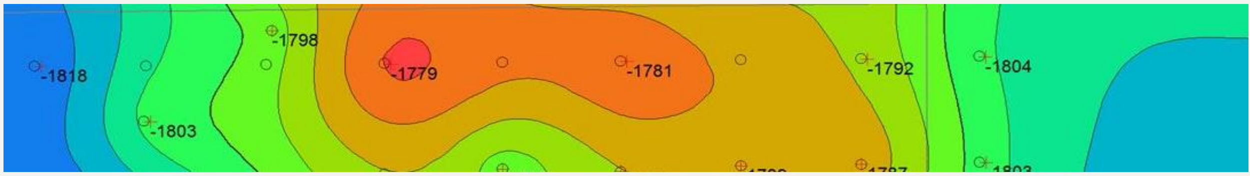

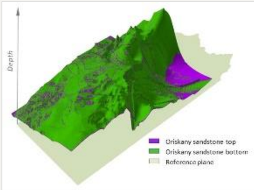

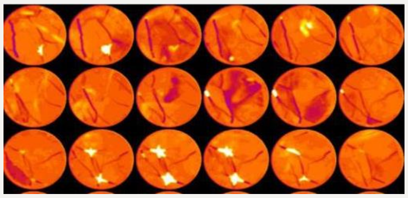

Overview of Potential Failure Modes and Effects Associated with CO_2 Injection and Storage Operations in Saline Formations

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Disclaimer

Overview of Potential Failure Modes and Effects Associated with CO_2 Injection and Storage Operations in Saline Formations

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LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

2D	Two-dimensional
3D	Three-dimensional
4D	Four-dimensional
ADM	Archer Daniels Midland Company
AMA	Active monitoring area
ANSI	American National Standards Institute
AoR	Area of review
°C	Degrees Celsius
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization, and storage
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon dioxide
CSA	Canadian Standards Association
DAS	Distributed acoustic sensing
DOE	Department of Energy
EA	Environmental Assessment
ECBM	Enhanced coalbed methane
EIS	Environmental Impact Statements
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
°F	Degrees Fahrenheit
FE	Fossil energy
FEP	Features, Events and Processes
ft	Foot, feet
Gt	Gigatonne
GHG	Greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
H_2S	Hydrogen sulfide
IBDP	Illinois Basin Decatur Project
IL-ICCS	Illinois Industrial Carbon Capture and Storage Project
InSAR	Interferometric synthetic aperture radar
IPCC	Intergovernmental Panel on Climate Change
IRS	Internal Revenue Service
ISO	International Organization for Standardization
LPO	Loan Program Office
m	Meter
MESA	Mission Execution and Strategic Analysis
MI	Mechanical integrity
MIT	Mechanical integrity testing
MMA	Maximum monitoring area
MPa	Megapascal
MRV	Monitoring, reporting, and verification
MVA	Monitoring, verification, and accounting
NA	Not available/applicable
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NIMBY	Not-in (or under)-my-backyard
NPDES	National Pollutant Discharge Elimination System
NRAP	National Risk Assessment Partnership
PISC	Post-injection site care
psi	Pounds per square inch
R&D	Research and development
RCSP	Regional Carbon Sequestration Partnership
RMP	Risk mitigation plan
SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
tonne	Metric ton
U.S.	United States
UIC	Underground Injection Control
USDW	Underground source(s) of drinking water
VSP	Vertical seismic profile
yr	Year

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EXECUTIVE SUMMARY

This document provides the United States (U.S.) Department of Energy's (DOE) Loan Program Office (LPO) and its applicants awareness of the potential failure modes that could occur and the possible adverse effects to human health or the environment associated with injection and geologic storage of carbon dioxide (CO_2) in onshore, saline-bearing formations as part of carbon capture, storage, and utilization (CCUS) efforts. It also addresses risk management strategies and the regulatory framework in place to minimize these potential impacts. CCUS is regarded as a key component in "all of the above" energy strategies aimed toward reducing CO_2 emitted to the atmosphere from anthropogenic sources. The deployment of CCUS technologies is contingent upon several factors including identifying viable storage sites that can provide for safe and effective long-term storage of CO_2, establishing effective CO_2 transportation between willing CO_2 capture sources to storage sites, gaining local public support, and attaining financial certainty for projects.

Decades of CCUS research and development (R&D), and experience from CCUS field projects has generated a body of knowledge suggesting that CO_2 storage can be conducted safely, resulting in minimal environmental impact and reduced likelihood of failure modes occurring if storage sites are properly selected, characterized, operated, monitored, and closed. As a result, a variety of best practices exist for preventing, detecting, or mitigating failure modes associate with CO_2 injection and storage. These best practices are available to the public in a series of best practice manuals[a] based on this body of knowledge. History has also shown that stakeholders (i.e., residents of communities in proximity to CCUS sites, landowners in proximity to CCUS sites, policy makers, non-governmental organizations, various industry groups, and potentially tribal nations all with some connection to a given CCUS project) have expressed their opposition to CCUS projects conducted within their general proximity; an effect that has shown can contribute to project delays and cancellations. Because experience has shown that outreach programs can help curtail stakeholders' concerns on a CCUS project, approaches to consider for an effective outreach program are discussed.

LPO helps projects implementing emerging or first-of-a-kind energy technologies like CCUS by overcoming financial barriers via guaranteed debt financing options. A variety of federal environmental laws apply to DOE loans and loan guarantees, including the National Environmental Policy Act (NEPA). NEPA compliance is integrated into LPO's decision-making procedures to ensure that the potential for environmental impacts is considered as part of the loan guarantee process. LPO intends to use the information and analyses within the report to 1) define the potential modes of failure and possible impacts associated with CO_2 storage agnostic to any specific project site or sites; 2) summarize known best practices that can be used to prevent, detect, or mitigate failures that may occur during CO_2 injection and storage and may reduce the effect severity on human health or the environment; and 3) assist in the review and consideration of the potential effects to human health or the environment associated with proposed CCUS projects pursuant to NEPA. The document summarizes existing credible

[a] https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/best-practices-manuals

scientific evidence and provides the current state of the science related to geologic storage of CO_2 based on the substantial body of knowledge that exists from years of laboratory research, CO_2 storage simulation studies, and small- and large-scale field-testing efforts.

A digest of failure modes and associated effects related to geologic storage of CO_2 was compiled for this report through synthesis of relevant sources of technical literature (reports, journal articles, presentations), evaluation of NEPA environmental assessments and environmental impact statements relating to CCUS projects reviewed by DOE, and U.S. Environmental Protection Agency (EPA) Underground Injection Control (UIC) permit applications (where applicable). Three specific potential failure modes were categorized from this digest: 1) lateral containment failure, in which fluid movement (i.e., CO_2, native brine, or other native gases in the storage reservoir) extends beyond the boundaries of the storage reservoir or confining caprock layer(s); 2) vertical containment failure, where fluids are able to move upwards from the storage reservoir to shallower formations or the atmosphere; and 3) induced and triggered[b] seismicity resulting from CO_2 injection-induced displacement along new or pre-existing faults or fractures. Under each failure mode category, multiple causes may exist. In certain cases, a given failure mode or modes, should they occur, could prompt the occurrence of another failure mode (i.e., triggered seismic activity damaging an existing well, causing flow pathways for vertical containment failure).

Any realized failure mode could result in adverse effects (depending on severity, which is not discussed in this report) to human health or the environment. Three failure effect categories are addressed in this report: 1) contamination of underground sources of drinking water (USDW), 2) contamination of non-USDW resources, and 3) physical damage to surface infrastructure and/or topography.

The information compiled in this report is relevant for assisting the LPO in completing environmental reviews pursuant to NEPA. The information is also relevant for evaluating reasonably foreseeable significant adverse impacts on the human environment and complying with protocols for incomplete or unavailable information per 40 Code of Federal Regulations 1502.21 as it relates to CO_2 injection and storage.

[b] According to McGarr and Simpson [1997], induced earthquakes are commonly understood as events where most of the stress change released during rupture was produced by the human action, while triggered events release a substantial amount of tectonic stress.

1 INTRODUCTION

Carbon capture, utilization, and storage (CCUS) is regarded as a critical component in the global effort to reduce carbon dioxide (CO_2) emitted to the atmosphere from anthropogenic sources. Long-term forecasts of future energy market and economic outlooks indicate that deployment of CCUS is an essential component of clean energy strategies that reduce greenhouse gas (GHG) emissions. The CCUS process involves the capture (separation and purification) of CO_2 from stationary anthropogenic sources (e.g., fossil-fueled power plants, industrial processes, even direct air capture) so that it can be transported to suitable locations where it is either converted into useable products, or injected into deep underground geologic formations for safe, secure, and permanent storage. [1] Geologic storage options include saline-bearing formations, depleted oil and gas reservoirs, and un-mineable coal seams. Captured CO_2 can also be used in the enhanced oil recovery (EOR) process, which has the distinct advantages of promoting additional hydrocarbon recovery from existing oilfields combined with CO_2 storage. [1, 2, 3] The integrated suite of technologies (CO_2 capture, transport, and storage) within the CCUS value chain are beneficial to multiple industry types, including the power generation sector as well as industrial and manufacturing processes like iron and steel plants, oil refineries, cement plants, ethanol production facilities, and petrochemical plants. [4]

Currently, only a few fully integrated projects that capture and geologically store large volumes of CO_2 are underway worldwide. However, according to the International Energy Agency and Global CCS Institute, the number of larger-scale CCUS projects is slowly growing and diversifying in terms of the source types capturing and geologically storing CO_2. [5, 6] The variety of small- and large-scale CCUS projects that have been completed or are currently in operation [7, 8] have demonstrated that significant CO_2 emission reductions (millions of metric tons [tonnes] per year) are possible. Additionally, these field projects have generated an extensive body of knowledge indicating that CO_2 storage can be conducted safely with little to no environmental impact if storage sites are properly selected, characterized, operated, monitored, and closed. [9] Despite the success of these projects to date, rapid CCUS deployment has not yet occurred and still faces many unique challenges in attaining wider commerciality. [10, 11] For example, large-scale integrated CCUS projects are highly cost-intensive and face several financial challenges in achieving deployment. [12, 13, 14] Successful projects to date have overcome financial constraints through government fiscal subsidies or by identifying a role for CCUS as part of a broader commercial business case. [15, 10]

In the United States (U.S.), the 45Q tax credit is a financial incentive intended to promote the development and deployment of CCUS technology and reduce CO_2 emissions into the atmosphere. The 45Q credit (Section 45Q of the Internal Revenue Code [26 U.S. Code § 45Q. Credit for carbon oxide sequestration]) originated in 2008 through the Energy Improvement and Extension Act. Section 45Q provides a tax credit per tonne of CO_2, which can be claimed by a carbon capture project (or storage project if appropriately transferred) when the CO_2 is securely stored through either 1) storage in geologic formations, like oil fields or saline reservoirs or 2) utilization, including as a feedstock to produce products like chemicals, concrete, or fuels. [16, 17] The 2018 Bipartisan Budget Act included a revamp of the tax credit available under Section 45Q of the Internal Revenue Code. The amended Section 45Q tax credit expands the value, duration, and eligibility of the credits for both CO_2 and carbon monoxide. The new provisions provide CCUS projects with 1) a new enhanced incentive to attract investment, 2) greater value for each tonne of CO_2 stored/utilized to help close cost-to-revenue gaps, and 3) additional flexibility to accommodate different business models across industry types. [18, 19, 20] As a result, there has been heightened interest from the private sector in deploying additional CCUS capacity in the near term. [21, 22, 23]

The U.S. Department of Energy (DOE) Loan Programs Office (LPO) can provide supplementation to 45Q for projects interested in CCUS secure financing. LPO helps projects implementing emerging or first-of-a-kind energy technologies like CCUS by overcoming financial barriers via guaranteed debt financing options. The modified 45Q tax credit can improve the certainty in the revenue streams of new CCUS projects, thereby improving their ability to potentially secure LPO-guaranteed debt financing and prospective private sector equity investment. [16, 23, 17]

In addition to securing financing, CCUS project operators must evaluate candidate storage sites for susceptibility to potential failure modes that could potentially result in adverse effects to humans, the environment, or infrastructure and comply with Environmental Protection Agency requirements under the Safe Drinking Water Act (SDWA) of 1974 including obtaining a permit prior to operation. The potential failure modes and the associated adverse effects associated with CO_2 storage will vary from one site to another – typically determined through site-specific risk assessment. However, in general, there are certain types of failure modes and associated effects common to CO_2 injection and storage regardless of site- or regional-specific conditions that must be understood for future storage site(s).

The purpose of this document is to provide DOE LPO and its applicants awareness of potential failure modes and potential adverse effects as risk factors associated with the injection of CO_2 for geologic storage. The review of these risk factors focuses on CO_2 storage in onshore deep saline formations, and excludes specific discussion related to onshore storage in depleted oil and gas reservoirs, and un-mineable coal seams. While overlap exists for the prominent failure modes across reservoir types, the report focuses on effects as they relate to the unique aspects associated with large-scale CO_2 injection in saline-bearing formations (i.e., buoyant injectant relative to native brine, increase in formation pressure over time, CO_2 corrosivity in the presence of water, and large-volume injection over extended timeframes). The document summarizes the existing credible scientific evidence and provides the current state of the science related to geologic storage of CO_2 based on the substantial body of knowledge that exists from the years of laboratory research, simulation studies, and small- and large-scale field-testing efforts. LPO intends to use the information to define potential failure modes and assist in its review and consideration of the potential environmental impacts (i.e., effects) of proposed CCUS projects pursuant to NEPA. Additionally, the information within this report is relevant for evaluating reasonably foreseeable significant adverse impacts on the human environment and complying with protocols for incomplete or unavailable information per 40 Code of Federal Regulations (CFR) 1502.21 as it relates to CO_2 injection and storage.

To ensure clarity with the terminology used throughout, the terms “risk,” “reasonably foreseeable significant adverse impacts,” and “human environment” are defined below as they are used in the context of this report:

- **Risk** – a semi-quantitative valuation coupling a specific potential cause of failure and its resulting specific potential failure effect. The statistical probability of the cause of failure occurring and the severity of the resulting potential failure effect are typically considered on semi-quantitative scales and are typically site-specific. This report does not attempt to quantify cause of failure mode probability nor the severity of resulting failure effects, and therefore does not formally assess risk. This report does not prescribe any specific risk assessment methodology. CO_2 storage site operators should, however, perform and continually update a site-specific risk assessment as best practice.
- **Reasonably foreseeable significant adverse impacts** - failure effects which may have catastrophic consequences on the human environment, with an underlying cause of failure that based on credible scientific evidence (i.e., not based purely on conjecture; within the rule of reason) has a probability of occurrence. Potentially catastrophic consequences, even if their underlying cause of failure probability is low (per 40 CFR § 1502.21) are considered reasonably foreseeable significant adverse impacts; however, no quantitative values are provided in the regulations to define "low probability."
- **Human environment** – comprehensively the natural and physical environment and the relationship of present and future generations of Americans with that environment (per 40 CFR § 1508.1). This report considers human environment within the context of three elements: 1) human health and safety of people in the affected region of a CO_2 storage site; 2) the economic livelihoods of the population in the affected region of a CO_2 storage site; and 3) the natural and physical environment in the affected region of a CO_2 storage site. Excluded from consideration are any potentially adverse failure effects associated with CO_2 injection and storage impacting the economics associated with the CO_2 source, CO_2 capture, CO_2 transport, and CO_2 storage operators and/or investors.

This document body includes three main sections which provide background on the CO_2 storage concept, an overview of the failure modes, effects, and best practices as they relate to failure prevention, detection, and mitigation, and a review of stakeholder feedback for selected CCUS projects in the U.S. The report also includes Conclusions (Section 5) and several Appendices that provide additional supporting information. The main sections 2 through 4 are organized as follows:

- **Section 2: Onshore Geologic Storage of CO_2 – Overview.** This section provides a foundational context to the CO_2 injection and storage component of the CCUS value chain. This section summarizes the role of CCUS as a CO_2 management technology and provides background on prominent regulations in the United States related to CO_2 storage. This section also provides an overview of how CO_2 storage sites are screened, characterized, developed, operated, monitored, and closed to ensure safe and effective long-term storage. Finally, this section discusses the resulting effects from CO_2 injection, and briefly discusses key findings and lessons learned from field projects implemented through DOE's Regional Carbon Sequestration Partnerships (RCSP) Initiative.
- **Section 3: Potential Failure Modes and Associated Effects to the Human Environment Related to Onshore Geologic Storage of CO_2.** This section includes an inclusive list of potential failure modes, causes of failure, and associated effects on the human

environment related to geologic storage of CO_2. This section also identifies failure prevention, detection, and mitigation approaches and best practices for each potential failure mode. The information has been synthesized from relevant sources of technical literature (reports, journal articles, presentations), evaluation of environmental project assessments relating to CCUS projects reviewed by DOE,[c] and UIC permit applications (where applicable). Additionally, this section evaluates and compares monitoring results from select CO_2 storage sites to the predictions or forecasted conditions and impacts made prior to injection operations. The discussion focuses on failure modes and associated effects from the injection and long-term storage of CO_2, not on effects from surface development activities or capture, compression, and transportation of CO_2.

- **Section 4: Additional Issues or Concerns from Public and Stakeholder Comment.** This section lists and summarizes concerns raised from stakeholder feedback related to CO_2 storage operations in the United States. The information is compiled from several sources, including previous environmental reviews or through UIC permitting processes, as well as lessons learned from the RCSP Initiative. Feedback from public stakeholders is critical in considering all aspects of CO_2 injection on the human environment. An analysis is provided which compares the comments received from public stakeholders by the volume that relates to project impacts on the human environment and the volume of comments that do not.

[c] The U.S. Environmental Protection Agency's (EPA) Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) program is responsible for the protection of underground sources of drinking water (USDW) from contamination by regulating the construction and operation of injection wells, including those related to geologic CO_2 EOR and CO_2 storage operations (Class II and Class VI wells). EPA is required to comply with the requirements of NEPA for many of its R&D efforts, facilities construction activities, and National Pollutant Discharge Elimination System (NPDES) permits for new sources. However, EPA is exempt from NEPA under the following statutes:

- Section 511(c) of the Clean Water Act exempts most EPA actions under the Clean Water Act from the requirements of NEPA
- Section 7(c) of the Energy Supply and Environmental Coordination Act of 1974 (15 U.S.C. 793(c)(1)) exempts all EPA actions under the Clean Air Act from the requirements of NEPA

Therefore, these environmental reviews were completed by DOE, as EPA's SDWA UIC program is exempt from performing environmental reviews under section 102(2)(C) and an alternatives analysis under section 102 (2)(E) of NEPA under a functional equivalence analysis. [40]

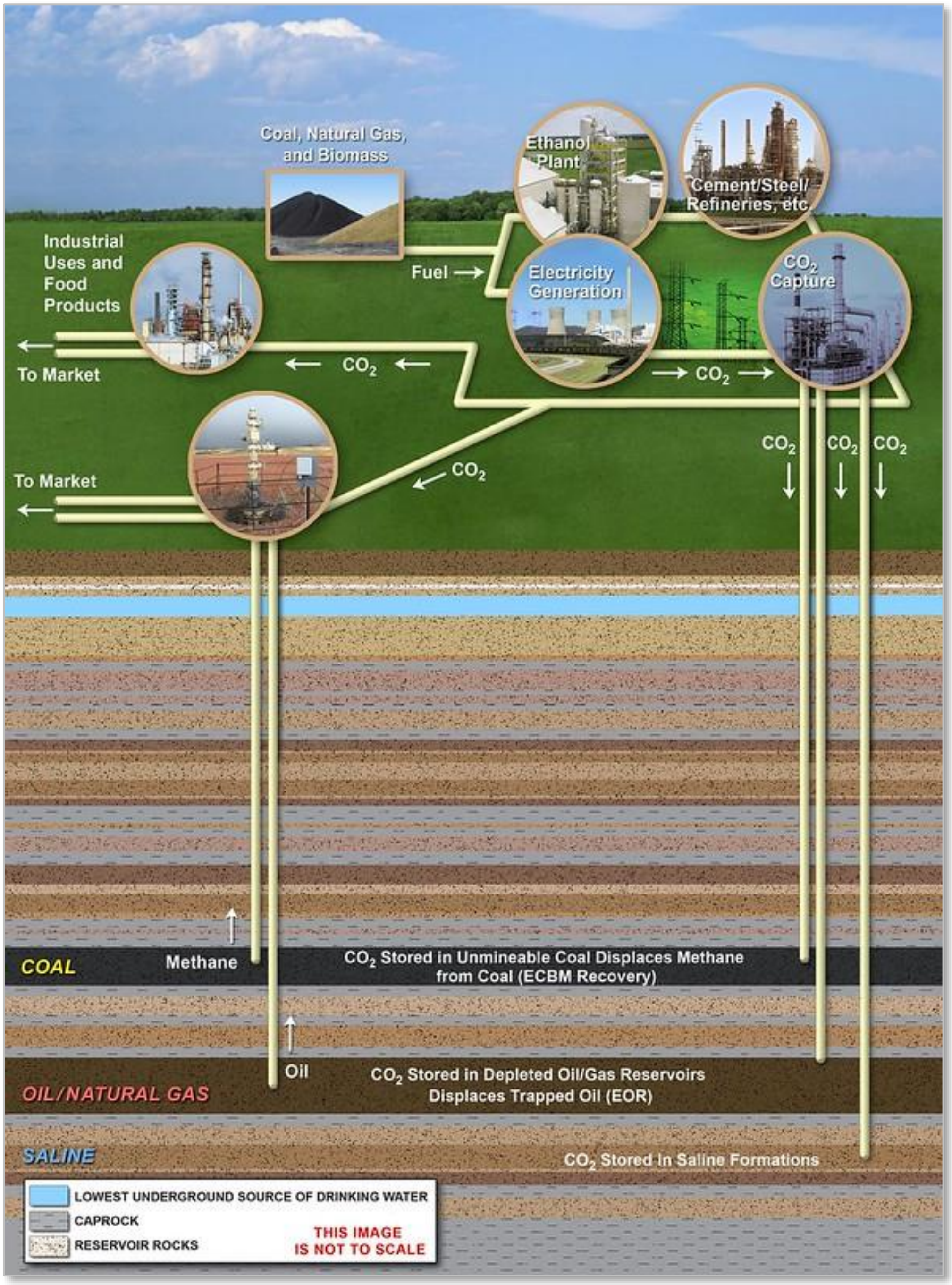
2 ONSHORE GEOLOGIC STORAGE OF CO_2 – OVERVIEW

CCUS is one of the fundamental components in a portfolio of solutions needed to change the emissions trajectory of the global energy system while providing affordable and reliable energy. Built on a combination of various processes and technologies (which broadly include CO_2 capture, transport, and storage), CCUS reduces CO_2 produced from power-generating and industrial sources from emission to the atmosphere – it can also remove CO_2 directly from the atmosphere through direct air capture techniques. [1] One of the technology components of CCUS is geologic storage of CO_2, which involves injecting captured CO_2 underground in deep (~2,600 feet [ft] or greater) geologic reservoirs for safe, secure, and permanent storage. [24] CO_2 can also be injected into oil reservoirs for the purposes of CO_2 EOR in order to recover additional oil and natural gas, typically as a tertiary recovery process. [25] Through CO_2 EOR, almost all of the injected CO_2 remains stored over the long-term – however, this specific process is not discussed in this report.

Identifying suitable geologic storage sites involves a methodological and careful analysis of both the technical and non-technical aspects of potential sites. [26] Five storage formation types, including saline-bearing formations, depleted oil and gas reservoirs, un-mineable coal seams, basalts, and organic shales (three are displayed in Exhibit 2-1) have generally been considered candidates for geologic storage of CO_2, each with their own unique advantages as well as drawbacks. [4] Key geologic parameters and reservoir characteristics must be adequately characterized for the proper design and construction of a project. Understanding of these attributes must be considered early on in project planning (i.e., during the site screening as well as site selection and site characterization phases of a CO_2 storage project). These attributes become better understood over time through each project phase (i.e., site screening, site selection and site characterization, permitting and construction, and operations) as new data is generated. As a result, project operations can be adjusted as site operators gain more confidence in understanding how sites respond to CO_2 injection.

Storage sites for CO_2 can be located to take advantage of favorable geologic attributes that prevent vertical or lateral migration from the intended storage reservoir. As a result, storage sites as part of CCUS are closely analogous to naturally occurring CO_2 fields in sedimentary basins. For instance, naturally occurring CO_2, whether derived from biological activity, igneous activity, or chemical reactions between rocks and fluids, has been naturally stored in the Earth's upper crust for millions of years either alone or in combination with other fluids (such as hydrocarbons). [28] In the United States, roughly two-thirds of the CO_2 used for EOR is extracted from natural geologic reservoirs [29] (e.g., McElmo Dome in Colorado); many of which have accumulated and stored CO_2 over millions of years. [30, 31] Furthermore, studies of oil and gas fields have indicated that hydrocarbons and other buoyant gases and fluids contained therein, including CO_2, can remain trapped for millions of years. [32, 33] Information from these analogous naturally occurring geologic formations along with the successful operation of industrial-scale geologic storage operations analogous to geologic storage of CO_2 (e.g., underground natural gas storage and deep well waste disposal [34]), provide evidence that CO_2 can be securely and safely contained in the deep subsurface.

Exhibit 2-1. Conceptual diagram illustrating storage of captured CO_2 from power-generating and industrial sources in three diverse types of onshore storage formation [27]



2.1 Onshore Geologic Formations for CO_2 Storage – Saline Formations Focus

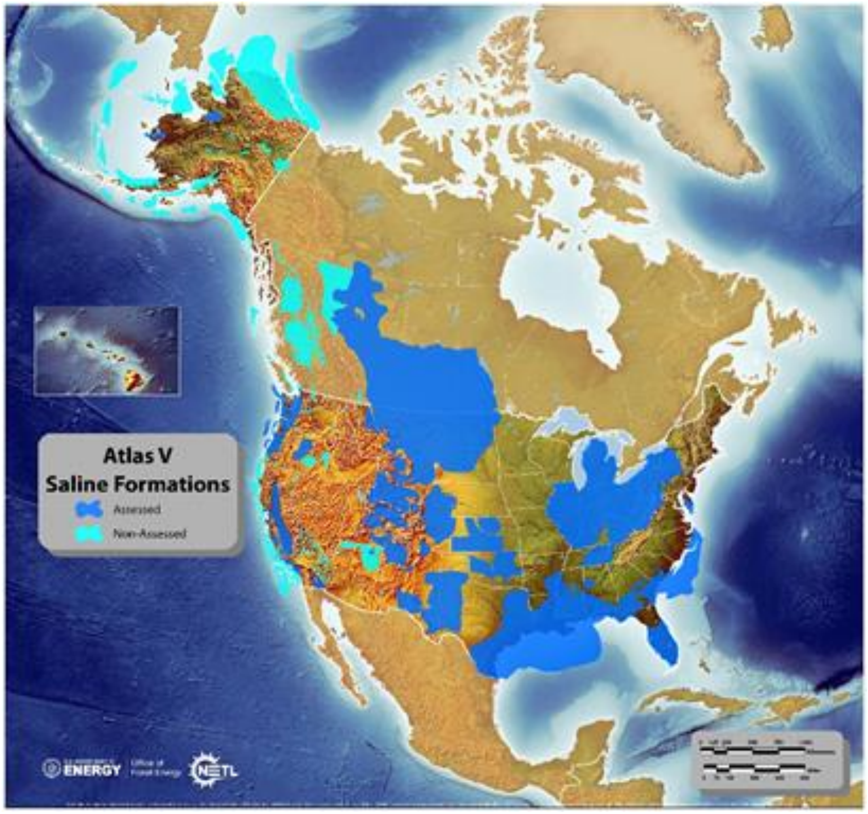
Promising potential candidates for CO_2 storage are porous and permeable rock formations that hold or have previously held fluids in place such as natural gas, oil, or brines. [26] Storage formation types that have generally been considered suitable candidates for geologic CO_2 storage are saline formations, depleted oil and natural gas reservoirs, un-mineable coal seams, basalt formations, and organic-rich shales. Relevant information on the latter four formation types as it relates to CO_2 storage, as well as maps highlighting their spatial extent in North America, is presented in Appendix A: Other Onshore, Geologic Formations Within North America Assessed by NETL. Each of the formation types provide their own unique benefits and potential challenges as CO_2 storage options. For example, each formation type will have different typical ranges and spatially varying patterns of permeability, porosity, and rock pore and surface characteristics corresponding to formation depositional environments and burial history that impact how fluids flow through, or are trapped in, formations. [26]

Saline formations are deep, sedimentary porous and permeable rocks saturated with salty water called brine that contains high concentrations of dissolved solids. Elevated total dissolved solids in saline formations make the brine unsuitable for agriculture or human consumption,[d] and would be difficult and expensive to treat for such applications. [28, 26] Saline formations provide suitable candidates for CO_2 storage because they are widely dispersed across several regions of North American (Exhibit 2-2) and offer vast storage capacity. Storage resource estimates, conducted by the National Energy Technology Laboratory (NETL) and RCSPs for saline formations in the United States and parts of Canada range between 2,379 and 21,633 billion tonnes (gigatons [Gt]); however, these estimates (calculated at the formation, basin, and continent scales) are prospective and, as such, have significant associated uncertainty. Also, practical constraints may impact the accessibility and ability to effectively utilize some of these resources. [4, 24]

Despite their substantial storage resource capacity, saline formations have not been as extensively explored compared to oil and gas reservoirs. [26] Regardless, according to Celia et al. (2015), the body of research available to date implies that the processes involved with CO_2 injection and storage into deep saline formations are fairly well understood, and the associated risks are manageable and not unusual compared to other analogous subsurface activities. [35]

[d] Saline formations with greater than 10,000 parts per million total dissolved solids in the brine are not considered USDW as per EPA's UIC Program; [40] USDW are protected by EPA's UIC Program, as discussed in Section 2.2.

Exhibit 2-2. Map displaying the distribution of saline formations that were assessed by NETL under the RCSP Initiative in parts of North America [4]

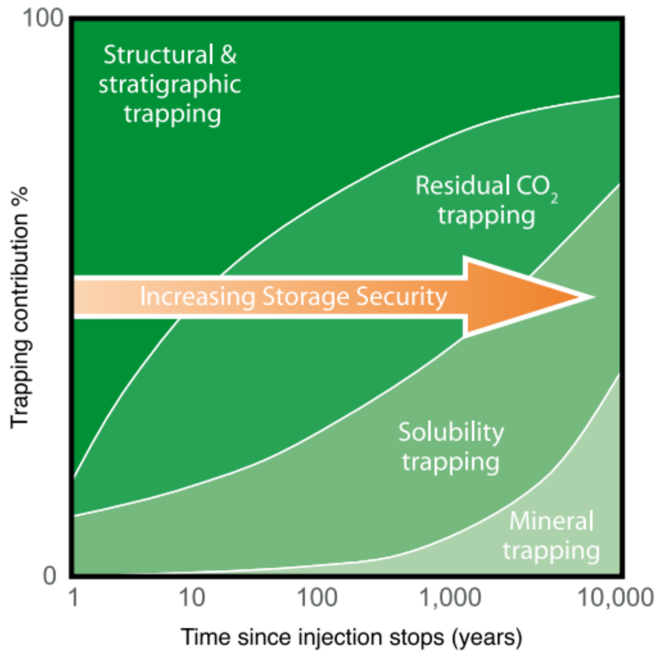


To maximize the efficiency of available storage resource (accessible pore space) and provide benefits for storage security, CO_2 is usually injected deep into suitable formations as a supercritical fluid (temperatures more than 88°F [31.1°C] and pressures more than approximately 1,057 pounds per square inch [psi] [72.9 atmospheres] having properties of both a gas [viscosity] and liquid [density]). [4, 36] Effective geologic storage sites promote the permanent trapping of CO_2 through a combination of five primary mechanisms including:

1. Structural trapping (trapping by geological features that formed in response to structural changes, e.g., folding and faulting);
2. Stratigraphic trapping (trapping by geological features formed as a result of sedimentary phenomena, e.g., unconformities, pinchouts, reefs);
3. Residual trapping (trapping of free-phase CO_2 in small pores held by fluid-rock interfacial forces);
4. Solubility trapping (CO_2 dissolved into in situ brine); and
5. Mineral trapping (e.g., CO_2 mineralization via chemical reaction).

The relative importance of these processes is expected to change over time as CO_2 migrates and reacts with the rocks and fluids, as illustrated conceptually in Exhibit 2-3. It is likely that 99 percent or more of the injected CO_2 will be maintained for over 1,000 years if stored in a suitable formation. [28]

Exhibit 2-3. Physical and geochemical trapping mechanisms for CO_2 storage in geologic formations and the relative contribution of each over time



Used with permission from the Intergovernmental Panel on Climate Change (IPCC) [28]

2.2 CO_2 Storage Regulatory Perspective in the United States

EPA is responsible for ensuring the safety of underground sources of drinking water through the SDWA, which provides a regulatory driver to manage injection of fluids in the sub surface. EPA's responsibilities for implementing the Act ensures that deployment of CCUS is protective of the environment and human health and safety by reducing GHG atmospheric emissions and preventing large-scale geologic carbon storage from endangering groundwater resources. Federal regulatory programs most applicable to CCUS pertain to EPA's UIC Program (40 CFR § 144 and 146)[e] and Greenhouse Gas Reporting Program (GHGRP) (40 CFR § 98).

The SDWA establishes requirements and provisions for the UIC Program to protect public health by preventing injection wells from contaminating USDW by infiltration of brine, displaced formation fluids, or any injected fluid. The EPA's UIC Program protects USDW from potential endangerment by setting minimum requirements for injection wells related to siting, permitting, construction, operation, monitoring, and closure. The UIC Program consists of six distinct well classes. The corresponding federal requirements for each well class are based on the type and depth of the injection activity and the potential for that injection activity to result in endangerment of USDW. [37] There are two primary UIC well classes that cover CO_2 injection projects [38]:

- Class II – wells typically used to inject fluids (e.g., CO_2 and brine) that are associated with oil and natural gas production. Quite often, CO_2 injected is incidentally stored during CO_2

[e] requirements in 40 CFR Parts 144 and 146 of the UIC Program of the SDWA, are not subject to Resource Conservation and Recovery Act as a hazardous waste per 40 CFR § 261.4(h).

EOR operations. These wells are not used when long-term CO_2 storage is a primary objective.

- Class VI – wells specific for the injection of CO_2 in deep geologic formations for the purpose of long-term storage. EPA established this well class to provide specific regulations for projects where the purpose is geologic storage (as opposed to incidental storage via CO_2 EOR using Class II wells).

In December 2010, EPA finalized minimum federal requirements under SDWA for underground CO_2 injection for the purpose of long-term geologic storage. The rule established the sixth well class (i.e., Class VI injection well) as part of the UIC Program. [39] Class VI regulations are outlined in the Code of Federal Regulations (CFR) parts 40 CFR § 144 Subparts A through E as well as 40 CFR § 146 Subpart E. The UIC Class VI regulations set minimum technical criteria for several aspects of CO_2 storage in order to ensure safe and effective operations and site closure. Class VI well requirements are designed to protect USDW. Requirements address siting, construction, operation, testing, monitoring, and closure.

The regulations address the unique nature of CO_2 injection for geologic storage, including the relative buoyancy of CO_2, the high subsurface mobility of supercritical CO_2, corrosivity of CO_2 in the presence of water while under subsurface pressure and temperature conditions, as well as the large injection mass anticipated at geologic storage project sites [3, 41] . Specifically, EPA developed criteria for Class VI wells that include [40],

- Extensive site characterization requirements
- Injection well construction requirements for materials that are compatible with and can withstand contact with CO2 over the life of a geologic storage project
- Injection well operation requirements
- Comprehensive monitoring requirements that address all aspects of well integrity, CO2 injection and storage, and ground water quality during the injection operation and the post-injection site care period
- Financial responsibility requirements assuring the availability of funds for the life of a geologic storage project (including post-injection site care and emergency response)
- Reporting and recordkeeping requirements that provide project-specific information to continually evaluate Class VI operations and confirm USDW protection

To date, EPA has issued a total of 6 Class VI permits; two wells were permitted for construction and CO_2 injection associated with the Archer Daniels Midland (ADM) project, and 4 wells were permitted for construction associated with the FutureGen 2.0 Project. The FutureGen 2.0 project was not completed, and the injection wells were not constructed. In the case of ADM project, the initial well was developed as part of the Illinois Basin Decatur Project (IBDP) and operated from 2011 to 2014, and is now in the post injection site care (PISC) phase of the Class VI permitting process. The second Class VI well associated with ADM project was developed as part of the Illinois Industrial Carbon Capture and Storage (IL-ICCS) project, which began CO_2 injection operations in 2017.

As of November 2020, Class VI program oversight has been delegated by EPA to North Dakota and Wyoming. EPA has indicated that Louisiana is also pursuing oversight authority for Class VI wells. States can be approved for this delegation of "primacy" when their regulations meet or exceed the federal UIC requirements.[f] [42]

The owners/operators of CO_2 geologic storage sites must also meet the requirements of EPA finalized regulations for "Mandatory Greenhouse Gas Reporting" for "Geologic Sequestration of Carbon Dioxide" (referred as Subpart RR under 40 CFR § 98.440 – 449) in addition to the Class VI-related regulations. This rule mandates the reporting of GHGs from facilities that inject CO_2 underground for containment over the long-term. The rule is complementary to and builds on EPA's UIC requirements. [43] Under the authority of the Clean Air Act, EPA finalized GHG reporting requirements for suppliers of CO_2 (including CO_2 capture), underground injection, and geologic storage of CO_2. The EPA's GHGRP oversees the associated GHG reporting under Subpart RR. [44] Compiled data is also made public each year.

Subpart RR requires facilities implementing geologic storage of CO_2 to 1) report basic information on the amount of CO_2 received, injected, and produced; 2) develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; 3) outline data and reporting requirements; and 4) report on the amount of CO_2 stored in the subsurface. [45] The MRV plan outlines a monitoring strategy for detecting and quantifying surface releases of CO_2 and an approach for establishing baselines for monitoring CO_2 surface releases. The plan is intended to be site-specific and establishes reporting on the amount of CO_2 stored in the subsurface using a mass balance approach. The MRV plan identifies the maximum monitoring area (MMA) and the active monitoring area (AMA). The MMA is defined as the area that must be monitored and is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized, as well as an all-around buffer zone of at least one-half mile. NETL has indicated that the AMA is an overlay between 1) the area projected to contain the free phase CO_2 plume at the end of a specific timeframe established by the operator, plus an all-around buffer zone of one-half mile or greater, if known release pathways extend laterally more than one-half mile; and 2) the area projected to contain the free phase CO_2 plume at the end of five years after the specific monitoring timeframe has passed. [46] This AMA-determined timeframe enables site operators to phase in monitoring so that during any given time interval, only that part of the AMA prone to leakage would require monitoring. [45] The boundaries of the AMA needs to be periodically reevaluated. The MRV plan must be developed by the project and approved by the EPA Administrator within the GHGRP. A summary of the technical requirements regarding Subpart RR is available in Appendix C: Overview of GHG Reporting Requirements Under Subpart RR.

The Subpart RR reporting requirements ensure that appropriate consideration is given to key monitoring elements of geologic storage projects. Geologic storage R&D projects can be granted an exemption from Subpart RR reporting but would then be required to report basic information on CO_2 received under Subpart UU. [47]

[f] Delegation of primary UIC enforcement authority from EPA to states, territories, and tribal regions is referred to as primacy. More information on primacy can be found on EPA's UIC primary enforcement authority website: https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program

2.3 Controlling Geologic Conditions Favorable for Safe and Effective Storage of CO_2

Decades of field experience from CO_2 EOR operations and CCUS-demonstration projects has shown that safe and effective long-term storage of CO_2 requires comprehensive knowledge and accounting of reservoir characteristics and other key geologic parameters that should be considered in the process of designing, constructing, and operating a successful geologic carbon storage project.

Candidate storage sites should, at a minimum, contain certain conditions that have been shown to provide for safe and effective injection and storage operations. [61] Additionally, sites must also be operated, monitored, and closed in a manner that avoids or manages risks. The UIC Class VI rules under 40 CFR § 146 contain a series of requirements that relate to the specific objectives of each project stage, outlined in Exhibit 2-5. The list of requirements is too lengthy to present in this report, but NETL summarized these relevant UIC Class VI requirements in the Analog Studies to Geologic Storage of CO_2 series [3, 26, 54, 34]; a summary is provided in Appendix B: Summary of UIC Class II and VI Technical Requirements.

The UIC requirements are intended to ensure that candidate storage sites can receive and store the volumes of CO_2 specified by operators, while protecting USDW, throughout each project stage. Additionally, the body of practical knowledge gained and best practices distilled from R&D and commercial field CCUS projects (discussed in Section 2.6) has facilitated the refinement of storage project implementation strategies over time. [30, 64] With these best practices established, geologic carbon storage projects are better prepared to safeguard against risks and potential impacts by implementing best practices into each project stage to exceed minimum regulatory requirements for protecting USDW while also effectively managing risks to human health and the environment.

A successful geologic carbon storage project must develop credible characterizations of reservoir and other geologic parameters, and define safe engineering operational envelopes to ensure, with sufficient confidence of the EPA or state regulatory authority, that a candidate site:

- Contains sufficient capacity for the volume of CO_2 expected to be stored over the life of a given project(s)
- Possesses the necessary injectivity (the measure of the ability of a formation or reservoir to accept injected fluids or gas) in order to receive CO_2 in the subsurface at the desired rate
- Has storage interval(s) with adequate depth so that the natural pressure and temperature can maintain stored CO_2 in a dense, supercritical state (typically greater than 2,600 ft, but can vary from site to site)
- Can confirm that the storage reservoir is not considered USDW—the total dissolved solids content of the native reservoir fluids must be greater than 10,000 parts per million total dissolved solids or greater, per EPA UIC rules

- Provides for safe injection and storage such that leakage of CO_2 or other displaced formation fluids is avoided, or, if it happens, it can be minimized and provide marginal impact
- Can be constructed, operated, and monitored to assure safe operations
- Can establish USDW non-endangerment after injection operations are complete so that the site can be closed and decommissioned

The requirements in the list above can be directly attributed to CO_2 storage site performance indicators that are required by EPA for safe, efficient, and successful CO_2 storage operation. These include: 1) injectivity, which is the rate at which CO_2 can be injected; 2) storage capacity, which is the total volume of CO_2 that the subsurface storage reservoir(s) can safely contain; and 3) containment, which relates to CO_2 retention in the subsurface over the long term. [50, 51, 52, 53, 54]

Injectivity is directly proportional to permeability, height or thickness of a reservoir open to injection, and the bottom-hole and reservoir pressure differential. Horizontal wells are an option for improving exposure to a greater extent of the reservoir, which may achieve larger injection rates while maintaining injection at lower pressures compared to vertical well configurations. [54, 55] Excessively high injectivity may not be favorable in many cases as it can lead to channelized CO_2 flow in the subsurface, which is sub-optimal for contacting and utilizing for storage the full extent of the reservoir's capacity, thereby reducing the total amount of CO_2 that can be stored effectively. Similarly, sand lenses or open fractures may act as high permeability channels that allow CO_2 to move much faster than would be expected based on the bulk properties of the rock. [56] Injectivity into shallow and lower permeability reservoirs can potentially be limited by the maximum allowable injection pressure. [57] Injection wells must operate below a minimum fracture pressure per UIC Class VI rules[g] to avoid initiating fractures in the confining zone(s) or cause the movement of injected CO_2 or formation fluids that could endanger USDW.

Storage capacity is the potential volume of a given formation for storage of a liquid or gas. It is a function of reservoir thickness, areal extent, porosity, and the density of CO_2 at specific subsurface temperature and pressure conditions. An additional parameter influencing storage capacity is the CO_2 storage efficiency, which could be called the effective pore volume. [58, 59, 53] The effective pore volume is the portion of the pore volume that would retain or store injected CO_2 out of the entire pore volume available. Reservoir heterogeneity at various scales (pore to basin-scale), is influenced heavily by reservoir depositional systems, and overall unit architectural settings are also factors. Additionally, the storage efficiency is also a function of developmental strategies and injection well planning. For instance, capacity (like site-wide injectivity) can be increased by deploying more wells and through optimized well design and/or placement within the storage reservoir, with approval of the permitting authority. [55]

Containment is essential for effectively storing large volumes of CO_2 in the subsurface. Since injected CO_2 is buoyant relative to other subsurface fluids (formation brine), gravitational

[g] For UIC Class VI wells, the exception to this rule is during any planned stimulation events per 40 CFR §146.88(a).

(buoyancy) forces will, therefore, drive CO_2 upward from point of injection toward the top of the storage reservoir. A confining layer(s) (also called a caprock, confining unit, or seal) is a geologic formation or series of formations that overlie the storage reservoir and prevent vertical migration. Shales, thick deposits of evaporites (like anhydrite/gypsum and salts), or certain carbonate rocks are common caprocks in a confining zone. [55, 24, 54] Confining layers should also be laterally extensive to ensure CO_2 containment as the plume expands over time. [60] Each of these key characteristics is influenced by prominent controlling geologic factors, which are summarized in Exhibit 2-4.

Exhibit 2-4. Summary of geologic controlling factors related to injectivity, storage capacity, and containment for potential geologic CO_2 storage sites

Characteristic	Favorable Geologic Controlling Factors	Inhibitors
Injectivity	• Thick reservoirs • High reservoir permeability • Homogeneity in reservoir permeability distribution	• Effective permeability constraints arising from geochemical effects (e.g., mineral dissolution/precipitation phenomena, salt precipitation) • Reservoir over-pressurization from injection and/or proximity to other injection wells • Near-well formation damage and effective permeability loss • Transport constraints associated with CO_2 and rock interactions
Storage Capacity	• Large reservoir areal extent • Large reservoir thickness • High reservoir porosity • Stacked reservoirs • Open boundary system	• Thin reservoirs with low net storage thickness • Limited effective pore volume due to high heterogeneity • Formations with limited areal extent and closed or semi-closed boundary conditions
Containment	• Multiple and/or thick confining zones that are laterally extensive • Low confining zone permeability absent of faulting or fractures • High confining zone capillary entry pressure • Absence of leakage conduits • Closed boundary system	• High permeability zones causing extensive vertical or lateral CO_2 and/or brine migration • Poor integrity of wellbores penetrating confining layers • Thinning or intermittent presence of caprock • Dissolution of confining zone material due to reactions with CO_2/brine mixture • Natural or induced seismic activity, which may activate flow pathways in confining units

When these specific characteristics are present at a candidate site, a “subsurface storage complex" exists, which is a geologic storage site with favorable subsurface conditions likely amenable for safe injection and permanent CO_2 storage. The characteristics are determined through a rigorous characterization process that includes assessing potential storage risks for new candidate sites and meeting the regulations under EPA’s permitting process, which grants permission to inject CO_2 for carbon storage purposes.

2.4 PHASES OF A CO_2 STORAGE PROJECT

The sequence of steps and actions for developing and implementing a CO_2 storage project can be broadly divided into several distinct project phases (Exhibit 2-5). Each phase of a project is intended to achieve specific objectives as it relates to implementing safe and effective CO_2 storage, and each of these phases is established under the Class VI regulations, including the specific data which is required for the issuance of a permit. Data and information collected in any given phase can and should be used to inform the implementation of subsequent phases. A brief summary of each phase and its role in CO_2 storage project development and execution is provided in the bullets below. Notable objectives associated with each phase, as well as an approximation of the timeframe to complete each phase based on a typical large-scale injection project, is provided in Exhibit 2-5: [54, 61, 3, 26]

- **Site screening:** Evaluating regions and sub-regions potentially suitable for CO_2 geologic storage based on analyses of readily accessible data. CO_2 source-to-sink matching is also critical. Potential sites that meet the necessary screening criteria can be selected for further, detailed characterization.
- **Site Selection and Characterization:** Builds on screening of selected sites to develop a more detailed characterization and understanding of the subsurface to assess a potential site's suitability for storage as a function of containment, injectivity, and capacity.
- **Permitting and Construction:** Utilizes data from site characterization to build a CO_2 injection permit application. Once an injection permit is approved, injection wells can be drilled, tested, and correlated with submitted geologic data; CO_2 injection is authorized. Monitoring wells and equipment are also installed. Relevant data collected during this phase, as well as the prior two phases, would be useful in evaluating projects pursuant to NEPA.
- **Operations:** Injection operational planning commences, active capture, transportation, and injection of CO_2 occurs, and site monitoring (pursuant to UIC and GHGRP) is conducted
- **PISC and Site Closure:** Involves monitoring of storage the reservoir(s) to assess stability of the CO_2 plume and to ultimately establish non-endangerment. Once non-endangerment is declared by the regulatory authority, site closure can be completed.
- **Long-term Stewardship:** The timeframe after PISC efforts result in determining non-endangerment and UIC Class VI stipulations are no longer in effect. The injection operator is released from any liability from CO_2 injection. While various states are establishing long-term liability policies [62], issues regarding financial liability and long-term stewardship of injection sites will need to be addressed on a project-by-project basis. [63]

Several of the project phases are also relevant to both NEPA and GHGRP requirements. For instance, the site screening, selection, and characterization project phases generate volumes of data related to the surface and subsurface conditions at candidate storage sites; information that could be useful as part of a NEPA EA or EIS development for federally subsidized projects.

Under Subpart RR, implementation of the MRV plans would occur during the operation and PISC periods of storage projects. As a result, there is overlap and synergies related to UIC requirements, NEPA, and Subpart RR at different stages of a given project's life.

Exhibit 2-5. Typical stages and expected typical completion timeframes for a large-scale CO_2 storage project in saline-bearing formations

<table>
<tr><th rowspan="2">Site Screening</th><th>Site Selection and Site Characterization</th><th>Permitting and Construction</th><th>Operations</th><th>PISC and Site Closure</th><th>Long-Term Stewardship</th></tr>
<tr><th colspan="4">UIC Class VI Regulations Applicability</th><th rowspan="2">Developing State Regulations</th></tr>
<tr><th colspan="3">Collected Data is Applicable to Informing the NEPA Process</th><th colspan="2">UIC Class VI Permit Applicable
MRV Plan Applicable</th></tr>
<tr><th>Up to 1 year</th><th>3+ years</th><th>2+ years</th><th>30 to 50 years</th><th>1 to 50+ years[1]</th><th>Length to be determined</th></tr>
<tr><td>Existing datasets gathered and analyzed

Evaluate source to sink proximity and connectivity

Down-select promising candidate sites</td><td>Down-selected sites undergo more detailed characterization including drilling test well

Prepare project plans for permitting

Select most promising site(s) for further development based on suitability of regional geologic structures conducive to receiving and confining the CO_2

Complete initial AoR[2] delineation via computational modeling

Acquire pore space rights</td><td>Development and submissions of permit proposals

Demonstrate financial responsibility

Drill and complete injection well(s)

Incorporate new well data into planning documents; work toward approval for injection

Construct site infrastructure, including installing monitoring wells and equipment</td><td>Inject CO_2 per stipulations in UIC Class VI permit

Monitor within AoR and reevaluate AoR extent periodically

Implement required reporting stipulations; for both UIC and GHGRP

Maintain financial responsibility per potential cost variation</td><td>Monitor site, CO_2 plume, and AoR per approved UIC Class VI permit

Implement required reporting stipulations for UIC

Establish non-endangerment

Close and restore site

Maintain financial responsibility per potential cost variation</td><td>Separate entity (e.g., state agency) takes over long-term stewardship</td></tr>
</table>

[1] Studies by Bacon et al. (2019) and Lackey et al. (2019) have found via risk-based modeling that the majority of risk of endangerment to USDW decreases within the first five years after CO_2 injection operations end. [65, 66] Therefore, with robust justification provided to UIC regulators, site operators may be permitted to implement alternatives to the default 50-year PISC under UIC Class VI permits – dependent heavily on site-specific conditions, the volume of CO_2 injection, and the specific injection strategy and monitoring strategies

[2] The area of review (AoR) per 40 CFR § 146.6 is a region surrounding the injection well(s) where USDW may be endangered by the injection activity, most notably due to pressures in the injection zone potentially causing the migration of the injection and/or formation fluid into USDW

2.5 Effects of CO_2 Injection into the Subsurface

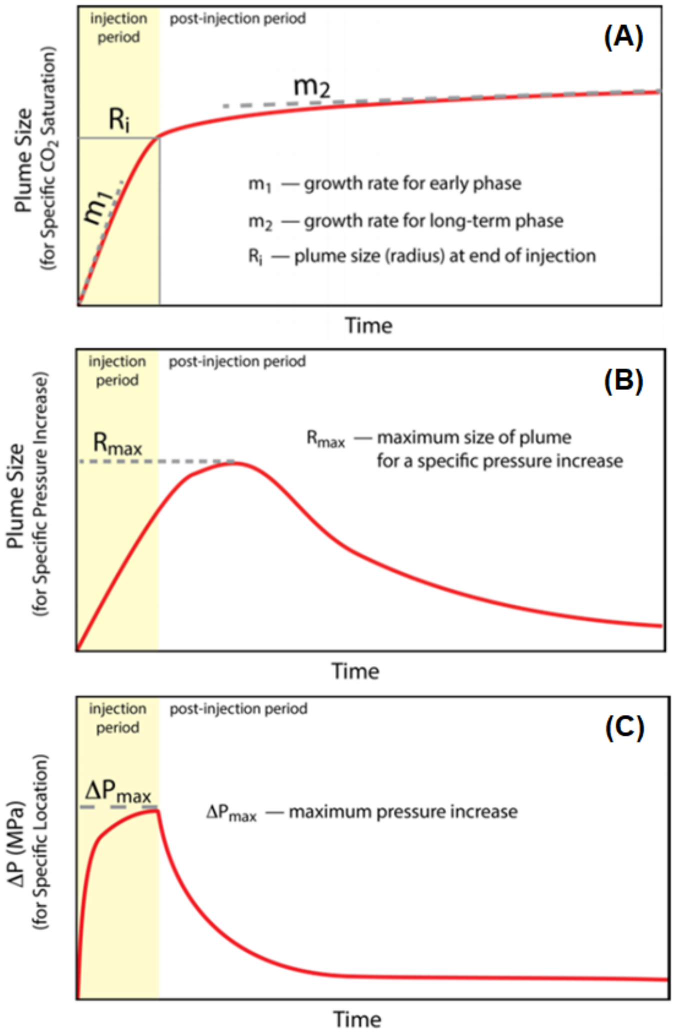
Injection of CO_2 into a porous storage reservoir(s) requires the displacement of the incompressible brine. Consequently, injection must occur at pressures that exceed the in situ formational pressures. [67] CO_2 injection causes a buildup of reservoir pressure in areas surrounding the injection well(s) and a migration of both formation fluids and injected CO_2 away from the injection well(s). The resulting distribution of pressure and CO_2 saturation within the injection zone(s) are major concerns for CO_2 storage operators. For instance, pressure is of concern as elevated levels can impact the integrity of caprock and cause the potential migration of brine or CO_2 outside of the injection zone. The location of CO_2 within the reservoir is of concern as it relates to both storage rights consideration (i.e., pore space access and rights) and overall displacement efficiency and storage capacity utilization. [68]

For a given storage project, the size and shape of the CO_2 plume and associated pressure front are strongly site-specific and depend on factors like the volume of CO_2 injected over the project duration, the number, placement, and orientation (e.g., vertical, deviated, or horizontal) of injection wells and brine production wells (for reservoir pressure management scenarios), and geologic aspects of the confining system and injection zone. These geologic aspects include specific reservoir geometry and architecture, heterogeneity, and anisotropy in geologic characteristics (as described in Exhibit 2-4). Specific factors noted that affect the mobility of CO_2 in the subsurface include

- Presence or absence of a stratigraphic trap(s)
- Presence or absence of a structural trap and existence of regional ground water flow
- Movement up-dip at the interface of injection zone and confining zone
- Presence of significant high-permeability pathway(s) that can result in preferential plume migration
- Effects associated with geochemical mechanisms
- Continual presence of a pressure differential (e.g., via CO_2 injection or due to other near-by operations) that can result in fluid movement

The size and shape of the CO_2 plume will increase over the period of active injection as well as after injection ceases (Exhibit 2-6). [69] An example of CO_2 plume and pressure response over time based on numerical simulation of reservoir response in the previously proposed FutureGen 2.0 project is presented in Exhibit 2-7 and Exhibit 2-8.

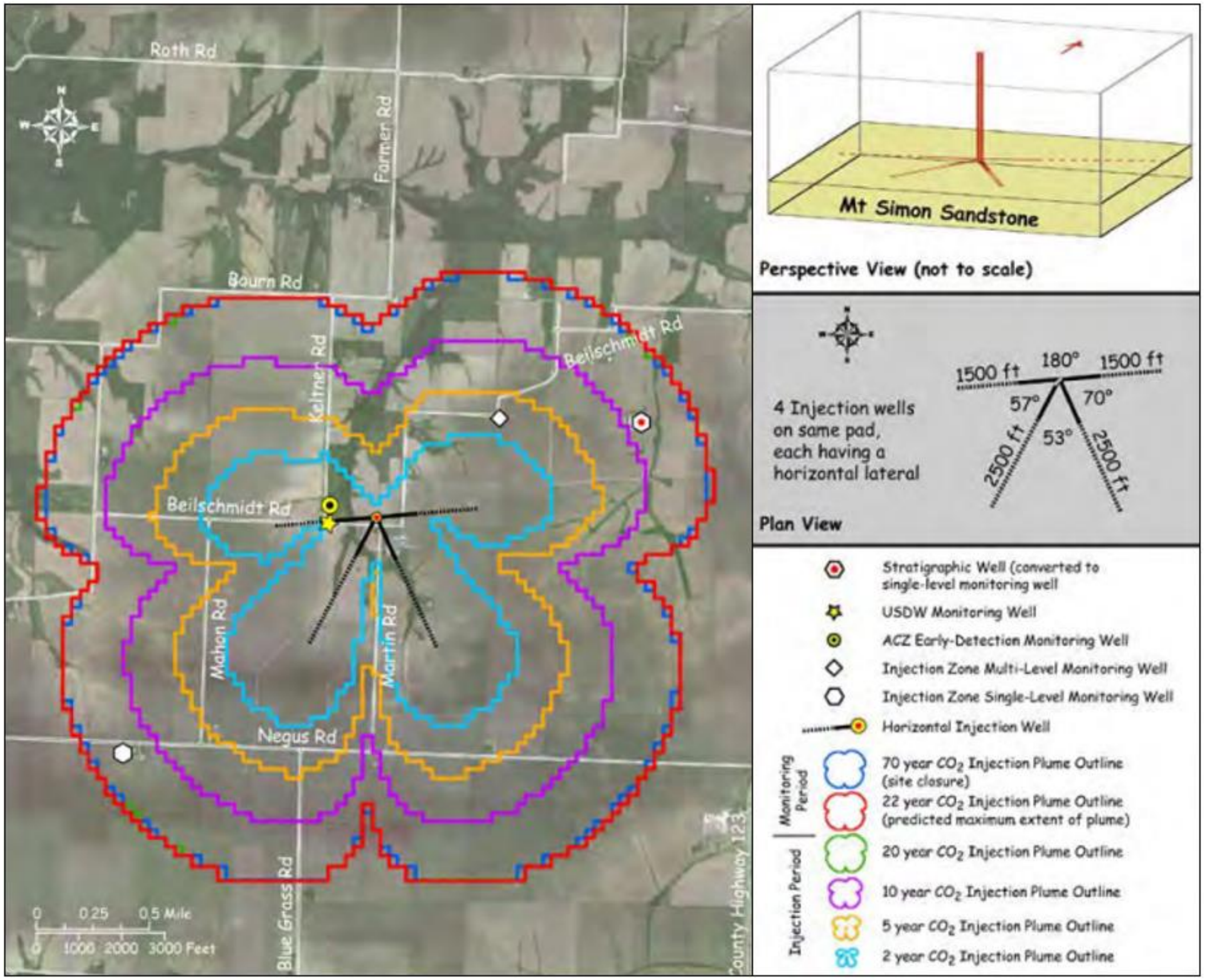
Exhibit 2-6. CO_2 plume and pressure front evolution over time [69]



Note: (A) schematic of the time evolution of a plume of CO_2, (B) schematic of the time evolution of a pressure plume, and (C) schematic of the time evolution of a pressure differential predicted at a particular point in reservoir

Relative low density of CO_2 relative to brine means that gravity tends to drive the buoyant rise of injected CO_2 in the storage reservoir. Additionally, the relatively low viscosity of supercritical CO_2 relative to brine corresponds to a higher mobility of the CO_2 relative to brine resulting in poor displacement and sweep efficiencies. [70, 71, 72] As a result, the CO_2 plume can continue to move during the injection phase, through the PISC phase, and beyond. However, as described in Section 2.1, several trapping mechanisms within the subsurface keep CO_2 immobile over the long term. [73, 74] In most saline aquifer geologic storage scenarios, the primary trapping mechanism is typically structural trapping; secondary trapping mechanisms include stratigraphic trapping, solubility trapping, and residual trapping mechanisms. Secondary trapping mechanisms tend to contribute more to overall CO_2 trapping over time. [75]

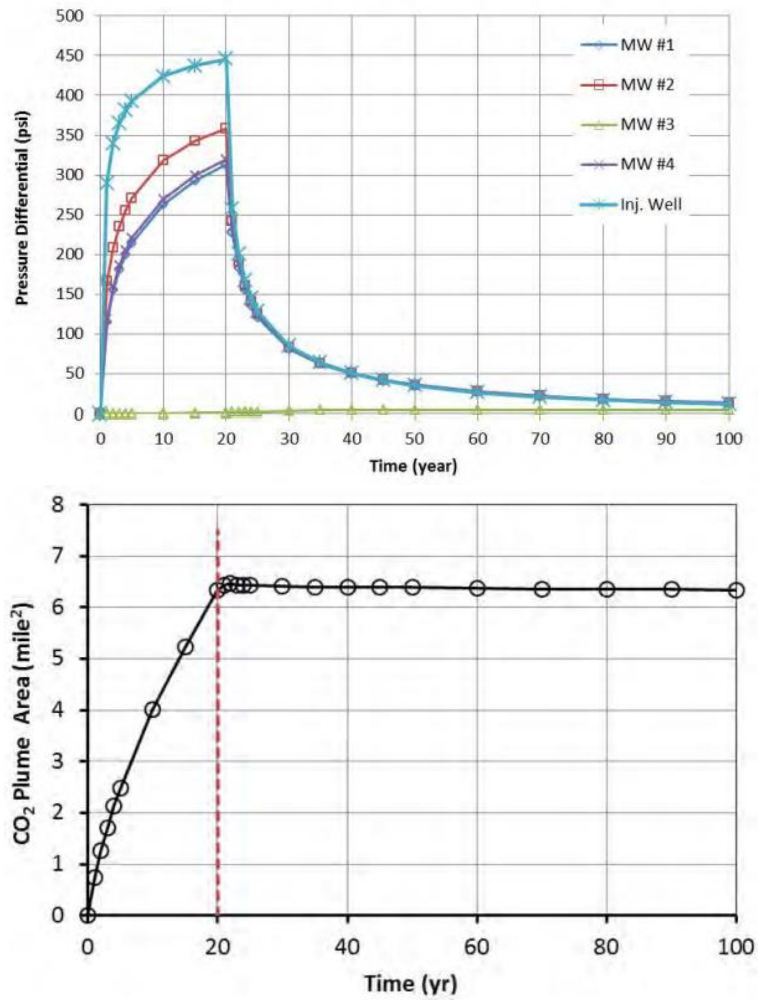
Exhibit 2-7. Time-series representations of the forecasted CO_2 plume at the FutureGen 2.0 project in the Illinois Basin



Note: The layout of the proposed injection and monitoring wells is also included

Source: EPA [76]

Exhibit 2-8. Simulated pressure differential versus time (top) and simulated plume area over time (bottom) for the FutureGen 2.0 project in the Illinois Basin



Source: EPA [76]

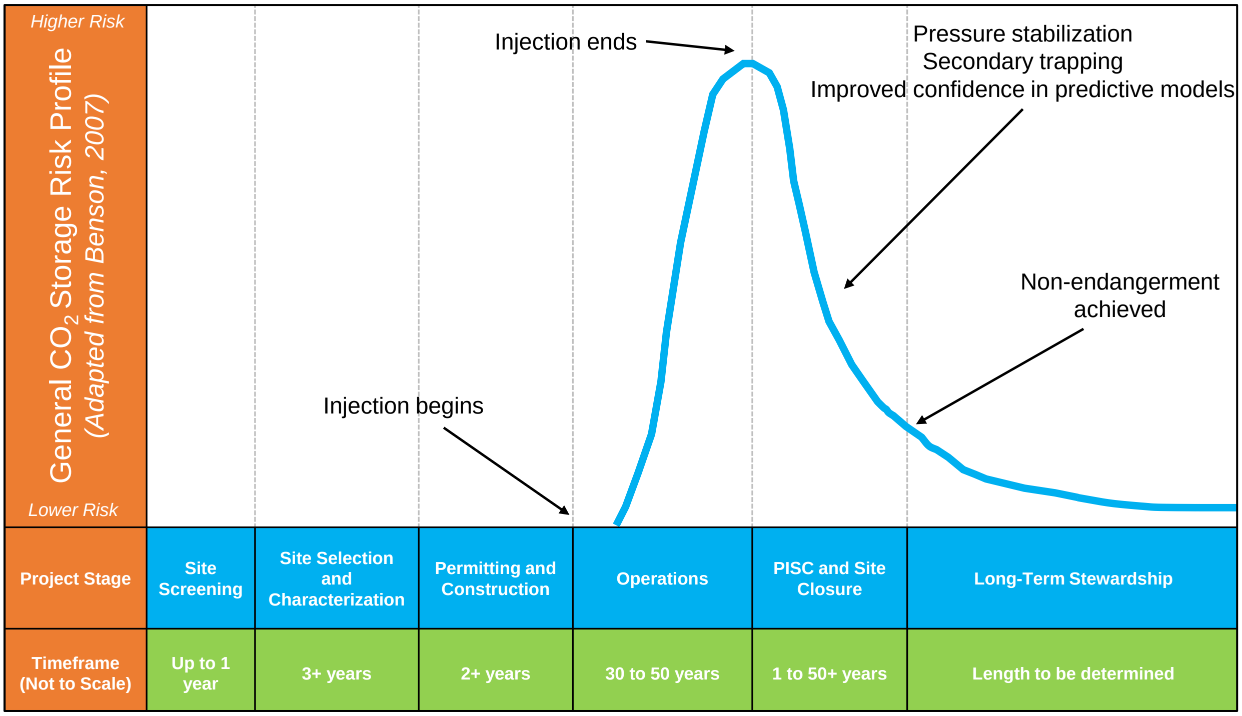
The pressure front (considered the extent of the pressure differential that is significant enough to cause adverse impacts to overlying receptors) associated with the CO_2 injection may extend significantly farther than the CO_2 plume itself. [77] This is particularly true in saline aquifers, where the geographical area affected by elevated pressure may be several orders of magnitude larger than the area occupied by CO_2. [78, 79, 77] The degree to which pressure will build up in the storage reservoir depends on a combination of operational and geologic factors including the CO_2 injection rate, rock properties like permeability, and the volumetric size of the storage reservoir, as well as the prevailing boundary conditions. Larger reservoirs with high permeability and an effectively open or semi-open boundary condition at the reservoirs' lateral extents may experience a relatively smaller buildup of pressure as compared to a smaller reservoir with closed or semi-closed boundary conditions, which would experience a more rapid pressure increase. [24]

The resulting increase in reservoir pressure due to CO_2 injection needs to be considered and managed because excessive pressure may induce hydraulic fracture formation, fault reactivation, seismic and aseismic slip, and the exceedance of caprock capillary entry pressure. [80, 81] Elevated formation pressure could also force CO_2 and other formation fluids through existing conduits, such as transmissive faults and improperly plugged abandoned wells. High formation pressure can impact overlying receptors, even if no leakage occurs and all injected CO_2 remains contained within the injection zone. For instance, injection-related pressure increase in shallow injection reservoirs (with burial depth <2,000 ft depth) may cause uplift of associated overburden, [82] which may potentially impact groundwater flow direction and water table levels in shallower formations, or potentially result in surface deformation. Prior to the start of any CO_2 storage project, operators should evaluate site-specific geologic attributes and operational parameters to determine the impact that expected injection pressures will have on the storage formation, caprock, and overburden. Therefore, the potential effects from elevated pressure can be minimized and managed through comprehension of 1) the relevant geologic attributes attained through site characterization and 2) the response of the geologic system to injection via reservoir simulation and an effective monitoring campaign.

The combination of the CO_2 plume and associated pressure front make up the footprint associated with CO_2 storage. [56] EPA's UIC rules denote that footprint extent provides the basis for the AoR. Delineation of the AoR may be performed at multiple stages of the project, as the footprint expands and changes shape during injection (as well as during PISC). Modeling and simulation that accounts for the physical and chemical properties of the injected CO_2 and associated fluids displaced is used in concert with site-specific data (e.g., 3D seismic, monitoring well logs) to delineate the total project footprint. Additionally, AoR delineation helps in refining and implementing effective monitoring strategies as the project progresses through operations and into PISC, as well as aid the project developer for acquiring proper authorization to access and use pore space to avoid liability for subsurface trespass and nuisance.

In general, the overall vulnerability to potential adverse impacts is expected to vary with time depending on the CO_2 storage project stage, as illustrated in Exhibit 2-9. The potential risk associated with storage sites increases with increased volumes of stored CO_2 and increased reservoir pressure. [83] After injection commences, pressure in the storage reservoir begins to build up. The pressure front may dissipate after injection stops or may remain elevated (more common for closed systems), depending on the lateral boundaries of the storage complex. Secondary trapping mechanisms become more prominent over time as well. Additionally, information attained from site monitoring during injection and PISC refines models of the injection reservoir response. The result reduces uncertainty, which may improve confidence in forecasting the fate of the CO_2 in the subsurface, as well as the likelihood of any potential adverse impacts from occurring. [84]

Exhibit 2-9. Example of a general risk profile over the lifespan of a theoretical CO_2 storage project



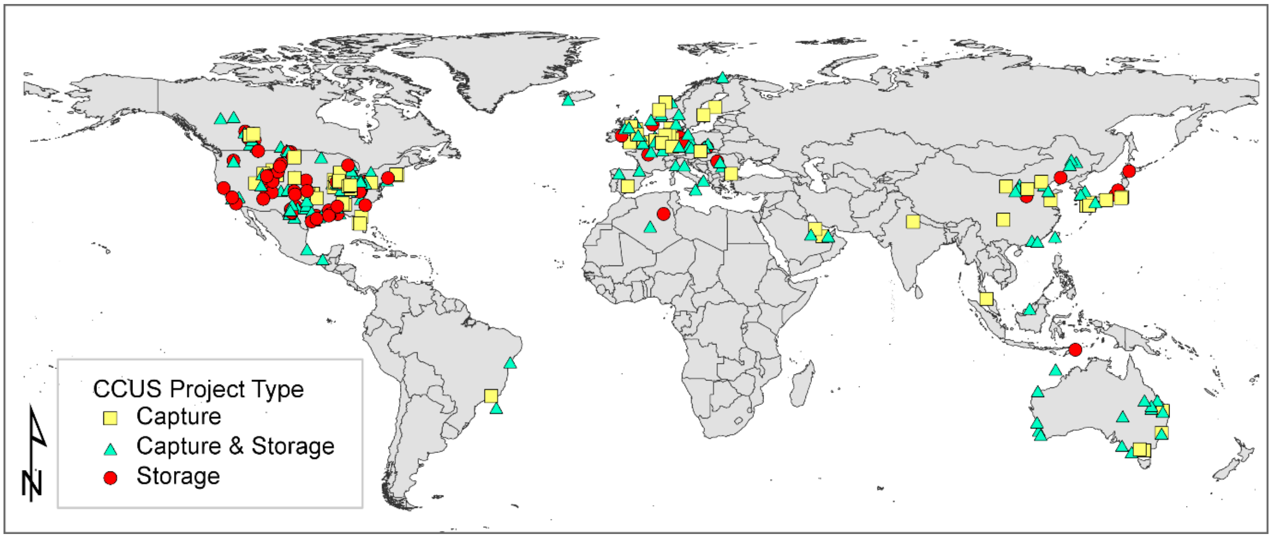
Note: Adapted from concepts from Benson (2007), Bromhal et al. (2014), and Pawar et al. (2015) [69, 84, 83]

2.6 Insights from CCUS Field Projects

The overall technology maturity and knowledge base for CCUS has increased substantially over the last decade and a half. In 2005, the IPCC special report on CO_2 capture and storage provided a summary of the state of knowledge about CCUS as an emerging technology for reducing CO_2 emissions to the atmosphere. [9, 28] The risks and impacts discussed in the 2005 IPCC report associated with the CO_2 storage component of CCUS emphasized more so on understanding the fate of injected CO_2, whereas less attention was placed on the effects of pressure buildup associated with CO_2 injection. [57] Since then, the CCUS community has significantly improved its overall knowledge base and addressed many of the technical gaps mentioned in 2005 by the IPCC. Nearly two-decades worth of financial investment in CCUS R&D worldwide has, in turn, led to the deployment of several field projects at various scales. A large body of research has subsequently been devoted toward characterizing the processes that control CO_2 migration, trapping, and containment in deep saline-bearing reservoirs [85, 35]—the CO_2 storage option that is the main focus of this report. As a result, field-, lab-, and modeling-based projects, as a collective whole, have created an extensive experience base that can inform planning and operational strategies for future CCUS projects.

As R&D activities continue to advance CCUS toward commercialization, field projects that implement and validate safe and effective CO_2 injection and storage technologies become critically important in generating best practices, lessons learned, and insights into the cause and effect of potential failure modes. Additionally, insights gained from CCUS field testing can help identify and potentially refine promising risk mitigation approaches. In 2018, NETL identified over 300 active, planned, or recently-completed CCUS-related projects (ranging from pilot testing to large-scale) across the globe (Exhibit 2-10). [8] These projects span various stages—from planning through project completion.

Exhibit 2-10. Map showing the locations of active, completed, or planned CCUS-related projects worldwide as identified by NETL [8]



Most of the world's current CCUS capacity is located in the United States and is attributed to a combination of government-supported pilot projects (implemented through the RCSPs, Clean Coal Power Initiative, and the Industrial Carbon Capture and Storage Program), capture and separation from several natural gas processing plants, and demand for CO_2 for use in EOR. [86] NETL's 2020 *"Safe Geologic Storage of Captured Carbon Dioxide - DOE's Carbon Storage R&D Program: Two Decades in Review"* reported that CCUS field projects supported by DOE and other organizations around the world have not demonstrated significantly adverse impacts to human health or the environment. Furthermore, research to date has indicated that no DOE-supported project has observed leakage or migration of CO_2 outside of the intended storage reservoir or above the confining caprock. [32]

While injection operations through the various field projects to date have largely been safe, experience has shown that the overall potential failure modes and impacts associated with CO_2 injection and storage can be extended beyond the containment-based risks that were the primary focus of the 2005 IPCC report. [84, 87] However, simultaneously, insights from the extensive set of CCUS field projects (Exhibit 2-10), combined with those gained from industries considered analogs, share technical grand challenge commonalities to CO_2 storage (like CO_2 EOR and underground natural gas storage [34]) and have helped to generate evidence-based best practices to identify and mitigate against potential failure modes and associated impacts. In fact, more recently deployed projects (Quest, in Alberta, Canada, and the IL-ICCS, in Decatur, Illinois) have taken advantage of the experiences and lessons learned from past projects and are implementing comprehensive risk assessment strategies aimed toward the development of optimized monitoring programs that evolve over the life of the project as risks are better understood and/or reduced. [88] A summary of CCS projects mentioned in this report is provided in Appendix D: General Information on CCUS Projects Referenced.

Section 3 provides an analysis of the potential failure modes, causes of failure, and failure effects, including those that are reasonably foreseeable significant adverse impacts (per 40 CFR 1502.21) to the human environment (described in Section 1) associated with CO_2 injection and storage into the subsurface. These failure modes and effects are based on an extensive review of current and credible scientific research related to CCUS generated through years of field and laboratory experience. The analysis in Section 3 is focused on failure modes and associated effects to the human environment from the injection and long-term storage of CO_2, and not on the effects associated with surface development activities or CO_2 capture, compression, and transportation.

3 Potential Failure Modes and Associated Effects to the Human Environment Related to Onshore Geologic Storage of CO_2

A significant degree of effort has been put into the development of frameworks for risk assessment and risk management associated with CCUS. [89] Risk management guidelines for CO_2 storage projects can be found in a best practices manual published in 2017 by NETL on "Risk Management and Simulation for Geologic Storage Projects." [87] Other notable developments in risk management can be leveraged as guidelines by CO_2 storage projects. Examples include

- EPA's "Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide" published in 2008 [56]
- ISO 310000 Risk Management – Principles and Guidelines, published in 2009, which provides risk management principles and generic guidelines [90]
- ISO 27914:2017 – This standard is specific to establishing requirements and recommendations for the geological storage of CO_2 with the purpose to promote commercial, safe, long-term containment of CO_2 in ways that minimize the risk to the environment, natural resources, and human health [91]
- Canadian Standards Associate's "Z741-12 – Geological Storage of Carbon Dioxide," published in 2012 with the intent to establish requirements and recommendations for geologic CO_2 storage, including specific risk management principles [92]
- Quintessa's "Generic CO_2 Features, Events and Processes (FEP) Database," updated periodically between 2006 and 2014, which provides a comprehensive list of all possible risk sources (or failure mechanisms) for CO_2 storage projects [93]
- Suite of risk assessment tools and guidance documents published by the National Risk Assessment Partnership (NRAP) initiative within DOE's Office of Fossil Energy and led by NETL [94]
- Quantitative failure modes and effects analysis (QFMEA) model, developed by Headwaters Clean Carbon Services LLC and its associates for DOE/NETL "Comprehensive, Quantitative Risk Assessment of CO_2 Geologic Sequestration," (Federal Award Number DE-FE0001112), determines quantitative risks and predicts quantitative impacts for CO_2 geologic storage project sites (i.e., deep saline reservoirs, enhanced oil recovery operations, or enhanced coal bed methane operations) along with other aspects of the CCUS value chain. Potential damage recovery costs, risk prevention/mitigation costs, and potential cost savings associated with risk mitigation are quantified while considering the complexity of detecting a failure early in selecting risk areas. The flexible QFMEA model can incorporate input from multiple sources (e.g., literature reviews, field data, computer simulations, etc.) and be modified as new information becomes available [95]
- Peer-reviewed journal articles on geologic CO_2 storage risk management. For example: Damen et al., discusses risks of CO_2 storage, risk mitigation, and avenues for R&D; [96]

Condor et al., compares CO_2 storage risk assessment methodologies; [97] Pawar et al., reviews advances in risk assessment and risk management associated with containment, site performance, public perception and market failure risks; [84] and Godec summarizes lessons learned from storage field projects [risk assessments] emphasizing preparation, start-up, and early injection operations [88]

ISO 27914:2017 for CCUS specifically recognizes that "site selection and management are unique for each project and that intrinsic technical risk and uncertainty will be dealt with on a site-specific basis". [91] As discussed in Section 1, "risk" implies the coupling of both the probability of a specific cause of failure and the severity of that failure's impact as defined by the stakeholders assessing risk. In risk assessments, probability and potential severity are typically ranked on numerical scales representing low to high probability, and low to catastrophic impact, respectively. Semi-quantified risks can therefore be ranked by their risk scores, and risk management procedures can be developed to address the highest-ranked risk scenarios of all coupled cause of failure/failure effect scenarios considered. [87] This report, however, is designed to be relevant to generally all onshore saline storage projects, and does not consider site-specific cause of failure probabilities nor site-specific severity of failure effects. Therefore, it does not formally assess risk in the context of a specific CO_2 storage project. This report also does not prescribe any specific risk assessment methodology; however, CO_2 storage site operators should perform and continually update a site-specific risk assessment as best practice. [87]

To inform stakeholders when considering site-specific risks, potential failure modes, and potential effects should failures occur, this section of the report provides a summary of existing credible scientific evidence synthesized from relevant sources of technical literature (reports, journal articles, presentations, and risk assessment frameworks), evaluation of environmental project assessments related to CCUS projects reviewed by DOE, and UIC permit applications (where applicable), which is relevant to evaluating the reasonably foreseeable significant adverse impacts of CO_2 injection and CO_2 storage (limited to storage in saline formations) on the human environment (defined in Section 1). Potential failure modes, causes of failure, and failure effects (terms defined below) are presented, along with "best practice" methods of failure prevention, failure detection, and failure mitigation.

The following definitions for nomenclature used in this study are derived and modified from the QFMEA approach of Lepinski, [95] in the context of the definitions for *"human environment"* in 40 CFR § 1508.1 and *"reasonable foreseeable significant adverse"* from 40 CFR § 1502.21 (see Section 1):

- **Potential failure mode(s)** – broad category that describes a type of event that if it occurs could result in adverse effects on the human environment. Each **potential failure mode** category consists of various potential causes of failure associated with CO_2 injection and/or storage in saline formations.[h] **Potential failure modes** common to CO_2 injection and storage regardless of any specific site corresponds to three prominent categories:

[h] Underlined terms are defined elsewhere in this section.

lateral containment failure, vertical containment failure, and induced and triggered seismicity.

- **Cause(s) of failure** – the underlying cause(s) of a potential failure mode, **causes of failure** are numerous and can be interrelated; examples include reservoir overpressure, insufficient reservoir properties, and seismic activity. Physical features, discreet events, and long-term processes (collectively termed, generically, “FEPs” [93]) commonly used in risk assessment literature are synonymous with **causes of failure**. [87] Excluded from this report are external causes of failure not directly associated with CO_2 injection and/or saline CO_2 storage (e.g., wellhead damage during routine maintenance, extreme weather events, terrorist attacks, or bolide (meteor) impacts).
- **Potential failure effect(s)** – impacts to the human environment resulting from one or more causes of failure; **potential failure effects** are broadly categorized in this report as 1) contamination to USDW, 2) contamination to non-USDW resources (which includes subsurface, surface, and/or atmospheric resources), and 3) physical damage to surface infrastructure or topography.
- **Failure prevention** – site characterization, site screening, and operational approaches and techniques that if employed, can reduce the probability of causes of failure occurring and/or can reduce the severity of potential failure effects. **Failure prevention** during operations often leverages failure detection techniques or operational best practices. The existing failure prevention toolset is substantial, and is derived from lessons learned from past CO_2 storage projects and other analogous industries (e.g., natural gas storage, CO_2 EOR, and subsurface disposal wells) [34]. Many **failure prevention** best practices are incorporated into UIC Class VI regulations and practiced by current CO_2 storage projects. Summaries of best practices are available in the literature (e.g., [52, 98]).
- **Failure detection** – monitoring techniques that if employed, can detect causes of failure directly, or indirectly by detecting potential failure effects. **Failure detection** techniques preemptively reduce the probability of causes of failure occurring by providing indication that a cause of failure may be plausible unless failure prevention operational approaches are implemented. **Failure detection** can reduce the severity of potential failure effects by detecting causes of failure or potential failure effects allowing for timely failure mitigation operational approaches to be implemented.
- **Failure mitigation** – techniques and that can be employed to remedy a cause of failure, should one occur, and to reduce the severity of future failure effects on the human environment. Excluded in this report is discussion on how potential failure effects¬ are mitigated (e.g., water treatment, ecosystem remediation), which are referenced in other literature (e.g., [99, 100]).

Section 3.1 and its subsections list and discuss 1) potential failure modes, 2) prominent examples of underlying causes of failure, 3) failure prevention tools and techniques, 4) failure detection tools and techniques, and 5) failure mitigation tools and techniques.

Section 3.2 and its subsections 1) list potential failure effects associated with onshore CO_2 injection and saline storage, and 2) discuss the potential severity of the listed potential failure effects in context of which represent reasonably foreseeable significant adverse impacts to the human environment.

Section 3.3 discusses the IBDP and IL-ICCS projects as case studies to illustrate how predicted possible causes of failure and potential failure effects, in the context of risk assessment, are changed and updated as new site characterization, injection operations, and monitoring data (i.e., data from failure prevention and failure detection tools and techniques) is acquired, analyzed, and integrated into risk management.

3.1 Potential Failure Modes, Causes of Failure, and Best Practices for Failure Prevention, Detection, and Mitigation

As discussed in Section 2.5, CO_2 injection and storage potential failure modes and causes of failure are related to the inability of the carbon storage complex to handle increases in reservoir pressure and/or effectively contain fluids (CO_2 and brine). Causes of failure, can be categorically grouped into three prominent potential failure modes:

1) Lateral containment failure
2) Vertical containment failure
3) Induced and triggered seismicity

Causes of failure are listed by failure modes in Exhibit 3-1, Exhibit 3-2, and Exhibit 3-3. Failure prevention, failure detection, and failure mitigation best practice approaches associated with each cause of failure are also listed in these exhibits. These best practices help avoid or reduce the probability of causes of failure occurring, and/or reduce the impact of the potential failure effects listed in Section 3.2 and Exhibit 3-6. These best practices are often required to be performed as part of the permitting process and regulatory reporting, especially those methods associated with preventing, detecting, and mitigating sources of failure that can lead to USDW contamination.

In several circumstances, a single best practice technique may be relevant to multiple causes of failure. For example, a few prominent uses of 3D seismic surveys for failure prevention and failure detection include:

- 3D seismic provides a geophysical interpretation of the subsurface over large spatial scales and can be used to estimate lateral continuity, thickness, and geomechanical and petrophysical properties (when calibrated against log and core data) of the storage reservoir(s), caprock(s), and other overburden layers
- 3D seismic interpretation can assess the storage complex's geologic structure (geometry) and locate most faults that could impact vertical containment or lead to triggered seismicity

- Comparing 3D seismic surveys acquired at different times (i.e., 4D seismic) can show where geophysical properties in the reservoir have changed over time indicating the extent of CO_2 plume growth

Acquiring and interpreting 3D seismic prior to operations is a failure prevention best practice that informs the site selection processes before CO_2 injection and underpins the reservoir models used to predict CO_2 plume movement. Acquiring and interpreting repeated 3D seismic surveys is a failure detection best practice to monitor CO_2 plume movement during and after injection. These activities help avoid or reduce the probability of occurrences of causes of failure that could potentially lead to lateral containment failures, vertical containment failures, and/or induced and triggered seismicity.

Another example of a best practice that is applicable to many, if not all, causes of failure is the failure mitigation approach of reducing or stopping CO_2 injection operations if a cause of failure is likely to occur or is in fact detected. Using water production wells to reduce reservoir pressure and/or improve CO_2 storage capacity is another failure mitigation (and failure prevention) option that is applicable to nearly all causes of failure.

In other cases, certain best practice approaches are fit for specific purposes. For example, laboratory mercury injection capillary pressure tests on caprock core samples are used exclusively to assess permeability for input into reservoir models that are part of vertical containment failure prevention techniques. [101]

Potential failure modes, causes of failure, failure prevention, failure detection, and failure mitigation are listed more comprehensively for lateral containment, vertical containment, and induced and triggered seismicity potential failure modes in Exhibit 3-1, Exhibit 3-2, and Exhibit 3-3, respectively, and discussed in the subsections below.

Exhibit 3-1, Exhibit 3-2, and Exhibit 3-3 are organized by the exhibit's associated potential failure mode's cause of failure categories and/or subcategories. For each cause of failure, best practice failure prevention, failure detection, and failure mitigation approaches are listed. Where failure prevention, detection, and mitigation best practices cover multiple failure categories and/or subcategories, the cells are combined for brevity of the exhibit; often particular best practice approaches are repeated as they cover multiple, non-adjacent (in the exhibit) cause of failure categories and/or subcategories. Similarly, references are provided from relevant sources of technical literature, evaluation of NEPA environmental assessments (EAs) and Environmental Impact Statements (EISs) relating to CCUS projects, and EPA UIC permit applications (where appropriate) for individual or grouped cause of failure categories and/or subcategories. Context and additional details are provided for each of these exhibits in Section 3.1.1 (Exhibit 3-1), Section 3.1.2 (Exhibit 3-2), and Section 3.1.3 (Exhibit 3-3).

Exhibit 3-1. List of potential lateral containment causes of failure and best practices for screening and prevention approaches associated with CO_2 injection and saline storage

<table>
<tr><th colspan="6">Potential Failure Mode: Lateral Containment Failure</th></tr>
<tr><th colspan="2">Cause of Failure</th><th>Failure Prevention Approach</th><th>Failure Detection Approach</th><th>Failure Mitigation Approach</th><th>Reference</th></tr>
<tr><td rowspan="3">Less residence time in reservoir than anticipated (in open reservoir systems that rely on residence time to help trap CO_2)</td><td>Caprock extent overlying storage reservoir(s) not as expansive as anticipated causing CO_2 and pressure to reach caprock spillpoints faster than anticipated</td><td rowspan="4">• 2D and 3D seismic to assess reservoir and caprock thickness, extent, and architecture during site characterization
• Lithology/stratigraphy assessment from existing well data to assess reservoir thickness and extent during site screening
• Perform modeling of selected sites during permitting and construction to evaluate performance during operations and PISC
• Select appropriate injection strategy for the site during permitting and construction that best ensures lateral containment during operations and PISC</td><td rowspan="4">• Monitoring temperature, pressure, and fluid chemistry for CO_2 breakthrough at monitoring wells located in the storage reservoir during operations
• CO_2 plume monitoring via electrical resistivity assessment during operations
• CO_2 plume monitoring using seismic methods like 2D seismic, 3D seismic, and/or vertical seismic profiles (VSP) during operations and PISC
• Update reservoir model, perform AoR reevaluation, and conduct forward modeling to anticipate future plume extent during operations and PISC</td><td rowspan="4">• Reduce or stop CO_2 injection rate during operations if plume migrates beyond lateral containment
• Use water curtains to keep CO_2 from extensive lateral migration during operations and PISC
• Use water production wells to produce brine from storage reservoir for pressure relief, capacity improvement, and potential plume steering during operations and PISC
• Shut in any water production wells if any CO_2 breakthrough occurs during operations and PISC</td><td rowspan="5">[102, 87, 103, 101, 98, 104, 105, 106, 107, 95]

[108, 109]</td></tr>
<tr><td>Lateral extent of storage reservoir not as expansive (or baffled) as anticipated causing CO_2 and pressure to expand faster than anticipated</td></tr>
<tr><td>Injection reservoir thinner than anticipated causing CO_2 and pressure to expand faster than anticipated</td></tr>
<tr><td rowspan="2">Lateral seal lacking or bypassed (in closed reservoir systems that rely on lateral seals for lateral containment)</td><td>Lack of far-field reservoir pore-cement or stratigraphic pinchout, resulting in plume expansion further than anticipated</td></tr>
<tr><td>High permeability thief zones present that bypass lateral seals and provide route(s) for CO_2 and pressure to disperse further than anticipated</td><td>• Coring and well log analysis from new stratigraphic wells to evaluate caprock and reservoir geologic properties during site characterization
• Correlation of well logs and core data to seismic attributes to infer reservoir properties across study domain during site characterization
• Pre-operation water pressure falloff testing to evaluate reservoir response to fluid injection during permitting and construction</td><td>• Monitoring temperature, pressure, and fluid chemistry for CO_2 breakthrough at monitoring wells located in the storage reservoir during operations
• CO_2 plume monitoring via electrical resistivity assessment during operations
• CO_2 plume monitoring using seismic methods like 2D seismic, 3D seismic, and/or VSP during operations and PISC
• Update reservoir model, perform AoR reevaluation, and conduct forward modeling to anticipate future plume extent during operations and PISC</td><td>• Plugging high-permeability zones with microbes or other permeability-reducing material during permitting and construction and operations
• Recomplete injection well perforation during permitting and construction or operations in less permeable injection intervals if possible</td></tr>
</table>

<table>
<tr><th colspan="6">Potential Failure Mode: Lateral Containment Failure</th></tr>
<tr><th colspan="2">Cause of Failure</th><th>Failure Prevention Approach</th><th>Failure Detection Approach</th><th>Failure Mitigation Approach</th><th>Reference</th></tr>
<tr><td colspan="2">Injection reservoir is less porous and/or thinner than anticipated, providing less storage capacity, and resulting in expansive plume dispersion</td><td rowspan="3">• Confirm the rate and volume of CO_2 provided by the source(s) that needs to be stored prior to site screening
• Quantify secure storage capacity available below caprock or within structural trap via reservoir modeling during site characterization</td><td rowspan="3">• CO_2 mass balance accounting (received vs. injected) with meters during operations
• CO_2 plume and downhole pressure and temperature monitoring in the storage reservoir using monitoring wells during operations and PISC
• CO_2 plume monitoring via electrical resistivity assessment during operations and PISC
• CO_2 plume monitoring using seismic methods like 2D seismic, 3D seismic, and/or VSP during operations and PISC
• Update reservoir model, perform AoR reevaluation, and conduct forward modeling to anticipate future plume extent during operations and PISC</td><td>• Use water production wells to produce brine from storage reservoir for pressure relief, capacity improvement, and potential plume steering during operations and PISC
• Shut in any water production wells if any CO_2 breakthrough occurs during operations and PISC</td><td>[102, 87, 103, 101, 98, 104, 105, 106, 107, 95]

[108, 109]</td></tr>
<tr><td colspan="2">Capture/injection rate needed is higher than anticipated resulting in expansive plume dispersion</td><td>• Reduce or stop CO_2 injection rate during operations
• Reduce reservoir pressure via extraction techniques (CO_2 or brine) and reinject into a more secure reservoir during operations or PISC
• Extract CO_2 at or near spillpoint with relief well during operations or PISC</td><td>[46, 107, 106]</td></tr>
<tr><td colspan="2">CO_2 migrates laterally beyond structural spillpoint resulting in expansive plume dispersion (in closed reservoir systems that rely on structural geometry for lateral containment)</td><td>• Use water curtains to keep CO_2 from extensive lateral migration during operations and PISC
• Shut in any water production wells if any CO_2 breakthrough occurs during operations and PISC</td><td>[85, 95, 110, 111]</td></tr>
<tr><td rowspan="4">CO_2-brine-lithology (and possibly deep-subsurface microbial) chemical reactions that result in wellbore-occluding and pore-occluding chemical precipitates and a reduction in injectivity</td><td>Hydrate formation from cold CO_2 and water mixing at high pressures in the wellbore during startup of injection</td><td rowspan="3">• Avoid storage site in shallow reservoirs (i.e., depths less than 800 meters) to keep CO_2 in supercritical state
• Coring and well log analysis from new stratigraphic wells to evaluate caprock and reservoir geologic properties during site characterization
• Avoid storage in under pressured and low temperature reservoirs
• Include the potential for CO_2 phase behavior in reservoir modeling during site screening and site characterization
• Fluid sampling to evaluate chemical properties of formation fluids in the storage reservoir during site characterization, permitting and construction, operations, and PISC
• Conduct reservoir simulation during site screening and site characterization to estimate the magnitude of geochemical effects that may lead to a reduction in injectivity that is likely to occur under site-specific conditions during operations</td><td rowspan="4">• Monitor the properties of the injected CO_2 stream during operations and evaluate compatibility with subsurface characteristics
• Monitor reservoir pressure at injection and monitoring wells for a sudden, drastic, and sustained increase during operations and PISC</td><td rowspan="4">• Increase/decrease CO_2 injection temperature to compensate for any cooling/heating effects during operations
• Inject methanol and glycol to inhibit or dissociate CO_2 hydrates
• Implement chemical treatment as necessary to control microbial communities during permitting and construction, operations, and PISC
• Design injection strategy to enable support flushing with hot water and/or strong acid prior to/during operations</td><td rowspan="4">[112, 113, 114, 115, 116, 117, 85, 87, 95, 118]</td></tr>
<tr><td>Halite precipitation as a result of brine evaporating in dry supercritical CO_2</td></tr>
<tr><td>Carbonate cement precipitation</td></tr>
<tr><td>Microbial extracellular material</td><td>• Characterize candidate sites during site characterization for microbial communities and potential microbial growth in the presence of CO_2 during operations</td></tr>
</table>

Potential Failure Mode: Lateral Containment Failure				
Cause of Failure	**Failure Prevention Approach**	**Failure Detection Approach**	**Failure Mitigation Approach**	**Reference**
Unanticipated insufficiencies in reservoir porosity and permeability as a result of co-sequestered CO_2 contaminants (e.g., H_2S) reducing reservoir capacity and injectivity	• Characterize and monitor the injected CO_2 stream chemistry to avoid contaminants	• Monitor sampled storage reservoir gas composition during operations and PISC • Monitor reservoir pressure at injection and monitoring wells for a sudden, drastic, and sustained increase during operations and PISC	• Use water production wells to produce brine from storage reservoir for pressure relief, capacity improvement, and potential plume steering during operations and PISC	[112, 113, 114, 115, 116, 117, 85, 87, 95, 118]
Storage reservoir pressure increase in sedimentary basins with interconnected reservoirs that host multiple CO_2 storage or liquid disposal projects, resulting in unanticipated CO_2 plume dispersion and more dramatic increase in reservoir pressure than anticipated	• Inventory and assess impact of similar projects proximal to proposed CO_2 storage site during site screening; disclose information to UIC regulating body as part of permitting and construction • Conduct regional modeling effort during permitting and construction that accounts for the influence of all injection or fluid producing projects near the proposed injection site to see how these projects could affect the evolution of the CO_2 plume and pressure plume from the storage project • Avoid selecting sites as part of site screening in close proximity to projects where interferences may occur • Coordinate operations with operators conducting nearby projects during all project stages	• CO_2 plume and downhole pressure and temperature monitoring in the storage reservoir using monitoring wells during operations and PISC • Maintain CO_2 injection pressure below 90 percent of caprock and/or reservoir fracture pressure during operations • CO_2 plume monitoring via electrical resistivity assessment during operations and PISC • CO_2 plume monitoring using seismic methods like 2D seismic, 3D seismic, and VSP during operations and PISC • Update reservoir model, perform AoR reevaluation, and conduct forward modeling to anticipate future plume extent during operations and PISC	• Use water production wells to produce brine from storage reservoir for pressure relief, capacity improvement, and potential plume steering during operations and PISC	[85, 119, 120]

Exhibit 3-2. List of potential vertical containment causes of failure and best practices for screening and prevention approaches associated with CO_2 injection and saline storage

<table>
<tr><th colspan="6">Potential Failure Mode: Vertical Containment Failure</th></tr>
<tr><th colspan="2">Cause of Failure</th><th>Failure Prevention Approach</th><th>Failure Detection Approach</th><th>Failure Mitigation Approach</th><th>Reference</th></tr>
<tr>
<td rowspan="5">Caprock failure</td>
<td>Existing closed fault(s) or fracture(s) which become transmissive due to reservoir overpressure, seismicity of any kind, or local stress field re-orientation or stress transfer</td>
<td rowspan="3">Determine caprock fracture pressure during site characterization
Conduct baseline study of initial stress state and mechanical properties of both storage reservoir and caprock as part of site characterization
Perform modeling of selected sites during permitting and construction to evaluate the performance of caprock with faults and fractures during CO_2 injection</td>
<td rowspan="4">Monitor CO_2 injection pressure during operations
Maintain CO_2 injection pressure below 90 percent of caprock and/or reservoir fracture pressure during operations
Storage reservoir pressure monitoring during operations and PISC
Monitor variation in stress state and geomechanical properties over time during operations and PISC
2D seismic, 3D seismic, and/or VSP to assess the integrity of caprock as part of operations and PISC
Above-zone monitoring to detect pressure, chemical, and/or temperature changes in shallower reservoirs which may indicate leakage during operations and PISC
Storage reservoir pressure monitoring during operations and PISC
Update reservoir model, perform AoR reevaluation, and conduct forward modeling to anticipate future plume extent during operations and PISC</td>
<td rowspan="3">Use water production wells to produce brine from storage reservoir for pressure relief, capacity improvement, and potential plume steering during operations and PISC
Injection of sealants into faults to reduce permeability during operations and PISC
Injection of microbes that generate precipitates capable of sealing fractures in caprock as part of operations and PISC</td>
<td>[85, 87, 84, 121, 95, 122]</td>
</tr>
<tr>
<td>Deformation of clay-rich caprock from pore-pressure-driven aseismic tremor and slip on stable regions of existing fault</td>
<td>[101, 102]</td>
</tr>
<tr>
<td>Brittle failure of caprock in the form of fault(s) or fracture(s) due to reservoir overpressure or seismicity of any kind, including hydraulic stimulation and aseismic stress transfer</td>
<td>[123, 124]</td>
</tr>
<tr>
<td>Deficient properties of caprock (e.g., high permeability, thin, overly fractured) making it prone to leakage</td>
<td>2D and 3D seismic to caprock thickness, extent, and architecture during site characterization
Lithology/stratigraphy assessment from existing well data to assess reservoir thickness and extent during site screening
Perform modeling of selected sites during permitting and construction to evaluate the performance of the caprock during CO_2 injection operations and PISC
Avoid storage sites without favorable geologic conditions amenable to safe and effect CO_2 storage
Consider sites where multiple stacked seals and storage reservoirs co-exist as part of site screening and site characterization</td>
<td>Use water production wells to produce brine from storage reservoir for pressure relief, capacity improvement, and potential plume steering during operations and PISC</td>
<td>[101, 102, 95, 122]</td>
</tr>
<tr>
<td>Unanticipated transmissive fault(s) or fracture(s)</td>
<td>2D and 3D seismic to assess the presence and location of faulting during site characterization
Avoid siting the storage project where faults penetrating the caprock are discovered as part of site screening and site characterization</td>
<td>Monitor passive microseismicity for any associated events during operations
Monitor for surface displacement (LiDAR, tiltmeters) during permitting and construction (as baseline), operations, and PISC
Monitor near surface aquifers and soil gas for changes from baseline conditions (i.e., salinity, pH, metals) during operations and PISC</td>
<td>Use water production wells to produce brine from storage reservoir for pressure relief, capacity improvement, and potential plume steering during operations and PISC
Injection of sealants into faults to reduce permeability during operations and PISC</td>
<td>[87, 95, 125]</td>
</tr>
</table>

<table>
<tr><th colspan="6">Potential Failure Mode: Vertical Containment Failure</th></tr>
<tr><th colspan="2">Cause of Failure</th><th>Failure Prevention Approach</th><th>Failure Detection Approach</th><th>Failure Mitigation Approach</th><th>Reference</th></tr>
<tr><td>Caprock failure</td><td>Induced reservoir pressure exceeds caprock's capillary entry pressure</td><td>Determine caprock fracture pressure during site characterization
Perform modeling of selected sites during permitting and construction to evaluate the pressures in the reservoir and caprock during CO_2 injection operations and PISC
Avoid sites as part of site characterization where fractured caprock exists</td><td>Maintain CO_2 injection pressure below 90 percent of caprock fracture pressure during operations
Above-zone monitoring to detect pressure, chemical, and/or temperature changes in shallower reservoirs which may indicate leakage during operations and PISC
Storage reservoir pressure monitoring during operations and PISC</td><td>Use water production wells to produce brine from storage reservoir for pressure relief, capacity improvement, and potential plume steering during operations and PISC
Shut in any water production wells if any CO_2 breakthrough occurs during operations and PISC
Injection of sealants into faults to reduce permeability during operations and PISC
Injection of microbes that generate precipitates capable of sealing fractures in caprock as part of operations and PISC</td><td>[95, 102]</td></tr>
<tr><td rowspan="4">Wellbore leakage failure causing high permeability leakage pathway, or well blow out up annulus/tubing, etc.</td><td>Improperly plugged and abandoned (P&A) wells (known or unknown)</td><td rowspan="3">Curate all wells within the AoR which penetrate the injection or confining zone(s) during site screening
Determine the type, construction, date drilled, location, depth, and record of plugging and/or completion for all wells in the AoR penetrating the injection or confining zone(s)</td><td rowspan="4">Above-zone monitoring to detect pressure, chemical, and/or temperature changes in shallower reservoirs which may indicate leakage during operations and PISC
Storage reservoir pressure monitoring during operations and PISC
Conduct mechanical integrity tests, fluid movement tracer logs, temperature and noise logs, and casing inspection logs on injection wells during operations
Use continuous recording devices to monitor the injection pressure, rate, volume and/or mass, and temperature of CO_2 stream; pressure on the annulus between the tubing and long string casing, and annulus fluid volume in injection wells during operations
Perform corrective active measures during operations, well penetrations through the caprock, and storage formations that may be impacted by the CO_2 and pressure plume</td><td rowspan="4">Repair leaking wells during operations and PISC with cement squeeze to plug leaks behind the casing or via well recompletion techniques, like replacing the injection tubing and packers, repairing damaged or collapsed casing, or wellhead repair
Perform well 'kill' techniques during operations or PISC, like injecting heavy mud into the well casing, to stop any blowouts</td><td rowspan="4">[85, 84, 101, 102, 117, 110]</td></tr>
<tr><td>Improperly sealed/cemented active wells (known)</td></tr>
<tr><td>Failure of borehole components like seals, casing, or cement between the formation and casing of otherwise properly sealed/cemented well as a result of unanticipated component failure, reservoir overpressure, or shaking from seismicity of any kind</td></tr>
<tr><td>Shearing of reservoir-penetrating wellbore that intersects a known or unknown fault, if fault displacement occurs during seismicity of any kind</td><td>3D seismic during site characterization to evaluate fault locations
Image logs after wellbore drilled as part of permitting and construction</td></tr>
</table>

Exhibit 3-3. List of potential induced and triggered seismicity causes of failure and best practices for screening and prevention approaches associated with CO_2 injection and saline storage

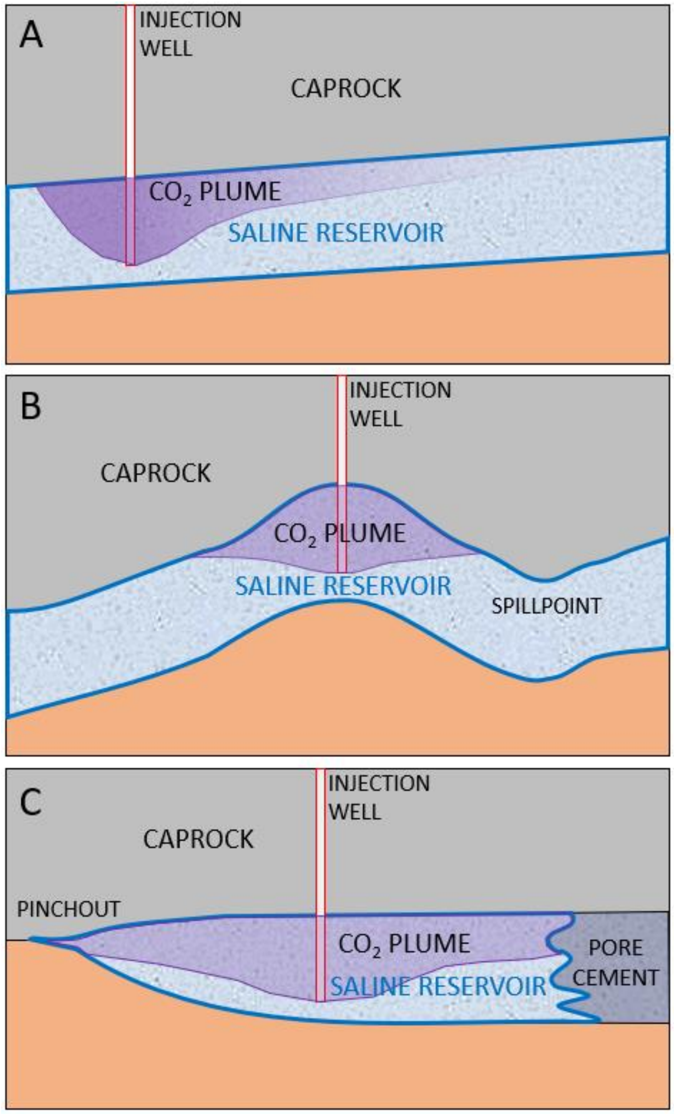
<table>
<tr><th colspan="6">Potential Failure Mode: Induced and Triggered Seismicity</th></tr>
<tr><th colspan="2">Cause of Failure</th><th>Failure Prevention Approach</th><th>Failure Detection Approach</th><th>Failure Mitigation Approach</th><th>Reference</th></tr>
<tr><td rowspan="3">Existing fault reactivated</td><td>Migrating brine reduces friction on existing fault that results in fault displacement</td><td rowspan="4">Assess site for natural seismic activity during site screening
Determine caprock fracture pressure during site characterization
Characterize the site and model geomechanics during site characterization
Identify any existing faults with use of 2D and/or 3D seismic surveys during site characterization
Perform modeling of selected sites to evaluate the impact of elevated pressure on geomechanics during permitting and construction
Select sites as part of site screening where redundant caprock layers exist</td><td rowspan="6">Monitor injection rates and pressures for any sudden or drastic changes during operations
Maintain CO_2 injection pressure below 90 percent of caprock fracture pressure during operations
Storage reservoir pressure monitoring during operations and PISC
Above-zone monitoring to detect pressure, chemical, and/or temperature changes in shallower reservoirs which may indicate leakage during operations and PISC
Monitor passive microseismicity during site characterization, permitting and construction (as baseline), as well as operations and PISC
Monitor for surface displacement (LiDAR, tiltmeters) during permitting and construction (as baseline), operations, and PISC
Update reservoir model and conduct forward modeling to anticipate potential failures due to geomechanical or geochemical effects during operations and PISC</td><td rowspan="4">Injection of sealants into faults to reduce permeability during operations and PISC</td><td>[85, 87, 126]</td></tr>
<tr><td>Increased pore pressure reduces stress on existing fault that results in fault displacement</td><td>[127, 95]</td></tr>
<tr><td>Pore-pressure-driven aseismic slip on stable existing fault, leading to stress transfer (and possible stress field rotation) to distal unstable fault zones (including those deeper than injection zone) that results in fault displacement</td><td>[123, 128, 121, 95]</td></tr>
<tr><td rowspan="3">New fractures and/or faults generated</td><td>Increased pore pressure directly causes brittle failure and faulting</td><td>[85, 87, 102]</td></tr>
<tr><td>Geochemical effects (especially relevant in carbonate formations), where dissolution of carbonate can lead to reduction in rock stiffness, reducing strength and inducing brittle failure. Additionally, acidic/oxidization attack on caprock mineralogy could occur</td><td rowspan="2">Characterization (i.e., core analysis) and modeling of reservoir and caprock geochemical, geomechanical, and thermal properties as part of site characterization
Eliminate sites from consideration during site screening and site characterization susceptible to substantial dissolution of minerals or thermal contraction</td><td rowspan="2">Increase/decrease CO_2 injection temperature to control rock temperature</td><td>[121]</td></tr>
<tr><td>Non-isothermal effects from CO_2 at lower temperature than injection zone causing brittle failure (e.g., rock contraction, thermal stress reduction, and stress redistribution around the cooled area)</td><td>[101, 129, 116, 121, 95]</td></tr>
</table>

3.1.1 Lateral Containment Failure

Single-phase CO_2 is more buoyant than saline brine and tends to migrate vertically within a reservoir and spread laterally up-dip until it is ultimately trapped or contained by vertical and/or lateral structural or stratigraphic closure (mechanisms presented in Exhibit 3-4). Without some form of closure, CO_2 may continue to disperse laterally until it is ultimately trapped by solubility and residual trapping mechanisms. [75] The effects of geologic heterogeneity within the reservoir can have a substantial effect on fluid flow, including CO_2 migration. CO_2 tends to migrate along the high-permeability pathways and may bypass lower-permeability regions within the reservoir. Lenses of low-permeability rock within the reservoir that make CO_2 migration pathways more tortuous are called “baffles.” Baffling and geologic property anisotropy will heavily influence fluid flow and the eventual distribution of CO_2 and pressure in the subsurface. For CO_2 storage projects, lateral containment failure can occur when CO_2, acidic brine, displaced brine and/or the pressure front exceeds the areal extent initially planned for, and monitored by, the storage project. The source’s underlying causes of lateral containment failure can be organized by those that result from initial CO_2 storage complex quality (i.e., injectivity and capacity) being poorer than anticipated based on site characterization, and by those that result from CO_2 injection and storage operations degrading the storage complex quality. Specific lateral containment causes of failure associated with poor initial storage complex quality vary depending on the storage project’s lateral trap style:

- For **open reservoir systems where residence time can help trap CO_2**, lateral containment can fail if the lateral extent of the reservoir is not as expansive or thick as initially assumed, or if the reservoir is less baffled than anticipated [101, 102, 117]
- For **closed reservoirs that rely primarily on structural geometry to help trap CO_2**, like those within anticlines or domes, lateral containment can fail if CO_2 or brine migrate beyond a structural spillpoint [85]
- For **closed reservoir systems that rely primarily on lateral seals to help trap CO_2**, lateral containment can fail if lateral seals like pore-cement or stratigraphic pinchouts are lacking, or if lateral seals can be bypassed altogether. [101, 102, 117] For example, the proposed FutureGen Odessa, Texas, site had noted concerns about a lack of up-dip anhydride cement stopping lateral migration as a potential cause of failure. [102] The ECO2S CCS project in Kemper County, Mississippi, listed concerns about the possibility of a porous unconformity allowing CO_2 to bypass the stratigraphic pinchout acting as the lateral seal [101]

Exhibit 3-4: Lateral CO_2 trap styles in cross-section view: open reservoir relying on residence time (A), closed reservoir relying on structural closure (B), and closed reservoir relying on lateral seals like stratigraphic pinchout or pore cement (C)



Specific lateral containment causes of failure associated with CO_2 injection and CO_2 storage operations degrading (or making insufficient) storage complex quality are all related to increases in reservoir pressure from decreased injectivity and/or capacity, and vary depending on the source of degradation:

- **Pore-occluding precipitates** can reduce porosity and permeability, reducing injectivity and CO_2 storage capacity, and increasing reservoir pressure
- **Non-CO_2 gasses** introduced from the injection stream or exsolved from native brine can reduce CO_2 storage capacity and increase reservoir pressure
- In open reservoir systems, **far-field reservoir pressure interference** from other storage projects (e.g., other CO_2 storage projects, underground natural gas storage, CO_2 EOR, or wastewater disposal operations) can result in reservoir pressure increases [85, 119]

Pore-occluding precipitates, non-CO_2 gasses, and far-field reservoir pressure interference all result in increases in reservoir pressure, and therefore are each potential underlying causes of vertical containment failure and/or induced and triggered seismicity failure (discussed in subsections 3.1.2 and 3.1.3, respectively).

Pre-injection failure prevention best practices for lateral containment failure associated with poor initial storage complex quality include pre-injection site characterization using 3D seismic surveys and petrophysical well logging. Calibrated with core analysis, seismic surveys and petrophysical logs can help determine lateral continuity storage complex parameters like areal extent, compartmentalization, thickness, porosity, and/or permeability. [87, 102, 103] Thermal, hydraulic, and geomechanical properties can also be assessed for use in modelling efforts (like the properties listed in Section 2.3), and numerical modeling. [85, 101, 84, 87, 32] If initial site characterization does not adequately reduce lateral containment uncertainty, the study area and associated data collection should be expanded, additional stratigraphic test wells should be drilled and characterized (i.e., logged and cored), and models and injection plans should be revised or redesigned based on new characterization data. [101] Reservoirs with insufficient initial physical reservoir properties should be avoided.

During and after injection, operationally, failure prevention and failure mitigation techniques are similar for all causes of lateral containment failure (and are applicable to vertical containment and seismicity potential failure modes), and only vary by terminology depending if they are preempting a potential cause of failure, or are in response to a detected cause of failure. Reducing CO_2 injection rates or stopping CO_2 injection altogether can be effective failure prevention or failure mitigation techniques. Best practices to improve injectivity and/or capacity include drilling additional injection wells, drilling horizontal injection wells, and maximizing the number or perforations (entries from the wellbore into the storage reservoir interval) to increase the wellbore-reservoir contact area over which CO_2 can be injected. [85, 101, 102, 124]

Assessing secondary storage intervals and perforating those additional zones would similarly help (i.e., stacked storage concept). [101] Another option includes drilling and incorporating brine extraction wells to reduce reservoir pressure, maintain lower pressures, and/or improve CO_2 storage capacity. In a worse-case scenario, controlled venting CO_2 at the surface from the wellhead is an option to reduce reservoir pressure. [87] Extraction wells drilled specifically for failure mitigation are called “relief wells.” To counter the expansion of the CO_2 plume and prevent lateral migration, another option is injecting water into the primary storage reservoir with wells drilled into the reservoir beyond the plume area. [87] The inclusion of the additional well infrastructure will come with added project costs.

Other operational failure prevention techniques for deficient reservoir properties include “treating” the reservoir prior to and during injection operations. Acid jobs that can dissolve rock matrix in appropriate reservoir lithologies and/or deliberate and control hydraulic fracturing (i.e., “stimulation”) can improve injectivity by improving porosity and permeability. [101, 124] It is important to note that pursuant to requirements of 40 CFR § 146.82(a)(9) for UIC Class VI wells, all stimulation programs must be approved as part of the permitting process. For example, the Mountaineer CCS II project, in West Virginia, anticipated performing hydraulic stimulation to improve injectivity. [124] In the case of hydraulic fracturing, care must be taken to not compromise the caprock's vertical containment capability.

Failure detection best practices for all causes of lateral containment failure during injection and post-injection include monitoring the lateral extent of CO_2 and the pressure front with time-lapsed 3D seismic and vertical seismic profiles (VSP). Monitoring injectivity at injection wells, and injection reservoir temperature, pressure, and fluid chemistry at injection wells and monitoring wells allows for potential lateral containment failure to be identified and remediated before failure occurs. [85, 87, 32, 84]

Failure prevention, detection, and mitigation techniques specific to lateral containment failure associated directly with storage complex quality degradation from CO_2 injection and CO_2 storage operations are dependent on the underlying cause of degradation (i.e., hydrates, halite precipitation, carbonate cement, microbial extracellular material, co-sequestered gaseous contaminants, or pressure interference from third party injection projects).

As discussed in Section 2.1, CO_2 injection pressures and temperatures are greater than 1,057 psi [72.9 atmospheres] and 88°F [31.1°C], respectively. Injection pressures must exceed reservoir pressure, but injection temperature is typically colder than reservoir temperature. Reservoir temperature increases with depth along a geothermal gradient of 27 to 54°F per kilometer of depth [15 to 30°C per kilometer]. During periods of injection start-up after a shut-down, the high pressure and low temperature of the injected CO_2, relative to the wellbore conditions at depth, which can equilibrate with warmer reservoir conditions during shut-down, can cause water and CO_2 to form hydrates in and near the wellbore. [95] Failure prevention and mitigation techniques include the common practice of injection of methanol and glycol, which inhibits hydrate formation by lowering the temperature necessary for hydrates to form and can dissociate hydrates that have already formed. [130] Failure detection techniques include monitoring reservoir pressure at injection and monitoring wells for sudden, drastic, and sustained increases in reservoir pressure.

Another factor that can reduce injectivity and storage capacity is halite precipitation in and near the wellbore as a result of brine evaporation in dry supercritical CO_2. [85, 112, 113] Failure prevention techniques include maintaining constant injection rates; if injection is slowed or ceases temporarily, brine can re-infiltrate the wellbore, and cause new halite precipitation when normal injection rates are resumed (e.g., halite precipitation reduced injectivity temporarily at the AquiStore project, since its CO_2 supply is intermittent). [131] Halite precipitation is easily recognized with failure detection techniques like injection pressure monitoring and televiewer logs to confirm halite in the wellbore. Failure mitigation commonly used for halite precipitation is water washing (i.e., injection of water to dissolve the halite). [130]

CO_2 can become involved in chemical reactions that result in carbonate cement precipitation which occludes porosity. [114, 115, 116] Failure prevention techniques include modeling the CO_2-brine-lithology chemical reactions expected and avoiding sites where carbonate cement precipitation is likely to occur and be cost prohibitive to mitigate. Failure detection for carbonate cement includes techniques like injection pressure monitoring and reservoir fluid monitoring. Failure mitigation techniques include injection of strong acids to dissolve carbonate cement.

Extracellular material produced by bacteria could occlude porosity; [132] however, research into this concept in CO_2 storage saline aquifers is ongoing to further understand these processes. Failure prevention best practices include characterizing the microbial communities and potential for microbial growth in the presence of CO_2, modeling potential mineralogy-brine-CO_2 geochemical (and microbial) interactions, and calibrating with laboratory experiments on reservoir core samples, reservoir brine samples, and CO_2 stream injectant samples or proxies. [101, 121] Failure prevention and/or mitigation approaches for sites identified as being prone to, or identified as having, high subsurface microbial growth and associated pore occlusion may be to inject antimicrobial chemical treatments [133] as necessary to control microbial communities during permitting and construction, operations, and PISC. Alternatively, enzymes could be developed and injected to inhibit or dissociate the pore-occluding extracellular material.

Co-sequestered CO_2 contaminants, like H_2S, [102, 117], or exsolution of native gasses like CH_4 at the CO_2 plume migration front [85] can reduce CO_2 storage capacity by occupying pore space and can reduce injectivity by reducing the relative permeability of CO_2. Failure prevention for injected contaminants include modeling the impacts of contaminants to set injection stream compositional limits, as well as metering the incoming CO_2 stream from each CO_2 source (also a failure detection best practice if contaminants are not anticipated). [101] Higher-purity CO_2 sources are preferred. [116] Failure detection best practices include injection pressure monitoring and reservoir fluid monitoring. Failure mitigation techniques would be the same as the general failure mitigation techniques listed previously in this section.

In the case of far-field pressure interference from third party injection projects, appropriate planning and permitting by operators and regulators are failure prevention best practices. [85] Additionally, modeling basin-scale pressure interference and buildup should be considered when making basin-wide capacity evaluations. [85, 119] Failure detection and failure mitigation best practices would be similar to those discussed previously in this section.

3.1.2 Vertical Containment Failure

As mentioned in Section 3.1.1, buoyant single-phase CO_2 tends to migrate vertically and up-dip until trapped within the storage complex. Expansive, continuous, strong, and impermeable caprock is therefore critical to maintaining vertical containment of CO_2 and native brine and preventing its leakage from the CO_2 storage complex. Causes of vertical containment failure can be due to either wellbore failure or caprock failure. Causes of wellbore failure are associated with caprock-penetrating wells becoming susceptible to compromised integrity from several possible causes:

- **Increased reservoir pressure** damaging wellbore components and/or forcing fluids through leakage conduits
- **Acidic CO_2 chemistry** in the subsurface which degrades wellbore components
- Explicit **wellbore component mechanical failure**
- **Wellbore shearing** during seismic events that include fault displacement

Caprock failure is associated with discontinuities or insufficiencies in the caprock that are initially present or that are created by circumstances from CO_2 injection and storage operations. Causes for caprock containment failure include:

- **Existing fractures or faults** susceptible to opening due to increased reservoir pressure
- **New fractures or faults** propagated by increased reservoir pressure and/or seismicity of any kind
- **Deficient caprock quality** properties (e.g., extent, continuity, geomechanical strength, geochemical reactivity, and permeability)
- **Deformation of the caprock** compromising its vertical containment integrity

Vertical containment failure prevention and certain failure mitigation best practices vary depending on if the cause of failure is associated with wellbore integrity or with caprock integrity. Failure detection best practices applicable to all causes of vertical containment failure (i.e., from fractures, faults, poor caprock quality, caprock deformation, and/or compromised wellbores) include pressure, chemical, and temperature monitoring in the injection reservoir, and in intervals above the injection zone. Above zone monitoring takes advantage of the speed and distance pressure fronts propagate ahead of the CO_2 plume to detect vertical containment failures well before CO_2 can migrate from the storage reservoir through far-field leakage conduits – allowing, in a sense, for early failure mitigation against CO_2 leakage. [85, 134] Land-surface uplift monitoring is also a best practice to rapidly detect potential vertical containment failures. [85, 135] Land-surface uplift monitoring can detect deformation at the surface indicative of vertical containment failure. For example, time-lapse interferometric synthetic aperture radar (InSAR) collected by orbital satellite monitoring at the In Salah CCS project in Algeria, showed surface deformation around an injection well. In combination with geomechanical modeling, the uplift was interpreted to be the opening of a fracture zone in the caprock due to high injection pressure. [85, 135] InSAR has limited effectiveness at locations where the surface is obscured by vegetation. The deployment of tiltmeters can also be used to detect surface deformation over time at CO_2 storage sites.

Wellbore failure represents one of the highest probable causes of vertical containment failure, and can result in leakage of CO_2 and brine from otherwise high-quality storage complexes. [136, 137] Any pre-existing or future injection, production, monitoring, or stratigraphic test wellbores that penetrate the storage reservoir could be a potential high-permeability pathway to the surface if certain components fail over time, even if specifically designed for CO_2 injection pressure and chemistry. Pre-existing wellbores from other operations (like oil and gas production) that were not designed for CO_2 storage project pressures and changes in reservoir chemistry toward acidic brine represent potential causes of vertical containment failure.

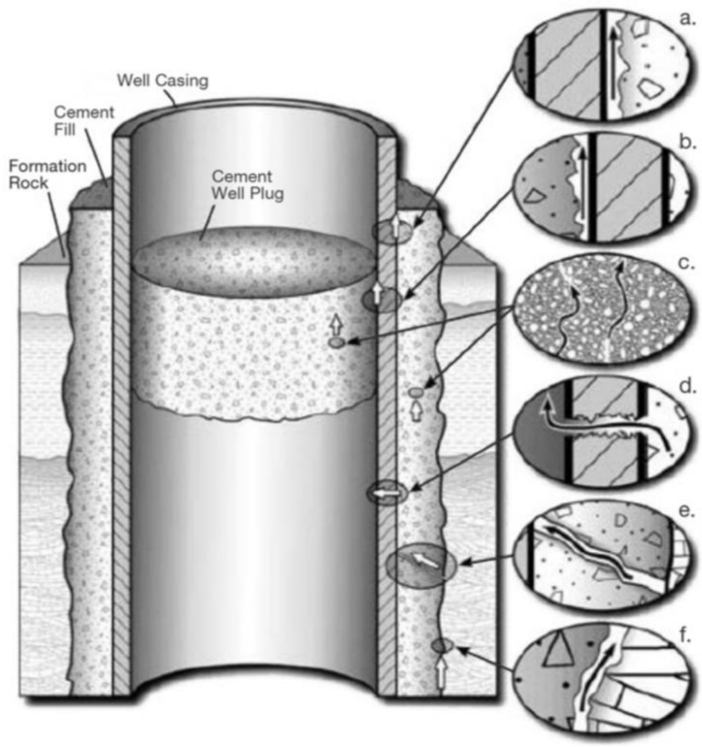
Wellbore failure prevention techniques address a myriad of potential causes of failure at a wellbore (Exhibit 3-5), and consist of site characterization efforts to identify known oil and gas development wells, and monitoring techniques like ground surveys and magnetic surveys to locate unknown orphaned and abandoned wells. [138] For CO_2 injection and storage projects, existing wellbores that penetrate the reservoir and confining layers are subject to potential corrective action if they occur within the AoR per UIC Class VI permitting requirements. The UIC requirements in this regard mandate assurance that all wells be plugged in a manner that prevents the movement of CO_2 or other fluids that may endanger USDW, and their construction includes the use of materials compatible with the injected CO_2 stream (per 40 CFR § 146.84). Wells that do not meet those standards must undergo corrective action (i.e., methods to ensure that wells within the AoR do not serve as conduits for the movement of fluids into USDW) by storage site operators. Best practice vertical containment failure prevention includes running wellbore integrity tests on all wells where data relating to the well's construction is lacking in quality or where no data is available to properly assess the well's design integrity. Existing wellbores that fail wellbore integrity tests should be re-entered and properly squeezed, recemented, resealed, or plugged and abandoned prior to injection and storage operations as a failure prevention best practice (or for failure mitigation, if injection operations are already underway). [85, 101, 84] For example, ten abandoned wellbores within the areal footprint of the FutureGen 1.0 project proposed for the Odessa, Texas, site were identified as needing proper plugging and abandonment. Additionally, eight active oil wells that penetrated the primary seal of the FutureGen 1.0 project proposed for the Jewett, Texas site, were identified as needing to be properly sealed and cemented. [102, 84]

The best practices described in this section as well as Sections 3.1.1 are recommended failure prevention methods to prevent migrating CO_2, acidic brine, displaced brine, or the pressure front from reaching and compromising wellbores that are drilled outside or above the CO_2 storage complex. Image logs are another failure prevention technique recommended on new wellbores drilled for CO_2 storage projects to ensure they do not intersect faults that could be reactivated by induced, triggered, or natural seismicity. [135] Site selection in seismically stable regions helps mitigate any risk of faulting shearing the wellbores. Failure prevention and failure detection of induced or triggered seismicity, as outlined in Section 3.1.3 is also a recommended best practice.

Failure detection best practices for vertical containment failure associated with wellbores include continuous monitoring of injection pressure, injection rate, injection volume and/or mass, and temperature of the CO_2 stream, as well as the pressure and volumes in the annulus between the tubing and long string casing, as prescribed by the UIC Class VI injection well regulations on mechanical integrity testing (40 CFR § 146.89). Also prescribed are fluid-movement tests (like tracer surveys or temperature and noise logs). Casing inspection logs to assess for corrosion in the long-string casing is also a best practice (that can also be mandated by regulators under 40 CFR § 146.89).

Failure mitigation best practices for vertical containment failure associated with wellbores include repairing leaking wells during injection operations or during PISC with cement squeeze to plug the leaks behind casing. Well recompletion techniques like replacing injection tubing and packers, repairing damaged or collapsed casing, or wellhead repair are also common failure mitigation best practices. Another method that can be used to mitigate a leaking well is injecting heavy mud into the well casing to “kill” the well and prevent further leakage or a blowout.

Exhibit 3-5. Potential leakage pathways for CO_2 in a well: the casing-cement interface (paths a and b), within the cement (c), through the casing (d), through fractures (e), cement-formation interface (f)



Used with permission from Elsevier [139]

Failure prevention approaches related to existing and/or new faults and fractures as causes of vertical containment failure rely on site characterization: assessing the caprock and CO_2 storage complex in general for the presence of faults, fault orientation, and regional stress regime. Sites that have regional extensional stress regimes should be avoided, as extensional stress reduces the amount of reservoir pressure needed to initiate new faults (and fractures) and reopen existing faults (and fractures), which could result in CO_2 migration along the fault and leakage from the storage complex. Compressional stress regimes are preferred for CO_2 storage projects. [102, 117] Within compressive stress regimes, faults oriented parallel to the maximum horizontal stress orientation should be assessed with additional care, since this fault orientation will open more readily than faults oriented perpendicular to maximum horizontal stress when subjected to increased reservoir pressure. Stress regime and stress orientation can be measured with oriented caliper and borehole imaging logs, analysis of natural seismicity moment tensor and hypocenter, as well as regional basin structural analysis. 3D seismic surveys during site characterization should be analyzed for the presence of faults and can be supplemented with InSAR and aerial photography to assess regional faults near or at the surface. [101] Microseismic monitoring and analysis during injection tests can confirm stress orientations and may indicate the presence and orientation of faults. [101]

Existing fractures are not as easy to identify pre-injection with 3D seismic as there is no visible offset of rock layers (the same is true for faults with throws less than the vertical resolution of the 3D seismic survey, or where the fault throw is entirely within homogenous rock layers).

Some attribute analysis techniques (like ant-tracking algorithms that track continuous features with fault shapes) are capable of assessing and predicting the presence of small-scale faults and fractures within caprock but should be calibrated with in situ measurements like those from image logs and oriented cores.

Operational vertical containment failure prevention best practices to avoid opening existing fractures and faults that are normally non-transmissive due to compressive regional stress, or creating new fractures from brittle failure, include keeping injection pressures below 80–90 percent of the fracture opening pressure. [102, 127] This best practice is in line with UIC Class VI regulations per 40 CFR § 146.88(a) which state storage operators may not inject at pressures exceeding 90 percent of the fracture pressure of the injection zone(s) or confining zone(s). [34] Fracture opening pressure in the caprock can be estimated from core analysis in labs, but in situ tests are recommended. Vilarrasa et al., recommends injecting water to increase reservoir pressure until microseismic events are recorded, and using the pressure recorded as the fracture opening pressure proxy for later CO_2 injection operations. [121]

Vertical containment failure detection best practices associated with faulting and fracturing include microseismic and vertical plume extent monitoring during injection, along with pressure monitoring in the reservoir and above the seal.

Vertical containment failure mitigation best practices associated with faulting and fracturing are to shut down injection and determine if seal integrity can be restored. [101] Similar to lateral containment failure mitigation best practices, pressure relief wells, capacity improvement, and plume steering with water injection wells are also all feasible vertical failure prevention and/or mitigation techniques. Sealants or microbes that generate precipitates capable of sealing fractures and faults can be injected into the fractures or faults to reduce permeability and transmissivity; however, sealants are still an area of ongoing R&D.

Besides fault and fracture discontinuities, localized zones of low quality caprock (e.g., thin, higher permeability, geomechanically weak, geochemically reactive to CO_2) could also relegate an otherwise expansive caprock susceptible to vertical containment failure.

Vertical containment failure prevention best practices associated with poor caprock quality include pre-injection site characterization of expansiveness and thickness of the caprock with 3D seismic and petrophysical logging calibrated to core sample analyses. Examples of core analyses include confirming mineralogy to assess caprock susceptibility to geochemical attack from acidic brine and performing geochemical and geomechanical modeling and laboratory tests with core and fluid samples to assess the caprock-CO_2-brine interactions. [101] If the caprock might be susceptible to geochemical reactions, modeling is needed to demonstrate CO_2-brine will not reach the caprock (e.g., IBDP and IL-ICCS projects' dolomitic caprock is susceptible to acidic brine). [136, 114, 116] Another caprock core analysis example includes mercury capillary injection tests to assess permeability of the caprock. [101] If core samples are unavailable or inadequate, re-entry of wellbores for sidewall core sampling may be necessary to acquire the rock material. [101] Simulation can be performed to test wider ranges of parameters that remain uncertain to better model the range of leakage possibilities. [101] Other failure prevention best practices during site characterization include identifying and testing secondary caprocks above the primary caprock that would serve as redundant barriers to vertical migration and leakage of CO_2 to near surface and surface resources. For example, the IBDP and IL-ICCS projects have a primary caprock and two secondary caprocks that are relied upon to reduce the risk of vertical containment failure. [136, 114, 116]

Current research suggests that caprock continuity may be susceptible to ductile deformation as a result of increased pressure or aseismic tremor. Recent studies have observed a form of seismic tremor at CO_2 EOR sites that is characterized by low-frequency, low amplitude seismic emissions with durations ranging from five seconds to 10 minutes. [123, 121] The origin of slow slip seismic events has not been conclusively established but researchers have proposed mechanisms involving plastic deformation in ductile, clay-rich rocks, slow slip displacement along fractures sub-optimally aligned in the stress field, and the jerky, tensile opening of fractures as possible tremor sources (discussed in more detail in Section 3.1.3 in regards to aseismic slip as induced or triggered seismicity cause of failure). Ductile deformation of caprock is an area needing further research and represents a potential cause of vertical containment failure because it could lead to thickness variations and geomechanical weaknesses that could affect caprock integrity.

3.1.3 Induced and Triggered Seismicity

Seismicity (i.e., earthquakes and microearthquakes) is brittle shear failure accompanied by sudden slip along new and existing fracture planes. Seismicity is a potential failure mode for CO_2 storage sites because seismicity can 1) lead to vertical containment causes of failure (i.e., leakage), and/or 2) cause felt earthquakes at the surface (the failure effects of which are discussed in detail in Section 3.2). There are three types of seismicity to consider:

- **Natural seismicity** – seismic events where stored tectonic stress is released as energy during fault displacement from natural causes not associated with CO_2 injection and storage operations. Sources of natural seismicity are considered to be outside the scope of this report. Natural seismicity is a cause of vertical containment failure considered in Section 3.1.2 as a potential underlying cause of existing faults and fractures becoming transmissive, or wellbore shearing due to fault displacement during a seismic event.
- **Triggered seismicity** – defined as seismic events caused by human operations, in this cases CO_2 injection and storage operations, where the majority of the energy released is sourced from naturally-stored tectonic stress. Triggered seismicity relies on pre-existing critically-stressed faults that harbor stored tectonic stress to be present at the CO_2 storage site prior to injection operations. For example, an existing sealed fault, closed under compressive stress, could be triggered by increased reservoir pore pressure that reduces the compressive stress, resulting in strain (i.e., shear displacement, movement along the fault).
- **Induced seismicity** – any release of seismic energy where the majority of the energy released is sourced by human operations (i.e., the majority of the energy released is not tectonically derived)—in this case, CO_2 injection and storage overpressure. Other examples of induced seismicity include seismic events associated with underground blasts, mining, filling/draining of large water impoundments, and deep fluid injection for wastewater and hazardous waste disposal. Induced seismicity is commonly generated when overpressure creates new fractures and small faults.

Induced and triggered seismicity events have the highest probability of occurring during injection (or extraction) processes, and the probability decreases when injection (or extraction) ceases. [140] Human injection operations alone do not generate the same magnitude of energy that is possible from what can be released from stored tectonic stress. Consequently, induced seismicity is typically characterized by seismic events that cannot be felt at the surface (i.e., below magnitude 2.0; considered microearthquakes or microseismicity). Humans can typically feel seismic events of moment magnitudes greater than 4.0 at the surface, [140] but serious damage to surface infrastructure hazardous to human health and safety is atypical for events below an approximate magnitude 6.0. [119] Triggered seismicity, which involves reactivation of critically stressed, naturally occurring fractures or faults, can generate release of significant amounts of energy stored as tectonic stress. While triggered seismicity is likely to be of low magnitude, it is more likely to result in earthquakes felt at the surface (i.e., magnitudes greater than 4.0; possibly greater than 6.0) than induced seismicity. Therefore, triggered seismicity can potentially result in reasonably foreseeable significant adverse impact to the human environment by causing damage at the surface. However, there have been no instances of geologic CO_2 storage projects causing felt earthquakes as of 2019. [121]

CO_2 injection pressures are regulated to be below the fracture gradient pressure to avoid creating new fractures, however, depending on the regional stress state, existing fault reactivation and resulting triggered seismicity can occur at pressures below the fracture gradient. [119] Fracture pressures can be measured in laboratory settings on rock samples, but it is difficult to assess and predict the minimum pressure threshold to reactivate existing faults, and the probability and size of resulting triggered seismicity.

The underlying cause of failure for induced and triggered seismicity from CO_2 injection and storage is elevated pore pressure or fluid migration that reduces the closure stress on existing faults. Similar failure prevention, detection, and mitigation techniques associated with reservoir pressure and migration control discussed in Section 3.1.1 for causes of lateral containment failures (like poor initial storage complex quality or degradation of storage complex quality), and Section 3.1.2 for causes of vertical containment failure (like wellbore failure or caprock failure) would be applicable best practices for preventing and detecting potential future induced or triggered seismic events.

Induced and triggered seismicity failure prevention best practices during site characterization and site selection include modeling the geologic structure of the storage site from the basement to the topmost seals of the CO_2 storage complex, with emphasis on existing fault identification and stress regime. It is important to note that faults with throw (displacement) less than seismic survey resolution, and large faults in underlying crystalline basement, may be difficult to identify in 3D seismic [119] due to lack of acoustic contrast created by fault throw displacement and layering of sedimentary rock. Site characterization should assess for extensional regional stress regimes, and sites with faults oriented in close alignment with the regional maximum horizontal stress orientation. Faults in these situations would be more susceptible to pore pressure overcoming the limited compressive stress keeping the faults closed; if reopened, displacement along the faults (i.e., triggered seismicity) is likely.

Reservoir models that integrate the storage complex architecture from 3D seismic with physics-based simulation approaches [85] of hydraulic, thermal, and geomechanical properties are recommended for failure prevention to help predict induced and triggered seismicity. These models should also attempt to distinguish induced and triggered seismicity from natural seismicity. Recommended parameters to incorporate in models include:

- Seismic velocities of primary and secondary waves
- Permeability and porosity
- Thermal expansion coefficient, thermal conductivity, and heat capacity
- Stiffness and strength properties (Young's modulus and Poisson ratio), cohesion and friction angles
- Properties at initial conditions (prior to injection) like fluid pressure profile, geothermal gradient, regional Gutenberg-Richter relationship (between magnitude and total number of natural earthquakes in a region over a given time period), and stress state (magnitude, orientation, and variability of stress tensor) [121]

Acquisition of these properties can come from laboratory analyses of core samples, but Vilarrasa et al., recommends measuring hydraulic and geomechanical properties at the field scale during a water injection-induced microseismicity test. Such a test performed in conjunction with pore pressure, temperature, and deformation monitoring provides a site-specific assessment of the maximum sustainable injection pressure. Deformation at depth can be measured at high resolution along wellbores using fiber optics (i.e., distributed acoustic sensing [DAS]) to derive geomechanical properties. Vilarrasa et al., recommends incorporating multi-sensor wide-aperture arrays of geophones at depth in conjunction with a network of shallow geophones to continuously monitor for microseismicity, enabling high accuracy location of events and their focal mechanisms. [121]

If preexisting injection projects exist at the site, monitoring data should be leveraged as a failure prevention best practice. For example, the AEP Mountaineer Plant project, in West Virginia, used its small-scale Class V injection well pressure buildup information to support the proposed Mountaineer CCS II project's injectivity assessment. [124] Archer Daniels Midland Company (ADM) leveraged data from microseismic monitoring during the IBDP project, to develop its baseline for seismic monitoring of the IL-ICCS commercial CO_2 storage project. [136] It is important to note that smaller-scale pilot injection projects may not provide results reflective of large-scale commercial injection. Similarly, one large-scale projects may not be reflective of other large-scale project(s) due to site-specific variations. For example, offshore saline storage in unconsolidated sediments that deform slowly are not as prone to faulting (e.g., Utsira Formation at the Sleipner West project, in Norway's North Sea) and therefore may not be useful proxies for larger-scale onshore saline aquifer projects. [119]

After injection operations begin, failure detection best practices for induced and triggered seismicity include microseismic monitoring and pressure monitoring in and above the injection zone using injection and monitoring wells. Failure prevention based on failure detection includes continuously revising reservoir models based on the pressure limits measured, [101] and developing and actively reacting to concise stoplight protocols relating injection operational decisions (e.g., proceed, reduce injection rates and inform regulators, cease injection) to predetermined monitored seismicity magnitude cutoffs. [101, 141] If injection pressures in monitoring wells exceed injection pressure limits set by Class VI permitting, injection operations are required to be shut down and investigated. Other real-time reservoir pressure management techniques like brine extraction to control plume migration and reservoir pressure is recommended as failure prevention and failure mitigation best practices. [101] The economic viability of brine extraction, handling, and disposal, however, remains a challenge. [85]

Increased pore pressure can also cause aseismic slip along otherwise stable existing faults. Aseismic implies the strain that occurs initially does not release energy observable to most monitoring techniques, and so cannot be reliably located and tied to an injection zone of interest. Aseismic slip can cause stress to transfer from the increased pore pressure zone to distal (i.e., far-field) unstable zones of the same fault. Added stress, and possibly stress field reorientation, at these far-field locations can lead to brittle failure and result in seismicity. [123, 121] Aseismic slip on existing unknown faults helps explain why microseismic events can sometimes be observed further than anticipated from an injection zone based on hydraulic connectivity alone. The result of aseismic slip can be deformation (as discussed in Section 3.1.2), induced-seismicity, and/or triggered-seismicity, potentially far from the injection zone and outside the initially identified CO_2 storage complex. For example, microseismic events recorded during injection monitoring at the IBDP project suggested reactivation of basement faults and fracture zones below the storage complex; this inference was supported by preexisting fractures observed in core analysis of the basement rock. [142] This microseismicity could be the result of aseismic slip that started in the injection zone. Aseismic slip and tremor is the subject of much ongoing research (e.g., [123, 121]) which has difficult-to-quantify probability.

Brittle failure of new rock (i.e., not associated with existing faults and fractures) that can lead to seismicity can occur as a result of the rock's geomechanical strength being exceeded by increased pore pressure, or being reduced by non-isothermal effects related to injecting CO_2 at a temperature lower than the reservoir, geochemical effects associated with acidic dissolution of rock matrix, or as a result of previous seismicity.

Increased pore pressure has been discussed previously in this section and sections 3.1.1 and 3.1.2. Non-isothermal effects include rock contraction, thermal stress reduction, and stress redistribution in reservoir zones cooled by CO_2 injected at a lower temperature than the reservoir. Geochemical effects associated with acidic dissolution of rock matrix, especially rocks with carbonate mineralogy like limestone and dolostone, reduce geomechanical strength and make the rock more prone to brittle failure. Failure prevention best practices for brittle rock failure include performing CO_2-brine-rock geochemical laboratory evaluations, especially in carbonate rich reservoirs, to better inform geomechanical models used to predict the risks of brittle failure. [121]

Seismicity can also damage wellbore components leading to wellbore failures. [85] Common failure prevention and failure detection best practices for induced and triggered seismicity include those associated with site characterization, monitoring, and well testing techniques aimed at preventing and detecting lateral and vertical containment and wellbore failure. It is best practice during site selection to avoid regions with historically documented natural seismicity, [102, 117] which, depending on the earthquake magnitude and its hypocenter's proximity to a CO_2 project, could perturb a CO_2 storage project leading directly to containment failure, or compromise the geomechanics of the CO_2 storage complex so that induced- or triggered-seismicity events are easier to initiate. An example of natural seismicity in proximity to a CO_2 injection project is the 2018 magnitude 6.7 earthquake located roughly 37 kilometers from the Tomakomai CCS Demonstration project in Japan. The earthquake briefly increased the project's injection zone reservoir pressure, but did not result in any leakage, induced seismicity, containment failure, or wellbore failure. [143]

After drilling injection well(s), best practice seismicity failure prevention techniques include wellbore imaging for fracture and fault identification, and compressive stress regime confirmation. Wellbore failure leak detection and mitigation techniques discussed in Section 3.1.2 are recommended best practices to detect and prevent leakage outside the CO_2 storage complex inducing or triggering seismicity beyond the monitored area of review.

3.2 Potential Adverse Effects From Failure Mode Occurrence

A failure effect can occur from one or potentially multiple modes of failure (potential failure modes and causes of failure are listed and discussed above in Section 3.1) and is the consequence of failure mode occurrence. While each mode of failure has a probability or likelihood of occurrence, each effect would have a corresponding severity, values largely dependent on site-specific circumstances. This section provides an overview of the potential adverse effects to the human environment that can occur from failure mode occurrence associated with CO_2 injection and storage in saline formations. Severity is not discussed in detail because severity varies based on the site-specific nature of the storage site and its surroundings. The section is organized by the following subsections:

- Section 3.2.1 lists potential failure effects.
- Section 3.2.2 discusses which potential failure effects may represent reasonably foreseeable significant adverse impacts to the human environment, as defined in Section 1.

3.2.1 Potential Adverse Failure Effects

Potential failure effects that can arise from failure modes and their underlying causes of failure include 1) impacts to existing surface (humans, plants, and animals) and/or subsurface (USDW, hydrocarbon assets, coal mining, gas storage) resources, as well as 2) physical damage to surface topography and infrastructure. These broad failure effect categories are listed in Exhibit 3-6 as:

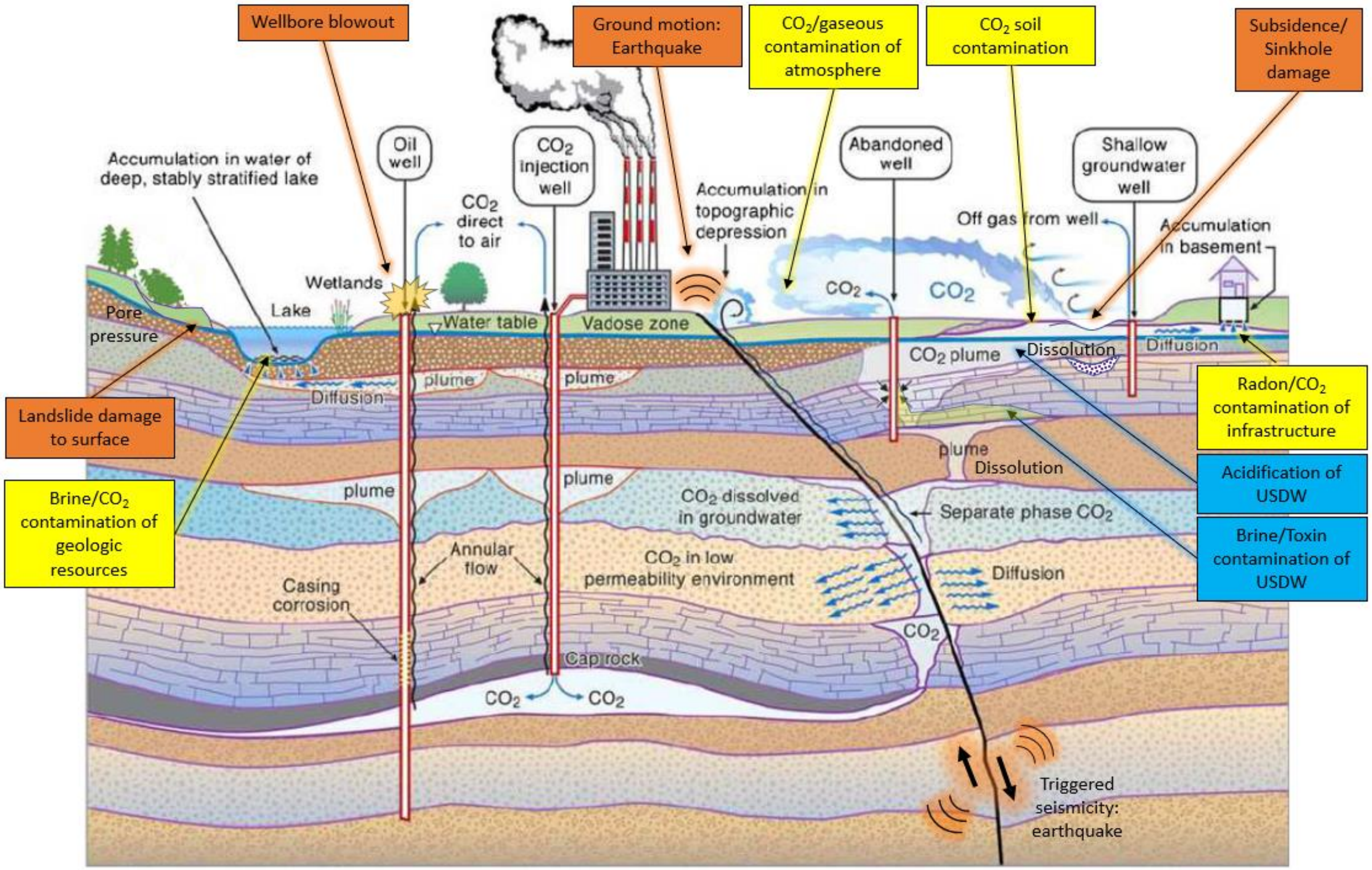
- Contamination of USDW
- Contamination of other (non-USDW) resources
- Physical damage to surface topography and infrastructure

Exhibit 3-6. List of potential failure effects associated with CO_2 injection and saline storage

Potential Failure Effect	Specific Effect	Reference
Contamination of USDW	Acidification of USDW from CO_2 infiltration, thereby affecting human, animal, and plant environments if the groundwater is produced and used	[85, 95, 87, 84]
	USDW becoming saline from displacement of natural brine into USDW thereby affecting human, animal, and plant environments if the groundwater is produced and used. Also, the displacement of brine into USDW could cause an increase of the water table, negatively affecting land quality and use	
	USDW becoming contaminated with toxic heavy metals, colloids, or other particulates dissolved and/or mobilized from CO_2 infiltration within or into USDW; thereby affecting human, animal, and plant environments if the groundwater is produced and used	[85, 102, 103, 95]
Contamination of Non-USDW	Radon displaced and emitted from vadose zone as a result of CO_2 leakage and infiltration into the shallower subsurface, affecting human environment via radon infiltration into residential or commercial infrastructure	[102, 117, 127]
	Soil gas concentration changes due to CO_2 infiltration, affecting terrestrial ecosystems within the human environment	
	Brine or CO_2 contamination by infiltration into nearby or overlying geologic, hydrologic, or infrastructure resources from, like bodies of water, coal mines, petroleum accumulations, or natural gas storage	[95, 102, 103, 124]
	Atmospheric release of CO_2 (or other contaminants, such as radon or methane, mobilized as a result of storage) affecting human and plant/animal environments	
Physical Damage to Surface Infrastructure and/or Topography	Landslides prompted from seismic activity or leakage of CO_2 into, and increased pressure in, shallow zones, which can damage buildings or infrastructure as well as natural environments/ecosystems	[127]
	Sinking (subsidence) or elevation (uplift) of the topography of the surface, gradual or sudden, caused by seismic activity or subsurface deformation, that can damage buildings, infrastructure, or agricultural drainage patterns	[95, 93, 121]
	Formation of sinkholes in shallower carbonate rocks, from process like leakage of CO_2 or acidic brine from the deep storage complex causing rock matrix dissolution and void enlargement which can cause damage to buildings or surface infrastructure	
	Ground motion, heave, or upward vertical displacement from seismic events (e.g., earthquake), which can cause damage buildings, infrastructure, and adversely change topography; ground-shaking represents a discreet human health and safety hazard	[85, 95, 87, 84]
	Wellbore blowout that can occur from equipment failure and cause leakage of CO_2, brine, or other native reservoir fluids into the surface water or atmosphere, damage to surface equipment, or liability costs; affects human and plant/animal environments. The potential explosive nature of wellbore blowout also represents a discreet human health and safety hazard	[95, 102, 117]

Contamination of USDW and non-USDW can occur through direct contact with uncontained CO_2 (i.e., leaked from the CO_2 storage complex), acidic brine, displaced brine, and contaminants associated with chemical reactions resulting from these fluids interacting with the rocks they migrated through. The communication between these resources and the fluids migrated from storage reservoirs is made possible through some mode of failure that prompted leakage. Damage to surface topography and infrastructure can occur through uplift, subsidence, or other deformation of the surface like landslides or sinkholes, felt earthquakes, and wellbore damage typically associated with the increased pore pressures and chemical reactions associated with leaked CO_2, acidic brine, and displaced brine. These specific potential failure effects are illustrated in Exhibit 3-7.

Exhibit 3-7. Potential failure effect examples from CO_2 storage operations



POTENTIAL FAILURE EFFECT:	Contamination of USDW	Contamination of Non-USDW	Physical Damage to Surface Infrastructure and/or Topography

Illustration not to scale (depth scale is condensed for illustrative purposes)

Source: EPA (modified) [144]

3.2.2 Severity of Potential Adverse Failure Effects

It is important to note that, in the context of formal risk assessment, most of the failure effects from contamination and physical damage (Exhibit 3-6), regardless of potential impact severity, are typically associated with negligible to minor risk. [145, 95, 146] Exhibit 3-6 failure effects precursor causes are likely to be:

- Avoidable with failure prevention best practices associated with site characterization and selection
- Detectable with existing failure detection technology (especially for larger-scale leaks that carry larger severity of impact to the human environment)
- Spatially limited (especially for point source leakage, like at a wellhead)
- Quickly remedied/addressed with existing failure mitigation tools and techniques

Therefore, the resulting failure effects are likely to be temporally limited. [147]

As described in NETL's 2020 "Safe Geologic Storage of Captured Carbon Dioxide - DOE's Carbon Storage R&D Program: Two Decades in Review" report, CCUS field projects worldwide injected more than 25 million tonnes of CO_2 in 2019, and none have had causes of failure that resulted in significant adverse impacts to human health or the environment. [32] There are examples of CO_2 EOR projects where CO_2 injection wells experienced blowout (e.g., [148]); however, construction requirements per Class VI CO_2 injection well permits provide failure prevention and failure detection aspects by requiring CO_2-specific construction materials and techniques and monitoring.

There are three potential failure effects that could result in catastrophic impacts that represent reasonably foreseeable significant adverse impacts to the human environment (as defined in Section 1):

1. Fast-conduit (high transmission) leakage of CO_2 to the atmosphere along a surface-intersecting fault
2. Fast-conduit (high transmission) leakage of CO_2 to the atmosphere along a wellbore
3. Triggered seismic event ("felt earthquake" above an approximate 6.0 magnitude)

There are no real examples of leakage of stored CO_2 to the surface along a transmissive fault, and it is highly unlikely to occur because site characterization and selection would disqualify storage sites with faults that intersect both the storage reservoir and the surface. UIC Class VI requirements specifically prohibit sites where transmissive faults or fractures exist (per 40 CFR § 146.83). However, unlikely as it may be, the resulting emission of stored CO_2 to the atmosphere through a fast-conduit could be analogous to natural CO_2 leakage along faults associated with volcanic and hydrothermal systems; which have historically caused adverse impacts to the associated human environment. [117, 149] The catastrophic nature of surface fault atmospheric emission would be dependent on the size and transmissivity of the fault, the amount and rate of CO_2 leakage, and the presence of low-lying areas with poor air circulation. For example, hydrothermal CO_2 leaks naturally to the surface at Mátraderecske, Hungary through vents (faults and fractures that reach the surface) which have caused several instances of death related to CO_2 concentration buildups in homes. [150] These surface-intersecting faults have a CO_2 flux approximately 40 times greater than slow-conduit (low transmission) permeable zones in the same area. [117] The slow-conduit zones leak CO_2 to the atmosphere at rates roughly an order of magnitude more than typical soil respiration rates because the leaked CO_2 has to diffuse through the overburden. Slow-conduit zones at Mátraderecske do not result in significant adverse impacts to the human environment because CO_2 leakage can be easily detected and mitigated with simple residential suction or blower units. [117] Unlike natural volcanic and hydrothermal CO_2 sources, CO_2 storage sites have a finite source of CO_2 to leak, and a CO_2 storage site's reservoir pressure can be managed with failure mitigation best practices (like those discussed in Section 3.1, e.g., ceasing CO_2 injection operations, brine extraction relief wells).

Similarly, fast-conduit leakage of stored CO_2 to the surface along a damaged wellbore could be catastrophic and also represents a reasonably foreseeable significant adverse impact to the human environment. The catastrophic nature of the atmospheric emission of CO_2 would depend on the size and transmissivity of the wellbore failure, the amount and rate of CO_2 leakage, and the presence of low-lying areas with poor air circulation. An additional catastrophic component of fast-conduit leakage along a wellbore is the chance of a wellbore blowout, which would represent a discreet human health and safety hazard for people in the immediate vicinity of the wellhead. However, wellbore blowouts are highly localized at the wellhead point source should they occur, can be detected rapidly, and timely remediated with available technology (based on natural gas storage analogs). [84] Blowouts during drilling of new wells are unlikely because of the common use of dense drilling fluids and blowout preventers, both reducing the likelihood of a blowout. Wells permitted, constructed and operated following UIC Class VI permit regulations are unlikely to experience wellbore failure that could lead to catastrophic leakage to the surface. Legacy wellbores, however, like plugged and abandoned oil and gas production wells, are unlikely to have been designed and constructed to address CO_2 storage pressures and acidic brine chemistry; without proper advance detection and mitigation of these wellbores, they could become fast-conduits for CO_2 leakage to the surface. Such wells would normally be identified and appropriately plugged by CO_2 storage operators following the UIC Class VI AoR and corrective action plan. [151]

The third potential failure effects that represents a reasonably foreseeable significant adverse impact is a felt earthquake resulting from triggered seismicity. As discussed in Section 3.1.3, increased pore pressure can reduce stress on an existing fault with stored tectonic stress, causing fault movement and an earthquake. [119] Existing faults in crystalline basement rock are more likely to be critically stressed, so storage complexes in closer vertical proximity to basement rock are of more concern for large triggered seismic events. Existing faults in the subsurface may go undetected by standard seismic techniques, especially if the throw (displacement) is smaller than the seismic resolution, or if the fault is contained within a thick seismic layer with no acoustic contrast to highlight the throw. The amount of seismic energy that could be released from an unidentified fault with unknown dimensions is difficult to assess; it is possible reactivating such faults could cause earthquakes of magnitude 6.0 or greater, but the probability of such an event is unknown. [119] Section 3.1.3 provides more context on best practices to prevent selecting sites prone to seismicity, and operate in ways to prevent or reduce the probability of triggered seismicity occurring. Surface damage from ground shaking associated with large earthquakes represent a discreet human health and safety hazard for all people in the affected region and can cause significant damage to fixed surface infrastructure.

While these three potential failure effects, in particular, could induce effects considered reasonably foreseeable significant adverse impacts on the human environment, in all likelihood, their causes of failure would be prevented and/or quickly detected and mitigated by qualified geologic carbon storage site operators implementing the appropriate failure prevention (i.e., site characterization), detection (i.e., monitoring), and mitigation (i.e., readily available mitigation procedures and techniques) best practices discussed in Section 3.1. The other potential failure effects listed in Exhibit 3-6 are unlikely to represent a reasonably foreseeable significant adverse impacts to the human environment, as defined in Section 1.

The potential failure effects of contamination of USDW are the focus of UIC Class VI injection well regulations which are designed to ensure that failures that could result in USDW endangerment are substantially avoided through prevention, detection, and mitigation. The specific effects listed in Exhibit 3-6 are dependent on lateral or vertical containment causes of failure (discussed in section 3.1.1 and 3.1.2) of the deep storage complex, and subsequent leakage of CO_2, acidic saline brine, displaced brine, [85, 84, 87] and any toxic heavy metals, colloids, or other particulates liberated along the leakage pathway into USDW aquifers. [85, 102, 103] The severity of potential failure effects from contamination of USDW is relatively low because the:

- Impacted contaminated area would likely be localized (near to the discrete cause of failure pathway in the subsurface, like a transmissive fault or a compromised wellbore)
- CO_2 itself does not make drinking water non-potable (e.g., Italian cities with CO_2-rich municipal waters) [117]
- Saline brines are dense, and if displaced into an aquifer defined as USDW, brines would likely stay in the lowest portions of the aquifer, limiting the vertical extent of contamination [127]
- Failure prevention methods (site screening, characterization, and selection practices) typically eliminate candidate locations with heavy metal deposits, [102] and model CO_2-brine-mineralogical interactions for the potential to liberate toxins; avoiding such candidates makes toxin liberation and subsequent contamination a negligible impact

The same causes of lateral and vertical containment failure and subsequent leakage that lead to USDW aquifer contamination could similarly lead to contamination of non-USDW resources. Increased pore pressure from leaked CO_2 could displace and increase natural radon emission rates [102, 117, 127] and/or increase CO_2 soil gas concentrations. [117] Leaked CO_2 that reaches other geologic features like federally protected waterways, coal mines, [124] petroleum accumulations, [103] and natural gas storage sites [102] could result in unanticipated safety concerns. The failure effect of atmospheric emissions of CO_2, in general, relates to climate change concerns and presents a potential asphyxiation risk should localized CO_2 accumulation occur. [102] However, the severity of potential failure effects from contamination of non-USDW is relatively low because:

- Radon emission rates, even if increased due to CO_2 pore pressure-induced displacement, is unlikely to exceed existing EPA-established action levels [102, 127]
- Potential incremental increases in CO_2 soil flux at injection sites due to CO_2 pore pressure from leakage, would likely be small as compared to typical soil respiration rates [117]
- CO_2 leaked into commercial resource extraction (and storage) operations are unlikely to preclude those operations [102, 103, 124]
- Leakage of CO_2 to the waterways and/or the atmosphere would be diffuse and remain at levels below rates that would impact human health, unless (as mentioned previously in this section) CO_2 is emitted along a large transmissive fault that breaches the surface, [102, 150] or leaked at a point source like a compromised wellbore, or allowed to accumulate in low lying and/or confined areas (e.g., residential basements)

While the potential failure effects of contamination of USDW and non-USDW resources are generally low severity (with the exception of fast-conduit leakage to the surface), most of the potential failure effects of physical damage to surface infrastructure and/or topography are of higher relative severity. Triggered seismic events of magnitude greater than approximately 6.0, and fast-conduit leakage along a wellbore (which includes the failure effect of a wellbore blowout) have already been discussed in this section as reasonably foreseeable significant adverse impacts to the human environment. The other potential failure effects listed in Exhibit 3-6 (landslides, [127] sinkholes, subsidence, [93, 102, 121] or ground heave [85, 87, 127, 84]) can feasibly be caused by triggered seismicity as the underlying cause of failure, but can also have other causes of failure. Increased pore pressure in the vadose zone from CO_2 leakage out of the deep storage complex and migration into the vadose zone can potentially cause landslides in landslide-prone areas. Acidic brine, leaked from the storage complex and migrating into shallower rock, can dissolve carbonate rocks leading to sinkholes and/or subsidence. Ground heave can result from deformation associated with increased pore pressure in the subsurface from fluid injection, or fluid leakage and migration. Ground heave not associated with seismicity is likely to be localized, and the uplift itself at a millimeter scale, making structural and drainage pattern damage negligible. [85, 102, 135] While landslides, sinkholes, and subsidence failure effects can all have the potential to represent discreet human health and safety hazards, and cause physical damage to surface infrastructure and/or topography, aspects of their causes of failure (with exception of triggered-seismicity) are mostly avoidable with site characterization and selection to avoid sinkhole and subsidence-prone sites with shallow carbonates, and landslide-prone sites with steep and unstable topographic features. [102]

3.3 Changes in Risk Perception at IBDP and IL-ICCS CO_2 Storage Projects

Storage operators can benefit from CO_2 storage projects operated under UIC guidance that can serve as case studies for comparing predicted and actual causes of failure and potential failure effects. Two projects within the United States, the IBDP at the ADM industrial facility and its subsequent IL-ICCS project (both permitted with Class VI wells), represent useful case studies. IBDP was a large-scale, saline reservoir storage test located in Decatur, Illinois. The project began in 2007 and CO_2 was sourced from ADM's corn wet milling plant with ethanol production. Injection into the Mt. Simon Formation started in 2011 and when it ceased in 2014, IBDP had stored approximately one million tonnes of CO_2. [152] Expanding the operations of IBDP to a larger-scale in Decatur, Illinois, IL-ICCS also sources CO_2 from ADM's corn wet milling plant and then transports it via pipeline to the Mt. Simon Formation for injection. Injection began in 2017, and as of August 2019, this ongoing project has injected and stored over 1.3 million tonnes of CO_2. [153] By the end of the 5-year injection period, IL-ICCS is predicted to inject and store approximately 3 to 5.5 million tonnes of CO_2. [136, 153]

3.3.1 Pre-Injection Risk Perception Changes at IBDP

In 2008, the IBDP undertook a formal risk analysis, where a group of project experts identified 119 physical features, discrete events, or long-term processes which relate to either a cause of failure or a potential failure effect; [87] each cause of failure or potential failure effect identified was termed an “FEP” for “feature, event, or process”. [93] The experts evaluated the risk associated with each FEP, assigning risk numbers derived by multiplying an FEP's perceived severity, ranked 1 to 5 (where 1 is “light” and 5 is “extreme”) by the FEP's perceived likelihood, ranked 1 to 5 (where 1 is “very unlikely” and 5 is “very likely”). The maximum risk number reflects the highest single-expert assessment, while the average risk number reflects the consensus of all project experts involved in the risk analysis. [87] The top 19 FEPs identified for IBDP in 2008, ranked by maximum risk, are shown in Exhibit 3-8, along with their average risk. [87] Eight of the top 19 FEPs identified in 2008 were associated directly with CO_2 injection and storage (as outlined in Section 3.1 and its subsections).

Exhibit 3-8. Top 19 FEPs (of 119 total), ranked by maximum risk, from the 2008 IBDP risk assessment [87]

RANK by plurality of high-risk scores	FEP	MAX RISK	AVG RISK
1	Toxic geologic components (metals)	20	7.2
2	Contamination of groundwater by CO_2	20	5.8
3	Undetected features	16	7.1
4	Human activities in the surface environment: on site	16	7.5
5	Exogenous economics: Supply prices	15	9.8
6	Near-surface aquifers and surface water bodies	15	5.6
7	Accidents and unplanned events: Project	15	5.8
8	Community characteristics	15	5.0
9	Legal/regulatory: Property rights and trespass	12	6.9
10	Fractures and faults	12	7.8
11	Schedule and planning	12	6.7
12	Reservoir pore architecture	12	6.2
13	Reservoir geometry	12	5.6
14	Actions and reactions: Local community	12	6.6
15	CO_2 solubility and aqueous speciation	12	8.0
16	Seismicity (induced earthquakes)	12	6.1
17	Actions and reactions: National/international Special Interest Groups and Non-Governmental Organizations (NGOs)	12	5.5
18	Legal/regulatory: Construction, discharge, and other operations permits	12	5.0
19	Land and water use	12	4.4

A second risk assessment in 2011 incorporated new data associated with well site development and other site characterization project efforts associated with IBDP and IL-ICCS (being planned at the time), resulting in more specific “scenarios” being described. A “scenario” in the 2011 IBDP risk assessment combines a specific cause of failure with potential failure effects. The scenarios were assigned a risk value using a similar severity and probability rubric as the 2008 risk assessment, and the top 14 scenarios, ranked by average risk, are shown in Exhibit 3-9. [52] A comparison of the two risk assessments’ top ranked FEPs and scenarios are shown in Exhibit 3-10. The comparison suggests several changes, as a result of additional site characterization between 2008 and 2011, in the perceived importance of potential failure modes and potential failure effects associated with CO_2 injection and CO_2 storage operations.

Exhibit 3-9. Top 14 scenarios, ranked by average risk, from the 2011 IBDP risk assessment [87]

Scenario Group	Scenario	Avg Risk
Seismicity	CCS2 increases reservoir pressure, triggers a felt seismic event, and regulators shut down both projects pending investigation.	9.71
Plume Footprint	Plume migrates beneath sensitive area or unexpectedly far, increasing monitoring requirements and cost.	9.17
Regulations, Permitting, Closure	Regulatory agency is surprised to learn of a connection between seismicity and injection, and requires shutdown pending investigation and additional monitoring.	8.65
Regulations, Permitting, Closure	CCS2 logs show a fault cutting the Mt. Simon that looks important (as a potential source of seismicity or influence on fluid movement), and regulators require IBDP injection to stop.	7.94
Plume Footprint	New and untested technologies malfunction, increasing cost, and impairing data acquisition.	7.94
Data Interpretation and Care	The IBDP project data is required to be made public without time for adequate analysis and/or significant publications from the project team, resulting in misrepresentation of the information.	7.75
Seismicity	ICCS does not effectively apply IBDP research on microseismicity, and induces seismicity that causes regulators to shut down both projects.	7.65
Operations, Mechanical Integrity	Packer in CCS1 fails and a costly workover is needed.	7.53
Staff and Expertise	A valuable subcontractor has scarce resources and does not send appropriate staff levels to complete a job.	7.53
Seismicity	IBDP operations cause seismic event that is felt by people in Decatur, leading to news reports that CCS causes earthquakes.	7.50
Health, Safety, Environment	Injury from a common industrial or drilling hazard.	7.29
Environmental Monitoring	Westbay multilevel groundwater characterization and monitoring system fails beyond repair, and VW1 must be re-completed.	6.89
Public interactions	An unplanned event occurs; news media become involved; key people are unavailable but a public response is needed.	6.50
Budget, Cost	DOE funding is reduced, and not enough funds remain for proper site/project closure.	5.94

Exhibit 3-10. Comparison of CO_2 injection and storage-related risk assessments for IBDP between 2008 and 2011

<table>
<tr><th>2008 FEPs Associated with CO_2 Injection and Storage</th><th>2008 FEPs Potential Failure Mode or Potential Failure Effect as defined in this Report</th><th>2008 FEP Risk Relative Ranking</th><th>2011 Scenarios Associated with 2008 FEPs</th><th>2011 Scenario Risk Relative Ranking</th></tr>
<tr><td>Toxic geologic components (metals)</td><td rowspan="2">(Potential Failure Effects)
Contamination of USDW
Contamination of non-USDW</td><td>1</td><td rowspan="2">None associated</td><td rowspan="2">Not applicable</td></tr>
<tr><td>Contamination of groundwater by CO_2</td><td>2</td></tr>
<tr><td>Undetected features (any unknown aspect of the subsurface [154])</td><td rowspan="2">(Potential Failure Modes)
Lateral Containment Failure
Vertical Containment Failure
Induced and Triggered Seismicity</td><td>3</td><td rowspan="2">CCS2 [IL-ICCS] logs show a fault cutting the Mt. Simon that looks important (as a potential source of seismicity or influence on fluid movement), and regulators require IBDP injection to stop</td><td rowspan="2">4</td></tr>
<tr><td>(Presumably detectable) fractures and faults</td><td>10</td></tr>
<tr><td>Reservoir pore architecture</td><td rowspan="3">(Potential Failure Modes)
Lateral Containment Failure
Vertical Containment Failure</td><td>12</td><td rowspan="3">Plume migrates beneath sensitive area or unexpectedly far, increasing monitoring requirements and cost</td><td rowspan="3">2</td></tr>
<tr><td>Reservoir geometry</td><td>13</td></tr>
<tr><td>CO_2 solubility and aqueous speciation</td><td>15</td></tr>
<tr><td rowspan="5">Seismicity (induced earthquakes)</td><td rowspan="5">(Potential Failure Mode)
Induced and Triggered Seismicity
(Potential Failure Effect)
Physical Damage to Surface Infrastructure and/or Topography</td><td rowspan="5">16</td><td>CCS2 [IL-ICCS injection well] increases reservoir pressure and triggers a felt seismic event, and regulators shut down both projects pending investigation</td><td>1</td></tr>
<tr><td>Regulatory agency is surprised to learn of a connection between seismicity and injection, and requires shutdown pending investigation and additional monitoring</td><td>3</td></tr>
<tr><td>CCS2 [IL-ICCS injection well] logs show a fault cutting the Mt. Simon that looks important (as a potential source of seismicity or influence on fluid movement), and regulators require IBDP injection to stop</td><td>4</td></tr>
<tr><td>ICCS [IL-ICCS] does not effectively apply IBDP research on microseismicity, and induces seismicity that causes regulators to shut down both projects</td><td>7</td></tr>
<tr><td>IBDP operations cause seismic event that is felt by people in Decatur, leading to new reports that CCS causes earthquakes</td><td>10</td></tr>
<tr><td colspan="3">Not explicitly mentioned in 2008's highest risk FEPs</td><td>Packer in CCS1 [IBDP injection well] fails and a costly workover is needed</td><td>8</td></tr>
</table>

Exhibit 3-10 illustrates that the perceived potential failure modes and potential failure effects associated with CO_2 injection and storage at IBDP changed between 2008 and 2011, most notably:

- Seismicity became a more prominent risk in the 2011 assessment: the number of specific failure mechanisms identified that could lead to seismicity increased, and their collective relative risk ranking rose considerably. In fact, felt triggered seismicity became the scenario with the highest overall ranked risk in 2011. Hnottavange-Telleen et al., suggested the change in risk ranking of seismicity is due to changes in public perception of risk, not a change in technical risk between 2008 and 2011. [155]
- Causes of failure related to insufficient reservoir properties like pore architecture, reservoir geometry, and CO_2-brine geochemistry in 2008 were likely consolidated into more specific and higher-ranked risk concerns about lateral plume migration and lateral or vertical containment failure in 2011.
- Concerns about detected faults and undetected features leading to all potential failure modes (lateral containment failure, vertical containment failure, and triggered and induced seismicity) remained relatively unchanged between 2008 and 2011. By 2017, leakage from faults, fractures, and bedding plane partings are considered to be highly improbable to nearly impossible for the IL-ICCS project based on the lack of faults or folds identified in 3D seismic, and minimal probability of (natural) seismic events in the region. [136]
- Highest-ranked risk concerns of contamination of groundwater by CO_2 or toxic metals in 2008 do not make the top risks in 2011, suggesting either their underlying causes of failure are likely to be prevented, detected, and/or mitigated well in advance (e.g., by the best practices discussed in Section 3.1), or that the potential failure effects were not considered severe, or some combination of both. According to Hnottavange-Telleen et al. (2009), the initial high risk ranking in 2008 of groundwater contamination was based on the "catastrophic" impact it would have on the project (i.e., project termination), and not the adverse impact contamination would have to human health or the environment. [154] Similar to seismicity risks, Hnottavange-Telleen et al. (2011), suggests the change in groundwater contamination risk ranking between 2008 and 2011 is due to changes in public perception of risk, not a change in technical risk. [155]
- Wellbore component failure is not mentioned in the top lists in 2008 but is a top-14 risk-ranked scenario identified in 2011. ADM's 2017 IL-ICCS MRV plan states that leakage from surface components, including the wellhead itself, represents the most probable potential for leakage of CO_2 to the surface of all the possible causes of leakage (e.g., from abandoned oil and gas wells, fractures, faults, bedding plane partings, confining zone limitations, or monitoring wells). [136]

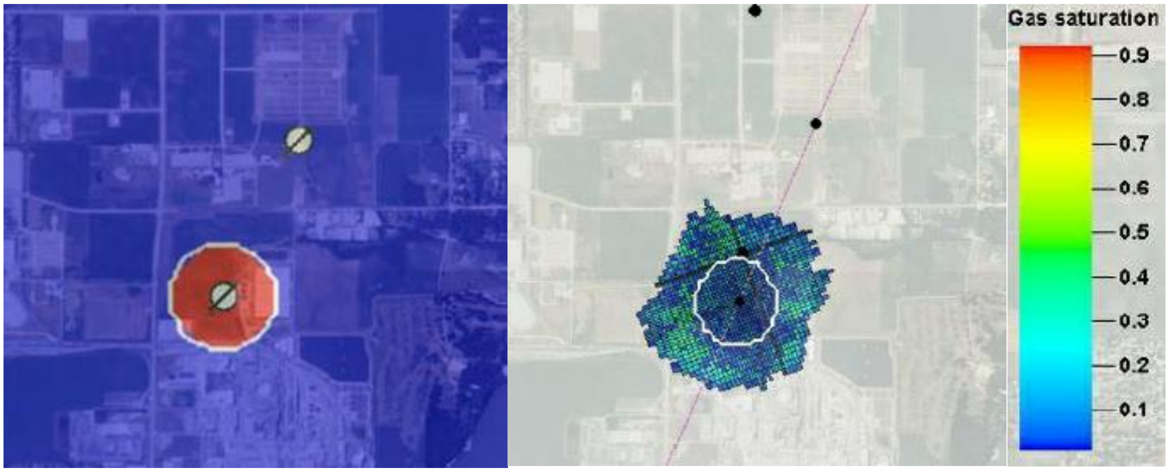
The two early risk assessments for IBDP illustrate the site-specificity of potential failure modes and potential failure effects. The dynamic nature of how relative perceived risk associated with certain potential failure modes and potential failure effects can change over time highlights the importance of continually updating formal risk assessments by integrating new site characterization and monitoring data as it is acquired. The two risk assessments also illustrate how public perception of risk can change over time (public perceptions of risk are discussed in more detail in Section 4).

3.3.2 Risk Perception Changes at IBDP and IL-ICCS During and After Injection Operations and Monitoring

With IBDP injection completed in 2014, and IL-ICCS injection ongoing, CO_2 storage operators can learn from reported results to date. Based on Midwest Geological Sequestration Consortium annual updates on IBDP and IL-ICCS from 2015 to 2019, presented at the NETL Carbon Storage R&D Annual Meetings, [156, 157, 153, 158, 159] literature (e.g., [152, 142]), MRV and Class VI permit documents, [136, 145] and risk assessments, [154, 87] several trends in failure detection monitoring, and their impact on how to assess causes of failure and potential failure effects are of interest:

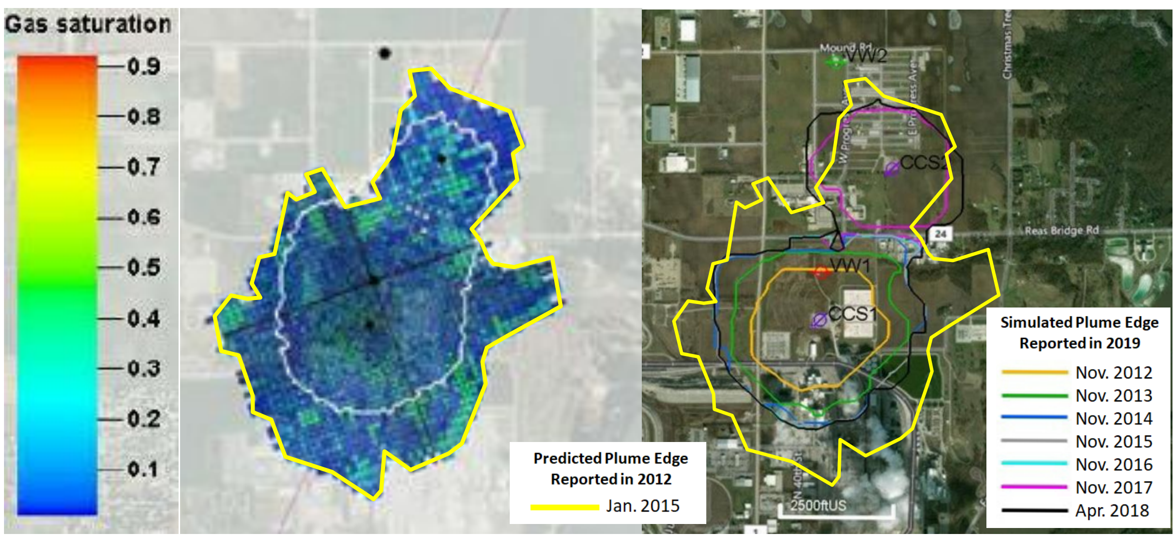
- Repeat pulsed neutron logging (i.e., Schlumberger's Reservoir Saturation Tool) used to monitor CO_2 plume migration from the IBDP verification well showed that CO_2 reached Zone 3 in March 2012 and Zone 2 in July 2012, much sooner than initially modeled. [158] This observation does not indicate a lateral containment failure, but did require reservoir simulations to be revised for permeability distribution
- Plume growth modeling predictions have changed over time, incorporating new monitoring data, like the pulsed neutron logging mentioned above. For example, the original plume growth model prediction (prior to 2011 injection) for the end of injection year 1 (2013) was too conservative, and under predicting actual plume growth rate. The original plume growth model had to be updated in 2012 based on the pulsed neutron logging monitoring [160] (mentioned in above). Exhibit 3-11 shows the side-by-side comparisons of the original model's prediction for the year 2013 and the updated 2012 model's prediction for the year 2013. The model revised in 2012 then over-predicted future plume size growth. Exhibit 3-12 shows the side-by-side comparison of the 2012 model's prediction for the year 2015 [160] with annual plume edges reported in 2019. Note that the 2012-predicted 2015 plume size exceeds the actual plume size reported in 2018. These comparisons illustrate that modeling efforts and their predictions are dynamic as they are updated to incorporate new monitoring and operational data. Site-specific risk assessments will similarly change and should also be updated to incorporate these new models. The areal extent of the plume reported in 2019 [159] is significantly smaller than the AoR that is actively monitored for the IL-ICCS project [136]

Exhibit 3-11. Map view of original (pre-injection) CO_2 plume extent prediction (in red) after 1 year of injection (a 2013 timestamp) (left; blue box)), compared with revised CO_2 plume extent prediction after 1 year of injection based on pulsed neutron logging monitoring data (right; grey box)



Source: McDonald [160]

Exhibit 3-12. Map view of 2015 CO_2 plume extent (left) predicted in 2012 (outlined in bright yellow), overlain on map of yearly CO_2 plume extents reported in 2019 (right)

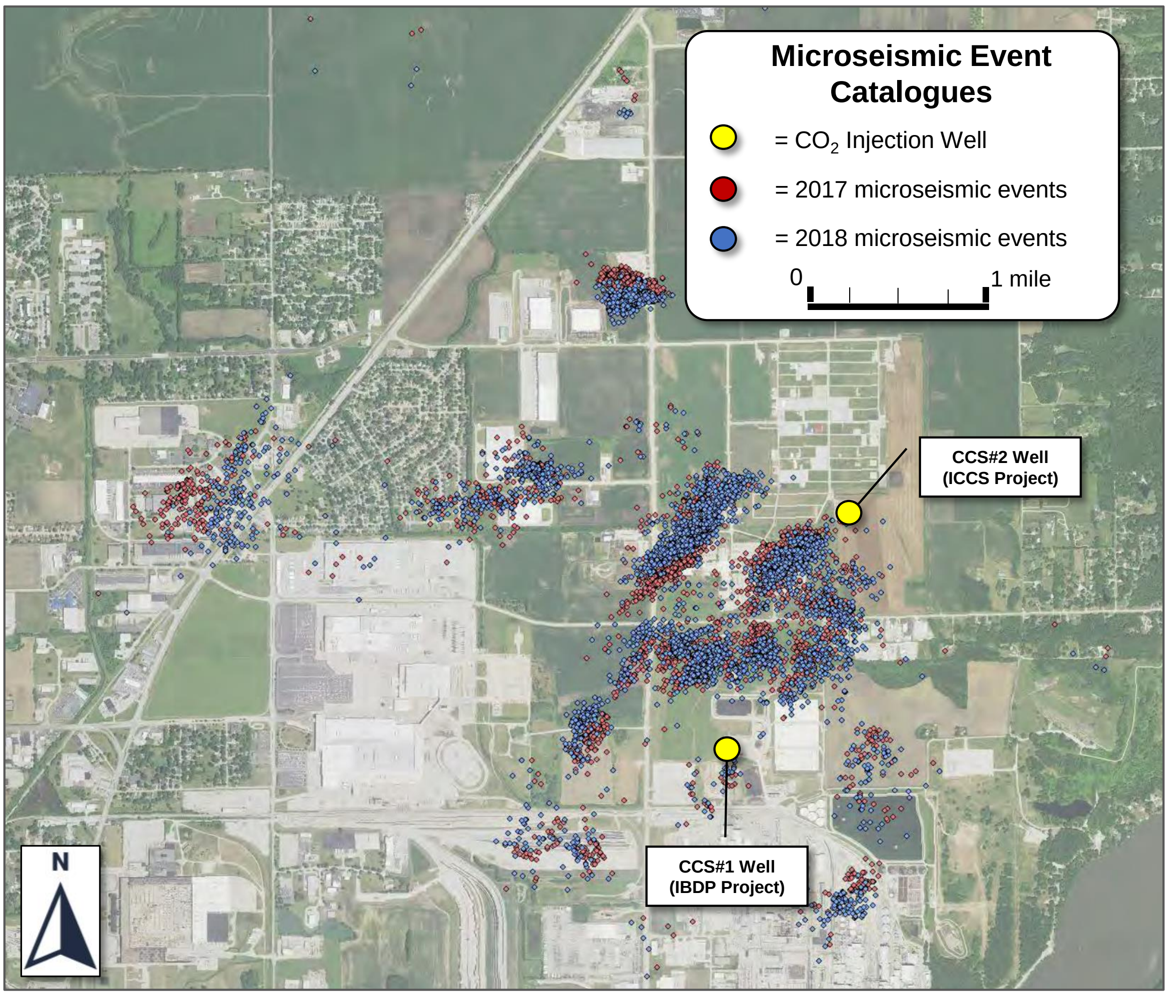


Note: CO_2 plume extent predicted in 2012 for the year 2015 exceeds the 2018 reported plume edge extent

Source: (Modified) McDonald [160] and (modified) Greenberg et al. [159]

- The 2015 interpretation of microseismic event timing, depth, and clustering during IBDP injection suggested localized planes of weakness caused by Precambrian topography (which the Mount Simon reservoir overlays) cause the majority of microseismicity outside the injection reservoir. [142] Pressure propagation is the likely cause of the microseismic events located deeper than the reservoir, as opposed to hydraulic connectivity of CO_2 plume or displaced brine (which would indicate storage complex downward vertical containment failure). [158] Microseismic location reinterpretation efforts in 2018 associated with geophone depth correction led to many microseismic events to be interpreted 150–400 ft deeper than initially interpreted, placing the majority of microseismic events within the Precambrian basement rock below the Mount Simon storage reservoir (see Exhibit 3-13 through Exhibit 3-15). [153] Additional microseismic location reinterpretation efforts in 2019, which incorporated 3D seismic reprocessing data resulted in rotating microseismic clusters that aligned more consistently with known stress orientation (see Exhibit 3-15). [159] More accurate microseismic interpretations improve the understanding of reservoir dynamics and may suggest induced seismicity is less likely to cause vertical containment failure.

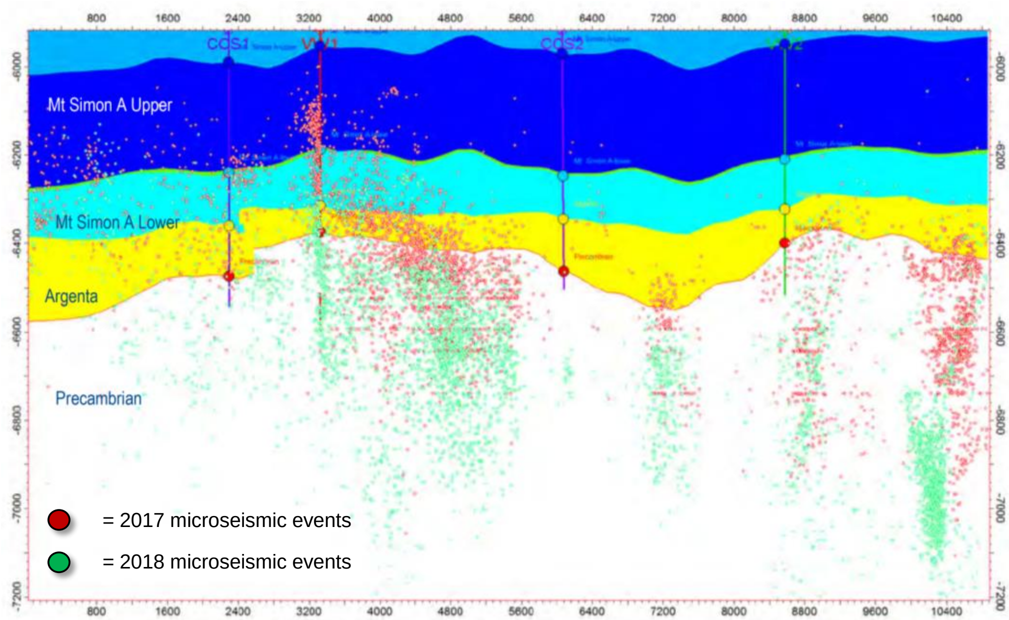
Exhibit 3-13. Map view projection of subsurface microseismic events recorded during IBDP CO_2 injection



Note: Events X-Y coordinates interpreted in 2017 (red) and reinterpreted in 2018 (blue), illustrating the importance of geophone location accuracy and precision, and the dynamic effect of integrating new data and analysis techniques to the understanding of CO_2 storage project subsurface mechanisms

Source: Greenberg et al. [153]

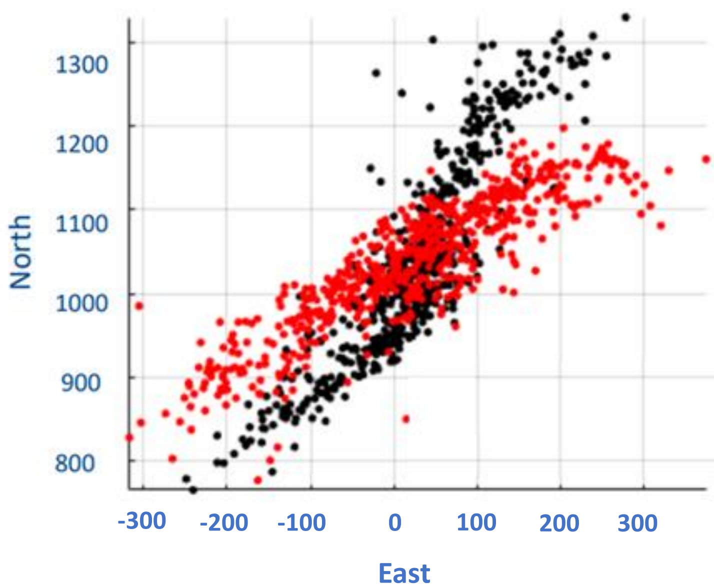
Exhibit 3-14. 2D cross-section depiction of microseismic events recorded during IBDP CO_2 injection



Note: Events' depth coordinates as interpreted in 2017 (red; many above the Precambrian surface) changed after reinterpretation in 2018 (green; mostly below the Precambrian surface), illustrating the importance of geophone location accuracy and precision to microseismic interpretation, and the dynamic effect of integrating new data and analysis techniques to the understanding of CO_2 storage project subsurface mechanisms

Source: Greenberg et al. [153]

Exhibit 3-15. Map view of a 2018 microseismic event cluster interpretation at IBDP (black dots) reinterpreted (red dots) by integrating repeat 3D and VSP data, improving XY (and Z, not shown) coordinate location interpretation



Source: Greenberg et al. [159]

- Upward plume growth was initially modeled to be limited due to horizontally oriented permeability baffles (i.e., mudstone layers within the storage reservoir). Pressure observations to date have since confirmed this prediction. [158] However, an extensive mudstone assumed to be a continuous vertical migration baffle between the deeper IBDP injection zone and the shallower IL-ICCS injection zone, predicted based on IBDP's petrophysical log and core analysis, [158] has since been demonstrated to not be continuous based on later IL-ICCS logging. [153] This is an example of a potential future cause of vertical and lateral containment failures, since there may be more pressure interference between IBDP and IL-ICCS than was originally considered
- Mount Simon brine is more corrosive than initially anticipated based on fluid sampling, [158] suggesting a greater potential for causes of failure related to CO_2-brine-mineralogy reactions. For example, wellbore failure from compromised wellbore cement, and reduced caprock integrity from corrosion
- 3D seismic survey data reprocessing efforts which included a more thorough and complex set of faults, integrated with temperature, pressure, pulsed neutron, and other log data, updated from 2018 to 2019, lead to improved history matching, [159] suggesting that causes of lateral containment failure, vertical containment failure, and induced or triggered seismicity from unidentified faults are better constrained in the context of updated site-specific formal risk assessment

In summary, it is best practice for CO_2 injection projects to consistently update their site-specific risk assessments as new data is collected and integrated, and new lessons are learned from other CO_2 storage projects and storage project analogs. The result is a dynamic risk assessment through time. Through proper site characterization, site selection, permitting, operating and monitoring, data can be collected to prevent, monitor, and mitigate causes of failure, avoiding or reducing the impact of potential failure effects should a cause of failure occur.

Ultimately, however, a few technical causes of failure associated with CO_2 injection and geologic storage represent reasonably foreseeable significant adverse impacts to the human environment: fast-conduit (high transmission) leakage of CO_2 to the atmosphere along a surface-intersecting fault or a compromised wellbore, and triggered seismic events (i.e., "felt earthquake" of magnitude greater than approximately 6.0). As with other causes of failure, appropriate failure prevention, failure detection, and failure mitigation can avoid or reduce the impact of these potential failure effects.

While the technical risks of CO_2 injection and geologic storage remain relatively low, public perception of these risks and others associated with CO_2 injection and storage is important to consider, as mentioned in Section 3.3.1. Section 4 addresses public feedback related to CO_2 storage operations in the United States, critical when considering all aspects of CO_2 injection and geologic storage on the human environment.

4 ADDITIONAL ISSUES OR CONCERNS FROM PUBLIC AND STAKEHOLDER COMMENT

Experience from prior field projects has demonstrated that the possibility exists for local communities to feel subjected to higher risks when CCUS is conducted within their general proximity. The perceived risks can be tied directly to CO_2 storage operations influenced by the probability of possible failure modes occurring and potential failure effects realized to the human environment. Additionally, risks can take the form of potential variation in socioeconomic norms to the surrounding community once CCUS is deployed, aversion to CCUS due to a lack of full understanding of the technology itself, or possibility of negligence in CCUS operations. Moreover, early experience has shown that negative public perception and local opposition can cause or contribute to project delays and cancellations and be a potential barrier for broader CCUS deployment. [161, 162, 163, 164, 165]

This level of perception is not uncommon for many types of new technologies being deployed, particularly those with some environmental aspect. For relatively new technologies like CCUS that may not be widely understood, it can be difficult to fully comprehend stakeholders'[i] perception and affinity (either positive, negative, or neutral) toward said technology when it is being considered for deployment within proximity to their homes, business, schools, etc. In most cases, past experience has suggested that negative perception toward CCUS is a result of a lack of understanding across the broader populous for how it is conducted and the best-practices available that can be implemented to make failure modes unlikely, preventable, or manageable, and that can provide safe-guards against potential effects to the human environment [166, 167] Additionally, experience has shown that the most prominent failure modes and effects associated with CCUS can vary in both perception and ranking priority depending on factors like the type of stakeholder group, as well as between CCUS experts and non-experts. [168]

The reactions and attitudes mentioned above, mostly focusing on the negative context, have been described by many to reflect 'not-in (or under)-my-backyard' (NIMBY) sentiments. [161, 169, 170, 171] The NIMBY effect is a natural response to the unknown and refers to local (i.e., near project sites) opposition motivated in part by self-interest, local safety, and property values. [161, 172] Eliminating the effect entirely from future CCUS projects is unlikely; however, it is possible to mitigate the effects and learn from past or ongoing projects to implement best practices going forward. For instance, DOE noted that one of the most valuable lessons learned by the RCSP Initiative is that public outreaching efforts need to be incorporated into CO_2 storage site project management strategies early on in a project's life cycle—ideally initiating at project conceptualization prior to any site screening. [173] Such an approach would facilitate dialogue and knowledge sharing with key stakeholders located near the project. This outreach would also inform stakeholders of project plans and potentially provide inclusion into future planning,

[i] Stakeholders in this context includes, but not limited to, residents of communities in proximity to CCUS sites, landowners in proximity to CCUS sites, policy makers, non-governmental organizations, various industry groups, and potentially tribal nations [177] all with some connection to a given CCUS project.

provide insight into CCUS and how it may benefit and impact their region and beyond, and provide feedback to project developers, which they can use to tailor operations as needed.

As projects progress, opportunities for stakeholder engagement often coincide with times of high exposure for a project, particularly during permitting or project approval milestones. [173] For instance, permitting often entails some form of formal public engagement either through notices in the paper, comment periods, or public hearings. As a result, feedback is normally received in response to potential CCUS development efforts. This section provides a summary of the more prominent concerns expressed by the public or other relevant stakeholders related to select CCUS projects in the United States. The information is compiled from EAs, EISs, and UIC Class VI permit application public and stakeholder comment periods. While it is not a comprehensive digest of the global public perception on CCUS, the collective information ties back to the failure modes, effects, prevention, detection, and mitigation measures related to impacting the human environment described previously in Section 3 specific to the projects evaluated. The information complied also provides perspective to other topics of stakeholder feedback not directly related to the human environment aspect.

4.1 Public and Stakeholder Comment on CCUS Projects in the United States

When given the opportunity, stakeholders have expressed their support or concerns on CCUS projects proposed within their general vicinity during public comment periods for NEPA reviews (e.g., EIS and EA) and/or UIC permit applications. To obtain a general understanding of the public's perception on CCUS technologies, the following documents related to a small subset of CCUS projects (some of which never moved forward to CO_2 injection) were evaluated to assess stakeholder perception associated with CCUS projects and determine the most prominent category topics discussed. The documents reviewed included:

- IL-ICCS EA (DOE EA-1828): evaluates potential environmental consequences of providing a financial assistance grant to ADM for the IL-ICCS project in Decatur, Illinois. Public commentary was from state agencies, Native American tribes, and various federal agencies with focus on site specifics or environmental regulation.
- Southeast Regional Carbon Sequestration Partnership (SECARB) Phase III EA (DOE EA-1785): evaluates potential environmental consequences of providing financial assistance in a cooperative agreement with SECARB. Like the IL-ICCS EA, it includes public commentary from state agencies, Native American tribes, and various federal agencies that focused on site specific concerns and endorsements.
- FutureGen 2.0 draft EIS (DOE EIS-0460): assessed a potential CCUS project in Morgan County, Illinois, near Jacksonville, Illinois. Commentary for this project came primarily from private citizens at public hearings hosted by DOE and project associates with public and private agency commentary more focused on project specifics. This project ended up not moving forward due to project funding issues.

- ADM CCS#2 UIC Class VI draft permit: includes responses to public commentary concerning specifics about the permit. Responses were only recorded from private citizens and were individually addressed by EPA.
- FutureGen 1.0 draft EIS (DOE EIS-0394): assessed potential CCUS sites in Mattoon, Illinois; Tuscola, Illinois; Jewett, Texas; and Odessa, Texas. The project ultimately did not move forward to injection. However, several rounds of public review at each of the exploratory sites was completed. Commentary came primarily through mail submissions from private citizens, with additional input from public and private organizations at hearings hosted by site municipality governments. Comments were received as they were presented in the EIS as follows:
    - FutureGen Project EIS – General for all sites (DOE EIS-0394)
    - FutureGen Project EIS – Jewett, Texas (DOE EIS-0394)
    - FutureGen Project EIS – Mattoon, Illinois (DOE EIS-0394)
    - FutureGen Project EIS – Odessa, Texas (DOE EIS-0394)
    - FutureGen Project EIS – Tuscola, Illinois (DOE EIS-0394)

This section provides the approach behind evaluating stakeholder perception regarding failure modes and effects associated with the completed or canceled CCUS projects based on review of public comments in the above documents. Results of this evaluation are also discussed.

4.2 METHODOLOGY

All comments within the aforementioned documents were reviewed, even though they pertained to all aspects of the corresponding CCUS project, not just the CO_2 injection and storage components and associated potential effects to the human environment (the focus of this study). During the assessment process, there was a recurrence of 15 prominent themes within the public comments (Exhibit 4-1). Each comment was mapped to one or more of these themes and categorized based on the primary topic(s) of its content. Of the 15 categories, 10 are directly related to potential impacts on the human environment (highlighted in Exhibit 4-1).

This approach allowed for a bulk analysis of public commentary across all projects; however, there are certain stipulations worth mentioning. The small project sample size distorts data accuracy due to disparities in response counts. Larger projects result in greater public interest and draw more commentary that can skew the data to reflect one community's response over another. Comments that touch upon more than one theme are tallied multiple times for each category they discuss (e.g., "This project will negatively impact local farms but provide new jobs for local contractors" would be categorized as a comment about "Impacts to soil and/or farmland" *and* "Socioeconomic impacts"). This assumption gives comments that discuss multiple themes more statistical weight than those that discuss only one, regardless of response quality. Comments are counted based on the content discussed and aligned to categories in Exhibit 4-1 regardless if the comment context is positive, negative or neutral. Additionally, this methodology does not account for subject matter expertise. A comment from a private citizen is given equal statistical weight to a response from a specialized public or private agency. It is important to note that interpretation of the concerns may diverge depending on the type of public feedback (i.e., from expert or lay person) because of different experience, knowledge, and background. [168]

Exhibit 4-1. Categories and description for each of the 15 themes used to group stakeholder comments from NEPA and UIC documentation regarding the CCUS projects reviewed

Category	Description
Related to Human Environment	
Impact to air quality and noise levels	Includes comments that described the potential effects on air quality (separate from GHGs) or noise from any aspect of the proposed project
Suitability of geologic conditions	Comments discussing relevant site geologic conditions and the storage reservoir complex's ability to receive, store, and contain CO_2 effectively. Effect of CO_2 injection is also included, including comments related to the resulting CO_2 plume size, existence of potential leakage pathways (e.g., through existing wells), and potential natural seismicity proximal to the project site
Land use impacts	Includes comments discussing impacts to surface conditions that could be potentially irreversible due to project implementation. This includes topics related to flood plain impacts, creation of unobstructed views to project facilities and sites, zoning and right of way concerns, transportation corridors, and archaeological considerations
Public health and safety	Any comments that described the potential effects on human health from any aspect of the proposed project
Biologic resources health and safety	Comments that described the potential effects on plant or animal health from any aspect of the proposed project
Impact to soil and/or farmland	Comments addressing the impacts on farmlands or soil
Project impact to climate and GHG emissions reduction	Comments that described CCUS as a GHG mitigation option and/or the role of the proposed project in decarbonization
Generation and disposal of waste material	Comments discussing any issues related to the generation of waste products from any portion of the project site development or operations
Surface water and groundwater impacts	Comments that related to both water usage as well as potential impact to water from CCUS project implementation. Water sources include rivers, streams, lakes, ponds, as well as USDW
Environmental justice	Comments addressing topics regarding same degree of protection from environmental and health hazards for all within proximity to the site, equal access and opportunity to the decision-making processes, and concerns regarding longer-term liabilities

Category	Description
Unrelated to Human Environment	
Site-specific comments	Comments that are unique to each specific project site (local weather and climate as an example) and do not fall directly into the other groupings
Socioeconomic impacts	Includes comments related to the CCUS project's impact on local economics and job creation or depletion. Comments with opinions related to either prudent or misuse of taxes to implement CCUS were also included
Documentation needs further information about project	Comments expressing insufficient detail exists in the documentation to glean insight on topics of interest
Not applicable	Included comments that do not relate specifically to the CCUS project. Most are corrections to labeling or typographic errors in project documentation
Advocacy, endorsement, or support	Comments that demonstrate an outpouring of support for project deployment without an explicit tie to socioeconomic benefits

4.3 Results Summary

A review of NEPA and UIC documentation provided results that spanned over a range of the 15 main themes. The most prominent themes covered a range of topics and were related to "Advocacy, endorsement, or support," "Impact to air quality and noise levels," and "Suitability of geologic conditions." The large number of responses categorized as "Advocacy, endorsement, or support" reflected a positive/favorable desire from private citizens, government officials, and local services (hospitals and fire stations as examples) to bring CCUS projects to their local community, whereas those in the latter two categories were more variable in their outlook toward CCUS. The least discussed topics per the comments were "Environmental justice" and "Generation and disposal of waste material." Comments that mentioned these rarely discussed themes mainly came from public or private organizations (non-governmental organizations, local businesses, etc.) as opposed to local residence, government officials, or Native American tribes. The number of comments per category as a contribution from each project document are displayed in Exhibit 4-2 (grouped by relation to the human environment) and shown as a percent of total received under each document in Exhibit 4-3 (which provides a perspective on the distribution of themes depending on the document). Raw data is presented in Appendix E: Occurrences of the 15 Themes in the Public Comments from NEPA and UIC Documentation for the Reviewed CCUS Projects.

Overall, nearly 60 percent of all comments reviewed were related to CCUS's potential effect to the human environment in proximity to project sites. A qualitative review of the data indicated response themes were heavily influenced by stakeholder type. Public agencies, like federal organizations (e.g., EPA, Department of Interior, Department of Agriculture) or local governments, are typically advocates for the deployment of new technology and the impacts associated with their domain of interest. Local governments are supportive of new projects that offer socioeconomic benefits to the community. Federal organizations are primarily concerned with environmental regulatory legislation and region-wide project impacts—specifically focused on their domains of interest.

Commentary from public and private organizations was focused on three themes: "Advocacy, endorsement, or support," "Site specific comments," and "Environmental justice." The first category reflected an overall interest from private-based organizations to encourage local investment in hopes of stimulating economic growth. The second theme was a concentration of commentary from project specific contractors or stakeholder groups, while the final topic was a concern for environmental advocacy groups.

Private citizens seemed generally concerned with community safety and socioeconomic impacts related to the given CCUS project. Many of the projects reviewed were located in small-towns or rural America. Private citizens in these regions had genuine interest in the economic stimulus a CCUS project could provide. However, of all the stakeholder types identified in the documentation, private citizens were the most concerned with the potentially adverse effects from CO_2 injection. There is a large margin of uncertainty about the potential environmental effects or property damage that could be caused from CCUS operations, and many of these concerns can be exacerbated by lack of clear communication from project-leaders. Efforts to inform citizens about the best practices available that can be used (or are planning to be implemented at a given project) to prevent, detect, and mitigate potential failure modes and associated effects of CO_2 injection and storage, can help curtail negative perceptions toward a project. Much like the potential failure modes and effects with CO_2 injection, public concerns associated with the geologic storage of CO_2 can be alleviated to some degree by implementing best practices acquired from CCUS research and/or from industries analogous to geologic storage of CO_2 (e.g., CO_2 EOR or natural gas storage). [161, 173]

Exhibit 4-2. Number count and cumulative percent of comments per theme (i.e., category) for all project documents reviewed

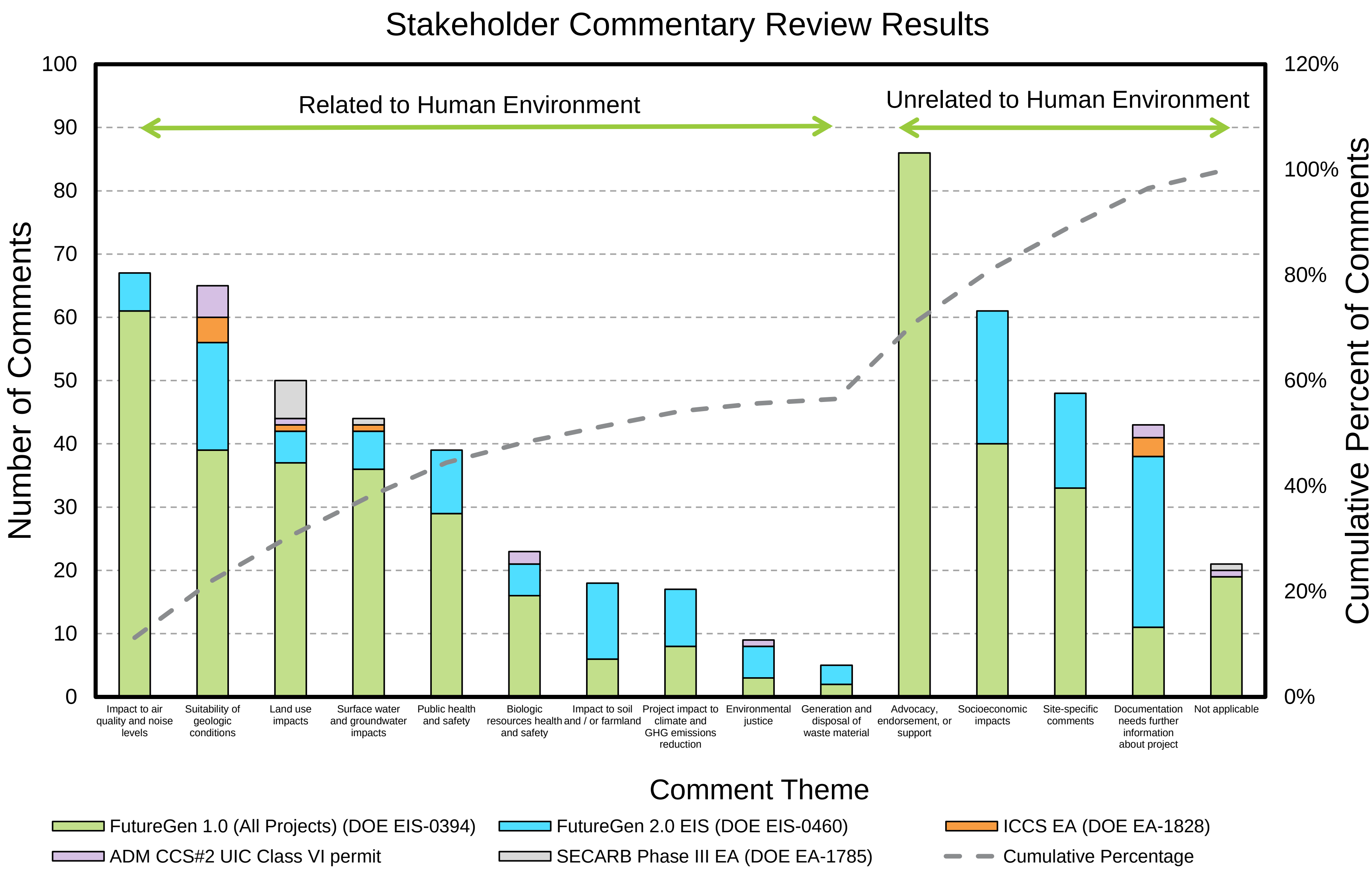
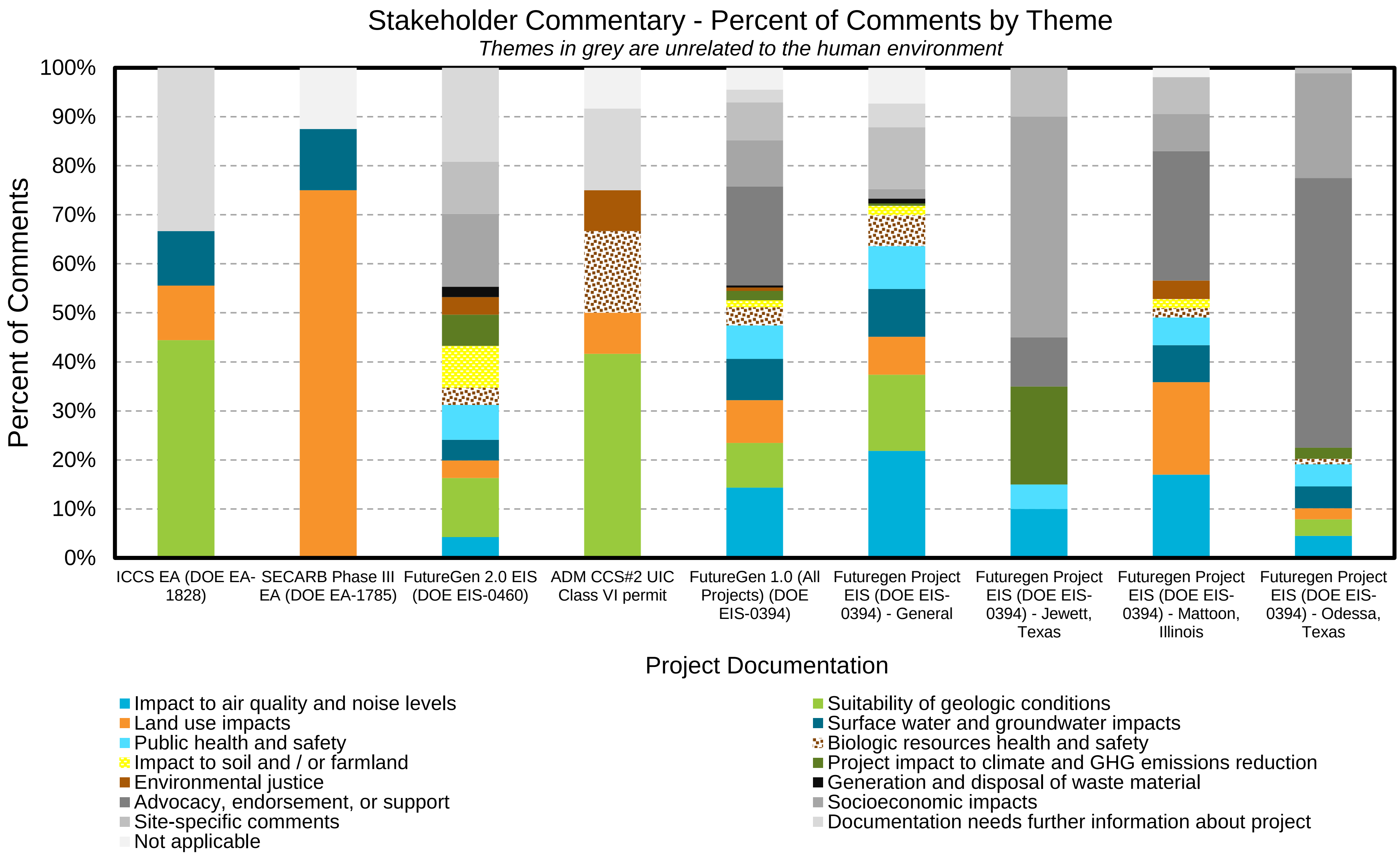


Exhibit 4-3. Percent breakout of category themes for each project document



5 CONCLUSIONS

CCUS is one of the promising CO_2 management strategies to help reduce and remove CO_2 emissions from the atmosphere. Geologic storage of CO_2, the last step in the CCUS value chain, involves injecting CO_2 captured from electric-generating or industrial sources underground in deep subsurface geologic reservoirs for safe, secure, and long-term storage. The CO_2 injection and storage process is broadly regarded as a safe endeavor if it is properly managed to address potential failure modes and associated adverse impacts to the human environment. Through synthesis of relevant sources of technical literature, evaluation of NEPA EAs and EISs relating to CCUS projects, and EPA UIC regulations and permit applications (where appropriate), a comprehensive list of potential failure modes and effects on the human environment associated with CO_2 injection and geologic storage were compiled. In addition, best practices were summarized that can help avoid or reduce the severity of any potential impacts through prevention, detection, and mitigation actions. Additionally, the perception of these potential failure modes and effects can influence stakeholder opinion on CCUS technology and potentially hinder the acceptance of a CCUS project. However, with an effective outreach program, project developers can educate stakeholders and address concerns through communication and transparency regarding their operations.

The review of relevant technical literature compiled from nearly two decades of CCUS-related research and demonstration suggests that potential failure modes and associated adverse effects with CO_2 storage operations are minimized when storage sites are properly screened, operated, monitored, and closed. Many circumstances that can potentially prompt failure modes can be avoided altogether through proper site selection and safe operations. The probability of given potential failure mode(s) occurring is dependent on site-specific conditions and operational factors, which may likely change over time for any particular CCUS project. Operators can integrate and regularly update monitoring approaches as site-specific circumstances change over time in order to properly detect potential failure mode occurrence throughout a project's lifetime, as well as to adjust operational conditions as needed.

Literature review conducted as part of this study has indicated that three distinct groups of potential failure modes are common to CO_2 storage and injection operations without explicitly considering site-specific conditions or circumstances: 1) lateral containment failure, 2) vertical containment failure, and 3) induced and triggered seismicity. Under each failure category, several causes of failure exist – many of which (but not limited to) are related to over-pressurization of the subsurface and the presence of existing leakage pathways like faults, fractures, or wellbores. All of these risks are mitigated by following UIC Class VI regulations pertaining to wellbore construction, operation, monitoring, and corrective action. Additionally, site selection efforts can help operators avoid higher-risk sites that would be problematic (e.g. sites with poorly plugged and abandoned wells). The other failure mode categories are derivations of either 1) naturally deficient geologic storage complex properties or 2) operator-induced design or operational circumstances which prompt failure in otherwise sufficient geologic settings. Both failure mode categories can be avoided by proper site characterization, modeling, monitoring, and safe operational practices.

Three possible effect categories were summarized through documentation review, which include: 1) contamination of USDW, 2) contamination of non-USDW resources, and 3) physical damage to surface infrastructure and/or topography. The severity of the impacts to the human environment associated with these potential effects vary and are site-specific. In practice CO_2 storage project developers use well established approaches to assess, manage, avoid, and mitigate the various possible effects associated with the potential failure modes. For example, sites with faults that intersect the surface can be identified and avoided with proper site characterization and selection. Induced or triggered seismicity may be difficult to predict in advance, but precursor conditions can be identified and avoided by keeping injection and reservoir pressures below known fracture gradients. Additionally, performing proper site characterization to avoid selection of sites with abundant faults and/or problematic stress regimes is recommended.

The IBDP and its follow-on IL-ICCS project provide UIC Class VI permitted case study examples of how site characterization, selection, development, operation and monitoring result in dynamic risk management and facility operation as more experience and data is acquired at a project site. Monitoring is shown to be critical to dynamically adjust and adapt operations to maintain a low-risk profile and up-to-date prediction of how future injection will impact the subsurface. These case studies showed how risk assessment scenarios are updated and informed based on monitoring results attained while the project performs injection and storage over time.

This report also worked towards identifying and methodologically reviewing patterns in public opinion from previous CCUS efforts in the United States, which can help toward evaluating local stakeholders' perceived potential risks (a subset of which includes failure modes and associated effects) related to CCUS. Public perception of CCUS can be positive, negative, or neutral. In most cases, perception is negative when there is a lack of understanding among stakeholders regarding CCUS in general. Such a circumstance provides an opportunity for an open dialogue between project developers and stakeholders, which can help reduce negative perceptions.

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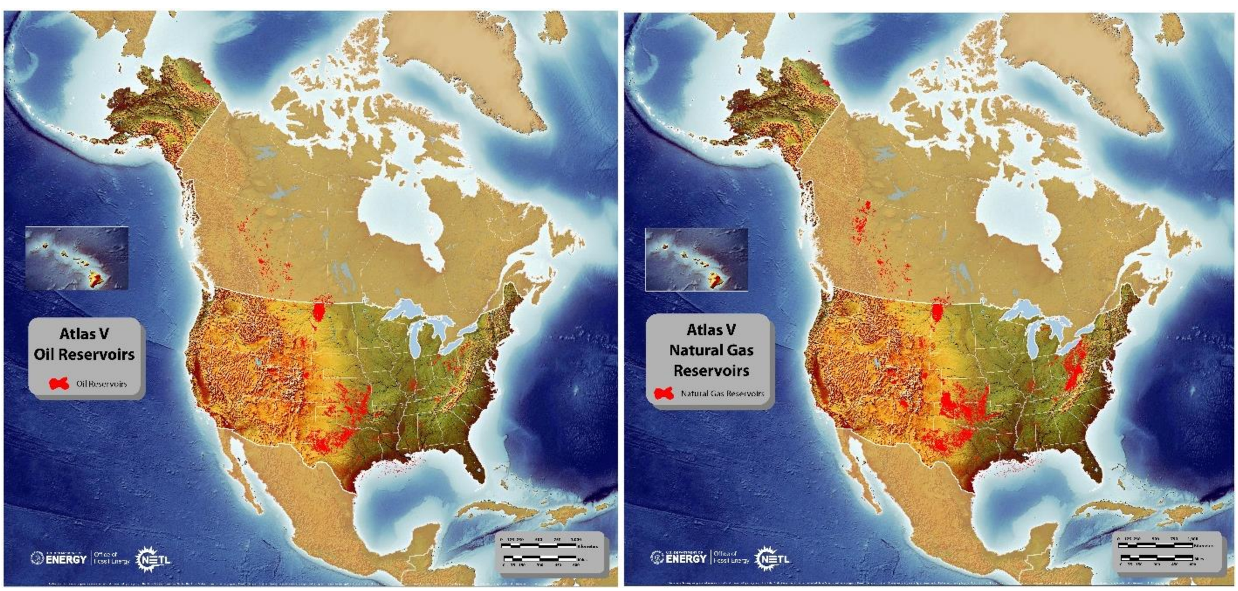
APPENDIX A: OTHER ONSHORE, GEOLOGIC FORMATIONS WITHIN NORTH AMERICA ASSESSED BY NETL

This appendix provides information on and maps displaying the other potential storage formation candidates for geologic storage of carbon dioxide (CO_2) assessed by the National Energy Technology Laboratory (NETL) in parts of North America as part of their Regional Carbon Sequestration Partnership (RCSP) Initiative: depleted oil and natural gas reservoirs, un-mineable coal seams, basalt formations, and organic-rich shales.

DEPLETED OIL AND NATURAL GAS RESERVOIRS

Oil and natural gas reservoirs are porous rock formations (usually sandstones or carbonates) containing crude oil and/or natural gas that have been physically trapped in structural (rocks folded or faulted to create trapping mechanism) or stratigraphic traps (caused by differences in rock lithologies). Even though they are not as widespread as saline formations, depleted oil and natural gas reservoirs are spread out throughout the United States, from the Appalachian Basin in the east, Permian and Gulf basins in the south, and Sacramento Basin in the west (Exhibit A-1). [24] Storage resource estimates, conducted by NETL through the RCSPs, for oil and natural gas reservoirs in the United States and parts of Canada range between approximately 186 and 232 billion metric tons (tonnes). [4]

Exhibit A-1. Map displaying depleted oil reservoirs (left) and natural gas reservoirs (right) assessed by NETL under the RCSP Initiative in parts of North America [4]



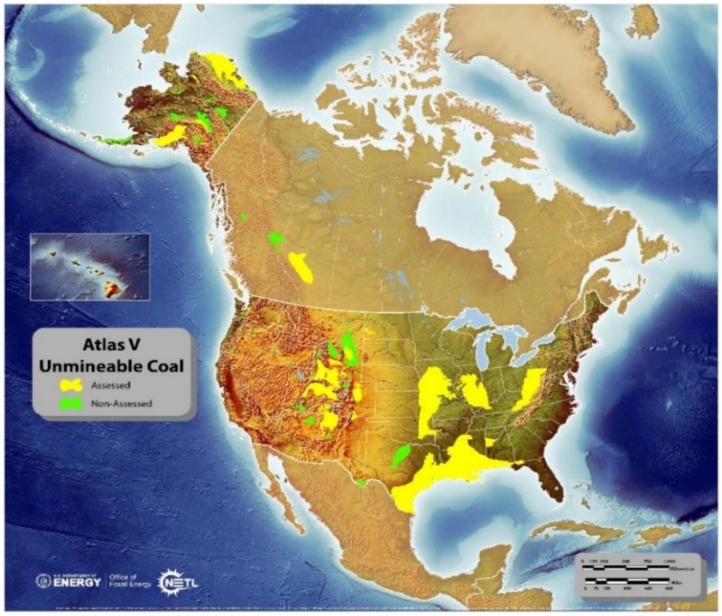
Traditionally, oil production from reservoirs occurs in three specific phases: 1) primary recovery—oil extraction using a reservoir's natural pressure and artificial lift recovering 10–20 percent of the original oil in place; 2) secondary recovery—water injection to increase reservoir pressure and displace the oil toward producing wells thus producing an additional 20–30 percent of the original oil in place; together, the primary and secondary phases recover 30–50 percent of the original oil in place leaving a significant amount of the oil in the reservoir; 3) tertiary—many types but frequently conducted injecting CO_2 for additional recovery of the original oil in place (enhanced oil recovery [EOR]). [4, 26] Natural gas can occur as an associated-dissolved gas (i.e., free or with crude oil in solution within reservoirs) or non-associated gas (reservoirs without considerable amounts of oil). Because of their higher recovery factors, natural gas reservoirs do not have conventional, commercial, enhanced recovery technology similar to oil reservoirs; however, some studies have concluded that gas recovery could be enhanced using CO_2. [4]

Depleted oil and natural gas reservoirs are ideal candidates for CO_2 storage for many reasons including 1) proven integrity and safety by storing hydrocarbons for millions of years under conditions suitable for CO_2 storage, 2) established architecture and properties from hydrocarbon exploration and production, 3) existing infrastructure and wells that may be used for CO_2 storage operations, 4) proximal locations for optimal source-sink matching, and 5) increased storage capacity due to pressure depletion in reservoirs with weak water drives (limited support from surrounding aquifer). [4, 24, 28] As an attractive option for CO_2 storage, CO_2 EOR has the potential to accelerate CO_2 emission reductions and storage by providing value to the captured CO_2 as a commodity for EOR instead of simply treating it as a waste product. [26] Even with their advantages, depleted oil and natural gas reservoirs pose several technical challenges including reduction of rock pore volume due to stress on rock properties during primary and secondary oil production, risks and impacts associated with leakage, diminished caprock integrity, and modeling of multiphase flows to ensure an adequate temperature to not damage the well or cement. [24] Storing additional CO_2 in an oil field after ceasing CO_2 EOR operations can also pose challenges such as the need for precise reservoir engineering so the CO_2 is not pushed outside the oil field's boundaries if CO_2 is continuously injected without the removal of brine or oil. [24]

UN-MINEABLE COAL SEAMS

As a rock primarily comprising preserved organic material, coal has the potential for CO_2 storage when it is considered unmineable because of geological, technological, or economic factors (typically too deep, too thin, or lacking the internal continuity to be economically mined with today's technologies). Methane is naturally found in coal seams, but coal preferentially absorbs CO_2 when it is injected. The CO_2 flows through cleat systems (fractures in coal that provide some permeability), diffuses into the coal matrix, and is adsorbed onto the coal micropore surfaces, displacing methane, in a process called adsorption trapping. [26] Depending on the coal type, experimental CO_2/methane adsorption ratios have been found to range from 2 to 13 (typical adsorption isotherms measured as millimole of gas adsorbed per gram of coal). Adsorption trapping as well as some physical trapping in the coal's cleats is the basis for CO_2 storage. [4, 26] Un-mineable coal seams are located throughout the United States but are more prominent in the South and Midwest (Exhibit A-2). Storage resource estimates, conducted by NETL and the RCSPs, for un-mineable coal seams in North America range approximately 54–113 billion tonnes. [4]

Exhibit A-2. Map displaying un-mineable coal seams assessed by NETL under the RCSP Initiative in parts of North America [4]

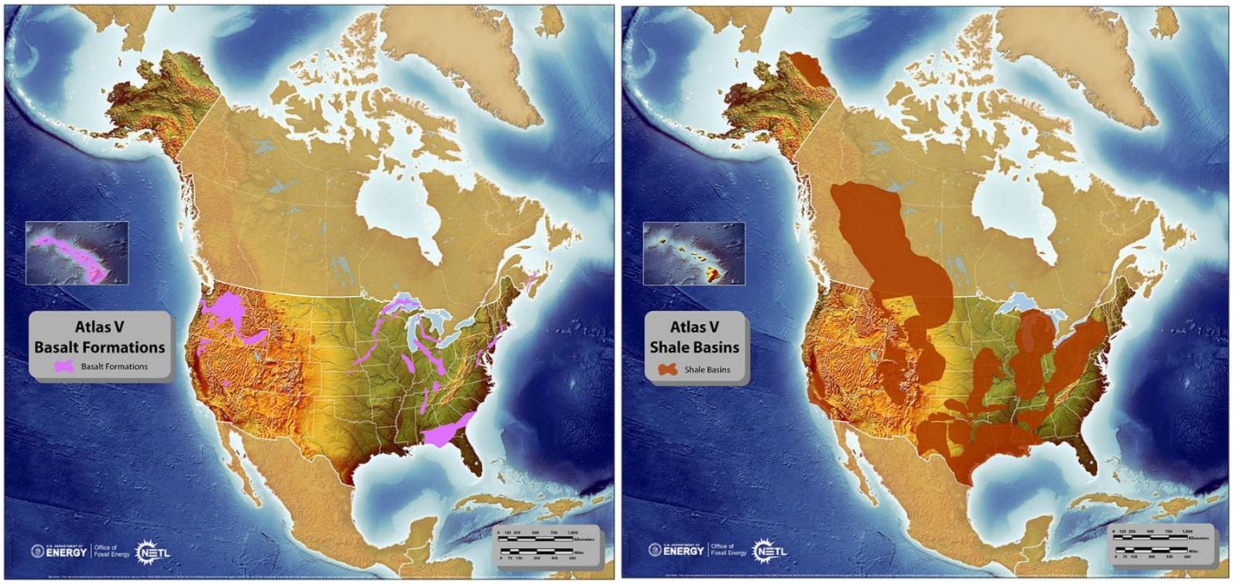


Because injected CO_2 does not need to be in the supercritical state for adsorption into coal, CO_2 storage can take place at shallower depths compared to storage in saline reservoirs or oil and natural gas reservoirs. However, geologic storage in un-mineable coal seams through adsorption processes is still a relatively undeveloped geologic storage technology and needs additional research because of certain risks (i.e., decreasing coal permeability, which adversely effects CO_2 injectivity rates and swelling of the solid coal matrix). [24, 26] Besides the benefit of being able to store CO_2 in shallower depths, injecting and storing CO_2 in un-mineable coal seams also allows methane to be recovered through a process called enhanced coalbed methane recovery and then sold, offsetting the costs of CO_2 storage. This process fares better than the typical way methane is recovered, by dewatering and depressurization, which can leave significant amounts of methane trapped in the coal seam. [26]

BASALTS AND ORGANIC-RICH SHALES

Basalts are geological formations with solidified lava. They are a promising geologic storage type for CO_2 because of their relatively large storage resource potential and geographic distribution (particularly in the Pacific Northwest and southeastern United States) (left map in Exhibit A-3). Generally, basalts have low permeability, porosity, and pore space continuity, and any permeability is generally associated with fracture networks. [28, 26] They also have a unique chemical makeup allowing the injected CO_2 to react with magnesium and calcium in the rock to form stable carbonate mineral forms of calcite and dolomite. Because basalts can potentially convert all the injected CO_2 and trap and isolate it from the atmosphere permanently, they could provide one of the safest options for permanently storing CO_2 in the subsurface. [4, 26] However, there are some key factors affecting CO_2 capacity and injectivity into basalt formations including effective porosity of top flow layers and interconnectivity. [26] More research is needed to determine if basalt formations are suitable for CO_2 storage particularly in regard to mineralization reactions and kinetics. [4, 24]

Exhibit A-3. Map displaying basalts (left) and organic-rich shales (right) assessed by NETL under the RCSP Initiative in parts of North America [4]



Formed from silicate minerals of a very fine grain size known as clay, organic-rich shales (i.e., oil and gas shales) are widespread throughout the United States making them another promising geologic storage type for CO_2 storage (right map in Exhibit A-3). Particularly, shales formed from high-organic materials are of interest for storage. [4] The storage resource potential of organic-rich shales is currently unknown but their large volumes suggest that they may possess significant storage capacity. [28] Because the plate-like structures of the clay particles cause them to stratify, resulting in rock layers with extremely low permeability, organic-rich shales are most often considered the confining zone or caprock for geologic storage thus providing a seal for many oil and gas reservoirs. [26] In addition to using organic-rich shales for potential CO_2 storage, efforts to use shales for enhanced gas recovery are ongoing because of recent advances in horizontal drilling and hydraulic fracturing technologies that can produce natural gas from organic-rich shales. [4] These technologies, coupled with the fact that adsorption of CO_2 is favored over methane, will improve feasibility of storing CO_2 in these unconventional reservoirs as well as using CO_2 for enhanced gas recovery. Even though additional engineering of the shale would add to the cost (which may include additional characterization efforts, reservoir simulation, and possibly monitoring-related activities), the potential for enhanced recovery of the natural gas could potentially offset this increase and provide a potential economic offset to the storage process. [4, 26]

APPENDIX B: SUMMARY OF UIC CLASS II AND VI TECHNICAL REQUIREMENTS

Exhibit B-1 below provides a side-by-side summary and comparison of relevant technical requirements for both Underground Injection Control (UIC) Class II and Class VI wells based on specific regulations outlined in 40 Code of Federal Regulations (CFR) § Parts 144 and 146. The content within was originally compiled in the National Energy Technology Laboratory's (NETL) Analogs to Carbon Dioxide (CO_2) Storage; specifically, underground natural gas storage and CO_2 enhanced oil recovery (EOR). [3, 26] These UIC regulations are based on the concept that injection into properly sited, constructed, and operated wells is a safe way to inject and dispose of fluids (like produced brine or CO_2) into the subsurface. [40]

Exhibit B-1. Overview of the technical requirements for Class II and Class VI UIC injection wells based on governing regulations

Requirement	UIC Class II	UIC Class VI
Siting and Characterization	• Site new wells in such a fashion that they inject into formation that is separated from any underground source of drinking water (USDW) by confining zone that is free of known open faults or fractures within the AoR • Demonstrate the presence and adequacy of injection and confining zones by presenting information on geologic formations • Create map showing injection well or project area for which permit is sought and applicable AoR • Develop maps, cross-sections, and a list of penetrations into the injection zone, and of regional geology • Perform specific wireline log runs and tests to inform well construction compatibility with the subsurface	• Demonstrate wells will be sited in areas with suitable geologic system comprising injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive total anticipated volume of CO_2 stream and confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in confining zone(s) • Identify and characterize additional zones, if required • Run appropriate wireline logs, surveys, and tests to determine or verify depth, thickness, porosity, permeability, and lithology of, and salinity of any formation fluids in all relevant geologic formations to ensure conformance with injection well construction requirements • Complete extensive site characterization, including the analysis of wireline logs, maps, cross-sections, USDW locations; determining injection zone porosity, identifying any faults, and accessing seismic history of area
Area of Review (AoR)	• Determine AoR by using mathematical model, such as modified Theis equation, to calculate zone of endangering influence or fixed radius of at least one-quarter mile around an injection well or width of one-quarter mile for circumscribing area around injection area • Identify all known wells that penetrate the proposed injection zone, or all known wells that penetrate formations that may be affected by the increase in pressure • Recognize and address any improperly completed or abandoned wells within AoR	• Determine AoR by computational model, which accounts for the physical and chemical properties of all phases of the injected CO_2 stream. This modeling is based on available site characterization, monitoring, and operational data • Identify and address any improperly completed or abandoned wells through corrective action within AoR • Delineate the AoR over the project lifetime (at least every five years)

Requirement	UIC Class II	UIC Class VI
Well Construction	• Case and cement wells to prevent movement of fluids into or between USDW • No specific regulations for tubing and packer requirements in 40 CFR 146 Subpart C	• Confirm all well materials are compatible with fluids with which the materials may be expected to come into contact • Verify surface casing extends through base of lowermost USDW and is cemented to surface using single or multiple strings of casing and cement • Ensure at least one long string casing extends to injection zone and is cemented by circulating cement to surface in one or more stages • Determine cement and cement additives are compatible with CO_2 stream and formation fluids and are of sufficient quality and quantity • Verify tubing and packing materials are compatible with fluids with which materials may be expected to come into contact. Injection conducted through the tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director • Fill annulus between tubing and long string casing with non-corrosive fluid
Operation	• Calculate injection pressure to assure it does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDW during injection • Prohibit injection between the outermost casing protecting USDW and the wellbore	• Ensure compliance with approved AoR and Corrective Action Plan and Emergency and Remedial Response Plan • Ensure injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) • Utilize alarms, automatic surface shut-off systems, and down-hole shut-off systems that initiate when operational parameters diverge beyond permitted ranges
Mechanical Integrity Testing (MIT)	• Conduct internal and external MITs every five years • Evaluate absence of significant leaks by monitoring tubing-casing annulus pressure with sufficient frequency, pressure test with liquid or gas, or records of monitoring showing absence of significant changes in relationships between injection pressure and injection flow rate for certain specified types of enhanced recovery wells • Use results of temperature or noise logs or cementing records demonstrating presence of adequate cement to determine absence of significant fluid movement	• Evaluate absence of significant leaks by initial annular test and continuous monitoring of injection pressure, rate, injected volumes, pressure on the annulus between tubing and long string casing, and annulus fluid volume • Use tracer survey or temperature or noise log at least once a year to determine the absence of significant fluid movement • Run casing inspection log to determine presence or absence of corrosion in long string casing, if required
Monitoring	• Monitor nature of injected fluids at time intervals sufficiently frequent to yield data representative of their characteristics • Complete periodic injection pressure, flow rate, and cumulative volumes (produced and injected) monitoring weekly for disposal wells and monthly for EOR • Perform annual fluid chemistry as needed or required by permit • No specific regulations for record keeping in 40 CFR 146 Subpart C	• Ensure compliance with approved Testing and Monitoring Plan • Use continuous recording devices to monitor the injection pressure, rate, volume and/or mass, and temperature of CO_2 stream; pressure on the annulus between the tubing and long string casing, and annulus fluid volume • Monitor corrosion of well materials • Complete pressure fall-off test at least once every five years • Perform periodic monitoring of groundwater quality and geochemical changes above confining zone(s) or additional identified zones • Test and monitor to track extent of CO_2 plume and presence of elevated pressure by using direct or indirect methods • Perform surface air monitoring and/or soil gas monitoring to detect movement of CO_2 that could endanger USDW, if required • Review Testing and Monitoring Plan periodically; review cannot be conducted less than once every five years

Requirement	UIC Class II	UIC Class VI
		• Provide quality assurance and surveillance plan for all testing and monitoring requirements
Injection Well Plugging	• Provide 45-day notice before plugging and abandonment • Plug well with cement and utilize Balance Method, Dump Bailer Method, Two-Plug Method, or other alternative method to place cement plugs • Confirm abandoned well is in state of static equilibrium with mud weight equalized top to bottom	• Provide 60-day notice in writing before plugging • Ensure compliance with Injection Well Plugging Plan • Flush each well with buffer fluid, determine bottom-hole reservoir pressure, and perform final external MIT • Submit plugging report within 60 days after plugging
Proof of Containment and Post-Injection Site Care (PISC)	• No specific regulations in 40 CFR 146 Subpart C	• Monitor site following cessation of injection to show position of CO_2 plume and pressure front and demonstrate that USDW are not being endangered • Maintain PISC for 50 years or until proof of non-endangerment to USDW is demonstrated • Ensure compliance with approved PISC and Site Closure Plan
Site Closure	• No specific regulations in 40 CFR 146 Subpart C	• Provide at least 120-day notice before site closure • Plug all monitoring wells in manner that will not allow movement of injection or formation fluids that endanger USDW • Submit site closure report within 90 days of site closure
Financial Responsibility	• Provide certificate that assures, through performance bond or other appropriate means, the resources necessary to close, plug, or abandon the injection well	• Demonstrate and maintain financial responsibility by using instrument(s); such as trust fund, surety bond, letter of credit, insurance, self-insurance (i.e., financial test and corporate guarantee), escrow account, or any other instrument(s); to cover costs of corrective action, injection well plugging, PISC and site closure, and emergency and remedial response • Update cost estimates of performing corrective action on wells in AoR, plugging injection well(s), PISC and site closure, and emergency and remedial response periodically to account for any amendments to plans (AoR and corrective action, injection well plugging, PISC and site closure, or emergency and remedial response)

APPENDIX C: OVERVIEW OF GHG REPORTING REQUIREMENTS UNDER SUBPART RR

The United States Environmental Protection Agency's Greenhouse Gas (GHG) Reporting Program requires the reporting of GHG emissions and other relevant information from certain source categories in the United States. Subparts RR and UU are related to the injection of carbon dioxide (CO_2) into the subsurface. Subpart RR of this rule requires GHG reporting from facilities that inject CO_2 underground for geologic storage (Subpart UU requires GHG reporting from all other facilities that inject CO_2 underground for any reason, including enhanced oil and gas recovery). Exhibit C-1 provides an overview of the technical requirements for Subpart RR.

Exhibit C-1. Summary of the technical requirements regarding Subpart RR

Requirement	Subpart RR – Geologic Sequestration of Carbon Dioxide 40 CFR 98.440 – 98.449
Source Category Definition	Any well or group of wells that inject a CO_2 stream for long-term containment in subsurface geologic formations, including UIC Class VI wells Does not include well or group of wells injecting CO_2 for EOR unless the following applies: • Intent is for long-term containment and MRV plan has been developed • Well is permitted as Class VI Research and development (R&D) projects shall receive exemption from reporting • Administrator will determine if projects qualify for R&D exemption after receiving request from project
Threshold Reporting	Must report if facility (i.e., well or group of wells) injects **any** amount of CO_2 for long-term containment. There is no threshold value or limit Discontinuation of reporting can occur when: • For Class VI, a copy of approved site closure is received from the Underground Injection Control (UIC) Program • For other wells, demonstration via monitoring/modeling that CO_2 will not migrate in a manner that results in surface leakage
GHG Reporting	Reporting items include: • Mass of CO_2 received • Mass of CO_2 injected into the subsurface • Mass of CO_2 produced • Mass of CO_2 emitted by surface leakage • Mass of CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment • Mass of CO_2 sequestered in subsurface • Cumulative mass of CO_2 reported as sequestered in subsurface
CO_2 Received/Geologic Sequestration Calculations	Provides equations for calculating the following items: • Mass of CO_2 received • CO_2 injected • CO_2 produced/recycled • Surface leakage • CO_2 stored in the subsurface
Monitoring and Quality Assessment and Quality Control Requirements	Provides requirements for the following procedures: • CO_2 received • CO_2 injected • CO_2 produced

Requirement	Subpart RR – Geologic Sequestration of Carbon Dioxide 40 CFR 98.440 – 98.449
	• CO_2 emissions from equipment leaks and vented emissions • Measurement devices
Missing Data Estimating Procedures	Approaches for estimating values for missing data whenever the monitoring procedures cannot be followed
Data Reporting Requirements	Data reporting requirements (mix between yearly or quarterly) pertain to the mass or volume of CO_2 distributed to and throughout the facility, including: • Mass/volume of CO_2 received from pipeline or container • Mass/volume of CO_2 sent to another facility • CO_2 concentration in flow • Source type of CO_2 • Mass of CO_2 emitted from equipment leaks/vented • Mass of surface leaks • Mass of CO_2 stored in subsurface • Annual monitoring report
Retained Records	The following records must be retained for three years: • Quarterly records of CO_2 received • Quarterly records of CO_2 produced • Quarterly records of CO_2 injected • Annual records pertaining to CO_2 emitted by equipment leaks and venting • Annual records pertaining to CO_2 leakage from subsurface • Other records as specified by MRV plan
Geologic Sequestration Monitoring, Reporting, and Verification (MRV) Plan	The MRV plan must contain the following components: • Delineation of maximum monitoring area and active monitoring areas • Identification of potential surface leakage pathways with likelihood, magnitude, and timing • Strategy for quantifying surface leakage • Strategy for establishing CO_2 baselines • Considerations for variables used in mass-balance equations associated with estimating leaks from surface equipment Plan must be submitted within 180 days of receiving a UIC Class VI permit. Offshore facilities not subject to Safe Drinking Water Act must submit MRV plans 180 days after receiving authorization to inject CO_2. Non-Class VI operators (i.e., enhanced oil recovery) may opt to submit an MRV plan at any time

Appendix D: General Information on CCUS Projects Referenced

Exhibit D-1 lists the geographic location of CO_2 saline storage projects mentioned in this report, as well as the project status. CO_2 saline storage projects with offshore injection wells are noted in the location column with "(offshore)." Project status, as of October 2020, is listed as "Proposed (cancelled)" to indicate the project never made it to the operating phase, "Operating" to indicate the project is currently injecting CO_2, "Closed during operations" to indicate the project was terminated early due to CO_2 containment concerns, or "PISC" to indicate the operating phase was completed, and the project is currently in the post-injection site care (PISC) phase. The "Injection Timeline" column indicates the year injection started and ended; if the end date for injection operations to cease has been published, that date is provided, as is the case of the IL-ICCS project. Estimated average annual injection rate, in million metric tons per year, is estimated based on storage totals and/or injection rates found in the references provided.

Exhibit D-1. General information on CCUS projects mentioned in this report

CCUS Project	Location	Project Status	Injection Timeline	Estimated average annual injection rate (million metric tons/year)	Reference
Aquistore	Saskatchewan, Canada	Operating	2015 - ongoing	~0.05	[174]
Illinois Basin Decatur Project (IBDP)	Decatur, Illinois, U.S.	PISC	2011 - 2014	~0.33	[152]
Illinois Industrial Carbon Capture and Storage (IL-ICCS)	Decatur, Illinois, U.S.	Operating	2017 - 2022	~0.55	[159]
In Salah	Algeria	Closed during operations	2004 - 2011	~0.54	[135]
Mountaineer CCS II	West Virginia, U.S.	Proposed (cancelled)	Not applicable		[124]
FutureGen 1.0	Jewett, Texas, U.S.	Proposed (cancelled)	Not applicable		[102]
	Mattoon, Illinois, U.S.		Not applicable		
	Odessa, Texas, U.S.		Not applicable		
	Tuscola, Illinois, U.S.		Not applicable		
FutureGen 2.0	Morgan County, Illinois, U.S.	Proposed (cancelled)	Not applicable		[127]
Quest	Alberta, Canada	Operating	2015 - ongoing	~1.07	[175]
Sleipner West	Norway (offshore)	Operating	1996 - ongoing	~0.9	[176]
Tomakomai	Japan (offshore)	Operating	2016 - ongoing	~0.85	[143]

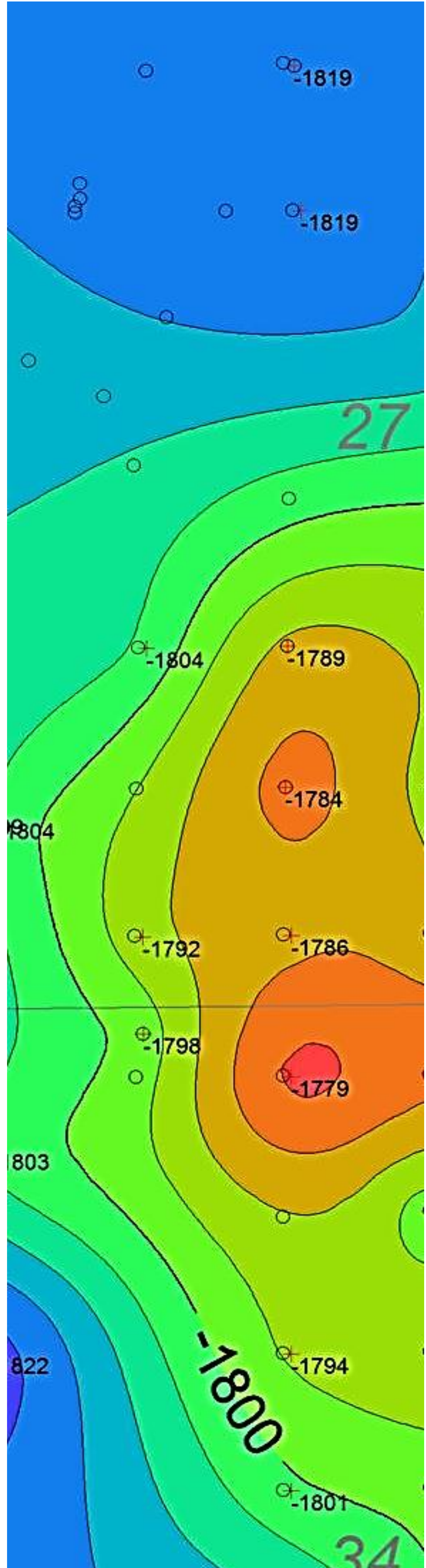
APPENDIX E: OCCURRENCES OF THE 15 THEMES IN THE PUBLIC COMMENTS FROM NEPA AND UIC DOCUMENTATION FOR THE REVIEWED CCUS PROJECTS

Comments from stakeholders in National Environmental Act (NEPA) and Underground Injection Control (UIC) documentation for several carbon capture, utilization, and storage (CCUS) projects were reviewed to determine common themes. These comments either expressed concerns or support for each project. Nine documents were reviewed that exhibited 15 prominent themes, nine of which were relevant to the human environment. The list of documents is below. Exhibit E-1 displays the themes (i.e., categories) and reviewed documentation along with a number highlighting the instances the themes appeared in each document. Categories are listed from high to low based on number of occurrences and blank cells correlate to no instances of those themes within the documents.

- Illinois Industrial Carbon Capture and Storage (ICCS) Environmental Assessment (EA) (Department of Energy [DOE] EA-1828)
- Southeast Regional Carbon Sequestration Partnership (SECARB) Phase III EA (DOE EA-1785)
- FutureGen 2.0 draft Environmental Impact Statement (EIS) (DOE EIS-0460)
- Archer Daniels Midland (ADM) Carbon Capture and Storage (CCS)#2 UIC Class VI draft permit
- FutureGen 1.0 draft EIS (DOE EIS-0394)
    - FutureGen Project EIS – General (DOE EIS-0394)
    - FutureGen Project EIS – Jewett, Texas (DOE EIS-0394)
    - FutureGen Project EIS – Mattoon, Illinois (DOE EIS-0394)
    - FutureGen Project EIS – Odessa, Texas (DOE EIS-0394)
    - FutureGen Project EIS – Tuscola, Illinois (DOE EIS-0394)

Exhibit E-1. Quantitative results on 15 themes in the public comments from NEPA and UIC documentation for the reviewed CCUS projects

Category	ICCS EA (DOE EA-1828)	SECARB Phase III EA (DOE EA-1785)	FutureGen 2.0 Draft EIS (DOE EIS-0460)	ADM CCS#2 UIC Class VI Draft Permit	FutureGen 1.0 Project EIS – General (DOE EIS-0394)	FutureGen 1.0 Project EIS – Tuscola, Illinois (DOE EIS-0394)	FutureGen 1.0 Project EIS – Jewett, Texas (DOE EIS-0394)	FutureGen 1.0 Project EIS – Mattoon, Illinois (DOE EIS-0394)	FutureGen 1.0 Project EIS – Odessa, Texas (DOE EIS-0394)	Total
Advocacy, Endorsement, or Support						21	2	14	49	86
Impact to Air Quality and Noise Levels			6		45	1	2	9	4	67
Suitability of Geologic Conditions	4		17	5	32	4			3	65
Socioeconomic Impacts			21		4	4	9	4	19	61
Land Use Impacts	1	6	5	1	16	9		10	2	50
Site-Specific Comments			15		26		2	4	1	48
Surface Water and Groundwater Impacts	1	1	6		20	8		4	4	44
Documentation Needs Further Information About Project	3		27	2	10	1				43
Public Health and Safety			10		18	3	1	3	4	39
Biologic Resources Health and Safety			5	2	13	1		1	1	23
Not Applicable		1		1	15	3		1		21
Impact to Soil and/or Farmland			12		4	1		1		18
Project Impact to Climate and GHG Emissions Reduction			9		1	1	4		2	17
Environmental Justice			5	1		1		2		9
Generation and Disposal of Waste Material			3		2					5



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