

Editorial

Assurance of wellbore integrity in the context of geological CO₂ utilization and storage

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Abstract:

Wellbore integrity is a critical prerequisite for the safe and long-term performance of geological CO₂ utilization and storage projects. The wellbore system-comprising tubing, packers, subsurface safety valves, casing, cement sheath, and their interfaces-acts as the key engineered barrier preventing upward CO₂ and brine migration from the storage reservoir to overlying aquifers and the atmosphere. This editorial discusses the two core factors threatening wellbore integrity in CO₂-rich downhole environments: chemical corrosion and mechanical failure. Key research questions and challenges related to chemical corrosion and mechanical failure are discussed. Finally, future research directions to ensure the maintenance of wellbore integrity are identified, including reliable tools for long-term wellbore durability prediction under coupled thermo-hydro-mechanical-chemical conditions, the development of self-healing tubing, casing and cement materials, and the standardization of well integrity evaluation and monitoring protocols.

1. Introduction

Geological CO₂ utilization and storage (GCUS)-a process that involves using CO₂ to improve resource recovery from subsurface formations or permanently storing it in deep saline aquifers, depleted oil and gas reservoirs, unmineable coal seams, and other geological formations-is widely regarded as one of the most viable large-scale strategies for mitigating anthropogenic CO₂ emissions. Among all surface and subsurface components of a GCUS project, the wellbore-comprising the tubing, casing strings, cement sheaths, and their interfaces-serves as the primary engineered barrier between the stored CO₂ and the overlying potable groundwater, atmosphere, and ecosystems. Wellbore integrity refers to the application of technical, operational and organizational solutions to reduce

risk of uncontrolled release of formation fluids throughout the life cycle of a well. The impairment of wellbore integrity is a big threat to the safety of GCUS projects. Historical data from CO₂-enhanced oil recovery (CO₂-EOR) operations indicate that wellbores with compromised integrity-manifested as casing damage, sustained casing pressure (annulus pressure buildup), formation of micro-annuli at cement-casing or cement-caprock interfaces, cement degradation, etc.-are among the most likely pathways for CO₂ or brine migration out of the target storage formation (Iyer et al., 2022). Such leakage not only reduces storage efficiency and compromises climate benefits but also poses risks of groundwater contamination and surface CO₂ release. In summary, ensuring long-term wellbore integrity under CO₂-rich, high-pressure, and high-temperature downhole environments in GCUS projects is a cornerstone

requirement for the technical feasibility, economic viability, and public acceptance of GCUS.

2. Two core factors impairing wellbore integrity

2.1 Chemical corrosion by CO₂

When injected CO₂ encounters formation water, it dissolves in water to form carbonic acid (H₂CO₃), which lowers the pH of the formation water to 2.5-6 depending on pressure, temperature, dissolved ions in formation water, and minerals in the formation. This acidic environment triggers several corrosive processes:

Tubing and casing corrosion: Carbon steel (e.g., J55, N80, P110) tubing and casing are susceptible to CO₂ corrosion. The anodic iron dissolution coupled with cathodic hydrogen generation leads to a loss of iron from the surface of tubing and casing, and the formation of a FeCO₃ film (Ding et al., 2025). A uniform and dense FeCO₃ scale can prevent further CO₂ corrosion of the tubing and casing. However, unfavorable conditions—such as high flow velocities, elevated CO₂ partial pressures, or the presence of O₂ and H₂S—can destabilize the FeCO₃ film, leading to severe localized corrosion of the tubing and casing (Xiang et al., 2017).

Cement sheath degradation: Conventional Class G cement is vulnerable to CO₂ attack. CO₂-bearing brine penetrates the cement matrix, reacting with calcium hydroxide and calcium silicate hydrate in cement to form calcium carbonate and amorphous silica (Kutchko et al., 2007). Continued influx of H⁺ partially dissolves the calcium carbonate layer and leaches calcium from the calcium carbonate layer and the cement matrix, transforming the original cement into a porous and friable material with drastically reduced compressive strength and increased permeability (Rasool et al., 2026). This process creates preferential pathways for CO₂ migration within cement or along the cement-casing/cement-caprock interfaces.

Packer damage: In GCUS operations, wellbore packers face severe degradation risks when exposed to high concentrations of CO₂ (Iyer et al., 2022). Packers are critical for maintaining zonal isolation, but the harsh CO₂ environment can damage both the elastomeric seals and the metallic components of the assembly. When CO₂ permeates the polymer matrix of elastomeric seals, it causes significant swelling, plasticization, and a loss of mechanical strength. Furthermore, the acidic environment initiates localized pitting and weight-loss corrosion on the packer's metallic slips, mandrels, and casing contact points, similar to the destabilization of protective FeCO₃ films seen in tubing and casing.

2.2 Mechanical failure

Mechanical failure arises from the coupled thermo-hydro-mechanical-chemical loads to the wellbore system during CO₂ injection and subsequent storage. Typical failure modes include mechanical failure of the casing and mechanical failure of the cement sheath. Mechanical failure of the casing primarily manifests as shear failure, tensile failure, and fatigue failure (Eissa et al., 2025). Shear failure occurs because CO₂ injection increases pore pressure in the reservoir, reducing the effective normal stress and thereby generating shear dis-

placement that deforms the casing. Tensile failure originates from the development of a micro-annulus along the interface between the casing and the surrounding cement sheath. The formation of this micro-annulus compromises the mechanical constraint that the cement sheath normally provides to the casing, causing tensile failure. Fatigue failure is caused by cyclic temperature or pressure variations along the wellbore during CO₂ injection and shut-in processes. During injection phases, the casing experiences elevated pressures and cooling effects, while shut-in periods introduce pressure decline and thermal recovery, creating continuous stress reversals within the casing. These fluctuating stresses initiate microscopic cracks at stress concentration points of the casing, such as thread connections or material defects. For the cement sheath, typical failure modes are listed below (Iyer et al., 2022). First, debonding of the cement sheath can occur at two distinct interfaces. At the cement sheath-casing interface, debonding is caused by incompatible deformation arising from differences in thermal properties between steel and cement. For instance, when compressed CO₂ is injected at low temperatures, the casing contracts more rapidly than the cement, creating microgaps at the interface (Yang et al., 2024). At the cement sheath-caprock interface, debonding is attributed to mechanical and chemical interactions between cement and formation rocks. Second, radial cracking occurs when the hoop stress exceeds the tensile strength of the cement sheath. Third, shear failure occurs along planes of maximum shear stress in the cement sheath when the stress state in the cement exceeds its shear strength envelope.

3. Key research questions and challenges

Given the dual threats of chemical corrosion and mechanical failure to well integrity, safeguarding wellbore integrity in GCUS projects requires a deep understanding and continuous exploration of key research questions related to chemical corrosion and mechanical failure.

First, there is an urgent need to establish a process-based model that quantitatively links chemical corrosion with mechanical failure. Such a model should capture the coupled evolution of porosity, permeability, mechanical properties, and mineral composition over time under CO₂ exposure. Specifically, it must account for mineral dissolution and precipitation reactions that alter pore structure, the resulting changes in fluid transport pathways, and the progressive degradation of elastic modulus and tensile strength. By integrating reactive transport simulations with mechanical constitutive laws, the model can predict how chemically induced weakening translates into crack initiation, interfacial debonding, and ultimately loss of sealing integrity under evolving downhole stress conditions.

Second, understanding how CO₂ alteration of casing, cement, and caprock affects the permeability of the cement sheath-casing and cement sheath-caprock interfaces is of critical importance. Previous studies have reported conflicting findings regarding permeability evolution at these interfaces (Newell and Carey, 2013; Shi et al., 2025). These discrepancies arise from variations in reaction conditions, cement composition, and curing time, as well as differences in hy-

draulic residence time and interface aperture. In short, a comprehensive framework that accounts for all relevant parameters remains absent.

Third, most experimental data on cement carbonation and steel corrosion are obtained over weeks to months under laboratory-mimicked GCUS conditions (Rasool et al., 2026), and the reaction duration is too short for long-term well integrity evaluation. Long-term experimental data of CO₂-induced tubing, casing, and cement degradation (i.e., CO₂ reaction time longer than 1 year) under realistic downhole conditions-including elevated temperature, pressure, and cyclic injection operations-are critically lacking. These data are essential for calibrating and validating predictive CO₂ corrosion models.

Fourth, a comprehensive framework is needed to achieve optimized CO₂ injection operations, which must account for thermal management during CO₂ injection through careful control of the injection rate. Furthermore, this framework needs to provide a design guide for centralization, because ensuring casing centralization prior to cementing promotes uniform cement placement, minimizes channeling, and enhances interfacial bonding. Last but not least, this framework needs to provide a design guide to achieve the compatibility of casing and cement with downhole well monitoring instruments such as pressure gauges, temperature sensors, and strain sensors.

4. Future prospects

Given the aforementioned research questions and challenges, key future research directions for wellbore integrity research in GCUS are proposed.

First, development of a coupled wellbore durability prediction model for long-term well integrity evaluation. Validated, multi-scale thermo-hydro-mechanical-chemical coupled models need to be developed to extrapolate laboratory results to decadal-centennial timescales under realistic downhole conditions. Also, the accuracy of the model needs to be validated by long-term experimental data of CO₂-induced tubing, casing, and cement degradation under realistic downhole conditions.

Second, assessment of impairment risk of legacy wells with weak integrity. The CO₂ storage formations of many GCUS projects pass through or be located near legacy wells drilled decades ago, and those wells were not designed for acidic CO₂ exposure. The presence of such legacy wells elevates the importance of understanding, evaluating, and remediating wellbore integrity risks of such wells. Also, systematic regional-scale assessment of the integrity status of legacy wells needs to be conducted in an urgent manner.

Third, development of tubing, casing, and cementing materials with self-healing capacity that can minimize CO₂-induced well integrity loss. Emerging research should focus on self-repairing smart alloys for tubing and casing manufacture, polymer-cement and clay-cement composites, and microcapsule-embedded self-healing cements. Those materials offer promising routes to autonomously seal micro-cracks induced by thermal cycling or CO₂ corrosion, and form super-stable protective layers on the surfaces of tubing and casing to minimize the effect of CO₂ corrosion.

Fourth, standardization and regulatory development to guide operations for well integrity assurance. Researchers, engineers, and decision makers in the field of wellbore integrity need to sit together to develop internationally harmonized testing and monitoring protocols specifically for GCUS wells, and develop globally accepted well integrity evaluation codes specific to CO₂ injection wells, monitoring wells, and abandoned wells, facilitating consistent design, approval, and long-term stewardship of GCUS sites.

Conflicts of interest

The authors declare no competing interest.

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