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Carbon Dioxide Capture and Sequestration (CCS) Safety

Review of Recent Operational and Scientific Developments

April 2025

Executive summary

Researchers at Texas A&M University (TAMU) have prepared this report as a meta-study that consolidates existing research and field experiences on the safety of carbon capture and storage (CCS) in the United States (U.S.). The report intends to explain safety risks, concerns, U.S. regulations, and operational experience for the non-technical reader.

This work was supported by the Greater Houston Partnership's Houston Energy Transition Initiative, a coalition of energy and industrial companies, academic institutions, community-based organizations, and local government entities dedicated to advancing an energy-abundant, low-carbon future as well as the Houston CCS Alliance, an effort among some of the world's most innovative energy, petrochemical, and power generation companies to advance the development of carbon capture and storage (CCS) in the greater Houston industrial area. TAMU conducted an initial critical analysis of the CCS value chain in the United States using publicly available data. As the lead author of this independent report, TAMU retains the right to disseminate it broadly.

Key Findings:

- Deploying CO_2 capture systems has clear environmental benefits. On average, current technologies can capture around 90% of CO_2 emissions from industrial sources, but not all applications are economical. In addition to reducing CO_2 emissions, these technologies help reduce pollutants (e.g., particulate matter (PM), sulfur oxides (SOx), and nitrogen oxides (NOx)).
- Key safety concerns about CO_2 sequestration include CO_2 leakage through faults and fractures, legacy wells (abandoned wells from past activities constructed to the standards of the day without consideration of future CCS deployment), induced seismicity, and caprock seal failure at permanent sequestration sites. After a review of existing operational and scientific literature, these risks were found to present a low probability of occurrence. There are control, monitoring, and management measures available to effectively mitigate these risks as required by the U.S. Environmental Protection Agency (EPA) or state regulatory authority.

- CO_2 is transported to a sequestration site via pipeline. While CO_2 pipeline incidents are rare, risks such as unintended releases due to impurities, corrosion, or mechanical failure exist. However, the Pipeline and Hazardous Materials Safety Administration (PHMSA) in the U.S. Department of Transportation and state regulations enforce strict design, monitoring, and maintenance standards, including regular inspections, corrosion-resistant materials, and emergency response protocols to ensure safe and reliable CO_2 transport.
- To protect public health and underground sources of drinking water (USDWs) from the unique nature of CO_2 injection for geologic sequestration, owners or operators are required to meet U.S. EPA requirements on strict site selection procedures, continuous monitoring/reporting during site selection, well construction, injection operation, and post-injection.

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List of Abbreviations

AIChE – American Institute of Chemical Engineers
API – American Petroleum Institute
Ar – Argon
ASME – American Society of Mechanical Engineers
CCS – Carbon Capture and Storage
CCUS – Carbon Capture, Utilization, and Storage
CH_4 – Methane
CO – Carbon Monoxide
CO_2 – Carbon Dioxide
DAS – Distributed Acoustic Sensors

DFOS – Distributed Fiber Optic Sensing
DNV – Det Norske Veritas
DOE – Department of Energy
DTS – Distributed Temperature Sensors
DREAM – Designs for Risk Evaluation and Management DSS – Distributed Strain Sensors
ERT – Electrical Resistivity Tomography
EPA – Environmental Protection Agency
H_2 – Hydrogen
H_2O – Water
H_2S – Hydrogen Sulfide
HCAs – High-Consequence Areas
IM – Integrity Management
InSAR – Interferometric Synthetic Aperture Radar
ISO – International Organization for Standardization
MEA – Monoethanolamine
NETL – National Energy Technology Laboratory
NO_x – Nitrogen Oxides
N_2 – Nitrogen
O_2 – Oxygen
PCC – Post-Combustion Carbon Capture
PHMSA – Pipeline and Hazardous Materials Safety Administration
PM – Particulate Matter
PNNL – Pacific Northwest National Laboratory
RPs – Recommended Practices
SBAS-InSAR – Small Baseline Subset Interferometric Synthetic Aperture Radar
SO_x – Sulfur Oxides
TRL – Technology Readiness Level
UIC – Underground Injection Control
USDW – Underground Sources of Drinking Water

1. What is carbon capture and storage?

Carbon capture and storage (CCS) is a tested means of reducing greenhouse gas emissions associated with the burning of hydrocarbon fuels. Carbon capture refers to a variety of technologies that separate CO_2 from emissions sources or preliminary fuels before or after combustion (Hasan et al., 2022). These include industrial sectors, such as steel, cement, chemicals for fertilizers and fuels, hydrogen production, and natural gas- and coal-fired power generation, just to mention a few (Yadav and Mondal, 2022). CO_2 captured from these industrial processes or electricity generation can then be compressed for transport to permanent geological storage (see Figure 1), reused for commercial products such as building materials, fuels, and chemicals, or used for enhanced oil recovery (EOR). In addition to capturing CO_2 from emissions sources, carbon capture technologies can reduce air pollutants (e.g., PM, SOx, and NOx) released into the atmosphere but harmful to human health (Larki et al., 2023).

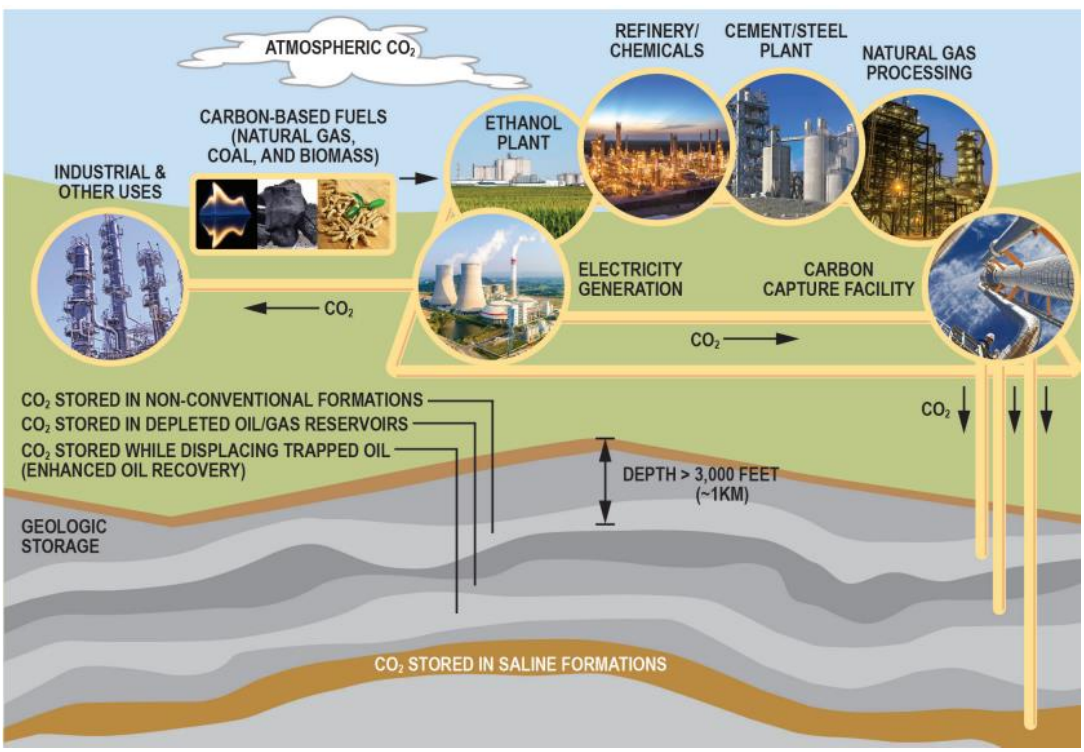

Figure 1. Carbon dioxide and storage system illustration (NPC, 2021)

Once compressed, CO_2 is transported via pipelines to onshore or offshore storage sites and injected deep into suitable geologic formations, typically a half-mile or more underground for permanent storage (El-Kady et al., 2024). Suitable storage sites are located below impermeable rock layers to ensure the CO_2 is permanently trapped in the chosen geologic formation and isolated from underground sources of drinking water. Before CO_2 storage begins, project developers identify and appropriately characterize potential sites. The primary technical storage methods include (Bachu, 2008; Sorimachi, 2022):

- **Underground geological storage**: CO_2 is stored in oil and gas fields, unmineable coal beds, and deep saline formations.
- **Industrial fixation**: CO_2 is fixed into inorganic carbonates for stable, long-term storage.

The ability to inject and safely store CO_2 deep underground is regulated by the U.S. Environmental Protection Agency's (EPA) Underground Injection Control (UIC) Class VI program or by states that have obtained primary enforcement authority (primacy) over Class VI permitting. The states of North Dakota, Wyoming, and Louisiana have received such authority from the EPA. The term Class VI refers to the type of well permitted for CO_2 storage. If organizations fail to follow the requirements, EPA or state regulators can revoke permits, require interventions (such as plugging additional wells), administer fines, and take other enforcement actions.

Five other well classifications are permitted by the EPA or delegated to states by the EPA for permitting injection wells for various substances. The EPA can revoke permitting authority from a state if the state's enforcement program does not comply with EPA requirements, such as when the state fails to act on violations or does not seek adequate enforcement (U.S. EPA, 2024a, 2024b).

2. Is CO_2 injection and storage safe?

Understanding the risks associated with CCS and their potential impact on industrial assets and the environment is essential. Equally important is evaluating the measures available for controlling, monitoring, and managing these risks. The measures, mandated and enforced by U.S. federal and state regulations and practiced by operators, are critical to minimize unwanted events. This section addresses common concerns related to CCS and the regulatory and technical safeguards in place to evaluate its current safety status.

2.1. Risk of CO_2 leakage is low to negligible

Based on recent events and the track record of CO_2 injection over three decades, the probability of abrupt or gradual leakage of CO_2 to underground reservoirs (located a half mile or more underground) is low to negligible (Alcalde et al., 2018). Studies suggest that, with proper site selection and regulation, 98% of stored CO_2 will remain contained for over 1,000 years (Alcalde et al., 2018).

The National Risk Assessment Partnership's integrated assessment model for carbon storage (NRAP-IAM-CS) is a tool developed by the U.S. Department of Energy (DOE) to assess the probability of CO_2 leakage from storage sites. The model considers site-specific factors and allows operators to estimate risks under various scenarios. Results suggest that the likelihood of leakage exceeding safety thresholds is very low (Pawar et al., 2016). An exemplary predicted probability is shown in Figure 2.

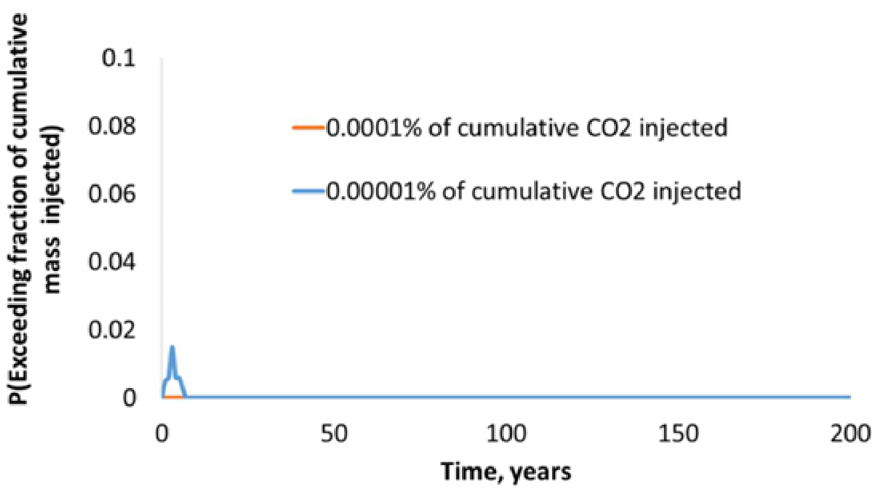

Figure 2. A sample result showing the negligible CO_2 leakage (Pawar et al., 2016)

2.2. How do regulations and technical interventions mitigate the risk of CO_2 leakage?

Regulators and operators are aware of various ways that, although unlikely, CO_2 might leak during injection and have put regulations and engineering practices in place to mitigate these risks. The U.S. EPA or state regulator requires operators to perform a detailed assessment of the geology, hydrology, and geomechanical properties of the proposed storage site, including data on the storage reservoir and the overlying confining layers before the commencement of any project. This involves gathering information about the underground environment to ensure suitability for

CO_2 injection and long-term containment (U.S. EPA, 2024b). Thus, safety is considered from the site selection stage. Sections 2.2.1 and 2.2.2 discuss relevant key safety concerns, regulatory requirements, and available technologies to address these concerns.

2.2.1. Injection well integrity

CO_2 injection wells are exposed to high-pressure environments and the potential presence of impurities in the injected solution. While the CO_2 itself is not corrosive, certain impurities in the stream can pose corrosion risks. To reduce corrosion risk, operators have strict pipeline specifications that limit corrosive agents, such as water and other impurities.

In CO_2 storage, well failure can be attributed to compromised well integrity, which occurs due to gradual formation leakage over time. This process is influenced by several factors including fluid movement, solute transport, chemical interactions, mechanical stress, quality and integrity of the annulus, casing degradation, seal deterioration, and inadequacies in abandonment procedures (Carroll et al., 2016a; Kiran et al., 2017; Zhang and Bachu, 2011). These factors are discussed in four categories: 1) well construction, 2) well operation, 3) loss of containment, and 4) abandonment.

2.2.1.1. Well construction

Cement quality: Cementing is a crucial component in securing the well casing and isolating the well from surrounding geological formations (Yousuf et al., 2021). Poor-quality cement can lead to cracks, allowing CO_2 and other fluids to escape. If this situation is not mitigated, CO_2 can react with the cement itself, degrading its structure and reducing its effectiveness over time (Abid et al., 2015; Glasser et al., 2008; Jang et al., 2016).

Casing corrosion: The well's steel casing is susceptible to corrosion, particularly in the presence of CO_2 and other "sour" gases, such as hydrogen sulfide (H_2S), in the injection stream. This process is significantly accelerated by the presence of water, which enables the formation of corrosive acids that corrode the metal and create potential leak points through which CO_2 can escape. (Laumb et al., 2016; Yevtushenko et al., 2014).

Regulatory and Technical Intervention: The U.S. EPA or state regulator requires operators to construct Class VI injection wells and in-zone monitoring wells, including casing and cement, with corrosion-resistant materials compatible with the subsurface conditions and fluids that they may be exposed to, such as high pressure and low pH levels (see § 146.86 at U.S. EPA (2024b)).

2.2.1.2. Well operation

Dynamic pressures: Injecting CO_2 involves substantial pressure fluctuations that can strain well materials and cause mechanical failures. Wells must withstand high pressures during injection, which requires structural integrity (Kiran et al., 2017).

Regulatory and Technical Intervention: The U.S. EPA or state regulator requires continuous monitoring throughout the injection process, including the tracking of pressure, temperature, and movement of injected CO_2. U.S. EPA or state regulators set operational limits on injection pressures to prevent over-pressurization that may lead to unintended fractures or leakage pathways. These limits are designed to maintain the integrity of the storage reservoir and the confining layers (see § 146.88 at U.S. EPA (2024b)).

2.2.1.3. Loss of CO_2 containment

Loss of mechanical integrity can result in CO_2 escape. Over time, CO_2 can chemically interact with the materials used in well construction, leading to corrosion, brittleness, or cracking. These chemical reactions coupled with sustained pressure from CO_2 injection can weaken seals, increase the risk of leakage, and compromise the well's containment capacity (Vafaie et al., 2023).

Regulatory and Technical Intervention: The U.S. EPA provides a clear definition of what mechanical integrity means in the context of CO_2 injection wells. It is required to evaluate the absence of significant leaks. The owners/operators must follow an initial annulus pressure test, and continuously monitor injection pressure and rate, injected volumes, pressure on the annulus between the tubing and long-string casing, and annulus fluid volume (see § 146.89 at U.S. EPA (2024b)). If a loss of mechanical integrity is discovered, the owner/operator must immediately investigate and identify, as expeditiously as possible, the cause of the loss of integrity. Operators must restore mechanical integrity before resuming injection (see § 146.88 at U.S. EPA (2024b)).

2.2.1.4. Site closure

Proper completion of wells is essential to ensure that they are equipped to handle long-term storage (Enriquez et al., 2024). Wells abandoned without adequate sealing and isolation methods pose significant risks of leakage, as they are no longer maintained or monitored (Postma et al., 2019).

Regulatory and Technical Intervention: Class VI rules from the U.S. EPA and state regulators require that operators demonstrate financial capability to cover costs associated with injection operations, monitoring, site closure, and potential remediation activities (see § 146.85 at U.S. EPA (2024b)). This requirement ensures that funds are available for all stages of the project, including long-term site care.

Operators must maintain detailed records and regularly report their activities to the US EPA or state regulator. This includes data on CO_2 injection volumes, pressures, and monitoring results. Recordkeeping ensures transparency and regulatory oversight throughout the lifecycle of the storage project (see § 146.91 at U.S. EPA (2024b)). Class VI permits require a detailed plan to address unexpected events, such as well failures or CO_2 leakage. To ensure safety, the plan should include methods for monitoring, mitigating, and responding to such incidents (see § 146.94 at U.S. EPA (2024b)).

2.2.2. CO_2 storage concerns

Key risks associated with underground storage are undetected faults and fractures that could cause induced seismicity, seal failure, and mineral dissolution (Anderson, 2017; Pawar et al., 2015; Xiao et al., 2024). These risks are discussed below with their anticipated likelihood and impact.

2.2.2.1. Undetected faults and fractures

When CO_2 is injected into a storage site, it is typically stored at a pressure above the normal reservoir pressure level. This higher pressure can activate faults and fractures, allowing CO_2 to seep through them (Shukla et al., 2010). Faults and fractures are cracks or breaks in the earth's crust. While faults are fractures along which movement has occurred, fractures are simply cracks without displacement (Peacock et al., 2016). The extent to which faults and fractures pose a risk depends on several factors, including size, orientation, connectivity, and the permeability of the surrounding rock (Viswanathan et al., 2022). If CO_2 begins to migrate through these features, it may eventually reach the surface and negate the purpose of underground storage.

Another potential impact of undetected faults and fractures is the risk of contaminating groundwater (see Table 1). If CO_2 escapes from the storage formation, it would have to travel thousands of feet up an improperly abandoned well, non-sealing fault, or other geologic pathways before reaching groundwater. This escaped CO_2 can react with surrounding minerals, potentially releasing contaminants like heavy metals into the water (Apps et al., 2010; Bashir et al., 2024). As contamination poses health and economic risks, this can be concerning for communities that rely on groundwater for drinking or agriculture. However, with proper monitoring and mitigation, as required by federal or state regulations, this can be avoided.

In addition to environmental impacts, faults and fractures can increase the risk of seismic activity or induced seismicity (see Section 3.3.2 for further details). When high-pressure CO_2 is injected into a geological formation, the added stress may cause faults to slip, resulting in small earthquakes (Evans et al., 2012; Rutqvist, 2012). These induced seismic events are typically minor; the likelihood of a seismic event affecting the operation and regular life is believed to be low (White and Foxall, 2016).

Technical Intervention: Operators detect faults and fractures as part of the site selection and project design process, using techniques like three-dimensional seismic mapping (Ivandic et al., 2012; Vo Thanh et al., 2019) to provide detailed images of the subsurface (see further discussions in Appendix A.1). Continuous monitoring is essential after injection begins, as the increased pressure may activate previously dormant faults or fractures (Ajayi et al., 2019). Tools like microseismic sensors (Goertz-Allmann et al., 2017; White et al., 2014) and ground deformation analysis (Morris et al., 2011; Seabra et al., 2024) can detect early signs of CO_2 movement and allow for timely intervention. Additionally, the Designs for Risk Evaluation and Management (DREAM) tool, developed by the Pacific Northwest National Laboratory (PNNL), can be used to optimize monitoring programs for detecting leaks in commercial-scale carbon storage projects (PNNL, 2024). These requirements and technical best practices aim to minimize CO_2 injection and storage risks and ensure that underground injection activities do not endanger drinking water sources.

Regulatory Intervention: According to U.S. EPA and state regulatory requirements, a detailed assessment of the geology, hydrology, and geomechanical properties of the proposed storage site, including data on the storage reservoir and overlying confining layers, must be done before commencement of any project. This involves gathering information about the underground environment to ensure its suitability for CO_2 injection and long-term containment. The US EPA or state regulator uses these requirements to ensure the project area's geology can receive and contain the CO_2 within the zone where it will be injected. (see § 146.83 at U.S. EPA (2024b)).

2.2.2.2. Legacy wells

Legacy wells, also known as abandoned or inactive wells, present another risk to CO_2 storage. Legacy wells were drilled, often decades ago, for oil and gas exploration or extraction and may not have been abandoned with the same standards as today and without future CCS in mind (Anwar et al., 2024). Many legacy wells lack adequate sealing or their seals may have degraded over time (King and Valencia, 2014) creating potential pathways for CO_2 to escape (Wise et al., 2024).

Legacy wells can create a conduit for CO_2 fluid flow, which could be caused by the failure or absence of a plug or mechanical barrier in the legacy well. The risks associated with legacy wells are like those posed by undetected faults and fractures: both can create unplanned pathways for CO_2 migration.

Technical Intervention: To manage this risk, operators can access publicly available drilling and abandonment records and use imaging and scanning techniques to locate legacy wells (Romanak and Dixon, 2022). Remediation methods, such as re-cementing or sealing the well, can reinforce the well (Zapata Bermudez et al., 2024). Ongoing monitoring around legacy wells is critical for the detection of early signs of CO_2 leakage (Iyer et al., 2022).

Regulatory Intervention: A detailed assessment of the projected CO_2 storage area is required before soliciting storage permission from the U.S. EPA or state regulators (see § 146.82 at U.S. EPA (2024b)). Operators must provide computational modeling results of the extent of the injected CO_2 plume and associated pressure front as part of post-injection site care and site closure (see § 146.93 at U.S. EPA (2024b)). To ensure the containment of CO_2 within the authorized zone and avoid the risk of reactivation of any undocumented artificial penetrations, operators must identify and address any deficiencies of existing wells within the "Area of Review" or permitted area.

2.2.2.3. Seal failure

The caprock, or seal, plays a crucial role in containing CO_2 in underground storage formations. This impermeable layer of rock acts as a barrier and prevents CO_2 from migrating upward and escaping from the storage formation (Bashir et al., 2024). Seal failure occurs when the caprock is compromised due to natural weaknesses, geological shifts, or the pressure exerted by injected CO_2 (Busch et al., 2010). If the seal fails, CO_2 can escape from the storage site, posing environmental and safety risks like those associated with faults and fractures.

Seal failure can be caused by several factors. The high-pressure injection of CO_2 can stress the caprock, especially if it contains small pre-existing cracks or fissures (Bruno, 2014; Zheng et al., 2022). Over time, this pressure can cause cracks to widen or new fractures to form and weaken the seal (Li et al., 2020). Chemical reactions between CO_2 and certain minerals in the caprock can erode the caprock's stability. These reactions may dissolve portions of the caprock, reducing its thickness and ability to act as a barrier (Carroll et al., 2016b; Fitts and Peters, 2013). If the seal fails, CO_2 can migrate into adjacent rock formations or toward the surface, potentially resulting in atmospheric leakage or contamination of groundwater sources (Gholami et al., 2021). CO_2 migration into aquifers can degrade water quality, like the contamination risks associated with mineral dissolution.

Technical Intervention: To minimize the likelihood of seal failure, operators can select storage sites with caprock layers that have proven impermeability and structural strength (Anderson, 2017). Advanced modeling techniques (see Wang et al. (2023)) help assess the seal's ability to withstand the pressure of CO_2 injection and monitoring systems track changes in pressure and detect any signs of caprock degradation (Ajayi et al., 2019). Chemical analysis of the caprock can also identify potential reactions with CO_2 that could weaken the seal over time (Jayasekara et al., 2020; Shukla et al., 2010). These preventive measures, combined with ongoing monitoring, are essential to maintaining the seal's integrity and ensure long-term storage security.

Regulatory Intervention: After injection operations cease, the U.S. EPA or state regulator mandates that operators continue monitoring the site to ensure the secure containment of CO_2. This includes tracking the stabilization of pressure to gain confidence that no leakage has occurred. A minimum of 50 years of post-injection monitoring is typically required, though this period can be adjusted if the operator demonstrates through monitoring and other site-specific data that the geologic sequestration project no longer poses a danger to USDWs (see § 146.93 at U.S. EPA (2024b)).

2.3. What can happen if CO_2 leaks during injection and post-storage?

As discussed, certain risk factors associated with CCS operations can lead to CO_2 leakage. The key concerns are: What is the potential impact if a leak happens? This report addresses these concerns from the perspectives of groundwater and soil contamination and induced seismicity since these consequences can detrimentally affect humans and the environment. It was mentioned previously that U.S. EPA provides strict guidelines to prevent the likelihood of these events occurring (see § 146.90 and § 146.95 at U.S. EPA (2024b)) and the mitigation measures outlined further reduce the potential impact on people or the environment.

2.3.1. Groundwater contamination

In the unlikely event of CO_2 leakage from geological storage half a mile or more underground, CO_2 would have to travel thousands of feet up an improperly abandoned well, non-sealing fault or other geologic pathway before it could reach groundwater (see Figure 3). If the CO_2 ascends to the surface, it could affect farmland, soil, and water resources. It is important to distinguish between underground sources of drinking water (USDWs) and water currently used for public consumption. USDWs in aquifers are defined as having total dissolved solids (TDS) levels of less than 10,000 ppm, highlighting their potential for future use as drinking water sources, even if they are not presently utilized. In contrast, water typically used for public consumption, particularly drinking water, has much lower TDS levels—commonly below 500 ppm, the Underground Injection Control (UIC) Program with an upper acceptable limit of 1,000 ppm for taste, odor, and other aesthetic considerations. Regulations are in place to protect USDWs, ensuring they remain viable as potential future sources of drinking or farming water (U.S. EPA, 2021). A summary of the potential impacts of CO_2 on groundwater (or aquifer) is provided in Table 1. Further discussions on remediation options for underground geological CO_2 storage projects are provided in Appendix A.2.

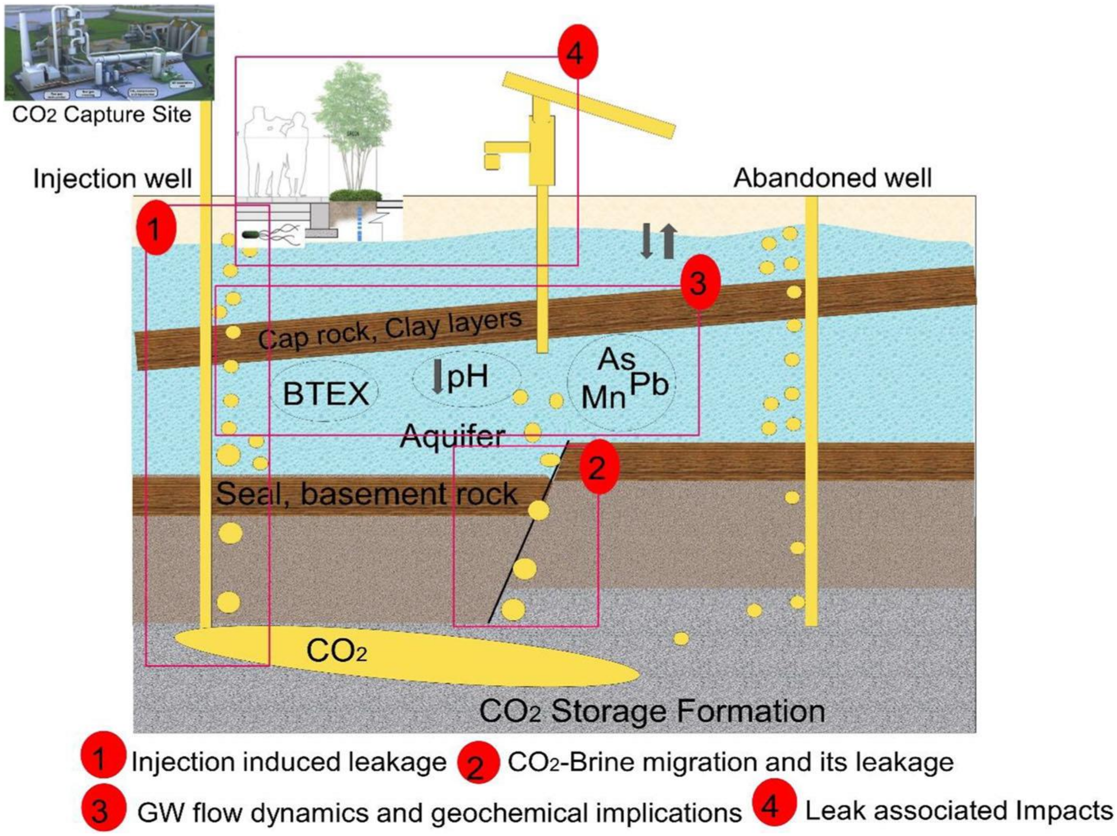

Figure 3. Schematic diagram of CO_2 leakage along faults, fractures, and wells (Gupta and Yadav, 2020)

Table 1. Summary of the impact of unlikely CO_2 Leakage on groundwater

Situation	Mechanism	Impact	Engineering and Regulatory Measures to mitigate risk
Water acidification	CO_2 dissolves into groundwater, making it more acidic.	Acidic water can draw out heavy metals from rocks, raising the levels of dangerous metals like lead, arsenic, and mercury in drinking water. In the short term, exposure to these metals can cause immediate health problems such as poisoning and damage to the nervous system. Over time, even small amounts of exposure can lead to serious, permanent health issues, including cancer, heart disease, and long-term brain disorders. These risks are even greater for vulnerable groups like children and pregnant women, making their presence in drinking water a serious public health issue.	1. Implement water treatment systems for impacted areas, i.e., aeration techniques to remove dissolved CO_2; and alkalinity adjustment using lime or sodium bicarbonate to increase pH levels. 2. Use bioremediation methods involving microbes that consume CO_2 or produce buffering substances. 3. Establish guidelines and enforce compliance for CO_2 storage operators to mitigate acidification risks through proactive measures.
Mineral dissolution	Acidic water has a low pH that may cause a breakdown of carbonate minerals and release calcium, magnesium, and other ions into the water.	The change can affect whether the water is suitable for drinking and agricultural use.	1. Analyze the mineral composition of the rock formation to assess the likelihood of dissolution. 2. Site-specific process description is required by the U.S. EPA and state regulator to prevent mineral dissolution and demonstrate an alternative plan (see § 146.93 at U.S. EPA (2024b))

Situation	Mechanism	Impact	Engineering and Regulatory Measures to mitigate risk
Contaminant mobilization	The release of CO_2 can alter water chemistry, potentially leading to the release of natural contaminants like arsenic from underground sediments.	Higher levels of these contaminants can be harmful if they make their way into drinking water supplies.	1. Develop treatment systems for affected groundwater, i.e., ion exchange filters to remove specific contaminants like arsenic or reverse osmosis systems to purify water with high levels of dissolved solids or toxins. 2. Use in-situ remediation techniques, such as injecting neutralizing agents into aquifers to immobilize contaminants. 3. Require operators to develop and submit detailed contingency plans for remediating contamination events before project approval. 4. Include financial assurance mechanisms to ensure funds are available for mitigation and cleanup efforts if contamination occurs. 5. Encourage collaboration between operators, scientists, and regulators to share best practices and improve mitigation strategies.
Brine displacement	Brines pushed out from deep underground by injected CO_2 can move or leak through cracks or faulty wells, reaching shallow aquifers. This	Adding salty water to groundwater or the shallow subsurface can harm wildlife habitats, limit or stop agricultural land use, and pollute surface water.	1. Like mitigation of contaminant mobilization, water treatment mechanisms are implemented in the form of desalination techniques (i.e., reverse osmosis or ion exchange

Situation	Mechanism	Impact	Engineering and Regulatory Measures to mitigate risk
	can contaminate drinking water sources by making them saltier.		systems) to treat affected groundwater and restore its usability. 2. Use balanced injection-extraction techniques to extract brine in controlled quantities while injecting CO_2 to reduce displacement pressures. 3. Mandate the development of contingency plans for mitigating brine displacement impacts, including rapid deployment of treatment systems if needed. 4. Involve local communities, agricultural stakeholders, and environmental groups in monitoring and decision-making processes.

2.3.2. Induced seismicity

Induced seismicity is a significant concern in various subsurface activities, including CO_2 storage. Extensive research indicates that CO_2 storage is generally safe, with minimal impact on human health and the environment and low potential for triggering seismic events. A review of historical data from multiple CO_2 storage sites is presented in this report.

CO_2 storage projects have generated vast amounts of data through surface and wellbore sensors. This data provides new insight into the relationship between fluid injection and seismic activity. Baseline seismic monitoring conducted before injection begins helps establish a reference point for seismic events unrelated to CO_2 injection and is crucial for distinguishing between natural and induced events.

Detailed observations from sites like the Illinois Basin Decatur Project (IBDP) (NETL, 2024) have enabled researchers to track the progression of seismic clusters and refine models for better prediction and mitigation. As this data grows, it becomes increasingly important to analyze and compare the seismic responses of different CO_2 storage sites, considering their unique geological characteristics. Such analysis not only bolsters understanding of CO_2 storage-induced seismicity but also helps differentiate it from seismicity caused by other industrial activities, such as wastewater disposal.

A summary of projects from the operational and scientific literature that detail the recorded seismic activity is provided in Table 2 (as derived from Cheng et. al., 2023), with accompanying induced seismic magnitudes illustrated in Figure 4. An interpretation of the observed seismicity levels is provided to understand how these may affect humans. The analysis suggests that the observed induced seismicity in different sites has minimal to no effect on daily life and site operations.

Table 2. Summary of observed induced seismicity at CO_2 injection projects

S/No.	Project	Category	Observed magnitude
1.	Aneth, USA	*CO_2-EOR	M (-1.2) to M 0.8
2.	Decatur, USA	CGS	M (-2) to M 1
3.	Weybrun, Canada	CO_2-EOR, Oil and gas reservoir	M (-3) to M (-1)
4.	Lacq-Rousse, France	CGS, Oil and gas reservoir	M (-2.3) to M (-0.5)
5.	In Salah, Algeria	CGS, Oil and gas reservoir	M (-1) to M 1.7
6.	Tomakomai, Japan	CGS	M<0
7.	Quest, Canada	CGS	M<0
8.	Aquistore, Canada	CGS	M<0
9.	Otway Basin, Australia	Oil and gas reservoir	M<0

*CGS – CO_2 Geological Storage; *EOR – Enhanced Oil Recovery

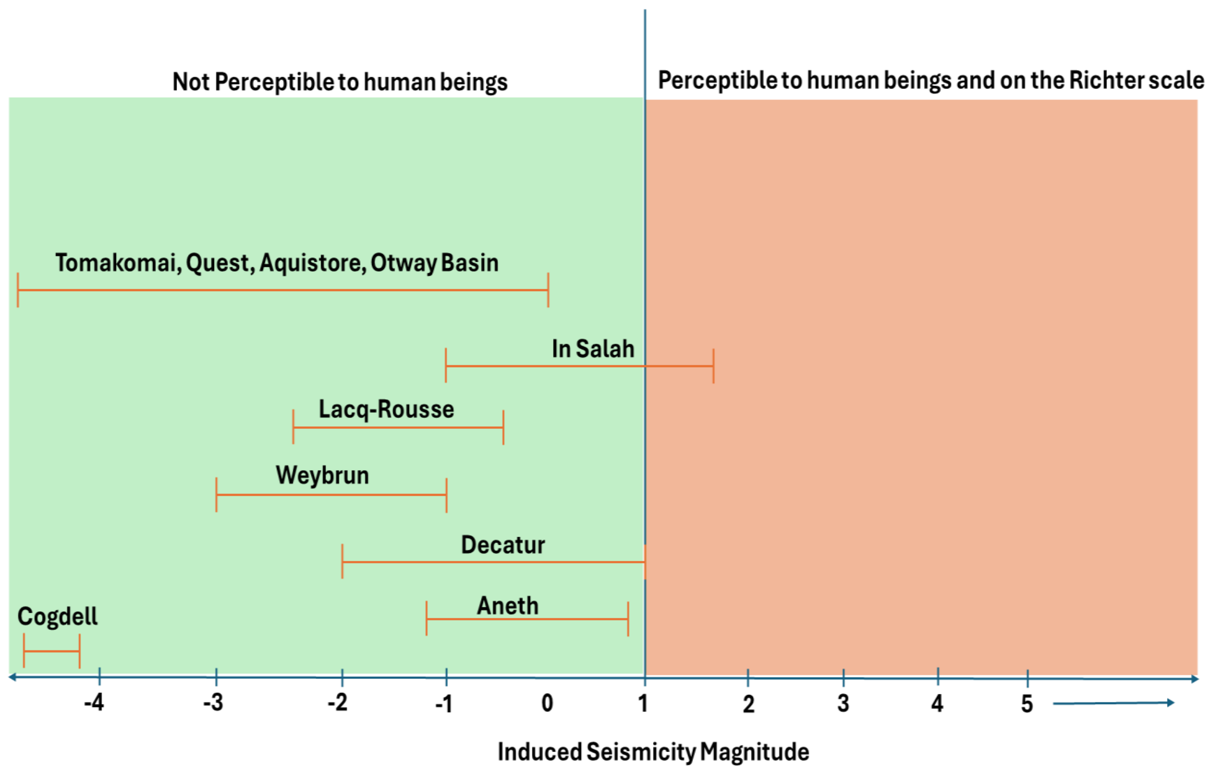

Figure 4. Summary of induced seismic magnitudes on CCS projects

A magnitude less than 0 is not perceptible to humans and, therefore, has no impact on life.

A magnitude 1-2 earthquake is comparable to the vibrations one might feel when a heavy truck drives by their house; this is not alarming.

A magnitude 3-4 earthquake can be compared to someone slamming a door: it causes some shaking; however, nothing is likely to fall over.

A magnitude 5-6 earthquake may feel like someone is jumping up and down on the roof: things begin to shake more noticeably, and objects could fall from shelves.

3. From source to sink: Is CO_2 transportation via pipelines safe?

CO_2 is transported through a pipeline from a capture facility to a site for use or sequestration. While there are similarities between CO_2 pipelines and pipelines that transport other substances, there are differences in how CO_2 pipelines are designed, permitted, constructed and operated. CO_2 is transported in what is called a dense liquid or supercritical phase, with density like a liquid and viscosity like a gas. In the U.S., federal and, in some cases, state regulations enforce CO_2 pipeline safety under the same statute as hazardous materials, which requires appropriate inspection requirements to identify safety issues and mitigate risk.

Stakeholders may have questions about the risks of impurities or contaminants that could enter CO_2 pipelines, retrofitting pipelines that have handled other substances to transport CO_2, or what could happen in the case of a leak or unlikely event of an unintended CO_2 pipeline release. As of December 31, 2021, there have been 112 recorded incidents involving onshore CO_2 pipelines in the United States between 1994 and 2021 (Xi et al., 2023). A recent report compared the incident rates of CO_2 pipelines to other pipelines carrying highly volatile liquids, refined products and crude oil and found that CO_2 pipeline incident rates were approximately 96% lower (Xi et al., 2023). It is important to note that the history of operating CO_2 pipelines is significantly shorter than pipelines carrying other hazardous materials. A more accurate measure is to report the number of incidents per unit length of the pipeline per year, but to the authors' knowledge, this research has not yet been conducted. With appropriate inspection requirements to identify safety issues and mitigate risk, and federal and state regulations, CO_2 pipelines have a low likelihood of incidents impacting human life. This section discusses the current technical mitigation and regulatory measures in place to address CO_2 pipeline safety, considering the over 5,000 miles of CO_2 pipelines operating today (see Figure 5).

Figure 5. Illustration Map of CO2 pipelines in the United States (NPC, 2021)

3.1 Impurities in CO_2 Pipelines and Risk of Unintended Release

In the case of carbon capture of anthropogenic or man-made sources of CO_2, the captured CO_2 may come from multiple sources. CO_2 pipelines are categorized into gathering pipelines and transmission pipelines. Gathering pipelines transport smaller volumes of CO_2 over shorter distances while transmission pipelines handle larger volumes over longer distances. Gathering CO_2 from multiple sources and processes can mean that the CO_2 stream will have variations in composition.

A common concern is that impurities in CO_2 pipelines (see Tables 4 and 5 for impurities and their level associated with different capture techniques) could compromise the integrity of the pipeline if not appropriately identified and remediated. While pipeline operators set specifications for the purity of CO_2 entering the pipeline, the Pipeline and Hazardous Materials Safety Administration (PHMSA) within the U.S. Department of Transportation has not finalized and implemented rules for the recommended range of acceptable impurity concentrations in pipelines. In a proposed rulemaking by PHMSA (2025), water vapor and hydrogen sulfide found in carbon dioxide product streams have been recommended to be less than 50 parts per million by volume (ppm) and 20 ppmv, which is a much more stringent range compared to that mentioned in scientific literature. These rules, proposed under the Biden Administration, are subject to review and have not been finalized or implemented by the current Trump Administration.

Table 3. Possible concentration ranges of the impurities in the captured CO_2 streams (Adu et al. (2019))

Components	Unit	Post-combustion	Pre-combustion	Oxy-fuel combustion
CO_2	vol%	99.7-99.9	95-99.7	74.8-99.95
O_2	vol%	0.0035 – 0.03	0.03 – 1.3	0.001 – 6.0
N_2	vol%	0.01 – 0.29	0.0195 – 1.3	0.01 – 16.6
Ar	vol%	0.0011 – 0.045	0.0001 – 1.3	0.01 – 5.0
H_2	vol%	Trace	0.002 – 3.0	Trace
H_2O	ppmv	100 - 640	0.1 - 600	0 – 1000
NO_x	ppmv	20 - 50	400	0 – 2500
SO_x	ppmv	0 - 100	25	0.1 - 25,000
CO	ppmv	1.2 - 20	300 - 4000	0 - 162
H_2S	ppmv	Trace	100 - 34000	Trace

Table 4. Recommended impurities' concentration ranges for CO_2 pipeline transportation (Halseid et al. (2014))

Component	Unit	Concentration
H_2O	ppmv	350-500
H_2S	ppmv	100-200
CO	ppmv	35-2000
O_2	ppmv	10-40000
NO_x	ppmv	100
SO_x	ppmv	100
Ar	vol%	4
N_2	vol%	4
CH_4	vol%	4
H_2	vol%	4

A concern with these impurities is their ability to cause corrosion, hydrate formation, and integrity issues, especially due to water vapor (Vitali et al., 2022; Wood, 2024). Corrosion in carbon steel pipes used for CO_2 transportation has been widely studied (Cole et al., 2011; Jones et al., 2024; Zeng et al., 2018). These impurities can affect the density, viscosity, and thermal conductivity of the CO_2 stream, affecting the pressure drop and heat transfer characteristics of CO_2 pipeline transportation. However, to our knowledge, there have been no incidents due to these phenomena.

Another concern is that impurities could cause a running ductile fracture leading to a failure and CO_2 release, but to date, we are unaware of any cases of running ductile fractures in CO_2 pipelines. These failures can be avoided by using appropriate materials, proper construction, technical monitoring and regulatory measures.

3.2 Technical mitigation of risks in CO_2 pipelines

Pipeline operators set specifications for the CO_2 entering a pipeline (see Table 4) and employ monitoring techniques to verify that the CO_2 meets the design specifications (i.e., CFR 49 part 195, ASME B31.4, DNV-RP-F104, and ISO 27913, commonly used in the United States). Operators typically require 95% or 99% purity of CO_2 in the stream composition. These specifications are intended to ensure safe operations and are the subject of continued research and joint industry partnerships (Wood plc, 2024). These research and partnership efforts are critical, as most current CO_2 transport lines in the United States use CO_2 from natural sources and may also come from a single source. Continued research and partnership are recommended to ensure pipeline safety as CO_2 pipelines transport more anthropogenic CO_2 from multiple sources in the future.

3.3 Regulatory intervention of risks in CO_2 pipelines

The U.S. Department of Transportation provides oversight for onshore pipelines in the United States. The Pipeline and Hazardous Materials Safety Administration (PHMSA) within the U.S. Department of Transportation regulates pipelines transporting CO_2 including the construction, operation and maintenance of pipelines, as well as enforcement measures. The Bureau of Land Management regulates CO_2 crossing federal lands. Tribal entities regulate pipelines through tribal lands. Some state agencies obtain permission from PHMSA to have the authority to regulate CO_2 pipeline safety if their standards meet or exceed the federal rules (49 CFR part 191-199).

Since CO_2 is heavier than air, in the event of a significant release, CO_2 can accumulate in low-lying areas, creating asphyxiation hazards. Dispersion modeling software can be used to model what would happen in the case of an unintended release of CO_2. In the U.S., federal and state regulations enforce additional requirements for pipelines in areas containing homes, industrial buildings and places of public assembly (49 CFR § 195.210 and § 195.248). Regular safety inspections are required in federal and state regulations, CFR 49 part 195. Inspections may include visual inspections, in-line robotic inspections and inspections that monitor other safety risks such as soil movement, which is believed to be a cause of the Satartia, Mississippi incident in 2020, which has since led to a review of the industry's best practices, in a proposed rulemaking that has yet to be finalized, published and implemented by PHMSA under the current presidential administration (2025).

3.4 Retrofitting existing pipelines for dense phase CO_2 transport – Regulatory and Technical Mitigation

Retrofitting existing pipelines is another option for dense phase CO_2 transport. Pipelines repurposed for CO_2 transportation must meet safety requirements from PHMSA for product flow, changes, pipeline age, expected additional lifetime in service, operating conditions, and conversion of service. Converted pipelines must meet the same requirements as pipelines built for CO_2 transportation alone.

4. Can CCS help improve air quality?

The process of capturing CO_2 often involves pre-treatment of flue (source) gases, which can also reduce the emissions of criteria air pollutants such as sulfur oxides (SOx), nitrogen oxides (NOx), and particulate matter (PM). These gases are major contributors to acid rain and ground-level ozone, harmful to human health and ecosystems. By removing CO_2 from exhaust gases, CCS processes often help remove or reduce PM, SOx, and NOx, improving air quality (Clean Air Task Force, 2023). For instance, the amount of NOx and SO_X present in a flue stream before any treatment is 150-250 and 120-200 ppmv, respectively (Aouini et al., 2014; Artanto et al., 2012) and ppmv (parts per million volume) is used to measure tiny amounts in a large mixture. In this respect, 150 ppmv SOx in air implies that if someone collects one million air particles, 150 of the particles will be SOx. The commonly used carbon capture techniques (e.g., post-combustion techniques like amine-based solutions) can significantly reduce these amounts. Studies (Martynov et al., 2016; Porter et al., 2015) have suggested that this number can be as low as 10 ppmv for NOx. This means only 4% of the NOx will be within the stream from the pre-capture stage. This is promising, but in reality, the reduction is even higher since the initial SOx and NOx removal technologies (e.g., scrubber) are applied before sending the flue gas stream for CO_2 capture (Chung et al., 2018).

Other CCS techniques (e.g., oxy-fuel and pre-combustion) also provide a reduction in PM, NOx, and SO_X. Oxy-fuel-based capture methods can outperform post-combustion techniques; however, these capture techniques have their use cases, which are often dictated by their working mechanism. In pre-combustion carbon capture, CO_2 is captured before fuel is burned, typically by gasifying the fuel with oxygen. A common example is integrated gasification combined cycle (IGCC) technology in coal plants. Post-combustion carbon capture takes place after combustion and captures CO_2 from exhaust gases using methods such as chemical absorption, physical adsorption, membrane separation, or chemical looping. Oxy-combustion carbon capture also occurs after combustion but in an oxygen-rich environment, where CO_2 generated in the process is separated using techniques like oxygen gas turbines. The oxygen-rich atmosphere is achieved by removing nitrogen from the air before combustion (Madejski et al., 2022; Yadav and Mondal, 2022). Figure 6 gives an overview of these three different CO_2 capture technologies. Interested readers are referred to (Spigarelli and Kawatra, 2013; Valluri et al., 2022; Yadav and Mondal, 2022) for more details.

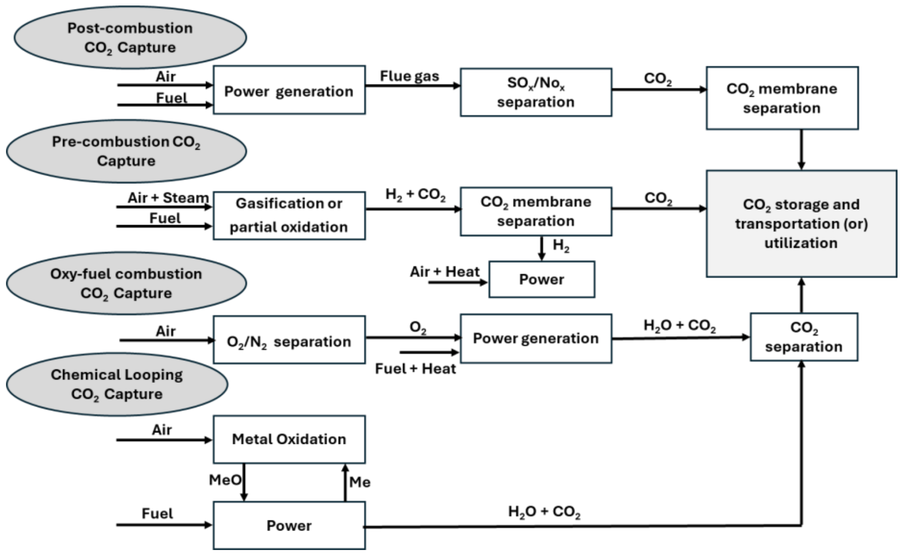

Figure 6. Flow diagram of commonly used CO_2 capture technologies (Valluri et al., 2022)

Another key concern may arise about capture technologies' maturity. A given technology may work effectively in lab-scale environments but may not reflect the same level of performance on an industrial scale. Existing CO_2 capture technologies (e.g., amine-based capture methods) are mature, reliable, and safe since, despite considering potential incident scenarios (Hillebrand et al., 2016; Paltrinieri et al., 2014; You and Kim, 2020), no known industrial incident has been reported at the CO_2 capture stage. This indicates that the safety aspects of these technologies are thoroughly studied, and industries have ensured adequate safeguards to prevent unwanted scenarios.

It should be noted that in addition to PM, SOx and NOx reduction, CO_2 capture techniques reduce other compounds (e.g., oxygen, argon, nitrogen, and water) generally termed impurities (Porter et al., 2015). While these compounds are not harmful to human health or the environment, they can have detrimental effects on assets such as fracture, cracking, and corrosion (Wetenhall et al., 2014). For instance, the presence of water can enhance corrosion vulnerability in pipelines during CO_2 transportation. These impurities have been studied in the existing literature and guidelines provided for mitigating their impact on the CCS system (Race et al., 2012; Vitali et al., 2022; Woods and Matuszewski, 2013).

5. Conclusion

This report provides a summary of scientific literature, openly accessible technical documents, and federal and state regulatory guidelines on CO_2 capture, transportation and sequestration in the United States, to address critical questions about CCS's safety and role in air quality improvement. The air quality benefits of CCS with mature CO_2 capture technologies can reduce emissions from industrial sources by up to 90%, along with substantial reductions in associated pollutants like PM, SOx, and NOx, though not all applications are currently economical.

CO_2 leakage at the sequestration site is a common safety concern. If a sequestration site loses containment, it may be due to undetected faults or fractures, legacy wells, and caprock seal failure. The U.S. EPA or state regulators provide strict requirements for managing these risks, including continuous monitoring, operational compliance, and reporting to ensure safe well construction, operation, and post-closure care. Control measures, such as corrosion-resistant materials, advanced well construction practices, and microseismic monitoring, are available to prevent and mitigate potential CO_2 leaks. Analytic tools and numerical models are available to predict risks, help reduce prediction uncertainty and provide an early warning system.

According to the available data, CO_2 released during injection or from the storage site is deemed to have an extremely low occurrence probability. However, in rare scenarios, if a leak happens, guidelines are provided for emergency risk management as an additional safeguard to protect humans and the environment. Induced seismicity, which can be of concern in injection operations, was also studied for its potential to disrupt site operations and daily life. The observed induced seismicity in existing operational records has had minimal to no effect on on-site operations and daily life. The maturity of CCS technology, combined with federal and state regulatory requirements, advanced technical interventions, and a low probability of leaks, allows stakeholders to gain confidence in its safety and minimal adverse impact on humans and the environment.

CO_2 is transported primarily via pipeline with a history of safer operations than pipeline transportation of other hazardous materials. Rare past incidents, such as the Satartia CO_2 pipeline failure, have resulted in federal regulatory and enforcement actions. With federal and state regulations as well as industry best practices in design and construction, impurity control, pipeline retrofits for CO_2 transportation, inspection and monitoring, emergency response, and technological advancements, CO_2 pipeline transportation is safe and presents a low likelihood of risk of severe incidents.

It is the combination of industry guidelines and federal and state regulations that ensure safe and effective carbon capture and storage. Operational history indicates that CCS is safe and presents a low likelihood of severe incidents, and continued cooperation between federal and state regulators and continuous improvement of industry best practices based on CCS deployment can sustain the operational track record.

Appendix

What are specific control and monitoring measures to mitigate and manage CCS safety risks?

As discussed in Sections 2.2.1 and 2.2.2, multiple monitoring and control methods are available for CCS. This appendix provides a summary of monitoring and remediation methods that can be used during injection and post-closure.

A.1. Injection measures

EPA guidelines require operators to continuously monitor parameters to assess the operating conditions and injection and storage safety. Regular inspections and audits ensure that wells meet these standards and remain safe throughout their operational life (Dixon et al., 2015). Most of the monitoring techniques are based on direct and indirect measurement techniques as discussed below.

1. Analytical/numerical models

Computational modeling is required by the US EPA for Class VI projects. Analytic and numerical models are available to assess mechanical integrity at CO_2 injection wells. Analytic models provide quick, simplified solutions for basic conditions, such as predicting stress, temperature, and pressure changes during CO_2 injection (Honglin et al., 2015). They offer valuable baseline insights into well stability. Numerical models, using techniques like finite element analysis (FEA) and computational fluid dynamics (CFD), simulate complex conditions including geological, thermal, and mechanical factors. These models assess stress, fracture, and corrosion risks, which enable detailed prediction of potential integrity issues (Yuan et al., 2013; Yvi et al., 2012).

2. Permeability Distribution Analysis

Permeability is a measure of how easily fluids like water or gas can flow through a material, such as rock or soil. Variations in permeability within the geological formation affect fluid flow and pressure profiles, which can influence the risk of CO_2 migration or leakage (Tao et al., 2010). Permeability distribution can be used as a leak indicator in CO_2 injection wells. By monitoring changes in permeability during injection, it is possible to detect anomalies such as localized high-permeability zones that may provide pathways for CO_2 to escape (Carey, 2018). Advanced techniques, including geophysical surveys and reservoir modeling, can help map permeability variations. Identifying these patterns enables early detection of potential leaks and supports timely intervention, enhancing the integrity of CO_2 storage sites.

3. Remote sensing and surface monitoring techniques

Technologies such as remote sensing, soil gas sampling, and groundwater monitoring provide external methods to detect CO_2 leakage (Verkerke et al., 2014). These allow comprehensive assessment of CO_2 migration, tracking potential leaks as they move toward the surface or into adjacent geological formations (Zhang et al., 2021). The integration of surface and subsurface monitoring techniques provides a multi-layered defense against undetected leaks. Collectively, these tools and technologies create a robust framework for managing CO_2 injection wells. They enable operators to continuously monitor integrity, assess potential risks, and respond to issues before they escalate, ensuring both environmental safety and operational efficiency.

4. Wireline logging methods

These are used to evaluate the condition of well casing, cement, and other structural components. By sending specialized instruments down the wellbore, operators can gather data on potential corrosion, cracking, or other forms of structural degradation. Regular wireline logging enables a timely intervention if well integrity begins to deteriorate (Kiran et al., 2017).

5. Seismic monitoring (4D seismic surveys)

This method uses repeated three-dimensional (3D) imaging over time, called "Four-dimensional (4D) seismic surveys," to monitor underground changes. The term “4D” adds time to the usual three spatial dimensions. First, a baseline scan of underground layers is done before injecting CO_2. Follow-up scans are taken periodically after CO_2 injection and, by comparing these images over time, we see how the CO_2 moves and spreads within the storage area. Changes in the strength and speed of the waves travelling through the ground help us understand how CO_2 affects the underground layers by showing shifts in their properties due to the CO_2. By studying this data over time, engineers gain confidence that the CO_2 remains securely stored and is not leaking or moving into other underground layers.

6. Pressure and temperature monitoring

When CO_2 is injected under pressure into the reservoir, it spreads, creating differences in density and pressure as the concentration changes. By measuring pressure and temperature along the well, engineers can accurately map the CO_2 spread. Sensors placed deep underground help monitor CO_2 and ensure that it stays securely within the storage area. These sensors track how CO_2 moves and spreads within the storage area. If CO_2 starts drifting beyond the intended zone, shifts in pressure and temperature act as early warnings. Any unusual pressure or temperature changes could signal that CO_2 is moving toward unintended areas, like faults or cracks. By monitoring the trends over time, engineers ensure the storage site remains stable and the CO_2 stays securely contained (Challener et al., 2016).

7. Geochemical monitoring

Regular testing of groundwater and soil gases around the storage site helps detect any CO_2 leaks and helps scientists understand how CO_2 interacts with the surrounding environment, providing valuable insights into the storage site's safety and stability. Geochemical monitoring involves regular sampling of groundwater from nearby aquifers to check for changes in chemical makeup. As discussed, if CO_2 escapes from the reservoir, it can dissolve in groundwater, changing the water’s pH and other chemical markers. Soil samples are also taken around the storage site. While CO_2 naturally exists in soil, a sudden increase can indicate a leak. Other gases like methane or hydrogen sulfide are monitored as their presence may suggest a breach in the storage site’s integrity. Geochemical monitoring is a key to long-term CO_2 storage surveillance. It is done before, during, and after CO_2 injection to set a baseline and detect changes over time. Regularly analyzing groundwater and soil gases helps confirm that CO_2 is securely stored and provides essential data for meeting regulatory standards (Kharaka et al., 2013).

8. Electrical resistivity tomography (ERT)

Surface-downhole electrical resistivity tomography (ERT) monitors changes in underground electrical resistivity, which shifts based on what materials are present, like rock, water, or gas. Since CO_2 conducts electricity less than water, areas with CO_2 show higher resistivity. By placing electrodes on the surface and in monitoring wells, this method uses electrical currents to create images of resistivity changes over time. The resulting data helps map the spread and movement of CO_2 and provides a clear picture of where it is located underground.

This technique provides high-resolution, non-invasive, real-time monitoring of the CO_2 plume, making it ideal for spotting potential leaks through cracks or faults that could allow CO_2 to escape. ERT enables operators to map exactly where CO_2 is and how it moves; ensuring it stays within the storage area. Continuous monitoring enhances the safety and effectiveness of CO_2 storage by offering early leak warnings and allowing quick corrective actions (Bergmann et al., 2012). Both surface and cross-hole ERT methods are effective, with cross-hole ERT being especially useful for deeper storage areas as it reaches greater depths than surface ERT. ERT can also detect lower CO_2 levels better than seismic methods, which makes it highly valuable for monitoring CO_2 storage sites (Jia et al., 2024).

9. Gravity surveys

Injecting CO_2 into a reservoir shifts fluids around and changes how mass is distributed underground. Since gravity is affected by mass, repeated gravity surveys can track these changes over time. The technique uses high-precision gravimeters to measure tiny changes in gravity at specific spots. By comparing these readings over time, we see how CO_2 and other fluids move within the reservoir. Measurements are taken either on the surface or in boreholes. Time-lapse gravity monitoring helps identify shifts caused by CO_2 injection and offers valuable insight into its movement and distribution underground. The effectiveness of gravity measurements at CO_2 storage sites depends on changes in density over time. When CO_2 is injected, it pushes out existing fluids, creating a contrast. CO_2 has a low density as a gas at normal conditions but becomes a more dense, supercritical fluid under high pressure (above 7.39 MPa) and temperature (over 31.1°C). This change in density helps reveal the movement and distribution of CO_2 in the storage area (Appriou et al., 2020).

10. Distributed Fiber-Optic Sensing

Distributed fiber-optic sensing (DFOS) technology measures strain and temperature by analyzing light scattering within fiber-optic cables. The technology is lightweight, portable, resistant to electromagnetic interference, and capable of real-time monitoring. It is also highly adaptable to different environmental conditions, making it effective for continuous monitoring.

DFOS monitoring can be divided into two types: fully distributed and quasi-distributed. Using different scattering methods, DFOS employs tools like distributed temperature sensors (DTSs), distributed strain sensors (DSSs), and distributed acoustic sensors (DASs) to monitor temperature, strain, and vibrations. DTS and DAS provide real-time monitoring of temperature and vibration fields. However, DFOS technology has some challenges, such as the need to bury fiber-optic cables and ensure these buried cables remain intact over time (Waller et al., 2020).

11. Interferometric synthetic aperture radar

Interferometric Synthetic Aperture Radar (InSAR) is a technology that uses satellite radar to measure tiny ground movements with millimeter accuracy by analyzing changes in radar images of the same area. First used in 2004 at the In Salah field (Stork et al., 2015) InSAR monitored surface shifts caused by CO_2 injection and detected movements of 5 to 150 mm per year. Since InSAR measures surface changes, it can only indirectly monitor CO_2 pathways. Future methods will likely combine InSAR with geological and other techniques for more comprehensive monitoring. However, InSAR has limitations in rugged areas like mountains, where data can be less accurate (Aziz et al., 2022). As InSAR technology advances, new sensors and algorithms are used to monitor ground changes in CO_2 storage sites. Examples include:

- L-band sensor: Used in the Scurry County CO_2-EOR field in West Texas.
- C-band sensor: Applied in the Jingbian CO_2-EOR field in Shaanxi, China.
- D-InSAR technology: Used at Aquistore CCS site in southeastern Saskatchewan, Canada.
- SBAS-InSAR technology: Employed in the Fengcheng Oil Field in Xinjiang, China.

A.2. Post-injection measures

The EPA typically holds operators responsible for any post-storage incident for a minimum of 50 years of post-injection monitoring, though this period can be adjusted if the operator demonstrates through monitoring and site-specific data that the geologic sequestration project no longer poses an endangerment to USDWs. For instance, computational analysis is required to see plume migration after site closure to assess potential risks. If any deviation is noticed, operators must inform the EPA for further action. Operators are required to keep monitoring methods in place even after site closure. EPA guidelines detail requirements for post-injection site care, and site closure (see § 146.93 at U.S. EPA (2024b)), emergency, and remedial responses (see § 146.94 at U.S. EPA (2024b)). Since most of the monitoring methods were discussed in the previous section, this section focuses on providing details of remedial options available for different scenarios (see Table 3 modified from Metz et al. 2015). It should be noted that these are exemplary scenarios and remedies. Operators are required to demonstrate a comprehensive, site-specific scenario analysis and identify the remedies which need to be submitted to EPA before site approval.

Table A1. Remediation options for underground geological CO_2 storage projects

S/No.	Scenario	Remediation Options
1.	Leakage-up faults, fractures and spill points	i. **Reduce Injection Pressure:** Lower injection pressure by slowing the rate or using more wells; reduce the risk of further leaks. ii. **Reduce Reservoir Pressure:** Extract water or fluids from the storage area to lower pressure and reduce the chance of fluid escape. iii. **Use Extraction Wells Near Leak:** Install wells near the leak to remove leaking fluid directly, controlling its spread and impact.
2.	Leakage through active or abandoned wells	i. **Repair Leaking Wells:** Use standard techniques (replace injection tubing, packers) to fix leaks in injection wells. ii. **Plug Leaks with Cement:** Seal leaks by injecting cement behind the well casing to stop seepage. iii. **Reduce Injection Pressure:** by slowing the rate or using more wells, reduce the risk of further leaks. iv. **Reduce Reservoir Pressure**: Extract water/fluids from the storage area to lower pressure and reduce the chance of fluid escape. v. **Use Extraction Wells Near the Leak**: Install wells near the leak to remove leaking fluid directly, controlling its spread and impact.
3.	[+]Accumulation of CO_2 in the region from the water table to the ground surface (also called the vadose region).	i. **Remove Gaseous CO_2 Accumulations:** Drill wells to intersect CO_2 accumulations and extract gas. CO_2 can be vented into the atmosphere or reinjected into a suitable storage site. ii. **Extract Residual CO_2**: Dissolve immobile CO_2 in water and extract it as a dissolved phase through groundwater extraction wells. iii. **Remove Dissolved CO_2:** Pump groundwater with dissolved CO_2 to the surface and aerate to remove CO_2. Treated water can be used or reinjected back into the groundwater. iv. **Address Contaminants:** Use 'pump-and-treat' methods to remove metals or trace contaminants mobilized by groundwater acidification. Alternatively, create hydraulic barriers with injection and extraction wells to contain contaminants. Passive biogeochemical processes may also be effective.

S/No.	Scenario	Remediation Options
4.	Leakage into the vadose zone and accumulation in soil gas	i. **Extract CO_2 from Vadose Zone:** Use standard vapor extraction techniques from horizontal or vertical wells to remove CO_2 from the vadose zone and soil gas. ii. **Use Caps or Barriers:** Decrease or stop CO_2 fluxes to the ground surface with caps or gas vapor barriers. Pumping below these barriers can help deplete CO_2 accumulations. iii. **Collect CO_2 in Trenches:** Dense CO_2 can be collected in subsurface trenches and pumped out for atmospheric release or reinjection underground. iv. **Apply Passive Techniques**: Use diffusion and 'barometric pumping' to slowly deplete one-time CO_2 releases. This method is not suitable for ongoing releases due to its slower pace. v. **Neutralize Soil Acidification:** Remediate CO_2-induced soil acidification through irrigation and drainage or by applying agricultural supplements like lime to neutralize the soil.
5.	Accumulation of CO_2 in indoor environments with chronic low-level leakage	i. **Control Indoor CO_2 Releases**: Apply radon and VOC control techniques, such as basement venting and pressurization, to manage CO_2 before it enters indoor environments.
6.	Accumulation in surface water	i. **Release from Shallow Water Bodies:** Shallow lakes and turbulent streams can naturally release dissolved CO_2 quickly back into the atmosphere due to turnover and turbulence. ii. **Venting Deep Lakes:** For deep, stratified lakes, use active venting systems to release gas accumulations, as successfully implemented at Lake Nyos and Monoun in Cameroon.

+ Vadose Zone is the region from the water table to the ground surface

A.3. Economic and Environmental Impact of CO_2 pipeline incidents.

To mitigate and prevent the recurrence of CO_2 pipeline incidents, it is essential to assess the historical nature of these incidents and examine their economic and environmental impacts. A recent study by Xi et al. (2023) reported important insights after analyzing 112 incidents in the PHMSA Incident Reporting database. The authors reviewed records of CO_2 pipelines, including PHMSA-regulated gathering pipelines and transmission pipelines. Data from smaller, non-PHMSA-regulated gathering lines was not available.

Equipment failure was the leading cause of incidents (53.03% of CO_2 pipeline incidents) from 1994 to 2021, followed by incorrect operation at 15.15%, material failure at 13.64%, corrosion failure at 10.61%, other causes at 6.07%, and natural force damage at 1.52% (Xi et al., 2023), as shown in Figure A1. However, natural force damage resulted in the largest economic losses, approximately 67.21%, while material failure contributed to the highest level of CO_2 pipeline incident-related carbon dioxide emissions, around 52.25%.

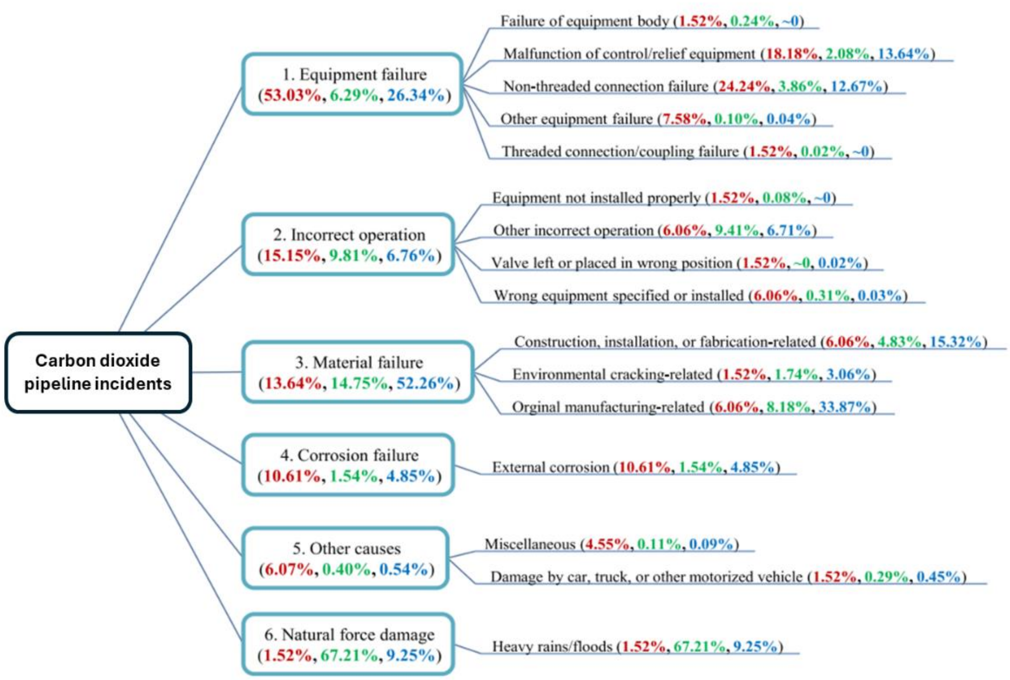

Figure A1. Primary and secondary causes of incidents in carbon dioxide pipelines (Xi et al., 2023)

Note: Red represents the proportion of incident frequency, green represents the proportion of economic losses, and blue represents the proportion of carbon emissions.

A.4. Other Key Regulations Proposed by PHMSA

These rules, proposed under the Biden Administration, are subject to review and have not been finalized or implemented by the current Trump Administration:

- Requiring the installation of advanced leak detection systems to promptly identify and address any leaks (§§195.134 and 195.444). This step helps with the early detection of small leaks that could grow over time.

- Implementing fracture control measures for new and modified pipelines to enhance their resilience against physical stress and failure (§195.111).

- Installing and maintaining fixed vapor detection and alarm systems at critical points, particularly for highly volatile liquid pipelines, to monitor the release of CO_2 and reduce the risk of undetected leaks (§§195.263 and 195.429).

- Prescribing requirements for hydrostatic pressure testing as an additional measure to verify the structural integrity of pipelines (§195.309).

In addition to the above steps, the proposed regulations include the following:

- Newly identified High-Consequence Areas (HCAs) in integrity management (IM) and public awareness programs.

- Conduct risk analyses to identify preventive and mitigative measures for enhancing public safety and environmental protection.

- Evaluate the impact of constituents like hydrogen sulfide (H_2S), water (H_2O), and other impurities in CO_2 streams, as these can lead to internal corrosion and present additional hazards.

- Develop a monitoring and mitigation program (i.e., § 195.579) that includes monitoring constituents within the CO_2 product stream that affect corrosion, such as microbial activity.

- Identify areas prone to large earth movements, develop plans for site-specific hazards, and monitor changing weather patterns to ensure pipeline safety.

In general, recommended practices (RPs) have been developed to guide the safe and reliable design, construction, and operation of pipelines intended for hazardous liquids, but no “RP” has been published directly for CO_2 pipelines. However, some existing and recognized pipeline standards exist, such as ISO 13623, DNV-RP-F104, and ASME B31.4 (Johnsen et al., 2011) and the API RP 11CO_2 which is expected but not finalized or published yet.

Holistically, in developing a comprehensive strategy for the safe operation of CO_2 transport pipelines, several critical factors must be addressed. Firstly, an emergency response plan and corresponding procedures should be outlined to manage any unforeseen incidents swiftly and effectively. Secondly, safety considerations concerning pipeline depressurization are paramount, requiring careful planning to mitigate risks associated with pressure fluctuations. Thirdly, robust protocols for pipeline inspection and repair must be established to ensure ongoing safety and reliability. These procedures are informed by industry standards such as DNV-RPF116, which defines operational controls and procedures essential for maintaining operational integrity. Additionally, managing the ramp-up and ramp-down of transmission rates is crucial to optimizing efficiency while ensuring consistent and safe transport operations. Integrating these elements ensures a comprehensive approach to managing safety and operational challenges throughout the lifecycle of CO_2 transport pipelines (Veritas, 2010; AIChE, 2024).

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