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Offshore CO_2 storage is a risky business

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Key findings

The injection and geologic storage components of CCS pose numerous risks, which are either being underestimated or completely ignored by the industry as it looks to sell the technology.

Industry and CCS advocates see offshore storage as offering favorable geologic conditions, proximity to carbon dioxide emitters, and simplified pathways to obtaining pipeline and well permits.

Without real-world, commercial-scale examples of geologic carbon storage operating over long periods, it is difficult to properly assess either the likelihood or severity of potential problems.

The likelihood of leaks and the lack of effective mitigation options call into question the climate-sparing argument made by CCS advocates, and also raises important questions about the financial implications of CO_2 containment failure.

Executive summary

Oil and gas companies, led by ExxonMobil, Repsol, and Chevron, have leased large tracts in the Gulf of Mexico for carbon capture and storage (CCS). Industry and CCS advocates see offshore storage as offering favorable geologic conditions, proximity to carbon dioxide (CO_2) emitters, and simplified pathways to obtaining pipeline and well permits. The comparative ease of working with state and federal landowners rather than a complex quilt of property owners and communities is an especially attractive proposition. Even with higher offshore costs, companies expect to realize savings as projects can be implemented more quickly.[1]

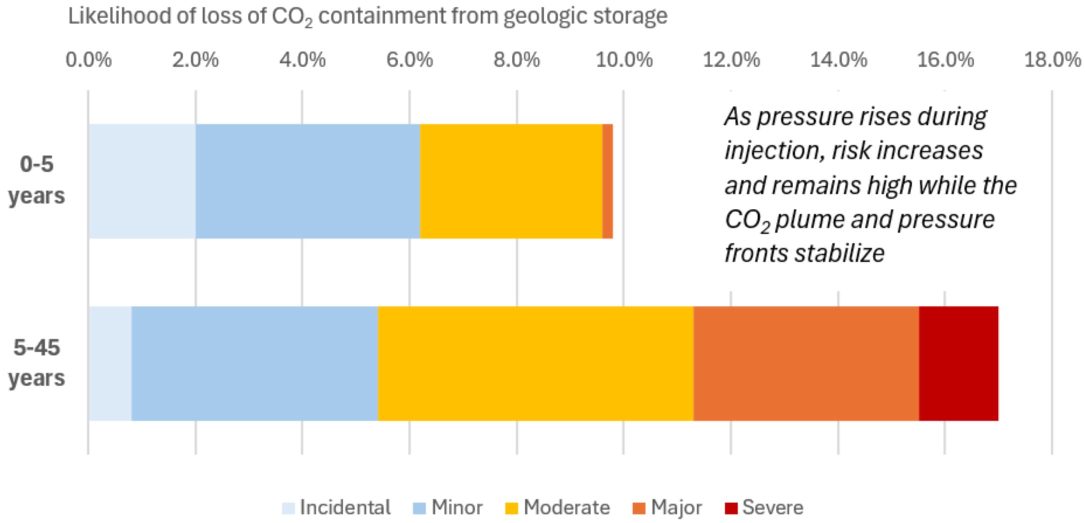
CO_2 injection and geologic storage are technologically complex processes that require highly specialized materials and operations. Those differ significantly from the oil and gas industry's touting of success in onshore enhanced oil recovery (EOR), which has centered on transporting CO_2 from natural sources and natural gas processing for injection into existing wells to force more oil out of the ground.

Our detailed review of the injection and geologic storage components of CCS highlights numerous risks. These are either being underestimated or completely ignored by the industry as it looks to sell the technology. For example:

- The regulatory environment around offshore geologic carbon storage is under development, untested, or undergoing significant changes in the U.S. It is subject to uncertainty that can impair access to financing and increase exposure to liability;
- The lack of long-term storage data for commercial-scale projects operating under real-world conditions;
- Operational challenges, particularly during the CO_2 injection and plume stabilization periods, could result in leaks that are more difficult to detect, manage, and mitigate in an offshore project; and
- Potential for leakage higher than anticipated from the storage reservoir calls into question the logic of CCS as a climate solution and presents a risk of long-term liability.

[1] IEEFA. Out of sight, out of mind: Pushing carbon storage offshore. March 2026.

Figure 1: CO_2 loss from geologic storage is most likely during injection and stabilization



Source: Adapted by IEEFA from Geoenergy.

Strong regulations and meaningful oversight for offshore CO_2 geologic storage are absent in the U.S.

The long-term geologic storage of carbon dioxide, without the aim of forcing more oil and gas out of the ground, is an emerging industry, using new technology, with few operational projects in the U.S. Permits and operation of CO_2 injection wells for storage are regulated under the Underground Injection Control (UIC) program for Class VI wells, which is administered by the Environmental Protection Agency (EPA) or the six states where primacy has been approved. EPA and states operate the UIC Class VI well program under the Clean Water Act and are required to ensure that identified underground sources of drinking water (USDWs) are protected.[2]

However, neither the EPA nor any state has substantial, long-term experience permitting and overseeing the operation of onshore or offshore Class VI wells. This is a new well category created specifically because of the unique properties and operational challenges of permanently storing CO_2 thousands of feet underground, and the regulatory environment is untested. By the end of the first quarter of 2026, only five projects with active CO_2 injection were reported at Class VI wells with a total capacity of about 5 million metric tons of CO_2 per year. Combined, the EPA and states have 387 Class VI well permit applications under review.[3] If even a fraction of these applications are approved, the upcoming regulatory burden is concerning, given the leakage problems at the first operational commercial-scale U.S. CO_2 sequestration project in

[2] EPA. Protecting Underground Sources of Drinking Water from Underground Injection (UIC). Accessed June 2026.
[3] Enverus. Class VI approvals build, submissions slow. June 2026.

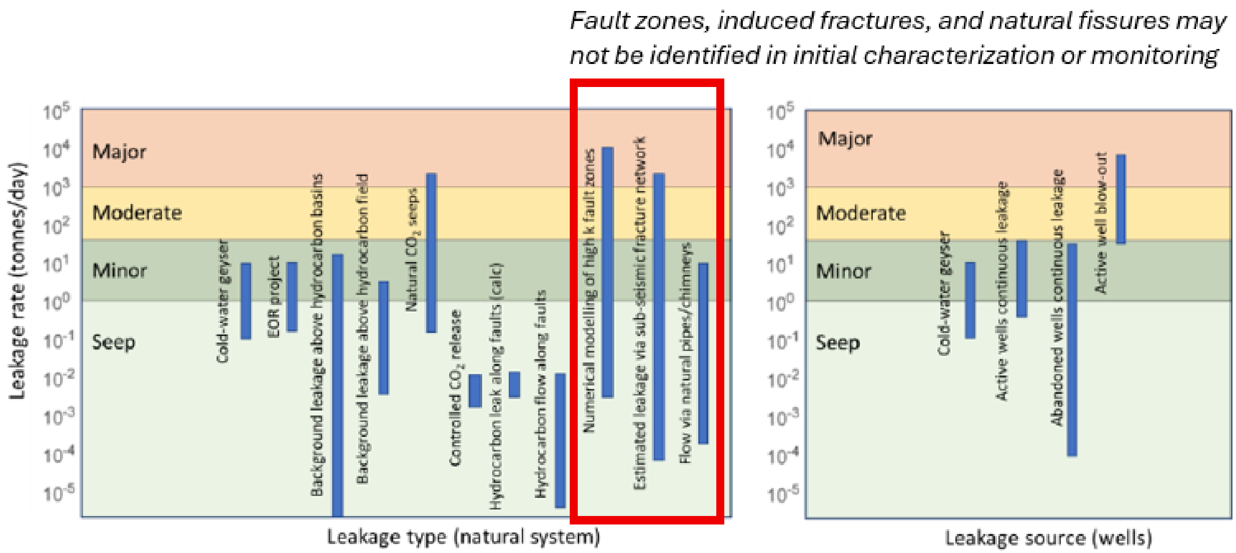
Decatur, Ill., operated by Archer-Daniels- Midland (ADM), which occurred only seven years after wells were drilled.[4,5]

While key assessments assume a slight likelihood and low severity of CO_2 leaks from geologic storage, a strong regulatory environment is key to minimizing risk. A 2025 report from the International Energy Agency Greenhouse Gas Research and Development Program (IEAGHG) evaluated the risks and likelihood of CO_2 leakage from geological storage that would be sufficient to reach or approach the surface.[6] The report relies on data from a 2023 report from the UK's Department for Business, Energy, and Industrial Strategy (BEIS) that examined the potential for loss of CO_2 containment from deep geologic storage in the UK's continental shelf.[7] The report found that the risk of reservoir failure was small. But this finding assumed a high degree of sensitivity and government oversight of geologic storage sites. Similarly, the report found that leakage rates were likely to be low due to strong government oversight and regulation that would ensure leaks were detected and addressed as quickly as possible. BEIS added that leaks would likely be much larger without carefully chosen and managed site selection, leak detection, and mitigation.[8]

U.S. regulatory oversight may not be ready for the task. In the U.S., the EPA and states issue permits and regulate against loss of containment. Loss of containment under EPA rules means that CO_2 or CO_2-containing brine moves out of its expected target reservoir and is no longer blocked from an identified U.S. drinking water aquifer by an impermeable layer approved under the permit. EPA regulations are not based on CO_2 releases to the surface.[9] In the U.S. context, BEIS figures should be considered very conservative estimates since it is much more likely that CO_2 could escape confinement without reaching the surface. Even so, the BEIS report highlights leakage along fault zones, induced fractures, and natural fissures with a wide range of potential leakage rates that could account for some of the largest losses (See Figure 2).

[4] E&E News. First US CO_2 injection well violates permit — EPA. September 2024.
[5] E&E News. ADM pauses Illinois carbon injection as it probes second leak. October 2024.
[6] IEAGHG. Reviewing the implications of unlikely but potential CO2 migration to the surface or shallow subsurface. January 2025.
[7] UK Department for Business, Energy & Industrial Strategy. Deep geological storage of carbon dioxide (CO2), offshore UK: containment certainty. February 2023.
[8] UK Department of Business, Energy, and Industrial Strategy. Deep Geological Storage of CO2 on the UK Continental Shelf: Containment Certainty Supplementary Note B: Geological Leakage Risks. January 2023.
[9] EPA. Geologic Sequestration of Carbon Dioxide in Deep Saline Formations: Report to Congress. January 2025.

Figure 2: Unidentified or induced geologic anomalies could result in major leaks



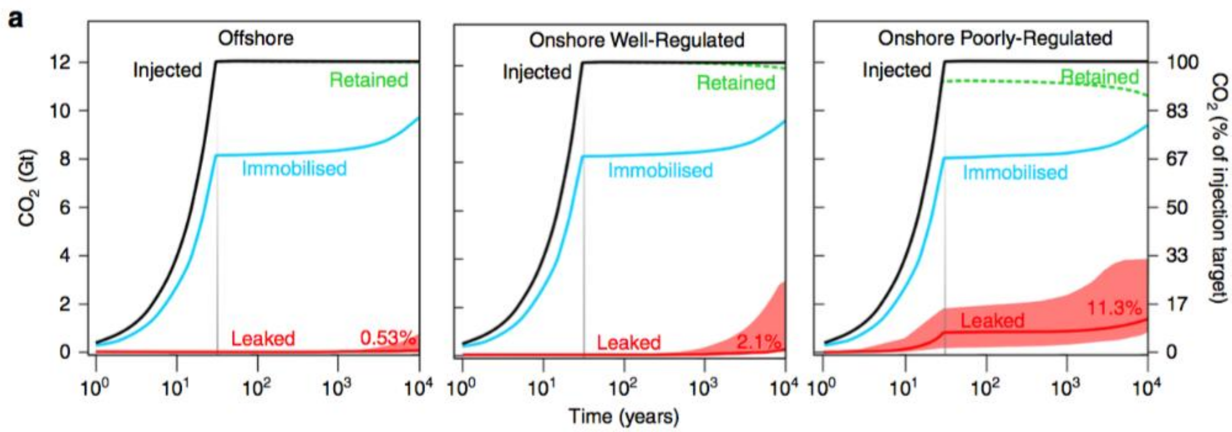
Source: IEAGHG, annotated by IEEFA.

Strong regulation of geologic storage of CO_2 can significantly reduce risks. For example, a 2021 analysis of potential leakage in onshore and offshore sites found significant differences between well-regulated and poorly regulated scenarios. While the study included an offshore well-regulated scenario, the authors did not model a poorly regulated offshore scenario. Even without this component included in the study, it is useful to compare the leakage estimates and timeframes for the well-regulated and poorly regulated onshore scenarios.

Figure 3 shows estimates of leakage rates under a "base case" (solid red line) representing industry expert input, along with a red-shaded buffer indicating the range of leakage rates reported by the experimental model runs. The onshore poorly regulated scenario shows as much as 5% of the CO_2 injection could be lost after 10 years, rising to about 17% after 50 years, and as high as 33% after 10,000 years.[10] These leakage rates are based on total target CO_2 injection amounts, meaning the actual annual rate would be much higher. For instance, if 5% of the assumed total injected volume of 12 gigatonnes (Gt) leaks by the 10-year mark, this represents 600 million metric tons of CO_2 lost from containment over that period. If roughly 3.75 Gt had been injected after 10 years (based on an estimate from the charts in Figure 3), the 600 million metric tons represent a 16% loss.

[10] Nature Communications. Estimating geological CO_2 storage security to deliver on climate mitigation. June 2018.

Figure 3: Estimates of CO_2 leakage depending on regulatory regime



Source: Nature Communications.

The U.S. regulatory environment for offshore CCS is undeveloped. Carbon storage in state waters is administered by the EPA or the state if it has primacy over the Class VI wells. There are no commercial-scale geologic storage projects operating offshore in the U.S.

CCS regulations for federal waters do not currently exist. Draft rules from the Interior Department's Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) were expected in May 2026, but had not been released by late June. This rulemaking was included in the administration's spring 2026 Unified Agenda and remains on it, though the date for the notice for proposed rulemaking (NPRM) has passed.[11] It has not been rescheduled, nor has it been cancelled outright, leaving companies in limbo.

ExxonMobil recently announced it will not renew its leases in federal waters in the Gulf of Mexico, originally acquired in 2021 and 2023, that were intended for CCS activities.[12] But this does not indicate a major shift in the company's large-scale CO_2 storage ambitions in the offshore, as it maintains large leases in Texas state waters. There are simply no regulations in place or on the near horizon that would govern the company's efforts to develop CCS projects and meet BOEM's requirement for an operating plan within the first five years of a new lease. Without an agency-approved operating plan, it is difficult for companies to extend leases.[13] Repsol also holds leases for large areas in federal waters but has not made an announcement about its intent to drop them.

The April 2026 announcement of a plan to reunify BOEM and BSEE into the Marine Minerals Administration (MMA) would take place on the heels of dramatic workforce reductions at both agencies and would likely result in an entity with a greater emphasis on leasing activities.[14]

[11] Office of Management and Budget. Spring 2025 Unified Agenda of Regulatory and Deregulatory Actions. Accessed July 1, 2026
[12] Energy Intelligence. Exxon Drops US Gulf Leases as Interior Shelves CCS Rules. June 2026.
[13] Code of Federal Regulations. 30 CFR 585.235. Accessed July 1, 2026.
[14] E&E News. Shrunken offshore energy regulator faces an outsize challenge. April 2026.

Critics of the planned merger of these agencies highlight the potential for conflict within a single agency that would be responsible for both leasing and oversight.[15,16] The agencies were originally separated as a result of an investigation after the massive 2010 BP Deepwater Horizon oil spill in the Gulf of Mexico.[17] Under the current U.S. administration, there has been a broad shift towards allowing industry to self-regulate. While this may accelerate construction and the start of operations, the weaker regulatory environment may be viewed as too risky for investors and insurers.

Operators must provide post-injection site care (PISC) for 50 years or as approved by the UIC program director.[18] The long-term management, monitoring, and liability for these operations remain with the operator unless legislation allows the state to assume those responsibilities and risks sooner. There is a tension between the EPA's approach of never assuming liability and that of many states willing to accept the liability for projects. Forcing operators to maintain ownership and liability for projects for hundreds of years is seen as a way to ensure they exercise the greatest care in their operations. Meanwhile, many states would like to encourage more CCS projects by taking on long-term stewardship to reduce project risks.[19] There are also states that could take on long-term care as soon as possible to gain more control over outcomes that might be difficult if operators simply walk away from long-term obligations, as has happened with abandoned oil and gas wells.[20]

[15] NRDC. Interior Department Plans to Recombine Offshore Agencies Split After Deepwater Horizon Disaster. April 2026.
[16] E&E News. Lawmakers greet remarriage of offshore energy agencies with concern, shrugs. April 2026.
[17] BOEM. Regulatory Reforms. Accessed May 2026.
[18] EPA. Geologic Sequestration of Carbon Dioxide Underground Injection Control (UIC) Program Class VI Well Plugging, Post Injection Site Care, and Site Closure Guidance. December 2016.
[19] McGuireWoods. EPA, States Differ on Approach to Carbon Capture and Storage Facility Liability. July 26, 2024.
[20] New Mexico Energy, Minerals, and Natural Resources Department. Agency Bill Analysis (HB458). February 2025.

How can risks of geologic storage be estimated?

Typical risk analyses for offshore oil and gas projects rely on decades of operational data.[21] However, CO_2 leakage risk studies from both onshore and offshore geologic storage lack real-world data. For offshore projects, researchers typically use information from onshore and offshore oil and gas well failures. Researchers point out challenges in using these datasets to predict the likelihood of leaks from injection, monitoring, and abandoned wells, as well as leakage from geologic reservoirs. Key problems include:

- Impact of the regulatory environment on wells included in the study;
- Assumptions that CO_2 wells will improve technologically in the future;
- Oil and gas well data that often report failures rather than leaked amounts;
- A mixed bag of wells by age and type that may skew outcomes;
- Geologic storage data from published reports based on modeling; and
- Approximate storage reservoir analogues such as those for natural gas and naturally occurring CO_2 deposits.[22]

Without real-world, commercial-scale examples of geologic carbon storage operating over long periods, it is difficult to properly assess either the likelihood or severity of potential problems.

Site characterization plays an essential role in determining whether a project should move forward and is considered the primary means of minimizing its risk of leaking. A study commissioned by BOEM to propose best management practices for offshore carbon storage outlines the recommended components of site selection and characterization. The main component is seismic data, which is collected and processed using sophisticated models to create a detailed understanding of the subsurface region of interest.[23] Often, limitations in data collection and modeling parameters prevent detection of smaller fissures or faults, especially if the target formation comprises multiple rock types.[24] Methods for improving modeling continue to evolve, but development is limited by the small number of storage sites in use and their substantial variability.

[21] BSEE. Probabilistic Risk Assessment: Applications for the Oil & Gas Industry. May 2017.
[22] UK Department of Business, Energy, and Industrial Strategy. Deep Geological Storage of CO2 on the UK Continental Shelf: Containment Certainty. January 2023.
[23] BOEM. Best Management Practices for Offshore Transportation and Sub-Seabed Geologic Storage of Carbon Dioxide. December 2017.
[24] iScience. De-risking fault leakage risk and containment integrity for subsurface storage applications. May 2024.

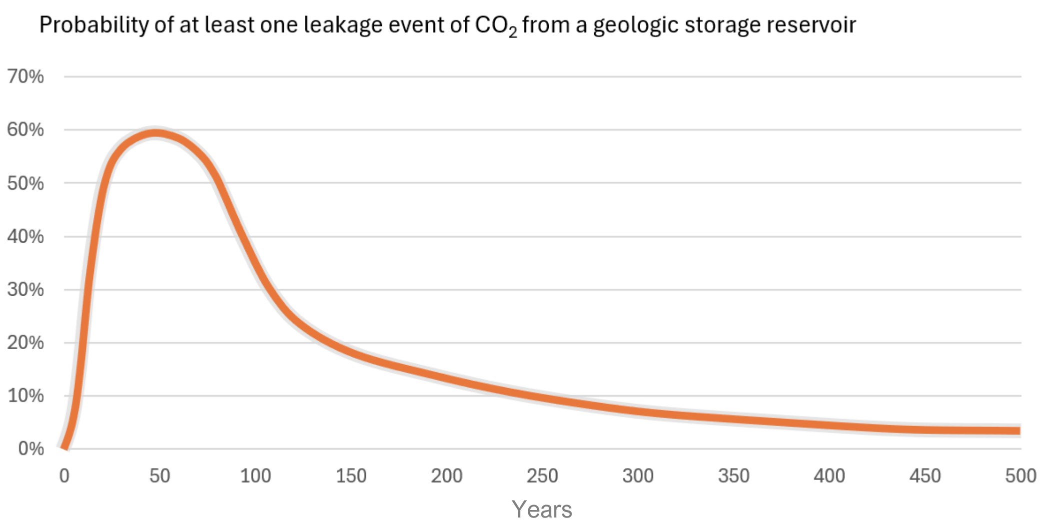
What could go wrong?

Loss of CO_2 containment at the storage site is most likely to occur during the injection and plume stabilization periods that typically extend for 25 to 50 years.

During injection, there are risks from acute issues such as caprock fracture, unexpected plume migration, and unanticipated pressure issues or geologic conditions. As injection proceeds and more CO_2 is stored, long-term problems such as corrosion of steel well casing and cement bonds begin to emerge. Similarly, as CO_2 and pressure plumes expand during injection and stabilization, incorrectly characterized fissures or faults may serve as conduits for leaks.[25] Small seismic events caused by well drilling and CO_2 injection have been shown to expand existing fractures or create new ones, leading to a loss of containment, as has been documented in EOR operations.[26]

Once the injection stops, a gradual process equalizes pressure in the storage reservoir. Pressure equalization takes much longer in saline reservoirs than in depleted hydrocarbon reservoirs. It remains a high-risk period for loss of containment as the CO_2 and pressure plumes continue to shift and expand. Figure 4 shows the annual probability of a leak of CO_2 from geologic storage in a hypothetical offshore storage project with an injection period of 20 years. The study found more than a 50% chance of a leak occurring when the project was 20 to 90 years old.[27]

Figure 4: Risk of CO_2 leaks from geologic storage are highest in first 100 years



Source: Adapted by IEEFA from Geoenergy.

[25] Geoenergy. Long-term risk assessment of subsurface carbon storage: analogues, workflows and quantification. May 2024.
[26] Clean Water Action. The Environmental Risks and Oversight of Enhanced Oil Recovery in the United States. August 2017.
[27] Geoenergy. Long-term risk assessment of subsurface carbon storage: analogues, workflows and quantification. May 2024.

Will the CO_2 permanently remain in the target reservoir?

The likelihood and potential severity of a CO_2 containment leak from a geologic storage reservoir is difficult to assess, as there are few operational carbon storage projects. But the likelihood is far from zero, and the impact could be serious.

The duration of the at-risk period is a key problem with CO_2 storage project risk assessment. The storage component requires predicting future risk over 25 to 50 years during the injection and stabilization periods and then for hundreds of years post-injection. In contrast, typical oil and gas projects focus on known risks during the initial phases of project operations and encompass much shorter time scales. Further, risk-benefit calculations for oil and gas projects are informed by the sector's long operating history. There is no such track record to draw on for CO_2 storage projects. Rather, CO_2 project risk analysis is a new area, with longer timeframes, little current data, and no data on long-term storage—all of which increase uncertainty.

Table 1 characterizes the severity of potential leaks from the storage reservoir by type and duration for geologic sources.[28] A key feature of the table is that moderate and major leaks would be identified within five years, depending on the seismic survey's periodicity, unless the leak was large enough to cause CO_2 to bubble to the surface. But in either case, the leak could be assumed to continue for 25 years, because there is no way for an operator to repair geologic storage reservoirs. The only real options available to operators are to stop injection to halt pressure increases and to extract brine to relieve pressure. Unabated leaks larger than seeps will continue to lose CO_2 until the pressure inside the reservoir equals the outside pressure, which could take decades. Even a "moderate" leak, responsible for losses of as much as 500 metric tons per day, could result in the release of 4.6 million metric tons of CO_2 over 25 years.

[28] UK Department of Business, Energy, and Industrial Strategy. Deep Geological Storage of CO2 on the UK Continental Shelf: Containment Certainty Supplementary Note B: Geological Leakage Risks. January 2023.

Table 1: Geologic storage worst-case leak assumptions

Leak rate (t/d) and category	Leak duration (years)	Pathway	Assumptions for reasonable worst-case scenario
Less than 1 Seep	Continuous once begun, 100 years	Any	Leak rate is stable and unlikely to increase, no safety or environmental impact and potentially higher risk to remediate.
1 – 50 Minor	100 years	Via an existing pathway (e.g. a non-sealing fault or fracture network or gas chimney) or lateral migration beyond the complex.	Cannot be remedied by revising injection strategy + decision taken to continue injection. (In reality, leak might be shorter-lived, and/or site could close prematurely.)
50 – 1000 Moderate *And* Greater than 1000 Major	25 years	Via existing large faults that extend over hundreds of metres (or major tectonically/volcanically active fault zone which do not occur in the UK)	Leak will be visible within 5 years on seismic survey (or at next seabed survey if leak to surface), injection stopped and site closed, a proportion of the CO_2 that was injected in the 5 years since leak began until identified would leak out until stabilised. Brine management might be considered.

Source: BEIS 2023, p. 48 (Note that the chart refers to UK offshore CO_2 storage regulations).

Industry often frames the risk of loss of containment as an average annual risk, which is very low. However, projects with timeframes spanning hundreds of years should be evaluated based on cumulative leakage risk. If this is done, the probability of containment loss rises from the level of "unlikely" with an average annual chance of a leakage event of 0.1% to "almost certain" over a period of 1,000 years.[29]

Figure 5: High probability of CO_2 leakage from geologic storage projects that span hundreds of years

Increasing Annual Event Rate

KEY
>10%
1% - 10%
<1%

Increasing Time

	Case 4	Case 3	Case 2	Case 1
Descriptive Risk Terms	*Highly Improbable*	*Very Unlikely*	*Unlikely*	*Possible*
Chance of an Event Per Year	0.001%	0.010%	0.100%	1.000%
Chance of No Events Per Year	99.999%	99.990%	99.900%	99.000%
Chance of One or More Events				
in 5 Years	0.01%	0.05%	0.56%	4.86%
in 10 Years	0.02%	0.11%	1.04%	9.63%
in 25 Years	0.03%	0.26%	2.45%	22.19%
in 50 Years	0.06%	0.50%	4.77%	39.64%
in 100 Years	0.11%	1.02%	9.54%	63.61%
in 250 Years	0.25%	2.53%	22.18%	91.82%
in 500 Years	0.49%	4.94%	39.35%	99.32%
in 1000 Years	0.96%	9.56%	63.20%	100.00%
Descriptive Risk Terms: 1000 Year Outcomes	*Possible*	*Highly Probable*	*Almost Certain*	*Certain*

Source: Geoenergy 2024.

Once the CO_2 and pressure plumes have stabilized, leaks are still possible. Exposure of well plugs, cement, and casing to CO_2-containing brine can lead to corrosion and leaks. This includes injection and monitoring wells introduced by the project, as well as abandoned wells within the area of reference. But leaks can also occur due to geologic features, such as fissures and faults that were insufficiently characterized or not identified at all during site selection, or that were created by the CO_2 storage project itself. New drilling or injection activities can also threaten the security of storage, with many states (e.g., Texas and West Virginia)[30,31] allowing drill-through rights of CO_2 reservoirs. Figure 6 shows the range of other oil and gas industry operations that could occur at depths overlapping with CO_2 storage, increasing the risk of disrupting the storage reservoir due to drill-through or activities in adjacent pore space. [32]

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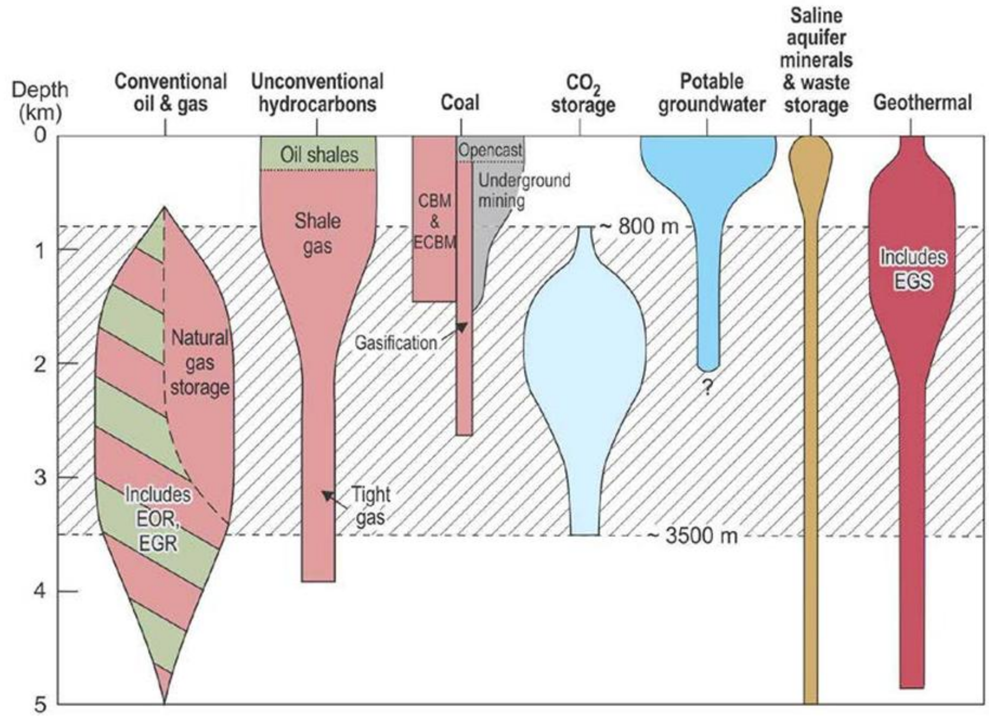
[29] Geoenergy. Long-term risk assessment of subsurface carbon storage: analogues, workflows and quantification. May 2024.
[30] Husch Blackwell. Mineral Rights and 45Q Recapture: An Overlooked Legal Risk in Texas Carbon Capture and Storage Projects. June 2026.
[31] West Virginia Code. Chapter 22. Environmental Resources § 22-11B-9. Oil, natural gas and coalbed methane activities at carbon dioxide sequestration sites; extraction of sequestered carbon dioxide. Current as of January 1, 2024.
[32] IEAGHG. Interaction of CO_2 Storage with Subsurface Resources. April 2013.

Figure 6: Potential overlap of oil and gas operations with CO_2 storage



Source: IEAGHG.

If the CO_2 is unmineralized, it can migrate or be lost from a storage reservoir. But this mineralization occurs over geologic time and can take thousands of years. After 1,000 years, this fixed and stable form of stored CO_2 may account for roughly 10% of the material stored in saline formations and less than 5% of the material stored in a depleted gas reservoir.[33] During this long-term storage phase, the risk of loss of containment persists due to ongoing chemical reactions that degrade wells, effects from other subsurface exploration or extraction activity, or unexpected geologic events.

Conclusion

Permanent geologic storage of CO_2 is an untested idea that is difficult to prove on human timescales. Leakage risks exist throughout the storage period and are most likely to occur during injection and initial plume stabilization. Wells and unidentified or induced geologic fissures are the most likely pathways for CO_2 migration from the target reservoir. Leaks can be small or catastrophic, and there are few methods available to operators to mitigate such problems. While some leaks can be addressed directly with actions such as well-casing repair,

[33] Geosciences. Carbon Dioxide Capture and Storage (CCS) in Saline Aquifers versus Depleted Gas Fields. June 2024.

others will continue to release CO_2 until pressure equalizes and the leak stops on its own. This process could take decades, while substantial amounts of the injected CO_2 are lost.

The likelihood of leaks and the lack of effective mitigation options call into question the climate-sparing argument made by CCS advocates. It also raises important questions about the financial implications of CO_2 containment failure. In the U.S., the 45Q credit for carbon capture is awarded to companies that capture CO_2 and store it in "secure geologic storage."[34] Companies that capture CO_2 can either manage its disposal or pay for it. This raises complex problems regarding the potential for loss and claw-back of awarded credits.

[34] IRS. Section § 1.45q-3 - Secure Geological Storage. April 2024.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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