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A COMPARATIVE NARRATIVE REVIEW OF GEOLOGICAL RISK ASSESSMENT OF HYDROGEN AND CO_2 IN DEPLETED RESERVOIRS IN THE UNITED STATES

Laura Enam Anyomi [1,*], Worlanyo Kweku Ablordeppey [2] and Abass Aliu [3]

[1] University of Ghana, Legon-Accra.
[2] Oklahoma State University.
[3] University of Development Studies, Tamale.
* Corresponding Author

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ABSTRACT

Depleted oil and gas reservoirs are increasingly considered for carbon dioxide (CO2) sequestration and large-scale hydrogen (H2) storage, due to their established geological characterization, infrastructure, and capacity to retain hydrocarbons. However, storage strategies developed for CO2 are being applied to H2 without sufficient accounting for their physical, geochemical, and microbiological behaviors. This creates uncertainty about whether depleted U.S reservoirs can safely support both decarbonization pathways. A narrative comparative review was conducted to synthesize evidence on fluid behavior, trapping mechanisms, reservoir suitability, risk factors, and monitoring for both gases. Covering fluid behavior, trapping mechanisms, reservoir suitability, risk factors, and monitoring for both gases. The findings show that H_2 is considerably less dense and more diffusive than supercritical CO_2, making it more buoyant, prone to migration through microfractures and legacy wells. Unlike CO_2, which can utilize multiple trapping mechanisms, H_2 primarily remains in the gas phase and depends heavily on structural containment. Its storage performance may also be affected by microbial activity and mineral reactions that could form methane or hydrogen sulfide. Hence, H_2 storage requires more stringent evaluation of caprock, fault, and wellbore integrity, alongside specific hydrogen sensing systems. It is concluded that depleted reservoirs in U.S. may support both applications, but reliable H_2 storage requires tailored site selection, monitoring, and risk management frameworks, which are significant to guide safer project design, limit leakage and gas losses, inform hydrogen-specific regulation and commercial use.

Keywords: Caprock Integrity, Fluid Properties, Underground Hydrogen System, Monitoring, Basin

1 INTRODUCTION

Decarbonizing the global energy system requires a massive expansion of subsurface carbon capture, utilization, and storage. The International Energy Agency (IEA) projects that annual CO_2 storage must grow from only a few tens of megatons today to several gigatons by mid-century to meet climate goals (Zhu et al., 2025). At the same time, hydrogen is rapidly emerging as a major clean energy carrier. Large-scale hydrogen is being pursued worldwide to store intermittent renewables and decarbonize industry. In many countries, governments are developing hydrogen infrastructure and storage strategies to ensure grid reliability and cut emissions (Muhammed et al., 2023).

However, the use of hydrogen as a fuel source requires large-scale storage to balance future demand discrepancies (Ma et al., 2024). Geological formations such as depleted oil and gas reservoirs, salt caverns, and saline aquifers have long been used for natural gas storage (Fig.1) (Uliasz-Misiak & Misiak, 2024). These formations are proven storage assets, having supported decades of hydrocarbon production, capable of holding large volumes of gas, and with proven sealing capacity (Maury Fernandez et al., 2024). Typically, depleted oil and gas reservoirs are widely distributed across regions in the United States and possess existing surface facilities, pipelines, and drilling data that could be assessed to explore hydrogen storage. The residual hydrocarbons left in such reservoirs also act as a natural cushion gas, reducing the amount of injected gas needed for pressure support (Muhammed et al., 2023). Simply put, depleted fields offer shared infrastructure that could serve both carbon dioxide sequestration and hydrogen storage.

Nonetheless, the subsurface behavior of H_2 differs markedly from CO_2. Carbon dioxide injection for permanent sequestration is intended to trap the gas indefinitely (often aided by dissolution into brine and mineralization) (Yakin et al., 2025). Hydrogen storage is a temporary, cyclical process aimed at later retrieval. Critically, hydrogen is much lighter and more diffusive than CO_2, which can undermine simple technology transfer (Massarweh & Abushaikha, 2024). Review studies highlight that existing Carbon Capture and Sequestration (CCS) practices may not directly apply to hydrogen due to differences in their physical and chemical properties (Maury Fernandez et al., 2024). Hydrogen plumes remain largely in the gas phase and are highly buoyant, raising leakage concerns. In contrast, CO_2 benefits from multiple trapping modes (structural, residual, dissolution, mineral) that hydrogen lacks (Isfehani et al., 2024). Industry discussions have sometimes assumed that CO_2 and H_2 storage are analogous because they use the same reservoirs, but this assumption has not been rigorously validated (Zhong et al., 2024).

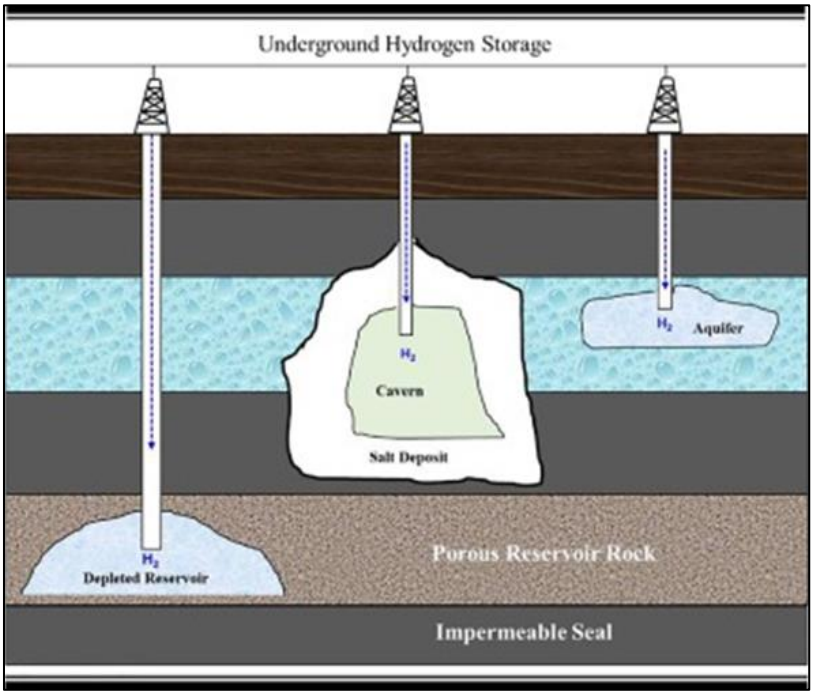


Figure 1: Schematic representation of underground hydrogen storage (Muhammed et al., 2023)

To date, most research has treated CO_2 and H_2 storage separately, without a head-to-head comparison for realistic reservoirs. This review addresses that gap by systematically evaluating the geological storage risks of hydrogen (H_2) and CO_2 under comparable conditions in U.S. depleted reservoirs. This paper adopts a comparison framework focusing on fluid properties and migration, trapping and permanence, reservoir geology, risk mechanisms (leak pathways, reactivity, mechanical failure), and monitoring strategies. The aim is to clarify which CCS insights can be transferred to hydrogen storage and where further dedicated analysis is required. This work thus provides a unified geological risk perspective. By filling the current gap in comparative analysis, this paper seeks to inform the safe development of both CO_2 sequestration and hydrogen storage.

2 METHOD

This study followed a narrative comparative review approach using transparent protocols. Searches were performed in Scopus, Web of Science, ScienceDirect, and Google Scholar with keyword combinations of “hydrogen storage”, “carbon dioxide storage”, “depleted reservoir”, “caprock integrity”, “CO_2 sequestration”, and U.S. basin names. We also consulted the reference lists of key papers. Inclusion criteria were peer-reviewed studies focusing on geological storage of

hydrogen or CO_2 in porous reservoirs, especially depleted oil/gas fields, with quantitative or qualitative data on trapping, migration, geochemistry, or monitoring. Reviews, field studies, simulations, and experiments were included if relevant to subsurface behavior or risk. The excluded were studies on salt-cavern storage, purely surface infrastructure, or non-geological hydrogen.

From the selected papers, data on fluid and rock properties, trapping percentages, reactant pathways, and monitoring methods were extracted for this study. A comparative analytical framework was applied to each topic dimension, and the results were summarized. The analysis emphasizes contrasts between H_2 high diffusivity and CO_2 high solubility and identifies knowledge gaps. The result is an interpretative synthesis that moves beyond summary to highlight trends, differences, and implications for U.S. reservoir deployment.

3 RESULTS

3.1 Fluid Properties and Subsurface Migration Behavior

In terms of fluid properties, hydrogen (H_2) largely differs from CO_2. H_2 has an exceedingly low molecular weight of 2 g/mol, yielding a density of 0.082 kg/m^3 at STP, which is approximately 40-70 kg/m^3 at typical reservoir P-T, vs. 700 kg/m^3 for supercritical CO_2 at depth (Gomez Mendez et al., 2024). It also has a low viscosity of about 9×10^{-6} Pa·s, on the order of light gases. By contrast, CO_2 with a molecular weight of 44 g/mol is nearly eight to ten times denser and more viscous under supercritical conditions (Zhong et al., 2024). These differences translate to higher buoyancy and mobility for H_2. This is observed in actual practice, where H_2 plumes injected into brine-saturated porous media ascend more rapidly; experiments and simulations show capillary fingering patterns dominated by H_2 due to its low interfacial tension and high mobility (Gomez Mendez et al., 2024; Zhong et al., 2024). For instance, Gomez Mendez et al., report that capillary fingering in H_2 brine systems causes significant H_2 residual trapping (loss) even at high capillary numbers. H_2 also requires roughly three times the pore volume to store the same energy as natural gas (or CO_2) because of its low density.

With diffusivity, H_2 is an order of magnitude greater than CO_2. This high diffusivity means H_2 will spread and mix more readily in pores, potentially escaping through microfractures that would confine CO_2. Reported diffusion coefficients are 4.3×10^{-9} m^2/s in water (at 25 °C, 0.5 MPa) and 6.5×10^{-5} m^2/s in gas mixtures (Wang et al., 2023). By comparison, dissolved CO_2 diffuses only on the order of 10^{-9} m^2/s. Misaghi Bonabi et al., found through simulation that an H_2 plume exists predominantly in the gas phase and exerts a higher pressurization on the reservoir, increasing the chance of migration to distant regions and caprock penetration. While a CO_2 plume tends to dissolve into the aquifer over time, benefiting from density-driven downward fingering which aids confinement (Misaghi Bonabi et al., 2025).

Due to the low viscosity and density of H_2 relative to connate brine, flow tends to be unstable with gravity override. Foam-like displacement, which is gravity segregation, can occur easily. CO_2 also exhibits gravity channeling, but its higher density moderates vertical segregation. Generally, H_2 behaves like an ultra-light, highly mobile gas that flows easily (high injectivity) but is harder to stop. CO_2 is more sluggish and partially soluble. These contrasts set the stage for very different migration patterns. H_2 plumes are wide and shallow, quickly reaching caprock interfaces, whereas CO_2 plumes are deeper and more diffuse with substantial brine exchange (Gomez Mendez et al., 2024).

3.2 Trapping Mechanisms and Long-Term Storage Security

CO_2 storage leverages multiple trapping mechanisms (Fig. 2). Structural trapping in anticlines or beneath seals is primary in early-stage storage. Over time, residual trapping (CO_2 ganglia retained by capillary forces) and dissolution trapping (CO_2 dissolving into formation water) sequester significant mass. Mineral trapping, also known as carbonate precipitation, occurs over timescales of years to millennia. In contrast, H_2 has negligible solubility in water (1.6×10^{-3} g/L at 25°C), so dissolved-phase trapping is essentially absent. H_2 also does not readily form stable minerals in sandstone reservoirs. Thus, underground hydrogen storage (UHS) must rely almost entirely on structural closure and capillary (residual) trapping (Misaghi Bonabi et al., 2025).

Misaghi Bonabi et al., finds that GCS benefits significantly from structural, dissolution, and residual trapping, whereas UHS relies mainly on structural trapping, making the integrity of sealing elements key. Experimental studies support this: capillary fingering in H_2 - brine cores lead to pockets of trapped H_2, indicating some residual immobilization (Gomez Mendez et al., 2024). However, much of the injected H_2 remains mobile and can return to production or escape. In practice, operators may retain a cushion gas (often methane or nitrogen) to suppress H_2 breakthrough and maintain pressure. Nonetheless, the absence of a significant dissolution buffer means H_2 has a higher inherent leakage potential.

By comparison, CO_2 increasingly dissolves over time, forming carbonic acid and diffuses into water, which effectively secures it. For instance, Zhu et al., notes that long-term CO_2 storage increasingly favors solubility and mineral trapping, which are far more secure than short-term structural traps (Zhu et al., 2025). H_2 cannot exploit these secondary traps.

Geochemical reactions also differ: CO_2 acidifies brine and dissolves carbonates, whereas H_2 tends to reduce minerals. H_2 can react with sulfide minerals to yield H_2S and with organic matter and microbes to produce CH_4 (Maury Fernandez et al., 2024). These reactions and associated byproducts can degrade the permanence of storage and complicate geochemical processes. Overall, CO_2 storage security is reinforced by self-sealing interactions, whereas H_2 storage security depends almost entirely on mechanical sealing and residual gas hold-up (Gomez Mendez et al., 2024).



Figure 2: The trapping mechanisms of CO_2 (applicable to H_2 during injection and withdrawal) (Muhammed et al., 2023)

3.3 Geological Controls and Reservoir Suitability in U.S. Basins

In addition, reservoir storage potential depends on factors like depth, pressure, temperature, porosity, permeability, heterogeneity, and caprock integrity. These criteria matter for both hydrogen and CO_2, though each gas responds differently. For example, high porosity and permeability allow higher injection rates, while a thick, impermeable caprock is needed to contain buoyant gas.

3.3.1 Permian Basin:

This region features stacked Permian-age sandstone reservoirs (e.g., Delaware and Midland sub-basins) sealed by thick evaporite layers. It has a very high geothermal gradient (80-90°C at 3 km) and a huge pore volume with existing oil/gas infrastructure. These conditions provide vast storage capacity. However, the high temperature can increase hydrogen reactivity (i.e., faster H_2S production), and multiple stacked layers with faults require careful zonal isolation to prevent gas migration between layers. Overall, the Permian offers abundant capacity, but hydrogen projects must manage thermal and chemical effects at depth (Fairhurst et al., 2021).

3.3.2 Gulf Coast:

The Gulf Coast is a mega-basin with deep sandstone aquifers (Miocene and younger) overlain by extensive salt and anhydrite caprocks. Many large CO_2 sequestration projects target this area due to its excellent seals and storage volume. The thick evaporite seals are highly impermeable to gas, which is favorable for both CO_2 and hydrogen containment. The basin has many depleted fields and salt cavern sites, meaning infrastructure and data exist (Roberts-Ashby et al., 2012). A challenge is the legacy of many old wells, which pose integrity risks for any stored gas. For hydrogen, the native brine salinity has little impact because hydrogen's solubility is inherently low, but any steel or cement degradation from hydrogen could be a concern. In general, the Gulf Coast's geology (high-capacity sands and robust seals) is advantageous, provided well integrity is managed.

3.3.3 Appalachian Basin:

This region contains numerous shallow (<2 km) depleted gas reservoirs in Paleozoic sandstones (Oriskany, Medina), with caprocks of organic-rich shale (e.g., Marcellus). Compared to the Permian and Gulf, the Appalachians have lower

pressures and cooler temperatures. The reservoirs here are often naturally fractured, and there are many legacy wells (Zagorski, 2014). These factors reduce storage security. Hydrogen stored here would undergo more frequent pressure cycling, which could reactivate small fractures or faults. Appalachian fields have moderate porosity but more complex faults and well networks, making them riskier sites. Both gases require careful fault and well screening in this basin.

3.3.4 Midcontinent (Illinois and Michigan Basins):

The Midcontinent hosts deep Cambrian-Ordovician sandstone reservoirs (e.g., Mt. Simon Sandstone and the Jordan Formation) with tight overlying shales (St. Peter and Eau Claire formations). These sandstones have been shown to have high porosity and permeability, and the overlying shales provide good seals. Many large-scale CO_2 studies target these formations, and they offer considerable storage capacity at depths of 2-3 km. The geology is relatively homogeneous, which leads to more predictable flow (Freiburg & Leetaru, 2015). For hydrogen, the Midcontinent is favorable because its mineralogy (low sulfates) may minimize H_2S generation, and proximity to Midwestern hydrogen production centers is convenient. The thick confining layers and extensive hydrocarbon infrastructure (pipelines, wells) also support potential storage.

It is described that depleted natural gas reservoirs are cost-effective, secure solutions for subsurface storage due to their proven deliverability and existing cushion gas. However, it is emphasized that individual reservoir characteristics dominate performance (Muhammed et al., 2023). A key scenario is that a reservoir's high porosity/permeability improves injectivity but also raises leakage risk if not sealed properly. Heterogeneity can trap injected CO_2 effectively but might allow hydrogen to find a pathway through small high-permeability streaks. In general, deeper and better-sealed formations (like those in the Permian and Gulf Coast) are advantageous for both gases. Conversely, basins with abundant fractures or wells (such as parts of the Appalachian) present greater challenges, especially for hydrogen.

All major U.S. basins contain candidate reservoirs for energy storage, but their suitability varies by gas. Thick salt or anhydrite seals (Permian, Gulf Coast) provide strong containment for either hydrogen or CO_2. Shallow, fractured, or heavily drilled systems (some Appalachian fields) are less secure, with hydrogen facing extra challenges due to its mobility. Ongoing pilot projects are beginning to address these basin-specific issues (ISGS, 2023), yet further study is needed to fully characterize how porosity, faulting, and rock composition affect hydrogen versus CO_2 storage in each region.

3.4 Comparative Subsurface Risk Mechanisms

Both CO_2 and H_2 storage share generic risks, including fault leakage, well integrity, and caprock breach, but H_2 introduces peculiar hazards. First, any open fracture or fault can act as a conduit. It is observed that Zhu et al., (2025) stress that an impermeable caprock is essential, as initial fractures can lead to leakage. While CO_2 leakage is governed by buoyancy-driven upward migration, the extreme buoyancy and diffusivity of hydrogen gas exacerbate this, meaning small faults that would only slowly transmit CO_2 could rapidly channel H_2. As found in this study (Misaghi Bonabi et al., 2025), the likelihood of escaping through fractures is higher for H_2 due to its mobility. Reactivated faults (from injection stress) pose parallel threats to both gases. A diagram showing the potential leakage pathway from a fracture along the wellbore is presented in Fig. 3.

The integrity of abandoned wells is also a major leakage risk that demands critical assessment. CO_2 is corrosive to steel and cement, and decades of CCS research focus on verifying cement durability (Opara, 2026). H_2 presents the complication of hydrogen embrittlement, where molecular H_2 can penetrate metal and cement pores, causing blistering and cracking (Maury Fernandez et al., 2024). The study further cautions that legacy well materials may be seriously degraded by H_2, which is not accounted for in current site screening (Maury Fernandez et al., 2024). Thus, an old CO_2-ready wellbore may fail prematurely under H_2 storage. Mitigation measures, such as re-cementing and plugging, will need to consider specific H_2 damage modes. The cementing problem associated with depleted wells is represented in Fig. 3.

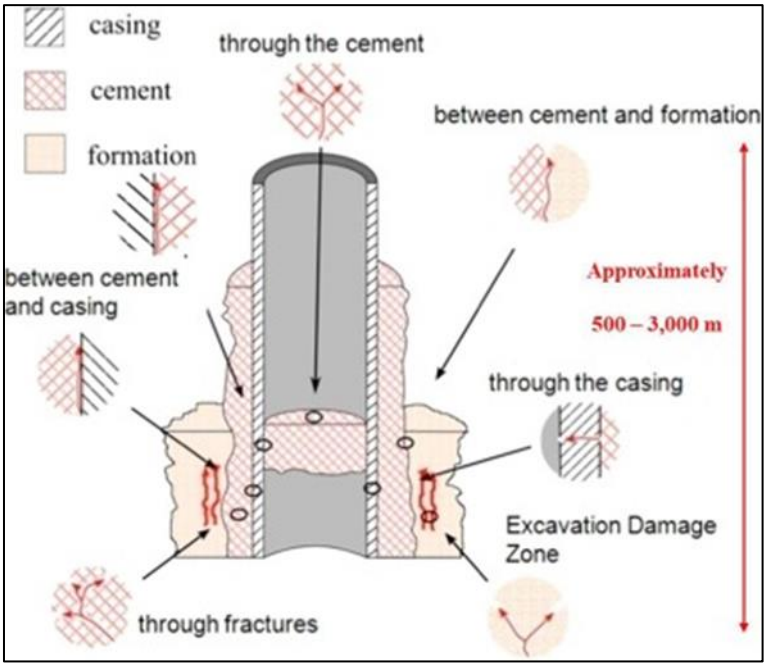


Figure 3: A schematic showing the potential leakage pathways along a wellbore (Muhammed et al., 2023)

Overpressure is another common hazard for both gases. Review studies show that injecting either gas raises reservoir pressure, risking caprock fracture (Opara et al., 2026). However, because H_2 remains in the gas phase, pressure buildup is more uniform (CO_2 partly dissolves, reducing volume). Some studies suggest H_2 injection cycles, especially rapid charge/discharge, can induce more frequent stress oscillations, potentially fatiguing the caprock. Capillary entry pressures also differ because hydrogen's lower density and higher buoyancy may challenge capillary seals more.

CO_2's geochemical influence is well-known – carbonic acid dissolves carbonates and the mineralogy changes. H_2 tends to be a reducing agent; thus, it can react with ferric iron in clays or pyrite to produce H_2S, or with carbonate-rich mudstones under reducing conditions. Studies indicate H_2 can generate H_2S and CH_4 from subsurface microbes and minerals (Gomez Mendez et al., 2024; Maury Fernandez et al., 2024). These byproducts degrade gas purity and corrode infrastructure (H_2S is toxic and corrosive). Meanwhile, CO_2 leakage can mobilize trace metals and lower pH (Opara, 2026). Both scenarios alter pore chemistry. Notably, Gomez Mendez et al., (2024) report that abiotic geochemical effects of H_2 injection on sandstone porosity are minor, but coupled biogeochemical effects (microbial biofilm formation) remain largely unknown.

Unlike CO_2 sequestration, which is typically a single or limited injection, H_2 storage is envisioned as reversible (Krevor et al., 2023; Yakin et al., 2025). Frequent injection/withdrawal cycles impose time-varying stress. This cycling may exacerbate caprock or formation fatigue (Ciotta & Tassinari, 2024). Although not yet well studied, repeated pressure swings by analogy with gas storage could reactivate minor faults or compromise the cement over long periods.

H_2 storage inherits all the CCS concerns (leaky wells, faults, caprock integrity) but with amplified severity due to its mobility and reactivity (Misaghi Bonabi et al., 2025). Microbial consumption is unique to H_2, although CO_2 can also feed methanogens; H_2 is a direct electron donor for many microbes. Monitoring must therefore focus on early detection of H_2 leaks (H_2S spikes) in addition to pressure or strain signals.

3.5 Monitoring and Leakage Detection Challenges

CO_2 sequestration has a mature toolbox of monitoring methods, including repeated seismic and gravity surveys to detect plume movement, downhole pressure and temperature logging to track reservoir changes, soil and groundwater sampling checks for surface leakage, and tracers (e.g., noble gases, CF_4) tag CO_2 plumes. Zhu et al. emphasize that a combination of geophysical (seismic, EM), geochemical (gas/fluid sampling), and even satellite (InSAR) techniques is used to find CO_2 leaks (Zhu et al., 2025).

In hydrogen storage, these methods face new challenges. The seismic velocity contrast between H_2 gas and water is very low, making time-lapse seismic of limited sensitivity to H_2 plumes (Ciotta & Tassinari, 2024; Mejida et al., 2026). Similarly, H_2 has a negligible gravitational signature, making chemical monitoring paramount. Unlike CO_2, which is measurable by gas chromatography, H_2 requires specialized sensors, such as fiber-optic H_2 sensors and electrochemical detectors to detect subsurface migration. In the U.S., existing H_2 sensors are mostly point detectors; for large storage

volumes and distributed fiber networks or gas-tracer systems are being explored (Tarkowski et al., 2021). Groundwater wells may need continuous $H_2/H_2S/CH_4$ analysis, as dissolved H_2 could precede gas leaks. Wellbore pressure/flow monitoring is critical but complicated by the bidirectional flow in cyclic operation.

The limitations of classical CCS pressure and geophysics monitoring mean H_2 storage will rely more on chemical and microbial signals. There is an unknown standardized monitoring suite that exists yet for UHS. Research is ongoing (DOE SHASTA projects) on tracer gases and novel sensors for H_2 (Tarkowski et al., 2021). In practice, operators may adapt CO_2 monitoring designs but must add specific H_2 components (e.g., hydrogen-selective fiber optics). A combined approach of periodic seismic to detect any large structural changes and continuous chemical sensing is also necessary.

Table 1: Comparative Geological Characteristics and Risk Profiles of H_2 and CO_2 Storage in Depleted U.S. Reservoirs

Parameter	CO_2 Storage	Hydrogen Storage	Geological Implication
Density (Gomez Mendez et al., 2024)	600-800 kg/m^3 (supercritical)	40-70 kg/m^3 (at reservoir P-T)	H_2 is 10 times lighter, leading to much stronger buoyancy and gravity override.
Diffusivity (in fluids) (Wang et al., 2023)	2×10^{-9} m^2/s in water; 1×10^{-4} m^2/s in gas	4.3×10^{-9} m^2/s in water; 6.5×10^{-5} m^2/s in gas	H_2 diffuses several times faster than CO_2, promoting rapid spread through pores.
Dominant Trapping Mechanisms (Misaghi Bonabi et al., 2025)	Structural, residual, dissolution, mineral	Primarily structural (and limited residual)	CO_2 benefits from multiple immobilization modes; H_2 largely depends on seal integrity and capillary hold-up.
Leakage Potential (Zhu et al., 2025)	Moderate; mitigated by dissolution and adsorption	High; small size and high mobility facilitate leaks	H_2 can escape through smaller fractures or micro-channels than CO_2.
Geochemical Reactivity (Maury Fernandez et al., 2024; Zhu et al., 2025)	Acidifies brine, dissolves minerals, precipitates carbonates	Reducing agent: can convert pyrite to H_2S, fuel microbes producing CH_4	CO_2 alters porosity via acid; H_2 may produce corrosive H_2S and consume H_2, altering gas quality.
Monitoring Maturity (Ciotta & Tassinari, 2024; Zhu et al., 2025)	Well-established (seismic, sensors, tracers)	Nascent; in development (fiber-optics, novel gas sensors)	CO_2 monitoring protocols exist; H_2 requires new tools for distributed leak detection.
Storage Security (Maury Fernandez et al., 2024; Misaghi Bonabi et al., 2025)	High (multi-trap sequestration over long-term)	Lower (single-mode trapping, greater uncertainty)	CO_2 storage benefits from redundancy; H_2 storage security is contingent on robust caprock and well integrity.
Technology Readiness (Krevor et al., 2023; Tarkowski et al., 2021)	Commercial pilot projects (e.g., U.S. CCS projects)	Early-stage (few pilots in the U.S.; mostly research)	CO_2 storage infrastructure and standards are advanced; H_2 storage methods and regulations are still evolving.

4 DISCUSSION

The comparative analysis from Table 1 underscores that hydrogen storage cannot be treated simply as an extension of CO_2 storage, despite superficial similarities of both involving injecting gas into rock pores. CO_2 is largely used for permanent sequestration, while H_2 is for cyclical energy supply. The fundamental differences in purpose and fluid behavior mean many CCS assumptions do not hold for hydrogen (Misaghi Bonabi et al., 2025; Zhong et al., 2024). For instance, the classic CO_2 risk framework presumes significant dissolution trapping over time. For H_2, this does not apply since solubility is approximately 1000 times lower (Misaghi Bonabi et al., 2025). Thus, the long-term containment assurances drawn from CO_2 monitoring must be re-evaluated for H_2.

However, some CCS protocols can partially be transferred. Site screening methods, including depth, seal thickness, and capacity, remain relevant to hydrogen storage. Operational practices such as testing well integrity and pressure monitoring are equally important for H_2. However, quantitative risk estimates differ in leakage rate and models calibrated for CO_2 (which consider diffusion and solubility) will underestimate H_2 leakage by orders of magnitude. Geochemical models must incorporate H_2 oxidation and microbial kinetics rather than CO_2 acid-base reactions. In essence, while the CCS knowledge base offers a starting point, every element, from injection design to safety assessment, requires H_2-specific adaptation. As Maury Fernandez et al. note, successful underground H_2 projects will require a "comprehensive understanding of the distinct chemical and physical properties of CO_2 and H_2" (Maury Fernandez et al., 2024).

Key trade-offs identified show that hydrogen can be injected and withdrawn rapidly due to high mobility and low viscosity, which is advantageous for daily balancing. Yet this same trait means poorer volumetric energy density (much larger volumes per MJ) and increased leak risk (Gomez Mendez et al., 2024). CO_2's high density stores more mass per volume; thus, fewer injection cycles for the same mass, but injection is slower and solidification time is longer. The storage efficiency (mass or energy stored per rock volume) favors CO_2, but operational flexibility favors H_2. Also, containment security, in contrast to throughput, is a trade-off: CO_2's multiple trapping provides inherent redundancy (structural, solubility, mineral), whereas H_2 relies on single-mode trapping, so any compromise to the seal is more severe (Heinemann et al., 2021). Hence, a reservoir with slightly compromised caprock might still hold CO_2 via dissolution but could lose H_2.

Operationally, H_2 storage implies repeated cycling stress on wells and geological formations. This impacts the fatigue life of materials and may lead to different fracture mechanics than static CO_2 injection (Krevor et al., 2023). Monitoring design must thus consider dynamic rather than static conditions. Selecting sites for H_2 will likely prioritize rock quality factors that are less critical for CO_2: for example, clay content that consumes H_2 should be minimized, and reservoirs should be far from souring bacteria. Traditional CO_2 screening focuses on capacity and injectivity, but H_2 screening must add criteria like "hydrogen affinity" of minerals and presence of H_2-consuming microbes.

Ultimately, existing CCS frameworks can guide hydrogen storage, i.e., risk models for pressure build-up, caprock evaluation techniques, but their parameters and safety factors need revision for hydrogen peculiarities (Zhong et al., 2024). Regulators and planners must account for H_2's distinct behavior: for example, the EPA's Class VI permit rules (designed for CO_2) may not fully address the well integrity issues of H_2. This comparative risk perspective review makes it clear that simply repurposing CO_2 models without modification could result in underestimating H_2 leakage and reaction hazards.

5 KNOWLEDGE GAPS AND IMPLICATIONS FOR U.S. AND GLOBAL ENERGY SYSTEMS

5.1 Knowledge Gaps

Despite the advancing rate of research in carbon capture and storage (CCS) and underground hydrogen storage (UHS), significant gaps remain in understanding subsurface hydrogen storage, especially at U.S. scales.

The performance of underground hydrogen storage varies widely by basin geology. Yet basin-specific studies such as those on the Permian vs. Illinois reservoirs are scarce. A detailed characterization of caprock sealing, depth, and mineralogy is needed for major U.S. basins.

Also, only a few pilot projects (often saline aquifers) are underway for H_2. There is a lack of pilot H_2 injections in representative depleted fields (e.g., Permian gas fields, Eastern shales). These are urgently needed to validate models, as some studies have highlighted the need for field data because injection strategy and reservoir characteristics significantly impact storage performance.

There is presently no consensus on best practices for H_2 monitoring. Commercial H_2 sensors exist, but they mostly detect point leaks. Distributed fiber-optic H_2 detectors and soil gas grids for wide-area subsurface sensing are still at an early research stage, and techniques for distinguishing small H_2 leaks from background using tracer gases are also underdeveloped.

Additionally, how H_2 injection alters rock mechanics over time is lacking. For CO_2, coupled reactive transport models exist, but not for hydrogen. There is no existing data on how pressure cycles and H_2 chemistry jointly affect porosity or induce fractures. Studies indicate that coupled biogeochemical impacts (e.g., biofilm effects) are underexplored.

Lastly, there are no standardized screening guidelines in existence for geologic hydrogen. Currently, site selection borrows CO_2 criteria and focuses on porosity/permeability, often neglecting legacy well inventories. Therefore, the

development of specific hydrogen risk-weighted screening, including microbial risk and material compatibility, is a clear need.

5.2 Implications for U.S. and Global Energy Systems

The comparative risk insights have important implications for U.S. energy strategy. Domestically, this analysis informs the selection of subsurface storage for emerging hydrogen hubs. It suggests that industry must integrate geological risk assessments, such as prioritizing reservoirs with robust seals and low contamination potential for hydrogen facilities in the early stages of planning. Also, tax credits for CCS policies and regulations should be updated to specifically address hydrogen safety standards. The infrastructure planning for a clean hydrogen economy must consider the subsurface constraints, such as upgrading well regulations or funding monitoring research.

Globally, these findings contribute to the broader clean energy transition and environmental sustainability. Many countries are pursuing hydrogen as a decarbonization tool, and they will face similar storage challenges. By clarifying what is transferable from CO_2 storage experience and what is not, this review helps avoid replicating mistakes abroad. It highlights that large-scale hydrogen deployment for long-duration grid balancing or hard-to-electrify sectors will hinge on safely unlocking subsurface storage. Thus, international collaborations like the IEA Hydrogen Technology Collaboration Program should incorporate these comparative geoscience findings. Altogether, establishing robust and hydrogen-specific subsurface storage frameworks is crucial for both U.S. energy security and global emissions goals.

6 CONCLUSION

Depleted U.S. oil and gas reservoirs offer enormous potential for energy storage: their extensive pore space and sealing history make them natural candidates for both CO_2 sequestration and seasonal hydrogen storage. Notwithstanding, this comparative review makes clear that hydrogen storage entails fundamentally different geological and operational risks than carbon storage.

This analysis also clarifies that existing CCS models can inform H_2 storage only to an extent. Key lessons from CO_2, such as the importance of caprock continuity and well integrity, are applicable but must be emphasized for H_2. It identifies that achieving safe, large-scale H_2 storage will require dedicated risk assessment protocols, new monitoring technologies, and field trials tailored to hydrogen behavior. Developing hydrogen-specific subsurface screening criteria, enhanced fiber-optic or tracer monitoring methods, and reservoir simulations that include H_2-biogeochemistry are also top priorities.

In closing, this comparative geological risk perspective provides a roadmap for leveraging lessons from carbon capture while illuminating the novel challenges of underground hydrogen. Ensuring that depleted reservoirs can securely host hydrogen, as a backbone of the clean energy economy, will depend on addressing the gaps identified here.

STATEMENTS ON COMPLIANCE WITH ETHICAL STANDARDS

Disclosure of conflict of interest

The authors declare no conflicts of interest regarding this manuscript.

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