Hydrogen and CO_2 Co-Storage in Mature Reservoirs: A New Frontier for the Energy Transition

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Abstract

The shift towards low-carbon energy systems necessitates large-scale strategies for managing carbon dioxide (CO_2) and storing renewable energy. Geological formations beneath the Earth's surface, which have been traditionally utilized in the petroleum sector for extracting hydrocarbons, present considerable potential for energy transition technologies like geological carbon storage (CCS) and underground hydrogen storage (UHS). This research assesses the technical viability, geological appropriateness, risks, and future prospects of subsurface energy storage systems. It examines key geological formations such as depleted oil and gas reservoirs, deep saline aquifers, and salt caverns for their storage capacity, containment integrity, and long-term stability. The study delves into significant technological challenges related to subsurface storage, including geomechanical stability, fluid migration, wellbore integrity, and monitoring needs. Additionally, it discusses risk assessment methods and uncertainty quantification techniques to evaluate potential environmental and operational risks. Emerging engineering solutions, such as advanced monitoring technologies, improved reservoir modeling, and enhanced sealing materials, are emphasized as crucial developments for ensuring safe and reliable storage operations. Moreover, the study investigates the integration of geological storage systems with renewable energy infrastructure, particularly focusing on hydrogen as a long-term energy carrier and CCS as a vital strategy for mitigating industrial emissions. Policy frameworks, regulatory governance, and public acceptance are also identified as critical factors influencing the large-scale implementation of these technologies. Overall, the findings indicate that subsurface energy storage offers a promising route for supporting global decarbonization efforts, while highlighting the need for ongoing research, technological innovation, and interdisciplinary collaboration to tackle remaining technical and societal challenges.

Nomenclature

Reservoir and Geological Terms

Symbol / Term	Meaning
Porosity (φ)	Fraction of pore volume to total rock volume
Permeability (k)	Ability of rock to transmit fluids
Caprock	Low-permeability sealing formation above the reservoir
Brine	Saline formation water present in subsurface reservoirs
Reservoir Pressure	Pressure within the pore spaces of the reservoir rock
Fracture Gradient	Pressure limit at which rock fracturing may occur
Fault Reactivation	Re-movement of pre-existing geological faults due to stress changes
Injectivity	Ability of a reservoir to accept injected fluids
Residual Trapping	Immobilization of gas in pore spaces after injection
Solubility Trapping	Dissolution of gas into formation brine
Mineral Trapping	Long-term immobilization of CO_2 through mineral reactions
Structural Trapping	Physical containment of gas beneath caprock structures
Relative Permeability	Effective permeability of one fluid phase in the presence of another
Wettability	Tendency of a fluid to spread on a rock surface
Capillary Pressure	Pressure difference between fluid phases in porous media
Geomechanics	Study of mechanical behavior of rocks under stress
Reactive Transport	Coupled fluid flow and geochemical reaction processes
Cyclic Injection	Repeated injection and withdrawal operations
Buoyancy	Upward force caused by density differences between fluids
Diffusion	Molecular transport from high to low concentration
Dispersion	Spreading of fluids caused by flow heterogeneity

Symbol / Term	**Meaning**
Hysteresis	Difference in flow behavior during injection and withdrawal cycles
Cushion Gas	Permanent gas volume used to maintain storage pressure
Deliverability	Ability to withdraw stored gas at required production rates
Seal Integrity	Capacity of caprock and wells to prevent leakage
Wellbore Integrity	Mechanical and chemical stability of wells during storage operations
Microbial Activity	Biological reactions affecting stored gases and reservoir conditions
Carbonic Acid	Acid formed when CO_2 dissolves in water
Supercritical CO_2	CO_2 above critical temperature and pressure conditions

Abbreviations

Abbreviation	**Full Meaning**
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CO_2	Carbon Dioxide
H_2	Hydrogen
UHS	Underground Hydrogen Storage
GCS	Geological Carbon Storage
HMC	Hydro-Mechanical-Chemical
HM	Hydro-Mechanical
H_2S	Hydrogen Sulfide
CH_4	Methane
CAPEX	Capital Expenditure
OPEX	Operational Expenditure
LCA	Life-Cycle Assessment
Mt	Megatonne
Gt	Gigatonne
TWh	Terawatt-hour
EOR	Enhanced Oil Recovery
ECBM	Enhanced Coal Bed Methane
$ScCO_2$	Supercritical Carbon Dioxide
UQ	Uncertainty Quantification
PRA	Probabilistic Risk Assessment
CO_2-EOR	Carbon Dioxide Enhanced Oil Recovery
Fe(III)	Ferric Iron

Abbreviation	Full Meaning
pH	Potential of Hydrogen
P–T	Pressure–Temperature
Unit	Meaning
m	Meter
km	Kilometer
MPa	Megapascal
°C	Degree Celsius
wt.%	Weight Percent
mD	Millidarcy
ppm	Parts Per Million
yr	Year
bar	Pressure Unit (Bar)
Pa	Pascal

1. Introduction

The worldwide initiative to keep climate change below 2°C, ideally 1.5°C, has significantly altered energy systems. The swift adoption of renewable sources like wind and solar is crucial, yet their production is inconsistent and does not always align with demand (Engeland et al., 2017). This discrepancy necessitates large-scale energy storage to transfer excess renewable electricity from times of surplus to times of shortage. Hydrogen, generated through low-carbon or renewable methods, complements direct electrification by serving as an energy carrier across multiple sectors (Dawood et al., 2020; Oliveira et al., 2021). Geological storage of CO_2 is vital for reducing emissions in sectors that are difficult to decarbonize and for reaching net-zero goals (Krevor et al., 2015; Solomon, 2007; IPCC, 2005). Subsurface formations that have held hydrocarbons for millions of years, such as mature oil and gas reservoirs and aquifers, present a unique opportunity. These resources could be converted into "dual-function" storage sites to accommodate both CO_2 and hydrogen storage. By integrating hydrogen and CO_2 storage in mature reservoirs, carbon management and energy storage could be linked, potentially reducing costs and speeding up the energy transition. However, while underground hydrogen storage (UHS) and CO_2 geological storage (CCS) have been thoroughly studied (Krevor et al., 2015; Jahanbakhsh et al., 2024; Boon & Hajibeygi, 2022; Opoku Duartey et al., 2025), the concept of co-storage remains largely unexplored. This thesis explores "Hydrogen and CO_2 Co-Storage in Mature Reservoirs: A New Frontier for the Energy Transition".

1.1. Background: Subsurface storage and the energy transition

The decarbonization of energy systems relies on three tightly coupled pillars:

1. Massive deployment of renewables,
2. Low-carbon hydrogen production and use, and
3. Large-scale CO_2 capture and geological storage.

Although renewable energy sources are expanding swiftly, they are significantly influenced by climate variability. Wind, solar, and run-of-river hydropower exhibit notable fluctuations from sub-daily to seasonal time frames, leading to substantial variations in the residual load, which is the disparity between production and demand (Engeland et al., 2017). Addressing these fluctuations on a terawatt-hour scale necessitates extensive storage solutions beyond batteries and short-term demand responses. Hydrogen offers a solution by serving as a versatile and transportable energy carrier. Surplus renewable electricity can be transformed into hydrogen through electrolysis, stored, and later converted into power, heat, or fuels. Power-to-hydrogen systems (often referred to as power-to-gas systems) provide both sector coupling and seasonal balancing capabilities (Dawood et al., 2020; Oliveira et al., 2021; Walke et al., 2011). Concurrently, CO_2 capture and storage (CCS) are essential for decarbonizing fossil-fuel-based industries and negative-emission technologies. Integrated assessment models and policy scenarios predict multi-gigatonne annual CO_2 injection into geological formations by mid-century (Krevor et al., 2015; IPCC, 2005). Projects such as Sleipner in the North Sea have already demonstrated long-term containment in saline aquifers, supported by extensive seismic monitoring and flow-reactive transport modeling (Solomon, 2007; Scholes et al., 2015).

Subsurface storage of both CO_2 and hydrogen relies on similar geological principles:

- Deep porous reservoirs (typically >800 m depth) where fluids exist at high pressure and, for CO_2, supercritical conditions;
- Overlying low-permeability caprocks (e.g., shale, evaporites) that provide structural sealing;
- A combination of trapping mechanisms—structural/stratigraphic, residual, solubility, and mineral trapping for CO_2 (IPCC, 2005).

Extensive research over the years has elucidated the mechanisms of CO_2 trapping, the security of its storage, and frameworks for assessing associated risks (Solomon, 2007; IPCC, 2005; Scholes et al., 2015). In contrast, a new wave of studies is emerging for hydrogen, aiming to develop a similar understanding of multiphase flow, geochemical reactions, geomechanics, and microbial impacts within porous media (Jahanbakhsh et al., 2024; Boon & Hajibeygi, 2022; Bo et al., 2023; Kumar et al., 2022; Panfilov et al., 2006; Chen & Hu, 2022; Opoku Duartey et al., 2025; pidjoe, n.d.). Recent strategic evaluations have determined that underground storage of CO_2 and hydrogen could be pivotal for a sustainable energy future, facilitating both carbon removal and the large-scale integration of renewable energy sources (Krevor et al.,2015). This broader perspective encourages the exploration of integrated storage solutions, rather than viewing CCS and UHS as separate technologies.

1.2.Mature reservoirs as dual-function energy storage assets

Mature hydrocarbon reservoirs, especially those that are depleted gas fields or oil fields nearing the end of their productive life, are highly appealing for large-scale underground storage. They provide:

- Known geology and petrophysics (porosity, permeability, structural traps) from decades of production history;
- Pre-existing wells and infrastructure, which reduce both development costs and timelines
- Pressure-depleted conditions that allow for re-pressurization through fluid injection, aiding in caprock stress management (Jahanbakhsh et al., 2024; Zhang & Yu, 2022).

For CO_2 storage, numerous national and regional atlases have already identified depleted fields as ideal targets with relatively well-defined capacity (Krevor et al., 2015; Solomon, 2007). In the case of hydrogen, both field-scale operations (like H_2-rich "town gas" storage) and recent numerical studies suggest that depleted gas reservoirs can safely accommodate large cyclic hydrogen inventories when geomechanical and well integrity constraints are properly managed (Kumar et al., 2022; Panfilov et al., 2006; Chen & Hu, 2022).

Mature reservoirs are especially promising as dual-function assets:

- In winter, hydrogen stored in the reservoir can be extracted to support power generation and heating, replacing natural gas.
- In summer, the same reservoir can receive CO_2 captured from industries or power plants, either as a permanent storage solution or as part of a co-injected gas mixture with hydrogen or cushion gas.

This dual use could unlock several synergies:

1. Shared infrastructure – Utilizing common wells, surface facilities, and monitoring systems reduces capital and operating costs compared to separate CCS and UHS projects.
2. Pressure management – The combined injection of CO_2 and hydrogen (and brine withdrawal, if necessary) can help maintain reservoir pressures within safe

geomechanical limits over long-term cyclic operations (Bo et al., 2023; Kumar et al., 2022; Panfilov et al., 2006; Zhang & Yu, 2022).

3. Enhanced resource utilization – Depleted fields and associated aquifers may offer storage capacities that far exceed those of salt caverns, which, while attractive, are geographically limited (Jahanbakhsh et al.,2024).

Some existing studies have explored the underground storage of H_2–CO_2–CH_4 mixtures in depleted gas reservoirs, focusing on hydrodynamic instabilities, gas mixing, and self-organization phenomena (Rabiee et al., 2023; Pruess & Spycher, 2007). However, these studies often treat CO_2 as an impurity or component of fuel gas rather than as a deliberately sequestered greenhouse gas. In the context of the energy transition, re-envisioning mature reservoirs as co-storage hubs for both hydrogen and CO_2 could offer the following:

- Seasonal energy storage on the scale of TWh, and
- Permanent sequestration of CO_2 at the Mt–Gt scale, leveraging the assets and expertise already present in the oil and gas industry (Krevor et al., 2015; Jahanbakhsh et al., 2024; Zhang & Yu, 2022).

1.3.Knowledge gap: integration of hydrogen and CO_2 storage

Although the idea is conceptually appealing, combining hydrogen and CO_2 storage within the same established reservoir presents intricate scientific and engineering challenges that remain unresolved.

1.3.1. Multiphase flow and transport in H_2–CO_2–brine systems

Hydrogen and CO_2 differ in density, viscosity, and solubility, interacting differently with water and mineral surfaces (Boon & Hajibeygi, 2022; Bo et al., 2023; Li et al., 2020). Experimental core-flooding and imaging show:

- Very low hydrogen relative permeability and strong liquid-phase hysteresis in H_2–brine systems, leading to limited gas mobility and trapping (Boon & Hajibeygi, 2022; Bo et al., 2023).
- Complex displacement patterns (fingering, gravity override, channelling) causing significant hydrogen trapping and spatial segregation (Boon & Hajibeygi, 2022).

For H_2–CO_2–brine mixtures, recent studies highlight strong coupling among interfacial tension, wettability, and gas solubility, which impacts storage security and gas recovery (Li et al., 2020;

Zhang & Yu, 2022). Yet, no standardized relative permeability or capillary pressure description exists for H_2–CO_2 co-storage in reservoir-scale simulators, especially under cyclic injection-withdrawal.

1.3.2. Geomechanical and integrity challenges under cyclic, multi-fluid loading

Storing hydrogen seasonally involves subjecting it to pressure changes repeatedly over many years. Numerical geomechanical research indicates that such cyclic pressure variations can lead to nonlinear, inelastic deformation in varied formations, which might impact surface uplift or subsidence and the stability of faults (Kumar et al., 2022). The introduction of CO_2—either separately or as part of a mixed gas stream—complicates the pressure history and stress path. Key open questions include:

- How do the combined pressure cycles of H_2 and CO_2 affect the integrity of caprock and the risk of fault reactivation?

The cyclic process of injecting and withdrawing H_2, along with CO_2 injection, exposes the reservoir-caprock system to ongoing changes in pore pressure, altering the in-situ stress state and potentially reducing safety margins against both shear and tensile failure (Engeland et al., 2017; Dawood et al., 2020; Oliveira et al., 2021). Geomechanical models for underground gas and CO_2 storage reveal that increased pressure raises effective stresses on faults and fractures, and if the combined H_2–CO_2 pressure history nears the failure threshold, it could lead to fault reactivation or tensile fracturing of the caprock (Engeland et al., 2017; Krevor et al., 2023). CO_2 injection typically operates near a long-term maximum pressure to optimize storage capacity, while H_2 introduces shorter-term, higher-frequency pressure fluctuations; the overlap of these signals can locally decrease the safety factor against failure, particularly near injection wells and critically oriented faults (Dawood et al., 2020; Jahanbakhsh et al., 2024). Additionally, the buoyancy of H_2 and the greater density of CO_2 cause them to segregate vertically, creating lateral pressure and stress gradients that can alter the tendency for fault slip and the normal stress on the caprock interface (Oliveira et al., 2021; Solomon, 2007). To reduce the risk of caprock damage and fault reactivation, most studies suggest maintaining maximum reservoir pressure well below the least principal stress (with an appropriate safety factor), limiting the amplitude and rate of pressure changes during H_2 cycling, and avoiding high-pressure gas buildup against known major faults or weak caprock areas (Engeland et al., 2017; Krevor et al., 2023; Jahanbakhsh et al., 2024).

- To what degree can co-storage operations utilize existing wells without jeopardizing the integrity of the seal over the long term? (Karatas, 2020; Pruess & Spycher, 2007).

Legacy wells are commonly identified as one of the most significant potential leakage routes in both CO_2 storage and underground hydrogen storage (IPCC, 2005; Boon & Hajibeygi, 2022; Bo et al., 2023). Insights from CO_2-EOR and storage initiatives indicate that containment failures frequently occur along the casing–cement–formation interface, where issues such as cement debonding, cracking, or long-term chemical degradation in CO_2-rich environments create preferential pathways (IPCC, 2005; Kumar et al., 2022). For H_2, additional challenges include hydrogen embrittlement of steels, degradation of elastomers, and relatively high diffusion rates of H_2 through cement and polymeric materials (Boon & Hajibeygi, 2022; Panfilov et al., 2006). Therefore, co-storage operations can only repurpose legacy wells if their integrity is confirmed through a systematic process: reviewing the historical construction and abandonment of wells, conducting diagnostic logging and pressure testing to identify defects, and thoroughly assessing material compatibility with both CO_2 and H_2 throughout the project's duration (Bo et al., 2023; Chen & Hu, 2022). Many legacy wells will necessitate remedial actions—such as cement squeezing, adding extra mechanical barriers, or replacing incompatible tubulars—and wells with poor records, significant corrosion, or clearly inadequate cement are generally considered high-risk and are either re-plugged or excluded from the active storage area (Kumar et al., 2022; Panfilov et al., 2006; Chen & Hu, 2022). In practice, co-storage projects can only reuse a portion of legacy wells, and even those typically require substantial remediation to meet long-term seal integrity standards (Bo et al., 2023; Kumar et al., 2022; Panfilov et al., 2006; Chen & Hu, 2022).

The design of the operational parameters for H_2–CO_2 co-storage must be based on integrated flow–geomechanical and well-integrity assessments to ensure that storage capacity and deliverability are met without jeopardizing containment (Engeland et al., 2017; Dawood et al., 2020; Oliveira et al., 2021; Jahanbakhsh et al., 2024). Initially, the maximum permissible reservoir pressure is determined using in-situ stress data, caprock and fault strength information, and historical pressure records, with numerical models assessing fault slip potential and caprock failure indices. Typically, the chosen maximum pressure is well below the least principal stress and often lower than the historical peak field pressure (Engeland et al., 2017; Krevor et al., 2023; Solomon, 2007). Next, the extent and frequency of H_2 cycling are limited to prevent progressive damage or fatigue-like weakening of the reservoir–caprock system; generally, seasonal, smoother cycles are favored over high-frequency, high-amplitude cycling (Oliveira et al., 2021; Jahanbakhsh et al., 2024). Additionally, the gas composition is selected to manage buoyancy, mobility, and reactivity: higher CO_2 levels increase density and long-term trapping but also boost geochemical interactions, while higher H_2 levels enhance mobility and necessitate stricter control over well materials and the purity of produced gas (Dawood et al., 2020; Solomon, 2007; Panfilov et al., 2006). In practice, various injection–withdrawal scenarios are simulated and ranked based on energy storage performance (H_2 working gas volume, deliverability), CO_2 retention, and risk metrics (probability of leakage, likelihood of fault slip, well integrity margins) (Oliveira et al., 2021; Krevor et al., 2023). The resulting operational parameters establish limits on maximum and minimum reservoir pressure, cycling schedule, and permissible composition ranges, which are then refined over time using monitoring feedback (pressure, microseismicity, well surveillance, and, where available, time-lapse geophysics) (Engeland et al., 2017; Krevor et al., 2023; Jahanbakhsh et al., 2024).

1.3.3. Geochemical and microbial interactions

When CO_2 dissolves in brine, it forms carbonic acid, which can either dissolve or precipitate minerals, thereby affecting porosity, permeability, and mechanical properties over extended periods (Solomon, 2007; IPCC, 2005). In contrast, hydrogen acts as a reducing agent and can donate electrons to subsurface microbial communities, facilitating reactions that consume H_2 and produce CH_4 or H_2S (Zivar et al., 2021).

In scenarios where CO_2 and H_2 are stored together, they may:

- Compete within mixed microbial communities
- Alter redox conditions across different reservoir compartments, and
- Change mineral reaction pathways compared to systems with only CO_2 or H_2.

CO_2 dissolves in formation brine, creating carbonic acid that lowers pH and initiates a series of mineral dissolution and precipitation reactions (Solomon, 2007; IPCC, 2005). In sandstones and carbonates, the dissolution of carbonates and some silicates can locally enhance porosity and permeability, while the subsequent precipitation of secondary carbonates and clays might decrease permeability and partially seal around the CO_2 plume (Solomon, 2007; IPCC, 2005; White et al., 2005). Over long durations, these reactions govern the shift from primarily structural and residual trapping to solubility and mineral trapping, but they can also alter the mechanical properties of both the reservoir and caprock (e.g., stiffness, strength), impacting geomechanical stability (IPCC, 2005; Ringrose & Meckel, 2019). Reactive-transport simulations and recent reviews of CO_2–brine–rock systems indicate that the balance between dissolution-driven weakening and precipitation-driven sealing is highly site-specific and sensitive to mineralogy, flow paths, and injection strategy (White et al., 2005; Ringrose & Meckel, 2019; Krevor et al., 2015). Hydrogen also serves as an energy-rich electron donor for subsurface microbial communities. Various anaerobic metabolisms—especially sulfate reduction, methanogenesis, and acetogenesis—can utilize H_2 as an energy source, consuming H_2 and generating CH_4, H_2S, and organic acids (Zivar et al., 2021; Busch et al., 2011; Young-Lorenz, 2013; HYD-Lead-Up, 2022). In porous-media UHS experiments and field observations, these microbial processes have been observed to (i) decrease the recoverable fraction of stored H_2, (ii) alter gas composition (e.g., enrichment in CH_4, CO_2, and H_2S), (iii) lead to microbially influenced corrosion of well materials, and (iv) cause bioclogging and local permeability reduction due to biofilm formation (Zivar et al., 2021; Busch et al., 2011; Young-Lorenz, 2013). Since microbial community structure and activity are influenced by temperature, salinity, electron acceptor availability (e.g., sulfate, CO_2, Fe (III)), and initial biomass, the extent of these effects is highly site-specific and remains challenging to predict in advance (Busch et al., 2011; HYD-Lead-Up, 2022). In a co-storage scenario where both CO_2 and H_2 are present, these geochemical and microbial processes become closely interconnected. The dissolution of CO_2 acidifies brines and may increase the availability of dissolved inorganic carbon and certain electron acceptors (e.g., Fe(III), sulfate) as minerals dissolve, while H_2 acts as a potent electron donor. This combination can create sharp redox gradients between H_2-rich and CO_2-rich zones and within the transition region where the two gases mix. In such mixed zones, microbial communities may:

- In mixed microbial communities, competition for H_2 occurs among sulfate-reducing bacteria, methanogens, and acetogens, influencing how H_2 is divided into CH_4, H_2S, and acetate.
- These organisms can also modify local pH and redox potential, which in turn affects mineral dissolution and precipitation rates, impacting porosity and permeability.
- Additionally, they can alter mineral reaction pathways, such as by encouraging sulfide mineral precipitation where H_2S is generated or by promoting carbonate precipitation through microbially induced changes in alkalinity (Zivar et al., 2021; Busch et al., 2011; Young-Lorenz, 2013; HYD-Lead-Up, 2022; Reitenbach et al., 2015).

These interconnected reactions have several practical consequences for H_2–CO_2 co-storage. Firstly, microbial consumption of H_2 in CO_2-rich brines can decrease the usable gas capacity and change the gas quality during extraction, necessitating further gas treatment due to the presence of H_2S and CO_2 exceeding pipeline standards. Secondly, localized mineral dissolution or precipitation caused by the interactions of CO_2, H_2, and microbes can either strengthen or weaken seal and reservoir integrity, depending on whether self-sealing or weakening processes prevail. Thirdly, microbially produced corrosive substances like H_2S and organic acids can exacerbate the corrosion of wells and surface facilities, particularly when H_2-induced embrittlement and biofilm growth are present (Krevor et al., 2015; Young-Lorenz, 2013; Feldmann et al., 2018). However, current research offers limited quantitative insights into these feedback mechanisms under realistic co-storage conditions. Most experimental and numerical studies still treat CO_2 and H_2 storage separately, with only a few beginning to explore combined H_2–CO_2 systems that incorporate both mineral reactions and microbial processes under reservoir conditions (IPCC, 2005; Rütters & Meyer, 2020; Krevor et al., 2015). Key uncertainties include the long-term development of microbial communities with repeated H_2 cycling, the stability of redox zonation as plumes move, and the scaling up of laboratory findings to diverse field settings. Consequently, geochemical–microbial interactions remain a significant knowledge gap in evaluating the long-term performance and risks of hydrogen and CO_2 co-storage, highlighting the need for site-specific characterization (brine chemistry, mineralogy, microbiology) and comprehensive reactive-transport–microbial modeling in future research (IPCC, 2005; Rütters & Meyer, 2020; Krevor et al., 2015; Reitenbach et al., 2015).

1.3.4. System-level design, risk and regulation

From a systems viewpoint, co-storage must comply with regulatory standards initially established for CCS, such as the long-term containment of CO_2, as well as new guidelines for UHS, like safeguarding groundwater and ensuring well integrity when exposed to H_2 (Karatas, 2020). The risk-assessment frameworks currently in place for UHS and CCS have largely been developed independently (IPCC, 2005; Karatas, 2020; Pruess & Spycher, 2007). To adapt these frameworks for reservoirs that serve dual functions and contain multiple fluids, new methodologies are needed to:

- Measure the combined risks of leakage and contamination
- Assess operational parameters for both CO_2 retention and H_2 deliverability, and
- Optimize monitoring strategies that can differentiate between the two fluids.

This array of uncertainties in multiphase flow, geomechanics, geochemistry, microbiology, and regulations represents the primary knowledge gap that this study seeks to fill.

1.4. Objectives and scope of this study

The primary goal of this thesis is to assess the technical viability and principal controlling factors of hydrogen and CO_2 co-storage in mature reservoirs, as well as to determine the conditions under which this co-storage could serve as a viable option for the energy transition. The specific objectives include:

1. **Conceptualization of co-storage in mature reservoirs**
    - Reviewing and synthesizing existing knowledge on subsurface CO_2 storage and underground hydrogen storage, with a focus on depleted oil and gas reservoirs as dual-function assets (Krevor et al., 2023; Jahanbakhsh et al., 2024; Kumar et al., 2022; Panfilov et al., 2006; Chen & Hu, 2022; Opoku Duartey et al., 2025; Rabiee et al., 2023; Walke et al., 2011).
    - Creating a conceptual framework for co-storage cycles (pressure, composition, time scales) pertinent to seasonal energy storage and ongoing CO_2 sequestration.
2. **Assessment of key physical processes controlling co-storage performance**
    - Investigating the multiphase flow behavior of H_2–CO_2–brine systems in porous media, including relative permeability hysteresis, capillary effects, buoyancy segregation, and gas mixing, using existing experimental data and numerical models (Boon & Hajibeygi, 2022; Bo et al., 2023; Panfilov et al., 2006; Rabiee et al., 2023; Li et al., 2020; Zhang & Yu, 2022).
    - Examining the geomechanical responses of mature reservoirs under cyclic H_2/CO_2 injection and withdrawal, with a focus on rock deformation, fault stability, and operational pressure limits (Kumar et al., 2022).
3. **Identification of risks and constraints specific to co-storage**
    - Analyzing potential leakage pathways (wells, faults, caprock) and integrity challenges when both H_2 and CO_2 are present, informed by CCS and UHS risk frameworks (IPCC, 2005; Karatas, 2020; Pruess & Spycher, 2007).
    - Discussing geochemical and microbial impacts that may affect storage performance, gas quality, and long-term stability in co-storage settings (Solomon, 2007; IPCC, 2005; Zivar et al., 2021).
4. **Definition of screening criteria and research needs**
    - Proposing screening criteria for selecting mature reservoirs suitable for co-storage (e.g., depth, pressure history, caprock properties, existing infrastructure).
    - Identifying priority knowledge gaps and research directions to enable future pilot projects and full-scale implementation of hydrogen and CO_2 co-storage in mature reservoirs.

1.4.1. Scope and limitations

The scope of this work is confined to porous media reservoirs, particularly depleted oil and gas fields and associated saline aquifers. Salt caverns, while significant for short-term hydrogen storage, are considered only as a comparative reference and not as co-storage candidates (Jahanbakhsh et al., 2024). The study emphasizes technical and scientific aspects—flow, geomechanics, geochemistry, and risk—rather than detailed economic optimization, which is briefly discussed using insights from CCS techno-economic analyses (IPCC, 2005; Benson & Cole, 2008). The analysis is based on existing laboratory experiments, field experience from CCS and UHS analogues, and published numerical studies, integrated into a conceptual and modeling framework tailored to co-storage. No proprietary field data are used, and regulatory and policy aspects are discussed at a high level.

2. Geological and Petrophysical Basis for Co-Storage

Storing hydrogen and CO_2 together in mature underground reservoirs combines three well-established but traditionally distinct technologies: conventional underground gas storage in depleted hydrocarbon fields and aquifers, underground hydrogen storage (UHS) for balancing renewable energy seasonally, and geological carbon storage (GCS/CCS) for long-term CO_2 sequestration. While these technologies share similar geological principles, they differ in their operational goals, gas characteristics, and risk profiles. Mature oil and gas reservoirs provide proven structural traps, well-documented geological frameworks, and extensive historical data from years of production and monitoring. Meanwhile, deep saline aquifers, which represent the largest theoretical storage capacity for CO_2 worldwide, are increasingly considered for hydrogen storage due to their vast potential. The main challenge of H_2–CO_2 co-storage is to utilize these subsurface resources while managing the combined behavior of two buoyant gases with distinct physical, chemical, and economic properties under varying pressure and saturation conditions (Engeland et al., 2017; Dawood et al., 2020; Oliveira et al., 2021; Krevor et al., 2023). Unlike standalone natural gas storage or CCS, co-storage introduces additional complexities such as density differences, relative permeability hysteresis, diffusion, and geochemical interactions. Therefore, a strong geological and petrophysical foundation is crucial to ensure storage capacity, injectivity, containment, and long-term integrity. This chapter explores reservoir types, key petrophysical parameters, the geochemical environment, and how reservoir maturity affects co-storage performance.

Hydrogen and CO_2 co-storage in mature reservoirs intersects three technologies:

- **conventional gas storage in depleted fields and aquifers**
- **underground hydrogen storage (UHS) for seasonal renewable balancing**
- **and geological carbon storage (GCS/CCS) for permanent CO_2 disposal**

Mature oil and gas fields offer proven traps and extensive datasets, while deep saline aquifers provide enormous theoretical capacity for CO_2 and potentially H_2. The key challenge for co-storage is to exploit this capacity while managing the combined behavior of two buoyant gases with very different physical, chemical, and economic characteristics under cyclic pressure and saturation changes (Engeland et al., 2017; Dawood et al., 2020; Oliveira et al., 2021; Krevor et al., 2023).

2.1.Reservoir Types Suitable for Hydrogen and CO_2 Storage

Subsurface hydrogen and CO_2 storage rely on the same broad classes of reservoirs used for natural gas storage and CCS:

- **Depleted oil and gas fields**
- **Deep saline aquifers**
- **Salt caverns** and, more rarely, **hard-rock caverns or coal seams as shown in figure (1).**

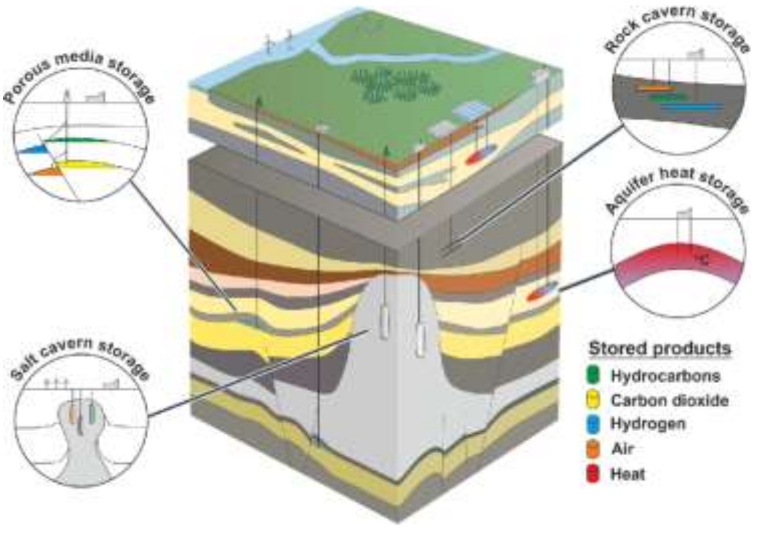

Figure 2.1. Conceptual illustration of subsurface reservoir types suitable for hydrogen and CO_2 storage, including depleted oil and gas reservoirs, deep saline aquifers, and salt caverns, source (Miocic et al., 2023).

2.1.1. Depleted gas reservoirs

Depleted gas reservoirs are considered the most promising options for the co-storage of H_2 and CO_2 because of their established containment capabilities, thorough subsurface analysis, and existing infrastructure. These reservoirs have proven their capacity to hold buoyant fluids over geological time periods, validating the effectiveness of structural, stratigraphic, and caprock sealing mechanisms, as illustrated in figure (2.1.1) (Engeland et al., 2017; Dawood et al., 2020).

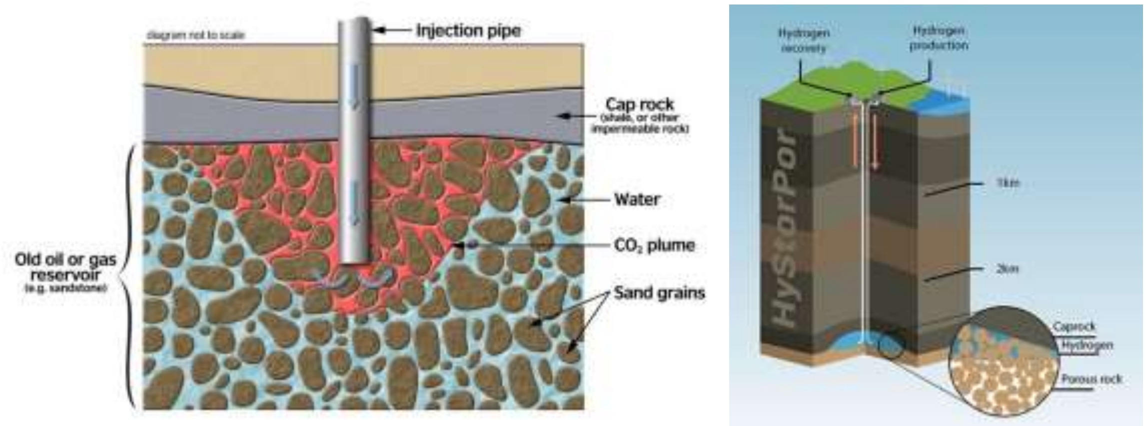

Figure 2.1.1. illustrates the repurposing of a depleted gas reservoir for hydrogen and CO_2 co-storage, highlighting structural trapping, caprock sealing, and the reuse of existing wells, sources Young-(Lorenz, Jillian., 2013), (HYD-Lead-Up, 2022).

As hydrocarbons are extracted, the resulting pressure drop increases the pore volume available, which can then be utilized for gas storage. Historical data on pressure and production offer crucial insights into how reservoirs behave, as well as the integrity of faults and the performance of caprock. Both numerical simulations and field research suggest that depleted sandstone gas reservoirs are well-suited for CO_2 sequestration and hydrogen storage, provided operations remain below the original reservoir pressure and fracture gradients (Engeland et al., 2017; Dawood et al., 2020). From an operational standpoint, these depleted reservoirs are ideal for cyclic storage. Often, existing wells, pipelines, and surface facilities can be reused or adapted, leading to reduced capital costs. Nonetheless, it is essential to carefully assess the integrity of legacy wells and the stress changes induced by production to prevent potential leakage during co-storage activities.

2.1.2. Deep saline aquifers

Deep saline aquifers are the most extensive global storage resource, characterized by their broad geographic spread and vast theoretical capacity. These aquifers are made up of porous sedimentary rocks filled with saline formation water and are capped by low-permeability layers such as shale, marl, or evaporites. When located at depths greater than roughly 800 meters, CO_2 is present as a dense or supercritical fluid, enhancing storage efficiency by increasing density and decreasing buoyancy, as illustrated in figure (2.1.2) (Oliveira et al., 2021).

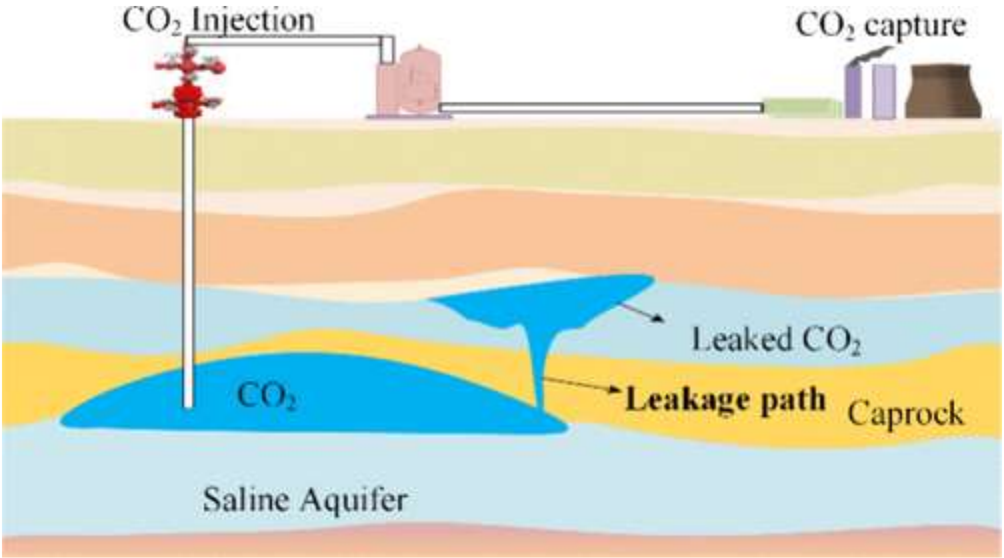

Figure 2.1.2. Deep saline aquifers consist of porous, brine-saturated sedimentary formations sealed by low-permeability caprocks, providing large capacity for CO_2 and hydrogen storage under supercritical conditions, source (Naga, Srinivasa R. et al, 2024).

While saline aquifers are typically less well-defined than depleted reservoirs, both experimental and numerical research highlight their significant potential for the long-term storage of CO_2 and possibly hydrogen (Oliveira et al., 2021; Krevor et al., 2023). In these systems, solubility trapping is particularly crucial, as both CO_2 and hydrogen can dissolve into the formation brines, thereby decreasing the volume of mobile gas. For co-storage purposes, saline aquifers provide substantial capacity but also bring uncertainties related to heterogeneity, pressure propagation, and long-term geochemical changes. Therefore, comprehensive site characterization, including seismic surveys, core analysis, and hydrodynamic modeling, is essential before deployment.

2.1.3. Salt caverns

Salt caverns offer outstanding containment capabilities due to halite's extremely low permeability and its ability to self-repair. These caverns are ideal for frequent hydrogen cycling and have been widely utilized for storing natural gas and hydrogen, as depicted in figure (2.1.3). Nonetheless, their limited storage capacity and restricted geographical distribution pose significant challenges for their use in large-scale H_2–CO_2 co-storage (Jahanbakhsh et al., 2024).

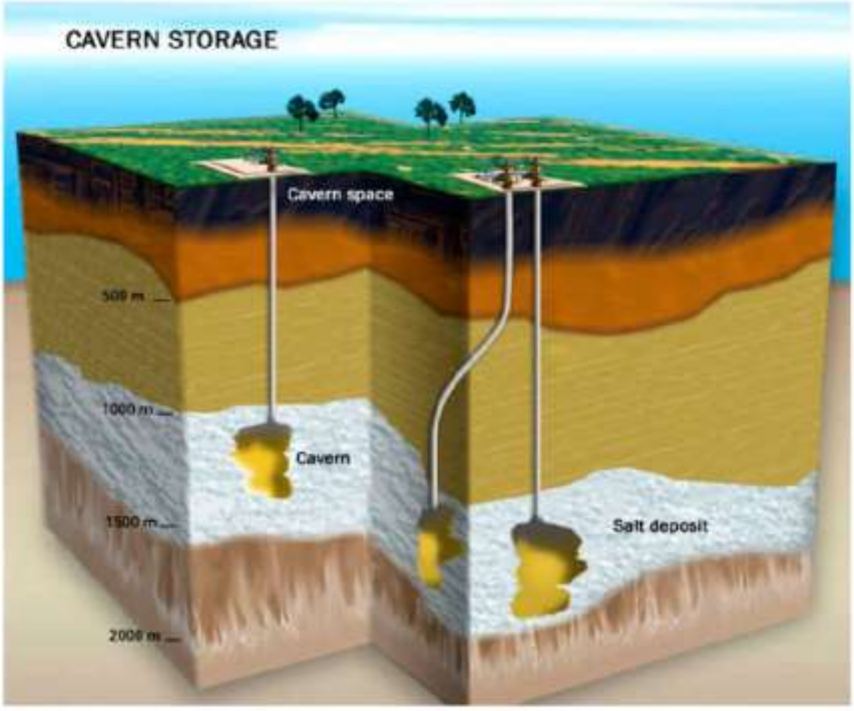

Figure 2.1.3. 1Conceptual illustration of an underground salt cavern used for hydrogen storage, showing solution-mined cavern geometry, halite formation with extremely low permeability, and high-frequency injection and withdrawal through vertical wells, source (Taneja et al., 2024).

Furthermore, salt caverns are not suitable for storing CO_2 because of geochemical incompatibility and mechanical issues. Consequently, although salt caverns are essential in hydrogen energy systems, porous reservoirs continue to be the main choice for the combined storage of hydrogen and CO_2.

2.2.Key Petrophysical Parameters: Porosity, Permeability, Wettability, and Capillary Pressure

Petrophysical characteristics are crucial determinants of storage capacity, injectivity, and containment efficiency in underground gas storage.

2.2.1. Porosity

Porosity is a key factor in determining a reservoir's volumetric storage capacity. Sandstone formations with porosity levels above roughly 15% are typically deemed appropriate for gas storage purposes. Both laboratory and field studies suggest that porosity alterations during cyclic gas injection are generally minimal when operational pressures are adequately managed (Solomon, 2007). Nonetheless, long-term geochemical reactions or mechanical compaction can locally alter porosity, especially near injection sites.

2.2.2. Permeability

Permeability dictates the reservoir's capability to accept and release stored gas. High permeability is particularly vital for hydrogen storage due to hydrogen's low viscosity and high mobility. Reservoirs with uneven permeability may form preferential flow paths, resulting in uneven gas distribution and decreased sweep efficiency. Numerical simulations and laboratory experiments indicate that cyclic loading can cause permeability changes through grain rearrangement, micro-fracturing, or compaction, particularly in weakly cemented sandstones (IPCC, 2005). These factors must be considered in storage design and simulation processes.

2.2.3. Wettability

influences multiphase flow behavior, relative permeability, and residual trapping efficiency. CO_2–brine systems often display intermediate-wet behavior, whereas hydrogen is strongly non-wetting compared to formation water. Recent experimental research shows significant relative permeability hysteresis in hydrogen–brine systems, which can greatly reduce hydrogen recovery efficiency during cyclic operations (Boon & Hajibeygi, 2022).

2.2.4. Capillary pressure

Capillary pressure affects gas entry pressure, plume migration, and residual trapping. High capillary entry pressures in fine-grained reservoirs and caprocks limit upward gas movement and enhance containment. Laboratory-scale experiments and pore-scale imaging confirm that capillary trapping is a crucial immobilization mechanism for both CO_2 and hydrogen in porous media, as illustrated in figure (2.2.4) (Bo et al., 2023).

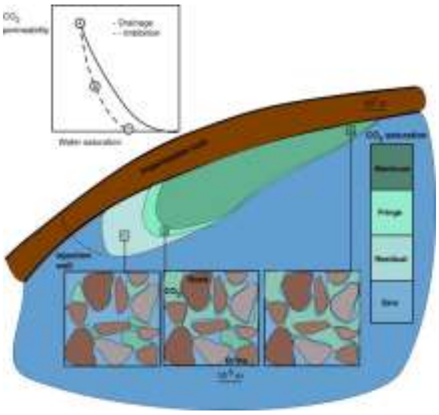

Figure 2.2.4. 1Conceptual sketch of capillary trapping following CO_2 injection, showing immobilization of residual gas, limited plume migration, reduced buoyant stress on the caprock, and associated relative permeability hysteresis during saturation decline, source (Krevor et al., 2015).

2.3.Geochemical Environment and Mineral Composition

The geochemical conditions within a reservoir significantly affect its long-term storage characteristics and structural integrity. The mineral composition of the reservoir dictates the degree of rock-fluid interactions that occur when gases are injected. Sandstone reservoirs, primarily composed of quartz, generally show minimal reactivity, whereas formations rich in carbonates are more prone to geochemical changes in acidic environments (Young-Lorenz, 2013). Specifically, CO_2 dissolves in the formation brine, creating carbonic acid, which lowers the pH and triggers mineral dissolution reactions. These reactions can locally increase porosity but may also result in secondary mineral formation, which decreases porosity, permeability, and injectivity (HYD-Lead-Up, 2022). Over extended periods, dissolved CO_2 can be immobilized through mineral trapping, forming stable carbonate minerals that improve storage security. Quartz-rich sandstone reservoirs are typically geochemically stable, while those containing carbonates and feldspars may exhibit increased reactivity, as illustrated in figure (2.3). Over long durations, CO_2 can be permanently immobilized by forming carbonate minerals, thereby enhancing storage security (Kumar et al., 2022). Hydrogen is mostly inert concerning most reservoir minerals; however, indirect geochemical effects might occur due to microbial activity, hydrogen consumption, or the production of by-products like hydrogen sulfide. Research has highlighted microbial reactions and biogeochemical processes as significant uncertainties in underground hydrogen storage, especially in reservoirs with appropriate temperature, salinity, and nutrient conditions (Panfilov et al., 2006; Chen & Hu, 2022).

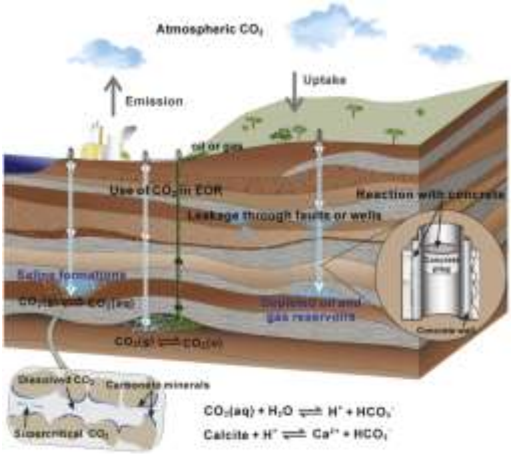

Figure 2.3. Chemical reactions in CO 2 geological sequestration sites are modified, source (Dai et al., 2020).

Therefore, geochemical compatibility between reservoir minerals, formation fluids, CO_2, and hydrogen must be carefully evaluated to ensure long-term storage performance.

2.4.Impact of Reservoir Maturity and Depletion on Storage Integrity

The maturity of a reservoir and its depletion history are crucial in assessing storage integrity and mechanical stability. As hydrocarbons are extracted, pressure depletion modifies the in-situ stress conditions, potentially leading to compaction or subsidence, which can impact porosity, permeability, and fault stability, as illustrated in figure (2.4) (Li et al., 2017). These phenomena are often well-documented, facilitating informed risk assessments when repurposing reservoirs. Hydrogen storage typically involves cycles of injection and withdrawal, causing pressure variations that might reactivate existing faults or fractures if operational thresholds are surpassed (Gasanzade et al., 2021). The co-injection of CO_2 can alleviate these issues by serving as a cushion gas, helping to stabilize reservoir pressure and lessen mechanical fatigue during cycling (Cussler, 2009). Both field experience and numerical studies suggest that reservoirs with extensive production histories and proven caprock integrity are generally suitable for secondary use as storage sites (Bear, 1988). Nonetheless, a comprehensive evaluation of geological, petrophysical, and geomechanical factors is necessary to ensure that storage operations remain within safe parameters throughout the project's duration (Bear & Bachmat, 1990).

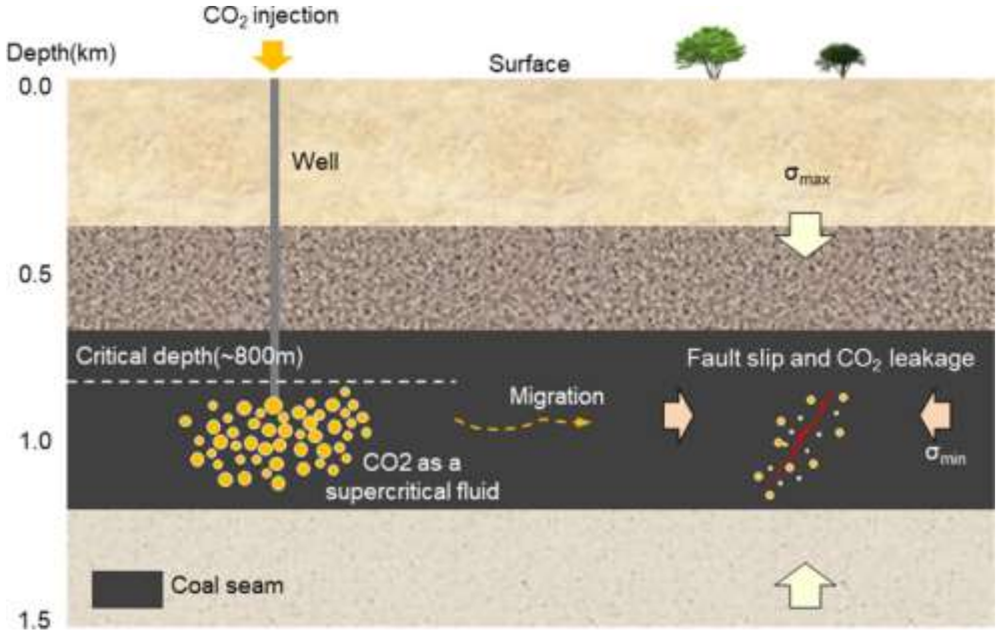

Figure 2.4. Schematic diagram of ScCO2 injection induced fault slip and CO2 leakage during CO2-ECBM, source (Wei, Liang and Chen, 2024).

Depleted reservoirs might have faults or fractures that were previously dormant but could become active due to changes in pressure. It is crucial to keep injection pressures below the original reservoir pressure and fracture gradients. Simulations at the field scale indicate that with proper pressure management and monitoring strategies, depleted reservoirs can safely support long-term storage of hydrogen and CO_2 (pidjoe, n.d.; Rabiee et al., 2023). In essence, while reservoir depletion does not prevent storage operations, it requires thorough geomechanical evaluation, conservative operational limits, and ongoing monitoring to ensure storage integrity is maintained.

3. Thermodynamic and Transport Interactions Between H_2 and CO_2

3.1.Phase Behavior and Mutual Solubility

The thermodynamic properties of hydrogen and carbon dioxide in subsurface environments play a crucial role in determining their distribution, movement, and storage effectiveness. At depths exceeding 800–1000 m, CO_2 typically behaves as a dense supercritical fluid due to its complex phase behavior, as temperature and pressure surpass its critical point, as shown in figure (3.1.1) (Liebscher & Münch, 2011).

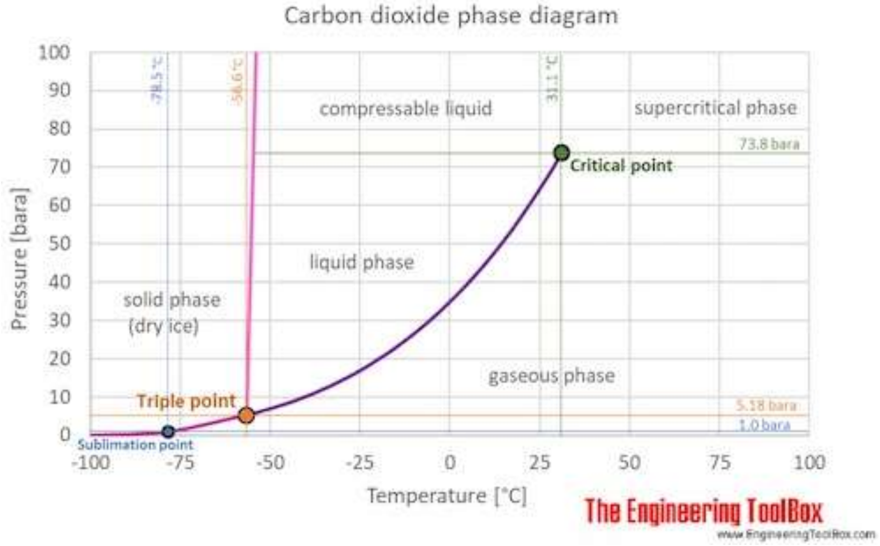

Figure 3.1.1. Carbon dioxide phase diagram, source (Engineeringtoolbox, 2018).

Unlike other substances, hydrogen remains in a gaseous state under most geological storage conditions due to its very low critical temperature and pressure, as depicted in figure (3.1.2) (Miocic et al., 2023). There is a significant density difference between hydrogen and CO_2, with hydrogen being much lighter and more buoyant. This difference encourages gravitational separation within the reservoir, causing hydrogen to rise while CO_2 settles in the lower parts of the pore space (Panfilov, 2020). The mutual solubility of these gases is limited; hydrogen has minimal solubility in brine, whereas CO_2 dissolves easily, aiding in solubility trapping (Hawez & Fazio, 2026).

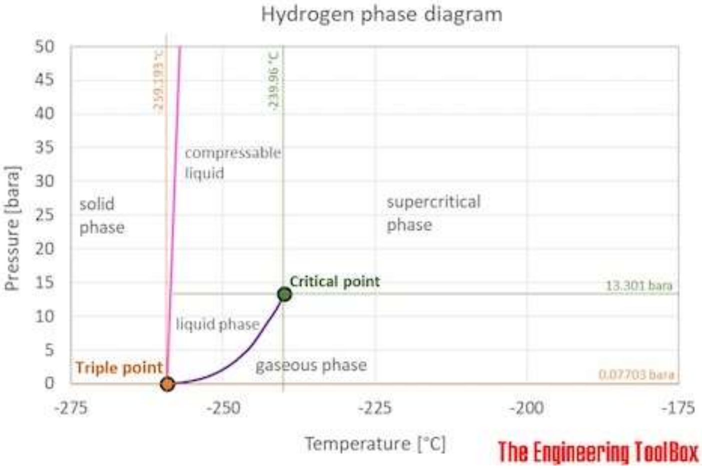

Figure 3.1.2 Hydrogen phase diagram, source (Engineeringtoolbox, 2008).

The presence of these gases leads to a multiphase system characterized by segregation driven by density and varying solubility behaviors. Grasping phase equilibria is crucial for forecasting plume development, gas blending, and the effectiveness of recovery during cyclic storage processes (Rutqvist, 2012).

3.2.Competitive Adsorption and Displacement Processes

In porous media, hydrogen and CO_2 vie for pore space and interact with rock surfaces. CO_2 tends to adsorb more strongly onto mineral surfaces, especially clays and materials rich in organic content, due to its greater molecular weight and quadrupole moment, as depicted in figure (3.2.1) (Lemmon et al., 2013). In contrast, hydrogen has a low adsorption affinity and primarily acts as a mobile, non-wetting phase (Naga et al., 2024).

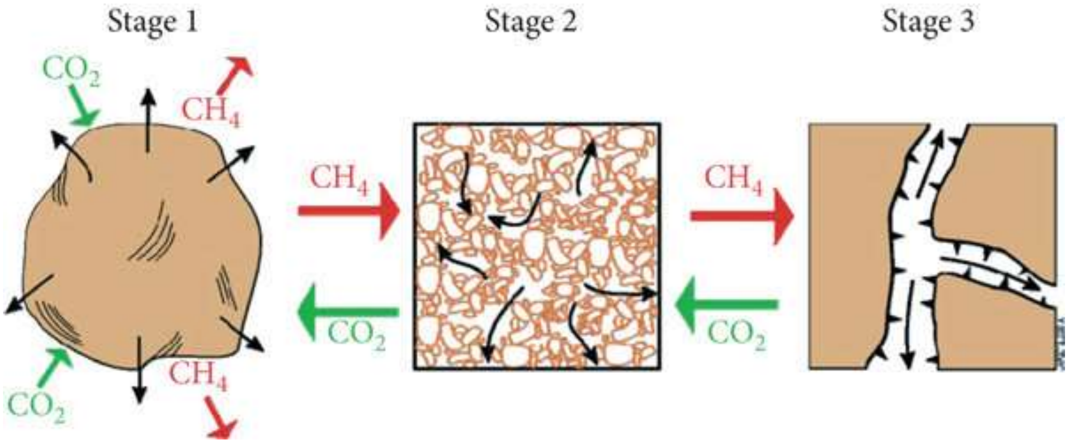

Figure 3.2.1 Schematic diagram of the competitive adsorption and transport of CO2 and CH4 in shales, source (Liu et al., 2020).

In scenarios involving co-injection or sequential injection, CO_2 can push aside existing fluids and fill smaller pore spaces, while hydrogen tends to move through larger pore channels. This competitive displacement can affect the distribution of gases, the efficiency of the sweep, and the behavior of residual trapping (Naderloo et al., 2023). Moreover, the adsorption of CO_2 can alter surface wettability, which indirectly impacts the pathways through which hydrogen flows (Saeed et al., 2023).

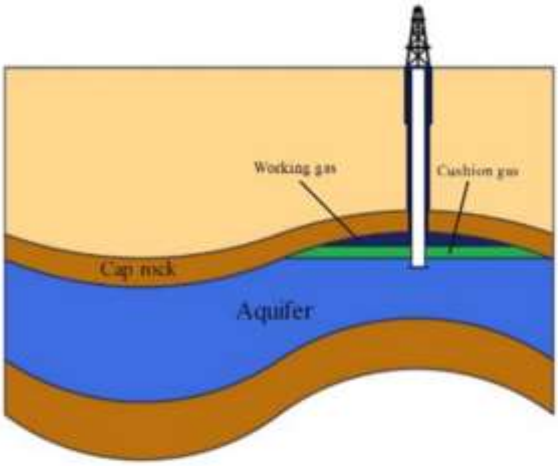

Figure 3.2.2. Hydrogen storage in depleted reservoirs, source (Mohammad Rasool Dehghani, Seyede Fatemeh Ghazi and Yousef Kazemzadeh, 2024).

These processes play a crucial role in cyclic storage operations, where the repeated cycles of injection and withdrawal can change fluid distribution and result in hysteresis effects. Therefore, accurately characterizing competitive adsorption is vital for precise modeling of hydrogen–CO_2 co-storage systems (Hawez et al., 2026).

3.3.Diffusion, Dispersion, and Molecular Interactions in Porous Media

Besides advective flow, the movement of gas in porous reservoirs is also influenced by molecular diffusion and mechanical dispersion. Due to its low molecular weight, hydrogen has much higher diffusion coefficients compared to CO_2 (Krevor et al., 2015). Consequently, hydrogen can quickly diffuse through pore networks and into adjacent formations, which may lead to increased mixing and losses over extended storage periods, as illustrated in figure (3.3) (Khather et al., 2020). Mechanical dispersion results from variations in velocity at the pore level, which enhances the mixing of gases during flow. In hydrogen–CO_2 systems, the effects of dispersion can help mitigate gravitational segregation by encouraging lateral spreading and interfacial mixing (Fischer et al., 2021). Nevertheless, if the integrity of the caprock or the efficiency of the seal is compromised, transport dominated by diffusion might increase the risk of hydrogen leakage (Hawez et al., 2021). Therefore, accurately representing diffusion and dispersion processes is essential in numerical models that aim to predict gas mixing, storage efficiency, and long-term containment (Wei et al., 2024).

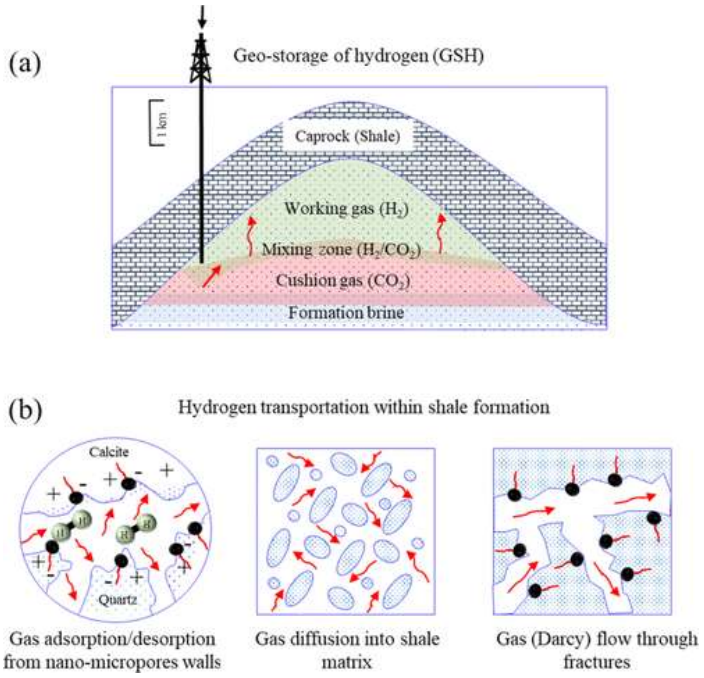

Figure 3.3. Illustration of geo-storage of hydrogen: (a) shale as a caprock and (b) flow behavior of hydrogen within shale system, source (Amer Alanazi et al., 2024).

3.4.Pressure–Temperature Effects and Hysteresis in Mixed Gas Systems

Variations in pressure and temperature significantly impact the behavior of hydrogen–CO_2 mixtures when stored underground. The process of cyclic injection and withdrawal causes repeated pressure changes, influencing fluid characteristics, relative permeability, and capillary pressure dynamics (Khather et al., 2020). While CO_2's density and viscosity are highly responsive to shifts in pressure and temperature, hydrogen's properties remain relatively stable (Asim et al., 2026). Hysteresis effects occur due to differences in fluid distribution during drainage and imbibition cycles. Both experimental and numerical research indicate that hysteresis in relative permeability can greatly diminish hydrogen recovery efficiency over time, as illustrated in figure (3.4) (Al-Yaseri et al., 2024). The presence of CO_2 can help alleviate these effects by stabilizing pressure and preserving favorable flow paths (Benson & Cole, 2008). Ignoring hysteresis in mixed gas systems can result in overestimating deliverability and underestimating residual trapping. Consequently, it is crucial to explicitly incorporate pressure–temperature coupling and hysteresis into reservoir simulation workflows for hydrogen and CO_2 co-storage projects (Usman, 2022).

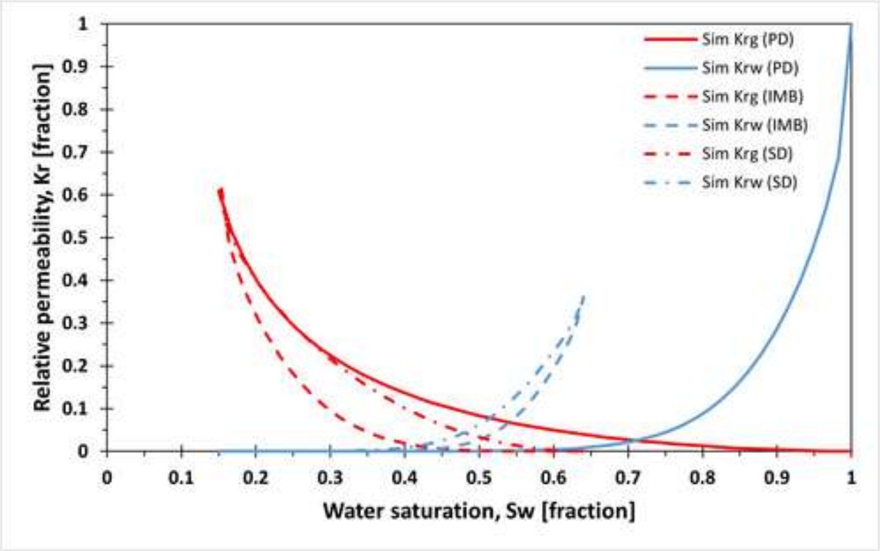

Figure 3.4. Hydrogen-water relative permeabilities show strong hysteresis both for hydrogen (Krg) and water (Krw), source (Maksim Lysyy et al., 2022).

4. Geochemical Reactions and Rock–Fluid Interactions

This chapter explores the interactions between H_2–CO_2 mixtures and formation brines, as well as reservoir minerals, during their co-storage in mature reservoirs. Unlike mere physical trapping, geochemical processes can modify pore structure, wettability, injectivity, and sealing behavior. These changes can either enhance storage security, such as through mineral trapping, or pose operational risks, like precipitation-induced impairment, depending on factors such as mineralogy, brine chemistry, impurities, and cycling conditions, as illustrated in figure (4) (Engineeringtoolbox, 2008; Engineeringtoolbox, 2018).

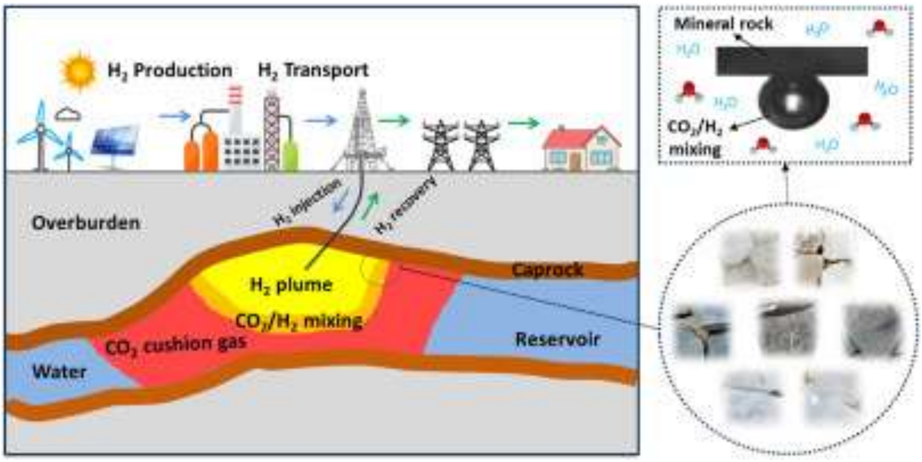

Figure 4. Conceptual schematic illustrating geochemical interactions between H_2–CO_2 mixtures, formation brines, and reservoir minerals during co-storage in mature reservoirs,, including CO_2 dissolution and acidification, mineral dissolution and precipitation, redox processes influenced by hydrogen, and long-term mineral trapping, source (Esfandyari et al., 2024).

4.1.Mineral Dissolution, Precipitation, and Carbonate Formation

When CO_2 is introduced into the reservoir, it dissolves in the brine, forming carbonic acid (H_2CO_3), which reduces the pH and initiates acid–rock interactions. In many reservoirs, the primary initial reaction is the dissolution of reactive minerals, particularly carbonates like calcite and dolomite. This process can locally increase porosity but may also weaken cementation and alter permeability pathways (Hawez et al., 2025; Yang et al., 2022). In sandstones, this dissolution might involve carbonate cements and feldspars, while in carbonates, the matrix dissolution can be more extensive and rapid, influenced by temperature, brine salinity, and flow regime, as depicted in figure (4.1) (Zhong et al., 2024). As the system progresses, dissolved ions (Ca^{2+}, Mg^{2+}, Fe^{2+}) might reprecipitate as secondary carbonates (calcite, dolomite, siderite) or other phases such as clays and silica. This can sometimes transition from a short-term "enhanced porosity" effect to a longer-term reduction in permeability due to precipitation near injection zones (Osame et al., 2025). The balance between dissolution and precipitation is significantly influenced by residence time, transport limitations, and brine composition, which means that the same reservoir might experience improved injectivity in one area and plugging in another (Engineeringtoolbox, 2008; Khather et al., 2020).

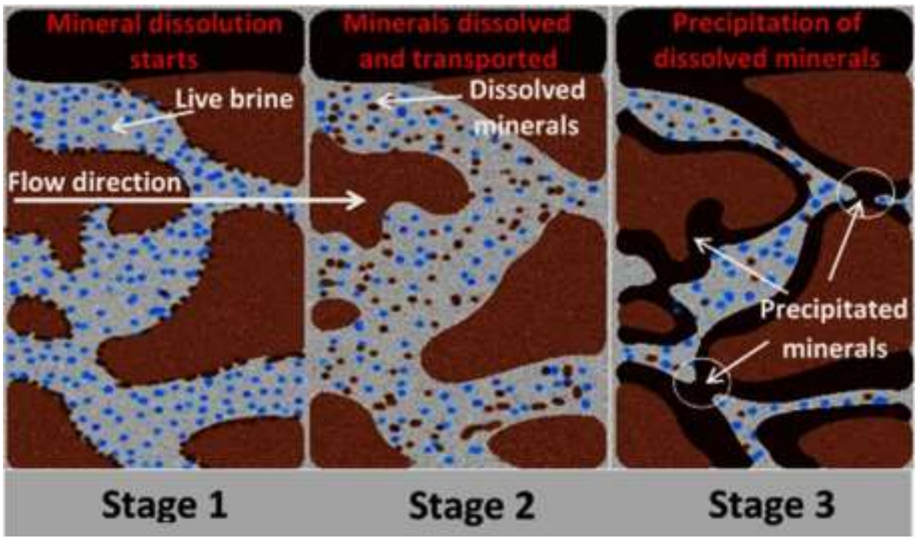

Figure 4.1. Dissolution and precipitation processes during CO2 injection, source (Khather et al., 2020).

In co-storage scenarios, hydrogen is often considered less reactive than CO_2, yet its presence can influence the redox state and indirectly affect mineral stability pathways. This can alter which carbonate phases are preferred and the rate at which they form (Jang et al., 2022). Consequently, evaluating carbonate formation and long-term mineralization in H_2–CO_2 systems requires the use of integrated geochemical–transport tools rather than relying solely on CO_2-based assumptions (Engineeringtoolbox, 2018; Abdulrahman et al., 2025).

4.2.Redox and pH Buffering Under H_2–CO_2 Mixtures

CO_2 primarily affects pH through acidification, while hydrogen mainly impacts redox conditions (Eh). In brine systems, pH buffering is achieved through carbonate equilibria and mineral dissolution, which can moderate acidity over time, particularly when carbonate minerals are present (Hawez et al., 2025; Poda & Talal, 2025). The pH trajectory is crucial as it directly influences dissolution kinetics, secondary mineral precipitation, and trace-metal mobility. Hydrogen adds another layer by acting as an electron donor in redox reactions. Geochemical modeling studies indicate that redox-sensitive minerals and aqueous species (e.g., Fe-bearing phases) may react to hydrogen, potentially affecting dissolution/precipitation pathways and causing minor but non-zero H_2 losses under certain mineralogies and impurity conditions (Jang et al., 2022). This becomes more significant in mature reservoirs where oxygen ingress is unlikely, but sulfate, iron minerals, or residual oxidants may be present in brines or near wells, and where cycling may intermittently expose fresh mineral surfaces (Dai et al., 2020). A key practical concern is that redox evolution can stimulate microbial pathways (e.g., sulfate reduction, methanogenesis) depending on temperature, salinity, nutrient availability, and residence time. These processes can consume H_2 and produce byproducts (e.g., H_2S, CH_4), impacting gas quality and potentially affecting materials integrity (Hawez et al., n.d.; Liu et al., 2020). Given the wide variation in brine chemistry and microbial habitability in mature reservoirs, site screening should consider redox buffering capacity, sulfate levels, iron mineral content, and assess microbial risk (Hawez et al., 2026).

4.3.Long-Term Mineral Trapping Mechanisms

The long-term security of CO_2 storage is enhanced by mineral trapping, where dissolved CO_2 is converted into stable carbonate minerals over extended periods. Reactive transport studies consistently show that mineral trapping is generally slower than structural and residual trapping, often becoming more significant after extensive water–rock interaction and pH buffering have occurred (Khather et al., 2020; Dehghani et al., 2024). The extent of mineral trapping is heavily dependent on the availability of divalent cations (Ca, Mg, Fe), which are controlled by feldspar/carbonate dissolution and the flow-driven supply of fresh brine and reactive surfaces, as illustrated in figure (4.3.1) (Engineeringtoolbox, 2018; Zhan & Zeng, 2023).

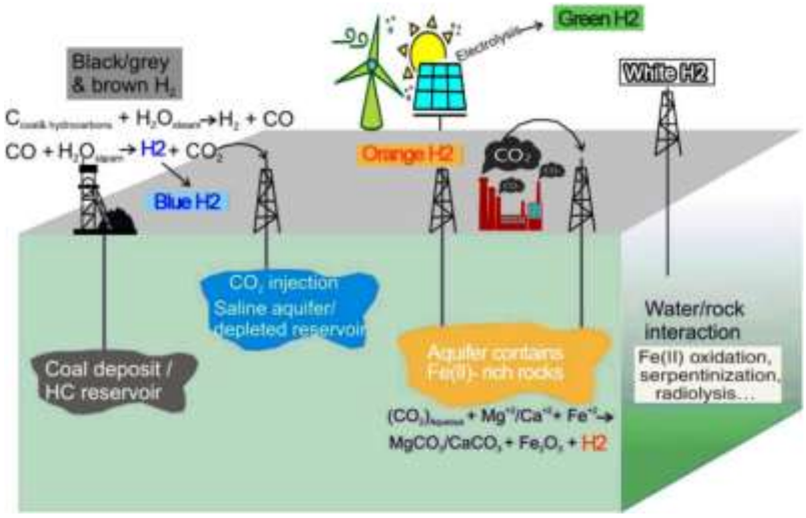

Figure 4.3.1A schematic block diagram highlights the different types of hydrogen generated by natural processes and as industrial byproducts. Note: for orange H_2 generation coupled with CCS, the saline aquifers or depleted reservoirs should contain reactive cations such as Fe^{2+}, Mg^{2+} and Ca^{2+}, source (Mahmoud Leila et al., 2025).

In the context of co-storage, the long-term scenario is more complex: while CO_2 mineral trapping can enhance containment, any process that uses H_2, such as abiotic redox reactions or microbial consumption, can decrease the hydrogen inventory and purity, as shown in figure (4.3.2) (Jang et al., 2022; Hawez et al., n.d.).

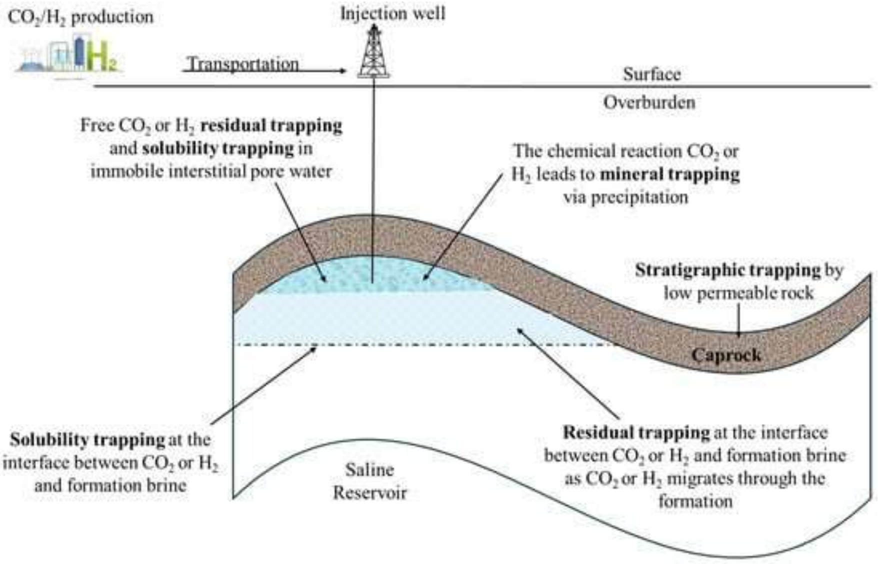

Figure 4.3.2A diagram showing the working gas (CO2 or H2) of underground gas storage (UGS) in the subsurface formation, source (Longe et al., 2024).

Consequently, a comprehensive evaluation of long-term trapping in H_2–CO_2 reservoirs should measure two concurrent outcomes:

1. **the increase in CO_2 immobilization (through solubility and mineralization)**
2. **and the effects on H_2 loss and quality (including redox reactions, biotic consumption, and byproduct formation).**

This dual focus is gaining importance in hydrogen storage research, which assesses geochemical and biogeochemical risks in porous reservoirs (Dai et al., 2020; Hawez et al., 2026).

4.4.Experimental and Modeling Evidence of Reactive Transport

Evidence supporting reactive processes is derived from (i) laboratory experiments such as batch tests, coreflood studies, micro-CT scans, and geochemical aging, and (ii) reactive transport modeling that spans from pore to field scales, as illustrated in figure (18). These experiments reveal that the interaction between CO_2 and brine decreases pH levels, leading to observable shifts in ion concentrations and occasionally altering the rock's microstructure. The results vary significantly depending on factors like lithology (chalk/carbonate versus quartz-rich sandstone), the salinity of the brine, and the duration of exposure (Yang et al., 2022; Zhong et al., 2024). Observations of microstructure are particularly valuable for determining whether dissolution processes expand flow paths or if precipitation events decrease permeability and injectivity near entry points (Engineeringtoolbox, 2008; Osame et al., 2025).

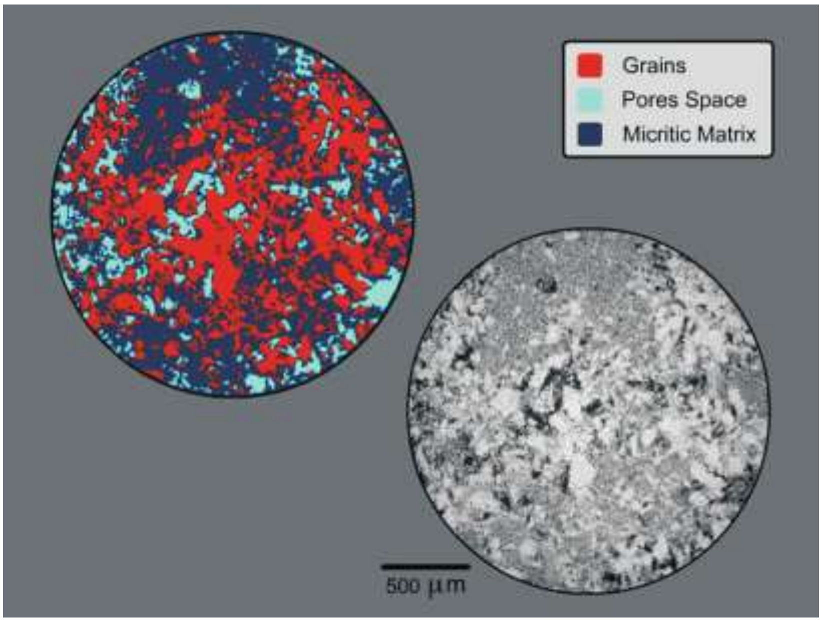

Figure 4.4.1Micro-CT scan of a carbonate rock (lower right) showing the intensity response of micrite (gray), grains (white), and pores (black). Segmented image (upper left) showing the grains (red), microporous micrite aggregates (blue), and pore space (cyan), source (Vanorio, Tiziana & Mavko, Gary, 2011).

Reactive transport models, such as TOUGHREACT-class workflows and similar frameworks, are employed to combine thermodynamics, kinetics, and transport processes to predict the long-term changes in mineral phases and trapping mechanisms. Reviews emphasize that the outcomes of these models are highly influenced by factors like reaction rate laws, assumptions about surface area, heterogeneity, and choices in upscaling; thus, calibration with laboratory and field data is crucial (Khather et al., 2020; Dehghani et al., 2024). Recent studies from MDPI and Springer showcase effective workflows for integrating CO_2–brine–rock interactions with reservoir-scale heterogeneity and for monitoring precipitation risks that could impact injectivity and sealing, as depicted in figure (4.2.2) (Engineeringtoolbox, 2018; Zhan & Zeng, 2023).

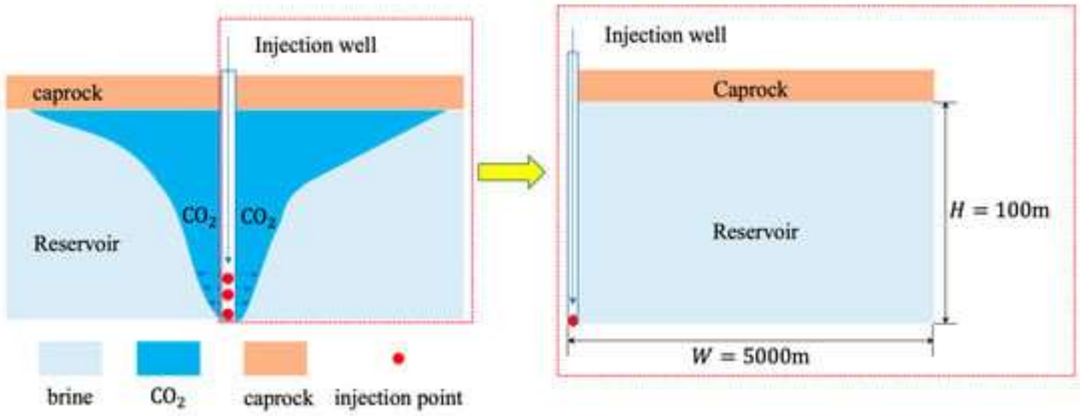

Figure 4.4.2The conceptual model of numerical simulation that shows the CO2-brine-rock reaction, source (Li et al., 2023).

In the context of hydrogen, recent SPE and peer-reviewed research focus on assessing the mechanisms of hydrogen loss and the effects of reservoir and brine geochemistry, highlighting that the mineralogy and brine composition specific to each site are the primary sources of uncertainty (Dai et al., 2020). The recommended approach involves a phased workflow: starting with screening for thermodynamic feasibility, followed by laboratory testing to examine kinetics and byproducts, and concluding with a calibrated reactive transport simulation for field-scale predictions, all while explicitly quantifying uncertainty (Khather et al., 2020; Hawez et al., 2026).

5. Geomechanical and Caprock Integrity Considerations

Storing hydrogen and CO₂ together in mature reservoirs presents interconnected mechanical and sealing challenges that can be more complex than storing a single gas, as illustrated in figure (5). The process of cyclically injecting and withdrawing gases alters pore pressure and sometimes temperature, which affects effective stress and deforms the reservoir-caprock system. This can potentially trigger the reactivation of faults or fractures if operational thresholds are surpassed (Shojaee et al., 2023; Asim & Hawez, 2024; Moradi & Groth, 2019). Furthermore, due to hydrogen's small molecular size and high diffusivity, the system may be more prone to micro-leakage pathways and defects in legacy wells. Therefore, ensuring integrity requires a combination of geomechanical controls, robust sealing, and wellbore risk management (Shojaee et al., 2023; Shabani et al., 2022).

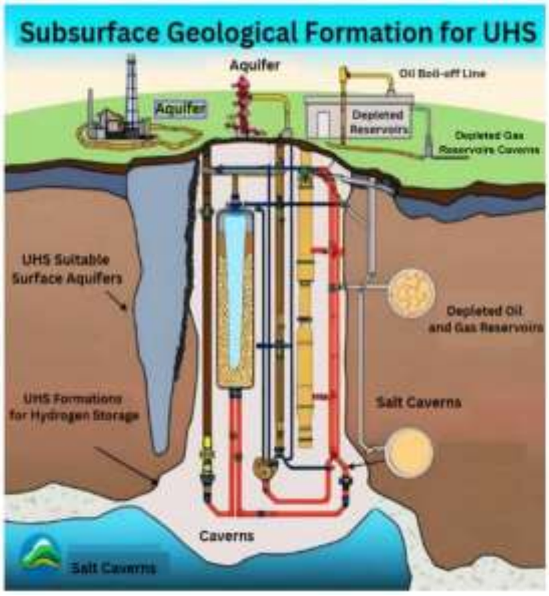

Figure 5. Subsurface geological formations for underground H2 storage, source (Poda and Talal, 2025).

5.1.Stress alterations due to cyclic injection and withdrawal

Cyclic subsurface storage operations, which consist of repeated cycles of injection, storage, and withdrawal, create time-dependent disturbances in the in-situ stress field of both the reservoir and adjacent formations. These disturbances are mainly controlled by variations in pore pressure, which directly affect effective stress as explained by poroelastic theory, as shown in figure (5.1.1). When injection occurs, the rise in pore pressure decreases the effective normal stress on rock grains, faults, and fractures, thus bringing the stress state closer to shear or tensile failure. On the other hand, during withdrawal, the pore pressure drops, leading to an increase in effective stress and a reversal of the stress path. Although a single cycle of injection and withdrawal might not cause significant deformation, repeated cycles can result in cumulative, irreversible strain accumulation, commonly known as stress ratcheting (Shojaee et al., 2023). Stress ratcheting is a significant concern in underground hydrogen storage (UHS) systems, where operational protocols often involve frequent cycling to manage seasonal or short-term energy needs. Each cycle applies and then releases stress on the rock mass, potentially weakening its mechanical strength over time, particularly in formations with existing weaknesses like faults, fractures, bedding planes, or mechanically weak layers. Laboratory tests and numerical models indicate that cyclic loading can diminish elastic moduli, increase plastic strain, and enhance permeability in both reservoir and caprock rocks, even when stress variations remain below peak failure levels (Shojaee et al., 2023). These effects are most evident near wellbores, fault zones, and lithological interfaces, where stress concentrations are greatest.

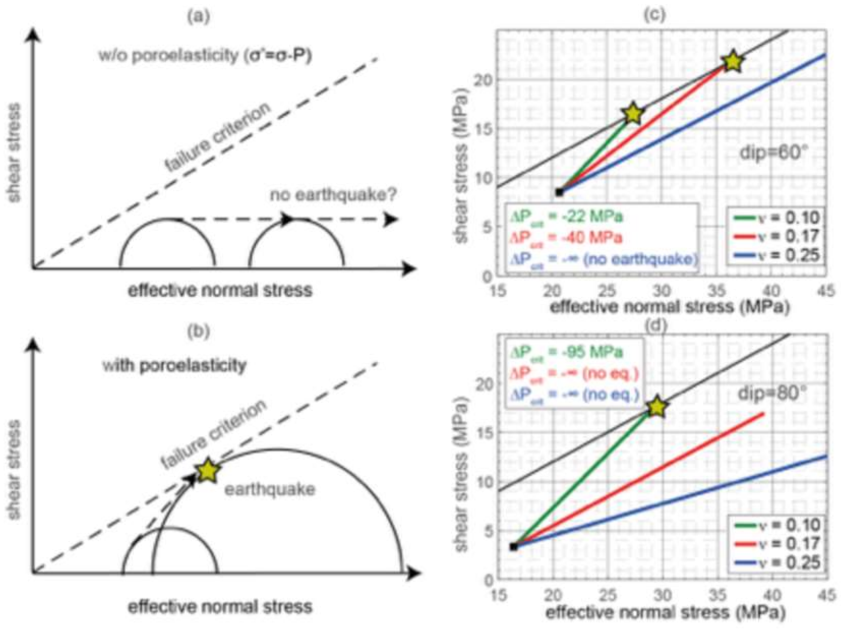

Figure 5.1.1. (a) Analysis of effective stress: For fluid extraction, pore pressure decreases in the reservoir and the effective stress increases accordingly, respectively. Hence, the Mohr circle moves to the right and no earthquake is induced. (b) Theory of linear poroelasticity: Because the horizontal effective stress increases less than the vertical effective stress, the Mohr circle grows and an earthquake can be induced. (c, d) Approximation of an infinite, unbounded reservoir for fault dips of 60° and 80°, respectively. The required pressure drops to achieve reactivation are only realistic ($\Delta P \geq -40$ MPa) for an optimally oriented fault zone (i.e., 60°) and low Poisson's ratios. For a steep dipping fault (i.e., 80°) and an average Poisson's ratio for rocks (i.e., 0.25), the approximation fails to explain induced earthquakes. The initial effective normal stress and initial shear stress are 20.7 MPa and 8.5 MPa, respectively, source (Zbinden et al., 2017).

In depleted reservoirs, the geomechanical response to cyclic re-pressurization is further complicated by the stress history from hydrocarbon extraction. Long-term pressure reduction during depletion alters the in-situ stress regime by increasing effective stress, leading to reservoir compaction, porosity reduction, and sometimes surface subsidence. This historical compaction changes the stress path during subsequent re-pressurization, making the reservoir's mechanical response during storage operations path-dependent rather than purely elastic (Vasile et al., 2024). Consequently, re-pressurization does not merely reverse compaction but may instead cause anisotropic deformation and localized stress redistribution. Re-pressurization can also alter stress anisotropy, particularly the ratio between vertical and horizontal stresses. Changes in stress anisotropy may decrease the stability margin of favorably oriented faults, raising the likelihood of shear reactivation as illustrated in figure (5.1.2). Fault stability is influenced by fault orientation relative to the principal stress directions, frictional properties, cohesion, and pore pressure evolution. Even small pressure increases can trigger slip on critically stressed faults, especially in reservoirs that were already near failure before depletion (Vasile et al., 2024). This mechanism has been extensively documented in CO_2 storage projects, wastewater injection, and enhanced oil recovery operations.

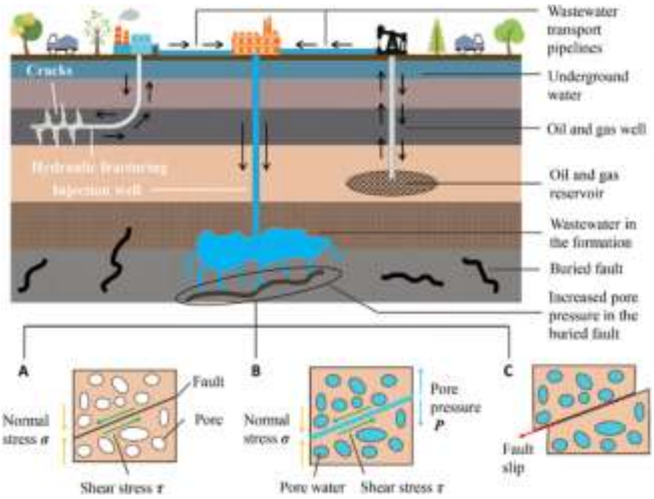

Figure 5.1.2. The whole process of fault slip induced by fluid injection in industrial production. (A) Before fluid injection, the fault is closed under the pressure of normal stress on both sides. (B) With the continuous injection of fluid during the production process, the pores and cracks in the fault are gradually filled with fluid. (C) When pore pressure increases to a certain value, the fault slips because the effective normal stress on both sides is less than the shear stress; then, an earthquake is induced, source (He, Li and Li, 2020).

Insights from carbon capture and storage (CCS) projects shed light on the geomechanical risks linked to pressure changes caused by injection. Observations from the field and modeling studies suggest that such pressure-induced deformation can appear as reservoir uplift, caprock strain, or fault slip, and in some cases, may lead to microseismicity or noticeable seismic events (Asim & Hawez, 2024). While most seismic activity induced by CCS is of low magnitude, these occurrences indicate stress redistribution and fault activation, which could threaten containment if they enhance permeability along fault lines. The CCS literature stresses the need to establish conservative pressure limits that keep injection pressures below fracture pressure, fault reactivation thresholds, and the tensile strength of caprock. These limits are usually determined using coupled reservoir–geomechanical models that consider in-situ stress, rock mechanical properties, and fault friction parameters (Asim & Hawez, 2024; Vasile et al., 2024). These practices can be directly applied to hydrogen and H_2–CO_2 co-storage systems, though stricter limits may be necessary due to the higher cycling frequency and different fluid properties involved. For underground hydrogen storage, geomechanical challenges might be more significant than for CO_2-only storage. Hydrogen storage operations often involve rapid pressure changes and higher cycling frequency, which intensify fatigue-like effects in the rock mass. Recent reviews highlight various potential geomechanical hazards associated with UHS, such as induced seismicity, fracture propagation, reservoir and caprock deformation, surface uplift or subsidence, and wellbore integrity degradation (Shojaee et al., 2023; He et al., 2020). Specifically, cyclic pressurization may hasten casing deformation, cement debonding, or micro-annulus formation in wells, which are critical leakage pathways. Additionally, hydrogen's low density and viscosity may facilitate rapid pressure transmission away from the injection zone, broadening the spatial extent of stress perturbations compared to CO_2. This behavior highlights the necessity to evaluate not only local wellbore stability but also regional fault networks and stress-sensitive formations. Therefore, site-specific characterization of fault geometry, stress orientation, and mechanical stratigraphy is crucial before storage deployment (He et al., 2020). Stress changes induced by cyclic injection and withdrawal are among the most significant integrity risks in hydrogen and H_2–CO_2 co-storage systems. The combined effects of historical depletion, changes in stress anisotropy, fault reactivation potential, and repeated loading–unloading cycles require thorough geomechanical evaluation. Best practices involve integrating laboratory testing, field-scale monitoring, and coupled geomechanical modeling to establish safe operational pressure windows and mitigate long-term integrity risks (Shojaee et al., 2023; Asim & Hawez, 2024; Vasile et al., 2024).

5.2.Caprock sealing efficiency under alternating H_2–CO_2 exposure

Ensuring the integrity of caprock is essential for the secure geological storage of gases, as it is responsible for the long-term containment of injected fluids and prevents them from migrating upwards to overlying layers or the surface. In systems where hydrogen and CO_2 are stored together, the effectiveness of the caprock is determined by a mix of mechanical sealing, capillary sealing, and geochemical stability, all of which can be affected by the alternating exposure to H_2 and CO_2 during cyclic storage operations (Asim & Hawez, 2024; Shabani et al., 2022). Compared to storing a single component, co-storage adds complexity due to variations in fluid properties, wettability behavior, diffusion characteristics, and reactivity.

5.2.1. Mechanical versus Capillary Sealing Mechanisms

Mechanical sealing pertains to the capacity of the caprock to stay intact when subjected to applied stresses, without forming new fractures or causing existing discontinuities to widen. This characteristic is influenced by factors such as the thickness of the caprock, its lithology, elastic and strength properties, the in-situ stress conditions, and the presence of faults or fractures. On the other hand, capillary sealing is determined by the capillary entry pressure, which is the minimum pressure needed for a non-wetting gas phase to penetrate the water-saturated pore network of the caprock (Asim & Hawez, 2024). In the context of CO_2 storage, extensive studies and field experiences indicate that capillary sealing often serves as the main containment mechanism, as long as injection pressures do not exceed the capillary breakthrough threshold, as illustrated in figure (5.2.1) (Asim & Hawez, 2024). However, this assumption requires reevaluation for hydrogen storage. The lower density, lower viscosity, and higher diffusivity of hydrogen modify both mechanical and capillary sealing behaviors. Although hydrogen typically acts as a strongly non-wetting phase, its small molecular size makes it more susceptible to micro-scale defects and pore-throat distributions that might be negligible for CO_2 (Shojaee et al., 2023; Shabani et al., 2022).

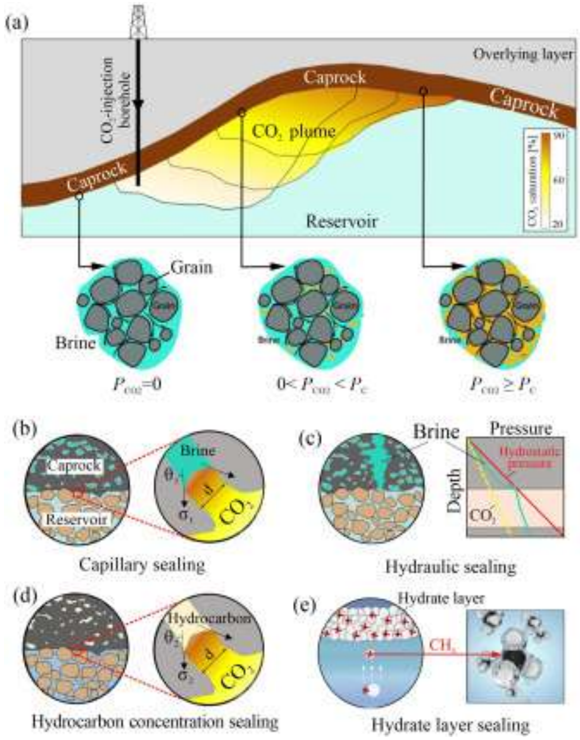

Figure 5.1.2.1Schematic diagram of caprock sealing mechanisms: (a) CO2 plume migration is prevented by the low-permeability caprock, (b) capillary sealing, (c) hydraulic sealing, (d) hydrocarbon concentration sealing, and (e) hydrate layer sealing, source (Chen, Li and Tan,2025).

5.2.2. Wettability and Interfacial Tension Effects

Wettability and interfacial tension (IFT) are crucial in assessing the effectiveness of capillary sealing. Minerals found in caprock, such as clays, quartz, feldspar, and carbonates, generally exhibit water-wet characteristics under subsurface conditions, which aids in gas retention. Nonetheless, research has shown that wettability can fluctuate based on factors like mineral composition, brine salinity, temperature, and gas type (Xu, 2012; Hawez & Asim, 2024). Recent lab studies on underground hydrogen storage reveal that hydrogen–brine–rock systems may display distinct contact angles and IFT values compared to CO_2–brine–rock systems, resulting in variations in capillary entry pressure (Xu, 2012). In certain instances, hydrogen shows lower capillary entry pressures than CO_2 for the same caprock, suggesting a decreased sealing margin if pressure is not meticulously managed (Shabani et al., 2022). These results highlight the necessity of measuring capillary properties specifically for hydrogen and mixed gas systems, rather than relying solely on CO_2-based models. Alternating exposure to H_2 and CO_2 during co-storage cycles might further alter wettability due to surface chemical changes or adsorption effects. The acidification of formation brine by CO_2 can modify mineral surfaces, potentially affecting contact angles and IFT over time. Such changes in wettability can either improve or diminish sealing efficiency, depending on the mineral composition and duration of exposure (Leila et al., 2025). Consequently, sealing behavior under co-storage conditions is dynamic rather than static.

5.2.3. Diffusive and Micro-Leakage Considerations

Besides capillary breakthrough, diffusive transport is another potential leakage pathway, especially concerning hydrogen. Even when capillary sealing functions well, hydrogen can diffuse through intact caprock at rates much higher than CO_2 due to its smaller molecular size and greater diffusion coefficient (Shojaee et al., 2023). While diffusion alone is unlikely to lead to rapid leakage on a field scale, it can result in a gradual loss of inventory over extended storage periods, particularly in thin or heterogeneous caprocks. Micro-fractures, nano-scale pore networks, and organic-rich layers may serve as preferential routes for hydrogen diffusion, as illustrated in figure (5.2.3).

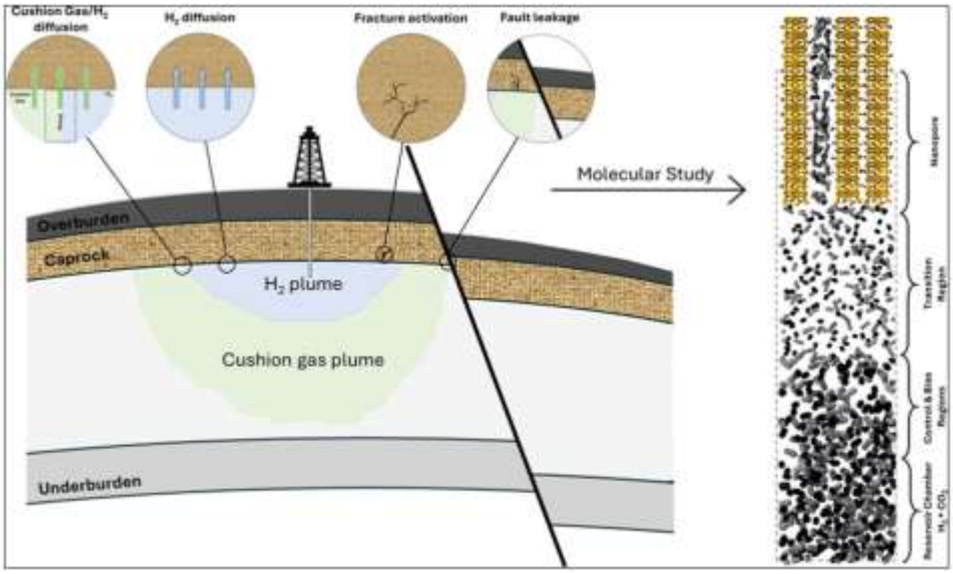

Figure 5.2.3. Potential diffusive and micro-leakage pathways for hydrogen through intact caprock matrices, micro-fractures, and nano-scale pore networks, source (Kamiab Kahzadvand et al., 2024).

These features are commonly found in shale caprocks and may not significantly affect CO_2 containment but are more pertinent for hydrogen (Shabani et al., 2022). Consequently, hydrogen storage projects necessitate more rigorous evaluation of caprock thickness, mineral composition, and microstructural properties to ensure long-term sealing.

5.2.4. Faults, Fractures, and Legacy Wells

Although intact caprock matrices serve as the main barrier, faults, fractures, and wells are the most significant sources of leakage risk in practice. Insights from CCS projects reveal that leakage risk can be predominantly influenced by inadequately characterized faults or improperly abandoned wells, even when caprock properties are favorable, as shown in figure (5.2.4) (Asim & Hawez, 2024). In mature reservoirs, legacy wells drilled during earlier development stages present a specific challenge.

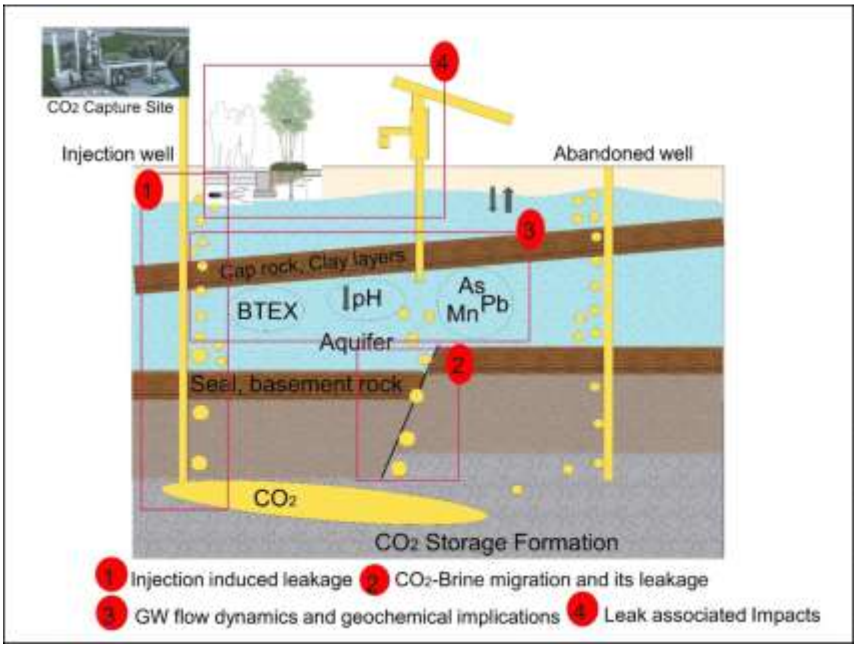

Figure 5.2.4. Schematic diagram of CO2 leakage along faults, fracture, and wells (injection and abandoned) and its impact on the fresh soil–water system, source (Gupta and Yadav, 2020).

The pressure fluctuations associated with hydrogen storage can cause mechanical fatigue in cement and casing, resulting in debonding or the formation of micro-annuli. These wellbore integrity problems are worsened by hydrogen's mobility and may create direct vertical migration pathways if not properly managed (Shojaee et al., 2023; He et al., 2020).

Consequently, the efficiency of caprock sealing cannot be assessed independently of wellbore integrity, necessitating integrated evaluations.

5.2.5. Implications for Co-Storage Design and Operation

The interplay of wettability changes, diffusion, mechanical stress, and existing infrastructure necessitates a cautious, site-specific approach to evaluating caprock sealing efficiency in H_2–CO_2 co-storage scenarios. Recommendations from current research suggest:

1. Directly measuring the capillary entry pressure for both H_2–brine and CO_2–brine systems under reservoir conditions (Xu, 2012; Shabani et al., 2022).
2. Assessing how wettability and interfacial tension (IFT) respond to variations in salinity, temperature, and gas composition (Hawez & Asim, 2024; Leila et al., 2025).
3. Managing pressure conservatively to stay below fracture pressure and capillary breakthrough limits (Asim & Hawez, 2024).
4. Conducting thorough assessments of fault and wellbore integrity, especially in older reservoirs with a history of extensive drilling (Shojaee et al., 2023; He et al., 2020).

The sealing efficiency of caprock in hydrogen and CO_2 co-storage systems is influenced by a complex interaction of mechanical, capillary, and transport processes. The alternating presence of H_2 and CO_2 adds uncertainty compared to single-gas storage, necessitating improved characterization, monitoring, and modeling. To ensure long-term containment, it is essential to integrate evaluations of caprock properties, operational strategies, and legacy risks within a comprehensive integrity framework (Shojaee et al., 2023; Asim & Hawez, 2024; Shabani et al., 2022).

5.3.Fracture propagation and self-sealing potential

Fracture propagation and fault reactivation are among the most significant integrity threats linked to the underground storage of hydrogen and CO_2 in mature reservoirs. Unlike intact caprock matrices, fractures and faults offer preferential high-permeability routes that can severely undermine containment if they become activated or expand during storage activities. In systems where hydrogen and CO_2 are co-stored, the risk is heightened by the cyclic process of injection and withdrawal, which subjects existing discontinuities to repeated mechanical stress and may gradually change their hydraulic and mechanical properties (Shojaee et al., 2023; He et al., 2020).

5.3.1. Mechanisms of Fracture Initiation and Propagation

Subsurface formations can experience fracture propagation through two main processes: tensile fracturing and shear-induced dilation, as depicted in figure (5.3.1). Tensile fractures occur when the pore pressure surpasses the sum of the minimum principal stress and the rock's tensile strength. In contrast, shear dilation happens when faults or fractures are reactivated by shear stress, leading to increased aperture and permeability (Vasile et al., 2024). When pore pressure rises due to injection, it reduces the effective normal stress, thereby facilitating both mechanisms if operational thresholds are exceeded.

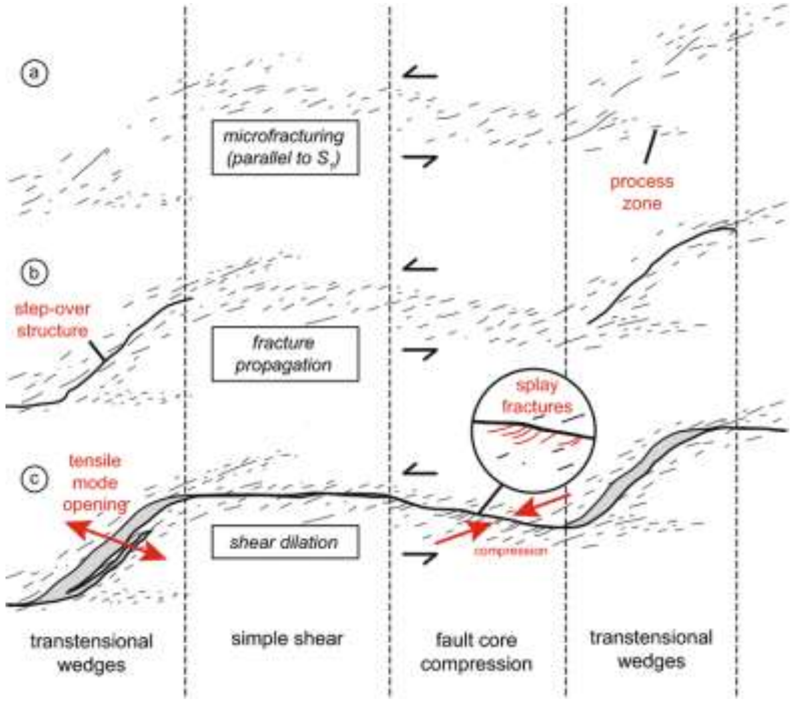

Figure 5.3.1. Interpretational model for the fracture propagation during shear fracture growth with a micro-fracturing, b fracture propagation and c shear dilation, as well as the resulting structural elements of the fault zone, source (Kluge et al., 2021).

In reservoirs that have been depleted, the stress field has already been altered due to historical pressure reduction, compaction, and loss of porosity. This changed stress condition can make faults and fractures more prone to failure compared to untouched reservoirs. During storage operations, re-pressurization might reactivate these discontinuities at lower pressure increments than anticipated, especially along faults that are well-aligned with the current stress regime (Vasile et al., 2024). Cyclic pressure changes can further weaken fracture surfaces through frictional wear and fatigue-like processes, gradually increasing transmissivity even if peak pressures do not exceed fracture pressure.

Insights from CCS projects show that fracture propagation and fault reactivation are likely outcomes of injection operations when pressure management is inadequate. Instances of injection-induced deformation, microseismicity, and increased permeability along faults have been observed in various CCS and fluid-injection scenarios, highlighting the need for conservative operational limits and ongoing monitoring (Asim & Hawez, 2024). These insights are directly applicable to hydrogen and H_2–CO_2 co-storage systems.

5.3.2. Cyclic Loading and Damage Accumulation

Cyclic injection and withdrawal present a unique challenge when compared to monotonic injection. The repeated application and removal of stress can result in damage accumulation, even if the stresses do not exceed the immediate failure threshold. Laboratory tests on reservoir and caprock materials indicate that cyclic loading can diminish elastic stiffness, increase irreversible strain, and improve micro-crack connectivity over time (Shojaee et al., 2023). This phenomenon is particularly significant near wells and faults, where stress concentrations are most pronounced. In the context of underground hydrogen storage, the cycling frequency is typically higher than that for CO_2 storage, reflecting the operational demands for energy balancing. Consequently, fracture fatigue and a gradual increase in permeability may occur over operational timescales, potentially raising the risk of leakage even in initially robust seals (He et al., 2020). Numerical modeling studies emphasize that cyclic stress paths can cause incremental fracture opening and fault slip, highlighting the importance of considering cumulative effects rather than relying solely on peak-pressure criteria.

5.3.3. Leakage Risk Associated with Fractures and Faults

When fractures or faults become active, they can serve as pathways with high permeability, circumventing capillary sealing mechanisms. In these situations, containment is dictated by the hydraulic characteristics of the fracture network rather than capillary entry pressure. Extensive research has been conducted on fault-related leakage pathways for CO_2 storage, and similar issues arise with hydrogen storage, compounded by hydrogen's high mobility and diffusivity (Shojaee et al., 2023). Even with narrow fracture apertures, hydrogen leakage can occur due to significant diffusive and advective transport. Additionally, fractures that intersect with legacy wells may provide a direct route to the surface if the integrity of the wells is compromised. Consequently, fracture propagation is often viewed as a system-level risk, involving interactions among the reservoir, caprock, faults, and wells, rather than being a localized issue (Asim & Hawez, 2024; He et al., 2020).

5.3.4. Self-Sealing Mechanisms: Concept and Evidence

Although fracture propagation poses certain risks, geological systems also have the ability to self-seal, which means that fracture permeability can diminish over time due to interconnected geochemical and mechanical processes. These self-sealing mechanisms are particularly significant for ensuring long-term storage security, as they can help restore containment partially or completely after fractures initially form. In the context of CO_2 storage, one of the key self-sealing processes is mineral precipitation, especially the formation of carbonate minerals. When CO_2 dissolves in formation brine, it creates acidic conditions that lead to mineral dissolution, followed by the precipitation of secondary carbonate minerals such as calcite, dolomite, and siderite as the system reaches equilibrium. These precipitates can build up within fracture openings, thereby reducing permeability and, in some instances, effectively sealing potential leakage paths (Hawez, Asim, & Fazio, 2024). Experimental studies and pore-scale imaging have shown that carbonate precipitation can significantly lower fracture transmissivity in CO_2-rich environments. Micro-CT and core-scale experiments have demonstrated noticeable reductions in fracture aperture and permeability after exposure to CO_2-saturated brines, supporting the feasibility of self-sealing in reactive caprocks (Longe et al., 2024). However, the rate and extent of sealing are highly dependent on factors such as mineralogy, brine composition, temperature, and flow conditions.

5.3.5. Role of Clay Minerals and Mechanical Closure

Besides mineral precipitation, mechanisms related to clay may also play a role in self-sealing. Swelling clays, particularly those rich in smectite, can expand when they come into contact with brines altered by CO_2, thereby decreasing fracture openings and pore connectivity. Additionally, mechanical compaction and the redistribution of stress can further promote the closure of micro-fractures as effective stress rises during withdrawal phases (Hawez, Asim, & Fazio, 2024). These processes are especially significant in shale caprocks, which have a high clay content and extremely low permeability. However, clay swelling can be a double-edged sword: while it can improve sealing, excessive swelling might cause local stress changes or weaken the rock structure. Thus, the overall effect of clay-induced self-sealing needs to be carefully assessed for each specific site.

5.3.6. Self-Sealing in H_2–CO_2 Co-Storage Systems

In co-storage systems, the potential for self-sealing is affected by the relative exposure to CO_2 and hydrogen. Phases rich in CO_2 encourage geochemical reactions that facilitate mineral precipitation and sealing, while hydrogen is mostly non-reactive and more prone to physical leakage pathways. As a result, the advantages of self-sealing are likely to be realized mainly during periods of CO_2 exposure, whereas hydrogen storage phases may depend more on mechanical and capillary sealing (Shojaee et al., 2023; Hawez, Asim, & Fazio, 2024). Therefore, the order of gas injection could influence integrity management. Strategies that keep CO_2 within fractures or near caprock interfaces might improve long-term sealing, whereas rapid pressure cycling dominated by hydrogen could heighten the risk of fracture reopening. These interactions underscore the importance of an integrated operational design that combines pressure management with an understanding of geochemical evolution.

5.3.7. Implications for Storage Design and Risk Management

The dual role of fractures—as both potential pathways for leakage and as candidates for self-sealing—has significant implications for storage design. It is crucial to maintain conservative injection pressures to prevent the initiation of fractures and the reactivation of faults, especially in depleted reservoirs with complex stress histories (Asim & Hawez, 2024; Vasile et al., 2024). Simultaneously, realistic evaluations should recognize that some level of fracture activation might occur and that self-sealing processes can positively contribute to long-term containment. Best practices, therefore, include: Best practice therefore involves:

1. Comprehensive analysis of fracture and fault systems, focusing on their orientation, density, and interconnections.
2. Integrated geomechanical and geochemical simulations to assess both the spread of fractures and their potential to seal.
3. Monitoring techniques (such as microseismic activity, pressure changes, and geochemical markers) to identify fracture activation and development during operations (He et al., 2020).

Fracture propagation is a primary geomechanical risk for hydrogen and CO₂ co-storage, particularly under cyclic loading conditions. However, geological systems may also demonstrate self-sealing behavior driven by mineral precipitation, clay swelling, and mechanical closure, as illustrated in figure (5.3.7). Understanding and managing the balance between these opposing processes is crucial for ensuring long-term storage integrity in mature reservoirs (Shojaee et al., 2023; Hawez, Asim, & Fazio, 2024; Longe et al., 2024).

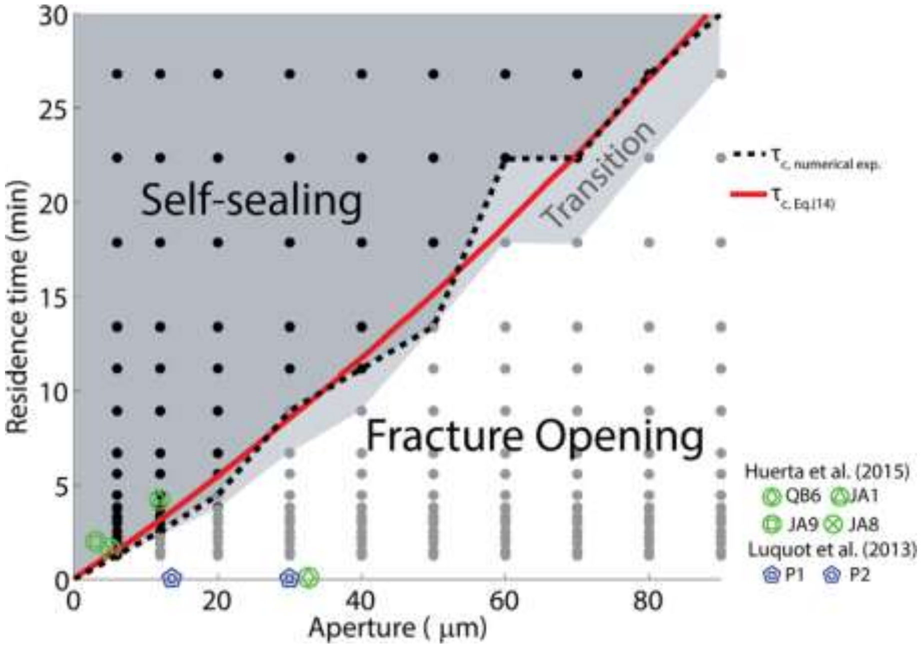

Figure 5.3.7. Predicted self-sealing or fracture opening behavior for the CO2-flooding numerical experiments in 250 cement fractures (class H) with different initial aperture size and initial fracture residence times. Black dots indicate self-sealing behavior and gray dots indicate fracture opening behavior after exposure to CO2-saturated water for 100 days. The thick dashed line indicates the critical residence time above which self-sealing occurs. The light gray indicates a transition zone where very small changes in initial fracture residence time and aperture size trigger the switch between opening and closing of the fracture, source (Brunet et al., 2016).

5.4. Coupled Geomechanical–Chemical Modeling Approaches

Assessing the long-term stability of systems that store both hydrogen and CO₂ cannot be effectively achieved through separate physical or chemical models. Instead, the performance and containment of these storage systems are influenced by interconnected processes such as fluid dynamics, changes in pore pressure, mechanical deformation, and geochemical reactions. These interactions are complex, nonlinear, and vary over time, especially during repeated cycles of injection and withdrawal. Consequently, contemporary integrity assessments increasingly depend on integrated geomechanical–chemical modeling frameworks, commonly known as hydro-mechanical-chemical (HMC) or thermo-hydro-mechanical-chemical (THMC) models (Shojaee et al., 2023; Vasile et al., 2024; Hawez, Asim, & Fazio, 2024).

5.4.1. Rationale for Coupled Modeling in Co-Storage Systems

In subsurface storage activities, the pressure variations linked to gas injection and extraction directly impact effective stress, which subsequently influences deformation, fault stability, fracture openings, and permeability. Concurrently, the presence of CO_2 initiates geochemical interactions with formation brines and minerals, potentially resulting in dissolution, precipitation, and alterations in porosity and permeability. These chemically driven property changes feedback into the system's flow and mechanical behavior (Hawez, Asim, & Fazio, 2024; Zhang et al., 2023). In the co-storage of hydrogen and CO_2, these interactions are particularly significant because:

1. Hydrogen storage involves cycles, intensifying stress-path dependence and fatigue effects.
2. CO_2 is chemically active, capable of modifying rock properties over time.
3. Faults and fractures react both mechanically and chemically, affecting leakage risk.
4. Caprock properties may change, either enhancing or diminishing sealing efficiency.

Models that consider flow, geomechanics, or geochemistry separately are therefore inadequate to fully capture the range of integrity risks and mitigation strategies in co-storage scenarios (Shojaee et al., 2023; Vasile et al., 2024).

5.4.2. Hydro-Mechanical (HM) and Hydro-Mechanical-Chemical (HMC) Frameworks

Hydro-mechanical (HM) models integrate fluid dynamics and pore-pressure changes with the mechanical deformation of both the reservoir and caprock. These models are extensively utilized in CCS projects to forecast phenomena such as reservoir uplift, subsidence, fault reactivation, and stress redistribution resulting from injection (Asim & Hawez, 2024; Vasile et al., 2024). In HM models, permeability and porosity can be considered as properties that depend on stress, allowing deformation caused by pressure to affect flow pathways. Hydro-mechanical-chemical (HMC) models build upon this by including geochemical interactions between fluids and rocks. Within these models, the dissolution or precipitation of minerals can alter porosity, permeability, and mechanical characteristics, establishing feedback loops among chemistry, flow, and deformation (Hawez, Asim, & Fazio, 2024). For instance, the precipitation of carbonates induced by CO_2 might decrease fracture permeability (self-sealing), whereas precipitation near wells could hinder injectivity. These contrasting effects can only be accurately represented when chemical processes are explicitly integrated with mechanical and flow models. In co-storage systems, HMC coupling is crucial for assessing how geochemical changes driven by CO_2 interact with pressure cycling caused by hydrogen, especially near caprock interfaces and fault zones.

5.4.3. Representation of Faults, Fractures, and Caprock Integrity

One significant benefit of coupled modeling is its capacity to explicitly depict faults and fractures as dynamic mechanical and hydraulic components, rather than as static features. Within coupled frameworks, faults can be assigned frictional characteristics and assessed using slip-tendency or Mohr–Coulomb failure criteria, enabling the prediction of reactivation under changing pressure and stress conditions (Vasile et al., 2024). Geochemical coupling further allows the permeability of faults and fractures to change due to mineral precipitation or dissolution. Research on CO_2 storage indicates that carbonate precipitation can gradually decrease fracture permeability, aiding in self-sealing behavior, while dissolution may initially increase permeability (Hawez, Asim, & Fazio, 2024; Longe et al., 2024). In co-storage systems, these effects must be weighed against hydrogen's high mobility, which can exploit even partially sealed pathways. Caprock integrity modeling also gains from coupling, as it allows for the simultaneous evaluation of stress-dependent permeability, chemical alteration, and fracture mechanics. This integrated approach is increasingly endorsed by CCS guidelines and research as the best practice for assessing long-term containment (Asim & Hawez, 2024; Vanorio & Mavko, 2011).

5.4.4. Cyclic Loading, Hysteresis, and Time-Dependent Behavior

One of the toughest challenges in modeling hydrogen storage is accurately depicting cyclic loading and hysteresis. The repeated process of injecting and withdrawing hydrogen results in non-elastic behavior, such as irreversible deformation, permeability hysteresis, and changing stress paths. Coupled models incorporate these effects by using constitutive laws that consider plasticity, damage accumulation, and changes in properties dependent on stress (Shojaee et al., 2023). When chemical reactions are factored in, the behavior over time becomes even more intricate. Factors like mineral precipitation rates, reaction kinetics, and transport limitations introduce additional timescales that may not match operational cycles. For instance, self-sealing through carbonate precipitation might take months or years, while pressure cycling could occur over days or weeks. Coupled modeling allows for the assessment of how these differing timescales interact and affect long-term integrity (Hawez, Asim, & Fazio, 2024; Zhang et al., 2023).

5.4.5. Implications for Design and Regulatory Compliance

From both engineering and regulatory viewpoints, coupled geomechanical–chemical modeling offers a solid foundation for establishing safe operational limits, evaluating leakage risks, and proving long-term containment. Regulatory guidelines for CO_2 storage are increasingly demanding integrated modeling to aid in permitting and monitoring plans (Asim & Hawez, 2024; Vanorio & Mavko, 2011). As hydrogen storage progresses towards large-scale implementation, similar expectations are arising.

For co-storage systems, coupled modeling aids in:

- Determination of maximum allowable injection pressure.
- Analyzing the stability of faults and fractures under cyclic conditions.
- Evaluating the evolution of caprock and its self-sealing capability.
- Designing monitoring and mitigation strategies based on risk assessment.

Coupled geomechanical–chemical modeling is an essential tool for comprehending and managing the intricate interactions that govern hydrogen and CO_2 co-storage in mature reservoirs. By combining flow, mechanics, and chemistry within a single framework, these models offer the necessary insights to ensure storage integrity, operational safety, and regulatory compliance over extended periods (Shojaee et al., 2023; Vasile et al., 2024; Hawez, Asim, & Fazio, 2024).

6. Risk Assessment and Monitoring Strategies

Storing hydrogen and CO_2 together in mature reservoirs presents the combined technical challenges of geological carbon storage (CCS) and underground hydrogen storage (UHS). This creates a complex system involving multiple fluids, cycles, and chemical reactions, necessitating thorough risk evaluation and ongoing monitoring. Unlike single-gas storage, co-storage systems must simultaneously ensure the long-term containment of CO_2, maintain the recoverability of hydrogen, preserve the integrity of the caprock, and protect wellbore infrastructure under repeated pressure changes across various reservoir types, as shown in figure (6) (Rostam & Hawez, 2023; Li et al., 2023). In subsurface storage, risk is generally defined as the likelihood of failure multiplied by the impact's consequences, covering mechanical, hydraulic, geochemical, and operational aspects. In H_2–CO_2 systems, these aspects are closely interconnected. Changes in pressure-induced stress can affect fault stability; geochemical reactions might alter permeability and sealing capacity; microbial processes could change gas composition; and hydrogen's high diffusivity may heighten sensitivity to micro-scale leakage pathways (Li et al., 2023; Ramesh Kumar et al., 2023; Hawez & Ahmed, 2014). Consequently, risk assessment should take a comprehensive, system-wide approach rather than evaluating each process separately. Monitoring is crucial for reducing uncertainty and ensuring regulatory compliance. International CCS experience shows that early detection of pressure anomalies, gas migration, or geomechanical deformation greatly improves containment assurance (Chen et al., 2025; Hawez, Sanaee, & Faisal, 2021). For hydrogen storage, new studies highlight additional monitoring needs concerning gas purity, microbial activity, and well material degradation (Ali et al., 2022). In co-storage projects, monitoring strategies must be able to differentiate between CO_2 and H_2 behavior, tracking both containment and operational performance.

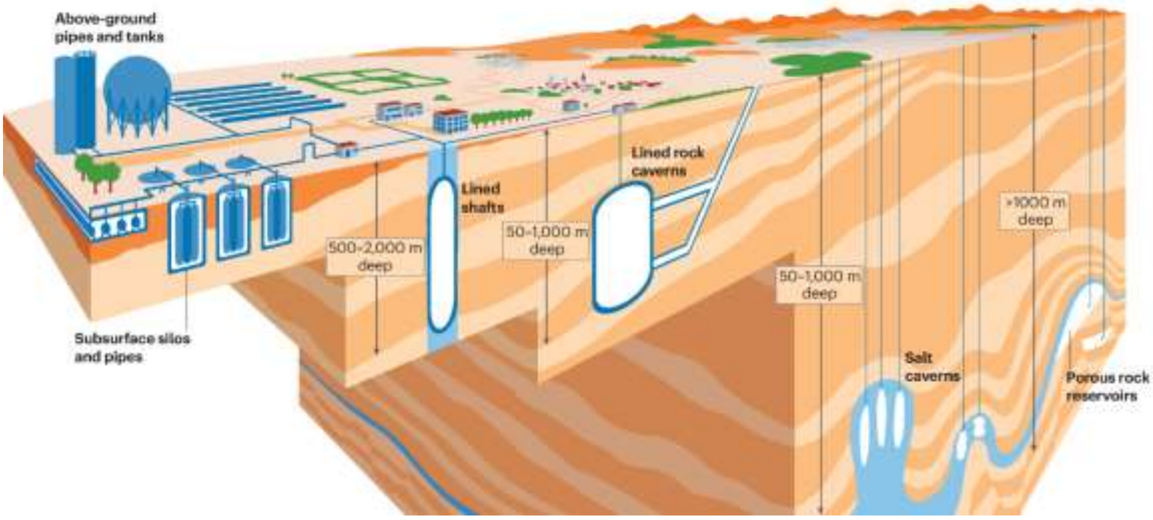

Figure 6. Conceptual framework for risk assessment and monitoring in hydrogen–CO_2 co-storage systems, illustrating the interaction between reservoir processes, potential leakage pathways, and surface/subsurface monitoring tools, source (Katriona Edlmann, 2024).

A comprehensive risk management framework for H_2–CO_2 co-storage typically includes:

- Identification of potential leakage pathways (faults, fractures, caprock matrix, legacy wells).

- Definition of safe operational pressure envelopes.
- Baseline characterization of geological, geochemical, and microbiological conditions.
- Continuous surveillance through geophysical, geochemical, and well-integrity monitoring.
- Quantitative uncertainty assessment and probabilistic forecasting.

6.1.Leakage Mechanisms and Mitigation

Ensuring the long-term containment of CO_2 and the operational retention of hydrogen are the main integrity goals in H_2–CO_2 co-storage systems. The risk of leakage occurs when the injected gases move beyond the designated storage area through structural discontinuities, diffusion through the caprock matrix, or engineered pathways like wells. Due to the significant differences in density, viscosity, diffusivity, and chemical reactivity between hydrogen and CO_2, their leakage mechanisms may vary in scale and dominant transport processes (Naderloo et al., 2023; Trimi et al., 2025).

Leakage pathways in porous reservoirs can be categorized into four main types:

1. Fault and fracture reactivation
2. Caprock capillary breakthrough or diffusive transport
3. Wellbore integrity failure (active or legacy wells)
4. Lateral migration beyond structural closure

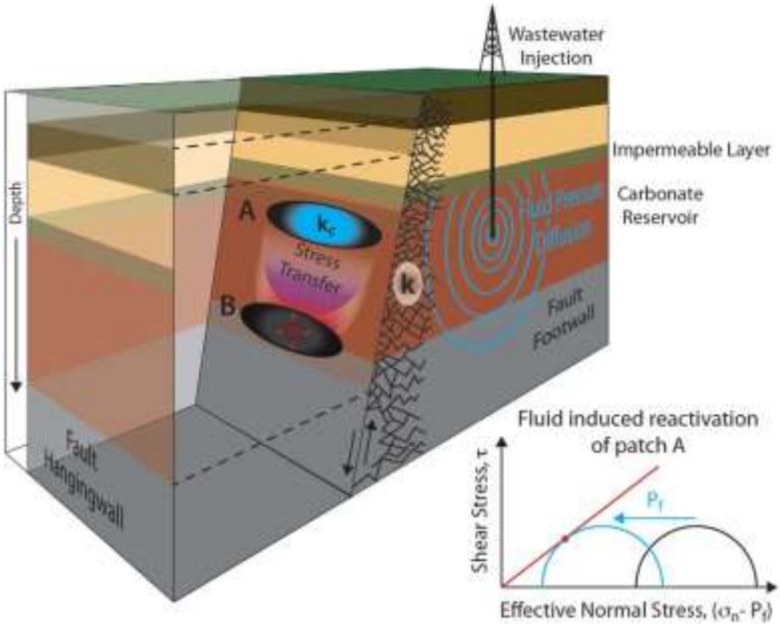

Figure 6.1. Schematic representation of fault reactivation due to fluid overpressure. Two end-members of fault slip behavior promoted by fluid assisted fault reactivation of patch A. Case 1) aseismic reactivation of patch A (slightly velocity strengthening) causes stress transfer and earthquake triggering on patch B (velocity weakening). Case 2) induced seismicity on patch A that due to fluid overpressure has a small D c and a velocity neutral behavior, Source (Scuderi and Collettini, 2016).

Mitigation Strategies

- Keep reservoir pressure below the fracture gradient and critical slip tendency limits.
- Utilize integrated reservoir-geomechanical modeling to establish safe operational boundaries.
- Avoid injecting near major faults that are critically oriented.
- Implement microseismic monitoring to detect fault activation early.

6.1.1. Fault and Fracture Reactivation

An increase in pore pressure due to injection decreases the effective normal stress on faults and fractures. When the stress path crosses the Mohr–Coulomb failure envelope, it can lead to shear slip or tensile fracturing, which enhances permeability and forms vertical leakage pathways, as illustrated in figure (6.1.1) (Kumar et al., 2022). In co-storage systems, the combination of prolonged CO_2 pressurization and frequent hydrogen cycling might hasten the fatigue-like weakening of faults that are already critically stressed (Kahzadvand et al., 2024). Hydrogen presents an additional challenge because its low density facilitates upward buoyant movement, so even small increases in fracture permeability can disproportionately enhance hydrogen leakage compared to CO_2 (Gupta & Yadav, 2020).

6.1.2. Caprock Leakage: Capillary Breakthrough and Diffusion

Caprock containment is mainly dependent on capillary sealing. Gas can only penetrate the caprock if the reservoir pressure surpasses the capillary entry pressure. In the case of CO_2, the interfacial tension and density contribute to relatively high entry pressures in water-wet shale caprocks (Saeed et al., 2023). Conversely, hydrogen's lower density and smaller molecular size might lead to reduced capillary entry pressures and increased diffusive transport (Hou et al., 2022). Even in the absence of capillary breakthrough, hydrogen can migrate through molecular diffusion within nano-scale pore networks. Although leakage driven by diffusion is generally slow, it can result in a gradual loss of hydrogen inventory over extended storage durations (Hemayati et al., 2024).

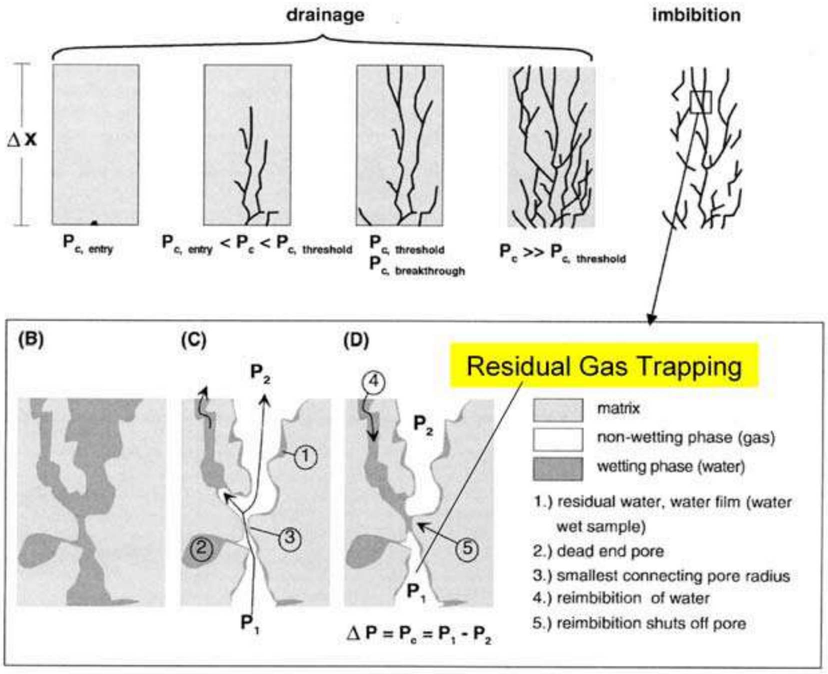

Figure 6.1.2. (A) Stages of capillary gas breakthrough (drainage), (B) Initially water-saturated sample, (C) Gas breakthrough, (D) Imbibition, source (Xue et al., 2009).

Mitigation Strategies

- Operate below capillary breakthrough pressure
- Characterize H_2-specific capillary entry pressure experimentally
- Ensure adequate caprock thickness and low permeability
- Use cushion gas strategies to stabilize pressure gradients

6.1.3. Wellbore Integrity Failure

Wells represent the most probable leakage pathway in mature reservoirs. Potential failure mechanisms include:

A. Cement degradation due to CO_2-induced carbonation as shown in figure (6.1.3).
B. Hydrogen embrittlement of steel casing
C. Micro-annulus formation during cyclic pressurization
D. Corrosion driven by microbially generated H_2S

Experience from CCS projects indicates that wells that are not properly abandoned pose the greatest leakage risk when they exist (Figueiredo et al., 2015). In co-storage systems, the repeated injection of hydrogen could worsen fatigue damage and material degradation (Kluge et al., 2021).

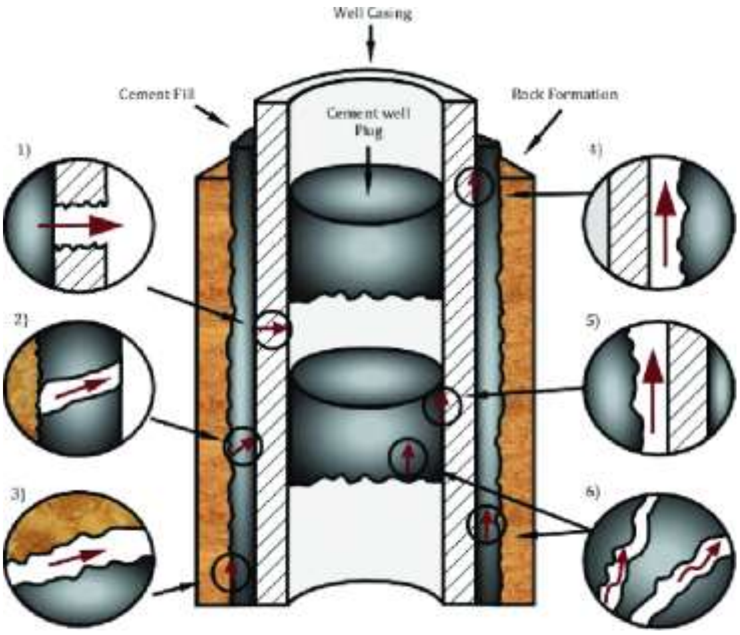

Figure 6.1.3. Overview of potential leakage pathways along an existing wellbore: through the casing (1), through fractures on the cement wall (2), between the cement wall and formation rock (3), between cement and casing (paths 4 and 5), and through the cement plugs (6), source (Recasens et al., 2017).

6.1.4. Lateral Migration and Structural Spill

If the amount of injected gas surpasses the structural closure capacity or moves beyond stratigraphic limits, it may lead to lateral spill. Although this might not immediately surface, it diminishes storage efficiency and complicates monitoring efforts (Brunet et al., 2016). The separation in density between CO_2 and hydrogen can also affect the shape and movement of the plume.

Mitigation includes:

- Precise structural mapping with 3D seismic technology
- Conservative injection rates
- Pressure management through brine extraction if needed.

6.2. Geophysical and Geochemical Monitoring Tools

Effective monitoring plays a crucial role in confirming containment, observing plume development, detecting leaks early, and minimizing uncertainty in hydrogen–CO_2 co-storage systems. Insights from international CCS practices have shown that ensuring long-term storage security depends not only on thorough site selection and pressure management but also on comprehensive Monitoring, Measurement, and Verification (MMV) programs (Gasda et al., n.d.; SPE, 2025). In the context of co-storage, monitoring must concurrently address:

1. CO_2 plume migration and trapping behavior as shown in figure (6.2)
2. Hydrogen distribution and recoverability
3. Pressure and stress evolution
4. Caprock integrity
5. Wellbore condition
6. Gas composition and microbial effects

Given that hydrogen and CO_2 possess distinct physical and chemical characteristics, a cohesive multi-technology monitoring approach is necessary (Gasda et al., n.d.).

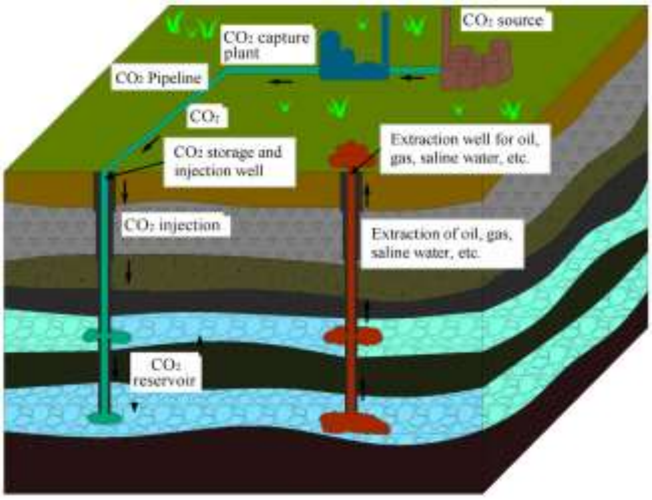

Figure 6.2. Overall schematic of carbon capture and storage concept, source (Li et al., 2018).

6.2.1. Geophysical Monitoring Methods

Geophysical tools provide non-invasive imaging of subsurface processes and are widely used in CCS projects.

A. Time-Lapse (4D) Seismic Monitoring

Time-lapse seismic surveys are used to identify changes in acoustic impedance that result from variations in gas saturation and pressure. The injection of CO_2 generally leads to noticeable reductions in seismic velocity due to its differences in density and compressibility compared to brine (SPE, 2025). Hydrogen, which is even less dense, might cause more subtle yet detectable changes, depending on the saturation level and reservoir characteristics (Bachu, 2008). 4D seismic technology has been effectively utilized in projects like Sleipner and Snøhvit to track the development of CO_2 plumes and confirm structural containment, as illustrated in figure (6.2.1) (SPE, 2025).

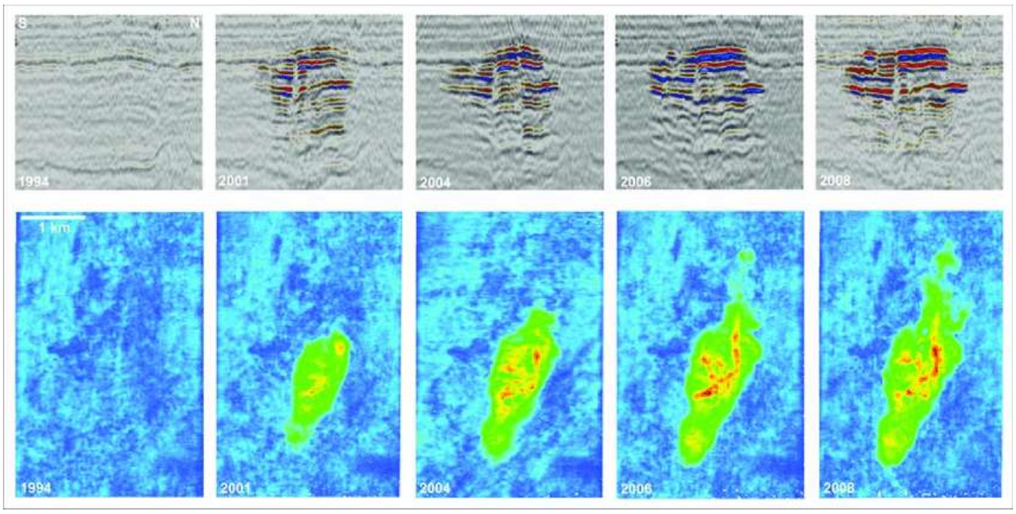

Figure 6.2.1.Time-lapse seismic images of the Sleipner CO 2 plume. NS inline through the plume (top); plan view of total reflection amplitude in the plume (bottom), Source (Chadwick et al., 2010).

B. Microseismic Monitoring

Microseismic arrays are used to identify minor seismic activities linked to fault slips or the activation of fractures. In the context of cyclic hydrogen storage, the process of repeated pressurization can produce microseismic signals that reflect changes in stress distribution (Heinemann et al., 2021). Detecting these signals early enables operators to modify injection rates before there is a significant increase in permeability.

C. InSAR and Surface Deformation Monitoring

Interferometric Synthetic Aperture Radar (InSAR) is a technique that measures surface deformation on a millimeter scale, which is related to changes in subsurface pressure. This approach offers a regional perspective on reservoir uplift or subsidence and is especially beneficial for depleted reservoirs that are being re-pressurized (Recasens et al., 2017).

6.2.2. Pressure and Downhole Monitoring

Maintaining constant pressure monitoring is crucial for ensuring safe operations. Pressure gauges installed in both injection and observation wells are used to monitor reservoir pressure in relation to fracture gradient and capillary entry pressure limits (Engeland et al., 2017). Fiber-optic systems like Distributed Temperature Sensing (DTS) and Distributed Acoustic Sensing

(DAS) facilitate the real-time identification of fluid movement, gas breakthroughs, and any anomalies in well integrity (Jenkins et al., 2024).

6.2.3. Geochemical Monitoring

Geochemical monitoring offers valuable insights into the movement of gases, the mixing of fluids, and reactive processes.

- **Gas Composition Analysis**

Produced gas sampling can detect:

- CO_2 concentration changes
- Hydrogen depletion
- Methane production via microbial methanogenesis
- And the generation of hydrogen sulfide (H_2S)

Isotopic tracing, like $\delta^{13}C$-CO_2, helps distinguish between CO_2 that is injected and that which occurs naturally (Edlmann, 2024).

- **Groundwater Monitoring**

Monitoring wells in shallow aquifers can identify changes in dissolved CO_2, pH levels, alkalinity, or dissolved hydrogen. Detecting geochemical anomalies early can signal leakage before it leads to extensive migration (Dawood et al., 2020).

6.2.4. Monitoring Challenges Specific to H_2–CO_2 Co-Storage

Co-storage presents a range of additional challenges:

A. The lower density of hydrogen might result in a reduced seismic contrast
B. Its high diffusivity could lead to subtle migration without noticeable pressure changes
C. Microbial activity might change the gas composition without causing structural leaks
D. The mixing of gases makes interpreting plumes more complex

Consequently, monitoring efforts must combine geophysical imaging with geochemical and well-based surveillance to establish reliable detection thresholds (Bachu, 2008; Edlmann, 2024).

6.3.Safety and Regulatory Considerations

To safely implement hydrogen–CO_2 co-storage in mature reservoirs, it is essential to adhere to regulatory frameworks initially designed for geological carbon storage (CCS) and underground gas storage, while also addressing new safety concerns related to hydrogen. Since co-storage combines long-term CO_2 sequestration with the cyclic storage of hydrogen, regulatory oversight must ensure environmental protection, operational safety, well integrity, and management of long-term liabilities (Coutanceau et al., 2018; Scuderi & Collettini, 2016).

Unlike traditional gas storage, co-storage systems must meet two distinct performance criteria simultaneously:

- Permanent containment of injected CO_2 over geological timescales
- Reliable, repeated withdrawal of hydrogen without compromising reservoir integrity

This dual objective increases regulatory complexity and requires integrated risk governance.

6.3.1. International CCS Regulatory Frameworks

Numerous nations oversee CO_2 storage through frameworks modeled after the EU CCS Directive (Directive 2009/31/EC) and associated guidelines formulated by the International Energy Agency (IEA) and IPCC (Coutanceau et al., 2018; Bickle, 2009). These regulations generally mandate:

i. Comprehensive site characterization
ii. Baseline environmental assessment
iii. Demonstration of containment integrity
iv. Risk-based monitoring plans

According to CCS regulations, operators are required to prove that injection pressures do not exceed fracture limits and that there is no considerable risk of leakage into groundwater or the atmosphere (Bickle, 2009). In co-storage systems, these regulatory guidelines still apply to the CO_2 component but must also be expanded to include risks specific to hydrogen operations.

6.3.2. Hydrogen-Specific Safety Considerations

Hydrogen introduces additional safety challenges compared to CO_2 due to its:

- Wide flammability range (4–75% in air)
- Low ignition energy
- High diffusivity
- Potential for embrittlement of steel infrastructure

Although CO_2 is not flammable, it can be dangerous due to the risk of suffocation, while hydrogen can lead to explosions if it escapes at the surface (Krevor et al., 2015). Consequently, it is essential for surface facilities, compressors, and pipelines to adhere to hydrogen safety regulations.

Subsurface safety considerations include:

- Hydrogen embrittlement of well casing materials
- Accelerated fatigue under cyclic loading
- Increased diffusive leakage potential
- Microbial H_2 consumption producing H_2S

These factors require material compatibility testing and stricter well integrity monitoring than typical CCS operations (Caglayan et al., 2020).

6.3.3. Environmental Protection and Groundwater Safety

Ensuring the protection of shallow groundwater resources is a key focus for regulatory bodies. The infiltration of CO_2 into drinking water aquifers can lead to changes in pH levels and the release of trace metals, while the movement of hydrogen might alter redox conditions and affect microbial activity (Rutqvist & Zoback, 2007). Environmental safety measures generally encompass:

1. Initial groundwater sampling before injection
2. Ongoing geochemical monitoring
3. Established corrective action plans for any detected leaks
4. Conservative buffer zones surrounding drinking water aquifers

Insights from CCS pilot projects indicate that systems for early detection play a crucial role in minimizing environmental risks (Kumar et al., 2023).

6.3.4. Operational Safety and Emergency Response

As illustrated in figure (6.3.4), regulatory frameworks mandate that operators develop emergency response plans for unforeseen incidents, such as:

- Sudden pressure changes
- Well integrity failure
- Induced seismic activity
- Surface gas emissions

Predefined microseismic thresholds often dictate that if seismic magnitudes surpass regulatory limits, operators must reduce injection rates or temporarily halt operations (Liu et al., 2015). The presence of hydrogen introduces additional emergency planning challenges due to its flammable nature and rapid dispersion. Consequently, co-storage facility designs must incorporate surface gas detection systems, explosion-proof equipment, and ventilation strategies (Krevor et al., 2015).

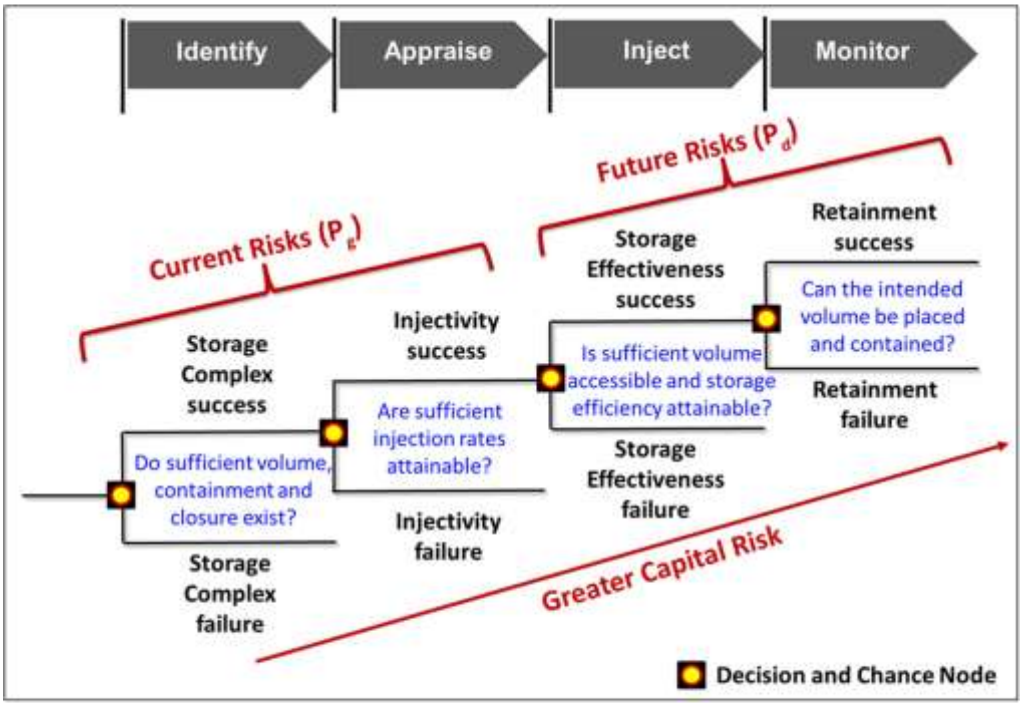

Figure 6.3.4. A staged approach to manage an SCS project can be summarized in a decision tree. Each stage is characterized by different types of data that need to be obtained and a threshold that needs to be met in order to progress to the next stage. Current risks, represented in SRMS by chance of discovery (P_g), can be addressed today. Future risks, represented in SRMS as chance of development (P_d), can be addressed via long-term injection, source (Jenkins et al., 2024).

6.3.5. Long-Term Liability and Post-Closure Management

Long-term stewardship represents a critical issue for CO_2 storage projects. Most CCS regulations require:

- Demonstration of long-term stability prior to site closure
- Transfer of liability to state authorities after a defined monitoring period
- Financial guarantees to cover potential remediation

In contrast, regulatory guidelines for hydrogen storage are still being developed. Since hydrogen is meant for repeated extraction rather than permanent storage, the focus is on ongoing operational oversight rather than post-closure monitoring (Caglayan et al., 2020).

In scenarios involving co-storage, regulatory frameworks may need to be aligned to address:

- Dual-purpose reservoir use
- The distinction between operational gas and permanently stored CO_2
- Liability in case of compositional mixing or gas quality degradation

6.4.Uncertainty Quantification and Probabilistic Risk Assessment

Subsurface systems are naturally characterized by uncertainty due to the scarcity of data, geological variability, and the intricate nature of interconnected physical, chemical, and mechanical processes. In the context of hydrogen–CO_2 co-storage, this uncertainty is further intensified by the interaction between two gases with distinct properties, the cyclic nature of operational conditions, and the changing geochemical and geomechanical dynamics. Consequently, a comprehensive risk assessment should integrate uncertainty quantification (UQ) and probabilistic risk assessment (PRA) instead of relying solely on deterministic forecasts (Gupta & Yadav, 2020; Xue et al., 2009).

Uncertainty in co-storage systems can be broadly categorized into:

- **Geological uncertainty,** such as: heterogeneity, faults, and caprock properties
- **Petrophysical uncertainty,** such as: porosity, permeability, wettability
- **Operational uncertainty,** such as: injection rates, cycling frequency, pressure limits
- **Model uncertainty,** such as: reaction kinetics, relative permeability, upscaling assumptions
- **Monitoring uncertainty,** such as: measurement error, detection thresholds

These uncertainties influence predictions of plume migration, leakage probability, hydrogen recovery efficiency, and long-term storage security.

6.4.1. Deterministic vs Probabilistic Approaches

Conventional reservoir simulations typically rely on deterministic inputs, resulting in a single "best estimate" outcome. This method, however, might underestimate risk as it fails to account for variations in crucial parameters (Chadwick et al., 2010). Probabilistic approaches overcome this shortcoming by considering uncertain parameters as distributions instead of fixed values, as depicted in figure (6.4.1). By generating multiple realizations, these methods allow for the evaluation of a spectrum of potential outcomes, facilitating the estimation of:

- Probability of leakage

- Range of pressure evolution scenarios
- Variability in gas recovery and storage efficiency

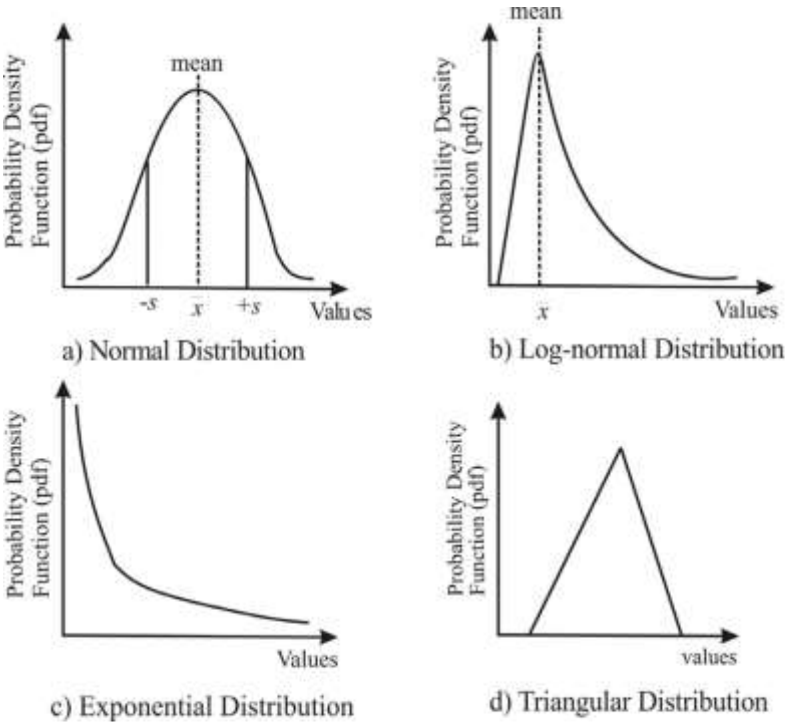

Figure 6.4.1. Useful probability distribution models for uncertainty analysis, source (Panthi, 2006).

6.4.2. Monte Carlo Simulation and Sensitivity Analysis

As depicted in figure (6.4.2), Monte Carlo simulation is a prevalent tool for quantifying uncertainty in subsurface storage. This method involves sampling uncertain parameters, such as permeability, fault transmissibility, and reaction rates, from probability distributions and conducting thousands of simulation runs (Hafner & Luciani, n.d.).
The outputs are analyzed statistically to determine:

- Probability of exceeding critical pressure thresholds
- Likelihood of leakage through faults or wells
- Variability in hydrogen recovery efficiency

Sensitivity analysis is employed alongside Monte Carlo methods to pinpoint which parameters most significantly influence system behavior. Research consistently indicates that fault permeability, caprock entry pressure, and well integrity are among the most crucial factors affecting leakage risk (Solomon, 2007).

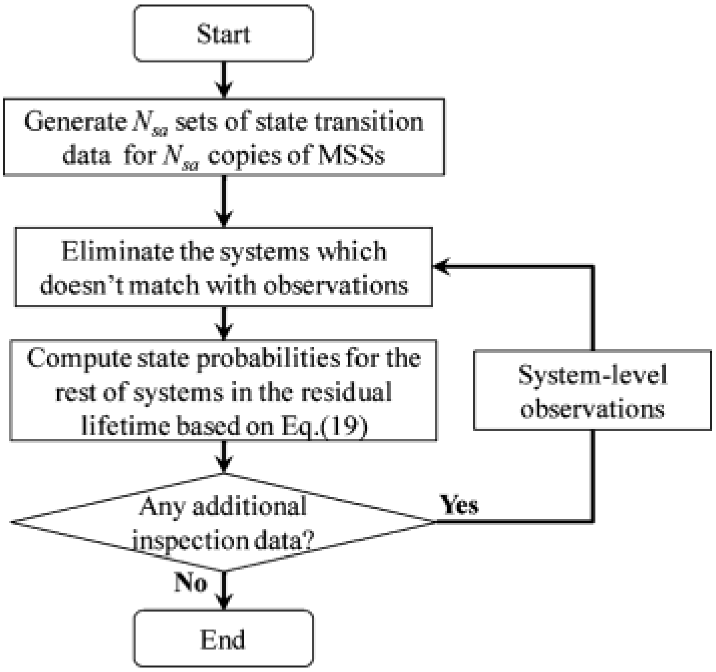

Figure 6.4.2. The flowchart of the Monte Carlo simulation, source (Liu et al., 2015).

6.4.3. Risk Metrics and Probability of Failure

Probabilistic risk assessment defines risk in terms of likelihood and consequence. Common metrics used in subsurface storage include:

- Probability of caprock breach
- Probability of fault reactivation
- Probability of well leakage
- Expected hydrogen loss fraction
- CO_2 containment efficiency

Risk can be represented through cumulative probability distributions or exceedance curves, which measure the probability of adverse events occurring, as illustrated in figure (6.4.3) (e.g., pressure surpassing fracture gradient) (semanticscholar, 2008).

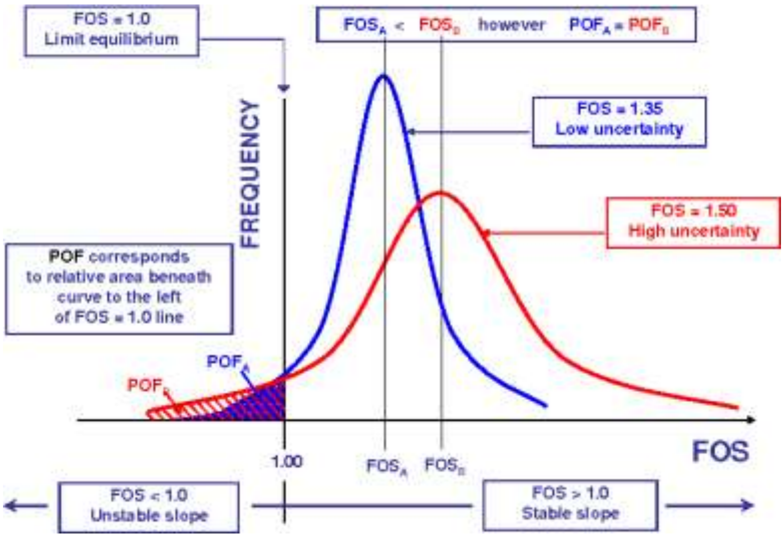

Figure 6.4.3. Definition of POF and Relationship with FOS according to uncertainty magnitude, source (semanticscholar, 2008).

6.4.4. Integration with Monitoring and Adaptive Management

Uncertainty quantification is an ongoing process that requires regular updates with monitoring data. This method, commonly known as history matching and model calibration, helps in gradually reducing uncertainty, as illustrated in figure (6.4.4) (Celia et al., 2015).

The main principles involve:

A. Updating reservoir models with pressure, seismic, and geochemical data
B. Modifying operational strategies (such as injection rate and pressure limits)
C. Implementing adaptive risk management

For H_2–CO_2 co-storage, this iterative process is crucial because:

- Hydrogen cycling causes variability over time
- Geochemical reactions evolve over long timescales
- Microbial activities might alter system behavior

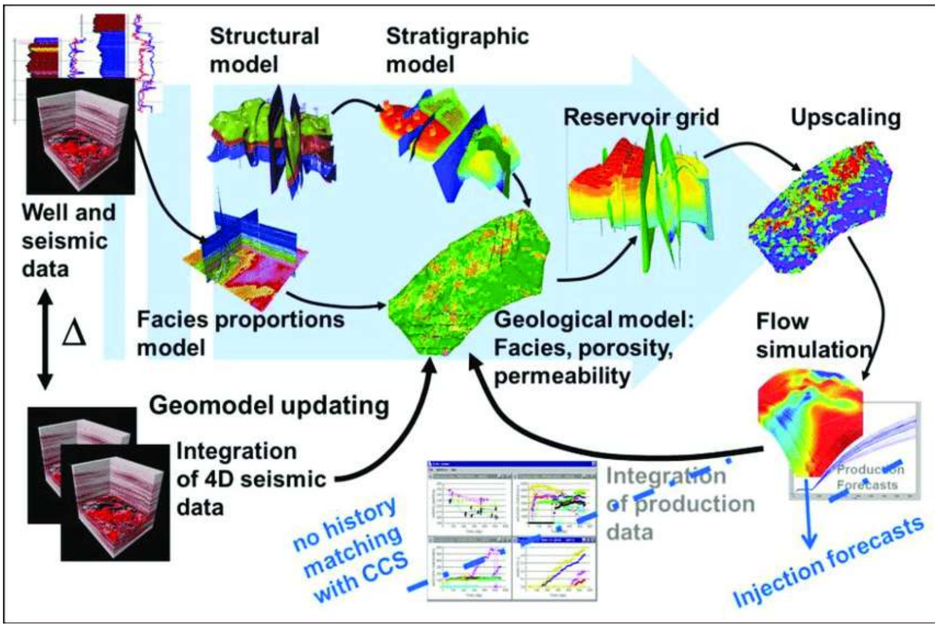

Figure 6.4.4. Integrated reservoir characterization and history matching workflow as used in the oil & gas industry, source (Fornel and Estublier, 2013).

6.4.5. Key Challenges in Co-Storage Uncertainty

Storing hydrogen and CO_2 together introduces more sources of uncertainty than systems with a single fluid.

- Limited experimental data for H_2–CO_2–brine interactions
- Uncertainty in microbial activity and hydrogen consumption
- Lack of standardized relative permeability models for mixed gases
- Coupled geomechanical–chemical feedbacks

These uncertainties highlight the need for multi-scale modeling approaches and site-specific calibration workflows (Fornel & Estublier, 2013).

7. Economic and Environmental Implications

Storing hydrogen and CO_2 together in mature reservoirs is not just a technical breakthrough but also a potentially game-changing approach to combining energy storage with carbon management in a single underground system. Economically, co-storage presents opportunities to maximize infrastructure use, lower capital costs, and create multiple income streams. Environmentally, it facilitates the reduction of greenhouse gases while integrating renewable energy sources (Vasco et al., 2010; Li et al., 2019). Typically, subsurface storage projects are designed for a single purpose, such as permanent CO_2 sequestration (CCS) or seasonal gas storage like natural gas or hydrogen. However, co-storage systems merge these goals, enabling reservoirs to serve dual functions by storing CO_2 and offering adaptable hydrogen storage for energy balancing. This integration can greatly enhance the overall economics of subsurface storage by spreading fixed costs across various value chains (Hartog, 2017). Nonetheless, economic success is heavily influenced by several factors as shown in figure (7):

1. Capital expenditure (CAPEX) for site development, wells, and facilities
2. Operational expenditure (OPEX) including compression, injection, and monitoring
3. Hydrogen market price and demand variability
4. Carbon pricing and incentives (e.g., carbon credits, emissions trading schemes)
5. Storage efficiency and hydrogen recovery losses
6. Long-term liability and regulatory compliance costs

Simultaneously, environmental performance must be assessed throughout the entire system lifecycle, including upstream hydrogen production, injection operations, subsurface reactions, and potential leakage risks (Myrttinen et al., 2014).

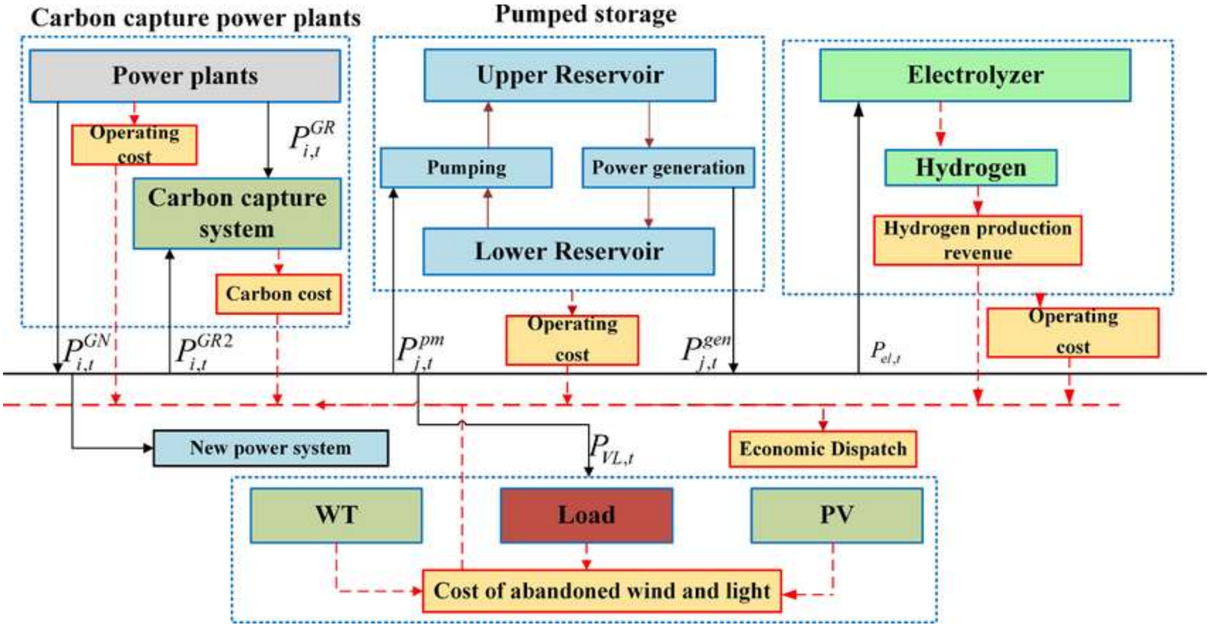

Figure 7. Power system economic dispatch framework considering FCCPP–pumped storage–electric hydrogen production combination, source (Huang et al., 2024).

7.1.Cost–Benefit Analysis of Co-Storage vs. Single Gas Storage

The economic viability of co-storing hydrogen and CO_2 hinges on whether integrating both storage functions in a single reservoir offers significant benefits compared to using separate systems dedicated to each purpose, like standalone CO_2 geological storage (CCS) or underground hydrogen storage (UHS). Therefore, a cost–benefit analysis should assess both the potential for cost reductions (CAPEX/OPEX savings) and the creation of additional value (multiple revenue streams and system flexibility) (Kharaka et al., 2006; Huang et al., 2024).

7.1.1. Capital Expenditure (CAPEX) Comparison

Capital costs in subsurface storage projects are dominated by:

- Site characterization (seismic, drilling, testing)
- Well construction and completion
- Surface facilities (compression, injection systems)
- Monitoring infrastructure

In systems designed for storing a single gas, expenses are entirely attributed to either CO_2 sequestration or hydrogen storage separately. Conversely, co-storage systems utilize shared infrastructure, such as wells, pipelines, compressors, and monitoring systems, which decreases the overall capital investment required per unit of stored energy or CO_2, as illustrated in figure (7.1.1) (Panthi, 2006).

For mature reservoirs, additional savings arise from:

- Reuse of existing wells and facilities
- Reduced exploration and appraisal costs
- Established geological knowledge

Studies indicate that infrastructure reuse can reduce CAPEX by **20–40%** compared to greenfield projects, depending on reservoir condition and required refurbishment (Huang et al., 2024; Birkholzer et al., 2012).

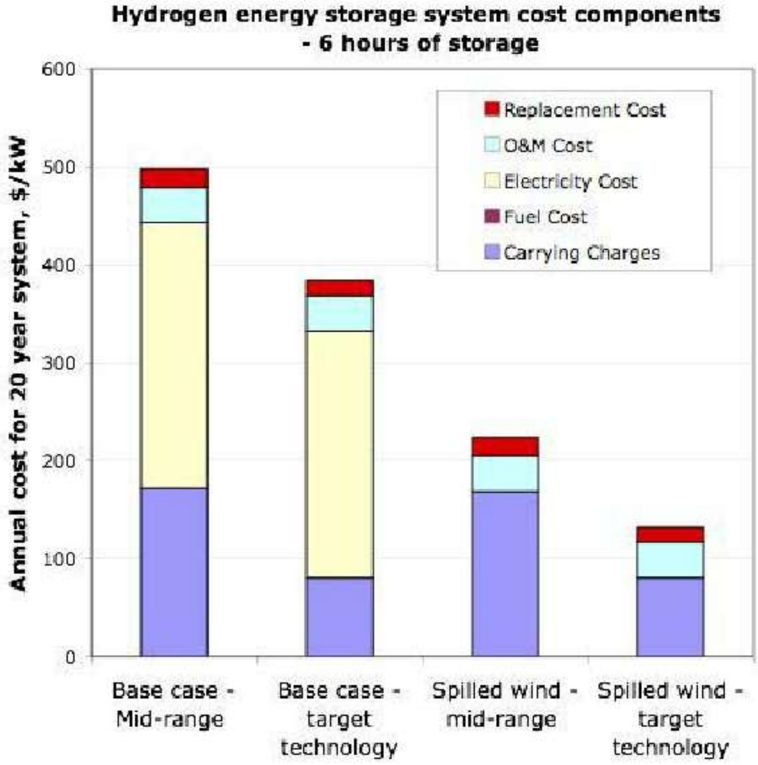

Figure 7.1.1. Annual cost components for hydrogen storage systems, source (Schoenung, 2011).

7.1.2. Operational Expenditure (OPEX) and Efficiency

Operational costs include:

1. Gas compression and injection energy
2. Monitoring and maintenance
3. Well workovers and integrity management
4. Gas processing and purification

In co-storage systems, OPEX may be reduced through shared operations; however, additional costs may arise due to:

- Gas separation requirements (H_2–CO_2 mixtures)
- Enhanced monitoring complexity
- Increased well integrity maintenance under cyclic conditions

If not properly controlled, hydrogen losses due to diffusion, microbial consumption, or mixing with CO_2 can negatively impact economic efficiency (Yang et al., 2024). However, by optimizing injection cycles and managing pressure, the overall efficiency of the system can be enhanced. This is especially true when CO_2 is used as a cushion gas, as it helps stabilize reservoir pressure and decreases the need for hydrogen compression (Schoenung, 2011).

7.1.3. Revenue Streams and Economic Value

A major advantage of co-storage systems is the ability to generate multiple revenue streams as shown in figure (7.1.3), including:

- Hydrogen sales for energy markets
- Carbon credits for CO_2 sequestration
- Grid balancing services (seasonal energy storage)
- Potential enhanced oil recovery (EOR) benefits

In contrast, single-gas systems rely on a single value chain (either carbon storage incentives or energy storage revenue).

The economic value of co-storage is therefore strongly dependent on:

A. Hydrogen market price volatility
B. Carbon pricing mechanisms (e.g., ETS, tax credits)
C. Policy incentives for decarbonization

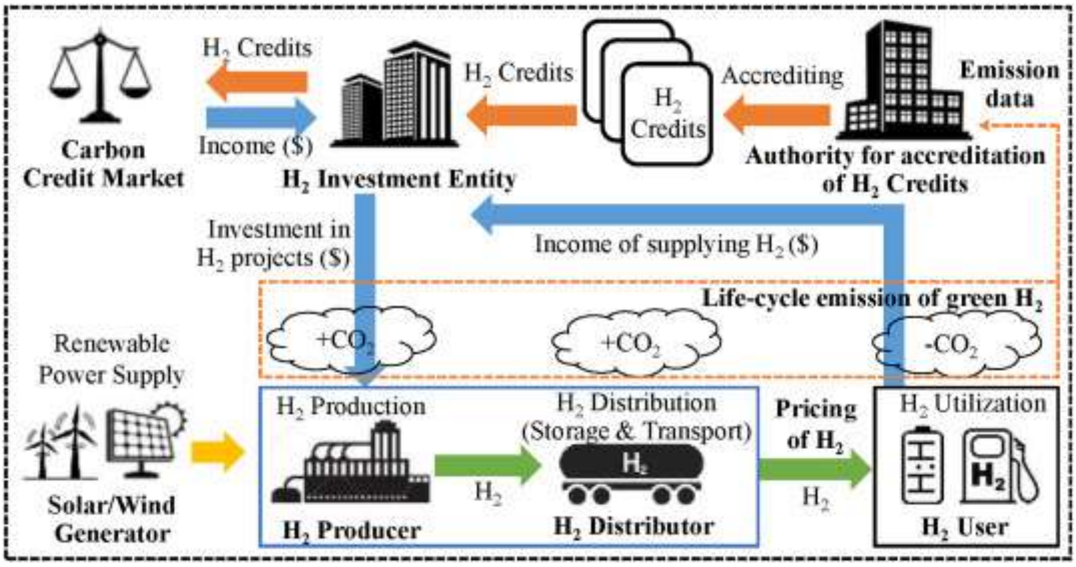

Figure 7.1.3. Schematic of business model 2 - investment for HC, source (Yang et al., 2024).

7.1.4. Economic Trade-Offs and Risks

Despite its advantages, co-storage introduces additional economic risks:

- Increased system complexity
- Uncertainty in hydrogen recovery efficiency
- Potential gas contamination affecting market value
- Higher regulatory and monitoring costs

Sensitivity analyses show that project viability is highly dependent on:

- Hydrogen recovery factor
- Carbon credit price
- Leakage risk and associated penalties

In some scenarios, co-storage may be less attractive than dedicated hydrogen storage if hydrogen losses are significant or if carbon pricing is low (Rubin et al., 2010).

7.1.5. Overall Cost–Benefit Assessment

Overall, co-storage systems offer strong economic potential when:

- Existing infrastructure can be reused
- Carbon pricing mechanisms are well established
- Hydrogen demand is high and stable
- Operational risks are effectively managed

The key advantage lies in cost sharing and revenue diversification, which can significantly improve project profitability compared to single-purpose storage systems.

7.2.Carbon Credit and Hydrogen Market Integration

The economic feasibility of hydrogen–CO_2 co-storage is heavily dependent on its capacity to align with both carbon markets and the burgeoning hydrogen economy. Unlike traditional storage systems that depend on a single value chain, co-storage offers a dual-market potential, allowing operators to profit from both CO_2 sequestration through carbon credits and hydrogen storage via energy markets (Oldenburg et al., 2009; Salma et al., 2024).

7.2.1. Carbon Credit Mechanisms and CO_2 Storage Value

Carbon pricing strategies, including carbon taxes, emissions trading systems (ETS), and tax credits, offer financial incentives for storing CO_2. Through these approaches, each ton of CO_2 that is permanently stored can yield a tradable credit or financial gain (Bedford & Cooke, 2001). In co-storage systems, the CO_2 injected into the reservoir directly aids in meeting carbon reduction goals, enabling operators to earn revenue from carbon credits while also utilizing the same reservoir for hydrogen storage (Oliver et al., 2008). Consequently, the economic worth of CO_2 storage is directly linked to:

1. Volume of CO_2 permanently stored
2. Carbon price per tonne
3. Verification and monitoring compliance

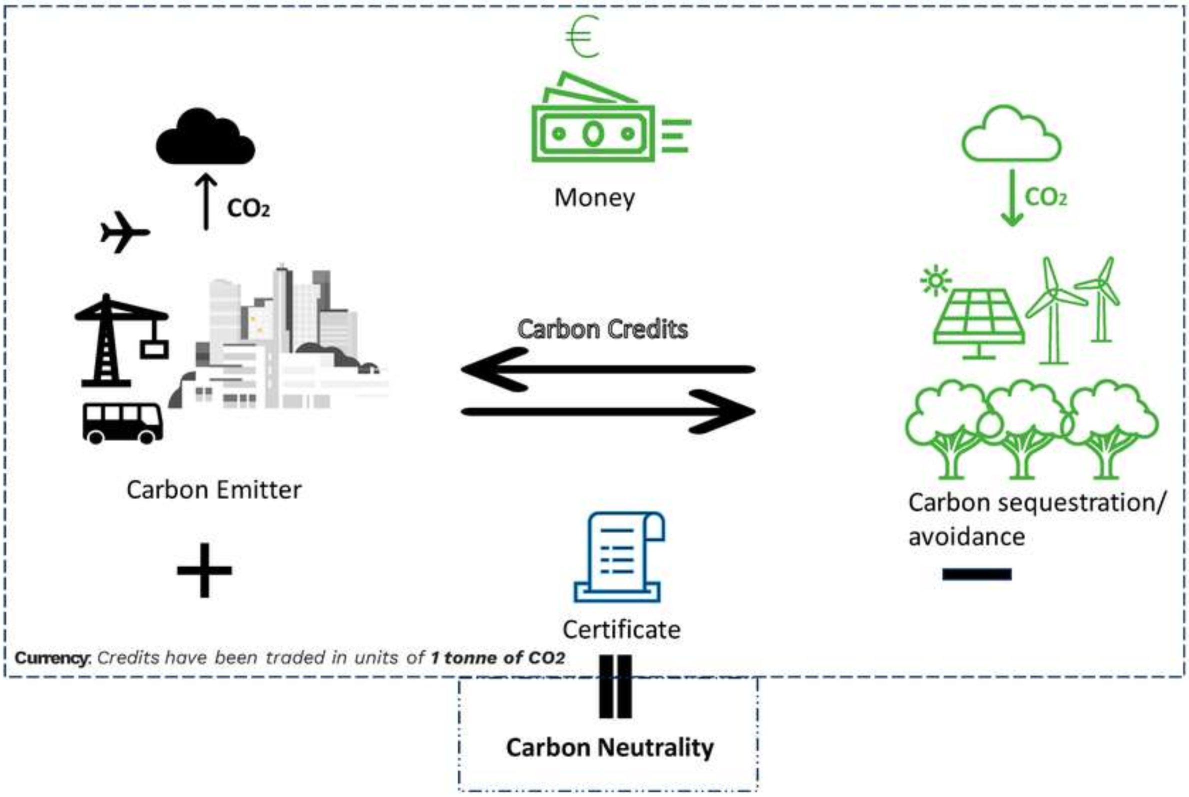

Figure 7.2.1. Simplified mechanism of carbon credit system, source (Salma, Fryda and Djelal, 2024).

7.2.2. Hydrogen Market Dynamics and Energy Storage Value

Hydrogenis gaining recognition as a crucial energy carrier in low-carbon energy systems, with uses in:

- Power generation and grid balancing
- Industrial decarbonization (steel, chemicals)
- Transportation (fuel cells)

The hydrogen market is anticipated to expand swiftly, propelled by the growth of renewable energy and decarbonization policies, as illustrated in figure (7.2.2) (Oldenburg et al., 2009). Underground storage is essential for seasonal balancing, enabling the storage of surplus renewable energy as hydrogen, which can be retrieved during times of high demand. In co-storage systems, hydrogen generates revenue by:

- Sale of stored hydrogen to energy markets
- Provision of grid flexibility services
- Arbitrage between low and high electricity price periods

Figure 7.2.2. The above graphic outlines the value chain and roles of hydrogen in renewable energy production and storage, energy supply and distribution, as well as low- and zero-carbon fuel in applications like industry, logistics and mobility, source (TÜV SÜD, 2026).

7.2.3. Synergy Between Carbon and Hydrogen Markets

The key advantage of co-storage lies in the synergistic interaction between carbon and hydrogen markets as shown in figure (7.2.3). These synergies include:

- Shared infrastructure reducing overall system cost
- CO_2 acting as cushion gas, improving hydrogen storage efficiency
- Simultaneous revenue generation from carbon credits and hydrogen sales
- Enhanced project bankability through diversified income streams

In addition, co-storage systems can contribute to negative emission technologies when combined with bioenergy or direct air capture (DAC), further increasing carbon credit value (Rubin et al., 2015).

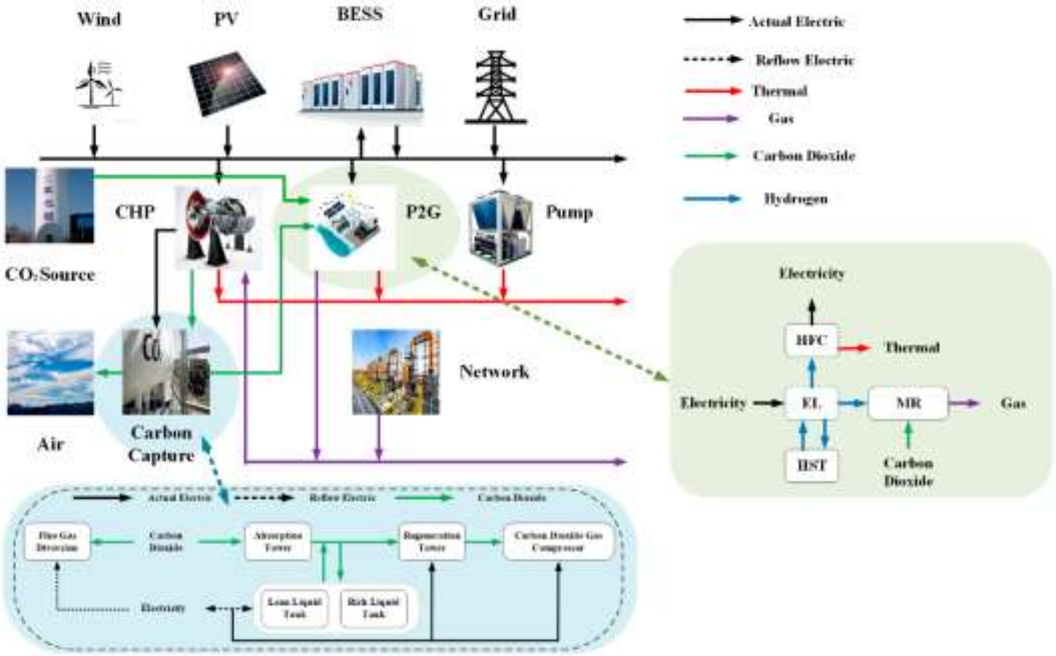

Figure 7.2.3. Integrated system linking renewable energy, hydrogen production and storage, and CO_2 capture and sequestration, demonstrating sector coupling and dual-market integration, source (Lu et al., 2024).

7.2.4. Market Risks and Uncertainties

Despite its potential, integration with carbon and hydrogen markets introduces several uncertainties:

- Volatility in carbon pricing
- Uncertainty in hydrogen demand and pricing
- Regulatory changes affecting incentives
- Verification requirements for carbon credits
- Hydrogen purity standards and market specifications

For instance, the presence of CO_2 or H_2S in hydrogen can diminish its market value or necessitate extra processing expenses (IEA, 2019). Consequently, achieving economic success relies on consistent policy frameworks and dependable monitoring systems to confirm CO_2 storage and the quality of hydrogen.

7.3.Life-Cycle Assessment of the Co-Storage System

Life-cycle assessment (LCA) is a structured approach employed to assess the environmental effects of a system throughout its entire life span, from the extraction of resources and infrastructure development to its operation, monitoring, and eventual decommissioning. In the context of hydrogen–CO_2 co-storage, LCA plays a crucial role in determining whether the system provides net environmental advantages, especially concerning the reduction of greenhouse gas (GHG) emissions and energy efficiency (IPCC, 2022; Lu et al., 2024). Unlike standalone carbon capture and storage (CCS) or hydrogen storage, co-storage systems encompass integrated processes such as hydrogen production (e.g., electrolysis), gas compression, injection, subsurface interactions, and potential leakage pathways Consequently, it is important to evaluate environmental impacts comprehensively rather than in isolation.

7.3.1. System Boundaries and LCA Framework

A typical LCA for co-storage systems includes the following stages:

- **Upstream processes**: hydrogen production (electrolysis or reforming), CO_2 capture as shown in figure (7.3.1)
- **Midstream processes**: compression, transport, injection
- **Subsurface processes**: storage, geochemical reactions, pressure cycling
- **Downstream processes**: hydrogen withdrawal, processing, and utilization
- **End-of-life phase:** site closure and long-term monitoring

The determination of system boundaries plays a crucial role in influencing LCA outcomes. For instance, hydrogen generated from renewable sources, known as "green hydrogen," results in significantly lower emissions than hydrogen derived from natural gas, referred to as "blue hydrogen" (IPCC, 2022).

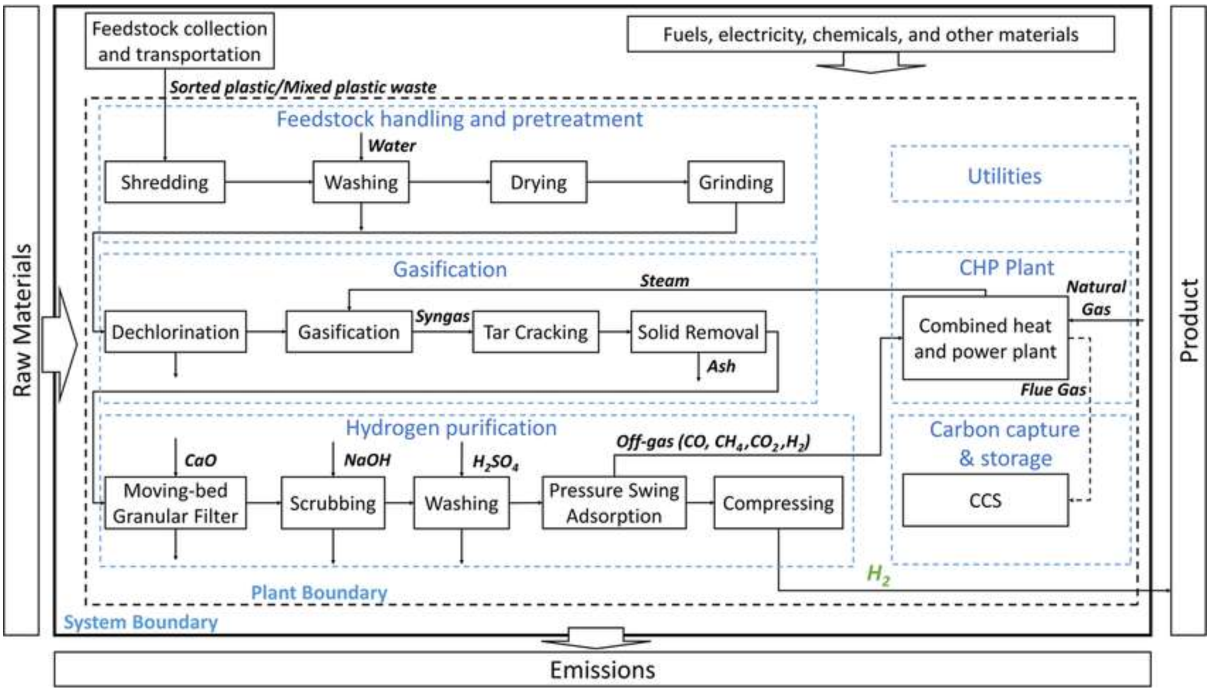

Figure 7.3.1. System boundary of Life Cycle Assessment and flow diagram of the plant. The flow diagram inside the plant boundary includes five main areas, including feedstock handling and pretreatment, gasification, hydrogen purification, combined heat and power (CHP) plant, and utilities, along with carbon capture and storage (CCS) for scenario analysis, source (Lan and Yao, 2022).

7.3.2. Greenhouse Gas Emissions and Carbon Balance

The main environmental goal of co-storage is to achieve a net decrease in greenhouse gas emissions as shown in figure (7.3.2). CO_2 sequestration plays a direct role in reducing emissions, while hydrogen storage facilitates a higher integration of renewable energy sources. Nonetheless, the overall lifecycle emissions are influenced by several factors:

- Energy source for hydrogen production
- Energy consumption for compression and injection
- Leakage rates of CO_2 and hydrogen
- Efficiency of hydrogen recovery

Research indicates that when renewable electricity is utilized, co-storage systems can attain nearly zero or even negative net emissions, especially when paired with carbon capture technologies (Fuss et al., 2018). On the other hand, high leakage rates or hydrogen production based on fossil fuels can greatly diminish the environmental advantages.

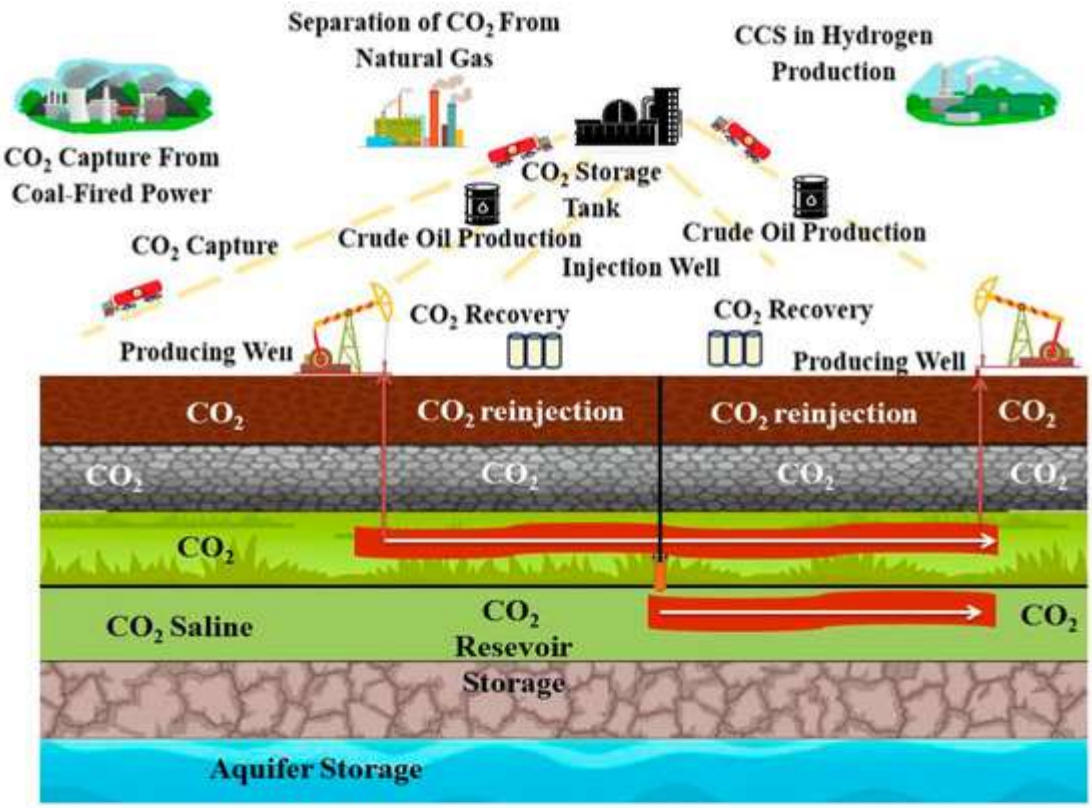

Figure 7.3.2. Components of CCS and its impact on greenhouse gas emissions reduction, source (Alizadeh, Khalili and Ahmadi, 2024).

7.3.3. Environmental Impacts Beyond CO_2

In addition to GHG emissions, LCA evaluates other environmental impacts, including:

- **Water consumption (especially for electrolysis)**
- **Land use and infrastructure footprint**
- **Resource use (steel, cement, energy)**
- **Potential groundwater contamination**

Subsurface processes may also influence environmental performance through:

- Mineral reactions altering formation chemistry
- Microbial activity producing byproducts (e.g., H_2S)
- Potential leakage affecting shallow ecosystems

Although these impacts are generally site-specific, studies indicate that they are typically minor compared to the climate benefits, provided that leakage risks are properly managed (TÜV SÜD, 2026).

7.3.4. Comparison with Alternative Energy Storage Systems

Co-storage systems can be compared with other energy storage technologies such as:

- Batteries (short-term storage)
- Pumped hydro storage
- Standalone hydrogen storage
- Standalone CCS

Compared to batteries, co-storage offers:

- Much larger storage capacity (TWh scale)
- Lower lifecycle material intensity
- Longer storage duration (seasonal)

Compared to standalone CCS or hydrogen storage, co-storage improves:

- Infrastructure efficiency
- System integration
- Overall environmental performance as shown in figure (7.3.4)

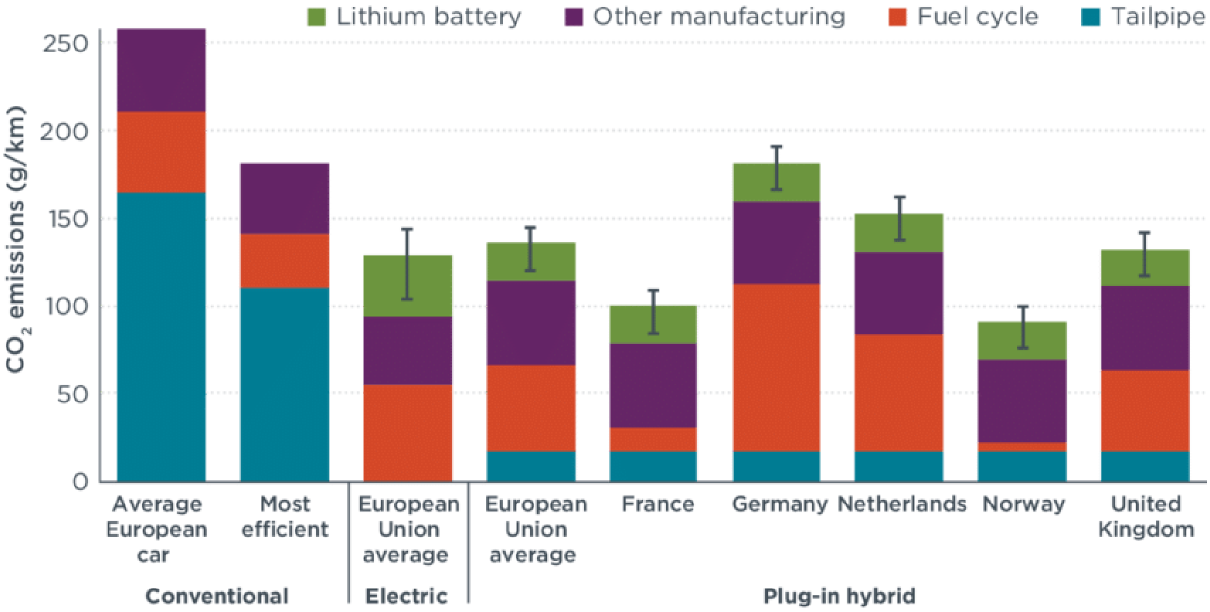

Figure 7.3.4. Comparison of life-cycle greenhouse gas emissions in conventional, electric, and plugin hybrid vehicles in various European markets, source (Lutsey, Nicholas & Hall, Dale, 2018).

7.3.5. Societal and Policy Relevance

Storing hydrogen and CO_2 together is not just a technical and economic approach but also a crucial element in the worldwide shift towards sustainable energy. The success of this initiative hinges on public acceptance, policy backing, regulatory consistency, and the involvement of stakeholders, all of which affect the feasibility and long-term viability of projects (ISO, 2006;

IEA, 2023). As energy systems move towards reducing carbon emissions, co-storage solutions can be pivotal in addressing the challenges of renewable energy fluctuations and cutting industrial emissions, thus aiding in achieving net-zero goals and ensuring energy security.

7.3.6. Contribution to Climate and Energy Policy Goals

Co-storage aligns strongly with international climate policies as shown in figures (7.3.6), including:

- Net-zero emission targets by 2050
- Expansion of renewable energy systems
- Development of hydrogen economies
- Deployment of carbon capture and storage (CCS)

By simultaneously enabling large-scale CO_2 sequestration and seasonal hydrogen storage, co-storage systems support two key pillars of decarbonization:

1. **Carbon management** (reducing atmospheric CO_2)
2. **Energy system flexibility** (balancing intermittent renewables)

This dual function makes co-storage particularly attractive in integrated energy system planning (Lan & Yao, 2022).

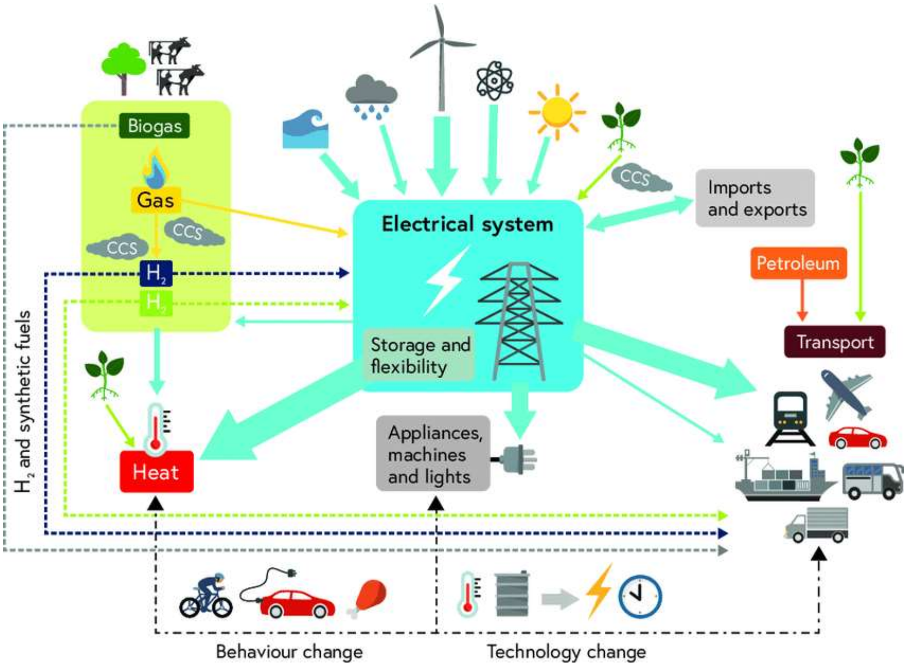

Figure 7.3.6. Illustrative Net Zero energy flows: technology mix (renewables, nuclear & fossil fuels); low behavioural change; higher engineered GHG removals (i.e. CCS), source (Dixon et al., 2021).

7.3.7. Public Acceptance and Social License to Operate

Public perception plays a critical role in the deployment of subsurface storage technologies. Concerns may include:

- Risk of gas leakage
- Induced seismicity
- Environmental impacts on groundwater
- Long-term safety and liability

Insights from CCS projects indicate that a lack of public confidence can hinder or halt project progress, even when technical risks are minimal (Bhandari et al., 2014). To tackle these issues, co-storage projects should focus on:

- Transparent communication of risks and benefits
- Community engagement and stakeholder participation
- Clear demonstration of monitoring and safety measures
- Inclusion of local communities in decision-making processes

7.3.8. Policy Incentives and Regulatory Support

Government policies and incentives are key drivers for the adoption of co-storage systems. Important policy instruments include:

- Carbon pricing (carbon tax, emissions trading systems)
- Subsidies for hydrogen production and storage as shown in figure (7.3.8)
- Investment support for CCS infrastructure
- Research and development funding

In numerous areas, policy frameworks are still in development, especially concerning hydrogen storage. Integrated policies are necessary for co-storage systems to simultaneously address both CCS and hydrogen energy (Alizadeh et al., 2024).

Key policy challenges include:

A. Harmonization of CCS and hydrogen regulations
B. Definition of ownership and liability for stored gases
C. Standardization of monitoring and verification requirements
D. Support for pilot and demonstration projects

Figure 7.3.8. Green hydrogen energy policy review methodology, source (Marouani et al., 2023).

7.3.9. Energy Security and Regional Development

Co-storage systems can enhance energy security by:

1. Reducing dependence on fossil fuel imports
2. Enabling local storage of renewable energy
3. Providing flexible energy supply during peak demand

For regions with mature oil and gas infrastructure, co-storage offers an opportunity to:

- Repurpose existing assets
- Preserve jobs in the energy sector
- Support economic diversification

This is particularly relevant for countries transitioning from hydrocarbon-based economies to low-carbon energy systems (Ashworth et al., 2012).

8. Case Studies and Field Demonstrations

Gaining practical experience at the field level is crucial for confirming the technical viability of hydrogen–CO_2 co-storage strategies. Although fully integrated co-storage initiatives are still in development, there is a wealth of operational data from CO_2 storage projects (CCS) and underground gas/hydrogen storage (UGS/UHS). These real-world examples offer valuable insights into reservoir dynamics, injectivity, containment, and long-term performance in conditions similar to those of co-storage systems (Alizadeh et al., 2024; Ashworth et al., 2012). For many years, mature reservoirs, especially depleted oil and gas fields and deep saline aquifers, have been effectively utilized for natural gas storage and, more recently, for CO_2 sequestration. These projects illustrate that:

- Subsurface formations can safely store large fluid volumes over long periods
- Caprock integrity can be maintained under controlled pressure conditions
- Monitoring technologies can effectively track plume migration
- Well integrity is a critical factor in long-term containment

While large-scale experience with hydrogen is still somewhat limited, it is expanding. Historical use of "town gas" and contemporary pilot initiatives demonstrate that hydrogen can be cyclically stored in porous reservoirs, albeit with additional challenges such as diffusion, microbial activity, and maintaining gas purity (IEA, 2023; Lan & Yao, 2022). This chapter examines specific field demonstrations to offer practical evidence supporting the feasibility of co-storage, with a focus on:

- Mature field retrofits for gas storage
- Performance comparison between reservoir types
- Lessons learned from CCS and hydrogen storage pilots

8.1.Selected Example of Mature Field Retrofits for Gas Storage

Due to their established containment capabilities, known geological characteristics, and existing infrastructure, mature oil and gas reservoirs have been extensively converted for subsurface storage. Large-scale projects, especially those involving CO_2 storage and underground gas storage, offer essential real-world data supporting the practicality of hydrogen–CO_2 co-storage systems. This section examines significant examples, providing quantitative operational data.

8.1.1. Sleipner CO_2 Storage Project (North Sea, Norway)

The Sleipner CO_2 Storage Project is the world's first commercial-scale CO_2 storage operation, initiated in 1996 by Equinor.

Key Data:

- Injection rate: **~1 Mt CO_2/year**
- Total stored (2024): **>20 Mt CO_2**
- Reservoir type: **Saline aquifer (Utsira Formation)**
- Depth: ~**800–1000 m**
- Storage mechanism: Structural, residual, solubility trapping

Time-lapse (4D) seismic monitoring has shown stable plume evolution with no evidence of leakage over nearly three decades as shown in figure (8.1.1) (Ashworth et al., 2012).

Key relevance to co-storage:

- Demonstrates long-term CO_2 containment
- Validates seismic monitoring techniques
- Shows pressure can be managed safely in large aquifers

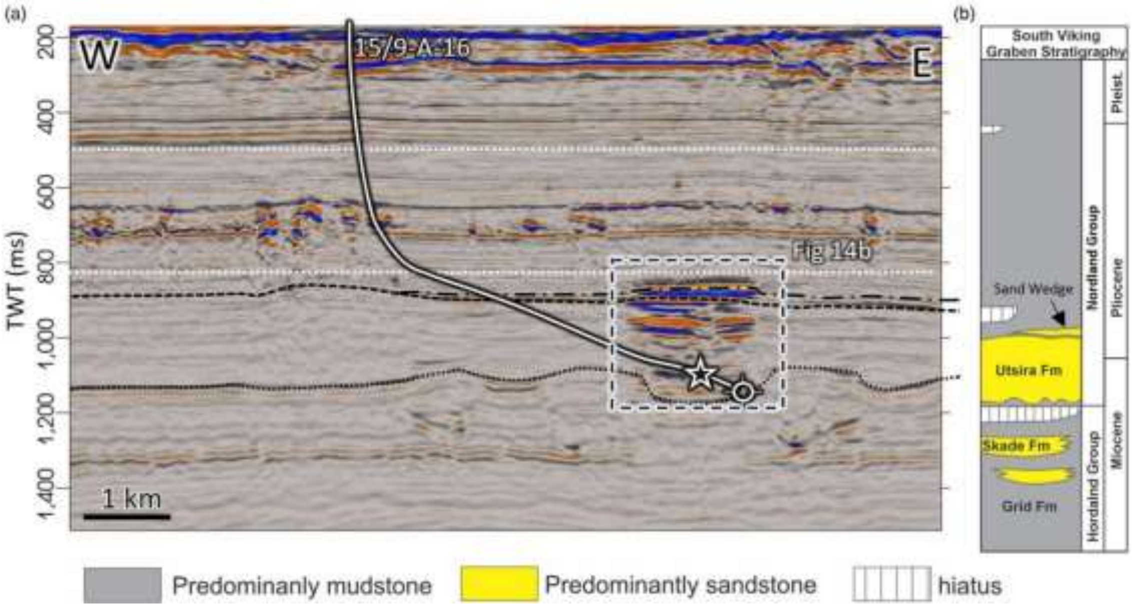

*Figure 8.1.1. (a) Seismic crossline section through the injection point from the 2020 seismic monitor survey.Refer to for location. Red/yellow amplitudes correspond to a decrease in acoustic impedance (a soft response). The injection well path is outlined in white, including a star indicating perforation interval. (**b**) Formation stratigraphy in the area near the CO_2 injection,* Source (Furre et al., 2024)

8.1.2. In Salah CO_2 Storage Project

The In Salah CO_2 Storage Project (2004–2011) provides critical insights into geomechanical behavior under injection.

Key Data:

- Injection rate: **~1 Mt CO_2/year**
- Total injected: **~3.8 Mt CO_2**
- Reservoir type: **Depleted gas reservoir**
- Depth: **~1800–1900 m**
- Observed uplift: **up to 5 mm/year**

Injection led to measurable surface deformation, indicating pressure buildup and fracture-related flow, but no major leakage occurred (IEA, 2023; Alizadeh et al., 2024).

Key relevance:

- Demonstrates the importance of pressure management
- Highlights geomechanical risks such as: fracture activation
- Validates InSAR as a monitoring tool, as shown in figure (8.1.2)

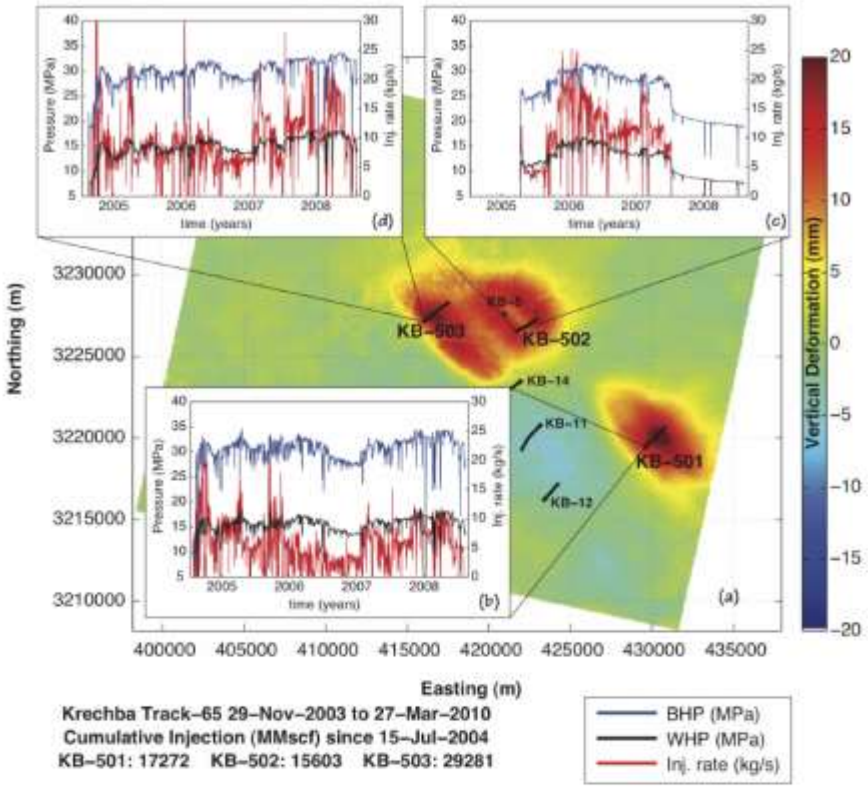

Figure 8.1.2. 1InSAR and injection data at In Salah. (a) Uplift measured by InSAR from Nov. 2003 to Mar. 2010 (courtesy of MDA/Pinnacle Technologies). (b,c,d) Measured injection rate (red line) and wellhead pressure (black line), and calculated bottomhole pressure (blue line) at the three injection wells (KB-501, KB-502, and KB-503), Source (Rinaldi et al., 2014).

8.1.3. Depleted Gas Reservoir Storage (Europe & USA)

Depleted gas reservoirs have been used for underground gas storage for decades, providing strong analogues for hydrogen storage.

Example: European UGS Fields

- Working gas capacity: **0.5–5 bcm per field**
- Depth: **500–3000 m**
- Cycle frequency: Seasonal (1–2 cycles/year)
- Recovery efficiency: **70–90% (natural gas)**

These reservoirs demonstrate:

- High deliverability
- Reliable cyclic operation

8.1.4. Hydrogen Storage Pilots (Europe)

Example: HyStock Hydrogen Storage Pilot

- Storage type: Porous reservoir (pilot-scale)
- Hydrogen injection tests: ongoing
- Objective: Validate hydrogen behavior in subsurface

Example: Underground Sun Storage Project

- Hydrogen injection into depleted gas reservoir as illustrated in figure (8.1.4)
- Focus: Hydrogen recovery and microbial effects
- Key finding: Hydrogen recovery >80% in controlled conditions

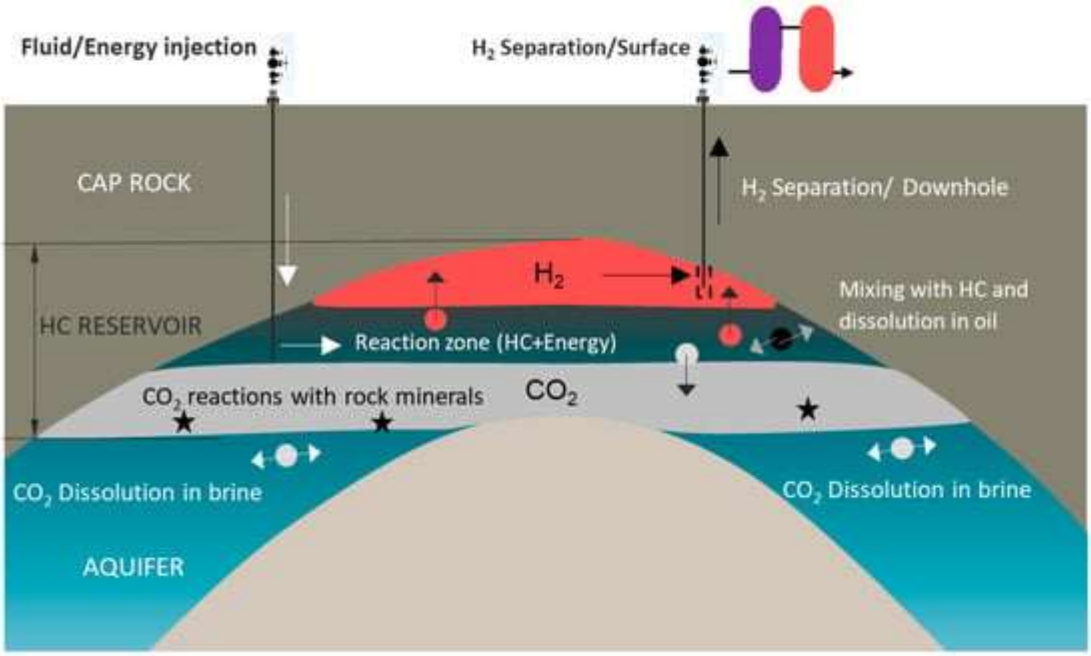

Figure 8.1.4. Schematic description of the H2 production from the depleted hydrocarbon reservoirs (HC for hydrocarbons), source (Alkan et al., 2024).

8.2.Comparative Performance of Depleted Oil/Gas Reservoirs vs. Aquifer Systems

Choosing an appropriate storage formation is crucial for assessing the effectiveness, safety, and cost-efficiency of hydrogen–CO_2 co-storage systems. The two primary geological storage options under consideration are depleted oil and gas reservoirs and deep saline aquifers, each offering unique benefits and drawbacks regarding injectivity, storage capacity, containment, and operational flexibility.

8.2.1. Storage Capacity and Availability

Deep saline aquifers present the greatest potential for global storage, with CO_2 storage capacities estimated to exceed 10,000 Gt worldwide, far outstripping those of depleted hydrocarbon reservoirs (Lan & Yao, 2022). For instance, the Utsira Formation alone is believed to have the capacity to store hundreds of millions of tonnes of CO_2. In comparison, depleted oil and gas reservoirs offer more limited but clearly defined storage capacities, generally falling within the range of:

- **0.1 to 10 bcm (gas equivalent)** per field
- Storage volumes constrained by the original hydrocarbon in place

However, these reservoirs benefit from:

1. Proven trap integrity
2. Known structural closure
3. Existing pressure and production data

8.2.2. Injectivity and Pressure Behavior

Injectivity—the ability to introduce fluids into the formation—is a key performance parameter.

Depleted Reservoirs:

- Initially exhibit high injectivity due to pressure depletion
- Re-pressurization may restore near-original conditions
- Pressure behavior is predictable due to production history

Aquifers:

- Injectivity depends on permeability and pressure dissipation
- Pressure buildup may be significant due to limited fluid withdrawal
- Requires careful pressure management to avoid fracture risk

8.2.3. Gas Recovery Efficiency

Recovery efficiency is particularly important for hydrogen storage due to its economic value.

Depleted Reservoirs:

- Recovery efficiency: **70–90%**
- Hydrogen pilots report **~60–85% recovery**
- Structural trapping supports controlled withdrawal

Aquifers:

- Recovery efficiency typically lower: **30–60%**
- Significant gas loss due to:
  - Residual trapping
  - Dissolution (especially CO_2)
  - Large plume dispersion

Hydrogen recovery in aquifers is especially challenging due to:

A. High diffusion rates
B. Buoyant migration
C. Limited structural confinement (Ashworth et al., 2012).

8.2.4. Containment and Leakage Risk

Depleted Reservoirs:

- Proven caprock integrity
- Known fault and well infrastructure
- Main risk: legacy wells

Aquifers:

- Less characterized structures
- Larger spatial extent led to higher uncertainty
- Pressure buildup may increase fault reactivation risk

However, aquifers benefit from:

- Multiple trapping mechanisms:
  - Structural
  - Residual

  - Solubility
  - Mineral trapping

8.2.5. Suitability for Hydrogen–CO_2 Co-Storage

Depleted Reservoirs:

- ✓ Controlled geometry and known properties
- ✓ High recovery efficiency which is critical for hydrogen storage
- ✓ Existing infrastructure reduces cost
- ✓ Suitable for cyclic operations

Aquifers:

- Large storage capacity
- Strong long-term CO_2 trapping
- Less suitable for hydrogen recovery

8.3. Lessons Learned from CO_2 Storage Pilots and H_2 Storage Tests

Field demonstrations and pilot-scale studies offer essential insights into the practical difficulties and operational limitations associated with subsurface gas storage. While hydrogen–CO_2 co-storage systems are still in their infancy, the extensive experience gained from carbon capture and storage (CCS) projects and underground hydrogen storage (UHS) pilots provides valuable lessons that can be directly applied to the design, risk management, and long-term performance evaluation of co-storage systems.

8.3.1. Pressure Management is Critical for Integrity

Pressure management has consistently emerged as the key element in ensuring the safety of CO_2 storage projects. At the In Salah CO_2 Storage Project, the increase in pressure caused by injection resulted in:

- Measurable surface uplift of approximately 5 mm/year
- Fracture-related flow pathways
- Increased risk of fault reactivation

Although no major leakage occurred, the project demonstrated that:

- ✓ Even moderate pressure increases can affect geomechanical stability as shown in figure (8.3.1)
- ✓ Caprock deformation can occur without visible leakage

- ✓ Safe operation requires maintaining pressure below fracture limits

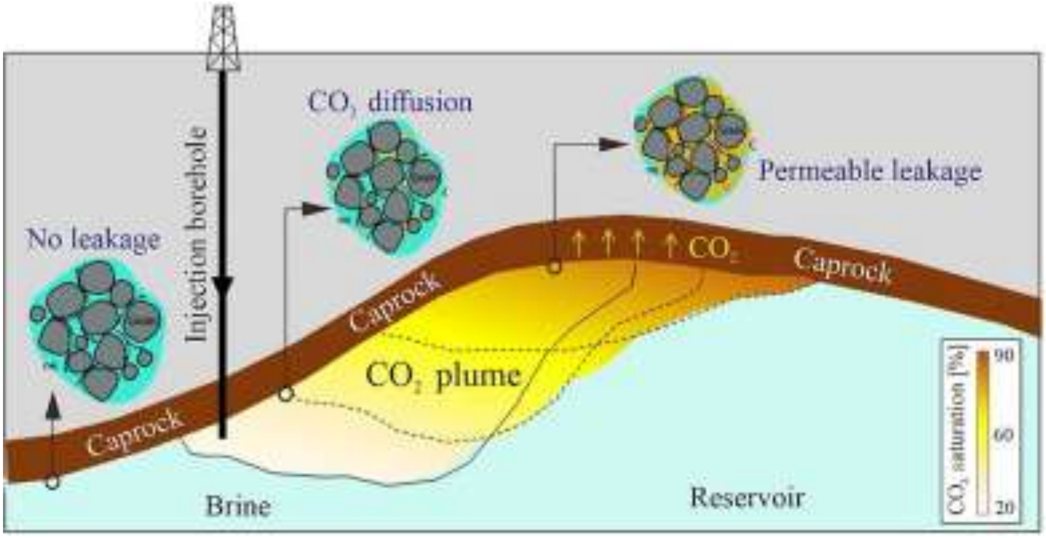

Figure 8.3.1. Conceptual illustration of pressure-induced geomechanical effects, including reduction in effective stress, fault reactivation, and caprock deformation during subsurface gas injection, source (Chen et al., 2024).

8.3.2. Monitoring Systems are Essential for Risk Detection

CO_2 storage projects have demonstrated that multi-scale monitoring systems are essential for ensuring containment. At the Sleipner CO_2 Storage Project:

- 4D seismic monitoring tracked plume migration over decades
- No leakage detected after >20 Mt CO_2 injected
- High-resolution imaging confirmed vertical containment

At In Salah:

- o InSAR satellite monitoring detected surface deformation as shown in figure (8.3.2)
- o Provided early indication of pressure buildup

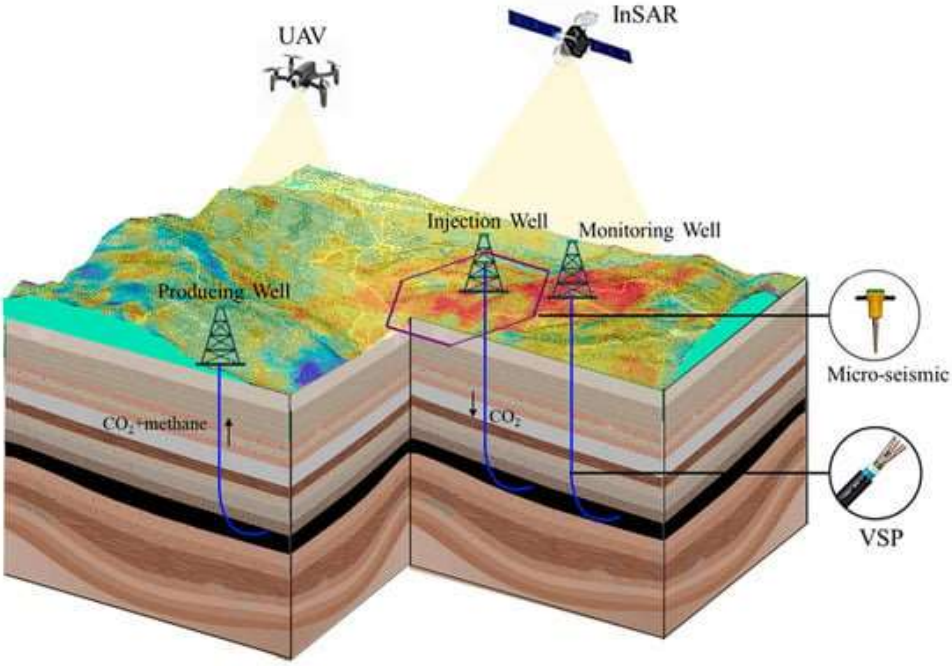

Figure 8.3.2. Schematic representation of hydrogen loss mechanisms in subsurface storage, including diffusion, microbial consumption, and gas contamination processes, source (Kamiab Kahzadvand et al., 2024).

8.3.3. Hydrogen-Specific Challenges: Losses and Purity

Hydrogen storage pilots reveal challenges not observed in CO_2 systems. Key Observations:

- Hydrogen recovery efficiency: ~60–85%
- Loss mechanisms:
    - Diffusion into surrounding formations
    - Microbial consumption (methanogenesis, sulfate reduction)
        - ✓ Gas contamination:
    - CH_4, H_2S formation

For example, in European hydrogen pilot projects:

A. Hydrogen losses were linked to biogeochemical reactions as shown in figure (8.3.3)
B. Gas quality degradation required surface treatment

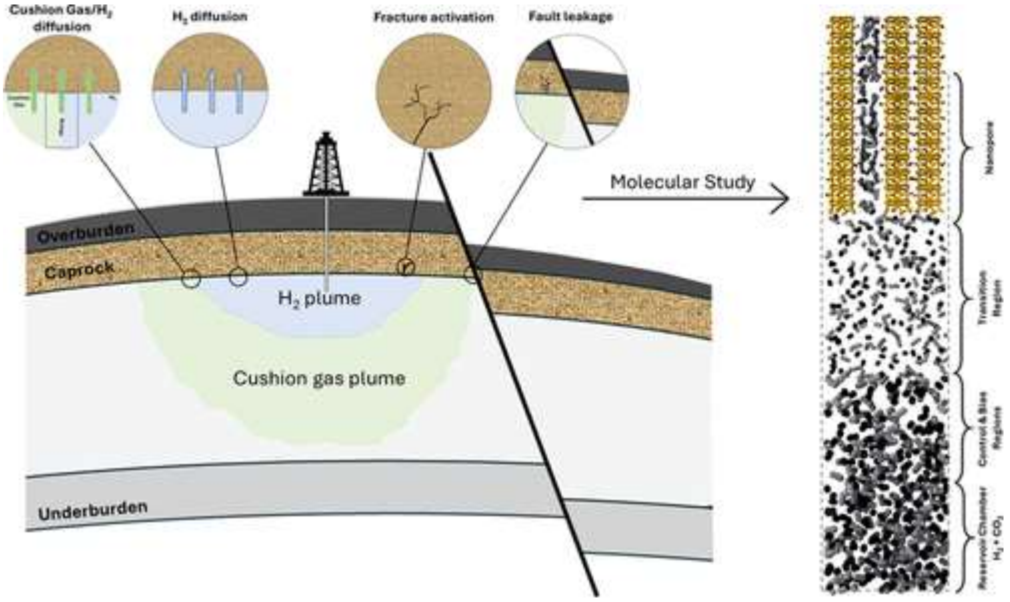

Figure 8.3.3. Schematic representation of hydrogen loss mechanisms in subsurface storage, including diffusion, microbial consumption, and gas contamination processes, source (Kamiab Kahzadvand et al., 2024).

8.3.4. Importance of Well Integrity and Legacy Infrastructure

Experience from CCS and gas storage shows that wells are the most critical leakage pathways.

Key findings:

- Poorly abandoned wells dominate leakage risk
- Cement degradation and micro-annulus formation are common issues
- Cyclic loading can accelerate:
  - Cement debonding
  - Casing deformation

For hydrogen storage:

Risk is amplified due to:

- High diffusivity
- Small molecular size
  - Even micro-scale defects can allow leakage as shown in figure (8.3.4)

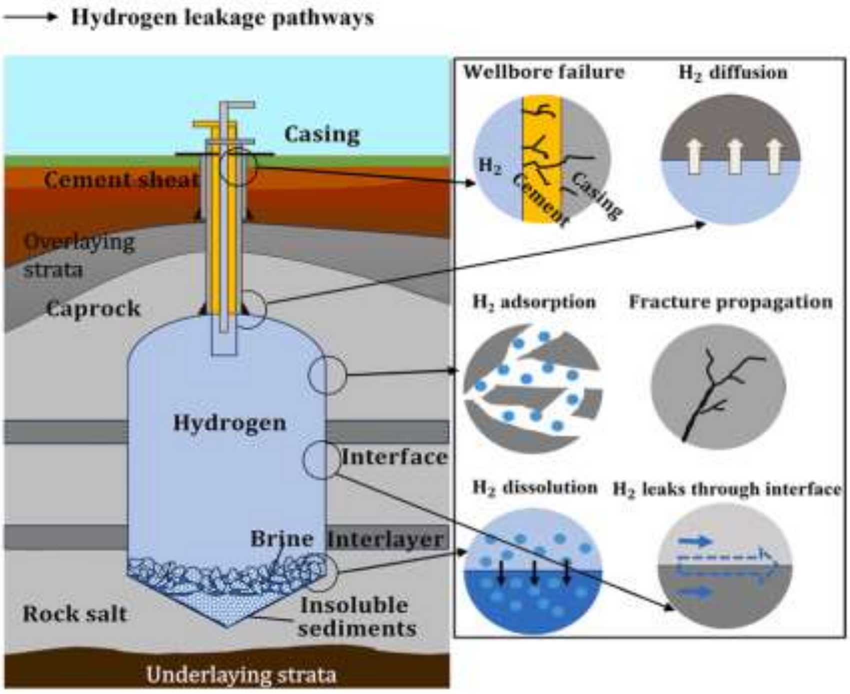

Figure 8.3.4. Hydrogen leakage pathways in salt caverns include wellbore failure, hydrogen diffusion, adsorption and dissolution, interlayer leakage, and fracture propagation, source (Qian et al., 2025).

8.3.5. Role of Geochemistry and Self-Sealing

CO_2 storage projects demonstrate that geochemical reactions can enhance containment through self-sealing mechanisms as shown in figure (8.3.5):

- Carbonate precipitation reduces fracture permeability
- Mineral reactions can stabilize leakage pathways

However:

  - Near-well precipitation may reduce injectivity
  - Hydrogen does not contribute significantly to self-sealing

Thus, in co-storage:

- ✓ CO_2 may enhance sealing
- ✓ Hydrogen relies more on mechanical and capillary trapping

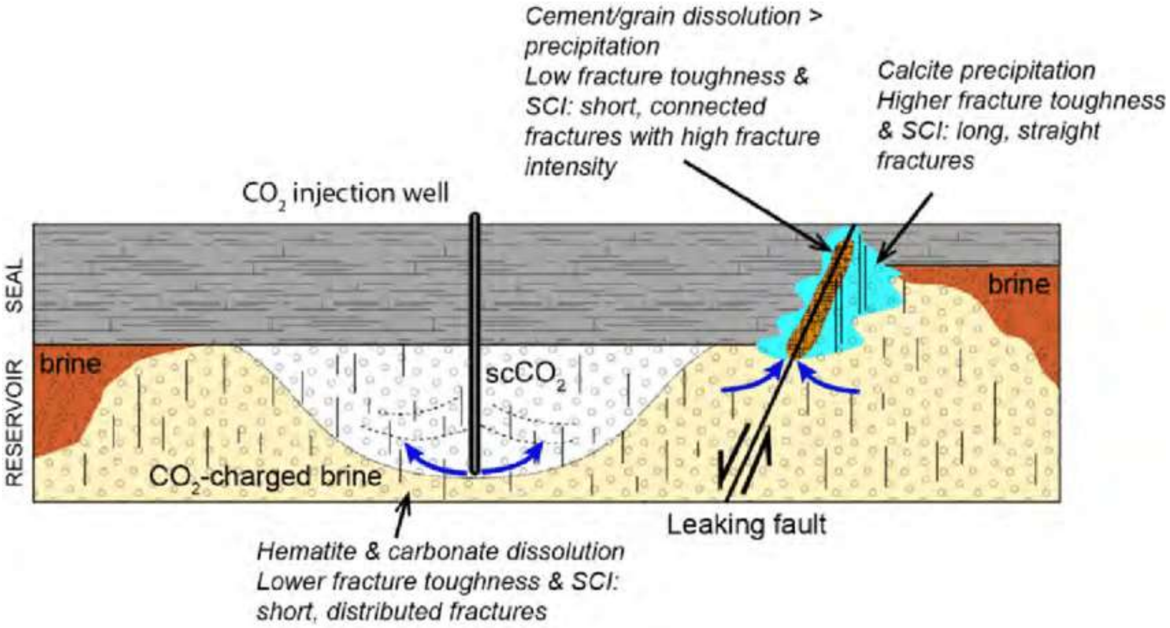

Figure 8.3.5. Schematic diagram showing possible distribution of fracture mechanical properties in a CO2 reservoir and overlying top seals and their impact on fracture patterns owing to long-term CO2-related alteration in the subsurface. The figure is schematic and not to scale. Fracture orientation is shown for a normal-faulting stress regime and would vary with stress conditions, Source (Major, Jonathan, 2018).

9. Outlook and Future Research Directions

The advancement of hydrogen–CO_2 co-storage in established reservoirs offers a promising approach to combining clean energy storage with carbon management. Although earlier chapters have shown the technical viability of these systems, their large-scale implementation is still hindered by technological, scientific, and regulatory obstacles. This chapter highlights essential research directions and future opportunities necessary to move co-storage systems toward commercial application.

9.1.Technological Challenges and Knowledge Gaps

Despite rapid progress in subsurface energy storage, several critical uncertainties remain in hydrogen–CO_2 co-storage systems. Key Knowledge Gaps:

- **Hydrogen behavior in porous media**

Hydrogen exhibits unique properties (low density, high diffusivity) that are not fully captured by conventional reservoir models developed for hydrocarbons or CO_2 (Qian et al., 2025).

- **Multiphase flow and mixing behavior**

Accurate modeling of H_2–CO_2–brine systems remain challenging due to:

  - Limited experimental data
  - Uncertain relative permeability relationships

  - Incomplete understanding of hysteresis effects
- **Geochemical interactions under co-storage conditions**

While CO_2 geochemistry is well studied, the role of hydrogen in:

- Redox reactions
- Microbial processes
- Long-term mineral evolution remains insufficiently understood (Watson & Bachu, 2009).
- **Cyclic geomechanical effects**

Repeated injection and withdrawal introduce:

  - ✓ Stress ratcheting
  - ✓ Fatigue in rock and wellbore systems
  - ✓ Long-term deformation risks

9.2.Emerging Materials and Subsurface Engineering Solutions

To address current limitations, research is increasingly focused on advanced materials and engineered solutions that enhance storage performance and safety (Zhang et al., 2022; Major, 2018).

Emerging Technologies:

- Advanced wellbore materials
  - Hydrogen-resistant steels
  - Improved cement formulations
  - Self-healing cements
- **Engineered sealing materials**
  - Nanoparticle-enhanced sealing agents
  - Reactive barriers for leakage mitigation
- **Reservoir engineering innovations**
  - Cushion gas optimization (CO_2 as stabilizer)
  - Smart injection strategies (pressure cycling control)
  - Multi-well injection–withdrawal systems
- **Digital and simulation tools**
  - Coupled THMC modeling
  - AI-based reservoir optimization
  - Real-time monitoring integration

9.3.Integration with Renewable Energy Systems

Hydrogen storage is closely linked to the global transition toward renewable energy systems. Key Integration Pathways:

- **Power-to-Hydrogen (P2H) systems**
    - Excess renewable electricity used for hydrogen production
    - Subsurface storage balances supply and demand
- **Seasonal energy storage**
    - Hydrogen stored during periods of excess generation
    - Withdrawn during peak demand
- **Carbon management integration**
    - CO_2 storage combined with hydrogen energy systems
    - Enables negative-emission energy cycles
- **Hybrid energy systems**
- Integration with:
    - Wind farms
    - Solar power plants
    - Industrial carbon capture

9.4.Policy, Governance, and Public Acceptance

The large-scale deployment of co-storage systems is not only a technical challenge but also a policy and societal issue. Key Considerations:

- **Regulatory frameworks**
    - Existing CCS regulations can be adapted
    - Hydrogen-specific standards are still evolving
- **Safety and risk management**
    - Public concerns related to:
        - ❖ Leakage
        - ❖ Induced seismicity
        - ❖ Environmental impacts
- **Economic incentives**
    - Carbon pricing and credits
    - Hydrogen market development
    - Government subsidies

- **Public acceptance**
    - Requires:
        - ❖ Transparency
        - ❖ Monitoring data disclosure
        - ❖ Community engagement

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Appendices

Appendix A – Reservoir Screening Criteria for H_2–CO_2 Co-Storage

Successful hydrogen (H_2) and carbon dioxide (CO_2) co-storage in mature reservoirs requires careful reservoir screening and site selection. Suitable reservoirs must have the right geological, petrophysical, geomechanical, and operational traits for storage capacity, injectivity, containment, and stability.

Depleted oil and gas reservoirs are ideal due to proven trapping mechanisms, geological data, and infrastructure. However, not all mature reservoirs suit co-storage. Critical parameters must be evaluated for underground hydrogen and CO_2 storage.

Key criteria include reservoir depth, porosity, permeability, caprock integrity, pressure history, fault stability, wellbore condition, and geochemical compatibility. Depth is crucial since CO_2 is a dense supercritical fluid below 800 m, enhancing storage and reducing buoyancy. High porosity and permeability ensure storage capacity and injectivity, while caprock integrity prevents leakage.

The reservoir should have stable geomechanical history with minimal fault reactivation risk during cyclic operations. Existing wells need evaluation as legacy wells may leak if cement degrades, corrodes, or hydrogen embrittlement occurs. Geochemical compatibility among reservoir minerals, brine, hydrogen, and CO_2 is vital to avoid reactions affecting porosity, permeability, or storage integrity.

Table A.1. Reservoir Screening Criteria for H_2–CO_2 Co-Storage

Parameter	**Preferred Condition**	**Importance**
Reservoir Depth	> 800 m	Maintains supercritical CO_2 conditions and improves storage efficiency
Porosity	> 15%	Provides adequate storage capacity
Permeability	Moderate to High	Improves injectivity and gas deliverability
Caprock Integrity	Strong, low permeability	Prevents upward gas migration and leakage
Reservoir Type	Depleted gas or oil reservoir	Proven containment and available infrastructure
Pressure History	Well-documented and stable	Supports safe pressure management

Fault Stability	Minimal fault reactivation risk	Reduces leakage potential
Well Integrity	Good cement and casing condition	Prevents leakage through legacy wells
Geochemical Compatibility	Stable rock–fluid interactions	Minimizes harmful reactions and corrosion
Reservoir Temperature	Moderate to high	Influences gas behavior and microbial activity
Infrastructure Availability	Existing wells and facilities	Reduces development costs
Monitoring Capability	Adequate surveillance systems	Ensures operational safety and risk management

Appendix B – Physical Properties of H_2 and CO_2

Table B.1. illustrates a comparative summary of the main physical properties of hydrogen (H_2) and carbon dioxide (CO_2) relevant to subsurface co-storage applications.

Property	**Hydrogen (H_2)**	**Carbon Dioxide (CO_2)**	**Importance in Co-Storage**
Molecular Weight	2 g/mol	44 g/mol	Influences density, diffusion, and mobility
Density	Very low	High	Controls buoyancy and vertical segregation
Viscosity	Very low	Moderate	Affects injectivity and fluid flow behavior
Solubility in Brine	Low	High	Influences solubility trapping mechanisms
Diffusivity	High	Moderate	Controls mixing and gas migration
Compressibility	High	Moderate	Affects storage pressure response
Critical Temperature	Very low	31.1 °C	Determines phase behavior underground
Critical Pressure	Low	7.38 MPa	Important for supercritical conditions

Phase Under Reservoir Conditions	Gas	Supercritical fluid / dense phase	Influences storage efficiency
Buoyancy	Very high	Moderate	Controls upward migration tendency
Relative Permeability Behavior	Strong hysteresis	Moderate hysteresis	Impacts cyclic injection and recovery
Wettability Behavior	Strongly non-wetting	Intermediate-wet	Influences capillary trapping
Capillary Trapping Efficiency	Moderate	High	Affects long-term immobilization
Mobility	Very high	Moderate	Influences sweep efficiency and leakage risk
Reactivity with Minerals	Generally low	Moderate to high	Controls geochemical alteration
Corrosive Potential	Indirect via embrittlement	Acidic in brine	Affects well and facility integrity
Microbial Interaction Potential	High	Moderate	Influences gas quality and losses
Leakage Risk	Higher due to low density	Lower due to trapping mechanisms	Impacts monitoring requirements
Cushion Gas Potential	Possible	Commonly used	Supports pressure management
Trapping Mechanisms	Structural and residual trapping	Structural, residual, solubility, and mineral trapping	Determines long-term containment
Geomechanical Impact	Cyclic pressure loading	Long-term pressure buildup	Affects fault stability and caprock integrity
Economic Role	Energy carrier	Emission mitigation	Supports energy transition goals

Appendix C – Risk Assessment Tables

Table C.1. Major Risks and Mitigation Strategies for H_2–CO_2 Co-Storage Systems.

Risk Category	Potential Cause	Possible Impact	Mitigation Strategy
Fault Reactivation	Excessive reservoir pressure increase	Leakage through faults and fractures	Maintain injection pressure below fracture gradient; continuous pressure monitoring
Caprock Failure	High pore pressure and cyclic loading	Upward gas migration	Conservative pressure management and geomechanical assessment
Wellbore Leakage	Cement degradation, poor casing integrity	Gas escape through legacy wells	Well integrity testing, cement remediation, casing replacement
Hydrogen Embrittlement	Interaction of H_2 with steel materials	Mechanical weakening of wells and pipelines	Use hydrogen-resistant materials and coatings
CO_2-Induced Corrosion	Carbonic acid formation in brine	Corrosion of tubing and facilities	Corrosion-resistant alloys and chemical inhibitors
Gas Mixing and Contamination	Diffusion and reservoir heterogeneity	Reduced hydrogen purity during production	Reservoir simulation and optimized injection strategy
Hydrogen Loss	Microbial consumption and diffusion	Reduction in recoverable H_2 volume	Reservoir screening and microbial monitoring
H_2S Generation	Sulfate-reducing microbial activity	Toxic gas production and corrosion	Biochemical monitoring and gas treatment systems
Reservoir Overpressure	Excessive injection rate	Caprock damage and induced fractures	Pressure control and injection optimization
Induced Seismicity	Stress redistribution and fault slip	Ground vibration and integrity loss	Microseismic monitoring and controlled injection operations

Fracture Propagation	Cyclic stress loading	Increased leakage pathways	Geomechanical modeling and operational limits
Lateral Gas Migration	Poor structural closure	Gas movement outside storage zone	Careful reservoir selection and monitoring
Capillary Leakage	Low capillary entry pressure	Gradual upward gas migration	Caprock characterization and seal evaluation
Diffusive Leakage	Molecular diffusion through caprock	Long-term gas loss	Thick low-permeability caprock selection
Microbial Growth	Favorable temperature and salinity conditions	Bioclogging and gas quality alteration	Reservoir characterization and microbial control
Mineral Dissolution	Acidic CO_2-rich brine reactions	Porosity and permeability alteration	Geochemical modeling and mineralogical analysis
Secondary Mineral Precipitation	Geochemical reactions	Injectivity reduction and pore blockage	Reactive transport analysis and monitoring
Surface Facility Failure	Equipment malfunction	Operational shutdown and safety hazards	Routine inspection and maintenance programs
Pipeline Leakage	Corrosion or mechanical damage	Environmental and safety risks	Leak detection systems and corrosion protection
Groundwater Contamination	Leakage into shallow aquifers	Environmental damage	Monitoring wells and containment verification
Pressure Cycling Fatigue	Repeated H_2 injection and withdrawal	Mechanical weakening of reservoir and wells	Limit cycling frequency and pressure amplitude
Uncertain Reservoir Heterogeneity	Incomplete subsurface characterization	Unpredictable gas migration	Detailed geological and seismic analysis
Monitoring Failure	Insufficient surveillance systems	Delayed leakage detection	Integrated monitoring technologies and redundancy

Economic Uncertainty	High operational and remediation costs	Reduced project feasibility	Techno-economic assessment and phased implementation
Regulatory and Legal Challenges	Lack of co-storage regulations	Project delays and compliance risks	Regulatory engagement and risk documentation
Public Acceptance Issues	Environmental and safety concerns	Delayed deployment	Public communication and transparency programs