

Review

Advances in Synergistic Corrosion Mechanisms of and Management Strategies for Impurity Gases During Supercritical CO₂ Pipeline Transportation

Yutong Yan ^{1,2,3}, Weifeng Lyu ^{1,2,3,4,*}, Hongwei Yu ^{1,2,3,4}, Wenfeng Lv ^{3,4}, Keqiang Wei ^{1,2,3} and Lichan Jiang ^{1,2,3}

¹ University of Chinese Academy of Sciences, Beijing 100049, China; yanyutong23@mails.ucas.ac.cn (Y.Y.)

² Institute of Porous Flow and Fluid Mechanics, Chinese Academy of Sciences, Langfang 065007, China

³ State Key Laboratory of Enhanced Oil & Gas Recovery, Beijing 100083, China

⁴ Research Institute of Petroleum Exploration and Development, Beijing 100083, China

* Correspondence: lyuweifeng@163.com

Abstract

Supercritical CO₂ (sCO₂) pipeline transport is a critical link for the large-scale implementation of Carbon Capture, Utilization, and Storage (CCUS) technology, yet its safety is severely challenged by residual impurity gases (e.g., H₂O, O₂, SO₂, H₂S, and NO₂) from the capture process. This review systematically consolidates recent research advances, with the key findings being the following. Firstly, it reveals that the nonlinear synergistic effects among impurities are the primary cause of uncontrolled corrosion, whose destructive impact far exceeds the simple sum of individual effects. Secondly, it delineates the specific roles and critical thresholds of different impurities within the corrosion chain reaction, providing a theoretical basis for targeted control. Consequently, engineering management must enforce strict impurity concentration thresholds integrated with material upgrades and dynamic operational optimization. Future research should focus on developing multi-impurity reaction kinetic models, elucidating long-term corrosion product layer evolution, and establishing standardized experimental systems. This review provides crucial theoretical support for establishing impurity control standards and optimizing anti-corrosion strategies for the safe transport of CO₂ in supercritical CCUS pipelines.

Keywords: supercritical CO₂ transport; impurity gas effects; synergistic corrosion mechanism; impurity concentration threshold; pipeline integrity



Academic Editor: Jacek Ryl

Received: 11 September 2025

Revised: 8 October 2025

Accepted: 10 October 2025

Published: 15 October 2025

Citation: Yan, Y.; Lyu, W.; Yu, H.; Lv, W.; Wei, K.; Jiang, L. Advances in Synergistic Corrosion Mechanisms of and Management Strategies for Impurity Gases During Supercritical CO₂ Pipeline Transportation. *Molecules* **2025**, *30*, 4094. <https://doi.org/10.3390/molecules30204094>

Molecules **2025**, *30*, 4094. <https://doi.org/10.3390/molecules30204094>

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

Global warming exhibits a significant correlation with the rising atmospheric CO₂ concentration. According to the Intergovernmental Panel on Climate Change (IPCC)'s Sixth Assessment Report, since the industrial revolution, the atmospheric CO₂ concentration has increased from 280 ppm to 420 ppm, directly leading to a global surface temperature rise of approximately 1.1 °C [1]. To address this severe challenge, CCUS technology has emerged as a critical pathway for reducing the atmospheric CO₂ concentration and achieving carbon neutrality goals. Among CCUS components, CO₂ pipeline transport, as the core link connecting the capture end to the storage end, widely employs supercritical state transmission technology to balance transport efficiency with economic viability (Figure 1a,b) [2–6]. However, constrained by the current maturity and economic considerations of capture technologies, the captured CO₂ stream inevitably contains impurity gases such as H₂O, O₂, SO₂, and H₂S. These impurities not only significantly alter the phase behavior of CO₂,

causing shifts in the critical point and expanding the gas–liquid two-phase region, but also induce severe corrosion issues (Figure 1d,f,g) [7–10].

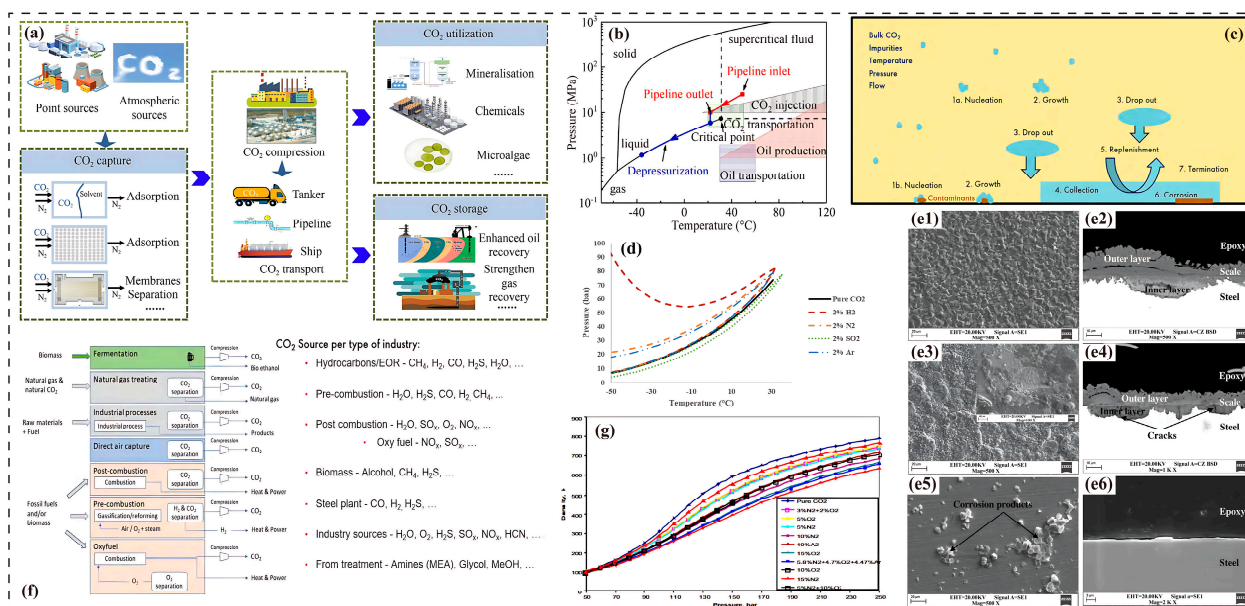


Figure 1. (a) Schematic diagram of the CCUS process [11]; (b) phase diagram of CO₂ and various operations involved in Carbon Capture and Storage (CCS)/CCUS [12]; (c) CO₂ corrosion process in the presence of H₂O [13]; (d) density–pressure relationship curve of CO₂ mixtures at 330 K [14]; (e1–e6) morphology and composition analysis of corrosion product scales formed on steel surfaces after 240 h of exposure in an sCO₂ environment at 10 MPa, 80 °C, and a flow velocity of 1 m/s: (e1,e2) P110 steel, (e3,e4) 3Cr steel, and (e5,e6) 316L stainless steel [15]; (f) impurity gases in CO₂ captured by different technologies [13]; (g) phase equilibrium of pure CO₂ and CO₂ with impurities [16].

The corrosion mechanism of CO₂ and its impurity gases on tubular materials primarily manifests as an electrochemical corrosion process. In aqueous environments, CO₂ dissolves to form carbonic acid (H₂CO₃), which further ionizes to produce H⁺, HCO₃[−], and CO₃^{2−}, constituting a corrosive medium. The predominant cathodic reaction is hydrogen ion reduction (2H⁺ + 2e[−] → H₂), while the anodic reaction is iron dissolution (Fe → Fe²⁺ + 2e[−]) (Figure 1c,e) [17]. The presence of impurity gases like H₂S, SO₂, and O₂ significantly alters this corrosion process: HS generated from dissolved H₂S forms a highly conductive FeS film with Fe²⁺, accelerating localized corrosion; SO₂ dissolved in water forms sulfurous acid (H₂SO₃), further lowering the solution pH and promoting Fe dissolution; and O₂ participates in the cathodic oxygen reduction reaction (O₂ + 2H₂O + 4e[−] → 4OH[−]), increasing the corrosion rate [18–21]. These impurity gases not only change the corrosion reaction pathways but also influence the overall corrosion behavior of the material by affecting the composition and structure of the corrosion product film [22]. More critically, impurities can alter the phase equilibrium of the CO₂–H₂O system, lowering the solubility threshold of water. This leads to an increased likelihood of free water phase precipitation in impurity-containing systems under the same water content, thereby triggering electrochemical corrosion [23,24]. Therefore, in-depth investigation of the coupled influence mechanism of impurities on CO₂ phase behavior and corrosion and the establishment of corrosion prediction models based on actual operational conditions have become key scientific issues for ensuring the large-scale application of CCUS technology [3,25].

Therefore, systematically reviewing the alterations caused by impurity gases (such as H₂O, O₂, SO₂, H₂S, NO₂, and non-condensable gases) to the thermodynamic/transport properties of sCO₂ pipeline fluid, deeply analyzing the complex electrochemical corrosion

mechanisms occurring at the interface with pipeline steel (particularly the synergistic effects between impurities), and clarifying critical impurity concentration thresholds and engineering control standards are crucial for accurately assessing pipeline service risks, optimizing transportation process parameters, and formulating economically effective corrosion prevention and control strategies. This review focuses on the core challenges posed by impurities to the CO₂ pipeline transportation system. It aims to comprehensively integrate the latest domestic and international research findings and clarify the influence patterns of different impurities (single and coexisting) on phase stability, corrosion behavior characteristics (uniform corrosion, pitting, and corrosion stress cracking (CSC)), and pipeline integrity, thereby providing a solid theoretical foundation and engineering guidance for the safe and efficient use of CO₂ pipeline transportation technology in the large-scale commercial application of CCUS.

2. Impact of Impurities on Pipeline Fluid Properties

2.1. Key Changes in Phase Behavior and Density

Impurity gases significantly impact pipeline transport efficiency by modulating the thermodynamic and transport properties of CO₂. Regarding phase behavior and density, non-condensable gases (e.g., N₂, CH₄, and H₂) elevate the critical pressure (increasing from 7.38 MPa to 7.55 MPa when the N₂ concentration reaches 7%), thereby increasing the operational difficulty of maintaining the supercritical state. Furthermore, light gases like H₂ significantly reduce the density (a decrease of >50% at 10% H₂ concentration) and expand the phase envelope (critical temperature < −56.7 °C), diminishing the transport capacity per unit volume [26,27]. In contrast, acidic gases (SO₂, H₂S) raise the critical temperature, which favors the stability of the dense-phase fluid at lower temperatures [28]. The molecular weight of the impurity gas has a notable impact on density: heavier gases (e.g., Ar) increase density, while lighter gases decrease it. This is directly linked to the economic feasibility of pipeline transportation [29–31].

2.2. Fluidity and Transportation Energy Consumption

Impurities significantly influence the fluidity and energy consumption of CO₂ pipeline transportation. During the compression stage, impurity gases markedly increase energy consumption: for every 1% increase in the concentration of O₂, N₂, and H₂, the compression work increases by approximately 2.5%, 3.5%, and 4.5%, respectively, with the lower molecular weight H₂ having a particularly pronounced effect. This is primarily because non-condensable gases occupy pipeline volume, increasing compression demands [28,32]. Furthermore, impurities affect pressure drop by altering viscosity and flow velocity. For instance, H₂O, SO₂, and NH₃ cause an increase in viscosity, which further elevates flow resistance and pressure drop, thereby reducing transport efficiency. Conversely, light gases decrease fluid viscosity but simultaneously increase flow velocity, leading to a significant rise in frictional resistance and a consequent increase in energy consumption. Therefore, optimizing impurity control is essential in pipeline system design to maintain operational economy [28,33].

3. Threats of Impurities to Pipeline Integrity

3.1. Core Role of H₂O

In sCO₂ pipeline systems, H₂O is the core factor initiating corrosion. By reacting with CO₂ to form carbonic acid, it lowers the environmental pH to 3–4, initiating the electrochemical corrosion process. This forms a conductive water film on the steel surface, accelerating anodic dissolution and cathodic reduction. When the H₂O concentration is below the critical value, only slow uniform corrosion occurs, with rates potentially below 0.025 mm/y. Once solubility is exceeded, particularly in the presence of impurities

like SO_2 or O_2 , a free water phase separates, and corrosion intensifies sharply, with rates potentially rising to 7 mm/y. This modulates the morphology of corrosion products and the susceptibility to localized corrosion, initiating pitting, CSC, and the formation of non-protective corrosion layers (e.g., FeCO_3), significantly increasing the risk of material degradation (Figure 2a) [34]. Aqueous phase separation becomes a major driver for wellbore corrosion, making strict water control essential to ensure system integrity [35,36].

The phase distribution inside the pipeline is strongly correlated with water content: at low water content, the CO_2 phase dominates, inhibiting the formation of a continuous water film; after exceeding the supercritical threshold, the aqueous phase accumulates at the bottom, forming corrosion hotspots [37–40]. For J55 steel, the surface becomes fully water-covered at water content > 75%, leading to corrosion product film rupture and initiating pitting. Under conditions with impurities, the localized corrosion rate of X80 steel in the water-rich phase can be up to 10 times that in the CO_2 -rich phase [41,42]. The critical water content is regulated by temperature and pressure parameters and remains controversial: reported thresholds vary significantly (100–1000 ppm), stemming from differences in experimental conditions (e.g., temperature gradients of 25–60 °C) [43–46]. For X65 steel at 50 °C/8 MPa, the uniform corrosion rate fluctuates between 0.01 and 0.4 mm/y, and the intensity of localized corrosion can be up to 14 times that of uniform corrosion [43,47,48]. The presence of H_2O also exacerbates corrosion through synergistic effects (e.g., interacting with SO_2/O_2 impurities to promote acid regeneration cycles) and modulates corrosion product morphology: at high concentrations, the product layer becomes porous and cracked, leading to continuous exposure of the substrate [17,49]. There is an urgent need to establish standardized testing methods and analyze the multi-field coupling mechanisms to improve pipeline integrity management.

3.2. Impact of O_2

During CO_2 pipeline transportation, O_2 , as a common impurity, exhibits a complex “concentration dependence” in its effect on the corrosion behavior of pipeline steels [50]. O_2 participates in the cathodic reduction reaction ($\text{O}_2 + 2\text{H}_2\text{O} + 4\text{e}^- \rightarrow 4\text{OH}^-$), inhibiting the formation of a dense, protective FeCO_3 film, thereby accelerating the uniform corrosion rate of steel [51,52]. This influence demonstrates distinct concentration-dependent characteristics, which specifically manifest as follows.

(1) Corrosion Promotion by Low-Concentration O_2

In water-saturated sCO_2 environments, trace O_2 (1.5 ppm) can increase the corrosion rate of carbon steel and 13Cr stainless steel beyond 100 mm/y [43]. When the O_2 concentration reaches 200 ppm, the corrosion rate of X70 steel significantly rises from a baseline of 0.0577 mm/y to 0.09 mm/y [53]. This acceleration stems from O_2 disrupting the integrity of the protective FeCO_3 film and promoting the formation of Fe^{3+} oxides [14,53]. Tang et al. [34] found, through comparative experiments, that an FeCO_3 – Fe_2O_3 bilayer structure forms on the surface of X65 steel in O_2 -containing environments, wherein the porous Fe_2O_3 film acts as a channel for corrosion propagation (Figure 2b). This finding aligns with the mechanism proposed by Dugstad et al. [54], where the O_2 – Fe^{2+} reaction leads to local dissolution of the FeCO_3 film.

(2) Corrosion Inhibition and Passivation Effect at High O_2 Concentrations

However, when the O_2 concentration increases to 5700 ppm, the corrosion rate becomes lower than that in an oxygen-free environment [43]. This concentration dependence may be related to the regulation of the corrosion product film structure by O_2 partial pressure. At low partial pressures (<500 ppm), O_2 hinders the stable deposition of FeCO_3 nuclei, resulting in the formation of a loose and porous Fe_2O_3 film (Figure 2b) [34,46], whereas, at high partial pressures (e.g., 1000 ppm), O_2 promotes the formation of dense oxides such as

Fe_3O_4 , FeOOH , and Fe_2O_3 , reducing the corrosion rate of X70 steel to 0.03 mm/y. X65 steel exhibits a passivation tendency, and, for 13Cr steel, it helps improve the denseness of the $\text{Cr}_2\text{O}_3/\text{Cr}(\text{OH})_3$ film (Figure 2g) [36,46,49]. Although uniform corrosion is suppressed, O_2 concentrations > 500 ppm can induce localized pitting corrosion (the pitting rate of X65 steel at 1000 ppm O_2 reaches 3 mm/y) due to galvanic corrosion caused by inhomogeneous oxide films [14].

From the perspective of corrosion kinetics, the intervention of O_2 in electrochemical processes exhibits stage-specific characteristics [55]. Studies on dynamic sCO_2 water-rich phases indicate that O_2 significantly accelerates the corrosion process in the initial reaction stage by promoting the oxidation of Fe^{2+} to Fe^{3+} . However, with the accumulation of $\text{Fe}(\text{OH})_3$ and Fe_2O_3 , their diffusion barrier effect leads to the enrichment of Fe^{2+} on the metal surface, which conversely aids the reconstruction of the protective FeCO_3 layer. This phenomenon is particularly evident in N80 steel, whose corrosion rate shows a trend of initially increasing and subsequently decreasing with reaction time [56]. However, studies on X65 steel reveal that O_2 causes the corrosion product film to transition from dense FeCO_3 to a multiphase mixed structure ($\text{FeCO}_3\text{--Fe}_2\text{O}_3$). In this structure, the FeCO_3 regions impede O_2 permeation, while the Fe_2O_3 regions become channels for ion migration, ultimately leading to a significant increase in the localized pitting rate [34,57]. This phase separation effect effectively explains why the average corrosion rate decreases in some studies while the pitting risk increases dramatically [19,46,58]. Under the synergistic action of stress and crevices, O_2 , while promoting the repair of the passive film outside crevices on 13Cr, enlarges the potential difference and exacerbates anodic dissolution inside the crevices (Figure 2c) [36].

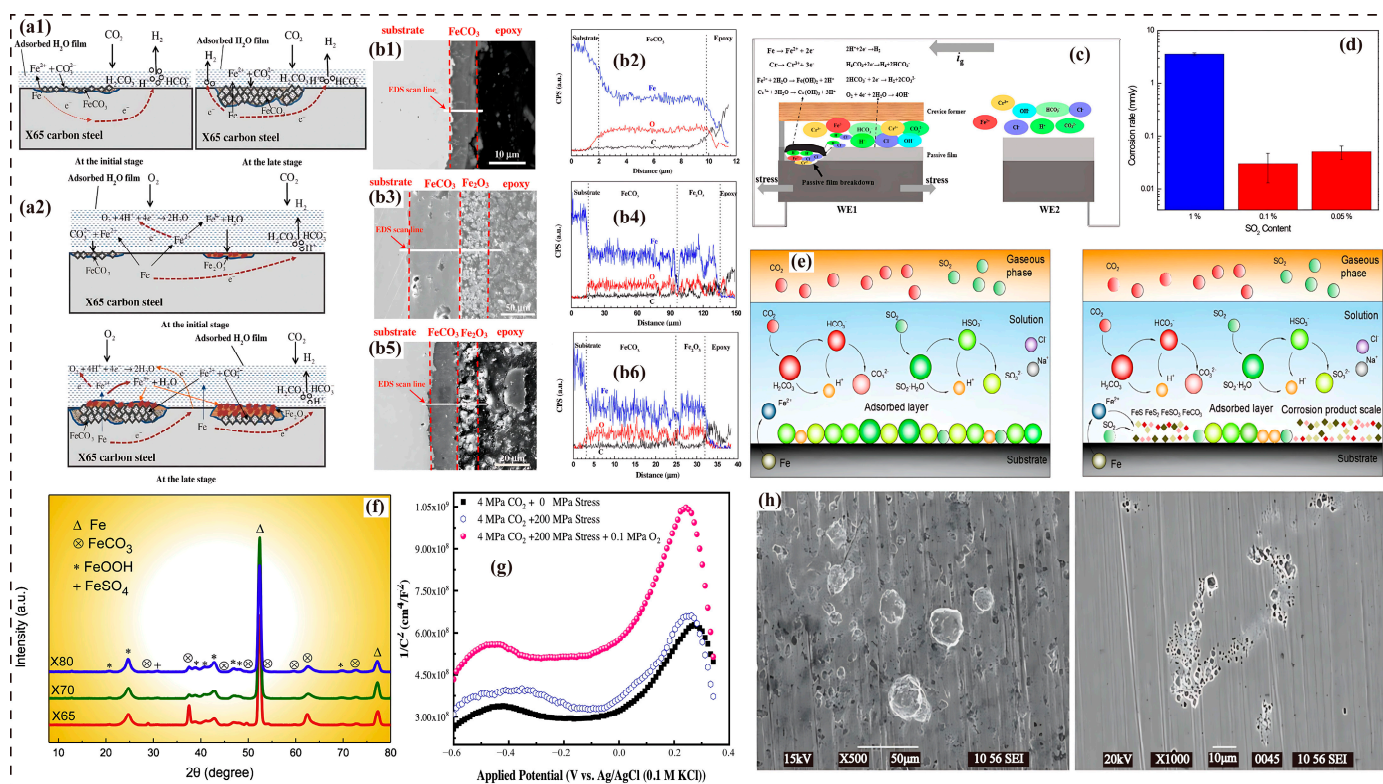


Figure 2. (a1,a2,b1–b6) Schematic diagrams of corrosion mechanisms and SEM images of corrosion products for X65 carbon steel in H_2O -saturated sCO_2 phase without and with O_2 [34]; (c) corrosion mechanism diagram of 13Cr in the presence of O_2 [36]; (d) effect of SO_2 concentration on the corrosion rate of carbon steel in sCO_2 phase at a CO_2 partial pressure of 8 MPa, a temperature of 50 °C, water content of 650 ppm, and an exposure time of 24 h [35]; (e) corrosion mechanism of X80 steel in a $\text{CO}_2\text{--H}_2\text{O}$

environment containing SO_2 [59]; (f) XRD spectra of X65 steel exposed to 10 MPa water-saturated sCO_2 containing 3.0% O_2 + 100 ppm SO_2 [60]; (g) Mott–Schottky curves of 13Cr stainless steel in solution containing 4 MPa CO_2 (with/without 0.1 MPa O_2) under different stress conditions [36]; (h) scanning electron microscopy images of corrosion surfaces of samples exposed to liquid CO_2 for 24 h at a CO_2 partial pressure of 8 MPa and a temperature of 50 °C in a 0.1% SO_2 environment and a 0.05% SO_2 environment [35].

The synergistic effect of temperature and O_2 further complicates the corrosion behavior. The formation and growth of FeCO_3 primarily consist of two stages: nucleation and particle growth. The nucleation process results in a dense and complete FeCO_3 product film. An elevated temperature promotes the rate of the nucleation process and simultaneously reduces the solubility product of FeCO_3 , facilitating FeCO_3 deposition and enhancing the protective effect of the corrosion product film on the substrate. However, an increased temperature also leads to a higher pH value and intensifies the anodic and cathodic electrochemical reactions on the steel surface, promoting the occurrence of corrosion reactions [61]. Influenced by these contradictory factors, the corrosion rate typically peaks between 60 and 90 °C [62,63].

For supercritical CO_2 environments containing O_2 , a comprehensive, multi-level protection system must be established:

① Material upgrade serves as the fundamental measure. Material selection should be graded according to O_2 concentration: low-Cr steels with excellent cost-effectiveness can be chosen for low-concentration conditions ($\text{O}_2 < 500$ ppm); 13Cr stainless steel is required for medium–high concentrations ($\text{O}_2 \sim 1000$ ppm); and 2205 duplex stainless steel is necessary for extremely harsh environments [14]. A cost-effective alternative can involve carbon steel combined with an epoxy resin liner [64];

② Use of corrosion inhibitor technology is an economically effective chemical protection method. Oxidizing inhibitors (e.g., molybdates) can preferentially react with O_2 to form a passive film; adsorption-type inhibitors (e.g., imidazoline derivatives) function by forming a monomolecular layer that blocks corrosive media [49,65]. Their injection method (continuous or pulse) and concentration need to be dynamically optimized based on system operating conditions and must be coordinated with dehydration processes to prevent moisture from reducing their efficiency [36,66];

③ Process optimization and intelligent monitoring constitute an active defense barrier. Strictly maintaining the supercritical state and maintaining reasonable flow velocities can significantly inhibit corrosion. Intelligent monitoring systems integrating laser oxygen analyzers and electrochemical noise sensors enable real-time, precise measurement of O_2 concentration and early warning of corrosion risks, providing crucial data support for proactive intervention [29].

3.3. Impact of SO_2

In CO_2 transportation pipelines, the corrosion behavior of SO_2 is jointly regulated by its dissolution characteristics and electrochemical reactions [61,67,68]. Residual moisture dissolves SO_2 to participate in cathodic ionization, generating sulfides under oxygen-free environments (Figure 2e) [59]. XRD spectra indicate similar types of corrosion products for X65, X70, and X80 steels, suggesting that steel grade has no significant influence on the phase composition of corrosion products (Figure 2f) [60].

The corrosion exhibits notable concentration dependence. An SO_2 concentration of 1% significantly increases the corrosion rate of carbon steel (approximately 3.5 mm/y). SO_2 concentrations below 0.1% cause minor corrosion that stabilizes over time, but 0.05% SO_2 in liquid CO_2 can initiate localized corrosion (reaching rates of 2.4 mm/y). High SO_2 concentrations lead to the formation of H_2SO_3 and H_2SO_4 , causing localized pH drops

and corrosive product formation, while low concentrations produce insufficient reaction products to continuously damage the steel surface (Figure 2d,h) [35].

Under oxygen-free conditions, low concentrations of SO_2 (30–300 ppm) can form a protective FeS film that inhibits corrosion [15,69]. However, when the concentration rises to 0.08%, the corrosion rate of X70 steel in sCO_2 reaches 3.48 mm/y, and it increases to 3.70 mm/y when coexisting with 0.33% O_2 . This exacerbation stems from SO_2 hydrolysis creating an acidic environment that damages protective layers [64,70]. Even trace amounts of SO_2 exacerbate pitting corrosion in pipeline steels due to the initial formation of weakly adherent FeS/FeS_2 films, whose protective efficacy decreases with increasing concentration [19,70–72]. Exposure to 500 ppm SO_2 elevates the corrosion rate of X70 steel in water-saturated sCO_2 to 1.10 mm/y [53].

Environmental conditions significantly modulate the corrosion process. SO_2 reduces water solubility in sCO_2 , promoting the precipitation of a weakly acidic H_2SO_3 water film. Increasing the SO_2 concentration causes a sharp decline in the pH of the separated aqueous phase (a 31.1% drop at 2000 ppm), resulting in a pitting rate of 0.08 mm/y for X65 steel [61,73]. While the synergistic effect of O_2 and SO_2 yields a relatively minor increase in corrosion rate, significant localized corrosion is still observed in high-pressure liquid CO_2 (containing 650 ppm H_2O + 0.05% SO_2) [35].

For corrosion environments containing SO_2 , comprehensive protection strategies should be adopted:

① Material upgrade forms the basis for resisting SO_2 corrosion. Material selection must be based on SO_2 concentration and operating conditions: 316L stainless steel is suitable for environments with $\text{SO}_2 < 100$ ppm; however, when the SO_2 concentration is high or it coexists with O_2 , 2205 or 2507 duplex stainless steels with superior pitting resistance should be selected [55]. An economical alternative can employ low-Cr steel (e.g., 3Cr) combined with a PTFE liner to effectively isolate the corrosive medium [64];

② Use of corrosion inhibitor technology is a key chemical method for corrosion control. Reducing inhibitors like thiosulfate can react with SO_2 to generate protective films; amine-based inhibitors function by neutralizing the formed sulfurous acid [68]. Employing a composite inhibitor system (e.g., a combination of imidazoline and molybdate) synergistically with pH regulators (maintaining the system pH at 5.5–6.5) can achieve more stable and efficient protection. The dosing strategy needs dynamic adjustment based on fluctuations in SO_2 concentration [49];

③ Process optimization and intelligent monitoring constitute a systematic line of defense. The core is ensuring that the fluid remains in a stable supercritical state and implementing strict dehydration ($\text{H}_2\text{O} < 50$ ppm) to fundamentally inhibit the formation of H_2SO_3 . In terms of fluid design, adopting low flow velocities and structures that improve the flow field's uniformity can prevent local enrichment of SO_2 [60]. Simultaneously, utilizing high-precision equipment such as ultraviolet fluorescence SO_2 analyzers for real-time monitoring and establishing a tiered early warning mechanism are essential guarantees for the early detection and proactive management of corrosion risks [64,74].

3.4. Impact of H_2S

In environments where CO_2 and H_2S coexist, metal corrosion is synergistically regulated by the gas concentration ratio, partial pressure ratio, and environmental parameters [64,75,76]. H_2S concentration exhibits a typical nonlinear effect: low concentrations (<500 ppm) significantly accelerate uniform corrosion but inhibit localized corrosion [77]. In sCO_2 , 50 ppm H_2S increases the corrosion rate of X65 steel from 0.17 mm/y to 0.24 mm/y, while raising the H_2S concentration to 100 ppm has a limited further effect on the corrosion rate, suggesting that 50 ppm may be the threshold concentration for the formation of a

protective FeS layer (Figure 3d) [77]. The increase is more pronounced in the presence of an aqueous phase, where the corrosion rate rises from 8.46 mm/y to 15.48 mm/y at the same concentration. This is because H₂S alters the phase equilibrium of the CO₂–H₂O system, promoting the separation of an aqueous phase that provides an electrolyte environment for corrosion (Figures 3a and 4b,c) [12,41]. Furthermore, H₂S modifies the water adsorption characteristics of the steel surface, promoting water film coverage and intensifying electrochemical corrosion. The mechanism for localized corrosion inhibition is related to the H₂S-promoted formation of a dense FeCO₃–FeS mixed film. This mixed film offers low protectiveness and is characterized by being porous and micro-cracked (Figure 3k) [57,68,78,79].

At medium-to-high concentrations (>500 ppm), H₂S exhibits a bimodal effect. When the H₂S partial pressure rises to 0.0004 MPa (approximately 40 ppm), the corrosion rate of N80 steel in 8 MPa sCO₂ increases from 4.23 mm/y to 4.61 mm/y. However, when the partial pressure reaches 0.4 MPa (approximately 40,000 ppm), the rate decreases to 0.72 mm/y (Figure 3b,c) [80]. This transition is governed by the CO₂/H₂S partial pressure ratio. A ratio <200 promotes H₂S-dominated formation of an FeS film. A ratio >500 favors CO₂-dominated formation of an FeCO₃ film (Figure 3j) [76,81,82]. When the CO₂ pressure is fixed, increasing the H₂S concentration causes the corrosion rate to first rise and then fall. Conversely, at a fixed H₂S pressure, increasing the CO₂ pressure ratio continuously elevates the corrosion rate and drives the transition of corrosion products from FeS to FeCO₃ [81,83,84]. The mixed film structure is loose and prone to spalling, exacerbating uniform corrosion.

When the H₂S concentration exceeds 1000 ppm, the anomalous increase in corrosion rate is primarily driven by the abrupt changes in CO₂ physical properties near the critical point, while density predominantly influences corrosion trends only in non-critical regions. The corrosion products shift from being dominated by FeCO₃ to FeS or FeCO₃–FeS mixed structures (Figure 3f) [12]. Research findings exhibit discrepancies. For instance, Sun et al. [80] observed that H₂S partial pressure regulates corrosion products in a step-wise manner (FeCO₃ at <0.016 MPa, mixed at 0.016–0.4 MPa, and predominantly FeS at >0.4 MPa), which aligns with Choi [85]. In contrast, Wei et al. [32] found that X65 steel forms an FeS–FeCO₃ bilayer film, which exacerbates localized corrosion due to galvanic effects. These differences may originate from variations in alloy composition and phase conditions. Addressing H₂S corrosion requires establishing a comprehensive system that considers both general corrosion and localized cracking:

- ① Material upgrade serves as the foundation for ensuring safety. For low H₂S concentrations (<50 ppm), sulfur-resistant carbon steel with controlled hardness can be selected; for medium–high concentrations or harsh service conditions, corrosion-resistant alloys such as duplex stainless steels or nickel-based alloys must be employed [32,86];
- ② Corrosion inhibitor technology is key to corrosion control. Film-forming inhibitors (e.g., quaternary ammonium salts, imidazoline derivatives) can form an adsorptive barrier layer on the metal surface. To ensure their effectiveness, inhibitor selection must be validated through autoclave testing and used in combination with oxygen scavengers to maintain the dissolved oxygen concentration at an extremely low level, thereby preventing degradation of the inhibitor film [83,84];
- ③ Process optimization aims to eliminate the root causes of corrosion. The core lies in stringent process control, including reducing the water concentration to <30 ppm through deep dehydration and precisely regulating the temperature, flow velocity (recommended 1–2 m/s), and system pH (6–7.5) in order to prevent aqueous phase condensation, mitigate mechanical erosion of inhibitor films, and inhibit the formation of localized acidic environments [41,64];

④ Monitoring and early warning systems constitute a safeguard for achieving proactive defense. It is necessary to integrate real-time monitoring technologies such as online H₂S analysis and electrochemical noise analyzers and establish a tiered alarm mechanism [17]. Combining periodic non-destructive testing with data-driven digital twin models enables accurate prediction of the Sulfide Stress Cracking (SSC) risk, facilitating early warning and proactive intervention [3].

3.5. Impact of NO₂

In CO₂ pipeline transportation, NO₂ is a highly corrosive impurity that accelerates aqueous phase separation and generates HNO₃ ($3\text{NO}_2 + \text{H}_2\text{O} \rightarrow 2\text{HNO}_3 + \text{NO}$) when coexisting with H₂O, significantly reducing the local pH, damaging the protective FeCO₃ film, and inducing pitting corrosion (Figure 3g) [17,70,74,87,88]. Studies confirm that NO₂-containing environments lead to thinning of corrosion product films and exacerbate uniform corrosion [70,89]. The corrosion exhibits strong concentration dependence. The corrosion rate of X52 steel at 5 °C increases fivefold compared with 25 °C (0.016 → 0.299 mm/y). At 50 °C, as the NO₂ concentration rises from 50 ppmv to 1000 ppmv, the corrosion rate shows an initial slow increase followed by a sharp rise (Figure 3e). In sCO₂, 100 ppm NO₂ can elevate the corrosion rate of carbon steel to 11.6 mm/y (twice that of SO₂ at the same concentration) [67,87,90].

The corrosion mechanism of NO₂ exhibits multiple characteristics. HNO₃ erosion reduces the film's denseness and creates voids, and synergy with O₂/SO₂ further amplifies the risk [17]. Low temperatures (e.g., 5 °C) significantly intensify the corrosion effect due to the reduced water solubility leading to an increase in the acid concentration. The corrosion rate of X65 steel at 5 °C is 3–4 times higher than that at 25 °C (Figure 3h,i) [64,74,90]. Under prolonged exposure, NO₂ not only accelerates uniform corrosion but also initiates localized pitting and SCC, particularly in dynamic flow fields where the uneven deposition of corrosion products creates stress concentration points [55,74,88]. Microscopic analysis revealed that NO₂ alters FeCO₃ morphology, reduces film denseness, and enhances galvanic effects, leading to synergistic development of pitting and uniform corrosion with far greater severity than other gases [17,70]. Therefore, strict control of NO₂ concentration and water content is essential to suppress corrosion progression.

3.6. Impact of Non-Condensable Gases

Non-condensable gases (N₂, O₂, Ar, CH₄, and H₂) promote the separation of free aqueous phase by reducing water solubility in sCO₂, inducing electrochemical corrosion [91]. The typical volumetric fraction threshold is 4%; beyond this limit, water separation occurs even at water content < 500 ppm [25,90]. CH₄ significantly alters the phase behavior: 10% concentration increases the critical pressure to 14.75 ± 0.25 MPa, requiring higher operating pressures; 20% concentration reduces the water solubility, triggering localized corrosion. When coexisting with H₂S, it may promote the formation of non-protective FeS films, with synergistic effects from N₂ further exacerbating the risk [57,92,93].

Ar lowers the critical temperature and raises the critical pressure (reaching 7.55 MPa at 4.5%), increasing the operational pressure. A concentration of 20% modifies fluid properties and reduces the protectiveness of corrosion product films [94]. N₂ is one of the most corrosion-promoting impurities. A concentration of 7% lowers the CO₂ critical temperature to 30.37 °C and raises the critical pressure to 7.55 MPa, while 10% concentration reduces the water solubility by 30%, forming corrosive liquid films, accelerating O₂ diffusion to enhance cathodic depolarization rates, and doubling the corrosion rate of carbon steel [49,57,92,95]. CO may generate formic acid, lowering the pH, and at 0.2% concentration catalyzes hydrogen permeation, increasing the hydrogen embrittlement risk [93].

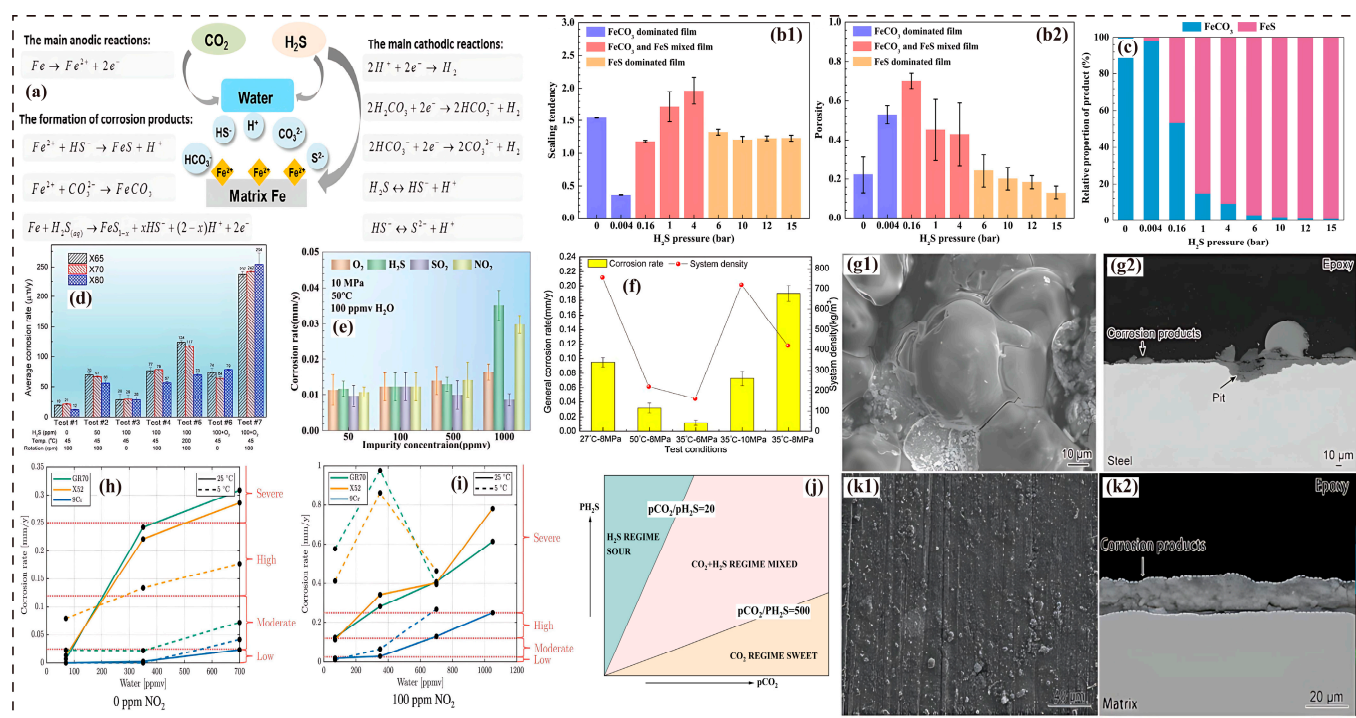


Figure 3. (a) Main corrosion reactions of steel in the sCO₂–H₂O–H₂S system [12]; (b1,b2,c) structural tendency of corrosion product films and calculated relative proportions of surface-generated FeCO₃ and FeS products on N80 steel in different sCO₂/H₂S environments (8 MPa CO₂, 80 °C, 72 h) [80]; (d) average corrosion rates of X65, X70, and X80 steel in H₂O-saturated sCO₂ flow with the presence of H₂S and/or O₂ under different temperatures and rotation speeds for 120 h [77]; (e) variation in corrosion rate of X52 steel in a high-pressure CO₂ environment influenced by impurity type and concentration under different factors [96]; (f) relationship between corrosion rate and system density of X65 carbon steel under different temperature–pressure conditions (H₂S 1000 ppm, H₂O 10 g) [12]; (g1,g2) SEM surface morphology and cross-sectional backscattered electron images of corrosion film on X65 steel in an sCO₂–NO₂ system at 8 MPa and 50 °C [74]; (h,i) relationship between NO₂ corrosion rate and water concentration (NO₂ content, 0 ppm and 100 ppm; temperature, 5 °C and 25 °C; red dashed horizontal line represents the corrosion severity threshold for carbon steel defined by the National Association of Corrosion Engineers (NACE) standard [90]; (j) H₂S corrosion control zoning diagram [97]; (k1,k2) SEM surface morphology of corrosion film on X65 steel in a water-saturated CO₂ (wsCO₂)–H₂S system at 8 MPa and 50 °C [68].

Additionally, maintaining a supercritical state requires elevated pressures, increasing compression costs and accelerating SCC [25]. At H₂ concentrations >0.5%, hydrogen atoms permeate the steel matrix, inducing SCC. In environments with 4% H₂, the hydrogen permeation flux of X65 steel triples, with the SCC susceptibility index reaching 0.28 (critical value 0.25) under dynamic pressure. High pressures (>8 MPa) and low temperatures (<10 °C) exacerbate this risk [93,94].

3.7. Corrosion Synergistic Effects

During sCO₂ pipeline transportation, the synergistic effects between impurity gases and H₂O exert complex and nonlinear influences on steel corrosion behavior, with mechanisms extending far beyond the sum of individual impurity effects (Table 1) [39]. As the core initiator of corrosion, H₂O not only enables electrochemical reactions but also regulates the phase distribution. At low water content (<1500 ppm), corrosion is mild, but exceeding the critical threshold (e.g., 1500–2000 ppm) leads to free aqueous phase separation, causing corrosion rates to surge from <0.025 mm/y to 7 mm/y and triggering localized pitting and SCC [10,25,98]. This aqueous phase separation is significantly amplified under impurity

coexistence; for instance, SO₂ can reduce the critical water content threshold from 1000 ppm to 50 ppm, accelerating the formation of acidic electrolyte films [41,54].

Table 1. Summary of corrosion mechanisms for different impurities.

Gas	Primary Impact Mechanism	Critical Concentration Thresholds and Corrosion Rate Data
H ₂ O	Initiates the corrosion process, forms an acidic water film, causes minor uniform corrosion at low concentrations, and accelerates pitting and general corrosion at high concentrations.	<50 ppm initiates mild corrosion (hazardous with SO ₂), 100–1000 ppm initiates pitting (1.2 mm/y), >1000 ppm yields general corrosion (19 mm/y), and the corrosion rate of X65 steel increases sharply at water content > 1500 mg/L.
O ₂	Accelerates corrosion at low concentrations (disrupts FeCO ₃ film), may inhibit corrosion at high concentrations (forms dense oxides), and synergistically exacerbates corrosion with SO ₂ .	1.5 ppm can increase the corrosion rate to >100 mm/y, 200 ppm raises the corrosion rate of X70 steel to 0.09 mm/y, the recommended concentration is <1000 ppm, and the corrosion rate reaches 20.47 mm/y when coexisting with 500 ppm SO ₂ .
SO ₂	May inhibit corrosion at low concentrations, accelerates corrosion at high concentrations (generates strong acids), and synergistically forms H ₂ SO ₄ with O ₂ , significantly increasing the corrosion rate.	0.05% SO ₂ in liquid CO ₂ causes a corrosion rate of 2.4 mm/y, 500 ppm increases the corrosion rate of X70 steel to 1.10 mm/y, the recommended concentration is <100 ppm, and corrosion products on X65 steel become porous when coexisting with 3% O ₂ .
H ₂ S	Accelerates uniform corrosion at low concentrations, may mitigate corrosion via FeS film at medium–high concentrations, and corrosion products are regulated by the CO ₂ /H ₂ S pressure ratio.	<500 ppm accelerates corrosion, 0.0004 MPa H ₂ S increases the corrosion rate of N80 steel to 4.61 mm/y, >0.4 MPa reduces it to 0.72 mm/y, and the recommended concentration is <200 ppm.
NO ₂	Generates HNO ₃ , significantly reduces pH, accelerates uniform and localized corrosion, the effect is intensified at low temperatures, and the risk is amplified synergistically with O ₂ /SO ₂ .	100 ppm leads to a corrosion rate of 11.6 mm/y, the rate at 5 °C is 3–4 times higher than at 25 °C; <1.5 ppm is recommended, and the localized corrosion rate reaches 6.8 mm/y when coexisting with 1000 ppm O ₂ .
N ₂ /H ₂ /CH ₄	Reduces water solubility, promotes free water separation, H ₂ may cause hydrogen embrittlement, CH ₄ alters phase behavior, and the total volumetric fraction should be <4%.	10% N ₂ reduces the water solubility by 30%, 4% H ₂ triples the corrosion rate, 20% CH ₄ decreases the water solubility, and corrosion intensifies with water separation when non-condensable gases >5%.

Interactions between impurities exhibit significant concentration dependence. Trace amounts of O₂ can elevate the corrosion rate of carbon steel beyond 100 mm/y by disrupting the protective FeCO₃ film and promoting the formation of Fe³⁺ oxides [14,43]. When O₂ coexists with SO₂ (e.g., 200 ppm O₂ + 500 ppm SO₂), their synergistic effect drastically increases the corrosion rate to 20.47 mm/y—far exceeding the sum of individual impurity effects (18.64 mm/y)—as O₂ catalyzes the conversion of SO₂ into highly corrosive H₂SO₄, which reacts with steel to form FeSO₄ and FeOOH (Figure 4a,g) [19,55,99]. This effect is further intensified at elevated temperatures (60–90 °C) due to enhanced oxidation of Fe²⁺, leading to porous Fe₂O₃ films that compromise the continuity of the product layer [34,63]. In sCO₂–SO₂–O₂–H₂O systems, environmental factors (e.g., impurity concentration, flow velocity) exert a far greater influence on corrosion than minor variations in material composition (Figure 4f,h) [60,71]. Notably, while high O₂ concentrations (>500 ppm) inhibit

uniform corrosion, they induce localized pitting (with pitting rates reaching 3 mm/y for X65 steel) due to galvanic corrosion caused by inhomogeneous oxide films [14,49].

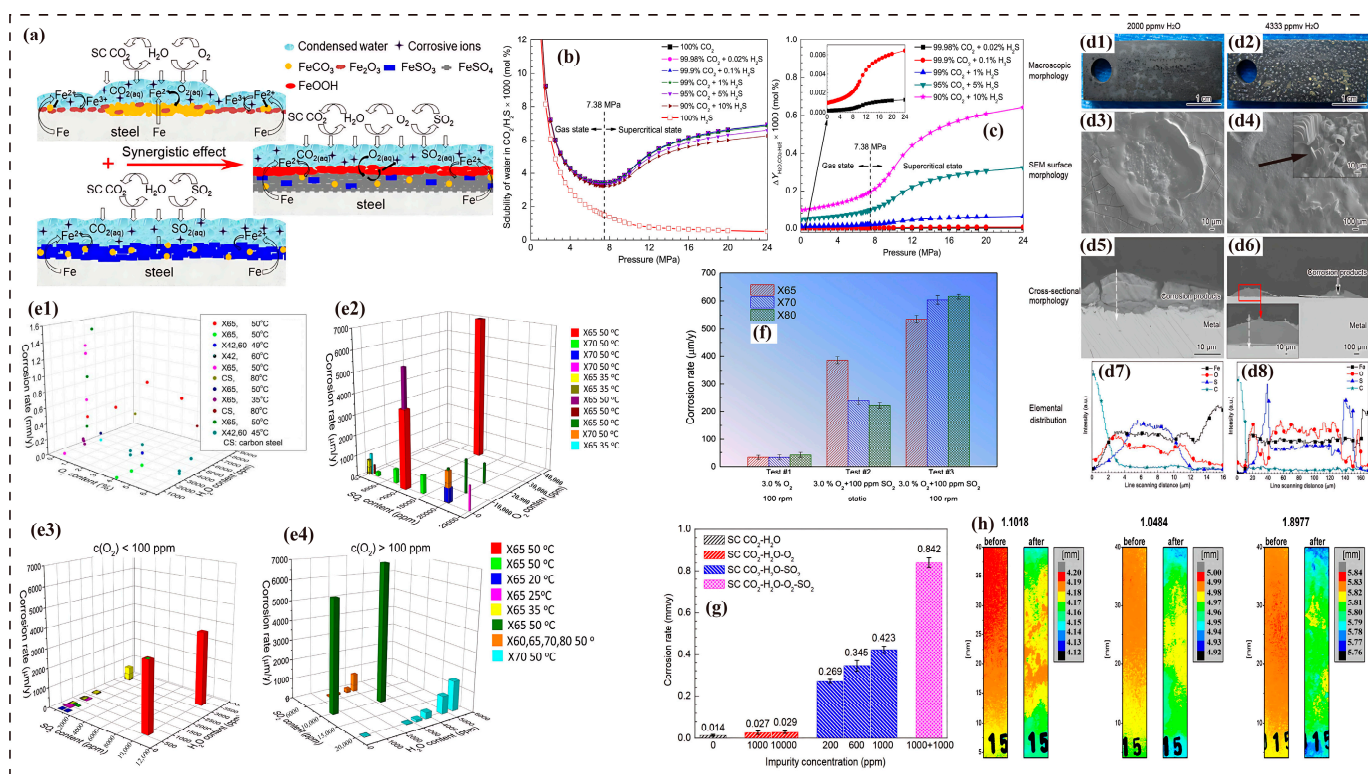


Figure 4. (a) Schematic models of corrosion and film characteristics in water-saturated sCO₂-H₂O-O₂, sCO₂-H₂O-SO₂, and sCO₂-H₂O-O₂-SO₂ systems [19]; (b,c) variation in H₂O solubility in CO₂ and/or H₂S with pressure and the corresponding precipitation amount [41]; (d1–d6) condition of X65 steel after 72 h of exposure in an sCO₂-H₂O-O₂-H₂S-SO₂ environment at 10 MPa and 50 °C (d1,d3,d5,d7) under 2000 ppmv water vapor conditions and (d2,d4,d6,d8) under 4333 ppmv water vapor conditions [41]; (e1) corrosion rate of carbon steel in an sCO₂ environment within a pressure range of 8–15 MPa and a temperature range of 35–80 °C under different water and oxygen contents [25]; (e2–e4) influence of SO₂, O₂, and H₂O on the corrosion rate of different steels in an sCO₂ environment within a pressure range of 8–10 MPa at different temperatures [60]; (f) average corrosion rate of X65 steel after 120 h of exposure in water-saturated CO₂ flow at 45 °C and 10 MPa under different impurity contents and rotation speeds [60]; (g) corrosion rate of X70 steel after 120 h of exposure in a water-saturated sCO₂ system containing O₂ and/or SO₂ at 10 MPa and 50 °C [19]; (h) thickness distribution comparison of pure iron 1.1018, pipeline steel L290NB 1.0484, and pipeline steel L485MB 1.8977 before and after exposure to a CO₂ environment with impurities (660 ppm SO₂, 0.66% O₂, 2.05% H₂O, 5 °C, 120 h) [71].

The corrosive effect of SO₂ is achieved through hydrolysis, forming H₂SO₃/H₂SO₄. When its concentration exceeds 100 ppm, it significantly reduces the aqueous phase pH (e.g., 2000 ppm SO₂ causes a 31.1% pH drop), leading to a pitting rate of 0.08 mm/y for X65 steel (Figure 4e) [47,61,73]. When coexisting with NO₂, the oxidation of SO₂ to H₂SO₄ accelerates, increasing the corrosion rate by 40% [70,74]. Low concentrations of H₂S (<500 ppm) accelerate corrosion (50 ppm H₂S increases the corrosion rate of X65 steel from 0.17 mm/y to 0.24 mm/y), while high concentrations (>1000 ppm) may form FeS films that inhibit uniform corrosion but pose a risk of localized pitting [57,78,80]. When H₂S coexists with O₂, elemental sulfur formation exacerbates localized corrosion, driving the corrosion rate of X70 steel beyond 7 mm/y [58,100]. The redox reaction between SO₂ and H₂S (2H₂S + SO₂ → 3S + 2H₂O) also generates sulfur deposits. When SO₂ > 200 ppm and

$\text{H}_2\text{S} > 500$ ppm, the sulfur generation rate reaches $1.2 \text{ kg/d}\cdot\text{km}$, causing equipment blockage and a pressure drop (X70 steel exhibits 38 g/m^2 deposit accumulation in O_2 -containing environments over 480 h, with a 15% pressure increase) (Figure 4d,g) [49,58,70,100]. The reaction between deposited sulfur and Fe forms FeS_2 , with a 40% volumetric expansion rate, accelerating crack propagation [12]. In environments where $\text{sCO}_2\text{--H}_2\text{O--O}_2\text{--H}_2\text{S--SO}_2$ coexist, the formation of H_2SO_4 and S makes the system over 10 times more corrosive than with single impurities. H_2O at 4333 ppm fully covers the metal surface, accelerating ion diffusion and electrochemical reactions. The product layer thickness surges to $150 \mu\text{m}$, with localized laminated FeSO_3 crystals and wormhole-like sulfur-rich phases (Figure 4d) [41].

NO_2 is the most hazardous impurity, with even 100 ppm capable of driving the corrosion rate of carbon steel to 11.6 mm/y . Its mechanism involves the reaction $3\text{NO}_2 + \text{H}_2\text{O} \rightarrow 2\text{HNO}_3 + \text{NO}$, generating a strong acid that disrupts the integrity of corrosion product films [70,87]. When synergized with O_2 (e.g., 100 ppm NO_2 + 1000 ppm O_2), the localized corrosion rate surges to 6.8 mm/y , with low-temperature (5°C) environments amplifying this effect by 3–4 times [74,90]. Non-condensable gases (e.g., N_2 , CH_4) indirectly exacerbate corrosion by reducing water solubility (7% N_2 decreases solubility by 30%), promoting aqueous phase separation. Two-phase flow corrosion occurs when their total volume fraction exceeds 4% [25,93,95].

Temperature–pressure parameters exhibit strong coupling effects with impurities. At high temperatures (80°C) and H_2S partial pressures exceeding 0.4 MPa, corrosion products shift from predominantly FeCO_3 to FeS , reducing the corrosion rate from 4.61 mm/y to 0.72 mm/y [80]. Conversely, when the pressure rises to 10 MPa, non-condensable gases necessitate higher operating pressures, accelerating SCC [94]. This multi-field coupling mechanism indicates that corrosion control requires integrated management of impurity concentration thresholds (e.g., $\text{O}_2 < 1000$ ppm, $\text{SO}_2 < 100$ ppm, $\text{NO}_2 < 1.5$ ppm), water content (< 650 ppm), and material selection to disrupt the autocatalytic corrosion cycles triggered by synergistic effects [19,70,86].

4. Engineering Standards for Impurity Control

4.1. Industry Specifications and Thresholds

Pipeline transportation has become the preferred solution for large-scale onshore CCS/CCUS projects due to its continuity, stability, economic efficiency, and technological maturity [50,101,102]. The total length of the existing global CO_2 pipeline network exceeds approximately 10,000 km, of which over 8000 km are located in the United States and are primarily used for CCUS with Enhanced Oil Recovery (CCUS-EOR), while Canada operates more than 300 km. To achieve carbon neutrality, China requires the construction of over 17,000 km of CO_2 pipelines, though only several hundred kilometers have been built so far. The core technology involves pressurizing gaseous CO_2 to a supercritical state (typically > 8 MPa) to avoid two-phase flow and optimize transportation costs. In contrast, offshore pipelines have not yet achieved large-scale development due to construction challenges and high costs, with only limited-distance subsea pipelines deployed in a few projects [101,103–105].

The existing pipeline network in North America exhibits significant regional variations, primarily categorized into three types. Type II pipelines, which are the most widely deployed, adhere to strict gas quality specifications (often utilizing natural carbon sources, operating at 1.72–15.17 MPa). Type I pipelines are short-distance, dedicated pipelines for point-to-point projects. Type III pipelines are used in regional blended networks with relatively lenient gas quality standards, requiring additional corrosion mitigation measures. Due to substantial differences in gas composition, Type III networks face challenges in interoperability with Type II systems [50,64,106]. North America lacks unified indus-

try standards, with pipeline gas quality primarily governed by commercial agreements. Existing projects maintain >95% CO₂ content to align with EOR requirements. In Europe, large-scale subsea pipeline networks (planned mileage: 30,000–150,000 km) are under development [94,107]. Ever since the DYNAMIS project proposed initial gas quality requirements in 2007, subsequent initiatives, such as Ecofys, Pace CCS, Porthos, and Norway's Northern Lights, have established differentiated specifications, significantly advancing the standardization of CO₂ pipeline transportation (Table 2) [108].

Table 2. Gas quality specifications for current European projects and related companies.

Medium Component	DYNAMIS Project		Northern Lights Project	Porthos Project	Ecofys Company	Pace CCS Company
	Saline Aquifer Storage	Content Limit Values CO ₂ -EOR Project	Content Limit Values (ppm/mol)	Content Limit Values (ppm/mol)	Content Limit Values	Content Limit Values (ppm/mol)
CO ₂		>95.5%	>99%	≥95%	>95%	≥95%
H ₂ O		0.05%	≤30	≤70	<4%	50
Ar			--		<4%	4%
N ₂		<4%	--		<4%	4%
H ₂			≤50		<4%	1%
CH ₄	<4%	<2%	--	≤4%	<4%	4%
O ₂	<4%	0.01%~0.1%	≤10		<4%	10
CO		0.2%	≤100		--	0.2%
COS		--	--		--	5
H ₂ S		0.02%	≤9	≤20	--	50
SO _x		0.01%	≤10		--	50
NO _x		0.01%	≤10	≤5	--	100
Amines		--	≤20	≤1	--	4.15%
C ₂₊		--	--	1200	--	

4.2. Synergistic Impurity Control Strategies

The management of impurities in sCO₂ pipelines requires a hierarchical control system. Dehydration serves as the primary step, where reducing the H₂O concentration to <50 ppm via molecular sieve adsorption effectively disrupts corrosive chain reactions [70]. Experimental data indicate that, when the water content exceeds 1500 ppm, the corrosion rate of X65 steel surges from 0.025 mm/y to 7 mm/y, while dehydration to 50 ppm reduces the corrosion rate by 98% [41]. Oxidizing impurities necessitate dual limits (maintaining O₂ < 100 ppm and NO_x < 1.5 ppm suppresses strong acid formation, thereby mitigating effective corrosion rates) [19,70]. Special attention must be paid to scenarios where the O₂ concentration exceeds 500 ppm, as NO_x levels as low as 50 ppm can trigger pitting corrosion through acidification reactions [53,74].

Economic optimization requires balancing compression energy consumption and specific impurity risks. The total volume of non-condensable gases should be <4 vol%; when their proportion increases from 2% to 6%, compression work rises by 35% and transportation costs increase by 28% [93]. Specific control targets include H₂ < 0.1% (to prevent hydrogen embrittlement), N₂ < 3% (to maintain phase stability), and CH₄ < 0.9% (to avoid two-phase flow) [94].

To mitigate sulfur deposition risks, synergistic control of H₂S (<200 ppm) and SO₂ (<100 ppm) is necessary to prevent the formation of elemental sulfur that could clog pipelines [49,70]. For existing sulfur blockages, treatment with 2–5 vol% carbon disulfide solvent can be applied, but the contact time must be limited to <4 h [70].

Dynamic regulation should optimize thresholds based on operational parameters. Under high pressures (>10 MPa), the O₂ threshold should be reduced to 50 ppm, while at elevated temperatures (>60 °C), the H₂S limit can be relaxed to 500 ppm [80,93]. Regarding materials, 13Cr stainless steel exhibits 20 times greater corrosion resistance than carbon steel in SO₂-containing environments, despite a 25–30% cost increase [63]. Real-time moni-

toring using Fourier Transform Infrared Spectroscopy–Gas Chromatography (FTIR-GC) is recommended to dynamically adjust dehydration units and amine scrubber parameters, maintaining impurity concentrations within safe windows [86].

5. Future Perspectives

Based on a systematic review of the mechanisms by which impurities affect CO₂ pipeline transportation, and considering current research gaps and technical challenges, future studies should focus on the following.

5.1. In-Depth Quantification and Prediction of Synergistic Effects of Impurities

While existing research has elucidated the mechanisms of individual impurities (e.g., H₂O, O₂, and SO₂), there remains a lack of systematic and quantitative description of synergistic corrosion behaviors under the coexistence of multiple components (e.g., O₂/SO₂/NO₂/H₂S). Future work should develop multi-impurity reaction kinetics models to clarify critical thresholds for synergistic effects. Simultaneously, the regulatory mechanisms of impurities on phase separation should be analyzed to establish mapping relationships among impurity concentrations, phase behaviors, and corrosion rates.

5.2. Long-Term Dynamic Corrosion Behavior and Product Layer Stability

Current experimental durations are generally too short to simulate decades of pipeline service conditions. The long-term evolution of corrosion product layers (FeCO₃/FeS)—particularly under high temperatures (>60 °C) or impurity perturbations (e.g., O₂ > 500 ppm)—urgently needs investigation. Dense FeCO₃ layers may transition into porous Fe₂O₃–FeSO₄ mixed structures, losing protectiveness and initiating pitting. In situ characterization techniques should be developed to dynamically track critical conditions for film failure. Additionally, the accelerated stripping of corrosion products by erosion in dynamic flow fields requires the construction of cyclic flow experimental systems combined with slow strain rate tests to quantify risks of SCC and hydrogen-induced cracking (HIC).

5.3. Standardized Experimental Systems and Interdisciplinary Integration

Significant data variability severely restricts engineering applications. Methodological differences between static autoclave and dynamic flow loop tests lead to substantial discrepancies, primarily due to non-standardized aqueous phase contact modes (continuous phase vs. droplets) and impurity consumption. Unified protocols and dynamic parameter simulation standards must be established. Concurrently, interdisciplinary collaboration is urgently needed, including integrating materials science to develop low-cost corrosion-resistant alloys, leveraging fluid dynamics to model critical droplet sizes for predicting acid condensation locations, utilizing artificial intelligence to fuse large-scale corrosion data for long-term rate prediction models, and employing transfer learning to generalize behavioral patterns across steel grades.

5.4. Engineering-Oriented Optimization of Impurity Control

Existing engineering standards lack multi-field coupling foundations. Operational condition-adaptive regulation must be developed in order to dynamically adjust impurity thresholds under varying conditions, integrate temperature–pressure–impurity variables, and map critical corrosion rate boundaries into engineering charts. Simultaneously, material and mitigation strategies should be front-loaded, including embedding corrosion considerations during pipeline design, defining upper limits for free water and impurity tolerances, and developing closed-loop online monitoring and control systems to dynamically optimize dehydration units and amine scrubber operational parameters.

Breaking through the four major bottlenecks—synergistic impurity effects, long-term corrosion evolution, experimental standardization, and interdisciplinary integration—constitutes the core pathway to achieving safe transportation in CCUS sCO₂ pipelines. Future efforts must synergistically advance fundamental mechanism research, engineering tool development, and standard system construction to provide scientific and technological support to the global carbon reduction infrastructure.

6. Conclusions

The impact of impurities on material integrity in sCO₂ pipeline transportation is a nonlinear process triggered by H₂O and dominated by the synergistic effects of multiple impurities. This review systematically dissected this complex mechanism, confirming that oxidizing impurities such as O₂, SO₂, and NO₂ significantly accelerate corrosion by disrupting protective corrosion product layers or generating strong acids in situ. The strength of their synergistic effect far exceeds the simple sum of individual actions, constituting a major threat to pipeline safety. Consequently, the key to the successful engineering of protection lies in the strict combined control of water content and critical impurity concentrations, coupled with the selection of appropriate corrosion-resistant materials. Future work must focus on developing cross-scale theoretical models and innovative characterization techniques to provide scientific and technological support for the safe transportation of CO₂ in the context of carbon neutrality.

Author Contributions: Y.Y.: writing—review and editing, visualization, supervision, methodology, investigation; W.L. (Weifeng Lyu): writing—review and editing, conceptualization, funding acquisition; H.Y.: investigation; W.L. (Wenfeng Lv): investigation, conceptualization; K.W.: conceptualization; L.J.: conceptualization. All authors have read and agreed to the published version of the manuscript.

Funding: This work was supported by the National Key R&D Program of China “Research and Application of Key Technical Standards for CO₂ Storage in Large Oil and Gas Reservoirs” (Grant No. 2023YFF0614100), the National Major Science and Technology Project of China “CO₂ Flooding for Significantly Enhanced Oil Recovery and Long-Term Storage Technology” (Grant No. 2024ZD14066) and the Major Development Pilot Project for Enhanced Oil Recovery (Grant No. 2023YQX10401).

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: No new data were created or analyzed in this study.

Conflicts of Interest: The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

References

1. Calvin, K.; Dasgupta, D.; Krinner, G.; Mukherji, A.; Thorne, P.W.; Trisos, C.; Romero, J.; Aldunce, P.; Barrett, K.; Blanco, G.; et al. *Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*; IPCC: Geneva, Switzerland, 2023.
2. Lyu, W.; Zhang, H.; Zhou, T.; Gao, M.; Zhang, D.; Yang, Y.; Zhang, K.; Yu, H.; Ji, Z.; Lyu, W.; et al. Progress in CO₂ flooding and storage techniques for lacustrine oil reservoirs in China and development directions of their large-scale application. *Pet. Explor. Dev.* **2025**, *52*, 1086–1101. [[CrossRef](#)]
3. Simons, A.; Tavangar, R.; Verbeken, K.; Depover, T. A review of corrosion in flowing conditions during dense phase CO₂ transport for carbon capture, utilization, and storage (CCUS). *Eng. Fail. Anal.* **2025**, *181*, 109905. [[CrossRef](#)]
4. Fu, L.; Ren, Z.; Si, W.; Ma, Q.; Huang, W.; Liao, K.; Huang, Z.; Wang, Y.; Li, J.; Xu, P. Research progress on CO₂ capture and utilization technology. *J. CO₂ Util.* **2022**, *66*, 102260. [[CrossRef](#)]
5. Yang, F.; Zhao, G.-B.; Adidharma, H.; Towler, B.; Radosz, M. Effect of Oxygen on Minimum Miscibility Pressure in Carbon Dioxide Flooding. *Ind. Eng. Chem. Res.* **2007**, *46*, 1396–1401. [[CrossRef](#)]

6. Gale, J.; Davison, J. Transmission of CO₂—Safety and economic considerations. *Energy* **2004**, *29*, 1319–1328. [\[CrossRef\]](#)
7. Slavchov, R.I.; Iqbal, M.H.; Faraji, S.; Madden, D.; Sonke, J.; Clarke, S.M. Corrosion maps: Stability and composition diagrams for corrosion problems in CO₂ transport. *Corros. Sci.* **2024**, *236*, 112204. [\[CrossRef\]](#)
8. Millet, C.; Néel, G.; Lima, L.; Rodriguez Barrera, D. Material Selection for Anthropogenic CO₂ Injection: Mechanical and Corrosion Performances of Steels Under Dense CO₂ with Impurities. In Proceedings of the CONFERENCE 2023, Denver, CO, USA, 19–23 March 2023; AMPP: Denver, CO, USA, 2023; pp. 1–21.
9. Vitali, M.; Corvaro, F.; Marchetti, B.; Terenzi, A. Thermodynamic challenges for CO₂ pipelines design: A critical review on the effects of impurities, water content, and low temperature. *Int. J. Greenh. Gas Control* **2022**, *114*, 103605. [\[CrossRef\]](#)
10. Johnsen, K.; Helle, K.; Rønneid, S.; Holt, H. DNV recommended practice: Design and operation of CO₂ pipelines. *Energy Procedia* **2011**, *4*, 3032–3039. [\[CrossRef\]](#)
11. Zhang, S.; Shen, Y.; Zheng, C.; Xu, Q.; Sun, Y.; Huang, M.; Li, L.; Yang, X.; Zhou, H.; Ma, H.; et al. Recent advances, challenges, and perspectives on carbon capture. *Front. Environ. Sci. Eng.* **2024**, *18*, 75. [\[CrossRef\]](#)
12. Sun, H.; Wang, H.; Zeng, Y.; Liu, J. Corrosion challenges in supercritical CO₂ transportation, storage, and utilization—A review. *Renew. Sustain. Energy Rev.* **2023**, *179*, 113292. [\[CrossRef\]](#)
13. SONKE, J.; Morland, B.H.; Moulie, G.; Franke, M.S. Corrosion and chemical reactions in impure CO₂. *Int. J. Greenh. Gas Control* **2024**, *133*, 104075. [\[CrossRef\]](#)
14. Wang, J.; Ryan, D.; Anthony, E.J.; Wildgust, N.; Aiken, T. Effects of impurities on CO₂ transport, injection and storage. *Energy Procedia* **2011**, *4*, 3071–3078. [\[CrossRef\]](#)
15. Wei, L.; Pang, X.; Gao, K. Corrosion of low alloy steel and stainless steel in supercritical CO₂/H₂O/H₂S systems. *Corros. Sci.* **2016**, *111*, 637–648. [\[CrossRef\]](#)
16. Luna-Ortiz, E.; Szklańczyk-Marshall, K.; Winter, M.; McAllister-Fognini, E. Impact of Hydrogen as Impurity in the Physical and Transport Properties of CO₂ Streams in CCS/CCUS Transport Systems: A Technical Discussion. In Proceedings of the 15th Greenhouse Gas Control Technologies Conference, Virtual, 15–18 March 2021; Social Science Research Network: Rochester, NY, USA, 2021.
17. Michel, A.; Solgaard, A.O.S.; Pease, B.J.; Geiker, M.R.; Stang, H.; Olesen, J.F. Experimental investigation of the relation between damage at the concrete-steel interface and initiation of reinforcement corrosion in plain and fibre reinforced concrete. *Corros. Sci.* **2013**, *77*, 308–321. [\[CrossRef\]](#)
18. Sui, P.; Sun, J.; Hua, Y.; Liu, H.; Zhou, M.; Zhang, Y.; Liu, J.; Wang, Y. Effect of temperature and pressure on corrosion behavior of X65 carbon steel in water-saturated CO₂ transport environments mixed with H₂S. *Int. J. Greenh. Gas Control* **2018**, *73*, 60–69. [\[CrossRef\]](#)
19. Wallaert, E.; Depover, T.; De Graeve, I.; Verbeken, K. FeS Corrosion Products Formation and Hydrogen Uptake in a Sour Environment for Quenched & Tempered Steel. *Metals* **2018**, *8*, 62. [\[CrossRef\]](#)
20. Hua, Y.; Barker, R.; Neville, A. The effect of O₂ content on the corrosion behaviour of X65 and 5Cr in water-containing supercritical CO₂ environments. *Appl. Surf. Sci.* **2015**, *356*, 499–511. [\[CrossRef\]](#)
21. Long, Z. Study on Corrosion Law of Tubing and Casing in EOR-CCUS System. Master’s Thesis, China University of Petroleum, Beijing, China, 2021.
22. Onyebuchi, V.E.; Kolios, A.; Hanak, D.P.; Biliyok, C.; Manovic, V. A systematic review of key challenges of CO₂ transport via pipelines. *Renew. Sustain. Energy Rev.* **2018**, *81*, 2563–2583. [\[CrossRef\]](#)
23. Hua, Y.; Neville, A.; Barker, R. Corrosion Behaviour of X65 Steels in Water-Containing Supercritical CO₂ Environments with NO₂/O₂. In Proceedings of the NACE CORROSION 2018 Conference and Expo, Phoenix, AZ, USA, 15–19 April 2018; pp. 1–17.
24. Cole, I.S.; Paterson, D.A.; Corrigan, P.; Sim, S.; Birbilis, N. State of the aqueous phase in liquid and supercritical CO₂ as relevant to CCS pipelines. *Int. J. Greenh. Gas Control* **2012**, *7*, 82–88. [\[CrossRef\]](#)
25. Sun, J.; Sun, C.; Wang, Y. Effects of O₂ and SO₂ on Water Chemistry Characteristics and Corrosion Behavior of X70 Pipeline Steel in Supercritical CO₂ Transport System. *Ind. Eng. Chem. Res.* **2018**, *57*, 2365–2375. [\[CrossRef\]](#)
26. Wang, J.; Ryan, D.; Anthony, E.J.; Wigston, A.; Basava-Reddi, L.; Wildgust, N. The effect of impurities in oxyfuel flue gas on CO₂ storage capacity. *Int. J. Greenh. Gas Control* **2012**, *11*, 158–162. [\[CrossRef\]](#)
27. Wilkinson, J.R.; Leahy-Dios, A.; Teletzk, G.F.; Dickson, J.L. Use of CO₂ containing impurities for miscible enhanced oil recovery. In Proceedings of the International Oil and Gas Conference and Exhibition, Beijing, China, 8–10 June 2010.
28. Mallon, W.; Buit, L.; van Wingerden, J.; Lemmens, H.; Eldrup, N.H. Costs of CO₂ Transportation Infrastructures. *Energy Procedia* **2013**, *37*, 2969–2980. [\[CrossRef\]](#)
29. Qiu, H. Cost Analysis of Offshore Carbon Dioxide Pipeline. *Chem. Eng. Des. Commun.* **2023**, *49*, 70–73.
30. McKaskle, R.; Beitler, C.; Dombrowski, K.; Fisher, K. The Engineer’s Guide to CO₂ Transportation Options. In Proceedings of the 16th Greenhouse Gas Control Technologies Conference (GHGT-16), Lyon, France, 23–27 October 2022.

31. Zeng, Y.; Luo, J.-L.; Li, K.; Arafin, M. Impacts of Impurities on Corrosion of Supercritical CO₂ Transportation Pipeline Steels. In Proceedings of the AMPP CORROSION 2018, Phoenix, AZ, USA, 15–19 April 2018; pp. 1–16.
32. Peletiri, S.P.; Mujtaba, I.M.; Rahmanian, N. Process simulation of impurity impacts on CO₂ fluids flowing in pipelines. *J. Clean. Prod.* **2019**, *240*, 118145. [[CrossRef](#)]
33. Sahak, M.Z.M.; Zain, M.M.; Alias, A.; Zulkifli, M.Y.; Rohani, S.N.; Rostani, K. Establishing Key Process Design Considerations for Carbon Capture, Utilization and Storage (CCUS) Towards Decarbonization of Existing Assets Operations. In Proceedings of the ADIPEC, Abu Dhabi, United Arab Emirates, 4–7 November 2024.
34. Tang, Y.; Guo, X.P.; Zhang, G.A. Corrosion behaviour of X65 carbon steel in supercritical-CO₂ containing H₂O and O₂ in carbon capture and storage (CCS) technology. *Corros. Sci.* **2017**, *118*, 118–128. [[CrossRef](#)]
35. Farelas, F.; Choi, Y.S.; Nesic, S. Effects of CO₂ Phase Change, SO₂ Content and Flow on the Corrosion of CO₂ Transmission Pipeline Steel. In Proceedings of the AMPP CORROSION 2012, Salt Lake City, UT, USA, 11–15 March 2012; pp. 1–16.
36. Zhu, G.Y.; Li, Y.Y.; Hou, B.S.; Zhang, Q.H.; Zhang, G.A. Corrosion behavior of 13Cr stainless steel under stress and crevice in high pressure CO₂/O₂ environment. *J. Mater. Sci. Technol.* **2021**, *88*, 79–89. [[CrossRef](#)]
37. Thodla, R.; Francois, A.; Sridhar, N. Materials Performance in Supercritical CO₂ Environments. In Proceedings of the AMPP CORROSION 2009, Atlanta, GA, USA, 22–26 March 2009; pp. 1–14.
38. Liu, G.; Fan, X.; Wang, C.; Zhao, X.; Meng, L.; Hu, Q.; Li, Y. Effect of Phase Change on corrosion behavior of X65 Steel in CO₂ transportation pipeline environment. *J. Pipeline Sci. Eng.* **2025**, 100262. [[CrossRef](#)]
39. Li, K.; Zeng, Y. Advancing the mechanistic understanding of corrosion in supercritical CO₂ with H₂O and O₂ impurities. *Corros. Sci.* **2023**, *213*, 110981. [[CrossRef](#)]
40. Dugstad, A.; Halseid, M.; Morland, B.; Sivertsen, A.O. Dense Phase CO₂ Corrosion and the Impact of Depressurization and Accumulation of Impurities. In Proceedings of the CORROSION 2013, Orlando, FL, USA, 17–21 March 2013.
41. Sun, C.; Sun, J.; Liu, S.; Wang, Y. Effect of water content on the corrosion behavior of X65 pipeline steel in supercritical CO₂-H₂O-O₂-H₂S-SO₂ environment as relevant to CCS application. *Corros. Sci.* **2018**, *137*, 151–162. [[CrossRef](#)]
42. Sun, C.; Sun, J.; Wang, Y.; Wang, S.; Liu, J. Corrosion Mechanism of octg carbon steel in supercritical CO₂/Oil/Water system. *ACTA Metall. Sin.* **2014**, *50*, 811–820.
43. Zhang, Y.; Ju, X.; Pang, X.; Gao, K. Effect of O₂ Concentration on Corrosion Rate of Steels in Supercritical CO₂. *J. Chin. Soc. Corros. Prot.* **2015**, *35*, 220–226.
44. Sim, S.; Cole, I.S.; Bocher, F.; Corrigan, P.; Gamage, R.P.; Ukwattage, N.; Birbilis, N. Investigating the effect of salt and acid impurities in supercritical CO₂ as relevant to the corrosion of carbon capture and storage pipelines. *Int. J. Greenh. Gas Control* **2013**, *17*, 534–541. [[CrossRef](#)]
45. Ayello, F.; Evans, K.; Sridhar, N.; Thodla, R. Effect of Liquid Impurities on Corrosion of Carbon Steel in Supercritical CO₂. In Proceedings of the 2010 8th International Pipeline Conference, Calgary, AB, Canada, 27 September–1 October 2010; ASME: Calgary, AB, Canada, 2010; Volume 1, pp. 111–123.
46. Choi, Y.-S.; Nesic, S.; Young, D. Effect of Impurities on the Corrosion Behavior of CO₂ Transmission Pipeline Steel in Supercritical CO₂–Water Environments. *Environ. Sci. Technol.* **2010**, *44*, 9233–9238. [[CrossRef](#)]
47. Hua, Y.; Barker, R.; Neville, A. The influence of SO₂ on the tolerable water content to avoid pipeline corrosion during the transportation of supercritical CO₂. *Int. J. Greenh. Gas Control* **2015**, *37*, 412–423. [[CrossRef](#)]
48. Cabrini, M.; Lorenzi, S.; Pastore, T.; Radaelli, M. Corrosion rate of high CO₂ pressure pipeline steel for carbon capture transport and storage. *Metall. Ital.* **2014**, *106*, 21–27.
49. Sun, C.; Sun, J.; Wang, Y.; Lin, X.; Li, X.; Cheng, X.; Liu, H. Synergistic effect of O₂, H₂S and SO₂ impurities on the corrosion behavior of X65 steel in water-saturated supercritical CO₂ system. *Corros. Sci.* **2016**, *107*, 193–203. [[CrossRef](#)]
50. Kairy, S.K.; Zhou, S.; Turnbull, A.; Hinds, G. Corrosion of pipeline steel in dense phase CO₂ containing impurities: A critical review of test methodologies. *Corros. Sci.* **2023**, *214*, 110986. [[CrossRef](#)]
51. Makarenko, V.D.; Shatilo, S.P.; Gumerskii, K.K.; Belyaev, V.A. Effect of oxygen and hydrogen sulfide on carbon dioxide corrosion of welded structures of oil and gas installations. *Chem. Pet. Eng.* **2000**, *36*, 125–130. [[CrossRef](#)]
52. Skaperdas, G.T.; Uhlig, H.H. Corrosion of Steel by Dissolved Carbon Dioxide and Oxygen. *Ind. Eng. Chem.* **1942**, *34*, 748–754. [[CrossRef](#)]
53. Wang, W.; Shen, K.; Tang, S.; Shen, R.; Parker, T.; Wang, Q. Synergistic effect of O₂ and SO₂ gas impurities on X70 steel corrosion in water-saturated supercritical CO₂. *Process Saf. Environ. Prot.* **2019**, *130*, 57–66. [[CrossRef](#)]
54. Dugstad, A.; Morland, B.; Clausen, S. Corrosion of transport pipelines for CO₂—Effect of water ingress. *Energy Procedia* **2011**, *4*, 3063–3070. [[CrossRef](#)]
55. Li, K.; Zeng, Y. Long-term corrosion and stress corrosion cracking of X65 steel in H₂O-saturated supercritical CO₂ with SO₂ and O₂ impurities. *Constr. Build. Mater.* **2023**, *362*, 129746. [[CrossRef](#)]

56. Li, Y.Y.; Jiang, Z.N.; Zhang, Q.H.; Lei, Y.; Wang, X.; Zhang, G.A. Unveiling the influential mechanism of O₂ on the corrosion of N80 carbon steel under dynamic supercritical CO₂ conditions. *Corros. Sci.* **2022**, *205*, 110436. [\[CrossRef\]](#)
57. Wei, L.; Pang, X.; Gao, K. Effect of small amount of H₂S on the corrosion behavior of carbon steel in the dynamic supercritical CO₂ environments. *Corros. Sci.* **2016**, *103*, 132–144. [\[CrossRef\]](#)
58. Sun, J.; Sun, C.; Zhang, G.; Li, X.; Zhao, W.; Jiang, T.; Liu, H.; Cheng, X.; Wang, Y. Effect of O₂ and H₂S impurities on the corrosion behavior of X65 steel in water-saturated supercritical CO₂ system. *Corros. Sci.* **2016**, *107*, 31–40. [\[CrossRef\]](#)
59. Li, C.; Xiang, Y.; Li, W. Initial corrosion mechanism for API 5L X80 steel in CO₂/SO₂-saturated aqueous solution within a CCUS system: Inhibition effect of SO₂ impurity. *Electrochim. Acta* **2019**, *321*, 134663. [\[CrossRef\]](#)
60. Zeng, Y.; Li, K. Influence of SO₂ on the corrosion and stress corrosion cracking susceptibility of supercritical CO₂ transportation pipelines. *Corros. Sci.* **2020**, *165*, 108404. [\[CrossRef\]](#)
61. Xiang, Y.; Wang, Z.; Li, Z.; Ni, W.D. Effect of temperature on corrosion behaviour of X70 steel in high pressure CO₂/SO₂/O₂/H₂O environments. *Corros. Eng. Sci. Technol.* **2013**, *48*, 121–129. [\[CrossRef\]](#)
62. Morland, B.H.; Norby, T.; Tjelta, M.; Svenningsen, G. Effect of SO₂, O₂, NO₂, and H₂O Concentrations on Chemical Reactions and Corrosion of Carbon Steel in Dense Phase CO₂. *Corrosion* **2019**, *75*, 1327–1338. [\[CrossRef\]](#) [\[PubMed\]](#)
63. Paul, S. Thermally Sprayed Corrosion Resistant Alloy Coatings on Carbon Steel for use in Supercritical CO₂ Environments. In Proceedings of the CORROSION 2015, Dallas, TX, USA, 15–19 March 2015; pp. 1–9.
64. Barker, R.; Hua, Y.; Neville, A. Internal corrosion of carbon steel pipelines for dense-phase CO₂ transport in carbon capture and storage (CCS)—A review. *Int. Mater. Rev.* **2017**, *62*, 1–31. [\[CrossRef\]](#)
65. Finšgar, M.; Jackson, J. Application of corrosion inhibitors for steels in acidic media for the oil and gas industry: A review. *Corros. Sci.* **2014**, *86*, 17–41. [\[CrossRef\]](#)
66. da Silva de Sá, J.; Ma, W.; Owen, J.; Hua, Y.; Neville, A.; Ponciano Gomes, J.A.C.; Barker, R. Effect of Flow Rate on the Corrosion Behavior of API 5L X80 Steel in Water-Saturated Supercritical CO₂ Environments. *Corrosion* **2021**, *78*, 58–67. [\[CrossRef\]](#)
67. Ding, H.; Xiang, Y.; Lu, W.; Yan, K.; Ren, J.; Yan, W.; Yao, E.; Zhao, X. Selective adsorption and corrosion mechanism of SO₂ and its hydrates on X65 welded joints steel in CO₂-saturated aqueous solution. *Corros. Sci.* **2024**, *238*, 112373. [\[CrossRef\]](#)
68. Yang, W.; Qin, X.; Zhang, R.; Sun, J.; Sun, C.; Xu, X.; Lin, X. Coupling effect of H₂S and SO₂ on the corrosion behavior of X65 pipeline steel in high-pressure CO₂ transport environments. *Corros. Sci.* **2025**, *256*, 113163. [\[CrossRef\]](#)
69. Dugstad, A. Fundamental Aspects of CO₂ Metal Loss Corrosion, Part I: Mechanism. In Proceedings of the CORROSION 2015, Dallas, TX, USA, 15–19 March 2015.
70. Dugstad, A.; Halseid, M.; Morland, B. Effect of SO₂ and NO₂ on Corrosion and Solid Formation in Dense Phase CO₂ Pipelines. *Energy Procedia* **2013**, *37*, 2877–2887. [\[CrossRef\]](#)
71. Ruhl, A.S.; Kranzmann, A. Investigation of corrosive effects of sulphur dioxide, oxygen and water vapour on pipeline steels. *Int. J. Greenh. Gas Control* **2013**, *13*, 9–16. [\[CrossRef\]](#)
72. Xiang, Y.; Wang, Z.; Xu, C.; Zhou, C.; Li, Z.; Ni, W. Impact of SO₂ concentration on the corrosion rate of X70 steel and iron in water-saturated supercritical CO₂ mixed with SO₂. *J. Supercrit. Fluids* **2011**, *58*, 286–294. [\[CrossRef\]](#)
73. Xiang, Y.; Li, C.; Long, Z.; Guan, C.; Wang, W.; Hesitao, W. Electrochemical behavior of valve steel in a CO₂/sulfurous acid solution. *Electrochim. Acta* **2017**, *258*, 909–918. [\[CrossRef\]](#)
74. Sun, C.; Yan, X.; Sun, J.; Pang, J.; Zhao, W.; Lin, X. Unraveling the effect of O₂, NO₂ and SO₂ impurities on the stress corrosion behavior of X65 steel in water-saturated supercritical CO₂ streams. *Corros. Sci.* **2022**, *209*, 110729. [\[CrossRef\]](#)
75. Ding, T.; Sun, C.; Sun, J.; Chen, Y.; Zhao, X.; Zhao, W.; Lin, X. A mechanistic model for the corrosion prediction of bare carbon steel in supercritical CO₂-H₂S-Cl- environments. *Corros. Sci.* **2025**, *256*, 113161. [\[CrossRef\]](#)
76. Srinivasan, S.; Tebbal, S. Critical Factors in Predicting CO₂/H₂S Corrosion in Multiphase Systems (Conference) | OSTI.GOV. In *Nace Corrosion*; NACE: Houston, TX, USA, 1998; pp. 1–12.
77. Li, K.; Zeng, Y.; Luo, J.-L. Influence of H₂S on the general corrosion and sulfide stress cracking of pipelines steels for supercritical CO₂ transportation. *Corros. Sci.* **2021**, *190*, 109639. [\[CrossRef\]](#)
78. Choi, Y.-S.; Hassani, S.; Vu, T.N.; Nešić, S.; B Abas, A.Z.; Nor, A.M.; Suhor, M.F. Strategies for Corrosion Inhibition of Carbon Steel Pipelines Under Supercritical CO₂/H₂S Environments. *Corrosion* **2019**, *75*, 1156–1172. [\[CrossRef\]](#) [\[PubMed\]](#)
79. Liu, R. Stress Corrosion Cracking Behavior and Prevention of High Strength Tubing Steels in Typical H₂S/CO₂ Annulus Environments. Ph.D. Thesis, University of Science and Technology Beijing, Beijing, China, 2015.
80. Sun, C.; Ding, T.; Sun, J.; Lin, X.; Zhao, W.; Chen, H. Insights into the effect of H₂S on the corrosion behavior of N80 steel in supercritical CO₂ environment. *J. Mater. Res. Technol.* **2023**, *26*, 5462–5477. [\[CrossRef\]](#)
81. Yan, W.; Deng, J.; Dong, X.; Zhang, C.; Li, L.; Li, X. Corrosion Products and Corrosion Behavior of Tubing Steel in CO₂/H₂S Environmen. *Corros. Prot.* **2011**, *32*, 193–196.
82. Masamura, K.; Hashizume, S.; Sakai, J.; Matsushima, I. Polarization Behavior of High-Alloy OCTG in CO₂ Environment as Affected by Chlorides and Sulfides. *Corrosion* **1987**, *43*, 359–365. [\[CrossRef\]](#)

83. Zafar, M.N.; Rihan, R.; Al-Hadhrani, L. Evaluation of the corrosion resistance of SA-543 and X65 steels in emulsions containing H₂S and CO₂ using a novel emulsion flow loop. *Corros. Sci.* **2015**, *94*, 275–287. [\[CrossRef\]](#)
84. Zhao, J.; Duan, H.; Jiang, R. Synergistic corrosion inhibition effect of quinoline quaternary ammonium salt and Gemini surfactant in H₂S and CO₂ saturated brine solution. *Corros. Sci.* **2015**, *91*, 108–119. [\[CrossRef\]](#)
85. Choi, Y.-S.; Hassani, S.; Vu, T.N.; Nešić, S.; Abas, A.Z.B. Effect of H₂S on the Corrosion Behavior of Pipeline Steels in Supercritical and Liquid CO₂ Environments. *Corrosion* **2016**, *72*, 999–1009. [\[CrossRef\]](#)
86. Sonke, J.; Paterson, S.J. Guidance for Materials Selection and Corrosion Control in CO₂ Transport and Injection for Carbon Capture and Storage. In Proceedings of the CONFERENCE 2022, San Antonio, TX, USA, 6–10 March 2022; AMPP: San Antonio, TX, USA, 2022; pp. 1–18.
87. Ruhl, A.S.; Kranzmann, A. Investigation of Pipeline Corrosion in Pressurized CO₂ Containing Impurities. *Energy Procedia* **2013**, *37*, 3131–3136. [\[CrossRef\]](#)
88. Ayello, F.; Evans, K.; Thodla, R.; Sridhar, N. Effect of impurities on corrosion of steel in supercritical CO₂. In Proceedings of the CORROSION 2010, San Antonio, TX, USA, 14–18 March 2010; pp. 1–16.
89. Castaño, J.G.; de la Fuente, D.; Morcillo, M. A laboratory study of the effect of NO₂ on the atmospheric corrosion of zinc. *Atmos. Environ.* **2007**, *41*, 8681–8696. [\[CrossRef\]](#)
90. Simonsen, K.R.; Goebel, J.; Hansen, D.S.; Pedersen, S. The influence of temperature, H₂O, and NO₂ on corrosion in CO₂ transportation pipelines. *Process Saf. Environ. Prot.* **2025**, *198*, 107190. [\[CrossRef\]](#)
91. Cui, G.; Yang, Z.; Liu, J.; Li, Z. A comprehensive review of metal corrosion in a supercritical CO₂ environment. *Int. J. Greenh. Gas Control* **2019**, *90*, 102814. [\[CrossRef\]](#)
92. Liu, G.; Zhi, S.; Liu, X.; Chai, C.; Wang, C.; Xinran, Y.; Qihui, H.; Shiduo, R. Research progress on internal corrosion of supercritical/dense-phase CO₂ pipelines for CCUS. *Oil Gas Storage Transp.* **2024**, *43*, 510–523.
93. Li, D.; Jiang, X. Numerical investigation of the partitioning phenomenon of carbon dioxide and multiple impurities in deep saline aquifers. *Appl. Energy* **2017**, *185*, 1411–1423. [\[CrossRef\]](#)
94. Harrell, B.; Araujo de Itriago, Y.C.; Herrera, G. Effect of Impurities Present in the CO₂ Stream on Injectivity and Seal Performance in Carbon Capture and Storage. In Proceedings of the Offshore Technology Conference, Houston, TX, USA, 5–8 May 2025.
95. Li, Z.; Han, Z.; Lin, B.; Xiao, Y.; Wang, Y.; Nie, Z.; Tang, J. Research Progress on Corrosion Behavior and Mechanism of Supercritical CO₂ Transport Pipeline. *Surf. Technol.* **2024**, *53*, 19–30. [\[CrossRef\]](#)
96. Ding, T.; Chen, Y.; Sun, C.; Zhang, Z.; Sun, J.; Li, G. Corrosion dominant factor and corrosion prediction model for X52 pipeline steel in high-pressure CO₂ streams with multiple impurities of H₂O, O₂, SO₂, H₂S and NO₂. *Eng. Fail. Anal.* **2025**, *179*, 109789. [\[CrossRef\]](#)
97. Pots, B.F.M.; Kapusta, S.D.; John, R.C.; Thomas, M.J.J.S.; Rippon, I.J.; Whitham, T.S.; Girgis, M. Improvements on de Waard-Milliams Corrosion Prediction and Applications to Corrosion Management. In Proceedings of the CORROSION 2002, Denver, CO, USA, 7–12 April 2002; AMPP: Denver, CO, USA, 2002; pp. 1–19.
98. Li, C.; Xiang, Y.; Song, C.; Ji, Z. Assessing the corrosion product scale formation characteristics of X80 steel in supercritical CO₂-H₂O binary systems with flue gas and NaCl impurities relevant to CCUS technology. *J. Supercrit. Fluids* **2019**, *146*, 107–119. [\[CrossRef\]](#)
99. Zhou, J.; Yang, Y.; Yu, Y. ReaxFF molecular dynamics investigation on the oxidation mechanism of Fe surface in supercritical CO₂ mixed with O₂. *J. CO₂ Util.* **2022**, *65*, 102224. [\[CrossRef\]](#)
100. Wei, L.; Pang, X.; Liu, C.; Gao, K. Formation mechanism and protective property of corrosion product scale on X70 steel under supercritical CO₂ environment. *Corros. Sci.* **2015**, *100*, 404–420. [\[CrossRef\]](#)
101. Dong, C.; Jiang, J.; Ye, B.; Sun, Z.; Zhang, Y.; Xia, C. Comparative life cycle assessment of CO₂ onshore transport in China: Pipeline or tanker truck? *J. CO₂ Util.* **2025**, *94*, 103057. [\[CrossRef\]](#)
102. Nazeri, M.; Haghighi, H.; McKay, C.; Erickson, D.; Zhai, S. Impact of CO₂ Specifications on Design and Operation Challenges of CO₂ Transport and Storage Systems in CCUS. In Proceedings of the SPE Offshore Europe Conference & Exhibition, Virtual, 7–10 September 2021.
103. Duncan, I.; Wang, H. Evaluating the likelihood of pipeline failures for future offshore CO₂ sequestration projects. *Int. J. Greenh. Gas Control* **2014**, *24*, 124–138. [\[CrossRef\]](#)
104. Qin, J.; Li, Y.; Wu, D.; Wong, H.; Wang, G. CCUS global progress and China's policy suggestions. *Pet. Geol. Recovery Effic.* **2020**, *27*, 20–28. [\[CrossRef\]](#)
105. Oosterkamp, A.; Ramsen, J. *State-of-the-Art Overview of CO₂ Pipeline Transport with Relevance to Offshore Pipelines*; POYTEC: Haugesund, Norway, 2008.
106. Sun, C.; Yang, W.; Sun, J.; Yan, X.; Lin, X.; Xu, X. Hydrogen permeation and SCC susceptibility of X70 pipeline steel in CO₂-saturated water environment containing acidic impurity. *Corros. Sci.* **2024**, *236*, 112259. [\[CrossRef\]](#)

107. Lima, L.; Millet, C.; Barrera, D.R.; Néel, G.; Conder, R.; Fathi, N. Material Selection for CCUS Injection Well: A Case Study in North Sea. In Proceedings of the AMPP Annual Conference + Expo, New Orleans, LA, USA, 3–7 March 2024.
108. Watt, J. Carbon dioxide transport infrastructure: Key learning and critical issues. *J. Pipeline Eng.* **2010**, *9*, 213–222.

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.