sustainability

MDPI

Review

A Review of Key Challenges and Evaluation of Well Integrity in CO_2 Storage: Insights from Texas Potential CCS Fields

Bassel Eissa [1,*], Marshall Watson [1], Nachiket Arbad [2], Hossein Emadi [1,*], Sugan Thiyagarajan [1], Abdel Rehman Baig [1], Abdulrahman Shahin [1] and Mahmoud Abdellatif [1]

[1] Bob L. Herd Department of Petroleum Engineering, Texas Tech University, 807 Boston Avenue, Lubbock, TX 79409, USA; marshall.watson@ttu.edu (M.W.); sugan-raj.thiyagarajan@ttu.edu (S.T.); abbaig@ttu.edu (A.R.B.); abshahin@ttu.edu (A.S.); mabdella@ttu.edu (M.A.)
[2] TRC Services of Texas, 2810 S County Road 1208, Midland, TX 79706, USA; narbad@trcsuckerrods.com
* Correspondence: beissa@ttu.edu (B.E.); h.emadibaladehi@ttu.edu (H.E.)

Abstract

Increasing concern over climate change has made Carbon Capture and Storage (CCS) an important tool. Operators use deep geologic reservoirs as a form of favorable geological storage for long-term CO_2 sequestration. However, the success of CCS hinges on the integrity of wells penetrating these formations, particularly legacy wells, which often exhibit significant uncertainties regarding cement tops in the annular space between the casing and formation, especially around or below the primary seal. Misalignment of cement plugs with the primary seal increases the risk of CO_2 migrating beyond the seal, potentially creating pathways for fluid flow into upper formations, including underground sources of drinking water (USDW). These wells may not be leaking but might fail to meet the legal requirements of some federal and state agencies such as the Environmental Protection Agency (EPA), Railroad Commission of Texas (RRC), California CalGEM, and Pennsylvania DEP. This review evaluates the impact of CO_2 exposure on cement and casing integrity including the fluid transport mechanisms, fracture behaviors, and operational stresses such as cyclic loading. Findings revealed that slow fluid circulation and confining pressure, primarily from overburden stress, promote self-sealing through mineral precipitation and elastic crack closure, enhancing well integrity. Sustained casing pressure can be a good indicator of well integrity status. While full-physics models provide accurate leakage prediction, surrogate models offer faster results as risk assessment tools. Comprehensive data collection on wellbore conditions, cement and casing properties, and environmental factors is essential to enhance predictive models, refine risk assessments, and develop effective remediation strategies for the long-term success of CCS projects.

Keywords: legacy wells; well integrity; sustained casing pressure; completion; carbon storage; self-sealing; casing corrosion; cement degradation

check for updates

Academic Editor: Luisa F. Cabeza

Received: 8 May 2025
Revised: 15 June 2025
Accepted: 20 June 2025
Published: 26 June 2025

Citation: Eissa, B.; Watson, M.; Arbad, N.; Emadi, H.; Thiyagarajan, S.; Baig, A.R.; Shahin, A.; Abdellatif, M. A Review of Key Challenges and Evaluation of Well Integrity in CO_2 Storage: Insights from Texas Potential CCS Fields. *Sustainability* **2025**, *17*, 5911. https://doi.org/10.3390/su17135911

Copyright: © 2025 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https://creativecommons.org/licenses/by/4.0/).

1. Introduction

As the global energy landscape shifts towards more sustainable practices, carbon capture and storage (CCS) has emerged as a critical strategy to mitigate greenhouse gas emissions [1,2]. Net emissions in the U.S. decreased from approximately 6800 million metric tons of CO_2 equivalent in the early 2000s to around 5500 million metric tons in 2022, showing a nearly 20% reduction since 2005 [3]. In 2024, there has been significant growth in CCS (Carbon Capture and Storage) projects, with 50 facilities now operational (3 focused

on transport and storage), and 44 more under construction (including 7 for transport and storage) [4]. By July 2024, the total number of CCS facilities reached 628, marking a 60% increase compared to the previous year [4].

Currently, the primary geological formations used for carbon storage globally include depleted oil and gas reservoirs, deep saline aquifers, unmineable coal seams, Basalt formations, salt caverns, and subsea storage sites [5–7]. Among these geological formations, depleted oil and gas reservoirs are a favorable option for CO_2 storage [8,9]. These reservoirs possess the key elements required for successful sequestration:

- A proven history of safely containing hydrocarbons for millions of years,
- A well-characterized geology, with data available on porosity, permeability, and caprock integrity, reducing the uncertainty associated with other storage options [10].
- The ability for existing infrastructures of wells and pipelines to be repurposed for CO_2 injection, with life extension analysis to ensure their suitability, making them a cost-effective choice [10,11].
- Lower pressure after hydrocarbon extraction, allowing for safe CO_2 injection without the risk of over-pressurization, leading to caprock failure or leakage through wellbores [8,9,12,13].
- Ease of monitoring due to proven caprock and existing wells [14].

Despite the advantages of CO_2 storage in depleted oil and gas reservoirs, there are specific selection criteria to ensure the feasibility of such projects. Storage site selection criteria for CO_2 can be categorized into four categories; see Table 1.

Table 1. Summarized reservoir screening factors and criteria for CO_2 storage reservoirs [15–18].

Category	Criteria/Property
Geological Factors	Reservoir Depth: 800–3000 m for CO_2 supercritical state
	Porosity and Permeability: High values for capacity and injectivity
	Caprock Integrity: Robust, impermeable seal to prevent CO_2 escape
	Trapping Mechanisms: Structural, stratigraphic, residual, solubility, mineral trapping
Technical Factors	Injectivity: Efficient injection without fracturing
	Storage Capacity: Adequate volume for projected CO_2 amounts
	Monitoring and Verification: Capability to track CO_2 plume and verify containment
Environmental Factors	Potential Leakage Pathways: Identification and mitigation of leakage risks
	Impact on Ecosystems: Assessment of risks to local ecosystems and biodiversity
Economic Factors	Proximity to CO_2 Sources: Shorter distances lower transportation costs
	Regulatory and Legal Framework: Adherence to applicable regulations
	Cost of Implementation: Overall economic viability and cost-effectiveness

This review focuses on environmental factors, specifically potential leakage pathways from legacy wells. The presence of legacy wells at the site, especially those penetrating the cap rock (seal) and the injection zone, may jeopardize the containment of the storage reservoir. The risk of leakage is a function of the density and age of those wells. Studies showed that wells drilled before 1950 pose a higher risk since there were no plugging standards at that time [13,19]. Also, the legacy wells' integrity may have been compromised due to casing corrosion or/and cement degradation, particularly when exposed to a corrosive environment [20].

Wellbore integrity aspects have been extensively studied over years. Starting from 1992, studies showed how cement sheath stress failure results in debonding and microannulus formation [21]. From 2007 to 2010, studies investigated the chemical reactions of carbonic

acid with portlandite cement, [22,23] and in 2013, reactive flow through the fractured cement was explored [24]. In 2016, all the three aspects (chemical reaction—mechanical stresses—Transport phenomena) were combined to understand the changes in wellbore integrity over time [25]. In 2017, well barrier failure mechanisms across the well barrier life cycle were identified and categorized [26]. In 2019, wellbore integrity issues across CO_2 storage projects were investigated using real-world data from operators and surveys [27]. In 2021, all cement degradation mechanisms along with the remediation technologies were systematically reviewed. In 2023, methods for cement sheath cracking detection and quantification were studied highlighting the importance of combining multiple sensing methods for accurate assessment [28]. In 2024 and 2025, risk and uncertainty assessment methods were comprehensively reviewed comparing regulatory frameworks and industry practices, highlighting the importance of advanced monitoring data in uncertainty quantification and integrated (hybrid) risk assessment [29,30]. Although previous reviews have investigated different wellbore integrity comprehensively, no review has been conducted highlighting the key problems of specific wells or shown how this understanding can be applied to wellbore conditions to determine the safety of those wells. While the study in 2019 provides valuable field experience regarding wellbore integrity in the CO_2 environment, the methodology used for selecting and analyzing the field studies is not fully transparent, introducing bias or limitations to generalization [27].

This review covers all the previously mentioned wellbore integrity aspects highlighting all key challenges, specifically in Texas Wells, in areas of potential CO_2 storage. This paper aims to review the following: (1) the importance of comprehensive understanding of wellbore integrity aspects with field data examples; (2) the chemical reactions of CO_2-rich brine with cement and how it affects its mechanical properties; (3) the fluid flow through cracks in the cement and pathways in the casing–cement interface; (4) causes of cement cracks and pathways; (5) the use of SCP data to correlate leakage with wellbore parameters; (6) the risk assessment and modeling used to quantify the risk of leakage through the wellbore during CO_2 injection and post-injection. With this understanding, we should be able to infer the integrity of the wells and whether they will contain CO_2 or require additional remediation actions.

2. Review of Legacy Well Problems

According to the U.S. Department of Energy (DOE), the number of depleted oil/gas reservoirs across the United States is over 11,000 and the actual estimation of the storage capacity of those fields is around 120–140 gigatons of CO_2, which represents a significant opportunity for storage [31]. Figure 1 shows the distribution of those fields across the United States, highlighting the region of legacy wells that our investigation focuses on.

Many of these legacy wells may have missing data, such as completion data, digital logs, or plugging details [13,32]. The data that are really critical to determine the integrity of the wells are the following: (1) the top of cement in annular space, specifically if those casings are within the storage or cap rock zones; (2) the plug details of those wells; (3) fishing operations if there is fish left in the hole and there are no reports available about it; (4) sidetracks, especially the ones that kick off within the cap rock and penetrate the storage reservoir, for which no data are available except a remark mentioning that they have been plugged back.

In West Texas, we investigated over 100 wells. Figure 1 shows problematic wells in one of those fields (black dots) that penetrate potential CO_2 storage reservoirs and identifies the key problems for those wells. Most of these wells were drilled and completed in the 1970s, with a depth of up to 20,000 ft. Over 90% of the cement used for casing cementing was class H. However, for plugging the well, class H and C were used. Our selection criteria for

the wells were based on the penetration of the potential CO_2 storage reservoir (Devonian, Silurian, and Fusselman) and the primary cap rock above this reservoir (Woodford). These data are publicly available on the RRC website [33]. Major problems are summarized in Figure 2.

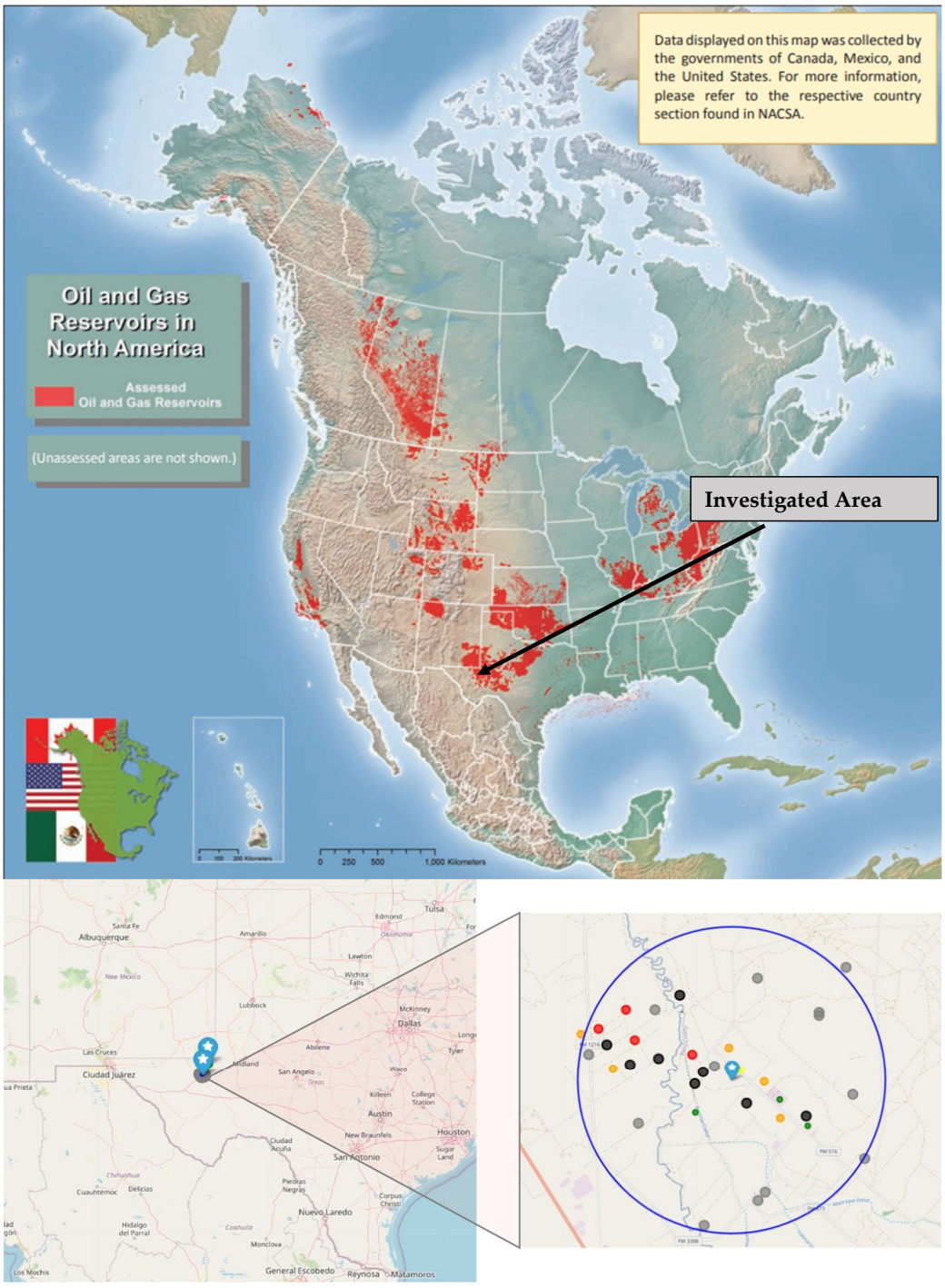


Figure 1. Distribution of potential CO_2 storage fields across the United States [31] and investigated fields.

According to the EPA standards for a class IV permit, safe wells within the AOR should have a cement plug through the primary confining zone [34]. Most improperly plugged wells in Texas have plugs above the cap rock, similarly to wells #1 and #3 in Figure 2. The key points that we need to look at are as follows: if wells like #3 have a plug set above the cap rock and open pathway (from the reservoir to wellbore) through

the perforations in the storage reservoir, what is the probability that the CO_2 plume will move out of the casing and cement into shallower formations and become too nearby to shallow wells that do not even penetrate the cap rock or the storage reservoir? Before that, we need to understand how much we can depend on the cement behind the casing. Furthermore, what is the most reliable estimation if the top of the cement behind that casing is not reported? What is the casing grade and fluid composition of this reservoir? Have there been corrosive fluids that could potentially have damaged the casing? To investigate these questions, the structure of this paper is organized as follows: We start by investigating how the in situ downhole conditions affect cement and casing integrity and how they will affect CO_2 solubility afterwards. Then, we discuss how CO_2 interacts with downhole fluid and how the resulting product reacts with cement. Since this fluid is dynamic and the cement is not fully solid (has cracks and characteristics of permeability), we further explore the impact of fluid transport and cement fracture behavior when the CO_2-rich fluid passes through it and how those reactions can have a positive effect (self-sealing). The main cause of fluid entering cement is the presence of cracks or the occurrence of debonding between the casing and cement. This is why we discuss different causes of cement defects, starting from investigations of the casing cementing job and ending with a consideration of the operational factors present throughout the well life cycle. Finally, this paper discussed different ways to evaluate wellbore integrity and reviews assessment methods supported with field examples and how they contribute to the evaluation process.

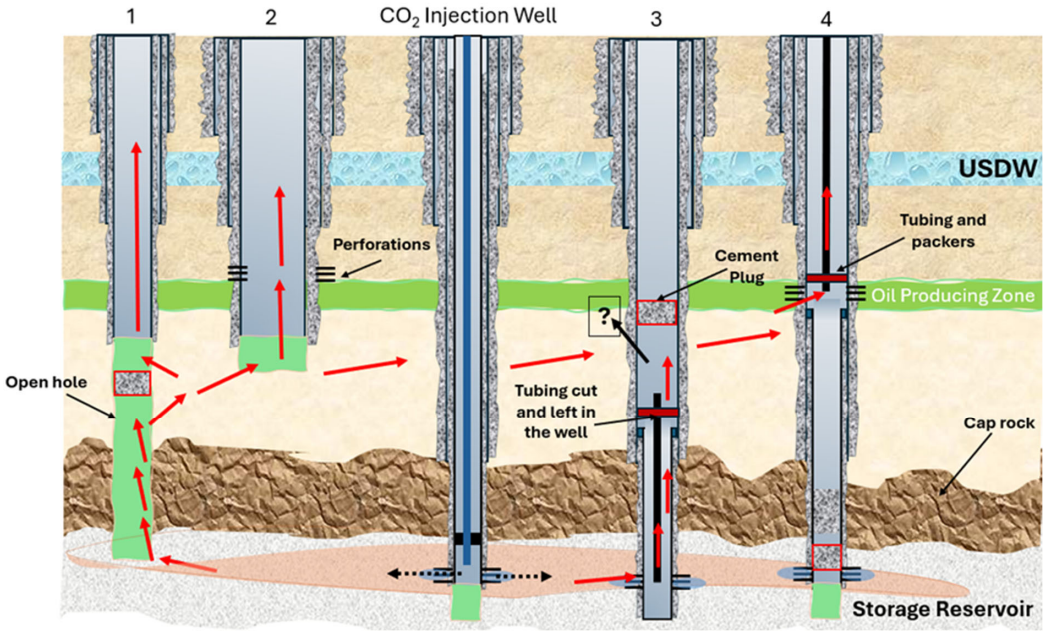


Figure 2. Plug placement in different wells with a risk of different leakage pathways being opened up. (1) A well with an open hole through the cap rock and injection zone with a plug placed above the cap rock resulting in leakage to upper formations and shallower wells; (2) a well not penetrating the cap rock near a leaky well; (3) a well with a plug left above the cap rock due to a fish lift in the well, raising concerns about leakage to upper formations; (4) a well that is plugged properly in the cap rock and storage reservoir and completed to produce from a sh. The crossflow from a defected well penetrating the injection zone provides a CO_2 flow path to the surface.

3. Wellbore Integrity in Downhole Conditions

To evaluate the possibility and quantify the risk of compromising the well integrity of legacy wells, it is important to know the materials installed in the downhole and the geological environment affecting those materials [35,36]. The primary cement used in older wells was designed for short-term operations, focusing more on mechanical strength

than long-term chemical stability [37]. Additives used in legacy well cementing were intended to modify the physical and chemical properties of the cement to suit specific well conditions [37–39]. However, in most cases, it did not consider the effect of injecting CO_2 [37]. Also, casing grades may not have been considered for such scenarios [40]. The chemical interactions that affect well integrity in the CO_2 storage zone involve CO_2, brine, and well materials (cement, steel) [20]. The reaction of CO_2 dissolved in brine with portlandite in cement forms calcium carbonate, which causes alteration zones of impacted permeability and structural integrity [41]. The carbonation reactions explained by Figure 3 are complicated by the existence of impurities such as H_2S and SO_2 or brine-dissolved salts such as NaCl, KCl, and $MgCl_2$. Impurities may introduce additional redox and sulfidation processes, resulting in alterations in cement mineralogy and mechanical properties [42,43]. High amount of sulfate in brine may cause the precipitation of gypsum or ettringite with the formation of expansion and cracking in cement, as well as its degradation [44]. Sulfate attacks weaken the cement matrix by transforming calcium silicate hydrate (C-S-H) into more porous and less stable phases [44]. On the other hand, the higher the concentration of brine-dissolved salts, such as NaCl, KCl, and $MgCl_2$, the lower the solubility of CO_2 in water due to the salting-out effect [45]. This means that in highly saline brines, there is less CO_2 that can be dissolved; thus, there will potentially be less carbonic acid formed, slowing down the rate of cement carbonation. Thus, cement integrity is highly dependent on specific environmental conditions, requiring careful evaluation to determine long-term stability.

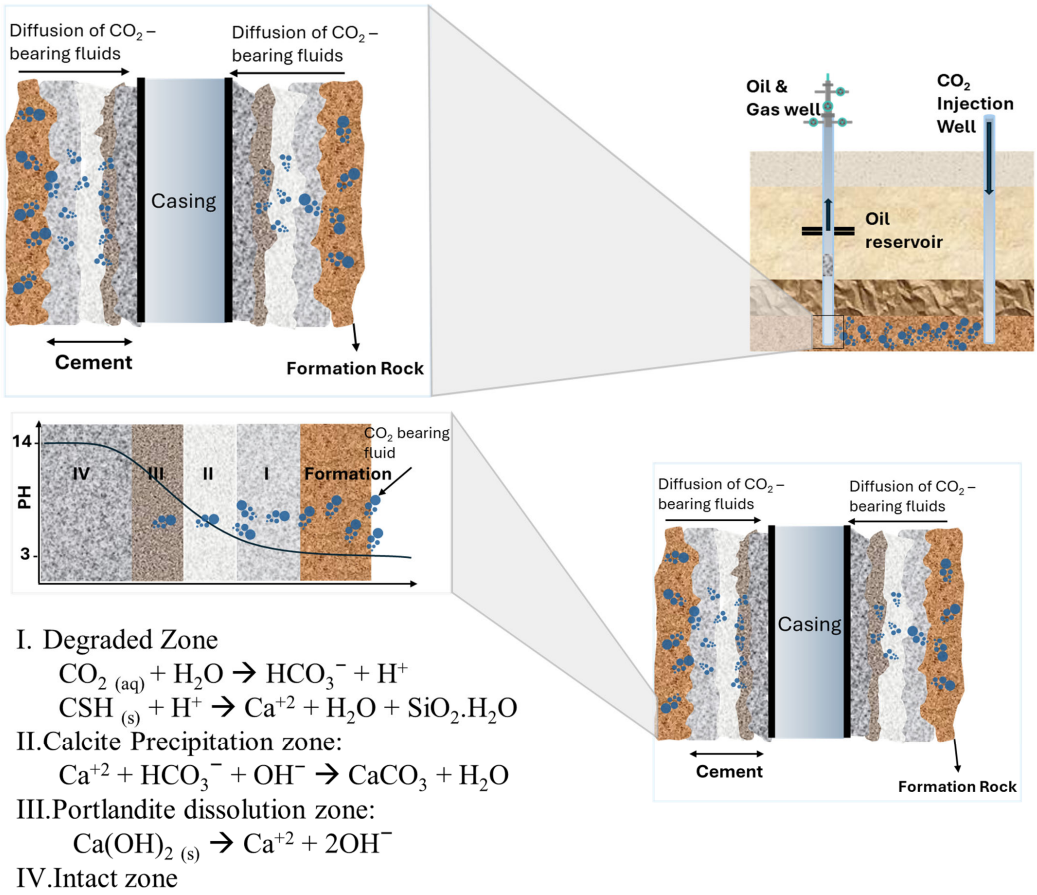


Figure 3. Cement interacting with CO_2-bearing fluid, causing alterations in cement properties.

3.1. Cement Integrity in CO_2-Rich Environments

In CO_2-rich environments, cement undergoes a series of chemical reactions that can gradually compromise its integrity; see Figure 3. The evaluation of cement integrity under different conditions is summarized in Table 2. When CO_2 dissolves in water, it forms

carbonic acid, which lowers the pH of the fluid to below 4 [41]. This acidic environment initiates the dissolution of portlandite ($Ca(OH)_2$) within hours to days of exposure to CO_2-saturated brine, releasing calcium ions and increasing the porosity of the cement. In lower-pH conditions, and at the higher pressures and temperatures that are typical in CO_2 storage sites, this dissolution process is more rapid. The greater the pressure, the greater the CO_2 solubility, which means that the reaction speeds up to make the cement more vulnerable to degradation [46,47].

Due to the dissolution of portlandite, which usually occurs within days to weeks, calcium carbonite (calcite) forms [41]. The precipitation of calcite has a dual effect: it reduces porosity and temporarily strengthens the cement by filling cracks and voids [41]. The long-term stability of this reaction, however, is very sensitive to environmental conditions such as pressure and temperature [48]. The reaction goes faster at higher temperatures, and the formation of calcite is promoted by higher pressures. The pH can drop below 12 after several weeks to months, causing calcium silicate hydrate (C–S–H), or other materials serving as binding agents, to degrade [48]. This degradation weakens the cement structure by lowering the mechanical strength and increasing the porosity [46]. At this stage, higher temperatures tend to accelerate the breakdown of the cement matrix, while pressure indirectly influences the process by enhancing CO_2 dissolution [48].

There are many environmental factors that influence the behavior of cement in CO_2-rich environments, such as the composition of the brine, pressure, and temperature. Under deep sandstone-like conditions (low pH, 2.4–3.7; elevated temperatures, 20–50 °C), Class H well cement degrades rapidly and the outer layers suffer from significant deterioration [22]. In this degradation process, temperature has a more dominant role than pH changes. Adding bentonite as an additive makes the cement more porous and therefore makes it degrade much faster than neat cement. However, under limestone-like conditions (pH 5, calcium-saturated brine, 50 °C), cement did not degrade, indicating a positive effect of the higher pH and calcium levels in the brine [23].

Salinity, pressure, and temperature further complicate the interaction between CO_2 and cement. Higher brine salinity reduces CO_2 dissolution, slowing down the chemical reactions, while increased pressure enhances CO_2 solubility in the brine, accelerating the reactions [49,50]. For example, at depths greater than 3280 feet, where CO_2 reaches supercritical conditions, the combination of a high temperature (above 88°F) and pressure (around 1450 psi) results in denser CO_2, increasing its reactivity with the cement [51]. Temperature also has a significant effect on pH and carbonate formation.. While pressure influences CO_2 dissolution, initial brine pH plays the most critical role in determining carbonate formation rates [52]. A higher pH, especially when adjusted with potassium hydroxide (KOH), stabilizes the brine and promotes calcite precipitation. However, it may take weeks or months to reach steady-state conditions in high-temperature environments, where reactions are quicker but require more time to complete [48].

Curing conditions—such as temperature, pressure, and curing time—are essential for improving cement's resistance to CO_2-induced degradation. Research shows that cement cured at higher temperatures and pressures is more durable against carbonic acid attacks than cement cured under lower-temperature and -pressure conditions. For instance, Cement cured at 50 °C and 30.3 MPa had better resistance to CO_2 attacks compared to cement cured at 22 °C and 0.1 MPa [53]. Similarly, higher curing pressures and temperatures contributed to greater long-term integrity under CO_2-rich conditions, emphasizing the importance of optimizing these conditions for subsurface applications [54].

The carbonation front, or the depth at which CO_2 penetrates and reacts with the cement, increases over time. Gouedard et al. [55] observed a carbonation depth of 1–2 mm after 44 h, progressing to 5–6 mm after three weeks, and reaching approximately 7 mm after

six weeks. To accelerate testing, electrophoresis were used by applying a voltage of 10–50 V to simulate long-term CO_2 exposure in a shorter time frame [56]. This technique revealed differences in the depth of alteration between the cathode and anode sides, making it a valuable tool for studying long-term cement durability.

Moreover, additives like pozzolan react much faster than neat cement with CO_2. Studies showed that a 65:35 pozzolan–cement blend fully reacted with supercritical CO_2 in just two days [57]. Although pozzolan additives can accelerate carbonation, they can maintain their mechanical integrity, making them a potential option for enhancing CO_2 resistance in cement formulations.

Table 2. Experimental work on evaluating CO_2-rich brine's interaction with cement under different conditions.

Author	Experiment/Study	Variables Tested	Conditions	Key Observations
[53]	Effect of curing conditions on integrity	Curing temperature, pressure, time	50 °C, 30.3 MPa vs. 22 °C, 0.1 MPa	Cement cured under higher-temperature and pressure conditions showed better resistance to CO_2-induced degradation.
[55]	Carbonation front penetration	Time	44 h to 6 weeks	Carbonation depth increased from 1 to 2 mm to ~7 mm.
[58]	Accelerated carbonation testing	Voltage application (electrophoresis)	10–50 V	Simulated long-term CO_2 exposure, revealing depth differences between cathode and anode.
[59]	Effect of $SCCO_2$ exposure on wellbore cement integrity.	$SCCO_2$ injection duration, pressure gradient, and temperature	54 °C, 19.9 MPa, 0.7 MPa pressure gradient for 99 days after 14 days of brine saturation	Cement exposed to $SCCO_2$ showed significant carbonation with reduced porosity (from 37.8% to 23.8%) and mass increase (19.6%). The carbonation extended ~5 mm into the cement core, forming calcite, aragonite, and vaterite, with improved sealing properties due to crystal growth in fractures.
[22]	Cement Degradation in Sandstone Brine	Brine composition, pH, Temperature	pH 2.4–3.7, Temp 20–50 °C	Rapid degradation of outer layers in Class H cement.
[60]	Effect of CO_2-rich brine on cement integrity	CO_2-rich brine exposure, temperature, pressure, and reaction duration	60 °C, 3 MPa pCO_2, 8 days of flow-through experiments	Distinct reaction zones formed, reducing Young's modulus by 75%, 64%, and 34% in depleted, carbonate, and amorphous layers, respectively.
[61]	Effect of flow rate and initial aperture on fractured cement	Flow rate, initial fracture aperture	60 °C; 10 MPa; flow rates: 0.05–2 mL/min; apertures: 7–43 μm; duration: 6–28 h	Permeability varied with flow rate and fracture aperture, stabilizing initially before dissolution, and precipitation altered flow.
[62]	Effect of CO_2-rich brine on fractured cement	Flow rate, fracture aperture, residence time	pH ~3.9, flow rate 0.0083 cm^3/s, fractured cement length 224.8 mm	Permeability decreased by 50%, with fracture self-healing driven by mineral precipitation. Small apertures and longer residence times promoted fracture closure and flow restriction.
[63]	Effect of CO_2 and CO_2-saturated brine on wellbore cement	Exposure to $SCCO_2$, CO_2-saturated brine, or both	50 °C, 10 MPa, 0.5 M NaCl brine, 56 days	Cement carbonation reached only a few millimeters, with minimal steel casing alteration. The stimated alteration depths for 30 years were 4.6 mm ($SCCO_2$) and 2.1 mm (CO_2-saturated brine), consistent with field data.

Table 2. *Cont.*

Author	Experiment/Study	Variables Tested	Conditions	Key Observations
[64]	Effect of CO_2-rich brine on fractured class-G cement	Fracture aperture, flow rate, hydrodynamic conditions	60 °C, 10 MPa, CO_2 partial pressure 2.3 MPa, flow rate 100 µL/min, average aperture 14 µm	Cement showed intense mass removal, but permeability increase was mitigated by Si-rich precipitation. Low-aperture zones self-healed via calcite precipitation, while high-aperture zones developed persistent flow paths.
[54]	Effect of CO_2-rich brine on well cement in depleted reservoirs	Depth, confining pressure, permeability	API Class G cement, simulated conditions of the Goldeneye reservoir (North Sea)	Permeability increased with depth, ranging from 2.06×10^{-21} m^2 at 1296 m to 1.17×10^{-20} m^2 at 2560 m, indicating the risk of leakage in deep abandoned wells.
[65]	Effect of CO_2-rich rich brine on cement reservoir rock composite	Porosity, permeability, mechanical properties, ion concentration	Simulated deep wellbore environments, long-term CO_2-rich brine exposure	Permeability increased by an order of magnitude due to sandstone alteration, while mechanical properties (Young's modulus and Poisson's ratio) decreased. No significant changes in porosity were observed.
[66]	Effect of temperature and vapor on cement carbonation	Temperature (20–300 °C), relative humidity, water-to-cement ratio	Liquid water, varying vapor content, carbonation duration of 1 h	Carbonation rate increased significantly at high temperatures with liquid water. High carbonation speed correlated with the formation of metastable calcium carbonate, influenced by vapor content and hydration products.
[67]	Effect of $scCO_2$ on Portland cement integrity	Exposure duration (2–5 weeks), pore size, tortuosity	65 °C, 20.7 MPa, $scCO_2$ exposure	Cement porosity decreased from 37% to 33%, with increased tortuosity (6× after 2 weeks, 3× after 5 weeks). Smaller pores (<30 nm) showed carbonate dissolution, while larger pores (30–200 nm) exhibited both precipitation and dissolution, limiting $scCO_2$ migration.

Impact of Fluid Transport, Fracture Behavior, and Self-Sealing Mechanisms on Cement Integrity

The behavior of cement is greatly influenced by the nature of the flow of fluids through the cement and the characteristics of cracks. When CO_2-saturated brine comes into contact with cement, fluid transport is the main motivating factor. Firstly, it transfers chiefly by diffusion, penetrating cracks and pores, in which it starts chemical actions with cement components that ultimately lead to the processes of deterioration [57]. However, for a structure with some fracturing or porosity, the process of degradation significantly accelerates due to advection, i.e., fluid movement through the fractures. This is because the fluid is always being replenished in such a way that the cement is always in contact with fresh CO_2-bearing brine fluid [68]. Conceptually, these transport processes working in tandem with rapid carbonation reactions are capable of either repairing or lengthening the cracks and ameliorating the hostile processes involved in the decay of cement [23].

With regards to fracture behavior, the size of the cracks is especially critical. While cement, in general, has a low permeability, which means it tends to limit fluid flow, there will always be zones of fracture and porosity, such as microannuli and channels that provide a higher permeability that allows CO_2-rich brine to permeate through [69]. These pathways, formed by microannuli, channels, and irregular fractures, are not super smooth; they are rugged and twisted, which can slightly decrease permeability and, therefore, cause the rate of fluid transfer through these paths to be slightly lower [70]. Cracks of small widths favor calcite deposition, which may heal them, while wider cracks continue to freely allow fluids through them, exposing the cement to more harm [71]. Whether these cracks simply close or remain open is still determined by the ratio of chemical activities and mechanical constraints [72–74].

The ability of cement for self-sealing depends on the rate at which fluids circulate and the duration of contact in the cement. When the fluids move slowly (0.0015–0.02 mL/min), it takes a longer time to precipitate minerals, such as calcium carbonate, that tend to seal the cracks [75]. This is best accomplished in small, confined cracks in which the fluid is forced to remain and gradually form a deposit of precipitating minerals that seal the crack [75]. On the other hand, fast-moving fluids (2 mL/min) fail to close the cracks, hence minimizing the possibility of self-sealing [62]. It is apparent from the above papers that under real and actual underground environments, slow flow rates and long residence times are favorable for self-sealing [64,76–79].

Alongside chemical sealing, mechanical behavior is critically important for fracture closure. Huerta et al. [78] indicated that plastic deformation of cement under stress could essentially seal any cracks. As the cement interacts with low-pH brine, its mechanical strength falls, making it less complicated for pressure to seal the cracks. As the fluid pressure falls and the cement weakens, cracks may have the ability to mend on their own [78]. As reported by the authors of [80], applying a confining pressure seems to cause micro-cracks in the cement to close elastically, especially at pressures under 15 MPa, constituting evidence of how chemical and mechanical sealing can operate together to ensure well integrity.

3.2. Casing Integrity for CO_2-Exposed Wells

While cement degradation poses significant risks to well integrity, it could be worsened if corrosive fluids reach the casing, as these will corrode the casing, creating additional pathways for fluid migration and compromising the structural stability of the wellbore system [81]. Corrosion can occur due to several mechanisms: environmental (oxidation from moisture before or after casing installation), galvanic (when two metals with different electrochemical potentials contact each other through an electrolyte, such as wellbore fluids), and chemical (due to reactive gases like CO_2, H_2S, or CH_4 that dissolve in water, forming weak acids that corrode steel) [82,83]. Moisture from drilling fluids or surrounding formations can exacerbate these issues once the casing is in place. Studies have shown that in areas like Alberta, wellbore leakage is strongly associated with external casing corrosion, which can result in both vertical and lateral fluid migration even before the casing fully deteriorates [84]. In cemented sections of wells, cracks or microannuli between the cement and casing allow corrosive fluids to reach the casing, speeding up corrosion [81]. Experiments have demonstrated that carbonated brine can flow through these gaps, leading to corrosion and deposits like iron bicarbonate [68]. The corrosion products, iron oxides (FeO, Fe_3O_4) and traces of iron carbonate ($FeCO_3$), can act as a significant leakage pathway along the wellbore. Gas flow tests were conducted using nitrogen gas through corroded and non-corroded steel specimens under varying confining stresses (500 psi to 2000 psi) to simulate wellbore conditions at depths of 575 feet to 2300 feet. These tests revealed that corroded casings have significantly higher transmissivity than non-corroded specimens. Since these products are deformable and have a mesoporous structure (containing pores with diameters in the range of 2:50 nanometers), this allows for changes in pore size and therefore connectivity, creating leakage pathways for long-term fluid leakage along the wellbore [85].

Qing et al. [86] investigated the stress corrosion of TP110 TS and P110 steel in a CO_2-H_2S environment and provided the results of the combined actions of anodic dissolution and hydrogen embrittlement. The study further revealed that the addition of sufficient imidazoline-type corrosion inhibitors can inhibit stress corrosion, whereas insufficient amounts can increase the likelihood of corrosion.

CO_2 partial pressure affects corrosion rates in oil pipes. Below 1 MPa, the corrosion rate is positively correlated with CO_2 partial pressure due to the slow formation of $FeCO_3$. However, when the pressure exceeds 1 MPa, $FeCO_3$ rapidly forms a protective film, and the corrosion rate decreases, showing a negative correlation [87]. As temperature increases and NaCl concentration decreases, the sensitivity to stress corrosion cracking (SCC) rises [88]. The increase in temperature accelerates the chemical and electrochemical reactions (carbonic acid formation and anodic dissolution), speeding up the corrosion rate and hydrogen production. On the other hand, lowering the NaCl concentration reduces the retardation effects that salt has on anodic and cathodic reactions facilitating anodic dissolution and hydrogen embrittlement. The SCC mechanism is mainly driven by anodic dissolution and hydrogen participation [88]. Harle's research on API X65 steel demonstrated that in low-pH environments, CO_2-induced stress corrosion causes high crack propagation rates. This was characterized as transgranular corrosion, which leads to deep cracks within the steel structure [89]. Although considerable progress has been made in understanding the mechanisms of casing corrosion and CO_2-induced cement degradation in wellbore environments, future work should focus on investigating corrosion under confining stress and examining corrosion products formed in the presence of specific pore fluids, as these factors could significantly influence the physical and chemical characteristics of corrosion products in actual wellbore environments.

4. Causes of Cement Defects

Debonding between cement and its surroundings, leading to micro-annulus formation, is primarily caused by insufficient mud removal during drilling, casing expansions and contractions during production or completion, and cement shrinkage during hydration and setting [90]. Leakage pathways may develop through gaps in the cement-casing, cement–formation interfaces, or cracks through the cement itself; see Figure 4. There are two types of cement pipe bonding: shear bonding and hydraulic bonding [91]. A shear bond provides mechanical support by resisting pipe movement, while a hydraulic bond prevents fluid migration by withstanding pressure until leakage occurs. Hydraulic bonding is key to isolating zones in wells, specially with regards to CO_2 storage. Debonding is often caused by factors such as cyclic temperature and pressure changes, cement shrinkage and hardening, and fluid-driven debonding, leading to reduced oil and gas recovery and potential environmental pollution [26,92–97].

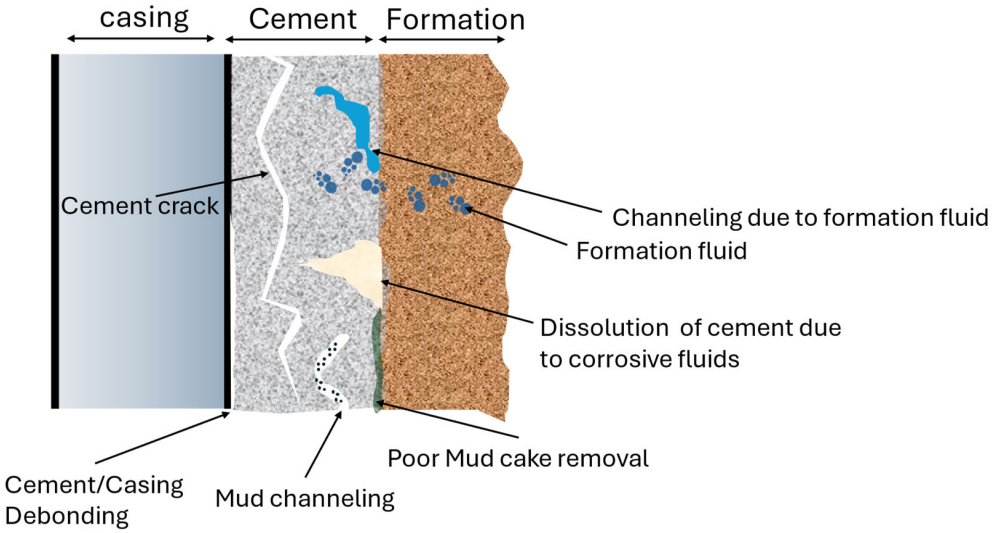


Figure 4. Different cement defects cause cracks and debonding between the casing cement and formation.

4.1. Cyclic Pressure and Temperature Changes

The accumulation of plastic strain in the cement slurry is the primary mechanism through which cyclic loading affects the cement–casing interface. When the cement matrix is repeatedly subjected to compressive stress, progressive deformation eventually occurs, with the fatigue of the cement matrix increasing the probability of forming micro-cracks and extending existing cracks, especially when the soft cement material is between the stiff casing and surrounding rock formations [98]. High-pressure water in hydraulic fracturing is periodically injected to fracture the surrounding rock, which imposes cyclic compressive loading on the well casing and transfers stress to the cement slurries [99]. In these conditions, cement slurries have a lower yield stress than the casing or formation; thus, they are more prone to fatigue failure [100]. Studies like [101] demonstrated that 86% of wells in the Fuling Shale reported sustained casing pressure (SCP) after cyclic loading, resulting in gas or oil leakage and reduced production. The occurrence of such incidents shows the need to understand the effects of cyclic loading on the fatigue properties of cement slurries [102].

Cyclic loading on cement slurries has also been investigated. Oil–well cement slurries were uniaxially cyclically loaded with a strain rate of 85% [99]. The author studied various cycle numbers (5, 20, 40, and 100) and observed that, as the number of cycles increased, the average Young's modulus of the cement slurries initially increased but later decreased. This indicates that the material stiffens during the early cycles but weakens after continued loading. Triaxial cyclic loading tests were conducted on cement samples at a 50% loading level and a 20 MPa confining pressure after curing at 90 °C [103]. It was found that plastic strain accumulated rapidly in the first three cycles, highlighting that the early stages of cyclic loading are critical for plastic deformation. Xi et al. [102] compared conventional and latex cement slurries in triaxial cyclic loading tests at a 70% loading level. They observed significant plastic strain in both formulations after 20 cycles, with latex slurries exhibiting slightly higher strain accumulation (0.56%) compared to conventional slurries (0.45%).

It was found that cement slurries subjected to HPHT environments exhibited decreased failure stress and increased brittleness compared to those tested at ambient temperatures [98]. This suggests that HPHT conditions exacerbate the potential for fatigue failure in cement slurries. Although those experimental studies focused on tracking fatigue loading and the resulting cement deformation due to cyclic loading, they did not show how cement permeability would change or how flow paths would be created. This explains the need for measuring cement permeability and how it is related to cyclic loading, taking into account the confining stress on the cement in the annular spaces. API standards need to be updated to account for the effects of compressive cyclic loading on oil–well cement slurries, especially in high-temperature, high-pressure environments, to help prevent well failures [98]. Future work should focus on quantifying the changes in cement permeability under cyclic loading and confining stress, as this would provide a clearer understanding of how flow paths are created and how well integrity is impacted during operations such as hydraulic fracturing.

4.2. Cement Hardening and Shrinkage

During cement hydration, chemical and bulk shrinkage lead to a reduction in cement volume. This reduction can compromise the cement's ability to maintain a tight bond with the casing and formation, allowing for pathways through which fluids may migrate [104]. The transition period, when the cement changes from a liquid to a solid, is critical because shrinkage during this time can cause a drop in hydrostatic pressure, potentially allowing formation fluids to enter the cement and cause fluid communication between different zones [104,105]. Proper cement slurry design and additives are used to mitigate these risks, reduce shrinkage, and maintain zonal isolation [90,104].

Once the cement has hardened, it enters into a critical phase in which its ability to resist external pressures is tested. A reduction in pressure because of cement's shrinkage allows fluids from the surrounding formations to seep into the cement, weakening its structure. This becomes especially problematic during times of mechanical or thermal stress when the cement can crack and especially around areas where shrinkage has left voids or weakened the bond [105]. However, though small, these cracks can grow over time, and the fractures allow fluids to migrate from one layer of the formation to the other [106].

In the long term, these cracks and gaps, if not properly managed, can pose significant risks to the overall wellbore's integrity. Preventing these issues requires paying meticulous attention to the cementing process, particularly by minimizing shrinkage and ensuring that the drilling mud is fully displaced before the cement is placed [68,106]. By addressing these potential pitfalls, wellbore integrity can be maintained, reducing the possibility of fluid migration and the costly repairs that follow [90].

Various methods of estimation of cement shrinkage have been developed to measure and quantify shrinkage under different conditions. The flask method was used previously; with this method, cement is poured into a flask covered with water, and the volume change is observed by measuring the water displacement. This method has been widely used. However, it has shown inaccurate results due to the small amount of slurry used [104]. As a result, different approaches have been adopted: API-standardized methods such as the ring mold, the membrane method, and the cylindrical sleeve, which have been modified to provide more reliable results by simulating downhole conditions [107,108]. Introducing real-time shrinkage testing under downhole conditions offered a more precise understanding of shrinkage behavior in high-pressure and high-temperature environments [109]. Despite these advancements, there are still limitations in capturing the complexity of cement shrinkage in real world wells, especially in wells driven by flowing tubing and casing. Further investigation is needed on issues such as shrinkage directionality (e.g., axial shrinkage resulting in disking) and the effects of confining pressure on shrinkage.

4.3. Fluid Driven Debonding

Cement interface debonding during wellbore operations is a serious issue often introduced by small defects from perforation or fluid injection processes; see Figure 5. These defects mainly occur at the casing–cement and cement–formation interfaces, caused by perforation explosion, which damages the cement structure [110]. As pressure builds up beyond what the cement sheath can withstand, the defects grow and begin to disseminate [111,112]. Furthermore, the process becomes more complicated with large pressure and temperature changes, which add stresses to the cement that are greater than the stresses increased by deformation and fracture [112,113]. It has been found that CCI and CFI interfaces can simultaneously experience debonding, especially during fluid injection. For instance, Lecampion et al. [113] built a model to predict the manner in which these cracks spread, while Jiang et al. [114] and Feng et al. [115] demonstrated which mechanisms would lead cracks to become more pronounced. Gu et al. [116] built a model for the simultaneous propagation of the fluid-driven debonding at both the casing–cement and cement–formation interfaces, assuming the presence of a competition between fractures at these two interfaces and fluid injection. Although leakage analysis results from Watson and Bachu [84] indicate that completion intervals do not affect cement integrity, cement debonding from perforation and fluid injection still threatens well integrity as defects propagate under pressure and temperature variations. More interpretation and understanding is required to understand the conflicting effects to better infer legacy wells' integrity for CCS projects.

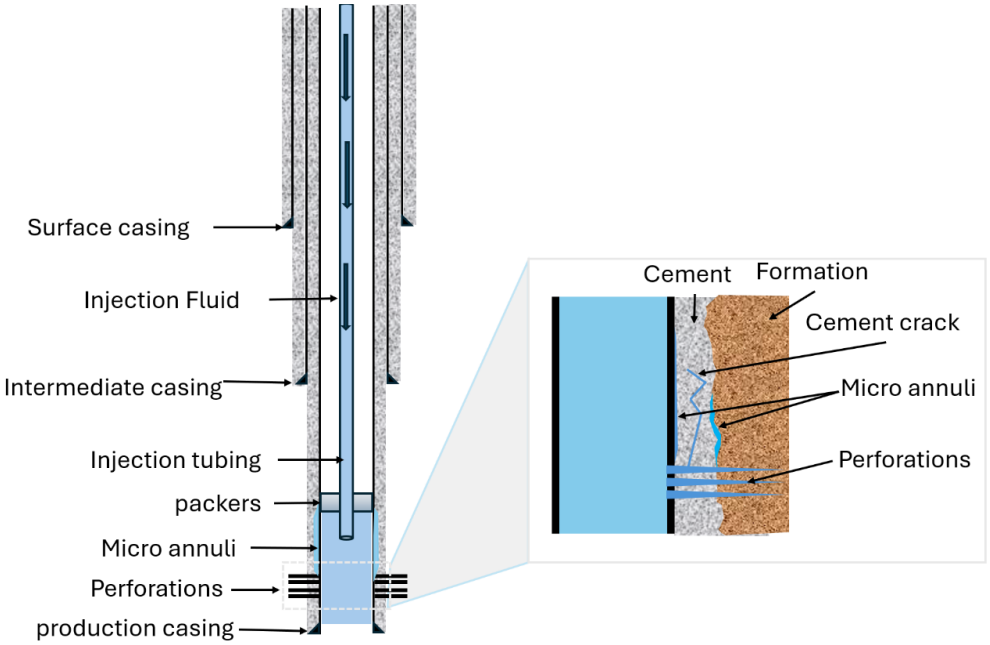


Figure 5. Schematic of a well showing the onset of debonding and cement cracks created during the injection period.

4.4. Well Design and Other Operational Activities

Operational factors can greatly compromise wellbore integrity by degrading the mechanical properties of steel and cement over time due to exposure to varying pressures, temperatures, and fluids [117–119]. Based on the analysis in Abraham et al. [120], casing wear can result in more than a 40% loss in the initial volume over a well's operational life, which in turn leads to a significant reduction in casing thickness and its burst pressure ratings. This casing deformation caused by uneven wear alters the geometry of the CCI. The severity of casing wear determines the stress levels, which sometimes exceed the unconfined compressive strength of standard cement formulations, leading to potential failures in the cement sheath [120].

Studies have tried to correlate compromised wellbore integrity with well design parameters to understand and develop new ways of minimizing the effect of these factors on well integrity [121,122]. Deviated or slant wells exhibit higher rates of SCVF/GM compared to vertical wells, likely due to mechanical issues such as casing centralization and cement slumping [122]. As the deviation angle increases, casing eccentricity becomes more pronounced, leading to the inefficient displacement of drilling fluids and potential cementing failures. To prevent wellbore failure, this increased eccentricity in highly deviated wells requires more stringent centralizer placement and control. A solution is offered by [123] through a casing eccentricity limit model that considers borehole size, wellbore deviation angle, and the rheological properties of drilling and displacement fluids. The model indicates that as wellbore deviation angles increase, the permissible eccentricity limit decreases, emphasizing the importance of tailored countermeasures to prevent well integrity failures in deviated and horizontal wells.

Proper cement coverage in the borehole space annulus is important to isolate the casing from formation fluid leakage through the space annulus. However, factors including fluid loss to the formation, loss circulation and wellbore washouts could result in improper cement coverage [124]. Fluid loss reduces the top of cement by filtering out only the water from the slurry, while lost circulation lowers the top of cement by causing a more significant loss of all fluids to the formation, leading to a more pronounced reduction in cement volume. These factors cause higher uncertainty in volumetric calculations to

estimate the cement top in the annular space. Washouts and wellbore irregularities, despite having an effect on volumetric calculations, are also important to determine centralizer placement in the well design stage [125,126]. These factors represent a true challenge in legacy wells, for which the only available data about the cement include the slurry volume. Trudel et al. [121] explored the effect of the cement top on wellbore, leakage focusing on unconventional horizontal gas wells drilled since 2010 in British Columbia, Canada. All wells showed a big increase in leakage when the TOC was lowered [121]. Some wells had sections with very tight microannuli (small gaps between the cement and casing) that still provided strong resistance to gas flow, even if the TOC was low, but these cases do not allow for reliable generalizations [121]. Excess cement can increase the displacement efficiency, ensuring full cement coverage [121]. Even though using extra cement has clear benefits, in practice, the amount used is often minimized to save on material costs, reduce rig time, and avoid the hassle of dealing with excess cement that returns to the surface [121].

Geological formations penetrated by the well and their physical fluid properties and pressures help identify the leakage sources and the best remediation action [121]. It is hard to determine the source of leakage for well-experiencing wellbore leakage or SCVF and therefore the remediation action [127]. However, with these data available it could be possible to determine the source of leakage and select the appropriate remediation action [128]. Sandl et al. [129] showed, throughout their analysis of Northern BC, that there is a positive relationship between wellbore leakage and the well intersection of the lower Debolt Formation (pressurized gas formation).

Squeeze cementing is used for remediation, according to current provincial regulations in BC [130], or during plugging of the wells to either plug depleted intervals or protect the underground source of drinking water [131]. The challenges of squeeze cementing are its low success rate and inconsistent reporting [127]. Trudel et al. [121] models the effect of squeeze cementing by incorporating the location of perforations determined by (1) the vertical spacing (shots per foot) and (2) perforation phasing. The author assumed that the cement slurry penetrated in all directions equally around each perforation, filling the penetrated microannulus within the specified penetration radius. This means the permeability of the microannulus in the direction of squeezing is equal to the permeability of the cement used for squeezing. The model showed that the leakage flow rates reduced compared to those before squeezing, and a significant reduction was seen in the initially high leakage flow rates. Quantifying the volume of cement entering the microannulus and how much it enters the perforations is likely to determine the success of the squeezing job [121].

Ref. [132] visualized a bar chart, presented in Figure 6, showing case studies that discuss the effect of different factors affecting wellbore leakage. However, the concern is the factors that showed no effect on the leakage were backed up by no more than two case studies, suggesting the need for more investigations to confirm their effects. On the other hand, factors with conflicting results were supported by the highest number of case studies, suggesting that better interpretation needs to be performed for these factors. For example, in [133], the authors conducted a hazard analysis comparing wells of different categories based on their age. Despite the expectation that more recent wells (2009–2012) would show fewer issues due to advancements in materials, stricter regulations, and evolving industry practices adapted to local geology, the data revealed a different trend. In northeastern Pennsylvania, the violation rate for unconventional wells was slightly lower for those drilled between 2009 and 2012 (9.1%) compared to those drilled from 2000 to 2008 (9.8%). However, newer wells had fewer years of inspection. When comparing wells of the same age, the newer wells had more violations than the older ones, for both conventional and unconventional wells [133]. Geography can act as a key factor in well integrity, with wells

in northeastern Pennsylvania being 8.5 times more likely to experience violations compared to other parts of the state, possibly due to complex geology and rapid drilling in areas with less drilling history.

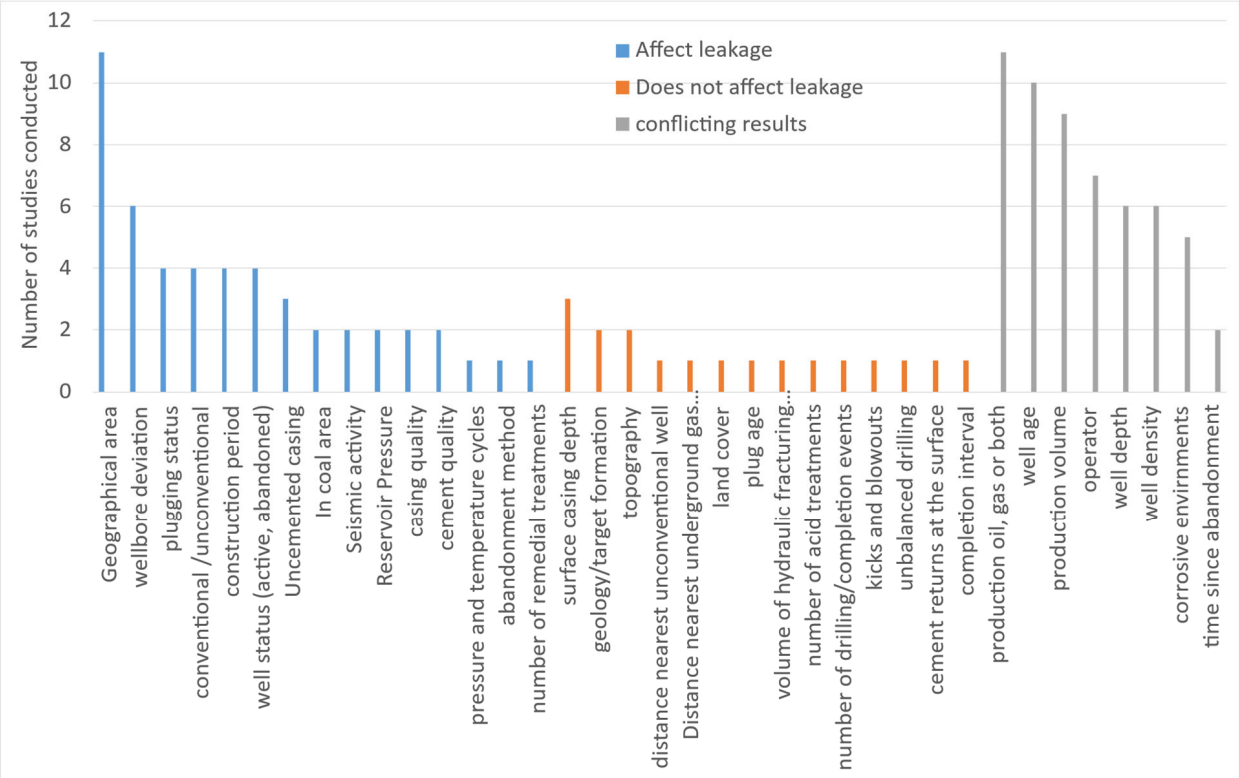


Figure 6. Well attributes could be wellbore integrity predictor parameters.

5. Wellbore Integrity Evaluation

Legacy wells can be evaluated mainly by these three methods. In the first method, well logs (CBL/VDL) are used to qualitatively determine the cement tops and the bonding between the casing and cement. Although this is the best method to use to estimate the cement top in the annular space, it is not always available. The second method is sustained casing pressure, which will be further discussed in detail in the next section. The third method is risk assessment. Based on the data availability and the required output, there are qualitative, semi-quantitative, quantitative, and integrated assessments that will be further discussed in the last part of the section discussing evaluation methods.

5.1. Sustained Casing Pressure

The factors discussed in Section 4 are likely to create leakage pathways. One of the common indicators of these pathways is the reported sustained casing pressure (SCP). In Canada, the space between the surface casing and production casing is left open, allowing vent flow if a barrier fails, whereas in the U.S. (except Pennsylvania), surface casing vents are sealed, causing pressure buildup in the event of barrier failure [134]. Conventional cement often fails to provide long-term isolation throughout the post-production phase [135]. Although sustained casing pressure is anticipated due to issues that arise during the well's life cycle, numerous case studies have shown that wells, which initially had no issues, can develop sustained casing pressure as time passes [128]. Su et al. [136] analyzed the gas composition in the annulus to infer the leakage point. A survey performed by [137] on 229 wells showed that older wells, particularly those over 20 years old, are more prone to sustained casing pressure (SCP) due to factors such as corrosion, cement degradation, and

casing wear, with an average SCP onset age of 38 years, as demonstrated by case studies of wells aged 60 and 38 years. According to analysis performed by [134] on 3923 wells located in the Wattenberg Field, Colorado, collecting SCP data from (COGCC database) to understand the factors that can predict well integrity loss indicated by SCP values, well deviation was the most significant factor. In addition, there was no statistically significant relationship between the number of hydraulic fracturing treatments and SCP. Carey [138] discussed how SCP data from offshore wells in the Gulf of Mexico and onshore wells in Alberta, Canada, are used to estimate effective permeabilities. These estimates are then compared with the permeability estimates derived from the FutureGen project. The FutureGen project provides a baseline for well failure frequencies and leak rates, which are used to develop log-normal distributions of well permeabilities. Synthesizing findings by comparing the permeability distributions derived from SCP data with those from the FutureGen project. This comparison helps validate the robustness of the probability distributions developed for estimating leakage risks. Table 3 provides the comparison between the SCP data and the FutureGen data that provides a comprehensive view of wellbore integrity risks.

Table 3. Comparison between FutureGen Risk analysis and SCP data concluded from [134,138].

Aspect	FutureGen Risk Analysis	Sustained Casing Pressure (SCP) Data
Approach	Risk assessment based on well failure events per year	Observations of pressure build-up within well casings (SCP)
Leak Rates	High-rate (e.g., 11,000 metric tons/year) and low-rate (e.g., 200 metric tons/year)	Observed leak rates and effective permeabilities, typically lower
Frequency	1 in 1000 well-years (oil and gas wells) or 1 in 100,000 well-years (CO_2 wells)	Frequency of SCP in wells, such as percentage of wells with SCP
Conceptual Model	Discrete events with wells either leaking significantly or not at all	Continuous spectrum of leakage potential from negligible to moderate
Permeability Calculation	Derived from assumed leak rates, pressure differences, and other parameters	Derived directly from observed pressure and flow rates
Risk Representation	Focus on discrete high and low leakage events	Continuous spectrum of leakage potential based on observed data
Data Sources	Analogs from natural gas storage and other studies	Direct observations of well performance in specific regions
Leakage Magnitude	Includes scenarios with very high leak rates	Typically shows lower effective permeabilities and leak rates
Probability and Impact	Low probability of significant leakage events but potentially high impacts	More frequent, smaller-scale leakage with cumulative impact potential

Although different research has focused on analyzing sustained casing pressure (SCP) data to infer well integrity failures or to correlate wellbore integrity parameters with leakage risks, such as surface casing vent flow and gas migration [122,134,139,140]. Others developed numerical models for predicting leakage and SCP behavior under varying conditions [141–143]. A study by [141], developed a numerical model to predict SCP based on volume consistency and mass conservation laws, and analyzed factors such as cement properties, micro annulus formation, wellbore pressure changes, and bonding strength. Table 4 summarizes the work conducted on evaluating well integrity through sustained casing pressure data.

Additionally, various case studies have explored methods for detecting wellbore leakage and applying innovative remediation techniques, including thermosetting resins, advanced cement systems, and mechanical solutions, Table 5.

Table 4. Summary of work conducted on using sustained casing pressure data to predict wellbore integrity.

Author	Description
[122]	Analyzed surface casing vent flow (SCVF) and gas migration (GM) to assess CO_2 storage leakage risks, correlating leakage with factors like economic activity, regulatory changes, and well conditions.
[140]	Incorporated SCP field observations, transport properties, and CO_2 flux estimation under varying conditions.
[139]	Assessed global datasets on well barrier and integrity failure across various countries, analyzing failure rates and factors influencing well integrity in both conventional and unconventional reservoirs, with a focus on abandoned, orphaned, and active wells.
[134]	Analyzed surface casing pressure (SfCP) data to evaluate well integrity in Colorado's Wattenberg Field, developing a critical SfCP criterion to assess the risk of stray gas migration, with findings showing that newer wells with deeper surface casings pose lower risks.
[138]	Developed a methodology to analyze the frequency and permeability of defective wells in CO_2 storage sites using bimodal log-normal distributions to estimate leakage risks, highlighting the need for further data to improve accuracy.
[141]	Developed numerical models to analyze the process of sustained casing pressure (SCP) and study cement integrity collapse, providing solutions like optimizing cement properties and using self-healing cement to mitigate SCP and improve well integrity.
[144]	Developed the first onshore modeling framework for sustained casing pressure (SCP) and surface casing vent flow (SCVF) in wells with open annuli, linking gas migration and leakage behavior to SCP/SCVF to better estimate methane leakage and support regulatory actions.
[142]	Developed a temperature-based SCP model for deepwater wells, integrating thermal elastic mechanics and formation fluid infiltration, and proposed an SCP relief tool to reduce pressure in annuli, improving casing integrity by up to 30%.
[143]	Developed a prediction model for sustained casing pressure (SCP) by integrating gas migration, experimentally validating the model, and analyzing the effects of tubing leakage and liquid density on SCP balance and recovery rates in high-pressure gas wells.

Table 5. Case Studies about the technology used to solve sustained casing pressure.

Author	Well Type	Case	Method of Spotting Leakage	How They Solved It?	Innovation
[145]	V	Fully cemented annulus	Noise and cement bond log	milling a 25-foot window in the 9 5/8″ casing to access the microchannels behind the cement. They then injected 3.2 bbl of thermosetting resin under 4500 psi pressure over 8 h, sealing the channels and successfully eliminating the sustained pressure	Thermosetting resin has low viscosity, deep penetration, adjustable curing time, and resistance to water contamination.
[145]	V	Two fully cemented annulus	Logging results, and confirmed when perforating the casings equalizing the sustained pressure between both annuli	injected 2.7 bbl of thermosetting resin through the perforations at 2000 psi pressure over a 7.5 h gel time, sealing the channels in the 9 5/8″, 13 3/8″, and 18 5/8″ casing strings, successfully eliminating the pressure build-up in both annuli	
[145]	V	B-annulus treatment	The leakage in the B-annulus was identified through gas returns during each pressure bleed-off, indicating gas migration through microchannels in the cement behind the 9 5/8″ casing.	used a 94 pcf density resin with a 4 h gel time, allowing 11 bbl of resin to settle by gravity to the top of the cement at 4920 ft MD. Pressure of 530–550 psi was applied for 4 h, sealing the gas migration channels	

Table 5. *Cont.*

Author	Well Type	Case	Method of Spotting Leakage	How They Solved It?	Innovation
[136]	V	Intermediate casing	gas source was further identified using gas composition analysis, isotopic fingerprinting, and noise and temperature logging,	Since the source was the shallow sweet gas with low risk, the well was temporarily plugged and abandoned (P&A) for future utility, lowering the risk level from high to medium	its integrated multi-disciplinary approach combining gas composition analysis, isotopic fingerprinting, pressure profiles, and noise and temperature logging to accurately diagnose gas sources in wells with sustained casing pressure, enabling tailored risk assessments and remediation strategies in high-risk sour gas environments
[136]	V	2nd intermediate casing	gas composition analysis, isotope fingerprinting, and pressure profile analysis, pointed to deep sour gas migration as the source. This was confirmed by noise and temperature logging, which indicated gas migration below the shallow gas perforations.	Due to the high risk from the corrosive deep sour gas containing H_2S, the well was permanently plugged and abandoned (P&A) to isolate the sour and sweet gas layers and eliminate the risk	
[146]		Sustained Annulus Pressure (SAP) buildup that frequently occurred after hydraulic fracturing operations, causing significant well integrity issues.		using the Enhanced Cement Integrity System (ECIS) during the well design phase. In a 16-well hydraulic fracturing campaign, they used ECIS in the perforated intervals of each well. The results showed an 80% reduction in SAP buildup, with only 1 out of 16 wells experiencing SAP, leading to cost savings of over 2 million USD in this campaign	The innovation of this paper is the Elastomeric Cement Integrity Sleeve (ECIS), a fluid-reactive, self-sealing elastomer that prevents sustained annular pressure (SAP) by sealing micro-annuli in wells, offering a simple, cost-effective solution that reduces remedial operations and enhances long-term well integrity
[147]	V		Cement Bond Log (CBL) and Sonic Noise Log (SNL)	Perf, Wash & Cement (PWC) technique was applied, improving the cement bond and providing a reliable seal across the cap rocks, as verified by post-operation CBL.	The PWC method enhanced the cement bond, successfully addressing leakage issues and improving well integrity in abandonment operations.
[147]		high pressure in the B annulus, nearing the Maximum Allowable Annular Surface Pressure (MAASP)		mechanical casing expander was deployed to create internal dents in the casing, improving zonal isolation by sealing micro-annuli and mitigating fluid leaks.	casing expander technology reduced B-annulus pressure by 88%, providing a mechanical solution to improve zonal isolation
[148]		The presence of sustained casing pressure (SCP), ranging between 300 and 400 psi, was observed post-repair, indicating communication issues due to casing leaks.	Presence of sustained casing pressure	A new generation of adaptive cement system was applied, delivered through coiled tubing for optimal placement in the problematic zone to seal the leaks.	The use of an adaptive cement system allowed for improved long-term remediation compared to conventional cement systems, offering better control over annular communication and reducing SCP recurrence.

Although work has been performed on predicting which wells are likely to develop sustained casing pressure and solutions have been provided through case studies, no model has yet been developed to quantify the amount of leakage due to SCP.

While some work has utilized sustained casing pressure reports to analyze wellbore leakage and to infer permeability ranges for different leakage rates [138,149], Hachem et al. [132] highlighted in their work the most affecting factor on wellbore integrity according to the number of case studies was geographical area. With that in mind, results

from SCP analysis, if utilized to areas not regulating SCP to infer integrity status, should consider similar geographical areas for more accurate results.

5.2. Risk Assessment

Figure 8 provides a workflow of wellbore evaluation using different evaluation methods. When sustained casing pressure reports and well log data (CBL/VDL) are not available qualitative risk assessment can provide valuable insights [150]. While previous work highlighted the need for standardized approaches for qualitative risk assessment and the limited availability of specific data in existing projects [151], recent work shows comparative analysis of the 4 RA types (qualitative, semi-quantitative, quantitative, and integrated) examining over 20 RA methods demonstrating the necessity for integrated (hybrid) RA frameworks for optimizing large scale CCS projects [30]. Many studies have been performed on qualitatively evaluating the risk of wellbore leakage [150,152–155]. Arbad et al. [150] categorized the wells according to the penetration of the CO_2 Storage zone, protection (by cement plug up to 50 ft thick and annular cement column up to 200 ft height) and accessibility level into 9 types. Lackey et al. [156] evaluated offshore legacy wells in the Gulf of Mexico into 4 groups depending on their accessibility and subgroups depending on their sealing protection and ease of remediation actions. Considering the complexity of remediation action due to fish, sidetracks or casing cut, commonly in deep wells, is the big issue that was highlighted in this methodology. Shell Quest Carbon Capture and Storage (CCS) project used the Bow-tie method, Figure 7, in their evaluation of the legacy wells by identifying potential threats, preventive measures, and consequences associated with well integrity failures [157]. The primary failure scenario is CO_2 and brine migration through a compromised wellbore. The threats include migration along legacy wells due to compromised cement or casing integrity. And the preventive measures involve well integrity evaluation assessments, cement bond evaluation, pressure management, and monitoring programs. The consequences are potential impacts of containment loss, including groundwater contamination, CO_2 release to the atmosphere, and soil contamination. Finally, the corrective safeguards are passive or active mechanisms that reduce the severity of consequences, such as the presence of multiple geological seals, overlying thief zones, and remediation strategies.

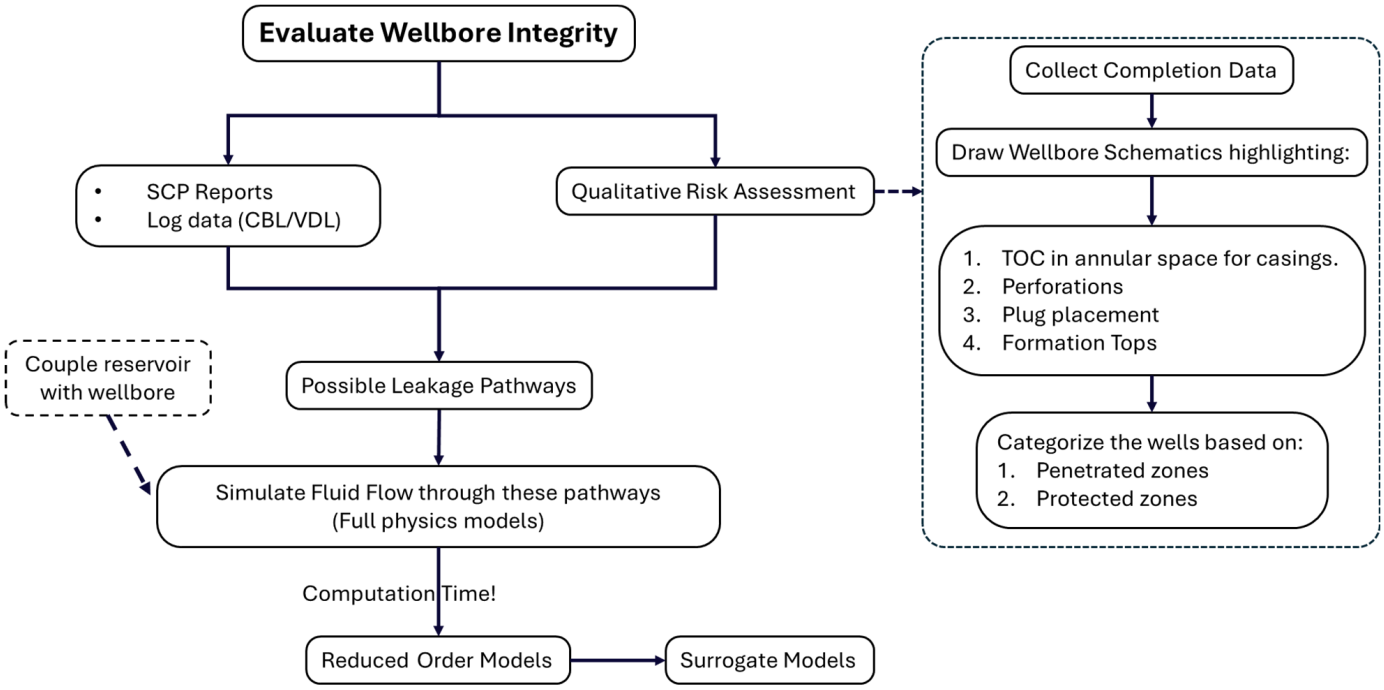


Figure 7. Flow chart for evaluating wellbore integrity, starting with a minimal amount of data.

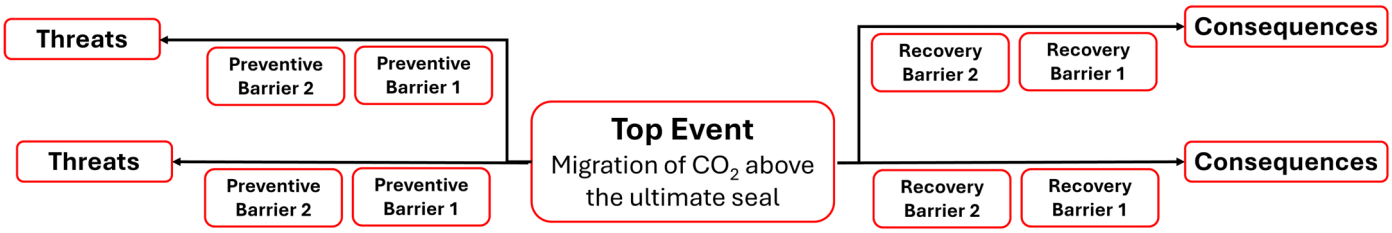


Figure 8. Bow-tie method for risk assessment.

While qualitative methods provide a structured framework for identifying risks and failure pathways, probabilistic methods offer a more data-driven approach by quantifying the likelihood of well-integrity failures and accounting for uncertainties [158]. Probabilistic models in geologic carbon storage (GCS) are primarily used to assess long-term containment risks by forecasting CO_2 leakage and containment effectiveness [158]. These models integrate site-specific data and uncertainties into simulations to quantify risks over time, incorporating monitoring data and updating predictions using probabilistic methods to reflect new observations [158–160]. This approach is particularly useful for integrating mitigation decisions based on detected leaks, allowing for dynamic and informed risk management throughout the operational lifecycle of GCS sites.

Although qualitative and probabilistic methods can provide good insights on leakage pathways, numerical and quantitative approaches provide a more detailed, physics-based analysis on how the flow goes through these flow pathways under varying conditions and predict failure mechanisms. Coupling the wellbore with the reservoir started by including the effect of changes in fluid saturation and driving forces of the storage reservoir on wellbore leakage [161–163]. Since that, developing full physics model as an accurate assessment tool for risk assessment has been evolving. Findlay [164] introduced foundational concepts for predicting average volumetric concentration in two-phase flow systems. Pan et al. [165] advanced this understanding by providing an analytical solution specifically for wellbore applications, emphasizing the importance of accurately modeling gas and liquid interactions. As the research progressed, Hu et al. [166] and Pan et al. [167] [166,167] incorporated more sophisticated simulators to analyze brine leakage, highlighting the limitations of traditional linear approaches and emphasizing the need for integrated wellbore-reservoir models to capture nonlinear flow dynamics. Bai et al. [153] continued this trend towards complexity by applying the finite element method and empirical correlations to determine mechanical integrity and leakage rates under a variety of conditions. Although quantitative models may give accurate results, they are computationally expensive. This complexity is an issue if the parameters have higher uncertainty, requiring running sensitivity analysis and stochastic models [168,169].

Reduced-order models (ROM) were introduced as solutions to reduce computational time, considering the most significant factors affecting well leakage and lookup tables for reservoir parameter changes [149,170,171]. The earlier, traditional ROMs covering a large predictive range often perform poorly in specific ranges, particularly at low values, as seen in CO_2 leakage and pH plume predictions [172–174]. To address this, approaches like "Frankenstein's ROMster," which integrate multiple sub-ROMs tailored to different predictive ranges, can significantly improve accuracy [169]. The author demonstrated his methodology by predicting the injection rate of CO_2 injection in a GCS project, resulting in a reduction in errors from over 200% to as low as 4%. Reduced-order models are known by various names, including response surface models, proxy models, meta-models, and surrogate models [169]. As numerical models become more comprehensive by incorporating various physical processes and accounting for uncertainties, surrogate models have evolved to handle large numbers of realizations while maintaining high accuracy [175].

Initially, machine learning techniques showed limited scalability and reached performance plateaus when faced with vast, complex datasets [175]. However, the advent of deep learning, inspired by neural networks, allowed models to process larger datasets through multiple layers, improving performance as data volume increased [176]. This shift led to the development of deep learning-based surrogate models in GCS applications, where they have been used to predict flow and geomechanical responses during CO_2 storage [158,177]. More recent advancements include the use of LightGBM by [178] for predicting CO_2 and hydrocarbon leakage with 200 simulation samples and the use of LSTM networks by [179] to predict CO_2 wellbore leakage based on 250 numerical realizations. Baek et al. [175] developed a model using deep learning and full-physics numerical flow simulations. The deep learning model was trained on 4191 realizations of numerical reservoir simulations. Feature analysis was used to evaluate the impact of various inputs on model accuracy, allowing for the removal of less significant features to improve prediction performance. By separating the regression problem into classification and regression tasks, the new wellbore ROM significantly enhanced model accuracy, reducing errors from 2.31 $\times$ 10 (log10(kg/s))0.5 to 9.44 $\times$ 10^{-5} (log10(kg/s))0.5. Table 6 summarizes different types of models and how they contribute to legacy well evaluation. Future work should refine ROMs by incorporating advanced deep learning techniques and feature selection to improve accuracy across diverse conditions. Expanding these models to handle more complex geologic and operational scenarios will enhance their effectiveness in predicting wellbore leakage and other critical factors in CO_2 storage, as will integrating monitoring inversion results to refine uncertainty parameters in forward simulations, exploring additional mitigation strategies, and extending the approach to brownfield cases, such as CO_2-enhanced oil recovery sites, to validate and improve risk assessment methods.

Table 6. Summary of key models and their best-use cases for CO_2 leakage assessment.

Model Type	Example Studies	Best Use Cases	Strengths
Qualitative (Risk Matrix, Register, FEPs, Index/scoring Based models)	[32,153,154,159]	- Legacy wells with incomplete records - Early-stage screening - Regulatory compliance reporting	- Simple and transparent - Can incorporate expert judgment without needing complete data
Probabilistic/Semi-Quantitative Models	[158–160]	- Fields with uncertain or partial monitoring - Updating risk with new data - Planning monitoring scope	- Can incorporate missing data with Bayesian updates - Useful for prioritization and ranking
Quantitative and Simulation-Based Models (e.g., Drift-Flux, T2WELL, TOUGH2, FEM)	[153,165–167,180]	- Leakage pathway modeling - Complex site-specific integrity analysis - Multi-phase CO_2 flow and injection design	- Mechanistic and physics-based - Captures coupled THM processes - High predictive accuracy for dynamic scenarios
Reduced Order Models (ROM)	[169,174]	- Rapid leakage rate estimation - Parametric studies - Screening multiple well scenarios	- Fast and efficient - Captures interactions from high-dimensional input spaces
Hybrid (Numerical + Experimental)	[181,182]	- Detailed integrity analysis - Accounting for micro-annuli, cracks, and real field effects	- Physically realistic - Bridges gap between lab data and numerical model predictions
Integrated Frameworks (Qualitative + Quantitative)	[149,183]	- Screening and risk assessment at basin-to-site scale - Planning monitoring strategies for legacy wells - Decision support under uncertainty	- Modular and user-friendly - Integrates experimental, simulation, and statistical tools - Adaptable to data-limited or regulatory settings

6. Conclusions

Evaluating wellbore integrity in CO_2 storage is crucial to determining the success of CCS projects. This review discussed the key challenges facing the wellbore and, in particular, legacy wells in AOI, highlighting potential problems from investigated fields in Texas. Downhole conditions are important factors in determining CO_2 solubility and reactions with cement. Although chemical and mechanical self-sealing mechanisms may be a potential leakage mitigation, their value is highly dependent on environmental conditions, fracture size, and fluid dynamics. Fracture sizes are dependent on well design and operational factors throughout the life cycle of the well. Casing integrity is proven to be compromised if exposed to the CO_2 environment. But no study has investigated the leakage possibility or sealability of the casing–cement barrier from the well to the outside, into the permeable formation. If potential fractures are available for leakage, well logs (CBL and VDL) along SCP can be used to understand the possible leakage flow paths. However, with a lack of data, which is always the case for legacy wells, especially in Texas, drawing wellbore schematics highlighting the impermeable formations, cement tops in annular space, and plug placement relative to these permeable formations is the best way to evaluate those wells. The top of the cement in the annular space is not always reported, introducing higher uncertainty in evaluation. The development of numerical models can give us detailed insights into quantifying leakage through these possible flow pathways. When it comes to computational time, reduced-order models and surrogate models offer faster results, enabling us to use them as risk assessment tools to run many sensitivity analyses on different case scenarios.

Future recommendations:

1. Field cement degradation analysis is limited to situations of re-entering and side coring in the well. Only one field study across the US has been conducted in the last 15 years.
2. A study to identify fields with similar geological and geographical characteristics across the US is needed to utilize data-rich field analysis and obtain results on limited-data fields.
3. Experimental work is needed to answer the following: does the presence of a second casing–cement layer significantly reduce leakage probability?

Author Contributions: Conceptualization, B.E. and M.W.; methodology, B.E., M.W., N.A. and H.E.; validation, S.T. and A.R.B.; formal analysis, A.R.B. and A.S.; investigation, M.A. and S.T.; resources, M.A. and N.A.; data curation, B.E.; writing—original draft preparation, B.E.; writing—review and editing, B.E., A.S. and M.A.; visualization, S.T.; supervision, M.W. and H.E.; project administration, M.W.; funding acquisition, M.W. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: The data presented in this study are available in Texas Railroad Commission at https://gis.rrc.texas.gov/GISViewer/ (accessed on 8 May 2025).

Conflicts of Interest: The authors declare no conflicts of interest.

Abbreviations

The following abbreviations are used in this manuscript:

CCI	Casing–Cement Interface
CFI	Casing–Formation Interface
SCC	Stress Corrosion Cracking
SCVF	Sustained Casing Vent Flow
GM	Gas Migration
CBL	Casing Bond Log
VDL	Variable-Density Log
AOI	Area of Interest

References

1. Ketzer, J.M.; Iglesias, R.S.; Einloft, S. Reducing Greenhouse Gas Emissions with CO_2 Capture and Geological Storage. In *Handbook of Climate Change Mitigation*; Springer: New York, NY, USA, 2012; pp. 1405–1440. [CrossRef]
2. Lebling, K.; Gangotra, A.; Hausker, K.; Byrum, Z. 7 Things to Know About Carbon Capture, Utilization and Sequestration. Available online: https://www.wri.org/insights/carbon-capture-technology (accessed on 14 June 2025).
3. EPA. Sources of Greenhouse Gas Emissions. Available online: https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions (accessed on 14 June 2025).
4. Global CCS Institute. Global Status of CCS Report 2024. 2024. Available online: https://www.globalccsinstitute.com/resources/global-status-report/ (accessed on 14 June 2025).
5. Zhu, D.; Peng, S.; Zhao, S.; Wei, M.; Bai, B. Comprehensive Review of Sealant Materials for Leakage Remediation Technology in Geological CO_2 Capture and Storage Process. *Energy Fuels* **2021**, *35*, 4711–4742. [CrossRef]
6. Ringrose, P. *How to Store CO_2 Underground: Insights from Early-Mover CCS Projects*; Springer International Publishing: Cham, Switzerland, 2020. [CrossRef]
7. Fentaw, J.W.; Emadi, H.; Hussain, A.; Fernandez, D.M.; Thiyagarajan, S.R. Geochemistry in Geological CO_2 Sequestration: A Comprehensive Review. *Energies* **2024**, *17*, 5000. [CrossRef]
8. Khurshid, I.; Fujii, Y. Geomechanical analysis of formation deformation and permeability enhancement due to low-temperature CO_2 injection in subsurface oil reservoirs. *J. Pet. Explor. Prod. Technol.* **2021**, *11*, 1915–1923. [CrossRef]
9. Hamza, A.; Hussein, I.A.; Al-Marri, M.J.; Mahmoud, M.; Shawabkeh, R.; Aparicio, S. CO_2 enhanced gas recovery and sequestration in depleted gas reservoirs: A review. *J. Pet. Sci. Eng.* **2021**, *196*, 107685. [CrossRef]
10. Lam, C.M.; Kuanji, J.J. Repurposing of Hydrocarbon Pipelines for CO2 Injection in CCS Project—Can it be Done? In Proceedings of the SPE Annual Technical Conference and Exhibition, San Antonio, TX, USA, 16–18 October 2023. [CrossRef]
11. Taman, A.; Ali, R.; Youssif, M.; Elnaggar, H.; Shoukry, A.; Shahin, A. Opportunities for Carbon Capture and Storage Deployment in Existing Coal-Fired Power Plants in Texas. In Proceedings of the SPE Oklahoma City Oil and Gas Symposium, Oklahoma City, OK, USA, 14–18 April 2025. [CrossRef]
12. Roberts, J.J.; Stalker, L. What have we learnt about CO_2 leakage from CO_2 release field experiments, and what are the gaps for the future? *Earth Sci. Rev.* **2020**, *209*, 102939. [CrossRef]
13. Lackey, G.; Vasylkivska, V.S.; Huerta, N.J.; King, S.; Dilmore, R.M. Managing well leakage risks at a geologic carbon storage site with many wells. *Int. J. Greenh. Gas Control* **2019**, *88*, 182–194. [CrossRef]
14. Quantification Techniques for CO_2 Leakage—IEAGHG. Available online: https://ieaghg.org/publications/quantification-techniques-for-co2-leakage/ (accessed on 1 May 2025).
15. Boruah, A. Reservoir Screening Criteria for CO_2 Storage. In *CO_2 Geosequestration: Capturing Carbon for a Sustainable Future*; Springer: Cham, Switzerland, 2025; pp. 19–40. [CrossRef]
16. Salim, O.; Sharma, K.V.; Piri, M. Storage of supercritical carbon dioxide in nanoporous media. *J. CO_2 Util.* **2025**, *92*, 103017. [CrossRef]
17. Aboahmed, A.; Mohanty, K. CO_2 Storage and Utilization in Heterogeneous Carbonate Reservoirs Using Nanoparticle Stabilized Foam. In Proceedings of the SPE International Symposium on Oilfield Chemistry, Galveston, TX, USA, 9–10 April 2025. [CrossRef]
18. Hanamertani, A.S.; Yu, Y.; Elkhatib, O.; Ahmed, S.; Jiao, Z.; McLaughlin, J.F. Evaluation of CO_2 Storage Potential During CO_2 Mobility Control Optimization for Enhanced Oil Recovery. In Proceedings of the SPE Western Regional Meeting, Anchorage, AK, USA, 22–25 May 2023. [CrossRef]
19. Callas, C.; Saltzer, S.D.; Davis, J.S.; Hashemi, S.S.; Kovscek, A.R.; Okoroafor, E.R.; Wen, G.; Zoback, M.D.; Benson, S.M. Criteria and workflow for selecting depleted hydrocarbon reservoirs for carbon storage. *Appl. Energy* **2022**, *324*, 119668. [CrossRef]

20. Nguyen, V.; Olayiwola, O.; Guo, B.; Liu, N. Well Cement Degradation and Wellbore Integrity in Geological CO_2 Storages: A Literature Review. *arXiv* **2023**, arXiv:2301.02357. [CrossRef]
21. Goodwin, K.J.; Crook, R.J. Cement Sheath Stress Failure. *SPE Drill. Eng.* **1992**, *7*, 291–296. [CrossRef]
22. Duguid, A.; Scherer, G.W. Degradation of oilwell cement due to exposure to carbonated brine. *Int. J. Greenh. Gas Control* **2010**, *4*, 546–560. [CrossRef]
23. Duguid, A.; Radonjic, M.; Scherer, G.W. Degradation of cement at the reservoir/cement interface from exposure to carbonated brine. *Int. J. Greenh. Gas Control* **2011**, *5*, 1413–1428. [CrossRef]
24. Wenning, Q.C.; Huerta, N.J.; Hesse, M.A.; Bryant, S.L. Reactive flow channelization in fractured cement- Implications for wellbore integrity. *Energy Procedia* **2013**, *37*, 5773–5780. [CrossRef]
25. Carroll, S.; Carey, J.W.; Dzombak, D.; Huerta, N.J.; Li, L.; Richard, T.; Um, W.; Walsh, S.D.; Zhang, L. Review: Role of chemistry, mechanics, and transport on well integrity in CO_2 storage environments. *Int. J. Greenh. Gas Control* **2016**, *49*, 149–160. [CrossRef]
26. Kiran, R.; Teodoriu, C.; Dadmohammadi, Y.; Nygaard, R.; Wood, D.; Mokhtari, M.; Salehi, S. Identification and evaluation of well integrity and causes of failure of well integrity barriers (A review). *J. Nat. Gas Sci. Eng.* **2017**, *45*, 511–526. [CrossRef]
27. Iyer, J.; Lackey, G.; Edvardsen, L.; Bean, A.; Carroll, S.A.; Huerta, N.; Smith, M.M.; Torsæter, M.; Dilmore, R.M.; Cerasi, P. A Review of Well Integrity Based on Field Experience at Carbon Utilization and Storage Sites. *Int. J. Greenh. Gas Control.* **2022**, *113*, 103533. [CrossRef]
28. Alberdi-Pagola, P.; Fischer, G. Review of Integrity Loss Detection and Quantification Due to Cracking in Cemented Wells. *SPE J.* **2023**, *28*, 965–982. [CrossRef]
29. Xiao, T.; Chen, T.; Ma, Z.; Tian, H.; Meguerdijian, S.; Chen, B.; Pawar, R.; Huang, L.; Xu, T.; Cather, M.; et al. A review of risk and uncertainty assessment for geologic carbon storage. *Renew. Sustain. Energy Rev.* **2023**, *189*, 113945. [CrossRef]
30. Hajiyev, E.; Watson, M.; Emadi, H.; Eissa, B.; Hussain, A.; Baig, A.R.; Shahin, A. A Comparative Study of Major Risk Assessment (RA) Frameworks in Geologic Carbon Storage (GCS). *Fuels* **2025**, *6*, 42. [CrossRef]
31. NATCARB/ATLAS. Available online: https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas (accessed on 5 May 2025).
32. Arbad, N.; Watson, M.; Emadi, H.; Eyitayo, S.; Leggett, S. Strategic Qualitative Risk Assessment of Thousands of Legacy Wells within the Area of Review (AoR) of a Potential CO_2 Storage Site. *Minerals* **2024**, *14*, 383. [CrossRef]
33. RRC Public GIS Viewer. Available online: https://gis.rrc.texas.gov/GISViewer/ (accessed on 7 June 2025).
34. EPA. Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance. Available online: https://www.epa.gov/sites/default/files/2015-07/documents/epa816r13005.pdf (accessed on 7 June 2025).
35. Huang, W.; Zhang, N.; An, Z.; Wang, P.; Liu, W. Research and Practice of Integrity Evaluation Technology for Deep Gas Wells. In *Proceedings of the 2021 International Petroleum and Petrochemical Technology Conference*; Springer: Singapore, 12 March 2022; pp. 409–418. [CrossRef]
36. Preston, D.J.; Elizabeth, B.; Curtis, M.O. Recommendations for Geologic Carbon Sequestration in California: I. Siting Criteria and Monitoring Approaches, II. Example Application Case Study. 2017. Available online: https://ww2.arb.ca.gov/sites/default/files/2018-12/LBNL_CARB_QM_Final_Report_6-15-17.pdf (accessed on 7 June 2025).
37. Zhang, L.; Dzombak, D.A.; Kutchko, B.G. Wellbore Cement Integrity under Geologic Carbon Storage Conditions. In *Novel Materials for Carbon Dioxide Mitigation Technology*; Elsevier: Amsterdam, The Netherlands, 2015; pp. 333–362. [CrossRef]
38. Zhang, M.; Bachu, S. Review of integrity of existing wells in relation to CO_2 geological storage: What do we know? *Int. J. Greenh. Gas Control* **2011**, *5*, 826–840. [CrossRef]
39. Song, Y.; Jun, S.; Na, Y.; Kim, K.; Jang, Y.; Wang, J. Geomechanical challenges during geological CO_2 storage: A review. *Chem. Eng. J.* **2023**, *456*, 140968. [CrossRef]
40. Chen, Q.; Fan, J.; Zhang, L.; Sun, J. Stress corrosion phenomenon of casing in CO_2 medium and magnetic memory detection. *e-J. Nondestruct. Test.* **2024**, *29*. [CrossRef] [PubMed]
41. Bagheri, M.; Shariatipour, S.M.; Ganjian, E. A review of oil well cement alteration in CO_2-rich environments. *Constr. Build. Mater.* **2018**, *186*, 946–968. [CrossRef]
42. Razak, A.A.A.; Saaid, I.M.; Yusof, M.A.M.; Husein, N.; Zaidin, M.F.; Sabil, K.M. Physical and chemical effect of impurities in carbon capture, utilisation and storage. *J. Pet. Explor. Prod. Technol.* **2023**, *13*, 1235–1246. [CrossRef]
43. Vakili, M.; Koutník, P.; Kohout, J. Addressing Hydrogen Sulfide Corrosion in Oil and Gas Industries: A Sustainable Perspective. *Sustainability* **2024**, *16*, 1661. [CrossRef]
44. Yang, Z.; Zhang, W.; Zhu, H.; Chen, Y.; Xu, L.; Wang, P.; Lai, Y. Thaumasite form of sulfate attack in ettringite rich-ternary systems: Effects of limestone filler, etching solutions and exposure temperature. *Dev. Built Environ.* **2023**, *15*, 100208. [CrossRef]
45. Liu, B.; Mahmood, B.S.; Mohammadian, E.; Manshad, A.K.; Rosli, N.R.; Ostadhassan, M. Measurement of Solubility of CO_2 in NaCl, $CaCl_2$, $MgCl_2$ and $MgCl_2$ + $CaCl_2$ Brines at Temperatures from 298 to 373 K and Pressures up to 20 MPa Using the Potentiometric Titration Method. *Energies* **2021**, *14*, 7222. [CrossRef]

46. Chen, J.J.; Thomas, J.J.; Taylor, H.F.; Jennings, H.M. Solubility and structure of calcium silicate hydrate. *Cem. Concr. Res.* **2004**, *34*, 1499–1519. [CrossRef]
47. Trapote-Barreira, A.; Cama, J.; Soler, J.M. Dissolution kinetics of C–S–H gel: Flow-through experiments. *Phys. Chem. Earth Parts A/B/C* **2014**, *70*, 17–31. [CrossRef]
48. Bagheri, M. Reactive Transport Modelling and Geomechanical Investigation of Wellbore Cements in CO_2 Storage Sites. Doctoral Thesis, Coventry University, Coventry, UK, 2020.
49. Duan, Z.; Sun, R. An improved model calculating CO_2 solubility in pure water and aqueous NaCl solutions from 273 to 533 K and from 0 to 2000 bar. *Chem. Geol.* **2003**, *193*, 257–271. [CrossRef]
50. Spycher, N.; Pruess, K.; Ennis-King, J. CO_2-H_2O mixtures in the geological sequestration of CO_2. I. Assessment and calculation of mutual solubilities from 12 to 100 °C and up to 600 bar. *Geochim. Cosmochim. Acta* **2003**, *67*, 3015–3031. [CrossRef]
51. Gibbins, J.; Chalmers, H. Carbon Capture and Storage. *Energy Policy* **2008**, *36*, 4317–4322. [CrossRef]
52. Druckenmiller, M.L.; Maroto-Valer, M.M. Carbon sequestration using brine of adjusted pH to form mineral carbonates. *Fuel Process. Technol.* **2005**, *86*, 1599–1614. [CrossRef]
53. Kutchko, B.G.; Strazisar, B.R.; Dzombak, D.A.; Lowry, G.V.; Thaulow, N. Degradation of well cement by CO_2 under geologic sequestration conditions. *Environ. Sci. Technol.* **2007**, *41*, 4787–4792. [CrossRef]
54. Recasens, M.; Garcia, S.; Mackay, E.; Delgado, J.; Maroto-Valer, M. Experimental Study of Wellbore Integrity for CO_2 Geological Storage. *Energy Procedia* **2017**, *114*, 5249–5255. [CrossRef]
55. Barlet-Gouédard, V.; Rimmelé, G.; Goffé, B.; Porcherie, O. Well Technologies for CO_2 Geological Storage: CO2-Resistant Cement. *Oil Gas. Sci. Technol.—Revue d'IFP Energies Nouvelles* **2007**, *62*, 325–334. [CrossRef]
56. Rimmelé, G.; Barlet-Gouédard, V. Accelerated degradation method for cement under CO_2-rich environment: The LIFTCO_2 procedure (leaching induced by forced transport in CO_2 fluids). *Cem. Concr. Res.* **2010**, *40*, 1175–1188. [CrossRef]
57. Kutchko, B.G.; Strazisar, B.R.; Huerta, N.; Lowry, G.V.; Dzombak, D.A.; Thaulow, N. CO_2 reaction with hydrated class H well cement under geologic sequestration conditions: Effects of flyash admixtures. *Environ. Sci. Technol.* **2009**, *43*, 3947–3952. [CrossRef]
58. Rimmelé, G.; Barlet-Gouédard, V.; Porcherie, O.; Goffé, B.; Brunet, F. Heterogeneous Porosity Distribution in Portland Cement Exposed to CO2-rich Fluids. *Cem. Concr. Res.* **2008**, *38*, 1038–1048. [CrossRef]
59. Wigand, M.; Kaszuba, J.P.; Carey, J.W.; Hollis, W.K. Geochemical effects of CO_2 sequestration on fractured wellbore cement at the cement/caprock interface. *Chem. Geol.* **2009**, *265*, 122–133. [CrossRef]
60. Mason, H.E.; Du Frane, W.L.; Walsh, S.D.; Dai, Z.; Charnvanichborikarn, S.; Carroll, S.A. Chemical and Mechanical Properties of Wellbore Cement Altered by CO_2-Rich Brine Using a Multianalytical Approach. *Environ. Sci. Technol.* **2013**, *47*, 1745–1752. [CrossRef] [PubMed]
61. Luquot, L.; Abdoulghafour, H.; Gouze, P. Hydro-dynamically controlled alteration of fractured Portland cements flowed by CO_2-rich brine. *Int. J. Greenh. Gas Control* **2013**, *16*, 167–179. [CrossRef]
62. Cao, P.; Karpyn, Z.T.; Li, L. Self-healing of cement fractures under dynamic flow of CO_2-rich brine. *Water Resour. Res.* **2015**, *51*, 4684–4701. [CrossRef]
63. Mito, S.; Xue, Z.; Satoh, H. Experimental assessment of well integrity for CO_2 geological storage: Batch experimental results on geochemical interactions between a CO_2–brine mixture and a sandstone–cement–steel sample. *Int. J. Greenh. Gas Control* **2015**, *39*, 420–431. [CrossRef]
64. Abdoulghafour, H.; Gouze, P.; Luquot, L.; Leprovost, R. Characterization and modeling of the alteration of fractured class-G Portland cement during flow of CO_2-rich brine. *Int. J. Greenh. Gas Control* **2016**, *48*, 155–170. [CrossRef]
65. Jahanbakhsh, A.; Liu, Q.; Mosleh, M.H.; Agrawal, H.; Farooqui, N.M.; Buckman, J.; Recasens, M.; Maroto-Valer, M.; Korre, A.; Durucan, S. An Investigation into CO2–Brine–Cement–Reservoir Rock Interactions for Wellbore Integrity in CO_2 Geological Storage. *Energies* **2021**, *14*, 5033. [CrossRef]
66. Wang, D.; Noguchi, T.; Nozaki, T.; Higo, Y. Investigation of the carbonation performance of cement-based materials under high temperatures. *Constr. Build. Mater.* **2021**, *272*, 121634. [CrossRef]
67. Mamoudou, S.; Curtis, M.; Dang, S.; Rai, C. Experimental evaluation of cement integrity on exposure to supercritical CO_2 using NMR: Application to geostorage. *Heliyon* **2024**, *10*, e24144. [CrossRef]
68. Carey, J.W.; Svec, R.; Grigg, R.; Zhang, J.; Crow, W. Experimental investigation of wellbore integrity and CO_2–brine flow along the casing–cement microannulus. *Int. J. Greenh. Gas Control* **2010**, *4*, 272–282. [CrossRef]
69. Strazisar, B.; Kutchko, B.; Huerta, N. Chemical Reactions of Wellbore Cement Under CO_2 Storage Conditions: Effects of Cement Additives. *Energy Procedia* **2009**, *1*, 3603–3607. [CrossRef]
70. Akhavan, A.; Shafaatian, S.-M.-H.; Rajabipour, F. Quantifying the effects of crack width, tortuosity, and roughness on water permeability of cracked mortars. *Cem. Concr. Res.* **2012**, *42*, 313–320. [CrossRef]
71. Iyer, J.; Walsh, S.D.; Hao, Y.; Carroll, S.A. Incorporating reaction-rate dependence in reaction-front models of wellbore-cement/carbonated-brine systems. *Int. J. Greenh. Gas Control* **2017**, *59*, 160–171. [CrossRef]

72. Walsh, S.D.; Mason, H.E.; Du Frane, W.L.; Carroll, S.A. Experimental calibration of a numerical model describing the alteration of cement/caprock interfaces by carbonated brine. *Int. J. Greenh. Gas Control* **2014**, *22*, 176–188. [CrossRef]
73. Walsh, S.D.C.; Du Frane, W.L.; Mason, H.E.; Carroll, S.A. Permeability of Wellbore-Cement Fractures Following Degradation by Carbonated Brine. *Rock. Mech. Rock. Eng.* **2012**, *46*, 455–464. [CrossRef]
74. Walsh, S.D.; Mason, H.E.; Du Frane, W.L.; Carroll, S.A. Mechanical and hydraulic coupling in cement–caprock interfaces exposed to carbonated brine. *Int. J. Greenh. Gas Control* **2014**, *25*, 109–120. [CrossRef]
75. Brunet, J.-P.L.; Li, L.; Karpyn, Z.T.; Huerta, N.J. Fracture opening or self-sealing: Critical residence time as a unifying parameter for cement–CO_2–brine interactions. *Int. J. Greenh. Gas Control* **2016**, *47*, 25–37. [CrossRef]
76. Dávila, G.; Luquot, L.; Soler, J.M.; Cama, J. 2D reactive transport modeling of the interaction between a marl and a CO2-rich sulfate solution under supercritical CO_2 conditions. *Int. J. Greenh. Gas Control* **2016**, *54*, 145–159. [CrossRef]
77. Deremble, L.; Loizzo, M.; Huet, B.; Lecampion, B.; Quesada, D. Stability of a leakage pathway in a cemented annulus. *Energy Procedia* **2011**, *4*, 5283–5290. [CrossRef]
78. Huerta, N.J.; Bryant, S.L.; Strazisar, B.R.; Kutchko, B.G.; Conrad, L.C. The influence of confining stress and chemical alteration on conductive pathways within wellbore cement. *Energy Procedia* **2009**, *1*, 3571–3578. [CrossRef]
79. Nakano, K.; Mito, S.; Xue, Z. Self-sealing of Wellbore Cement under the CO_2 Batch Experiment Using Well Composite Sample. *Energy Procedia* **2017**, *114*, 5212–5218. [CrossRef]
80. Fabbri, A.; Corvisier, J.; Schubnel, A.; Brunet, F.; Goffé, B.; Rimmele, G.; Barlet-Gouédard, V. Thermo-Hydromechanical and Chemical Coupling in Geomaterials and Applications: Proceedings of the 3 International Symposium GeoProc'2008—Effect of carbonation on the hydro-mechanical properties of Portland cements. *Cem. Concr. Res.* **2009**, *39*, 1156–1163. [CrossRef]
81. Choi, Y.-S.; Young, D.; Nešić, S.; Gray, L.G. Wellbore integrity and corrosion of carbon steel in CO_2 geologic storage environments: A literature review. *Int. J. Greenh. Gas Control* **2013**, *16*, S70–S77. [CrossRef]
82. Jones, S.C. Using the Inertial Coefficient, ß, To Characterize Heterogeneity in Reservoir Rock. In Proceedings of the SPE Annual Technical Conference and Exhibition, Dallas, TX, USA, 27–30 September 1987; Volume 45. [CrossRef]
83. Lusk, D.; Casserly, T.; Gupta, M.; Boinapally, K.; Cao, Y. Armoured against Corrosion. *Hydrocarb. Eng.* **2008**, *13*, 115–118. Available online: https://www.researchgate.net/publication/286228830_Armoured_against_corrosion (accessed on 7 June 2025).
84. Watson, T.L.; Bachu, S. Evaluation of the Potential for Gas and CO_2 Leakage along Wellbores. *SPE Drill. Complet.* **2009**, *24*, 115–126. [CrossRef]
85. Anwar, I.; Chojnicki, K.; Bettin, G.; Taha, M.R.; Stormont, J.C. Characterization of wellbore casing corrosion product as a permeable porous medium. *J. Pet. Sci. Eng.* **2019**, *180*, 982–993. [CrossRef]
86. Qing, L.I.; Deping, Z.; Xiaorong, L.I.; Wei, W.; Baozhuang, S.U.N.; Chi, A.I. Comparison of Stress Corrosion Behavior of TP110TS and P110 Steel in a Simulated Annular Environment of CO_2 Injection Well. *J. Chin. Soc. Corros. Prot.* **2020**, *40*, 302–308.
87. Cui, H.; Mei, P.; Liu, Z.; Lu, L. The effect of CO partial pressure on the stress corrosion 2 behavior of N80 oil pipe steel in the CO_2 driven injection well annulus environment. *J. Eng. Sci.* **2020**, *42*, 1182–1189.
88. Sadeghi, M.A.; Javidi, M. Investigation on stress corrosion cracking of API 5L X65 steel in CO_2 corrosion medium. *Mater. Sci. Eng. A* **2021**, *824*, 141856. [CrossRef]
89. Harle, B.; Beavers, J. Technical Note: Low-pH Stress Corrosion Crack Propagation in API X-65 Line Pipe Steel. *Corrosion* **1993**, *49*, 861–863. [CrossRef]
90. Alkhamis, M.; Imqam, A. A Simple Classification of Wellbore Integrity Problems Related to Fluids Migration. *Arab. J. Sci. Eng.* **2021**, *46*, 6131–6141. [CrossRef]
91. Carter, L.; Evans, G. A Study of Cement-Pipe Bonding. *J. Pet. Technol.* **1964**, *16*, 157–160. [CrossRef]
92. Li, X.; Zeng, Y.; Ding, Z.; Liu, R.; Lin, H.; Harris, C. Cement Sheath Integrity in Anisotropic Shale Formations: A Numerical Investigation. *Geofluids* **2022**, *2022*, 1–16. [CrossRef]
93. Gu, C.; Li, X.; Feng, Y.; Deng, J.; Gray, K. Numerical investigation of cement interface debonding in deviated shale gas wells considering casing eccentricity and residual drilling fluid. *Int. J. Rock Mech. Min. Sci.* **2022**, *158*, 105197. [CrossRef]
94. Lockyear, C.F.; Ryan, D.F.; Gunningham, M.M. Cement Channeling: How to Predict and Prevent. *SPE Drill. Eng.* **1990**, *5*, 201–208. [CrossRef]
95. Yousuf, N.; Olayiwola, O.; Guo, B.; Liu, N. A comprehensive review on the loss of wellbore integrity due to cement failure and available remedial methods. *J. Pet. Sci. Eng.* **2021**, *207*, 109123. [CrossRef]
96. Skorpa, R.; Vrålstad, T. Visualization of Fluid Flow Through Cracks and Microannuli in Cement Sheaths. *SPE J.* **2018**, *23*, 1067–1074. [CrossRef]
97. Yan, X.; Jun, L.; Gonghui, L.; Qian, T.; Wei, L. A new numerical investigation of cement sheath integrity during multistage hydraulic fracturing shale gas wells. *J. Nat. Gas Sci. Eng.* **2018**, *49*, 331–341. [CrossRef]
98. Yang, H.; Wang, L.; Huang, G.; Zhao, J.; Yang, C.; Bi, Z.; Guo, Y.; Liu, W.V. Effects of compressive cyclic loading on the fatigue properties of oil-well cement slurries serving in deep downhole environments. *Constr. Build. Mater.* **2024**, *428*, 136360. [CrossRef]

99. Shadravan, A.; Kias, E.; Lew, R.; Maharidge, R. Utilizing the Evolving Cement Mechanical Properties under Fatigue to Predict Cement Sheath Integrity. In Proceedings of the SPE Kuwait Oil and Gas Show and Conference, Mishref, Kuwait, 11–14 October 2015. [CrossRef]
100. Deng, K.; Yuan Yue Hao, Y.; Li, Z.; Lin, Y. Experimental study on the integrity of casing-cement sheath in shale gas wells under pressure and temperature cycle loading. *J. Pet. Sci. Eng.* **2020**, *195*, 107548. [CrossRef]
101. Liu, K.; Gao, D.; Taleghani, A.D. Analysis on integrity of cement sheath in the vertical section of wells during hydraulic fracturing. *J. Pet. Sci. Eng.* **2018**, *168*, 370–379. [CrossRef]
102. Xi, Y.; Li, J.; Tao, Q.; Guo, B.; Liu, G. Experimental and numerical investigations of accumulated plastic deformation in cement sheath during multistage fracturing in shale gas wells. *J. Pet. Sci. Eng.* **2020**, *187*, 106790. [CrossRef]
103. Deng, T.; Zeng, Z.; Xu, J.; Wen, J. A geometric analysis-based approach toward mechanical analytics of multi-packer completion tubular string. *J. Pet. Explor. Prod.* **2024**, *14*, 1553–1588. [CrossRef]
104. Reddy, B.R.; Xu, Y.; Ravi, K.; Gray, D.W.; Pattillo, P. Cement-shrinkage measurement in oilwell cementing—A comparative study of laboratory methods and procedures. *SPE Drill. Complet.* **2009**, *24*, 104–114. [CrossRef]
105. Sabins, F.L. Problems in Cementing Horizontal Wells. *J. Pet. Technol.* **1990**, *42*, 398–400. [CrossRef]
106. Lavrov, A. Stiff cement, soft cement: Nonlinearity, arching effect, hysteresis, and irreversibility in CO_2-well integrity and near-well geomechanics. *Int. J. Greenh. Gas Control* **2018**, *70*, 236–242. [CrossRef]
107. Chenevert, M.E.; Shrestha, B.K. Chemical Shrinkage Properties of Oilfield Cements. *SPE Drill. Eng.* **1991**, *6*, 37–231. [CrossRef]
108. Backe, K.R.; Lile, O.B.; Lyomov, S.K.; Elvebakk, H.; Skalle, P. Characterizing Curing-Cement Slurries by Permeability, Tensile Strength, and Shrinkage. *SPE Drill. Complet.* **1999**, *14*, 162–167. [CrossRef]
109. Goboncan, V.C.; Dillenbeck, R.L. Real-Time Cement Expansion/Shrinkage Testing Under Downhole Conditions for Enhanced Annular Isolation. In Proceedings of the SPE/IADC Drilling Conference, Amsterdam, The Netherlands, 19–21 February 2003. [CrossRef]
110. Yan, Y.; Guan, Z.; Xu, Y.; Yan, W.; Chen, W. Study on Debonding Issue of Cementing Interfaces Caused by Perforation with Numerical Simulation and Experimental Measures. *SPE Drill. Complet.* **2020**, *35*, 684–695. [CrossRef]
111. Zhang, F.; Dontsov, E. Modeling hydraulic fracture propagation and proppant transport in a two-layer formation with stress drop. *Eng. Fract. Mech.* **2018**, *199*, 705–720. [CrossRef]
112. Feng, Y.; Gray, K.E. Parameters controlling pressure and fracture behaviors in field injectivity tests: A numerical investigation using coupled flow and geomechanics model. *Comput. Geotech.* **2017**, *87*, 49–61. [CrossRef]
113. Lecampion, B.; Bunger, A.; Kear, J.; Quesada, D. Interface debonding driven by fluid injection in a cased and cemented wellbore: Modeling and experiments. *Int. J. Greenh. Gas Control* **2013**, *18*, 208–223. [CrossRef]
114. Jiang, J.; Li, J.; Liu, G.; Lian, W.; Xi, Y.; Yang, H.; Li, W. Numerical simulation investigation on fracture debonding failure of cement plug/casing interface in abandoned wells. *J. Pet. Sci. Eng.* **2020**, *192*, 107226. [CrossRef]
115. Feng, Y.; Li, X.; Gray, K.E. Development of a 3D numerical model for quantifying fluid-driven interface debonding of an injector well. *Int. J. Greenh. Gas Control* **2017**, *62*, 76–90. [CrossRef]
116. Gu, C.; Feng, Y.; Mosleh, M.H.; Li, X.; Sanei, M.; Deng, J. Fluid-Driven Debonding of Cement Interfaces of an Injector Well: A Coupled Thermo–Hydro–Mechanical Approach. *Rock. Mech. Rock. Eng.* **2024**, *57*, 4513–4531. [CrossRef]
117. Li, Q.; Han, Y.; Liu, X.; Ansari, U.; Cheng, Y.; Yan, C. Hydrate as a by-product in CO_2 leakage during the long-term sub-seabed sequestration and its role in preventing further leakage. *Environ. Sci. Pollut. Res.* **2022**, *29*, 77737–77754. [CrossRef]
118. Li, Q.; Liu, J.; Wang, S.; Guo, Y.; Han, X.; Li, Q.; Cheng, Y.; Dong, Z.; Li, X.; Zhang, X. Numerical insights into factors affecting collapse behavior of horizontal wellbore in clayey silt hydrate-bearing sediments and the accompanying control strategy. *Ocean Eng.* **2024**, *297*, 117029. [CrossRef]
119. Li, Q.; Wu, J.; Li, Q.; Wang, F.; Cheng, Y. Sediment Instability Caused by Gas Production from Hydrate-Bearing Sediment in Northern South China Sea by Horizontal Wellbore: Sensitivity Analysis. *Nat. Resour. Res.* **2025**, *34*, 1667–1699. [CrossRef]
120. Abraham, J.J.; Amani, M. Field Evaluation and Assessment of Wellbore, Casing and Cement Integrity During Critical High-Pressure Operations in Existing and Abandoned Wells. In Proceedings of the Gas & Oil Technology Showcase and Conference, Dubai, United Arab Emirates, 13–15 March 2023. [CrossRef]
121. Trudel, E.; Frigaard, I.A. Modeling the effect of operational activity on wellbore integrity and wellbore leakage in British Columbia. *Geoenergy Sci. Eng.* **2023**, *227*, 211850. [CrossRef]
122. Watson, T.L.; Watson, T.L.; Bachu, S. Evaluation of the Potential for Gas and CO2 Leakage Along Wellbores. In Proceedings of the E&P Environmental and Safety Conference, Galveston, TX, USA, 5–7 March 2007. [CrossRef]
123. Wang, C.; Meng, R.; Li, M.; Kuru, E.; Jin, J. A Novel Casing Eccentricity Limit Model for Optimizing the Placement of Centralizers in Highly-Deviated Wells. *Arab. J. Sci. Eng.* **2022**, *47*, 12057–12073. [CrossRef]
124. Nelson, E.B.; Guillot, D. *Well Cementing*, 2nd ed.; Schlumberger: Houston, TX, USA, 2006; Available online: https://books.google.com/books?id=FblqPAAACAAJ (accessed on 18 March 2025).

125. Sarmadi, P.; Renteria, A.; Thompson, C.; Frigaard, I.A. Effects of wellbore irregularity on primary cementing of horizontal wells, Part 2: Small scale effects. *J. Pet. Sci. Eng.* **2022**, *210*, 110026. [CrossRef]
126. Renteria, A.; Sarmadi, P.; Thompson, C.; Frigaard, I.A. Effects of wellbore irregularity on primary cementing of horizontal wells, Part 1: Large scale effects. *J. Pet. Sci. Eng.* **2022**, *208*, 109581. [CrossRef]
127. Abboud, J.M.; Watson, T.L.; Ryan, M.C. Fugitive methane gas migration around Alberta's petroleum wells. *Greenh. Gases Sci. Technol.* **2021**, *11*, 37–51. [CrossRef]
128. Montague, J.A.; Pinder, G.F.; Watson, T.L. Predicting gas migration through existing oil and gas wells. *Environ. Geosci.* **2018**, *25*, 121–132. [CrossRef]
129. Sandl, E.; Cahill, A.; Welch, L.; Beckie, R. Characterizing oil and gas wells with fugitive gas migration through Bayesian multilevel logistic regression. *Sci. Total Environ.* **2021**, *769*, 144678. [CrossRef]
130. BCOGC. British Columbia's Oil and Gas Reserves and Production Report. 2018. Available online: https://www.bc-er.ca/files/reports/Reserves-and-Production-Reports/2023-Oil-and-Gas-Reserves-and-Production-Report.pdf (accessed on 14 June 2025).
131. RRC. RRC Technical Report (Injection Disposal Permit Procedures). Available online: https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/injection-storage-permits/oil-and-gas-waste-disposal/injection-disposal-permit-procedures/ (accessed on 14 June 2025).
132. El Hachem, K.; Kang, M. Reducing oil and gas well leakage: A review of leakage drivers, methane detection and repair options. *Environ. Res. Infrastruct. Sustain.* **2023**, *3*, 012002. [CrossRef]
133. Ingraffe, A.R.; Wells, M.T.; Santoro, R.L.; Shonkoff, S.B.C. Assessment and risk analysis of casing and cement impairment in oil and gas wells in Pennsylvania, 2000–2012. *Proc. Natl. Acad. Sci. USA* **2014**, *111*, 10955–10960. [CrossRef]
134. Lackey, G.; Rajaram, H.; Sherwood, O.A.; Burke, T.L.; Ryan, J.N. Surface Casing Pressure As an Indicator of Well Integrity Loss and Stray Gas Migration in the Wattenberg Field, Colorado. *Environ. Sci. Technol.* **2017**, *51*, 3567–3574. [CrossRef]
135. Ali, W.; Al-Turki, F.A.; Abbas, A.; Alalhareth, M. Application of Innovative Resin System to Improve Wellbore Integrity: Case Studies from Saudi Arabia. In Proceedings of the SPE Asia Pacific Oil & Gas Conference and Exhibition, Adelaide, Australia, 17–19 October 2022. [CrossRef]
136. Su, S.; Vo, M.; Jia, C.; Yuan, J.; Zhang, J.; Zhang, Q. Integrated Gas Source Analysis for Wells with Sustained Casing Pressure: A Case Study from Sour Gas Fields in Sichuan Basin, China. In Proceedings of the International Petroleum Technology Conference, Virtual, 23 March–1 April 2021. [CrossRef]
137. Alshammari, A.E.; Alsdeiri, S.A.; Alhamdan, M.A. The Sustained Casing Pressure: Periodical Annuli Pressure Survey Campaign Findings in Mature Offshore Oil Field. In Proceedings of the SPE Western Regional Meeting, Anchorage, AK, USA, 22–25 May 2023. [CrossRef]
138. Carey, J.W. *Probability Distributions for Effective Permeability of Potentially Leaking Wells at CO_2 Sequestration Sites*; U.S. Department of Energy Office of Scientific and Technical Information: Washington, DC, USA, May 2018. [CrossRef]
139. Davies, R.J.; Almond, S.; Ward, R.S.; Jackson, R.B.; Adams, C.; Worrall, F.; Herringshaw, L.G.; Gluyas, J.G.; Whitehead, M.A. Oil and gas wells and their integrity: Implications for shale and unconventional resource exploitation. *Mar. Pet. Geol.* **2014**, *56*, 239–254. [CrossRef]
140. Tao, Q.; Checkai, D.; Huerta, N.; Bryant, S.L. Model to Predict CO_2 Leakage Rates Along a Wellbore. In Proceedings of the SPE Annual Technical Conference and Exhibition, Florence, Italy, 19–22 September 2010. [CrossRef]
141. Zhang, B.; Lu, N. OTC-28500-MS Control and Analysis of Sustained Casing Pressure Caused by Cement Sealed Integrity Failure. In Proceedings of the Offshore Technology Conference Asia, Kuala Lumpur, Malaysia, 20–23 March 2018. [CrossRef]
142. Wang, Y.; Zeng, J.; Gao, D. Assessment on the sustained casing pressure (SCP) with consideration of the infiltration of formation fluid into the annulus of deepwater wells. *J. Pet. Sci. Eng.* **2020**, *189*, 106999. [CrossRef]
143. Ding, L.; Chen, W.; Han, C.; Li, S.; Zhang, Q. Study on prediction of sustained casing pressure in tubing-casing annulus based on bubble migration experiment. *Phys. Fluids* **2023**, *35*, 097103. [CrossRef]
144. Lackey, G.; Rajaram, H. Modeling Gas Migration, Sustained Casing Pressure, and Surface Casing Vent Flow in Onshore Oil and Gas Wells. *Water Resour. Res.* **2019**, *55*, 298–323. [CrossRef]
145. Alam, M.; Minor, J.; Nizami, G.U. Solving Sustained Casing Pressure Problems at the Source. In Proceedings of the SPE Symposium—Well Integrity Management, Al-Khobar, Saudi Arabia, 21–22 May 2024. [CrossRef]
146. Osorio, A.; Vliegenthart, A. Utilization of Innovative Elastomeric Cement Integrity Sleeve as A Field Proven Cement Assurance Solution: A Sustained Annular Pressure Prevention Case Study. In Proceedings of the International Petroleum Technology Conference, Dhahran, Saudi Arabia, 12 February 2024. [CrossRef]
147. Elendu, C.; Nwamara, N.; Alinnor, C.; Enekhai, H.; Ojukwu, I.; Ayoo, J.; Abolarin, O. The Diagnostics and Recompletion Strategy of a Well with Sustained Casing Pressure. In Proceedings of the SPE Nigeria Annual International Conference and Exhibition, Lagos, Nigeria, 1–3 August 2022. [CrossRef]

148. Jain, B.; Tambe, A.; Waugh, D.; MunozRivera, M.; Campbell, R. Successful Remediation of Sustained Casing Pressures in Gas Cap Injector Wells with the Use of Flexible and Self Healing System. In Proceedings of the SPE Middle East Oil & Gas Show and Conference, event canceled, 28 November–1 December 2021. [CrossRef]
149. Vasylkivska, V.; Dilmore, R.; Lackey, G.; Zhang, Y.; King, S.; Bacon, D.; Chen, B.; Mansoor, K.; Harp, D. NRAP-open-IAM: A flexible open-source integrated-assessment-model for geologic carbon storage risk assessment and management. *Environ. Model. Softw.* **2021**, *143*, 105114. [CrossRef]
150. Arbad, N.; Watson, M.; Heinze, L. Risk matrix for legacy wells within the Area of Review (AoR) of Carbon Capture & Storage (CCS) projects. *Int. J. Greenh. Gas Control* **2022**, *121*, 103801. [CrossRef]
151. Condor, J.; Unatrakarn, D.; Wilson, M.; Asghari, K. A comparative analysis of risk assessment methodologies for the geologic storage of carbon dioxide. *Energy Procedia* **2011**, *4*, 4036–4043. [CrossRef]
152. Bowden, A.R.; Rigg, A. Assessing risk in CO_2 storage projects. *APPEA J.* **2004**, *44*, 677. [CrossRef]
153. Bai, M.; Song, K.; Li, Y.; Sun, J.; Reinicke, K.M. Development of a novel method to evaluate well integrity during CO_2 underground storage. *SPE J.* **2015**, *20*, 628–641. [CrossRef]
154. Zulqarnain, M.; Zeidouni, M.; Hughes, R.G. Field-scale well leakage risk assessment using reduced-order models. *Greenh. Gases Sci. Technol.* **2019**, *9*, 567–581. [CrossRef]
155. Arbad, N.; Watson, M.; Heinze, L.; Emadi, H. Qualitative risk assessment of legacy wells based on publicly available data for class VI well permit applications—Illinois basin case study. *Int. J. Greenh. Gas Control* **2024**, *133*, 104106. [CrossRef]
156. Lackey, G.; Pantaleone, S.; Montgomery, J.K.; Busse, K.; Aylor, A.W.; Moffett, T.J. Evaluating offshore legacy wells for geologic carbon storage: A case study from the Galveston and Brazos areas in the Gulf of Mexico. *Int. J. Greenh. Gas Control* **2024**, *139*, 104276. [CrossRef]
157. Brown, C.F.; Lackey, G.; Mitchell, N.; Baek, S.; Schwartz, B.; Dean, M.; Dilmore, R.; Blanke, H.; O'Brien, S.; Rowe, C. Integrating risk assessment methods for carbon storage: A case study for the quest carbon capture and storage facility. *Int. J. Greenh. Gas Control* **2023**, *129*. [CrossRef]
158. Wang, Z.; Dilmore, R.M.; Bacon, D.H.; Harbert, W. Evaluating probability of containment effectiveness at a GCS site using integrated assessment modeling approach with Bayesian decision network. *Greenh. Gases: Sci. Technol.* **2021**, *11*, 360–376. [CrossRef]
159. Zausa, F.; Caia, A.; Morcella, T. Semi-Quantitative Evaluation of Cement Degradation and Corrosion of Tubular Materials on converted CCS Wells and Risk Assessment on Well Barriers Integrity. Available online: http://onepetro.org/OMCONF/proceedings-pdf/OMC23/All-OMC23/OMC-2023-362/3333287/omc-2023-362.pdf/1 (accessed on 10 June 2025).
160. Azzolina, N.A.; Small, M.J.; Nakles, D.V.; Glazewski, K.A.; Peck, W.D.; Gorecki, C.D.; Bromhal, G.S.; Dilmore, R.M. Quantifying the benefit of wellbore leakage potential estimates for prioritizing long-term MVA well sampling at a CO_2 storage site. *Environ. Sci. Technol.* **2015**, *49*, 1215–1224. [CrossRef]
161. Pawar, R.; Bromhal, G.; Dilmore, R.; Foxall, B.; Jones, E.; Oldenburg, C.; Stauffer, P.; Unwin, S.; Guthrie, G. Quantification of Risk Profiles and Impacts of Uncertainties as part of US DOE's National Risk Assessment Partnership (NRAP). *Energy Procedia* **2013**, *37*, 4765–4773. [CrossRef]
162. Viswanathan, H.S.; Pawar, R.J.; Stauffer, P.H.; Kaszuba, J.P.; Carey, J.W.; Olsen, S.C.; Keating, G.N.; Kavetski, D.; Guthrie, G.D. Development of a Hybrid Process and System Model for the Assessment of Wellbore Leakage at a Geologic CO_2 Sequestration Site. *Environ. Sci. Technol.* **2008**, *42*, 7280–7286. [CrossRef]
163. Gan, M.; Nguyen, M.C.; Zhang, L.; Wei, N.; Li, J.; Lei, H.; Wang, Y.; Li, X.; Stauffer, P.H. Impact of reservoir parameters and wellbore permeability uncertainties on CO_2 and brine leakage potential at the Shenhua CO_2 Storage Site, China. *Int. J. Greenh. Gas Control* **2021**, *111*, 103443. [CrossRef]
164. Findlay, J.A. In Two-Phase Flow Systems. 1965. Available online: http://heattransfer.asmedigitalcollection.asme.org/ (accessed on 7 June 2025).
165. Pan, L.; Webb, S.W.; Oldenburg, C.M. Analytical solution for two-phase flow in a wellbore using the drift-flux model. *Adv. Water Resour.* **2011**, *34*, 1656–1665. [CrossRef]
166. Hu, L.; Pan, L.; Zhang, K. Modeling brine leakage to shallow aquifer through an open wellbore using T2WELL/ECO2N. *Int. J. Greenh. Gas Control* **2012**, *9*, 393–401. [CrossRef]
167. Pan, L.; Oldenburg, C.M. T2Well-An integrated wellbore-reservoir simulator. *Comput. Geosci.* **2014**, *65*, 46–55. [CrossRef]
168. Bacon, D.H.; Demirkanli, D.I.; White, S.K. Probabilistic risk-based Area of Review (AoR) determination for a deep-saline carbon storage site. *Int. J. Greenh. Gas Control* **2020**, *102*, 103153. [CrossRef]
169. Chen, B.; Harp, D.R.; Pawar, R.J.; Stauffer, P.H.; Viswanathan, H.S.; Middleton, R.S. Frankenstein's ROMster: Avoiding pitfalls of reduced-order model development. *Int. J. Greenh. Gas Control* **2020**, *93*, 102892. [CrossRef]
170. Nordbotten, J.M.; Kavetski, D.; Celia, M.A.; Bachu, S. Model for CO_2 leakage including multiple geological layers and multiple leaky wells. *Environ. Sci. Technol.* **2008**, *43*, 743–749. [CrossRef] [PubMed]

171. Celia, M.A.; Nordbotten, J.M.; Court, B.; Dobossy, M.; Bachu, S. Field-scale application of a semi-analytical model for estimation of CO_2 and brine leakage along old wells. *Int. J. Greenh. Gas Control* **2011**, *5*, 257–269. [CrossRef]
172. Keating, E.H.; Harp, D.H.; Dai, Z.; Pawar, R.J. Reduced order models for assessing CO_2 impacts in shallow unconfined aquifers. *Int. J. Greenh. Gas Control* **2016**, *46*, 187–196. [CrossRef]
173. Jordan, A.B.; Stauffer, P.H.; Harp, D.; Carey, J.W.; Pawar, R.J. A response surface model to predict CO_2 and brine leakage along cemented wellbores. *Int. J. Greenh. Gas Control* **2015**, *33*, 27–39. [CrossRef]
174. Harp, D.R.; Pawar, R.; Carey, J.W.; Gable, C.W. Reduced order models of transient CO_2 and brine leakage along abandoned wellbores from geologic carbon sequestration reservoirs. *Int. J. Greenh. Gas Control* **2016**, *45*, 150–162. [CrossRef]
175. Baek, S.; Bacon, D.H.; Huerta, N.J. Enabling site-specific well leakage risk estimation during geologic carbon sequestration using a modular deep-learning-based wellbore leakage model. *Int. J. Greenh. Gas Control* **2023**, *126*. [CrossRef]
176. Kim, S.; Lee, K.; Lee, M.; Lee, J.; Ahn, T.; Lim, J.-T. Evaluation of saturation changes during gas hydrate dissociation core experiment using deep learning with data augmentation. *J. Pet. Sci. Eng.* **2022**, *209*, 109820. [CrossRef]
177. Zhang, L.; Dilmore, R.; Huerta, N.; Soong, Y.; Vasylkivska, V.; Namhata, A.; Wang, Y.; Li, X. Application of a new reduced-complexity assessment tool to estimate CO_2 and brine leakage from reservoir and above-zone monitoring interval (AZMI) through an abandoned well under geologic carbon storage conditions. *Greenh. Gases Sci. Technol.* **2018**, *8*, 839–853. [CrossRef]
178. Mehana, M.; Chen, B.; Pawar, R. Reduced-Order Models for Wellbore Leakage from Depleted Reservoirs. In Proceedings of the 10th Unconventional Resources Technology Conference, Houston, TX, USA, 20 June 2022; American Association of Petroleum Geologists: Tulsa, OK, USA, 2022. [CrossRef]
179. He, X.; Zhu, W.; Santoso, R.; Alsinan, M.; Kwak, H.; Hoteit, H. CO_2 Leakage Rate Forecasting Using Optimized Deep Learning. In Proceedings of the SPE Annual Technical Conference and Exhibition, Dubai, United Arab Emirates, 21–23 September 2021. [CrossRef]
180. Cai, Y.; Lei, H.; Li, X.; Feng, G.; Cui, Y.; Bai, B. Modeling of possible CO_2 leakage with phase transition in wellbore-reservoir system based on the Ordos CCS project, China. *Int. J. Greenh. Gas Control* **2022**, *114*, 103578. [CrossRef]
181. Ford, E.P.; Moeinikia, F.; Lohne, H.P.; Arild, Ø.; Majoumerd, M.M.; Fjelde, K.K. SPE-185890-MS Leakage Calculator for Plugged and Abandoned Wells. 2017. Available online: http://onepetro.org/SPEBERG/proceedings-pdf/17BERG/1-17BERG/D011S005R004/1279073/spe-185890-ms.pdf/1 (accessed on 6 June 2025).
182. Zhao, J.; Zheng, J.; Ren, L.; Lin, R.; Zhou, B. A review on geological storage of marine carbon dioxide: Challenges and prospects. *Mar. Pet. Geol.* **2024**, *163*, 106757. [CrossRef]
183. Cangemi, L.; Williams, J. Deliverable D2.3 Report on the REX-CO2 well screening tool Project name ERA-NET ACT: Re-using Existing Wells for CO_2 Storage Operations Executive summary. *BGS*. 2020. Available online: https://rex-co2.eu/documents/REX-CO2-D2.3%20REX-CO2%20well%20screening%20tool.pdf (accessed on 6 June 2025).

Disclaimer/Publisher's Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.