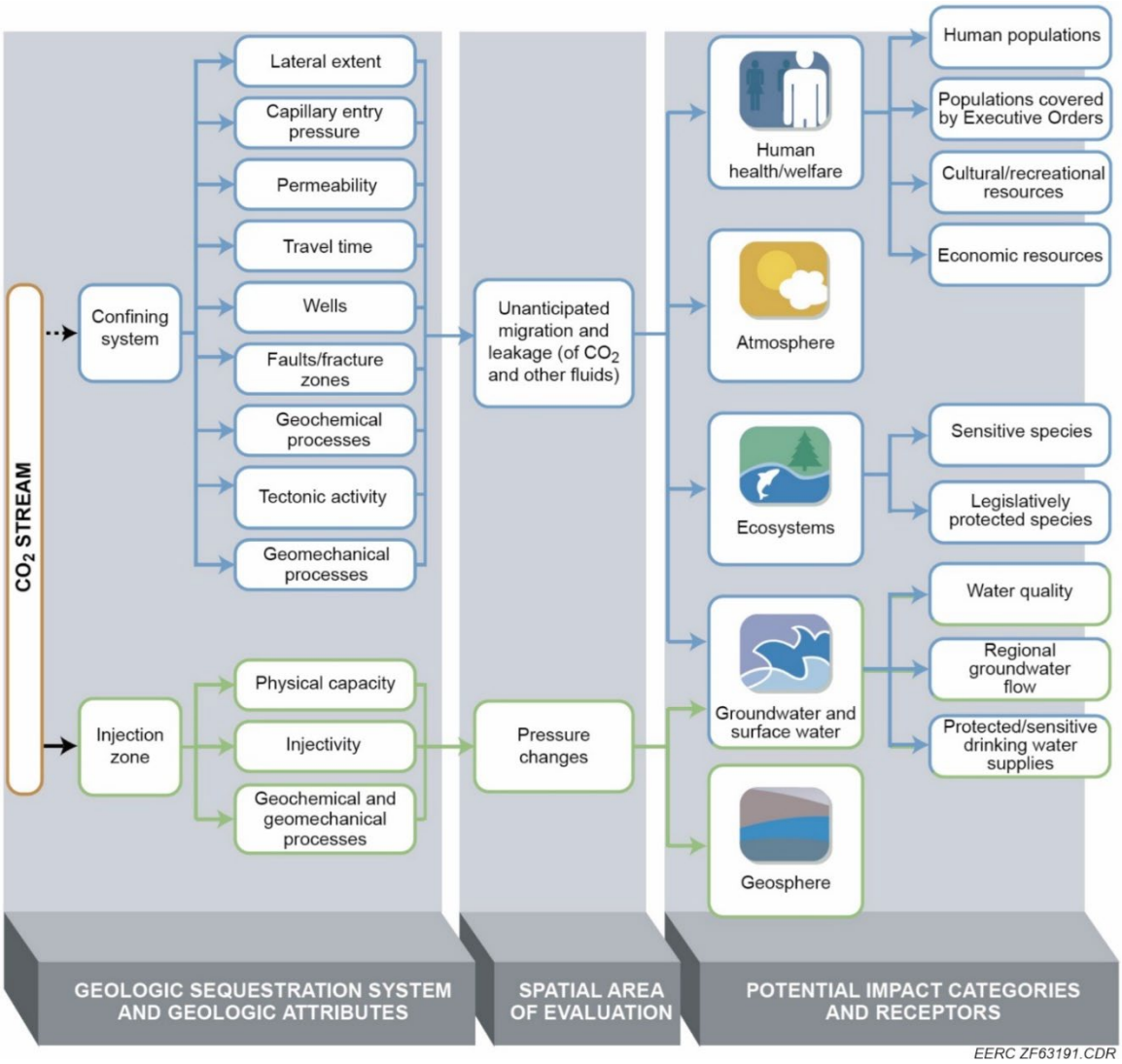


Figure 7-2. VEF conceptual model (from Figure 3-1 in U.S. Environmental Protection Agency [2008]).

### *7.2.2 Quantitative Risk Analysis*

In this document, the "quantitative" in quantitative risk analysis can refer to two characteristics. First, there is quantitative in the sense of running physics-based models to predict a future system condition based on a set of inputs to quantitatively assess the system: e.g., pressure buildup or $CO_2$ plume extent in the storage unit—some physical metric of the storage system performance that relies on underlying quantitative methods. Second, there is the mathematical approach for linking those physics-based model outputs into quantitative statements about risk scenario likelihood or severity. Therefore, quantitative risk analysis can be "fully quantitative," meaning physics-based models to derive outputs that feed into risk scenario likelihood or severity calculations, or "semiquantitative" (National Energy Technology Laboratory, 2017), meaning some combination of physics-based models and expert judgment, which are then used to estimate

risk scenario likelihood or severity. Many storage project risk analyses have been versions of the latter. While methods for calculating risk scenario likelihood or severity from numeric inputs are well-developed (e.g., Watson, 1961; U.S. Nuclear Regulatory Commission, 1981), methods for physics-based, fully quantitative simulations of risk scenarios for storage projects are less developed; therefore, judgment from subject matter experts continues to be used in the risk analysis. Appendix C summarizes different types of quantitative information that can be used in the risk analysis and organizes quantitative methods into four groups: i) geologic modeling and reservoir simulation, ii) geochemical modeling, iii) geomechanical modeling, and iv) computational modeling of the broader storage system. The outputs from these quantitative methods provide inputs to the risk team for the risk analysis (scoring).

Geologic modeling and reservoir simulation, geochemical modeling, geomechanical modeling, and computational modeling of the broader storage system are all quantitative methods in the sense that they rely on underlying physics-based equations to forecast the storage system behavior in response to $CO_2$ injection. However, the final step of the risk analysis is to translate those modeling results into quantitative risk likelihood and severity scores, along with some measure of the uncertainty in the risk scoring.

#### *7.2.2.1 Risk Likelihood Scoring*

The risk likelihood scoring often relies on expert judgment, where subject matter experts consider the evidence (i.e., the outcomes of the quantitative tools just described) and score the risk likelihood based on best professional judgment. Uncertainty in the risk likelihood scores can be quantified from the variability in the expert respondents. For example, if three experts estimate the risk likelihood score for a specific risk scenario as 1%, 5%, and 5%, then the median value is 5%, the range is 1%–5%, and the maximum (worst case) is 5%.

If more than one reservoir simulation is conducted, for example to account for the underlying uncertainty in the subsurface characteristics used to develop the models, then the outcomes of these multiple realizations can inform the probability (frequency) of specific events, which can then be used to score the likelihood of risk scenarios. These multiple realization approaches are sometimes called "ensemble approaches" (where the set of realizations represents the ensemble) or "stochastic approaches" (because the ensemble captures statistical uncertainty in the inputs and therefore propagates the uncertainty into the simulated outputs). For example, if ten reservoir simulations, each with slightly different properties based on the site characterization data, suggest that the $CO_2$ plume will not reach any of the known legacy wellbores within the operational or PISC phases, then this result suggests that risk scenarios of vertical leakage of $CO_2$ via vertical wellbores is very low, i.e., 0 out of 10, or 0% (commonly scored as a small probability but not zero, e.g., <1%). Ensemble approaches are computationally intensive, as each reservoir simulation can take hours or longer to execute. However, approaches that include end-member models, for example low-, average-, and high-porosity models, can be used to evaluate the range of plausible outcomes with fewer realizations. Moreover, tools like DOE's National Risk Assessment Partnership (NRAP NRAP-Open-IAM (Open-source Integrated Assessment Model) have stochastic simulations embedded in the code, which therefore permits the user to run hundreds or thousands of cases to examine the effect of uncertainty on the risk likelihood. Ensemble approaches can be extended to other quantitative tools like geochemical and geomechanical models.

#### *7.2.2.2 Risk Severity Scoring*

While the risk analysis respondents can rely on available site data, reservoir simulations, and other quantitative tools to estimate a risk likelihood score, often a common challenge for the respondents is linking technical risks, such as $CO_2$ leakage, to a project impact (e.g., environmental impact). This aspect of the risk analysis can be supported by a table of physical consequences that describes specific, measurable metrics and assigns them to a physical impact score. Then, in a subsequent step, these physical impact scores are translated to the risk impact scores developed when the context for the risk assessment is established.

The relationship between the matrix of physical consequence and the risk severity scores should be developed with the input of key stakeholders and reflect the specific concerns of these stakeholders. A given physical consequence does not necessarily affect all impact categories. However, for any physical consequence, an impact "driver" can be determined. The driver is the most severely impacted category, resulting in the highest range of severity levels stemming from the physical consequence. Figure 7-3 provides an example physical consequence matrix for a storage project in the PCOR Partnership region. This matrix features quantitative values that can be estimated using models and simulations or physically measured during monitoring activities. These physical consequences are separated into four families: injectivity loss, decrease in $CO_2$ storage capacity, containment, and seismicity. The physical consequence that is being measured is shown in the yellow row, labeled "Proposed Metric," for example, "injectivity loss for one well." The unit of measure to quantify the proposed metric is in the next row, labeled "Proposed Unit."

For example, the unit of measure for injectivity loss is "duration," which is measured in a time of loss of hours, weeks, or months. The next five rows designate increasing ratings of physical consequences. For instance, less than 2 hours of injectivity loss is deemed a very low physical consequence with a corresponding score of "Impact 1," whereas a loss of injectivity for greater than 1 month is considered a worst-case scenario, scoring an "Impact 5." The matrix of physical consequences, therefore, provided the subject matter experts with a measurable set of metrics for gauging the relative impact of specific physical risks.

#### *7.2.2.3 Translating Risk Likelihood and Severity to the Project Risk Criteria*

For each risk scenario in the risk register, the risk likelihood and severity scores derived from the risk analysis must be translated to the risk criteria established for the storage project. This step can be considered either part of the risk analysis or the risk evaluation; this document describes the risk criteria under risk evaluation.

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| Physical Consequence Family | Injectivity Loss | | Decrease in $CO_2$ Storage Capacity | Containment | | | Seismicity |
|---|---|---|---|---|---|---|---|
| | | | | Leakage to Atmosphere | | Contamination of Usable Water | |
| Physical Consequence Subfamily | | | | $CO_2$ | $CO_2$ | Brine | |
| **Proposed Metric** | Injectivity Loss for One Well | Average Total Monthly Injectivity Loss | Loss with Respect to Initial Storage Volume Estimate | Max. Ground Level Concentration | Overall Loss Volume with Respect to Stored $CO_2$ | Increase of TDS Concentration in Water | Induced Seismicity |
| **Proposed Unit** | Duration | % of nominal injectivity | % of initial storage volume estimate | % | % of stored $CO_2$ | ppm | Richter scale |
| **Reference** | Time of loss | 1 month | Injection period (50 years) | Continuous | Liability period (100 years) | Depth 350 m | Instantaneous |
| **Impact 1 (very low)** | <2 hr | <0.1% | <1% | <0.5% | <0.1% | <1000 (freshwater) | <3 |
| **Impact 2 (low)** | 2–10 hr | 0.1%–1% | 1%–5% | 0.5%–5% | 0.1%–1% | 1000–10,000 (brackish) | 3–4 |
| **Impact 3 (moderate)** | 10 hr – 1 week | 1%–5% | 5%–20% | 5%–15% | 1%–5% | 10,000–15,000 (highly brackish) | 4–5 |
| **Impact 4 (high)** | 1 week – 1 month | 5%–25% | 20%–50% | 15%–30% | 5%–10% | 15,000–40,000 (seawater) | 5–6 |
| **Impact 5 (very high)** | >1 month | >25% | >50% | >30% | >10% | >40,000 (brine) | >6 |

Figure 7-3. Example physical consequence matrix for a storage project in the PCOR Partnership region used to help subject matter experts estimate risk severity scores.

## 7.3 Risk Evaluation

The risk evaluation integrates the results of the risk analysis—the likelihood that risk scenario will occur and the severity of the consequences should the risk scenario occur—to determine the "criticality" of the risk scenario. The criticality of the risk scenario is used to evaluate the acceptability of the risk scenario and permit a refined ranking of the project risk scenarios for the purpose of identifying and prioritizing those which may require risk mitigation or risk treatment. The risk likelihood, severity, and criticality scales are developed when establishing the context for the risk assessment (see Section 6.0). Example risk likelihood, severity, and criticality scores based on PCOR Partnership experience are provided below.

### *7.3.1 Likelihood*

Risk likelihood refers to the probability of a risk occurring and is described by specifying a frequency over a given period (e.g., frequency in 100 years). Table 7-2 illustrates an example five-point frequency scale, showing the i) risk likelihood score from 1 to 5; ii) minimum, average, and maximum probability over the 100-year reference period; and iii) verbal descriptions from "virtually impossible" to "very likely." Risk likelihood is commonly scored on a logarithmic scale, which is why the average probability is the mean of the log-transformed minimum and maximum values. Other rubrics can be used to formulate alternative risk likelihood scales. For example, as described in Section 4.2, the CARB LCFS CCS protocol uses a three-point scale and assigns risk likelihood into three ranges: <1% (low), 1%–5% (moderate), and >5% (high). Regardless of the rubric that is used, it must be possible to assign the risk scenarios to the different categories using the available tools such as reservoir simulations, supplemental calculations, or judgment by subject matter experts.

**Table 7-2. Example Risk Likelihood Scoring Matrix Using a Five-Point Scale for the Probability of a Risk Occurring Over a 100-year Reference Period**

| Likelihood Score | Minimum Probability | Average Probability | Maximum Probability | Meaning |
|---|---|---|---|---|
| 5 | 25% | 50% | 100% | Very likely |
| 4 | 5% | 11% | 25% | Likely |
| 3 | 1% | 2% | 5% | Unlikely |
| 2 | 0.1% | 0.3% | 1% | Very unlikely |
| 1 | 1E-10 | 0.00003% | 0.1% | Virtually impossible |

### *7.3.2 Severity*

Severity of consequences (negative impacts) of a risk scenario to the storage project is determined based on interviews with both internal and external stakeholders and the application of several different quantitative risk analysis tools. Inputs from these interviews and modeling efforts are combined to assess the individual stakeholder concerns and risk tolerance levels, which are then compared to any existing risk assessment criteria of the storage project developer as a basis for evaluating the severity of the risk scenario.

Table 7-3 illustrates an example five-point severity scale, showing the i) risk severity score from 1 to 5, ii) health and safety impact categories, and iii) environmental impact categories. Like risk likelihood, other rubrics can be used to formulate alternative risk severity scales. For example, as described in Section 4.2, the CARB LCFS CCS protocol uses a three-point scale and assigns risk severity into three ranges: insubstantial, substantial, and catastrophic. Once again, regardless of the rubric that is used, it must be possible to assign the risk scenarios to the different categories using the available impact categories. Table 7-3 provides example definitions of these severity classifications for two risk categories: i) health and safety and ii) environmental impacts. These severity classifications may also be assigned for other risk categories that are of concern to the project developer such as financial impacts or impacts to corporate image/public relations.

**Table 7-3. Example of a Risk Severity Scoring Matrix Using a Five-Point Scale for Consequences to Health and Safety and Environmental Impacts**

| Severity Score | Health and Safety | Environmental Impact |
|---|---|---|
| 5 | Fatality | Permanent environmental damage |
| 4 | Long-term disability | Shutdown/reduction of operation to prevent 5 |
| 3 | Lost time incident | Impact above reportable level |
| 2 | Minor recordable (no lost time) | Greater than measurable impact but less than reportable level |
| 1 | Near miss | Measurable impact |

### *7.3.3 Criticality*

Risk criticality is determined from the combination of the risk likelihood and the severity scores. One of the most common methods for evaluating both scores simultaneously is through risk maps. A risk map is a method for evaluating the quantitative results of the risk analysis by plotting the risk likelihood score on the *y*-axis and the risk severity score on the *x*-axis for each individual risk scenario. Figure 7-4 shows an example risk map combining the previous five-point scales. In this example, the risk criticality uses an additive approach, such that each cell represents the sum of the risk likelihood and risk severity scores. Using this approach, lower-likelihood, lower-severity risks plot in the lower left-hand corner of the risk map, while higher-likelihood, higher-severity risks plot in the upper right-hand corner. The example risk map uses colors to denote different levels of risk criticality and defines four levels and suggested actions:

- Green (2–4): Low
- Yellow (5 and 6): Transition
- Orange (7 and 8): Moderate
- Red (9 and 10): High


Figure 7-4. Example risk map and suggested actions using five-point risk likelihood and severity scales.

The risk maps are frequently the final output of the risk evaluation. At this stage, the risk maps are discussed among the project stakeholders, and the subject matter experts further investigate the higher-ranking risks. After finalizing the risk maps, the storage project developer and manager then move to risk treatment for those risks that have been identified as unacceptable.

Risk maps are very easy to construct and to convey the risk criticality outcomes to stakeholders. The low, transition, moderate, and high classifications can be used to rank the risk scenarios of a storage project and prioritize them for additional investigation, monitoring, or possible mitigation.

The risk scores should account for risk controls that prevent or mitigate the identified risk scenarios. The risk likelihood and severity scores used to evaluate risk criticality would therefore represent the "residual risk," or the difference between the inherent risk and the impact of risk controls, i.e., the remaining risk after controls are implemented. For example, if a risk scenario failure mode includes vertical migration of $CO_2$ or formation brine through cement in deep monitoring wells, then possible controls would be prevention (the cement behind casing that is $CO_2$-resistant, a cement bond log performed to ensure quality cement job to surface, and required cement returns to surface during drilling to ensure cement behind pipe throughout the drill string) and controls (pressure monitors with on-site well monitoring and distributed temperature sensing [DTS] fiber installed along the well casing to monitor temperature). These controls reduce the residual risk and should be reflected in the risk criticality scoring.

There are several alternatives to risk maps for risk evaluation. One of the more popular techniques is the bowtie method (Tucker and others, 2013; Risktec, 2014). The bowtie method provides a graphical illustration of the pathways from causes to consequences for the identified risk scenarios. Illustrating the preventative and mitigation controls against their respective causes and consequences in such a structured way demonstrates that risks are understood and are being controlled, which can highlight gaps in risk control that should be a focus for remedial action (Tucker and others, 2013). The fundamental structure of the bowtie method is provided in Figure 7-5, which shows the top event of release of $CO_2$ in the middle, causes and preventative barriers on the left, and mitigation measures and consequences on the right. The diagram resembles a bowtie, which was the basis for the method name.

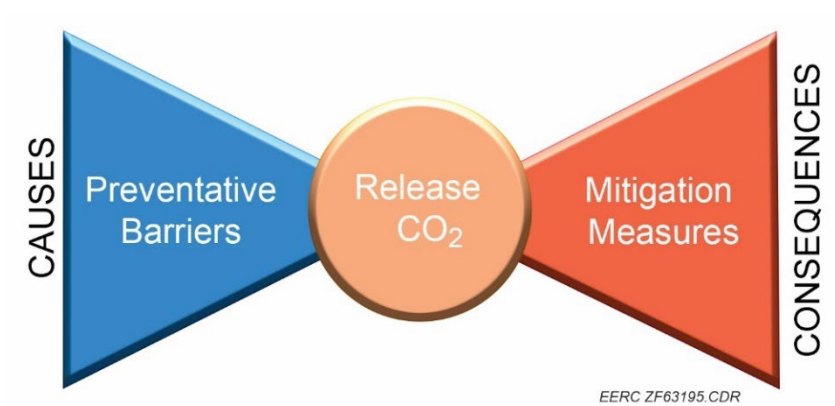


Figure 7-5. Illustration of the bowtie diagram (Risktec, 2014).

### *7.3.4 Evaluating Uncertainty*

Whether using expert judgment from subject matter experts or quantitative methods relying on modeling and simulation, there is uncertainty in the risk likelihood and severity scores, which affects the risk evaluation. The risk team should attempt to quantify the degree of uncertainty attached to the risk criticality scores.

For a storage project in the PCOR Partnership region, the risk team used heat maps to visualize the uncertainty in the risk scores among a relatively large number of respondents who participated in the risk analysis process. Figure 7-6 shows a heat map example that illustrates the respondent risk likelihood (probability) and severity scores for project cost, schedule, scope, and quality.[6] The risks are grouped according to a defined set of common risk categories: Group 1 – capacity, injectivity, and retention; Group 2 – containment (lateral migration); Group 3 – containment (vertical migration via P&A wells); Group 4 – containment (vertical migration via injection wells): Group 5 – containment (vertical migration via producing wells); Group 6 – containment (other)/seismic; and Group 7 – executing fieldwork/other. The heat map provides a visual assessment of the risk category and region that had the greatest number of responses.

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| Risk Grouping | Risk No. | Probability | | | | | | | | Cost | | | | | Schedule | | | | | Scope | | | | | Quality | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 1 | 2 | 3 | 4 | 5 | 1 | 2 | 3 | 4 | 5 | 1 | 2 | 3 | 4 | 5 | 1 | 2 | 3 | 4 | 5 |
| Group 1 | 5 | 3 | 7 | 1 | | | | | | 7 | 2 | | | | 8 | 2 | | | | 5 | 5 | | | | 6 | 4 | | | |
| Group 1 | 8 | 1 | 10 | | | | | | | 8 | 2 | | | | 8 | 2 | | | | 4 | 6 | | | | 6 | 4 | | | |
| Group 2 | 11 | 3 | 7 | | 1 | | | | | 8 | 1 | | | | 9 | 1 | | | | 6 | 4 | | | | 8 | 2 | | | |
| Group 3 | 32 | 2 | 7 | 2 | | | | | | | 7 | 1 | | 1 | | 3 | 4 | 1 | 1 | 1 | 5 | 3 | | 1 | 3 | 4 | 2 | | 1 |
| Group 3 | 38 | 1 | 8 | 2 | | | | | | | 7 | 1 | 1 | | | 3 | 4 | 2 | | 1 | 5 | 3 | 1 | | 2 | 5 | 2 | 1 | |
| Group 3 | 68 | 7 | 3 | 1 | | | | | | 1 | 6 | 1 | | 1 | 1 | 1 | 5 | 1 | 1 | 2 | 4 | 3 | | 1 | 3 | 4 | 2 | | 1 |
| Group 3 | 74 | 7 | 4 | | | | | | | 1 | 6 | 1 | 1 | | 1 | 1 | 5 | 2 | | 2 | 4 | 3 | 1 | | 3 | 4 | 2 | 1 | |
| Group 4 | 44 | 6 | 4 | | | | | | | | 6 | 1 | | 1 | | 1 | 5 | 1 | 1 | 1 | 4 | 3 | | 1 | 2 | 4 | 2 | | 1 |
| Group 4 | 50 | 6 | 4 | | | | | | | | 6 | 1 | 1 | | | 1 | 5 | 2 | | 1 | 4 | 3 | 1 | | 2 | 4 | 2 | 1 | |
| Group 4 | 80 | 2 | 7 | 2 | | | | | | 1 | 6 | 2 | | | | 3 | 5 | 1 | | 1 | 6 | 3 | | | 2 | 6 | 2 | | |
| Group 4 | 86 | 2 | 7 | 2 | | | | | | 1 | 6 | 1 | 1 | | | 4 | 3 | 2 | | 1 | 6 | 2 | 1 | | 2 | 6 | 1 | 1 | |
| Group 5 | 56 | 8 | 3 | | | | | | | 1 | 6 | 2 | | | 1 | 2 | 5 | 1 | | 2 | 4 | 4 | | | 3 | 4 | 3 | | |
| Group 5 | 62 | 8 | 3 | | | | | | | 1 | 6 | 1 | 1 | | 1 | 2 | 4 | 2 | | 2 | 4 | 3 | 1 | | 3 | 4 | 2 | 1 | |
| Group 5 | 92 | 7 | 3 | | | | | | | | 6 | 2 | | | | 2 | 5 | 1 | | 1 | 4 | 4 | | | 2 | 4 | 3 | | |
| Group 5 | 98 | 7 | 3 | | | | | | | | 6 | 1 | 1 | | | 2 | 4 | 2 | | 1 | 4 | 3 | 1 | | 2 | 4 | 2 | 1 | |
| Group 6 | 104 | 9 | 2 | | | | | | | 2 | 5 | 2 | | | 1 | 3 | 4 | 1 | | 2 | 5 | 3 | | | 5 | 2 | 3 | | |
| Group 6 | 105 | 9 | 2 | | | | | | | 2 | 5 | 2 | | | 1 | 3 | 4 | 1 | | 2 | 4 | 3 | | | 4 | 2 | 3 | | |
| Group 6 | 106 | 10 | 1 | | | | | | | 1 | 5 | 3 | | | 1 | 3 | 4 | 1 | | 1 | 5 | 3 | | | 3 | 3 | 3 | | |
| Group 6 | 107 | 7 | 4 | | | | | | | 1 | 4 | 3 | 1 | | | 2 | 5 | 2 | | 1 | 4 | 4 | 1 | | 3 | 2 | 4 | 1 | |
| Group 6 | 110 | 7 | 4 | | | | | | | 1 | 4 | 4 | | | | 2 | 6 | 1 | | 1 | 4 | 5 | | | 3 | 2 | 5 | | |
| Group 6 | 113 | 8 | 3 | | | | | | | 1 | 6 | 2 | | | 1 | 3 | 4 | 1 | | 2 | 4 | 3 | | | 4 | 2 | 3 | | |
| Group 6 | 116 | 7 | 4 | | | | | | | 1 | 5 | 3 | | | | 3 | 4 | 2 | | 1 | 4 | 4 | | | 3 | 2 | 4 | | |
| Group 6 | 119 | 4 | 6 | | | | | | | 1 | 4 | 4 | | | 1 | 2 | 5 | 1 | | 2 | 3 | 3 | 2 | | 4 | 1 | 5 | | |
| Group 7 | 123 | 1 | 2 | 3 | 4 | 1 | | | | 5 | 6 | | | | 5 | 6 | | | | 8 | 2 | | | | 8 | 2 | | | |
| Group 7 | 125 | 3 | 5 | 1 | 1 | | | | | 6 | 3 | | | | 5 | 4 | | | | 9 | | | | | 9 | | | | |
| Group 7 | 126 | 2 | 8 | | | | | | | 7 | 2 | | | | 2 | 7 | | | | 7 | 2 | | | | 7 | 2 | | | |
| Group 7 | 127 | 3 | 6 | | | | | | | 5 | 4 | | | | 2 | 7 | | | | 7 | 2 | | | | 7 | 2 | | | |
| Group 7 | 128 | 1 | 7 | 1 | 1 | | | | | 2 | 6 | 1 | | | 1 | 7 | 1 | | | 5 | 4 | | | | 6 | 2 | 1 | | |
| Group 7 | 129 | 2 | 5 | 3 | 1 | | | | | 3 | 6 | 1 | | | | 10 | | | | 5 | 5 | | | | 4 | 6 | | | |
| Group 7 | 130 | 3 | 5 | 2 | 1 | | | | | 3 | 7 | | | | 1 | 9 | | | | 5 | 5 | | | | 3 | 7 | | | |
| Group 7 | 131 | 5 | 4 | | 1 | | | | | 3 | 4 | 2 | | | 2 | 4 | 3 | | | 3 | 5 | 1 | | | 4 | 2 | 3 | | |

Figure 7-6. Example heat map for risk likelihood and severity scores.

[6] In this example, the risk team decided to use an eight-point risk likelihood scale, which is why the scores range from 1 to 8, and a five-point risk severity scale for cost, schedule, scope, and quality.

Dark blue in the figure represents the highest proportion of responses, whereas lighter blue to white (no color) represents the least responses. For example, the probability scores for the first entry in the table (Group 1, Risk 5) included three respondents who scored a "1," seven respondents who scored a "2," and one respondent who scored a "3." The total number of responses resulted in 11. The dark blue coloring shows the most frequent response (the mode). In addition, the minimum and maximum scores are also visible, which illustrates the range of scores provided.

The heat map allows the risk team to assess the risk scoring in a single figure. Unusually high or low scores should be vetted with the individual respondents to understand their rationale for the score that they provided. Heat maps like the example provided here, or alternative visualization methods, provide useful approaches for conveying uncertainty to the stakeholders and for quantifying the degree of uncertainty attached to the estimated risk criticality scores.

## 8.0 RISK TREATMENT

For each risk scenario in the risk register, after completing the risk analysis and risk evaluation, the risk team should document its rationale to support elimination of identified risk scenarios from further evaluation based on very low likelihood and/or immaterial significance of potential impacts (International Organization for Standardization, 2017). However, if one or more risk scenarios is determined to exceed a threshold risk criticality (as determined when establishing the context for the risk assessment), then the risk scenario must be managed using one of four risk treatment options: 1) acceptance, 2) transference, 3) avoidance, or 4) mitigation (Project Management Institute, 2021).

For ethanol producers who intend to sell the lower-carbon ethanol produced with CCS in the CARB LCFS, the LCFS CCS protocol requires that any risk scenarios that are classified as high risk must be mitigated such that they can be reclassified as medium or low risk (California Air Resources Board, 2017).

The primary result of the risk treatment is to address those risks that are determined to have an unacceptable criticality. A secondary result of the risk treatment is to inform the design of the monitoring and verification program in support of a risk-based monitoring plan.

## 9.0 PCOR PARTNERSHIP RISK MANAGEMENT EXPERIENCE

PCOR Partnership risk management experience includes nearly two decades comprising storage project development activities, guidance documents, regulatory permit applications and hearings, and interactions with authorities responsible for managing financial incentive programs. Collectively, this experience provides unique insights about implementing the risk management process described in Sections 5.0–8.0 on real-world, commercial storage projects. An important learning from the PCOR Partnership risk management experience has been the evolving risk assessment goals and objectives, such that the risk criteria and nature of the risk analysis have changed over time. This evolution is an important learning, because as CCS expands into other

geographic regions with less mature storage project-permitting experience, similar evolutions may occur.

### 9.1 Early Storage Projects

During early storage projects under Phase III of DOE's Regional Carbon Sequestration Partnership (RCSP) Program, many of the risk assessments were "screening-level" and focused on storage system performance and a set of nontechnical risk scenarios that could affect project success. These screening-level risk assessments (conducted circa 2009–2016) were commensurate with the state of knowledge at the time about storage site geology and the evolving regulatory paradigms and societal views of CCS, all of which affected the risk management process.

For storage system performance, project developers were often concerned with injectivity (the rate and pressure at which $CO_2$ can be pumped into the storage unit without fracturing the formation), storage capacity (the amount of $CO_2$ that can be stored within a particular storage complex), and the footprint of the $CO_2$ plume in the storage unit. Site characterization data were more often sparse at this time, resulting in geologic models and reservoir simulations with significant uncertainty about the underlying petrophysical properties of the storage unit (e.g., porosity and permeability) and other factors that affect fluid flow, and these uncertainties propagated into the simulations of injectivity, storage capacity, and $CO_2$ plume. Therefore, broad ranges of input parameters were used to explore storage system performance under assumptions of lower-porosity storage units (pessimistic) and higher-porosity storage units (optimistic) to understand the sensitivity of injectivity, storage capacity, and $CO_2$ plume to these inputs. The results were used to bracket pessimistic and optimistic end members that provided insights to the project developers about the risk of the storage project achieving the design performance standards (e.g., 2 Mt of $CO_2$ per year for 25 years, or 50 Mt of $CO_2$ stored) or maintaining the $CO_2$ plume within a specified areal extent. Recognizing that protection of USDWs was a major tenet of the UIC program, project developers were also concerned with vertical containment of the injected $CO_2$ and formation fluids (brine). Again, site characterization data were sparse, and the risk analyses largely relied on published regional data rather than site-specific characterization data to evaluate potential migration pathways that might exist in the primary seal. Finally, with known induced seismicity related to underground injection activities first observed in the 1960s at the Rocky Mountain Arsenal near Denver and the increase in earthquake activity in Oklahoma since 2009, project developers were concerned about the potential for induced seismicity from the planned storage project. Once again, the risk analyses largely relied on published regional data rather than site-specific characterization data to quantify risk scenarios about the presence of faults and the likelihood of induced seismicity. In addition to providing coarse estimations about a set of storage system performance risk scenarios, these early risk assessments also emphasized the need for site-specific data from well logs, rock core, and 3D seismic surveys to i) constrain geologic model inputs and reduce uncertainty in the reservoir simulation results, ii) reduce uncertainty about the presence of potential pathways for fluid migration from the storage unit into overlying geologic units of the storage complex, and iii) reduce uncertainty about the presence of known faults that could be affected from the storage project.

For nontechnical risks, the status of CCS projects at the time contained significant uncertainty as North Dakota Class VI primacy was not granted until April 2018 and Wyoming

Class VI primacy was not granted until October 2020—after Phase III of DOE's RCSP Program. Therefore, although the EPA Class VI program was established, project developers were cautious about public opinion, CCS regulations, or the ability to adequately secure rights/access to pipelines and/or injection sites. These concerns affected risk judgments and drove conservative risk scoring for nontechnical risks, many of which were viewed as significantly greater threats to project success than storage system performance.

The risk assessments for earlier storage projects were more analogous to "go/no-go" decision points—providing a formal process to elicit expert opinion about a set of risk criteria from which project developers could make judgments about progressing further down the storage project life cycle. The risk likelihood scores were like the ones presented in this document—discrete scores used to estimate the probability of occurrence over a specified time frame. However, the criteria used to analyze risk severity generally went beyond health, safety, and environment and included other potential risk impacts like cost, project schedule, permitting/compliance, and corporate image/public relations. The risk scoring for earlier storage projects was characterized by uncertainty (large ranges between the minimum and maximum risk scores) and conservatism (risk scores that were biased high in likelihood, severity, or both). Despite these challenges, the risk assessments for these earlier storage projects concluded that there were no potential risk scenarios that would prevent the storage complexes from serving as commercial-scale storage sites and projects progressed toward further investigation.

### 9.2 Recent Storage Projects

More recent storage projects (post-2020) have had the benefit of primacy (in North Dakota and Wyoming), subsurface pore space policy in North Dakota (NDCC Chapter 47-31), and the body of research that was conducted through the RCSP Program, CarbonSAFE Initiative, and industry efforts, which collectively reduced uncertainty about regulations and commercial-scale deployment of safe and durable geologic storage of captured $CO_2$.

The focus of risk assessments for more recent storage projects has been on permitting Class VI wells (or storage facilities in North Dakota), approval of MRV plans, and pathway certification of CI values to acquire credits through the CARB LCFS low-carbon fuel market (specific to ethanol produced with CCS). These risk assessments have focused on regulatory compliance and potential risk scenarios that affect health, safety, and environment, rather than nontechnical risks like public opinion or CCS regulations or other potential risk impacts like cost, project schedule, permitting/compliance, and corporate image/public relations. The risk analyses have benefitted from site-specific characterization data and therefore increased understanding about the storage unit and broader storage complex. As a result, the risk scoring for recent storage projects has been characterized by less uncertainty (smaller differences between the minimum and maximum risk scores) and more optimistic risk scores (lower likelihood, severity, or both). In addition, the risk scoring has evolved from earlier risk assessments that relied more heavily on expert judgment, which can be subjective and prone to bias and variation, toward more quantitative techniques that incorporate robust geologic modeling and reservoir simulation, geochemical modeling, geomechanical modeling, and additional computational modeling tools for the broader storage site.

Despite the above-described evolution and the move toward more quantitative approaches, the risk analysis portion of the risk assessment remains challenging and integrating across disciplines continues to be one of the most time-consuming elements of the risk management process. PCOR Partnership experience has demonstrated the value of managing the risk analysis in concert with the storage project regulatory permit requirements, which drive the geologic exhibits and site characterization needs for the permit and the risk analysis. For example, for storage projects located in North Dakota, each of the permit applications has included a table in the appendix documenting the SFP requirements, including: i) permit item, ii) NDAC reference, iii) requirement regulatory summary (a brief synopsis of the permit requirement), iv) SFP reference (section and page number), and v) figure/table number and description (Department of Mineral Resources, 2022). Review of this table of regulatory permit requirements early and often with the project team helps ensure continuity among the different disciplines working on the storage project. In conjunction with these regulatory requirements, identifying Gantt chart dependencies is crucial for the risk analysis. For example, well drilling, acquisition of well logs and rock core samples, laboratory measurements conducted on the rock core samples, and petrophysical analysis of the well logs and laboratory measurements are all precursors to inputting the site-specific geologic data into the project geologic model. In addition, the acquisition, processing, and interpretation of a 3D seismic survey are also potential precursors to building the project geologic model. In turn, the geologic model is a prerequisite for reservoir simulation. Each of these activities must occur prior to generating reservoir simulations of pressure buildup or $CO_2$ plume forecasts for the storage unit. Therefore, the project schedule must account for the dependencies of preceding tasks to allocate sufficient time to the risk team to conduct the risk analysis. The current document is constructed to help guide storage project developers through the risk management process to help facilitate this type of coordination and project management.

### 9.3 Concluding Remarks

This document provides a recommended risk management process for storage projects. The risk management process integrates existing guidance documents, federal and specific state-level regulatory requirements, and additional requirements imposed on project developers if they choose to pursue the Section 45Q credit and/or low-carbon fuel market financial incentive programs. The recommended risk management process and suggestions for techniques to establish the context and conduct risk assessment and risk treatment activities can be used or, if warranted, readily adapted by most storage project developers to satisfy their risk management needs.

The risk management process integrates nearly two decades of risk management experience within the PCOR Partnership. However, there is no one-size-fits-all risk management approach for storage projects. Instead, risk management is about having a detailed process in place, adhering to that process throughout the project life cycle, and adapting the process depending on site-specific conditions, applicable regulatory requirements, and any additional requirements imposed by pursuing one or more financial incentive programs. Risk assessment is an iterative process composed of identifying, analyzing, and evaluating individual project risks, recognizing that the relevant risks can change for a specific storage project as it matures and moves from one phase to the next (e.g., from site screening, to feasibility, to commercial operation, to closure/postclosure). With each phase of project development, additional data become available and the uncertainty associated with the results of the risk assessment decreases over time. Consequently, the project

phase affects the nature of available information and the degree of stakeholder knowledge about the potential project risks. The risk management process must therefore be developed based on the current level of project understanding and the commensurate site characterization data, modeling, and simulation results.

This document encompasses the current body of knowledge and best practices for applying a standardized risk management approach for storage projects. These best practices will continue to evolve and be refined over time as commercialization of the $CO_2$ storage industry proceeds.

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# APPENDIX A

# GUIDANCE DOCUMENT SUMMARIES

# GUIDANCE DOCUMENT SUMMARIES

## A.1 ISO 31000 RISK MANAGEMENT – PRINCIPLES AND GUIDELINES (2009)

International Organization for Standardization (ISO) 31000 summarizes the general risk management principles, framework, and processes that can be applied to almost any type of project. ISO 31000 was intended to meet the needs of a wide range of stakeholders, including i) those responsible for developing risk management policy within their organization; ii) those accountable for ensuring that risk is effectively managed within the organization as a whole or within a specific area, project, or activity; iii) those who need to evaluate an organization's effectiveness in managing risk; and iv) developers of standards, guides, procedures, and codes of practice that, in whole or in part, set out how risk is to be managed within the specific context of these documents.

In addition to recommendations on monitoring and review of the risk management process, a significant contribution of ISO 31000 is the risk management process, which includes five steps and has been carried forward through most subsequent documents pertaining to risk management and storage projects:

- **Establish the context:** The context for the risk management describes the objectives, defines the external and internal parameters to be considered when managing risk, and sets the scope and risk criteria for the remaining process.

- **Risk identification:** The risk identification process identifies sources of risk, areas of impacts, events (including changes in circumstances), and their causes and potential consequences. The aim of this step is to generate a comprehensive list of risk scenarios based on those events that might delay, degrade, or prevent the achievement of project objectives.

- **Risk analysis:** The risk analysis involves consideration of the causes and sources of risk, their consequences, and the likelihood that those consequences can occur. Risk analysis provides an input to risk evaluation and to decisions on whether risks need to be treated.

- **Risk evaluation:** The risk evaluation is used to assist in making decisions, based on the outcomes of risk analysis, about which risks need treatment and the priority for treatment implementation.

- **Risk treatment:** Risk treatment involves selecting one or more options for modifying risks; reducing their likelihood, severity, or both; and implementing those options.

The risk management principles, framework, and processes outlined in ISO 31000 formed the basis of most risk assessments conducted for storage projects prior to 2017. After 2017, ISO 27914 (2017) supplanted ISO 31000 because ISO 27914 is tailored specifically to storage projects. However, the risk management process established in ISO 31000 is identical to the risk management process in ISO 27914.

## A.2 CSA Z741-12 – GEOLOGICAL STORAGE OF CARBON DIOXIDE (2012)

The standards established under Canadian Standards Association (CSA) Z741-12 were prepared by the Technical Committee on Geological Storage of Carbon Dioxide, which was a joint Canada–U.S. Technical Committee, under the jurisdiction of the Strategic Steering Committee on Business Management and Sustainability. The standards published under CSA Z741-12 i) establish requirements and recommendations for the geological storage of carbon dioxide to promote environmentally safe and long-term containment of $CO_2$ in a way that minimizes risks to the environment and human health; ii) are primarily applicable to saline aquifers and depleted hydrocarbon reservoirs, but this does not preclude their application to storage associated with hydrocarbon recovery; iii) include, but are not limited to, the safe design, construction, operation, maintenance, and closure of storage sites; and iv) provide recommendations for the development of management documents, community engagement, risk assessment, and risk communication.

The primary sections in CSA Z741-12 include i) management systems; ii) site screening, selection, and characterization; iii) risk management; iv) well infrastructure development; v) monitoring and verification; and vi) closure. These sections are incorporated into ISO 27914 and are therefore discussed in detail in Section 2.7 of the white paper.

The risk management process summarized in CSA Z741-12 mirrors the ISO 31000 process, with greater details about establishing context; risk assessment (risk identification, analysis, and evaluation); risk treatment; and methods for monitoring, reviewing, and documenting the risk management process. CSA Z741-12 outlines several categories of elements that should be included in the risk identification:

- **Natural environment:** i) atmosphere, ii) surface and marine environment, and iii) biosphere and geosphere.

- **Regional natural resources:** i) groundwater, ii) hydrocarbon resources, iii) mineral resources, iv) coal seams, and v) geothermal energy extraction potential.

- **Infrastructure and facilities:** i) surface (buildings, transportation corridors, power distribution lines, oil and gas production and processing facilities, and water reservoirs) and ii) subsurface (wells, mines, waste repositories, gas storage operations, and acid gas disposal sites).

- **Human culture:** social context local to the project, including people and culture (demographic and historical factors that can influence how the project will affect, be viewed by, and be participated in by the local population).

- **Legal and regulatory environment and industry best practices:** i) relevant legislation, regulations, and directives; ii) codes, standards, protocols, and guidelines that can guide risk management and facilitate demonstration of compliance with legislation, regulations, and directives; and iii) manuals that document current industry practices and can guide cost-effective implementation of $CO_2$ storage technology in accordance with industry best practices.

- **Project operator and subcontractors:** i) economic ownership of, contributions to, and liabilities for each component in the carbon capture and storage (CCS) system; ii) specification of the project operator's responsibility and the limits on its authority, including its risk management policies and guidelines; iii) the experience of the organizations involved in the project with regard to managing risk through the development and implementation of a comprehensive risk management plan; iv) delegation of responsibilities, functions, and relationships among organizations and individuals to ensure diligent and timely execution of project tasks; and v) available resources, capacities, and capabilities for performing isolated project functions and for integration across all project components in the CCS system.

CSA Z741-12 recommends implementing the risk management process during the initial site-screening, selection, and characterization periods and iteratively repeating the process in a consistent, transparent, and traceable manner throughout the project life cycle.

The standards put forth in CSA Z741-12 provided one of the earliest guidance documents for storage projects and influenced later guidance documents and project planning. CSA Z741-12 remains a valuable resource for risk management applied to storage projects.

## A.3 PCOR PARTNERSHIP BEST PRACTICES MANUAL FOR SUBSURFACE TECHNICAL RISK ASSESSMENT OF GEOLOGIC $CO_2$ STORAGE PROJECTS (Azzolina and others, 2017)

From 2003 to 2017, the Plains $CO_2$ Reduction (PCOR) Partnership conducted a series of risk assessments for storage projects as part of its activities under the Regional Carbon Sequestration Partnership (RCSPs)—a nationwide network of seven regions created by the U.S. Department of Energy (DOE) to help determine and implement the technology, infrastructure, and regulations most appropriate to promote carbon storage in different regions of the United States and portions of Canada. This experience included two Phase III demonstration projects (large-scale projects with a target of storing 1 million tonnes [Mt] or more of $CO_2$) involving $CO_2$ storage in a deep saline formation and associated $CO_2$ storage incidental to $CO_2$ enhanced oil recovery (EOR). In addition to the Phase III demonstration projects, there were many completed and ongoing CCS-related projects within the PCOR Partnership region. Collectively, this experience was used to develop a best practice for conducting risk assessments for implementing storage projects, with a focus on subsurface technical risks related to injection into a storage unit.

This best practices manual identified the key elements comprising a risk assessment for a storage unit and defined important risk management terminology and technical factors that are unique to the geologic storage of $CO_2$. It also provides best practices for implementing a risk assessment based on the ISO 31000 risk management framework and lessons learned from conducting risk assessments for storage complexes within the PCOR Partnership region. Case studies of these real-world examples, which highlight key aspects of applying the risk assessment process to storage projects, are provided to support the proposed best practices.

Several attributes of the best practices manual that are specific to risk management applied to storage projects include:

- Emphasis of the adaptive management approach (AMA) on deploying storage projects, which integrates site characterization, modeling, simulation, and monitoring measurements into risk assessment efforts over the development phases of the project.

- Illustration of a functional model of the storage project, which defines the storage system boundaries, the system components that will be evaluated in the risk assessment, and the functions of these components. The functional model helps identify potential failure modes (where the storage system might fail) and failure causes (how the storage system might fail), which together lead to a set of potential project-specific risks.

- A common set of storage system performance risk categories that should be considered for storage projects: i) storage capacity, ii) injectivity, iii) lateral and vertical containment of subsurface fluids (e.g., $CO_2$, formation brines, and/or oil), and iv) induced seismicity.

- Illustrations of how to incorporate geologic models and reservoir simulations into the risk assessment to account for the limited site-specific subsurface characterization data.

- Example risk criteria for risk likelihood (probability) and risk severity (impact), with methods for risk criticality mapping and evaluation.

- Demonstrations of quantifying uncertainty in the risk-scoring criteria from subject matter experts, including probabilistic methods for risk evaluation.

The best practices manual encompassed the current body of knowledge for conducting risk assessments for storage projects. The best practice workflow extended the framework of ISO 31000 and integrated key concepts from CSA Z741-12 and over a decade of PCOR Partnership project experience. However, the document predated ISO 27914 and, therefore, does not incorporate all the information provided in ISO 27914.

## A.4 NETL BEST PRACTICES – RISK MANAGEMENT AND SIMULATION FOR GEOLOGIC STORAGE PROJECTS (2017)

The DOE National Energy Technology Laboratory (NETL) presents a framework for risk management that incorporates the knowledge gained through the experiences of the RCSPs. NETL includes best practices that are intended to help project developers and other stakeholders assess and manage storage project risks. As suggested by the title, the manual includes best practices for both risk management and numerical simulation.

The best practices for risk management recommend assessing risk by estimating the probability of an event that results in adverse impact and quantifying the magnitude of those adverse impacts or consequences. NETL describes qualitative, semiquantitative, and quantitative tools to determine the probability and magnitude of a given risk scenario during the risk analysis process, with overall risk defined as the sum of the products of individual risk probabilities and impacts. NETL overarching best practices for a comprehensive risk management program include the following:

- Integrate risk management into project design and implementation
- Identify site-specific project risk scenarios
- Characterize and rank the probability and impact of project risk scenarios
- Develop and implement risk management plans (RMPs)
- Complete periodic updates to the risk analysis

The best practices for numeric simulation provide an overview of background information on the roles and types of numeric simulation and then outline the following overarching best practices for using numeric simulation to help manage geologic storage projects:

- Determine simulations needs
- Determine required physical processes, scale, and complexity
- Identify specific simulators and appropriate software
- Gather input data and develop numeric models
- Integrate numeric simulations with other project elements

The NETL document is a useful resource for risk management applied to storage projects. In addition, it provides a comprehensive overview of simulation and other computational methods that site developers can use to support risk analysis, with multiple case studies illustrating work performed by the RCSPs.

## A.5 IEAGHG TECHNICAL REPORT (2018)

The International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) was formed in 1991. Currently, IEAGHG is supported by its 37 members, comprising 18 contracting parties and 19 multinational sponsors. Funding for IEAGHG is provided by the members (International Energy Agency Greenhouse Gas R&D Programme, 2022). IEAGHG studies and evaluates technologies that can reduce GHG emissions derived from the use of fossil fuels. Their main activities are to i) evaluate technologies aimed at reducing GHGs; ii) help facilitate the implementation of potential mitigation options; iii) disseminate the data and results from evaluation studies; and iv) help facilitate international collaborative research, development, and demonstration activities.

IEAGHG coordinates several international research networks. The networks bring together the expertise and experience of organizations at the forefront of research, development, and demonstration into GHG mitigation technologies. The Risk Management Network includes three subject areas: i) data management and risk analysis, ii) regulatory engagement, and iii) environmental impacts. Since 2005, IEAGHG has published multiple summary reports of its Risk Management Network meetings, beginning with the launch meeting August 23–24, 2005, in Utrecht, Netherlands, and ending with the meeting June 18–22, 2018, at the Energy & Environmental Research Center (EERC) in Grand Forks, North Dakota. The next Risk Management Network meeting will be hosted in Pau, France, on a date to be confirmed. A full list of Risk Management Network technical publications may be found on the IEAGHG website at https://ieaghg.org/networks/risk-management-network.

IEAGHG combined the IEAGHG Modeling Network with the Risk Management Network and generated a summary report for the theme of the meeting, which was how advances in modeling and risk management improve pressure management, capacity estimation, leakage detection, and the prediction of induced seismicity. The document summarizes the key outcomes of each of the meeting's 14 sessions:

- Modeling capacity at reservoir and formation scale
- Upscaling core to reservoir: link to predicting $CO_2$ at reservoir scale
- Untraditional reservoirs and modeling risk
- Modeling and pressure management in the near-wellbore environment
- Leakage: modeling and monitoring
- Bayesian modeling in risk assessment and management
- Approaches for geologic $CO_2$ storage risk assessment in early project stages: constraining uncertainty to inform decisions
- Risk management approaches for fault properties and induced seismicity
- Forecasting and managing risk at $CO_2$ surface facilities: likelihood and mechanistic modeling
- Active pressure management/natural equilibration at formation and basin scale
- Modeling and risk assessment: industry and regulatory perspectives
- Conformance and concordance
- The way forward: conclusions and recommendations

The IEAGHG 2018 Technical Report provides a thorough resource for modeling, simulation, and other technical approaches that stakeholders can use to quantitatively analyze potential risk scenarios for storage projects.

## A.6 EPA GUIDANCE DOCUMENTS

The U.S. Environmental Protection Agency (EPA) provides several final Class VI guidance documents on its website (www.epa.gov/uic/final-class-vi-guidance-documents) along with summaries of its responses to public comments received on draft versions of the guidance documents (U.S. Environmental Protection Agency, 2022). These documents were finalized between 2010 and 2018, and include, in chronological order:

- *Research and Analysis in Support of UIC Class VI Program Financial Responsibility Requirements and Guidance* (U.S. Environmental Protection Agency, 2010).

- *Underground Injection Control (UIC) Program Class VI Well Construction Guidance* (U.S. Environmental Protection Agency, 2012a).

- *Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance* (U.S. Environmental Protection Agency, 2012b).

- *Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance* (U.S. Environmental Protection Agency, 2013d).

- *Underground Injection Control (UIC) Program Class VI Well Site Characterization Guidance* (U.S. Environmental Protection Agency, 2013c).

- *Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* (U.S. Environmental Protection Agency, 2013b).

- *Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells* (U.S. Environmental Protection Agency, 2013a).[1]

- *Underground Injection Control (UIC) Program Class VI Primacy Manual for State Directors* (U.S. Environmental Protection Agency, 2014).

- *Underground Injection Control (UIC) Program Class VI Well Recordkeeping, Reporting, and Data Management Guidance for Owners and Operators* (U.S. Environmental Protection Agency, 2016a).

- *Underground Injection Control (UIC) Program Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance* (U.S. Environmental Protection Agency, 2016b).

- *Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors* (U.S. Environmental Protection Agency, 2018).

Across the above guidance documents, there is no stand-alone risk management guidance document and, therefore, no prescriptive risk management process recommended by EPA. However, the concepts of risk management, risk scenarios, and risk assessment are contained within many of the documents in the context of the broader site characterization and monitoring requirements throughout the storage project life cycle. In general, examples where risk is referenced in EPA final Class VI guidance documents discuss insurance (financial responsibility requirements), the emergency and remedial response plan, and testing and monitoring requirements. Additional insights for risk management are provided in the information about transitioning Class II wells (formally defined at 40 Code of Federal Regulations [CFR] 144.6 as wells into which fluids associated with oil and gas production are injected, including carbon dioxide injected for the purpose of enhanced recovery) to Class VI wells (formally defined at

[1] EPA (2013d) was never finalized and remains a draft. However, some of the information about transitioning Class II wells to Class VI wells is found in 40 CFR Parts 124, 144, 145, 146, and 147.

40 CFR 146.81 et seq. as wells specifically for the injection of carbon dioxide for the purpose of geologic sequestration).

For example, EPA (2010) states:

> "Insurers generally require a risk assessment prior to issuing a policy. Owners or operators generally pay for the risk assessment to be conducted. The cost of insurance is a premium established by the policy underwriter's assessment of site-specific risks. The price reflects the likelihood of a range of possible claims (U.S. Environmental Protection Agency, 2010)."

Financial responsibility requirements are beyond the scope of this document; however, the outcomes of the risk assessment provide inputs to the storage project financial responsibility requirements.

With respect to the emergency and remedial response plan, EPA (2012b) states:

> "The Class VI Rule does not identify the specific elements of the Emergency and Remedial Response Plan. U.S. EPA envisions that each plan will be site-specific and risk-based, and depend on a variety of factors, including the nature of any movement of $CO_2$ or other fluids, the presence of USDWs [underground sources of drinking water], and what, if any, impacts could result from $CO_2$ movement into unintended zones, $CO_2$ leaks, or ground water or surface water contamination (U.S. Environmental Protection Agency, 2012b)."

EPA (2012b) provides additional information about the types of information to be included in the potential risk scenarios. For example, EPA recommends that the plan consider, for each identified resource or infrastructure element potentially at risk, any potential adverse events that may occur (e.g., a well blowout, unanticipated/emergency corrective action on deficient wells in the area of review [AOR], equipment failure, fluid movement, metals leaching, contamination of the water supply, earthquakes/land deformation, or $CO_2$ seeps into buildings that endanger occupants). The emergency and remedial response plan may also consider whether the likelihood of the event is high, medium, or low and tier the actions in the plan accordingly. The language in EPA (2012b) therefore implies a risk assessment that identifies potential risk scenarios ("potential adverse events that may occur") and analyzes the risk scenarios for the likelihood of occurrence and potential impact on groundwater or surface water.

The testing and monitoring requirements described in EPA guidance place a significant emphasis on the AOR and detecting potential risks that may lead to the endangerment of USDWs (U.S. Environmental Protection Agency, 2013d).

In addition, 40 CFR 144.19(a) requires that owners or operators that are injecting $CO_2$ for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI permit when there is an increased risk of endangerment to USDWs compared to Class II operations. Although the document was never finalized, EPA (2013d) enumerates several risk factors for consideration in evaluating risk of endangerment to USDWs:

- Increase in reservoir (storage unit) pressure
- Increase in $CO_2$ injection rates
- Decrease in reservoir production rates

- Distance between the injection zone (storage unit) and the USDWs
- Suitability of Class II AOR delineation
- Quality of abandoned well plugs
- Anticipated recovery of injected $CO_2$ at cessation of injection
- Source and properties of injected $CO_2$
- Additional factors determined by the UIC program director, which include but are not limited to:
  - Migration of $CO_2$ into regions known to exhibit faults, fractures, or additional migration pathways.
  - Evidence of surface leakage of $CO_2$ or constituents mobilized by the injection process.
  - Increased risk of induced geomechanical activity, including fault slippage, because of increased injection rates and pressures.

  These risk factors shed light on several aspects of the storage project design and storage complex characterization that could affect the potential risk of endangerment to USDWs.

Beyond EPA final Class VI guidance documents, insights about potential risk scenarios for storage projects are found in early guidance documents under the UIC program. Specifically, EPA's *Study of the Risks Associated with Class I Underground Injection Wells* (U.S. Environmental Protection Agency, 2001) is useful, given that the 40 CFR Part 148 requirements for Class I restricted hazardous waste wells were the starting point for the Class VI well regulations. EPA (2001) was prepared in consultation with a panel of experts on Class I deep well injection practices and emphasizes two potential pathways through which injected fluids can migrate to USDWs: 1) failure of the well or 2) improperly plugged or completed wells or other pathways near the well. The document enumerates examples of well malfunction scenarios and describes siting and construction requirements to minimize the risk of endangerment to USDWs.

The set of EPA final Class VI guidance documents and early guidance documents under the UIC program provide valuable resources for storage project developers. While these documents do not provide specific guidance for conducting risk management on storage projects, they do emphasize the importance of the AOR and potential risks to the endangerment of USDWs. EPA's focus on potential risks to the endangerment of USDWs is consistent with the fact that the Safe Drinking Water Act (SDWA) establishes requirements and provisions for the UIC program under the Class VI rule of the UIC program – Wells Used for Geologic Sequestration of $CO_2$. Additional details about regulatory requirements are discussed in Section 3.0 of the white paper.

## A.7 ISO 27914 CARBON DIOXIDE CAPTURE, TRANSPORTATION, AND GEOLOGICAL STORAGE – GEOLOGICAL STORAGE (2017)

ISO 27914 provides recommendations for the safe and effective storage of $CO_2$ in subsurface geologic formations through all phases of a storage project life cycle. The document summarizes key input needs for storage project elements, which mirror many of the standards provided in CSA Z741-12, and include the following:

- **Management systems:** The management systems outline the scope of activities, project boundaries, and management principles to help ensure that the storage project operator meets site-specific project and regulatory needs.

- **Site screening, selection, and characterization:** The site screening, selection, and characterization lists eight specific elements for site characterization and provides detailed descriptions about the data needs for each of the eight elements:
  - Geological and hydrogeological characterization of the storage unit
  - Characterization of confining strata
  - Baseline geochemical characterization
  - Baseline geomechanical characterization
  - Well characterization
  - Modeling
  - Flow modeling (reservoir simulation)
  - Geochemical modeling

- **Risk management:** A detailed risk management process is provided, which builds on the framework established in ISO 31000 and incorporates learnings from CSA Z741-12 to provide significantly greater detail about considerations for establishing the context and for the risk assessment (risk identification, risk analysis, and risk evaluation). The key elements of a risk treatment plan are also provided for each identified risk scenario that has not been eliminated from further evaluation. The goal of the risk treatment plan is to ensure that risk is reduced to and maintained at an acceptable level.

- **Well infrastructure:** The materials, design, and construction of wells related to geological storage of $CO_2$ are based on principles and methods developed by the oil and gas industry. Processes and procedures associated with well infrastructure, including material requirements, design, and construction, are thoroughly described within existing industry standards and in industry-recommended practice documents.

- **$CO_2$ storage site injection operations:** The primary objective of $CO_2$ storage site injection operations is to inject a $CO_2$ stream into the storage unit at the required rate over the planned duration of the storage project to store the target mass of $CO_2$ in a safe and efficient manner. The recommended operations associated with the subsurface injection of fluids are based on principles and methods developed by the oil and gas industry that are described within existing industry standards and in industry-recommended practice documents.

- **Monitoring and verification:** The primary purposes of monitoring and verification (M&V) are i) to assist in managing health, safety, and environmental risks and ii) to assess storage performance. M&V activities are an integral part of risk management, enabling an assessment of the storage project performance and providing confidence that $CO_2$ emission reductions are effective.

- **Site closure:** The purpose of this section is to identify criteria for site closure that, if met, provide a high degree of confidence that injected $CO_2$ will be retained within the storage unit and that risks associated with the project are de minimis and to outline the requirements of a process that will allow the project operator to demonstrate compliance with these criteria. At the end of the closure period, the storage facility should be suitable for other uses and no need for future interventions should be anticipated.

The ISO 27914 risk management framework, terminology, storage project elements, and contents are consistent with ISO 31000 and CSA Z741-12. ISO 27914 provides the foundation of the risk management process and recommendations incorporated into Sections 5.0, 6.0, and 7.0 of the white paper, which closely follow ISO 27914 Section 6.0 (Risk Management), with additional clarification assembled from PCOR Partnership project experience.

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# APPENDIX B

# WDEQ CLASS VI RISK ACTIVITY TABLE

**WDEQ CLASS VI RISK ACTIVITY TABLE**

(adapted from Wyoming Department of Environmental Quality, 2021, Chapter 24: Class VI Injection Wells and Facilities Underground Injection Control Program: Reference Number 020.0011.24.10052021, Appendix A, effective October 5, 2021)

| | Major Risk (Feature, Event, or Process) |
|---|---|
| **1.0** | **Mineral Rights Infringement (Trespass)** |
| 1.1 | Leakage migrates into mineral zone or hydraulic front impacts recoverable mineral zone; causes may include plume migration different than modeled. |
| 1.2 | Postinjection discovery of recoverable minerals. |
| 1.3 | New technology (or economic conditions) enables recovery of previously uneconomically recoverable minerals. |
| 1.4 | Act of God (e.g., seismic event). |
| 1.5 | Formation fluid impact because of $CO_2$ injection. |
| 1.6 | Address contributing causes 3.1, 3.2, 3.3, 3.5, 4.3, and 4.4 |
| **2.0** | **Water Quality Contamination** |
| 2.1 | Leakage of $CO_2$ outside permitted area. |
| 2.2 | Leakage of drilling fluid contaminates potable water aquifer. |
| 2.3 | Rock/acid water (i.e., geochemistry) interaction contaminates potable water by carryover of dissolved contaminants. |
| 2.4 | Act of God (e.g., seismic event). |
| 2.5 | Formation fluid impact due to $CO_2$ injection. |
| 2.6 | See also contributing causes 3.1, 3.2, 3.3, 3.5, 4.3, and 4.4 |
| **3.0** | **Single Large Volume $CO_2$ Release to the Surface – Asphyxiation/Health/Ecological** |
| 3.1 | Overpressurization (i.e., induced). |
| 3.2 | Caprock/reservoir failure. |
| 3.3 | Well blowout (e.g., at surface or bore failure below ground), includes monitoring wells; causes could include seal failure (e.g., well, drilling, or injection equipment). |
| 3.4 | Major mechanical failure of distribution system or storage facilities above ground or below ground (i.e., near the surface). |
| 3.5 | Orphan well failure (e.g., well not identified prior to injection). |
| 3.6 | Sabotage/terrorist attack (e.g., on surface infrastructure). |
| 3.7 | Act of God (e.g., major seismic event) |

Continued . . .

| | Major Risk (Feature, Event, or Process) |
|---|---|
| **4.0** | **Low-Level $CO_2$ Release to Surface – Ecological Damage Because Of Low-Level Releases; Potential Asphyxiation of Human or Ecological Receptors** |
| 4.1 | Overpressurization (i.e., induced). |
| 4.2 | Caprock/reservoir failure (e.g., plume migrates along fault line/fissure to surface). |
| 4.3 | Incomplete geological seal (e.g., inaccurate characterization of sub-surface geology). |
| 4.4 | Well seal failure (e.g., well, drilling, or injection equipment), including monitor wells. |
| 4.5 | Mechanical failure of distribution system or storage facilities above or below ground (e.g., near surface). |
| 4.6 | Orphan wells (e.g., well not identified prior to injection). |
| 4.7 | Induced seismicity leading to leakage. |
| 4.8 | Act of God (e.g., seismic event) |
| **5.0** | **Storage Rights Infringement ($CO_2$ or other entrained contaminant gases) – Form of Mineral Rights Infringement** |
| 5.1 | Leakage migrates into adjacent pore space; causes may include plume migrates faster than modeled. |
| 5.2 | Postinjection decision (e.g., due to new technology or changed economic conditions) to store gas in adjacent pore space. |
| 5.3 | Acts of God affecting storage capacity of pore space. |
| 5.4 | Formation fluid impact due to $CO_2$ injection. |
| 5.5 | Will also require primary contributing causes 3.1, 3.2, 3.3, 3.5, 4.3, and 4.4 |
| **6.0** | **Modified Surface Topography (subsidence or uplift) Resulting in Property/Infrastructure Damage** |
| 6.1 | Induced Seismicity – Pressure from geochemistry induced reactivation of historic fault or dissolution of material caused by subsidence. |
| 6.2 | Formation fluid impact due to $CO_2$ injection. |
| **7.0** | **Entrained Contaminant (Non-$CO_2$) Releases** |
| 7.1 | Change in $CO_2$ composition/properties (e.g., concentration of contaminate in $CO_2$ supply increases). |
| 7.2 | Microbial activity initiated by injection process or composition. |
| 7.3 | Will also require primary contributing causes 3.1, 3.2, 3.3, 3.5, 4.3, and 4.4 |
| **8.0** | **Accidents/Unplanned Events (Typical Insurable Events)** |
| 8.1 | Surface infrastructure damage. |
| 8.2 | Saline water releases from surface storage impoundment. |

# APPENDIX C

# EXAMPLES OF QUANTITATIVE METHODS TO SUPPORT RISK ANALYSIS

# EXAMPLES OF QUANTITATIVE METHODS TO SUPPORT RISK ANALYSIS

## C.1 GEOLOGIC MODELING AND RESERVOIR SIMULATION

Geologic modeling and reservoir simulation provide the core sets of tools for understanding the behavior of carbon dioxide ($CO_2$) and pressure in the storage unit in response to $CO_2$ injection. A typical geologic (or static) model to support simulation of injection will depict the storage unit, primary seal, and relevant structural data. The geologic model refers to the collation of subsurface data into a three-dimensional (3D) representation of the geology and hydrogeology of the storage unit and at least a portion of the primary seal. The basis for model construction is a combination of measured subsurface characteristics and geological interpretation. Reservoir simulation refers to the process of using specialized software to create quantitative predictions of the dynamic effects of $CO_2$ injection, including migration of $CO_2$ and other formation fluids, pressure and temperature behavior, and the long-term fate of injected $CO_2$ within the modeled volume (Bosshart and others, 2019).

Reservoir simulation is used to simulate an injection scenario: for example, two injection wells completed in a storage unit injecting 2 million tonnes (Mt) of $CO_2$ per year for 25 years and then an additional 100 years of postinjection. The results of the reservoir simulations provide insights about pressure buildup and $CO_2$ plume extent in the storage unit over the operational phase (e.g., 25 years) and the postinjection and site closure (PISC) phase (e.g., 100 years), which are critical inputs to the risk analysis (see Figures 1-1 and 1-2 of the white paper—a significant portion of the risk management process applied to storage projects is to evaluate risk scenarios related to the interplay of the $CO_2$ plume, area of review [AOR], and legacy wellbores with surface features).

Some of the key outputs from the reservoir simulation with respect to risk analysis include the following (National Energy Technology Laboratory, 2017; Azzolina and others, 2017):

- What was the estimated injectivity of the storage unit, and how many injection wells will be needed to inject the target $CO_2$ mass injection rate?

- What was the maximum bottomhole pressure (BHP) for the injection well(s) during the operational phase, and how did those values compare to the estimated fracture pressure of the storage unit and primary seal?

- What was the simulated areal extent of the $CO_2$ plume in the storage unit? Based on these results, what was the proximity of the $CO_2$ plume at the end of the operational and PISC phases to known wellbores, faults, or other important site features?

- What was the simulated pressure buildup in the storage unit at the end of the operational and PISC phases? Based on these results, what is the area of review (AOR) and how does the AOR compare to known wellbores, faults, or other important site features?

Figure C-1 shows an example from a storage project in the PCOR Partnership region. The map shows the storage facility area and AOR boundaries in relation to nearby legacy wells and

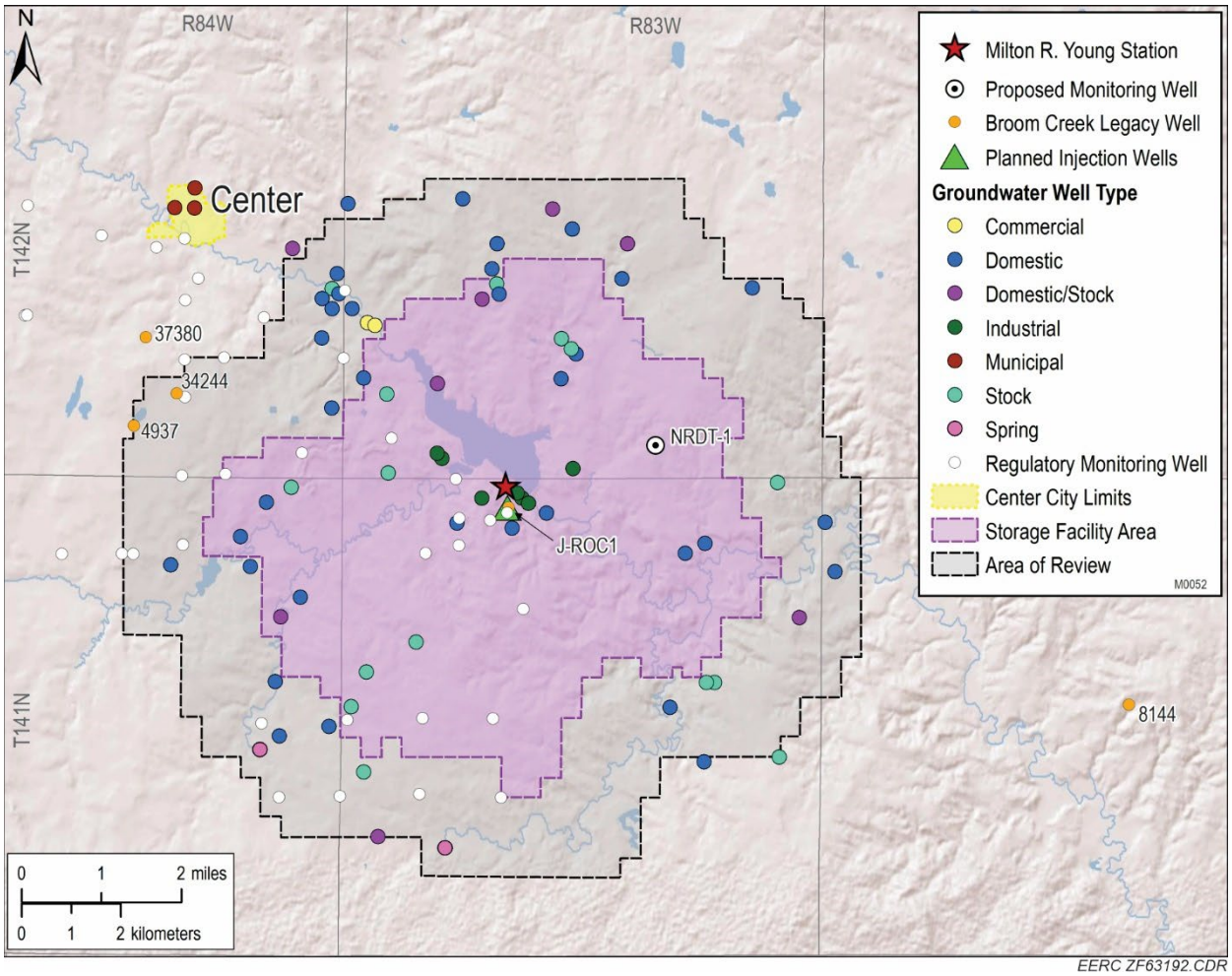


Figure C-1. AOR map in relation to nearby legacy wells and groundwater wells showing the storage facility area and AOR boundaries for a storage project in the Plains $CO_2$ Reduction (PCOR) Partnership region (Source: North Dakota Industrial Commission [NDIC] Case No. 29032, www.dmr.nd.gov/oilgas/C29032.pdf).

groundwater wells. The storage facility area was identified based on the reservoir simulation output of the areal extent of the subsurface $CO_2$ volume at the end of the injection period (20 years), in which $CO_2$ saturation was predicted to be greater than or equal to 5% (NDIC Case No. 29032, www.dmr.nd.gov/oilgas/C29032.pdf). The AOR was delineated using a risk-based approach, which utilized the simulated pressure buildup in the storage unit to delineate the areal extent beyond which no significant leakage would occur from the storage unit to overlying aquifers via legacy wellbores (if they existed). The region beyond which no significant leakage would occur does not present an endangerment to the underground source of drinking water (USDW); hence, the region inside of this areal extent is a risk-based AOR (Burton-Kelly and others, 2021). The proximity of the storage facility area and associated AOR to legacy wells and groundwater wells provided valuable information to the risk team to inform expert judgment on the likelihood of risk scenarios related to injectivity, storage capacity, and the potential for leakage of $CO_2$ or brine via legacy wellbores or other pathways.

## C.2 GEOCHEMICAL MODELING

Geochemical modeling involves modeling the major, minor, and trace mineralogical components of the rocks in the storage unit and primary seal; the chemical composition of formation fluids; and the interactions among the mineralogical components, formation fluids, and injected $CO_2$ in the storage unit and at the storage unit–primary seal interface under site-specific temperature and pressure conditions.

Geochemical modeling can be conducted in the context of reservoir simulation to analyze how geochemical interactions may affect injectivity, storage capacity, or other performance metrics of the storage unit. For example, for a storage project in the PCOR Partnership region, the project team investigated the effects of introducing the $CO_2$ stream to the storage unit using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package, GEM, which was also the simulation software used for the evaluation of the reservoir dynamic behavior resulting from the expected $CO_2$ injection. The base case reservoir simulation without geochemistry (base case) was rerun with the geochemical analysis option included (geochemistry case), and results from the two cases were compared. The geochemistry case used mineralogy data for the storage unit obtained from rock core samples and XRD (x-ray diffraction). While some geochemical alteration effects were seen in the geochemistry case, these effects were not significant enough to cause observable change to storage unit performance or the mechanical integrity of the storage formation (NDIC Case No. 28848, www.dmr.nd.gov/oilgas/C28848.pdf). These additional geochemistry cases provided quantitative results to the risk team for evaluating risk scenarios about the potential impact of geochemical interactions on storage unit injectivity and storage capacity—two key performance metrics included in the risk analysis.

Additional geochemical modeling for the same storage project in the PCOR Partnership region used PHREEQC geochemical software (Parkhurst and Appelo, 2013) to calculate the potential effects of injected $CO_2$ on the primary seal at reservoir temperature and pressure conditions. The mineralogy of the primary seal used data obtained from rock core samples and XRD. A vertically oriented one-dimensional (1D) simulation was created where the primary seal was exposed at the bottom to $CO_2$ and the $CO_2$ was allowed to enter the formation by diffusion processes. The geochemical modeling results were modeled at 1-meter increments above the primary seal–$CO_2$ exposure boundary. While the results showed geochemical processes at work, even at extreme exposure levels, these processes did not extend more than 3 meters up into the primary seal during the simulation period. Therefore, these results showed that exposure to $CO_2$ would not cause deterioration of the primary seal and provided quantitative results to the risk team for evaluating risk scenarios about the potential impact of geochemical interactions on the primary seal and storage permanence (NDIC Case No. 28848, www.dmr.nd.gov/oilgas/C28848.pdf).

## C.3 GEOMECHANICAL MODELING

Geomechanical modeling refers to techniques to quantify the potential for and effects of stress changes, deformations, and induced seismicity resulting from the planned $CO_2$ injection. During $CO_2$ injection into storage formations, pore pressure increases while reservoir temperature

decreases. These changes of pore pressure and temperature induce localized stress variations that could cause formation integrity issues during $CO_2$ injection and storage.

Geomechanical modeling can be relatively simple, relying on triaxial stress measurements coupled with graphical approaches like Mohr's circle (e.g., Parry, 2004). Geomechanical modeling can also include more complex studies like mechanical earth models (MEMs). 1D MEMs are created along wellbores from well log and drilling data to identify current in situ stress conditions. Using the 1D MEMs for calibration, 3D MEMs are created for stress stability analysis and identifying potential integrity issues, such as induced seismicity from reactivating critically stressed faults in response to $CO_2$ injection, unintended $CO_2$ migration from storage intervals due to a ruptured confining zone, localized permeability changes, and other geomechanical risk scenarios (Belobraydic and others, 2022). The decision to develop a MEM and the range of geomechanical modeling along the spectrum from 1D to 3D MEM depend on the site-specific conditions, which dictate the level of site characterization studies needed to satisfy the permitting requirements and the risk assessment. For example, storage projects with adequate storage capacity relative to the planned $CO_2$ mass injection rate may not affect the subsurface stress regime to the extent that a MEM is necessary to properly characterize geomechanical risk. In those cases, simpler approaches are likely adequate.

For a storage project in the PCOR Partnership region, 1D and 3D MEMs were developed to assess geomechanical risk for a stacked storage scenario—a storage project with two storage units vertically stacked in the stratigraphy (i.e., Storage Unit 1, Sealing Formation 1, Storage Unit 2, Sealing Formation 2). The 1D MEMs were completed along key wellbores to derive dynamic and static constitutive properties, overburden stress, maximum horizontal stress, and minimum horizontal stress at the time of drilling and were used to calibrate and propagate the initial stress and rock strength conditions in the 3D MEM. Pore pressure and fluid temperatures for each 20-year injection scenario were forward-modeled to calculate effective stress evolution and thermal stress generated on the stacked storage complex for each time step. Three injection scenarios were evaluated: i) stand-alone Storage Unit 1 injection (0.70 million tonnes [Mt]/year), ii) stand-alone Storage Unit 2 injection (1.13 Mt/year), and iii) simultaneous Storage Units 1 and 2 injection with two separate wells. Figure C-2 illustrates the 3D MEM results for the third scenario, showing simulated effective stress (top panel) and the change in effective minimum stress from initial conditions (bottom panel). The 3D MEM results demonstrated geomechanical isolation and no pressure communication between the two storage units, with no shear or tensile fracture failures observed in the interburden or upper confining zone. The isolation between the formations was observable in the effective stress evolution during the 20-year injection period (Belobraydic and others, 2022). The 1D and 3D MEM outputs provided quantitative results to the risk team for evaluating potential geomechanical risk scenarios.

In addition to MEMs, the U.S. Department of Energy's National Risk Assessment Partnership (NRAP)—a collaboration of five U.S. national laboratories focused on quantifying and managing subsurface environmental risks to support implementation of safe and secure large-scale storage project sites—has created three tools to support quantitative analysis of geomechanical stress and induced seismicity.

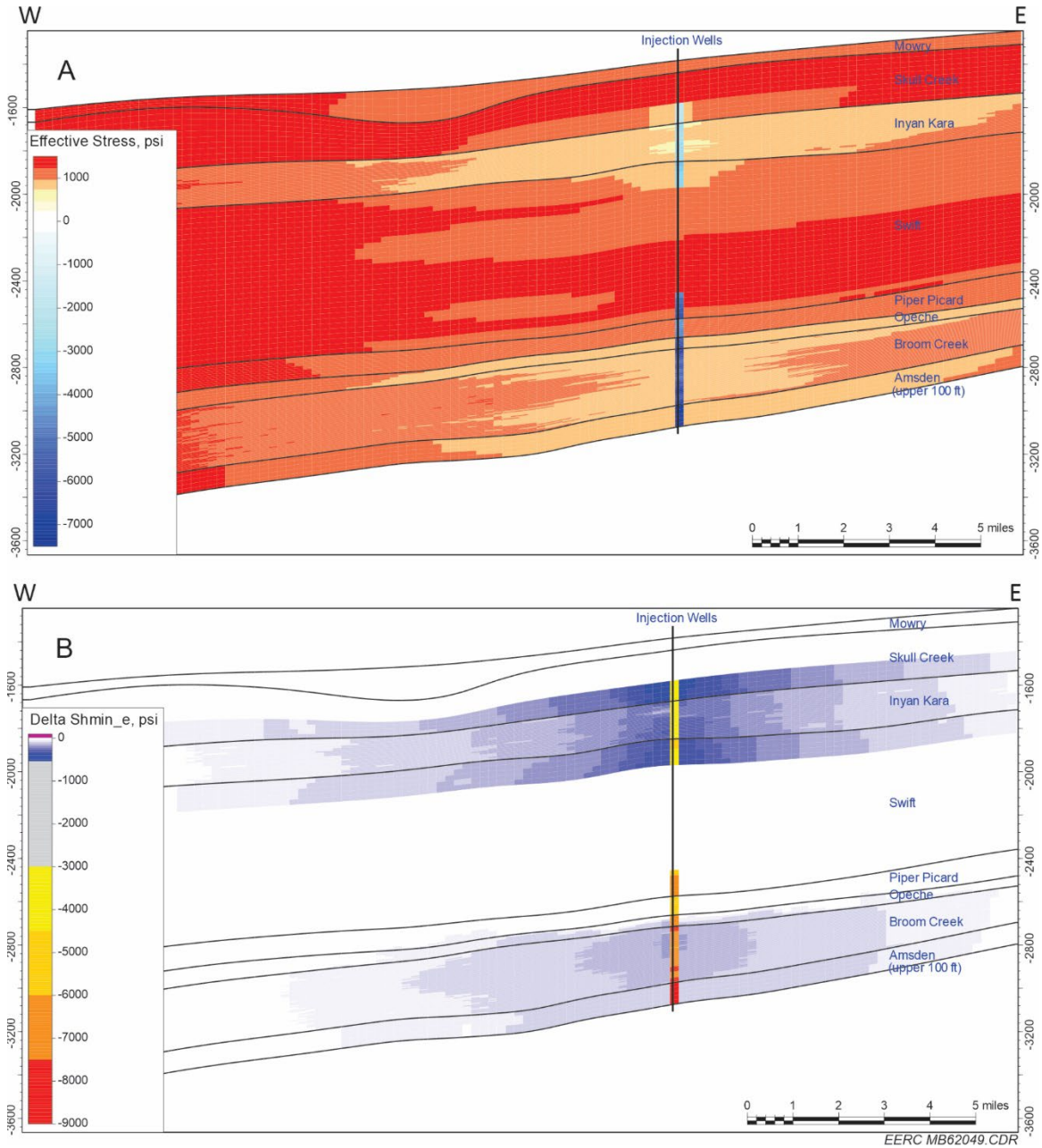


Figure C-2. Effective minimum horizontal stress including thermal stress evolution results after 20 years of $CO_2$ injection into Storage Unit 1 (Inyan Kara Formation) and Storage Unit 2 (Brook Creek Formation): A) west-to-east cross section displaying the resulting effective minimum stress magnitude and B) west-to-east cross section displaying the change in effective minimum stress from initial conditions. Vertical scale is feet below mean sea level (source: Belobraydic and others, 2022).

- **SOSAT (State-of-Stress Analysis Tool):** SOSAT uses a Bayesian approach to quantify the current state of stress and how the state of stress will evolve because of subsurface fluid injection. SOSAT then uses calculated stress state probability distributions to estimate the probability of activating a critically oriented fault over a specified range of pore pressures (Burghardt, 2018). SOSAT helps target collection of specific additional data to constrain uncertainties in geomechanical risk and to help operators to make informed decisions during the operational phase (Appriou, 2019) (https://edx.netl.doe.gov/nrap/state-of-stress-analysis-tool-sosat/).

- **STSF (Short-Term Seismic Forecasting):** The STSF tool uses site-specific catalogs of measured seismicity to forecast future event frequency over the short term. The STSF tool uses a model developed for the decay of aftershocks of large seismic events to determine the event rate in future time bins (Bachmann and others, 2011). This model is adapted with a term to modify the background seismicity rate above a predetermined magnitude threshold as a function of injection-related parameters (e.g., injection rate or BHP). This injection-related seismicity forecasting capability can be a valuable tool to complement stoplight approaches for induced seismicity risk planning and permitting (https://edx.netl.doe.gov/nrap/short-term-seismic-forecasting-stsf/).

- **RiskCat:** RiskCat provides an approach and computational framework to assess risk from induced seismicity for storage project sites. This approach is an adaptation of the conventional probabilistic seismic risk analysis (PSRA) method developed for application in estimation of risk of structural damage from naturally occurring earthquakes (e.g., Cornell, 1968; Budnitz and others, 1997). It links the probability of occurrence of earthquakes to their primary consequences; for induced seismicity from storage project activity, these consequences will include nuisance resulting from minor felt ground shaking and potential minor structural damage. This approach to applying PSRA to storage project-related seismicity is described in detail by White and Foxall (2016) (https://edx.netl.doe.gov/nrap/riskcat/).

## C.4 COMPUTATIONAL MODELING OF THE BROADER STORAGE SYSTEM: NRAP-OPEN-IAM

Building a geologic model and running reservoir simulations using commercial-grade software platforms provide the "gold standard" for estimating pressure and $CO_2$ behavior in the storage unit in response to $CO_2$ injection. However, these fluid flow simulations are typically limited to the storage unit and primary seal and do not include the geologic units of the remaining storage complex, additional overlying geologic units like the lowermost USDW, or ground surface because of the computational burden of conducting such a complex simulation (Burton-Kelly and others, 2021). Consequently, depending on the needs of the risk assessment, additional computational modeling tools may be required to conduct quantitative risk analysis for potential risk scenarios that could impact USDWs or the surface.

One of the NRAP tools, NRAP-Open-IAM (Open-source Integrated Assessment Model), provides a pragmatic approach to computational modeling of the broader storage system. NRAP-Open-IAM builds on many years of NRAP tool development for risk assessment, including $CO_2$-

PENS (Predicting Engineered Natural Systems) (Stauffer and others, 2009) and NRAP Integrated Assessment Model-Carbon Storage (NRAP-IAM-CS) (Stauffer and others, 2016). NRAP-Open-IAM builds on the functionality of NRAP-IAM-CS within an open-source Python framework. NRAP-Open-IAM allows the user to define a conceptual model for a storage complex and to simulate leakage of $CO_2$ or displaced formation fluids (brine) via leaky wellbores from the storage unit to overlying aquifers or the atmosphere. Therefore, Open-IAM provides a quantitative modeling tool to support risk management decisions for storage projects (https://edx.netl.doe.gov/nrap/nrap-open-iam/).

Through the PCOR Partnership and the CarbonSAFE (Carbon Storage Assurance Facility Enterprise) Initiative (National Energy Technology Laboratory, 2022), the EERC has extensively tested NRAP-Open-IAM using commercial-scale storage project reservoir simulations and site-specific storage complex stratigraphy (Peck and others, 2020; Mahmood and others, 2021). The test results show that the current version of NRAP-Open-IAM is a useful tool for the heuristic modeling of a storage project and what-if scenario modeling for $CO_2$ and brine leakage through wellbores. The NRAP-Open-IAM results can be used to provide quantitative insights into the likelihood and severity of leakage risk scenarios given project-specific inputs and can therefore inform risk scenario scoring.

For storage projects in the PCOR Partnership region, the EERC has used NRAP-Open-IAM to demonstrate the likelihood of leakage risks and to quantify the magnitude of leakage should the risk scenario occur. A major benefit of this approach is the ability to use compositional reservoir simulation of a heterogeneous geologic model as a source of pressure buildup and $CO_2$ plume in the storage unit rather than a homogeneous, isotropic model generated in other analytical or semi-analytical solutions.

Figure C-3 shows the results of applying the hybrid approach to a storage project in the PCOR Partnership region. Reservoir simulations for the storage unit (Broom Creek Formation) were exported from CMG GEM, formatted using customized scripts, and imported into NRAP-Open-IAM, which was then used to simulate potential leakage via a legacy wellbore located within the AOR that was identified during the site characterization and evaluated by a professional engineer pursuant to North Dakota Administrative Code (NDAC) Section 43-05-01-05 Subsection 1b(3). Based on the NRAP-Open-IAM simulations, the $CO_2$ leakage rates to the lowermost USDW (Fox Hills Formation) were estimated to be zero (top panel in Figure C-3), even under conditions where the wellbore effective permeability values were varied from -17 to -13 $\log_{10}$ $m^2$ (0.01 to 101 mD), which are three to seven orders-of-magnitude greater, respectively, than the expected value of less than or equal to -20 $\log_{10}$ $m^2$ (1E-05 mD) (Watson and Bachu, 2007; 2008; Carey, 2017). The brine leakage rates into the lowermost USDW were also estimated to be zero across all NRAP-Open-IAM simulation cases (bottom panel in Figure C-3). These results showed that even under extreme assumptions of a wellbore with high effective permeability, the site-specific data comprising reservoir simulations, properties of the storage unit and broader storage complex, and locations and properties of the wellbores resulted in zero leakage of $CO_2$ or brine from the storage unit to the lowermost USDW. These outcomes allowed the risk team to score the risk scenarios as low probability more confidently (e.g., less than 1% probability over occurrence over the 100-year time frame).

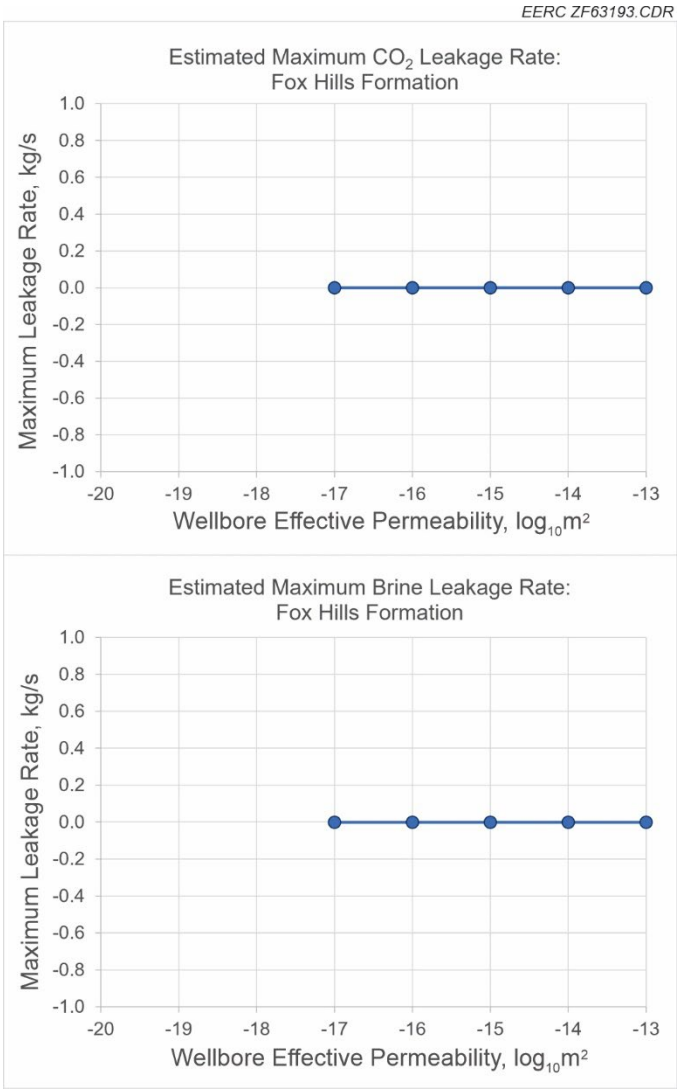


Figure C-3. NRAP-Open-IAM maximum $CO_2$ leakage estimates (top) and brine leakage estimates (bottom) into the lowermost USDW (Fox Hills Formation) at the end of 20 years of $CO_2$ injection via a monitoring well located approximately 1 mile from the $CO_2$ injection well and assuming wellbore effective permeability values from -17 to -13 $\log_{10}$ $m^2$ (0.01 to 101 mD), which are three to seven orders-of-magnitude greater, respectively, than the expected value of less than or equal to -20 $\log_{10}$ $m^2$ (1E-05 mD) (Watson and Bachu, 2007; 2008; Carey, 2017).

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