

## Review

# Opportunities and Challenges of Grid-Scale Green Hydrogen Energy Storage

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## Abstract

Hydrogen (H<sub>2</sub>) has emerged as a promising sustainable energy vector due to its scalability, high energy density, and its ability to enable sector coupling across electricity, heating, transportation, and industry. There remains a huge technical challenge to overcome. The economic implications of low round-trip efficiency, high capital costs, the limited lifespan of fuel cells and electrolyzers, and infrastructure constraints on H<sub>2</sub>'s relative competitiveness have not been comprehensively studied. In a comparative assessment against other storage options such as batteries, pumped hydro, and compressed air energy storage (CAES), we highlight the potential of H<sub>2</sub> as a grid-scale storage solution. The novelty of this paper is that it compares H<sub>2</sub> as a competing option with other storage technologies and highlights its unique suitability for seasonal and grid-scale applications where others fall short. The paper also discusses the technological opportunities for AI and other digital technologies in the H<sub>2</sub> grid. Unlike general reviews, this work emphasizes the engineering performance of H<sub>2</sub>'s production cost and economic viability, electrolyzer technology maturity, infrastructure readiness, safety and lifecycle considerations, and provides critical synthesis and implications. With this, the paper extends beyond the theoretical capacity for H<sub>2</sub> and gives an engineering-focused analysis that informs the drive toward sustainable and resilient power grids.

**Keywords:** Hydrogen; electrolyzer; PEMFC; SOFC; Pumped-hydro; CAES; SMES; artificial intelligence; hydrogen storage; grid-scale energy storage; round-trip efficiency; levelized cost of hydrogen

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## 1. Introduction

H<sub>2</sub> has emerged as a compelling candidate for sustainable long-duration energy storage in renewable-based power systems, offering the potential to address variable generation, improve system frequency, and enable sector coupling across electricity, heating, and transportation [1]. Its high gravimetric energy density, approximately 120 MJ/kg, is nearly three times that of conventional fossil fuels [2], and its long-term storage capability positions H<sub>2</sub> well to address seasonal imbalances in electricity supply and demand [3]. Despite the benefits, the widespread deployment of H<sub>2</sub> for grid-scale storage faces several challenges [4,5]. Its topmost disadvantage is its low round-trip efficiency compared to

other storage technologies, such as lithium-ion batteries and pumped hydro. High capital costs, limited lifetimes of electrolyzers and fuel cells, and system integration challenges with existing grid infrastructure are additional challenges [6].

While electrolyzer and fuel cell technologies have seen recent improvements, the overall system-level efficiency (thermal cycling losses, ceramic electrolyte degradation, ionic conductivity loss, balance-of-plant energy demand) remains lower than the competing energy storage technologies [7,8]. Furthermore, the costs of electrolyzers, compression or liquefaction, safe and cost-effective storage solutions, grid operations, and ancillary services have not yet matured to the point of economic viability [9,10].

Ongoing research on safe large-scale H<sub>2</sub> storage, including underground storage and optimizing power-to-hydrogen-to-power (P2H2P), is promising, but many challenges, such as scalability and safety (pipeline materials, leak detection, codes and standards, and lifecycle performance), persist [4,11]. Additionally, the lack of mature grid-integration designs hinders the adoption of H<sub>2</sub> as a sustainable grid-scale energy storage solution.

Grid-scale storage technologies are essential to decarbonized power systems. Emerging options, including mechanical storage, electrochemical batteries, and thermal storage, support the wider deployment of low-carbon electricity sources such as solar photovoltaic and wind power [12]. In terms of scale, grid-scale storage generally refers to systems rated from about 10 MW to multiple GW that are directly connected to trans-mission or distribution networks. Their capacity is defined by the power they can deliver continuously, measured in MW, GW, or TW, and the duration of delivery before depletion, measured in MWh, GWh, or TWh [13].

While prior studies have examined H<sub>2</sub> technologies in isolation, there remains a critical gap in engineering-focused analyses that integrate technical performance and system-level grid integration. This paper fills the gap by systematically evaluating the opportunities and challenges of H<sub>2</sub> for grid-scale energy storage required to realize the vision of a H<sub>2</sub> grid. The findings aim to inform and guide future research and technology development to advance H<sub>2</sub> as a viable solution for sustainable, resilient power systems.

The rest of the paper is structured as follows. Section 2 provides a literature review on the opportunities of H<sub>2</sub>. Section 3 discusses H<sub>2</sub> challenges. Critical synthesis and implications were outlined in Section 4. Section 5 presents H<sub>2</sub> storage methods under compressed gas and liquid storage. Comparative assessment of H<sub>2</sub> storage versus other grid technologies was discussed in Section 6. Section 7 explores the application of digital tools for grid-scale H<sub>2</sub> optimization. Finally, the conclusion section summarizes the findings in Section 8.

## 2. Materials and Methods

This paper employs a multi-criteria analytical framework to evaluate H<sub>2</sub> as a grid-scale energy storage solution, stratified across three interconnected dimensions: technical performance, economic viability, and system integration readiness. Technical performance is assessed using quantitative indicators including round-trip electrical efficiency, electrolyzer system-level efficiency, and storage energy density, benchmarked against competing technologies including lithium-ion batteries, pumped hydro, CAES, and SMES under equivalent operating conditions. Economic viability is evaluated using levelized cost of H<sub>2</sub> (LCOH) and levelized cost of storage (LCOS) metrics, incorporating capital expenditure, balance-of-plant losses, compression efficiencies, and operational lifetime assumptions drawn from published techno-economic studies and institutional projections from IRENA, the U.S. DOE, and S&P Global. System integration readiness is assessed against infrastructure maturity indicators, global warming potential (GWP), compliance capability, sector coupling potential, and geological storage availability.

These dimensions are applied consistently throughout the opportunities and challenges analysis, enabling a comparative synthesis that identifies not only where H<sub>2</sub> performs well but also where it holds a defensible advantage over alternatives at specific storage durations, deployment scales, and grid penetration levels. This layered approach helps to move beyond theoretical capacity assessments and provide engineering-grounded conclusions that are actionable for policymakers, grid planners, and investors.

The analytical inputs were drawn from a structured review of peer-reviewed literature, institutional technical reports, and industry databases. Primary sources consulted include IRENA's global renewable energy and H<sub>2</sub> cost databases, the U.S. Department of Energy's Hydrogen and Fuel Cell Technologies Office publications, and the European Hydrogen Bank project documentation. Peer-reviewed studies were sourced from engineering and energy journals including *Applied Energy*, the *International Journal of Hydrogen Energy*, *MDPI*, and *Energy Conversion and Management*. Techno-economic data for competing storage technologies were drawn from publicly available datasets maintained by the National Renewable Energy Laboratory (NREL) and the Electric Power Research Institute (EPRI), ensuring that cross-technology comparisons are based on consistent, independently verified cost and performance benchmarks.

These sources were selected based on three criteria: methodological transparency, institutional independence, and prioritizing databases and reports produced without direct commercial interest in H<sub>2</sub>. Deployment relevance data is drawn from studies published between 2020 and 2026 to reflect the current state of electrolyzer cost trajectories, storage technology maturity, and grid integration experience.

### 3. Opportunities

#### 3.1. Long-Duration and Seasonal Energy Storage

The most technically compelling application of grid-scale H<sub>2</sub> is in storage timeframes that electrochemical battery technologies cannot economically serve [14]. Green H<sub>2</sub> systems can absorb surplus electricity during periods of excess variable renewable energy (VRE) generation and dispatch the stored energy over timescales from hours to multiple days [15]. This capability becomes critical when both hydropower reserves and battery systems are depleted [16]. Quantitative modeling of gigawatt-scale renewable electrolyzer systems across U.S. industrial sites indicates that large-scale seasonal storage requires between 1457 and 19,837 MT of H<sub>2</sub> to smooth annual supply disparities from renewable-powered electrolyzers [17], with underground storage in geological formations such as salt caverns identified as the most economical configuration, and liquid organic hydrogen carriers (LOHCs) providing viable alternatives where suitable geology is unavailable and curtailment is unavoidable [18,19].

Curtailment of VRE is rising as capacity growth outpaces grid absorption. In California, the California Independent System Operator (CAISO) curtailed 3.4 million MWh of utility-scale wind and solar in 2024, up 29% year on year, while peak spring curtailment reached 23% of available solar generation as installed capacity expanded from 9.7 GW in 2014 to 28.2 GW by end-2024 [20,21]. In China, solar curtailment reached 6.6% and wind curtailment 5.7% in H1 2025, with Tibet curtailing more than 30% of both wind and solar output; in 2024, China raised its national curtailment tolerance ceiling from 5% to 10% as new capacity exceeded grid absorption [22,23]. In Europe and other high-renewables markets, recent curtailment in Chile, Ireland, and the United Kingdom has reached 5–15%, while the IEA projects VRE penetration nearing 70% in Germany, the Netherlands, Portugal, and Chile by 2030 [24]. Scenario modeling shows that curtailment rises nonlinearly with VRE penetration of about 8%, 13%, and 23% at 45%, 65%, and 85% VRE shares, respectively, without long-duration storage. This lowers the effective electricity input cost

for electrolytic H<sub>2</sub>, the main driver of LCOH, and partially offsets H<sub>2</sub>'s round-trip efficiency disadvantage relative to battery storage [25,26].

### 3.2. Sector Coupling and Energy System Integration

Beyond grid storage, H<sub>2</sub>'s role as a universal low-carbon energy carrier offers transformative potential through sector coupling [27]. The integration of H<sub>2</sub> into hard-to-abate sectors such as steel production, chemical manufacturing, heavy-duty transport, and maritime shipping creates demand structures that, when aggregated, can justify the infrastructure investment required for large-scale production and distribution [28]. S&P Global's analysis indicates that the future pattern of international H<sub>2</sub> trade could be on par with current fossil-fuel commodity markets, with exporting nations leveraging comparative advantages in renewable energy to supply industrial importers [29].

Even though H<sub>2</sub> integration into the gas grid can be challenging, for example, retrofitting of several old gas grids, advanced separation and purification technology can enhance the extraction of high-purity H<sub>2</sub> at the final consumption point. Groundbreaking technology such as pressure swing adsorption (PSA), combined with a membrane permeation system developed by Linde and Evonik, has demonstrated the ability to recover H<sub>2</sub> from natural gas blends containing up to 90% H<sub>2</sub>, with purity exceeding 99.99% [30]. The innovation is cost-effective and ready for deployment on the existing gas grid under harsh conditions for long-term operation.

For stability, the combination of battery storage for short-duration dispatch and H<sub>2</sub> for longer-duration storage has been modeled across 145 countries, with findings suggesting that this hybrid configuration enables a reliable 100% clean electricity grid at a lower cost than either technology deployed in isolation [31]. The Hyflex power demonstration project validated the technical feasibility of 100% H<sub>2</sub> combustion in a 12 MW gas turbine in 2023 [32], while JERA achieved 20% ammonia co-firing at a 1 GW coal-fired power plant in 2024, establishing key proof-of-concept milestones for hydrogen-derived fuels in dispatchable generation [33].

Zhou et al.'s bi-level optimization framework provides quantitative evidence of both sector-coupling opportunity and planning bottlenecks [34]. Nevertheless, by connecting surplus wind generation through P2H and P2A processes with coal-ammonia co-firing and district heat supply in a unified integrated energy system (IES), their model shows that H<sub>2</sub> functions most effectively as a low-carbon energy vector when the electricity, gas, and heat systems are optimized together. The combination of lower-level mixed-integer linear programming (MILP) scheduling and upper-level lifecycle NPV maximization demonstrates that capacity planning and operational dispatch are closely interdependent. A systems-level insight is often missed by single-sector H<sub>2</sub> roadmaps.

The results show that, under 2019 assumptions, electrolyzer capital costs alone render all P2H-P2A capacity economically unattractive, while a 20% cost increase in the 2030 scenario eliminates viability altogether with an impact greater than comparable changes in coal or carbon trading prices [34]. Transport infrastructure imposes a similarly binding constraint: delivering H<sub>2</sub> by long-tube trailer costs roughly an order of magnitude more than moving green ammonia by tank truck, shaping which decarbonization pathway is investable in the near term. The P2H-P2A pathway delivers a higher NPV (\$28.35 M versus \$24.34 M) not because it performs better energetically, but because it has lower infrastructure and transport costs [34]. Together, these findings show that the main constraints on H<sub>2</sub>-enabled sector coupling are not co-firing or storage readiness, but rather electrolyzer cost trajectories and transport choices, which must be resolved through coordinated system-level planning before deployment.

### 3.3. Market Growth and Policy Momentum

The global H<sub>2</sub> energy storage market was valued at USD 16.86 billion in 2024 and is projected to reach USD 27.13 billion by 2033, at a compound annual growth rate (CAGR) of 5.43% [35]. Asia-Pacific leads with a 36% market share, driven by national H<sub>2</sub> strategies in China, Japan, and South Korea, while China alone is expected to increase storage-related spending by approximately 140% [35,36]. In Europe, the European Hydrogen Bank, backed by 800 million EUR from the EU Innovation Fund, has established fixed-price production support mechanisms with up to 10-year duration for certified renewable H<sub>2</sub> projects [29]. In the United States, the Inflation Reduction Act (IRA) provides production tax credits of up to USD 3.00/kg for qualifying low-carbon H<sub>2</sub>, representing a significant, if time-bound, cost intervention [37,38].

However, the accelerated Section 45V production tax credit now requiring construction to begin by December 2027 under the (Public Law 119-21, July 2025), rather than expiring in 2033 illustrates how sovereign policy risk can reshape project economics independently of technology performance [37]. Such temporary support may lead to pipeline slowdowns if technology costs remain above market-competitive levels when subsidies expire, weakening the scale economies needed for continued cost reductions [38].

## 4. Challenges

### 4.1. Round-Trip Efficiency Losses

The most fundamental technical constraint of H<sub>2</sub> as a grid storage medium is its round-trip electrical efficiency (RTEE). Conventional water electrolysis coupled with H<sub>2</sub> fuel cells achieves RTEE values of approximately 30–40% [7], compared to 85–95% for lithium-ion battery systems [39]. Advanced electrolyzer systems under development have demonstrated projected RTEE values exceeding 80% in laboratory settings, achieved by eliminating parasitic losses associated with oxygen co-production [40]. These remain at early technology readiness levels (TRL) and have not been validated at grid scale [41,42].

Practical electrolyzer systems currently achieve system-level efficiencies of approximately 60–70% for alkaline and proton exchange membrane (PEM) technologies when balance-of-plant losses are included, with additional energy penalties of up to 25% incurred during compression and storage [42]. IRENA projects that alkaline PEM and anion exchange membrane (AEM) systems will surpass 87.6% electrolyzer-level efficiency under optimistic development scenarios, and that solid oxide electrolyzers (SOECs) may approach or exceed 100% electrical efficiency when industrial waste heat is utilized [36,43]. However, these projections remain conditional on sustained R&D investment and do not reflect current deployed performance. The efficiency deficit relative to batteries is partially mitigated in seasonal storage applications, where curtailed renewable energy serves as the input [17]. However, this argument is valid only in grids with established VRE surpluses, not during the ongoing buildout phase.

Energy storage technologies should not be compared based on instantaneous RTE alone; the required storage timescale is also important. Lithium-ion batteries (LIBs) deliver high cycle-level RTE of 90–95%, but they also self-discharge at 2–3% per month under ambient conditions [44,45]. This loss increases with state of charge (SoC), rising from about 3  $\mu$ A at 60% SoC to about 40  $\mu$ A at 80% SoC [46]. As a result, high-SoC strategies that maximize available energy can also increase standby losses. Over several months, these accumulated idle losses reduce the practical efficiency advantage of LIBs [47].

Conversely, compressed H<sub>2</sub> storage leaks less than 0.12% per month [44], roughly an order of magnitude less than LIBs, making it better suited for long-duration and seasonal storage. Its system-level RTE is only 30–40% because of irreversible losses during electrolysis and fuel-cell reconversion [48,49]. The key design trade-off is a crossover: LIBs are

preferable when high cycle efficiency over days or weeks is most important, while H<sub>2</sub> is more appropriate when retaining stored energy over months rather than conversion efficiency. For meaningful technology comparisons, system designers must treat storage timescale as a primary constraint.

Similarly, optimal PEMFC operating temperature depends on load and state of health (SOH), rather than remaining fixed [44]. As SOH decreases, this optimum shifts lower because degraded membranes are more susceptible to drying. Physically, the optimum is reached when the catalyst-layer liquid water has just evaporated, thereby reducing mass-transport losses while maintaining membrane hydration and limiting ohmic resistance. This SOH-current-temperature relationship has been modeled with  $R^2 = 0.9625$ , supporting degradation-adaptive thermal management [47,48]. Under dynamic loads, voltage is a poor health indicator because it is strongly affected by current. Converting instantaneous voltage to its rated-current equivalent using virtual polarization curves produces a virtual relative power loss rate (VRPLR), reducing current-indicator correlation from  $\sim 0.88$  to  $-0.02$  and isolating cell aging [44]. Shutdown and restart can cause reversible voltage recovery discontinuities that standard recurrent models tend to overfit [45].

#### 4.2. Production Cost and Economic Viability

Green H<sub>2</sub> production cost remains the most decisive barrier to grid-scale deployment. Current levelized costs of H<sub>2</sub> (LCOH) for production range from USD 3.8 to 11.9/kg, compared to USD 1.5–6.4/kg for gray H<sub>2</sub> produced via steam methane reforming (SMR) [50]. This cost differential is driven by several factors (Equation (1)). However, the two primary factors are (i) electricity costs, which account for approximately 50–70% of green H<sub>2</sub> production costs, and (ii) electrolyzer capital expenditure (CAPEX), which currently exceeds USD 2000/kW for leading commercial systems [50,51].

$$LCOH(\$/\text{kg}) = \frac{(C_{\text{capital}})CRF + C_{O\&M}^{\text{fixed}} + C_{O\&M}^{\text{variable}}}{\dot{m}_{H_2}} \quad (1)$$

where  $C_{\text{capital}}$  is capital cost, CRF is capital recovery factor,  $C_{O\&M}^{\text{fixed}}$  is fixed operation and maintenance cost,  $C_{O\&M}^{\text{variable}}$  is variable operational and maintenance cost,  $\dot{m}_{H_2}$  is annual H<sub>2</sub> production rate in kg/y [52]. The key enabler for green H<sub>2</sub> production is reducing the magnitude of the numerator terms or increasing the denominator (annual production  $\dot{m}_{H_2}$ ) term.

Achieving cost parity with fossil-based H<sub>2</sub> requires renewable electricity input costs of USD 20–30/MWh [51]. This condition is only achieved in a limited number of high-irradiance or high-wind regions globally [53]. The U.S. Department of Energy's Hydrogen Shot Initiative targets an LCOH of USD 1.00/kg by 2031, requiring simultaneous reductions in CAPEX electricity costs and improvements in electrolyzer efficiency [54]. Independent analysis suggests this target is optimistic under moderate development scenarios; by 2050, projections for alkaline electrolyzer CAPEX range from USD 88/kW under an optimistic scenario to USD 388/kW under a pessimistic scenario, reflecting significant uncertainty in cost trajectories [36].

In 2023, green H<sub>2</sub> accounted for less than 1% of global H<sub>2</sub> production, with output growing only 6% year-on-year from 2022 [36,53]. By contrast, announced final investment decisions for blue H<sub>2</sub> (SMR with carbon capture) in North America are projected at over 1.5 million tons per annum in 2025, which is ten times the equivalent capacity for green H<sub>2</sub> [19]. This capital allocation reflects the persistent cost gap and underscores that a policy subsidy alone is insufficient to drive the transition at the required speed [29,36].

#### 4.3. Electrolyzer Technology Maturity and Diversity

Four principal electrolyzer technologies are currently at various stages of commercial readiness: (i) alkaline water electrolyzers (AWE), (ii) PEM electrolyzers, (iii) SOEC, and (iv) AEM electrolyzers [55,56]. AWE represents the incumbent technology with decades of operating history and the lowest capital cost, but its limited ability to ramp dynamically constrains its integration with variable renewable sources [57]. PEM electrolyzers offer faster response and greater operational flexibility at a higher material cost, owing to platinum-group metal catalysts and fluorinated membrane requirements [58,59]. SOEC systems achieve the highest potential efficiencies but operate at 600–900 °C, making them unsuitable for dynamic power applications and reducing durability under cycling conditions [60]. AEM technology remains in early commercial stages, with unresolved degradation challenges [55].

The diversity of electrolyzer architectures complicates in techno-economic assessment and procurement, as efficiency, stack life, CAPEX, and integration requirements vary significantly across technology types and operating conditions [58]. Standardization of performance metrics and lifecycle assessment boundaries remains a major challenge complicating policy design, project financing, and cross-study comparisons [61].

#### 4.4. Infrastructure Readiness and Planning Bottlenecks

Grid-scale H<sub>2</sub> deployment requires coordinated production, compression, storage, and distribution infrastructure. Nevertheless, none of these exist at the required scale in most jurisdictions [24,36]. Pipeline retrofitting can reduce H<sub>2</sub> transport costs by 50–70% compared to new construction [6,44], but compatibility with existing natural gas infrastructure is limited by H<sub>2</sub> embrittlement of steel components and leakage through polymer seals [62,63]. Meanwhile, underground geological storage, while economically attractive, faces constraints related to H<sub>2</sub> leakage, groundwater contamination risk, induced seismicity, and competition with compressed air energy storage applications [31,64].

A significant planning imbalance has been identified in the European context [36]. For instance, the lead times for offshore and onshore wind power development are significantly longer than those for electrolyzer installation or manufacturing [29,65]. This structural mismatch means that the bottleneck for green H<sub>2</sub> scale-up is not the electrolyzer technology itself, but the renewable electricity generation capacity required to feed it, which is also needed for direct electrification, creating a resource-allocation tension that H<sub>2</sub> roadmaps frequently understate.

The infrastructure barriers outlined above illustrate a coordination failure: H<sub>2</sub> demand is too limited to justify investment in pipelines and storage. Demand cannot grow without infrastructure already in place. Policy intervention is needed to break this cycle. Contract-for-difference (CfD) mechanisms are already used for renewable H<sub>2</sub> through the European Hydrogen Bank, which runs EU Innovation Fund-backed fixed-premium auctions for terms of up to ten years [66]. This offers long-term revenue certainty and reduces investment risk before the market matures. Regulated asset base (RAB) models for dedicated H<sub>2</sub> pipelines, now being implemented in the United Kingdom under the Gas Act 1986 framework with Ofgem as the economic regulator [67], enable developers to recover costs through regulated tariffs rather than merchant revenues, reducing reliance on simultaneous demand aggregation.

From a business-model perspective, aggregated offtake consortia can create the demand signal needed to support upstream infrastructure investment without direct public capital. In this approach, anchor customers in steel, chemicals, and heavy transport jointly back long-term H<sub>2</sub> purchase agreements. The model resembles corporate power purchase agreements (PPAs), which have helped drive the deployment of renewable generation capacity [68] by spreading financial risk across several creditworthy counterparties rather

than placing it on a single developer. These arrangements should be co-designed with renewable energy developers, so electrolyzer capacity commitments are matched by dedicated generation agreements, easing rather than worsening the resource-allocation tension between green H<sub>2</sub> production and direct electrification.

#### 4.5. Safety, Environmental, and Lifecycle Considerations

H<sub>2</sub>'s low ignition energy (0.02 MJ), wide flammability range (4–75% in air), and small molecular size create safety challenges in storage, transport, and end-use applications that are more demanding than those with natural gas [69]. Lifecycle assessment of H<sub>2</sub> systems is further complicated by inadequate standardization of system boundaries, leading to inconsistent emissions accounting that can misrepresent the net carbon benefit of green H<sub>2</sub> pathways [70,71]. Emerging evidence also suggests that molecular H<sub>2</sub> itself may function as an indirect greenhouse gas through its interactions with tropospheric methane and stratospheric ozone chemistry, though quantifying this effect at scale remains an active area of research [72].

Indeed, H<sub>2</sub> is not a direct greenhouse gas; nonetheless, it can warm the climate indirectly by increasing atmospheric methane, tropospheric ozone, and stratospheric water vapor. Current estimates place its 100-year Global Warming Potential (GWP100) at  $11.6 \pm 2.8$ , rising to  $40.1 \pm 24.1$  over 20 years [73,74]. Around 60% of this effect is linked to a longer methane lifetime, while the remainder is attributed to ozone formation [75]. Recent modeling also indicates that existing estimates may be about 20% too high because of hydroxyl radical (OH) biases in atmospheric chemistry models [76].

Leakage is the main driver of H<sub>2</sub>'s climate impact: effects increase by 45% at 5% leakage and double at 13% leakage [77]. If deployed globally without adequate controls, H<sub>2</sub> leakage could add 0.1–0.2 °C of warming over the next century [78]. With effective controls, leakage-related warming remains below 0.5 kgCO<sub>2e</sub>/kgH<sub>2</sub> across major production pathways, adding less than 15% [79]. Atmospheric H<sub>2</sub> concentrations reached about 555 ppb in 2024, although the reasons for this increase are still unclear [80].

Certification and standardization frameworks are beginning to address these concerns. However, the Green Hydrogen Standard (GHS) is the only globally recognized certification system for green H<sub>2</sub> and its derivatives, incorporating principles of additionality, temporal matching of renewable generation, and geographic correlation between production and generation assets [19]. S&P Global identifies harmonization of such standards across jurisdictions as one of three critical preconditions for the emergence of a liquid international H<sub>2</sub> market [29].

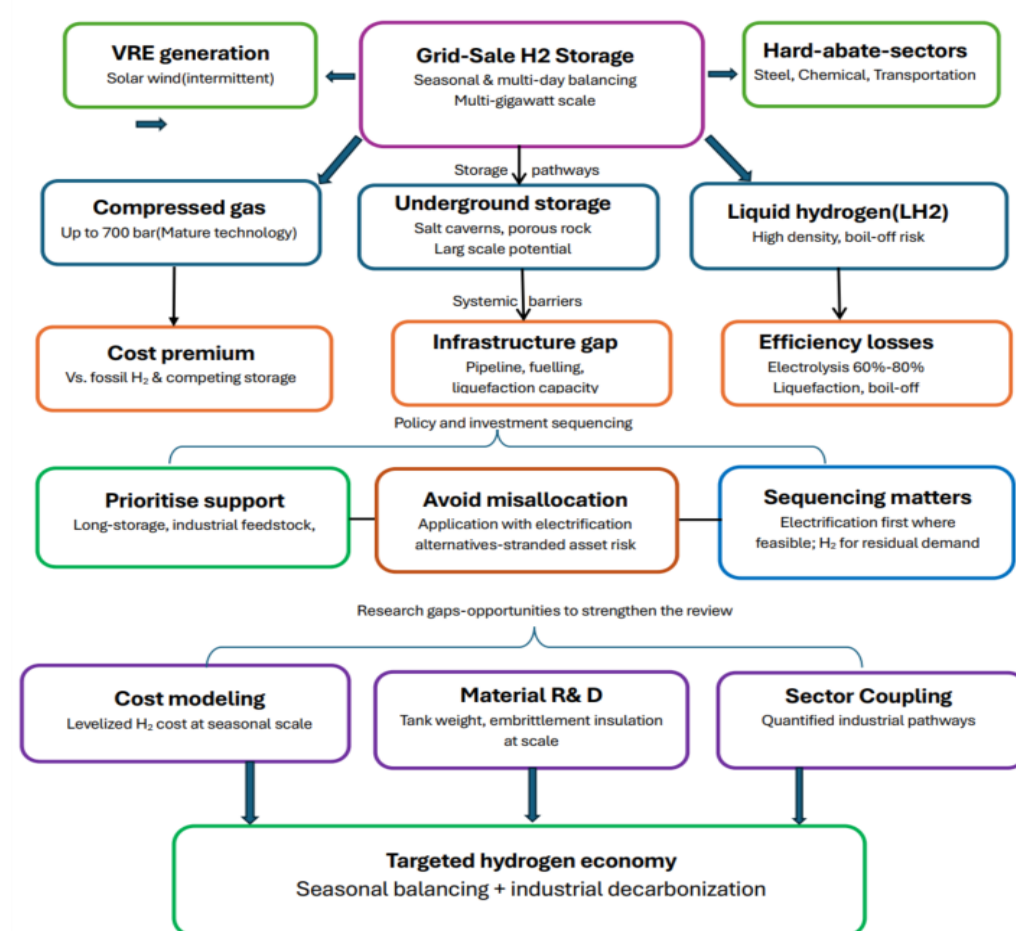
## 5. Critical Synthesis and Implications

The preceding analysis reveals a technology with a genuine and important role in the decarbonized energy system, but one that is simultaneously burdened with expectations it cannot fulfill in the near term [24]. Grid-scale H<sub>2</sub> storage is likely indispensable for seasonal and multi-day grid balancing at VRE penetrations that would otherwise require prohibitive overcapacity (Figure 1). Its role in sector coupling for hard-to-abate industries is well-established. However, the persistent cost premium over both fossil H<sub>2</sub> and competing storage technologies, combined with systemic infrastructure deficits and unresolved efficiency losses, means that H<sub>2</sub> cannot serve as a generalized near-term substitute for direct electrification or short-duration battery storage.

The policy and investment implications are mainly about sequencing and prioritization: public support should be directed towards long-duration storage, industrial feedstock substitution, and applications for which no credible alternative pathway exists, while avoiding deployment in end uses where direct electrification is already economically competitive. The risk of misallocating capital to H<sub>2</sub> in applications better served by

other technologies is nontrivial and has been identified as a potential source of stranded assets and delayed decarbonization [81]. Delivering on H<sub>2</sub>'s role in long-duration grid balancing requires storage infrastructure capable of operating at seasonal and multi-gigawatt scales [36]. The two most technically advanced and commercially available pathways for achieving this are compressed gas storage and liquid H<sub>2</sub> storage, each presenting distinct trade-offs in efficiency, cost, and infrastructure requirements.

Large-scale H<sub>2</sub> deployment will achieve its decarbonization potential only if public support, infrastructure investment, and incentives are deliberately directed toward applications where H<sub>2</sub> has a clear advantage, such as seasonal storage and industrial feedstock substitution. At the same time, policy should avoid end uses better served by direct electrification, where misallocated capital could create stranded assets and slow decarbonization. Figure 1 below shows a block diagram of grid-scale H<sub>2</sub> deployment pathways.



**Figure 1.** Grid-scale H<sub>2</sub> storage: pathways, barriers, and deployment priorities.

## 6. Hydrogen Storage Methods

Effective storage technologies must balance energy density, round-trip efficiency, safety, scalability, and cost [39], despite the variety of H<sub>2</sub> storage approaches, including cryogenic liquids, high-pressure gas, and material-based options such as metal hydrides, ammonia, and liquid organic H<sub>2</sub> carriers [50,56]. Material-based storage, while offering high energy density, remains constrained by high costs and limited commercial maturity for multi-gigawatt applications [82]. Advanced catalyst research and the development of novel materials to improve reaction kinetics and reduce costs are therefore required [83]. For grid applications requiring seasonal storage, compressed gas and liquid H<sub>2</sub> remain the most technically advanced and widely deployed options [84,85].

### 6.1. Compressed Gas Storage

Compressed GH<sub>2</sub> is stored at 350–700 bar in high-strength composite tanks, which are the primary commercially demonstrated technology [86]. Geological options, including depleted natural gas reservoirs, salt caverns, aquifers, and repurposed mine rock formations, also exist, although their adoption for large-scale grid applications remains limited [87]. These storage modes offer superior safety, durability, and low leakage, enabling terawatt-hour (TWh)-scale energy storage at competitive costs [88]. To date, using geological formations for compressed GH<sub>2</sub> storage offers the best viable option for multi-gigawatt, grid-scale installations [89,90].

Gas compression consumes 10–15% of the lower heating value (LHV) of H<sub>2</sub> [91]. Storage of GH<sub>2</sub> remains attractive, mainly due to the lower infrastructure costs than liquefaction technologies [92,93]. The ACES Delta project in Utah, for example, plans to store up to 100 metric kilotons of H<sub>2</sub> in salt caverns, enabling both seasonal storage and power generation [94]. The cavern-based system carries a levelized cost of storage (LCOS) of \$0.20–0.50/kg H<sub>2</sub>, making it among the most cost-effective options for grid applications [95]. Nevertheless, several issues remain to be addressed, including high-pressure safety requirements and compressor durability [31].

### 6.2. Liquid Hydrogen Storage

H<sub>2</sub> must be cooled to 20 K to liquefy, a process that increases its volumetric energy density by nearly threefold compared to GH<sub>2</sub> at 700 bar [96]. The high density makes LH<sub>2</sub> attractive for sectors that require compact solutions, such as aviation, shipping, and international H<sub>2</sub> trade. However, the liquefaction process is energy-intensive, consuming 30–40% of H<sub>2</sub>'s LHV [97], making it less efficient than compressed storage. Also, boil-off losses from LH<sub>2</sub> storage are a major challenge, even in well-insulated tanks, due to continuous heat ingress [98,99]. While LH<sub>2</sub> is well-suited for short-term transportation, its storage losses limit its long-term feasibility. Moreover, capital investment in cryogenic infrastructure exceeds that for compressed gas facilities; large liquefaction systems require advanced refrigeration cycles, such as the Claude or helium Brayton cycles, and specially designed cryogenic materials, resulting in significant CAPEX [10,85].

Despite LH<sub>2</sub> limitations, it plays a crucial role in enabling global energy trade. Japan, for instance, has invested heavily in LH<sub>2</sub> supply chains, completing a pilot project that imported LH<sub>2</sub> from Australia [100]. For grid-scale storage, high energy requirements and related infrastructure costs make it less competitive than compression or underground storage methods [101]. New, more efficient liquefaction technologies, such as the magnetocaloric refrigeration process, are currently under development [102]. With the technical and economic characteristics of compressed gas and LH<sub>2</sub> storage established, a comparative assessment against competing grid-scale storage technologies is necessary to identify where H<sub>2</sub> holds a credible advantage and where alternatives are more viable. Boil-off rate (BOR), defined as the fraction of stored LH<sub>2</sub> lost per day due to heat ingress, is the primary efficiency metric for cryogenic storage [103]. BOR decreases with increasing tank volume owing to the falling surface-to-volume ratio. Table 1 summarizes BOR for current insulation systems alongside projected values for active cooling strategies.

Broad area cooling (BAC) using liquid nitrogen on a 40,000 m<sup>3</sup> evacuated-perlite tank is projected to lower BOR from ~0.04%/day to 0.004%/day about a 90% reduction. Though it requires additional refrigeration infrastructure [104]. Conventional LH<sub>2</sub> liquefaction using the Joule–Thomson/Claude cycle achieves only ~23% of Carnot efficiency [105]. The magnetocaloric effect (MCE) is an adiabatic temperature change induced by varying the magnetic field in solid-state rare-earth materials, offering an emerging alternative that avoids gas-phase compressors and greenhouse-gas refrigerants. Tables 1 and 2 summarize the key performance parameters.

**Table 1.** Liquid hydrogen boil-off rates: current and projected.

| Configuration                                                           | Tank Volume              | BOR(%/day) | Source    |
|-------------------------------------------------------------------------|--------------------------|------------|-----------|
| Small tank—vacuum-jacketed insulation                                   | 60–300 m <sup>3</sup>    | 0.3–0.4    | [106,107] |
| Medium tank—vacuum-jacketed insulation                                  | 1100–2300 m <sup>3</sup> | <0.1       | [106]     |
| NASA LC-39 ground storage—perlite vacuum                                | ~3000 m <sup>3</sup>     | ~0.07      | [107]     |
| Large ship-borne—evacuated perlite, no active cooling                   | 40,000 m <sup>3</sup>    | ~0.04      | [104]     |
| 40,000 m <sup>3</sup> + local area cooling (LN <sub>2</sub> )—projected | 40,000 m <sup>3</sup>    | 0.011      | [104]     |
| 40,000 m <sup>3</sup> + broad area cooling (LN <sub>2</sub> )—projected | 40,000 m <sup>3</sup>    | 0.004      | [104]     |
| EU Clean H <sub>2</sub> JU target 2024 (maritime)                       | ≥350 t                   | ≤0.5       | [108]     |
| EU Clean H <sub>2</sub> JU target 2030 (maritime)                       | ≥2800 t                  | <0.3       | [108]     |

**Table 2.** Conventional vs. Magnetocaloric hydrogen liquefaction.

| Metric                                   | Conventional (Claude/JT) | Magnetocaloric (projected)        | Ref.      |
|------------------------------------------|--------------------------|-----------------------------------|-----------|
| Energy penalty (% of H <sub>2</sub> LHV) | 30–40%                   | ~15–25% (target)                  | [105,109] |
| Best industrial efficiency (% Carnot)    | ~23%                     | Not yet confirmed at scale        | [105]     |
| Working fluid/refrigerant                | Helium gas compression   | Solid-state MCE materials; no GHG | [109,110] |
| Pilot capacity demonstrated              | Industrial (multi-t/day) | >5 t/day (HyLICAL, 2024–2025)     | [111]     |
| Technology readiness level (TRL)         | TRL 9                    | TRL ~4–5 (2025)                   | [111]     |

Despite the economic potential of these storage mediums, several challenges need to be addressed. For example, subsurface energy applications, including H<sub>2</sub> storage and CO<sub>2</sub> sequestration, depend strongly on fracturing fluid mechanics and proppant transport. In CO<sub>2</sub>-based stimulation, proppant settling is controlled by fluid viscosity, drag coefficient, and the intermolecular network among thickener, cosolvent, and CO<sub>2</sub> molecules [112]. Fluid solid coupling models validated at R<sup>2</sup> = 98.7% show that 8 mPa·s viscosity limits settling to 3.2 m and 0.21 m/s, while pressures above 16 MPa further reduce settling by compressing intermolecular spacing and increasing bond energy [112]. However, high temperatures of 383 K weaken the fluid network, accelerate sedimentation, and constrain deep reservoir stimulation and storage design [112].

Coupled modeling shows that reservoir heat disrupts H<sub>2</sub> bonds in fracturing fluid, reducing viscosity and increasing filtration loss [113]. Wall thickness, heat-transfer coefficient, radius, and pressure gradient influence rheology; at heat-transfer coefficients above 1000 W/(m<sup>2</sup>·K), viscosity loss increases by about 2.5 times [2]. These thermo-hydraulic effects inform casing design, fluid formulation, and injection strategies for improved fracture conductivity and reservoir integrity in subsurface H<sub>2</sub> storage [112,113].

Critically, inadequate storage infrastructure has direct consequences for the returns on renewable energy investments. Research suggests that without sufficient storage capacity, approximately 20% of installed VRE capacity may remain unutilized, constituting stranded capital investment [43]. In this context, H<sub>2</sub> storage serves a grid-level function that justifies its lower round-trip efficiency relative to batteries: the energy stored would otherwise be curtailed and economically valueless [6].

## 7. Comparative Assessment of H<sub>2</sub> vs. Other Grid-Scale Technologies

### 7.1. Lithium-Ion Batteries

Lithium-ion battery energy storage systems (LBESS) are the leading technology for short- to medium-duration grid storage, owing to their high round-trip efficiency and rapid response times on the order of milliseconds [114]. These systems operate via electrochemical charge-and-discharge cycles between the anode and cathode, enabling them to provide fast frequency regulation and peak shaving [115]. Although LBESS outperforms H<sub>2</sub> storage systems in both efficiency and deployment speed, they are limited in

scalability for seasonal or long-term applications [116]. By contrast, H<sub>2</sub> storage systems typically deliver round-trip efficiencies of 30–40% with response times of seconds to minutes, making them less suitable for real-time grid balancing but well suited for seasonal storage [1]. H<sub>2</sub> can effectively complement LBESS for grid-scale storage rather than directly replacing it [117].

### 7.2. Pumped Hydro

Pumped hydro storage (PHS) is the most mature and widely deployed grid-scale energy storage solution, operating by moving water between reservoirs at different elevations [118]. With round-trip efficiencies of 70–85% and operational lifespans exceeding 50 years, PHS is highly reliable for bulk storage [119]. However, it is geographically constrained and requires large-scale infrastructure [120]. When comparing PHS and hydrogen energy storage systems (HESS), HESS offers greater geographic flexibility and the advantage of coupling with the industrial, heating, and transport sectors [119]. While PHS has lower operational costs over its lifespan, HESS offers faster deployment timelines and can be scaled more quickly to meet variable demands. For instance, the Bath County PHS in the U.S. demonstrates PHS effectiveness at a large scale, while Germany's use of H<sub>2</sub> for storage supports renewable energy integration and industrial decarbonization [121].

### 7.3. Compressed Air Energy Storage (CAES)

Compressed Air Energy Storage (CAES) stores compressed air in underground tanks or caverns, which can later be released to drive turbines and generate electricity [122]. Although CAES is economically feasible for medium-duration applications, large-scale use is constrained by geological requirements [120]. By comparison, H<sub>2</sub> offers greater deployment flexibility and can serve a wider range of energy applications [119]. Moreover, H<sub>2</sub> can be stored across multiple locations and serves as an energy source for electricity generation, transportation, and industrial applications, making it more versatile than CAES [122].

### 7.4. Superconducting Magnetic Energy Storage (SMES)

Superconducting Magnetic Energy Storage (SMES) systems store energy in the magnetic field generated by direct current flowing through superconducting coils [123]. Their near-instantaneous response makes them highly suitable for applications requiring rapid power delivery, such as voltage stabilization and power quality enhancement [124]. For example, SMES systems are being considered for data centers to prevent power disruptions, while H<sub>2</sub> storage is used to mitigate seasonal variations in renewable power supply [125]. SMES, however, is constrained by limited energy capacity, making it unsuitable for long-duration storage. HESS, while slower to respond, can provide weeks to months of storage capacity, filling a critical gap in the energy storage sector [126].

Although each technology has unique advantages, a hybrid ESS that integrates H<sub>2</sub> with existing technologies can offer the most technically robust approach for achieving high renewable energy penetration and enhancing grid resilience in future energy systems. Table 3 below summarizes various grid-scale technologies.

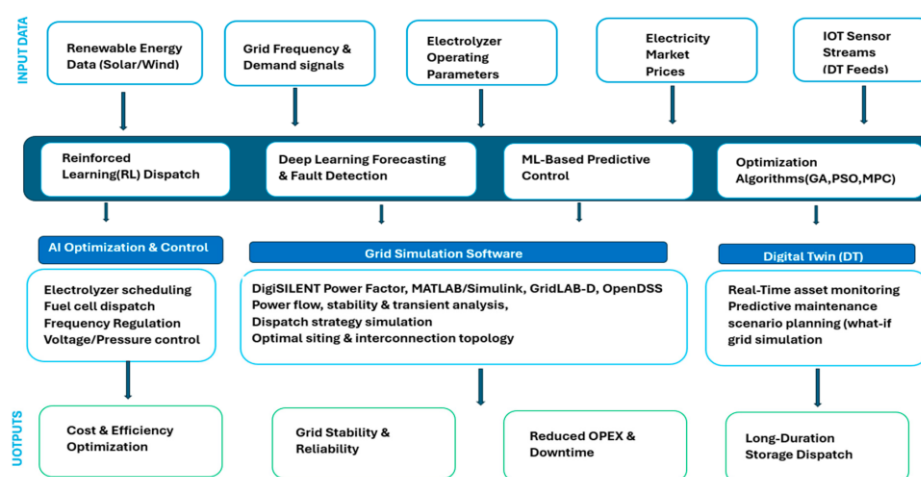
**Table 3.** Comparative Assessment of Technologies.

| Technology                 | Round-Trip Efficiency (%) | Discharge Duration | Capital Cost (USD/kWh)                       | Geographical Limitations     | LCOS-Frequency Regulation (USD/MWh) | LCOS-Seasonal Storage (USD/MWh) | Reference |
|----------------------------|---------------------------|--------------------|----------------------------------------------|------------------------------|-------------------------------------|---------------------------------|-----------|
| Hydrogen (H <sub>2</sub> ) | 30–50                     | Days to months     | 150–500 (electrolyzer + storage + fuel cell) | Flexible (salt caverns, com- | 150                                 | 150                             | [127–129] |

|                          |       |                                            |                                                                                       |                                                           |     |                |               |
|--------------------------|-------|--------------------------------------------|---------------------------------------------------------------------------------------|-----------------------------------------------------------|-----|----------------|---------------|
|                          |       |                                            |                                                                                       | pressed/liq-<br>uid H <sub>2</sub> )                      |     |                |               |
| Lithium-Ion<br>Batteries | 85–90 | 4–8 h                                      | 150–400                                                                               | Minimal                                                   | 150 | 400            | [127,130,131] |
| Pumped<br>Hydro          | 70–85 | 6–20 h                                     | 50–150                                                                                | High (re-<br>quires ele-<br>vated water<br>reservoirs)    | 50  | 200            | [127,132,133] |
| CAES                     | 40–60 | 8–26 h                                     | 50–100                                                                                | High (re-<br>quires cav-<br>erns or reser-<br>voirs)      | 70  | 250            | [132–134]     |
| SMES                     | 90–80 | Millisec-<br>onds to a<br>few sec-<br>onds | ~\$300–\$2200/kWh<br>(large E/P sys-<br>tems), >\$100<br>k/kWh for short-<br>duration | No terrain<br>constraints.<br>can be sited<br>near loads. | 300 | Not applicable | [130,135–137] |

## 8. Application of Digital Tools for Grid-Scale H<sub>2</sub> Optimization

The transition to grid-scale HESS demands a tightly integrated digital ecosystem spanning intelligent control, high-fidelity simulation, and real-time asset management. Figure 2 presents a unified Digital Intelligence Framework that maps data input flows encompassing renewable energy variability, grid signals, electrolyzer parameters, market pricing, and IoT sensor streams through an AI/machine learning (ML) core to three inter-dependent digital tool pillars. (i) AI-driven optimization and control, (ii) grid simulation software, and (iii) digital twin (DT) platforms. Together, these pillars converge on four key performance outcomes: cost and efficiency optimization, grid stability and reliability, reduced OPEX and system downtime, and long-duration storage dispatch. The subsections elaborate on each of the pillars in detail.



**Figure 2.** Integrated Digital Intelligence Framework for Grid-Scale H<sub>2</sub> Energy Storage System (HESS) Optimization.

### 8.1. Artificial Intelligence for Optimization and Control

Artificial intelligence (AI) is a transformative enabler of improved operational efficiency, reliability, and cost-effectiveness in grid-scale HESS [138]. Three complementary AI models, namely ML, reinforcement learning (RL), and deep learning (DL), address distinct operational challenges across the H<sub>2</sub> storage value chain. ML-based regression and

neural network models enable high-resolution forecasting of VRE output from solar photovoltaic and wind resources, thereby enabling proactive scheduling of electrolyzer operations to anticipate generation surpluses or shortfalls [139]. These models are effective for time-series anomaly detection and equipment fault prediction in electrolyzer stacks and fuel cell systems [140].

RL-based agents, trained in simulated grid environments, enable dynamic and adaptive dispatch strategies that co-optimize H<sub>2</sub> charging and discharging against real-time electricity market prices, grid frequency deviations, and network congestion signals [138]. Such agents can simultaneously balance competing objectives by maximizing storage revenues, maintaining frequency regulation ancillary service commitments, and prolonging electrolyzer stack life through temperature, voltage, and pressure control without explicit pre-programmed rules [140]. Genetic algorithms and model predictive control (MPC) are widely applied for multi-objective operational planning across multi-hour to day-ahead horizons [141,142].

Prominent research institutions active in this domain include the National Renewable Energy Laboratory (NREL, USA), Forschungszentrum Jülich (Germany), the Paul Scherrer Institute (Switzerland), and Imperial College London (UK), among others. The work of DeepMind (Google) on data center cooling control demonstrates a 40% reduction in cooling energy consumption using RL and has provided a widely cited proof of concept for applying similar algorithms to electrolyzer operational control [143]. Research teams at NREL and the Hydrogen and Fuel Cell Technologies Office (U.S. DOE) are adapting analogous frameworks for electrolyzer fleet management and grid service provision [51,144].

DT and IoT integration have improved real-time monitoring and predictive maintenance in H<sub>2</sub> systems. In a PV-hydrogen microgrid, a DT-enhanced SCADA framework achieved R<sup>2</sup> values of 0.982 for the PV generator and 0.888 for the PEM electrolyzer, indicating high-fidelity state estimation under operating conditions [145]. Similarly, incorporating Physics-Informed Neural Networks into a PEM electrolyzer DT reduced mean squared error by 12% compared with conventional neural networks and enabled degradation parameter extraction for predictive maintenance [146]. These results show that physics-constrained DT frameworks can support autonomous fault detection and lifecycle management in H<sub>2</sub> energy systems.

## 8.2. Modeling Grid Integration and System Dynamics

Accurate representation of H<sub>2</sub> system interactions with complex power networks requires specialized grid simulation software capable of resolving phenomena ranging from steady-state power flow to millisecond-scale electromagnetic transients. Table 4 provides a structured comparison of the principal simulation tools employed in HESS integration studies, distinguishing their primary domains, specific H<sub>2</sub>/HESS capabilities, user interfaces, and licensing models.

DIgSILENT PowerFactory, developed by DIgSILENT GmbH (Gomaringen, Germany), is the industry-leading platform for transmission and distribution network analysis for grid code compliance verification of H<sub>2</sub> plant interconnection [147]. Its built-in electrolyzer and fuel cell models support frequency response and inertia studies, which are critical for assessing the grid-forming capabilities. MATLAB/Simulink version R2024b (MathWorks, Natick, MA, USA) is the dominant research and development platform for control system design, enabling hardware-in-the-loop (HIL) testing of MPC- and RL-based dispatch controllers before deployment [148,149]. GridLAB-D, maintained by the Pacific Northwest National Laboratory (PNNL) under the U.S. Department of Energy, addresses distribution-level integration of HESS within smart grid architectures, including transactive energy frameworks and demand-response co-optimization [150]. OpenDSS

complements GridLAB-D by focusing on power quality and harmonic analysis for inverter-interfaced storage systems, which is particularly relevant for evaluating the grid coupling of power-electronics-controlled electrolyzers [150].

These tools support power flow calculations to identify optimal HESS siting, evaluate interconnection topology, and assess loading effects on the host network, collectively enabling systematic grid integration planning. A key methodological consideration is the coupling of these simulation environments: multi-tool co-simulation frameworks (e.g., MATLAB/Simulink linked to PowerFactory via FMI/FMU interfaces) are increasingly adopted when a single platform cannot simultaneously resolve all relevant timescales.

**Table 4.** Comparative Overview of Grid Simulation Software For H<sub>2</sub>/Hess Integration Studies.

| Software/Tool          | Developer/Origin                         | Primary Application                                                  | H <sub>2</sub> /HESS Capability                                                                                          |
|------------------------|------------------------------------------|----------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------|
| DIgSILENT PowerFactory | DIgSILENT GmbH, Germany                  | Power system stability, load flow, transient and dynamic analysis    | Frequency/voltage stability of H <sub>2</sub> re-conversion plant; fault studies; grid code compliance                   |
| MATLAB/Simulink        | MathWorks, USA                           | Dynamic system modeling, control design, numerical computation       | Electrolyzer and fuel cell stack modeling; MPC/RL-based dispatch controller design; HIL testing                          |
| GridLAB-D              | U.S. Dept. of Energy/PNNL, USA           | Distribution grid simulation, smart grid and DER integration         | Distribution-level HESS siting; demand-response with H <sub>2</sub> dispatch; transactive energy modeling                |
| OpenDSS                | EPRI, USA                                | Distribution system power flow; harmonics; PV/DER integration        | Power quality analysis for H <sub>2</sub> plant grid coupling; inverter-interfaced storage modeling                      |
| PSS®E                  | Siemens Energy, Germany                  | Transmission network planning, stability, and short-circuit analysis | Bulk-system H <sub>2</sub> plant interconnection; inertia and frequency response studies                                 |
| PSCAD                  | Manitoba Hydro International/MHI, Canada | Electromagnetic transient (EMT) simulation                           | Detailed switching transients in power electronics interfacing electrolyzers to grid                                     |
| Homer Pro              | Homer Energy (UL), USA                   | Microgrid optimization and techno-economic feasibility               | H <sub>2</sub> storage sizing and dispatch optimization; leveled cost of H <sub>2</sub> ; renewable curtailment analysis |
| TRNSYS                 | Univ. of Wisconsin–Madison, USA          | Transient energy system simulation (thermal + electrical)            | Thermal–electrical co-simulation of PEM electrolyzer systems; waste-heat integration modeling                            |

### 8.3. Digital Twin Applications for H<sub>2</sub> Infrastructure

DTs are high-fidelity virtual replicas of physical H<sub>2</sub> infrastructure, continuously synchronized with real-world assets via IoT sensor networks and edge computing platforms [151]. They are emerging as a transformative operational technology for large-scale HESS. The DT paradigm enables four distinct operational functions for real-time asset monitoring, predictive maintenance, operator training, and scenario-based optimization [152].

Real-time asset monitoring through DTs provides continuous, high-resolution visibility into electrolyzer stack performance (cell voltage distribution, membrane degradation indicators), compressor health metrics, pressure vessel integrity, and fuel cell output degradation, enabling condition-based maintenance regimes that replace costly time-based schedules [153]. AI-augmented predictive maintenance algorithms embedded in the DT environment identify incipient failure signs such as anomalous impedance evolution in electrolyzer cells, within days to weeks before functional failure, enabling planned maintenance interventions that avoid unscheduled outages and their associated revenue losses [154]. Demonstrated applications include H<sub>2</sub> refueling station operators using DTs

to detect early signs of compressor degradation and proactively schedule maintenance, thereby eliminating service interruptions [155].

Beyond monitoring, DTs function as operational rehearsal environments where operators can simulate extreme weather scenarios, grid islanding events, or sudden VRE generation drops to pre-develop and validate control strategies under conditions that cannot be safely tested on live infrastructure [156]. The DT platform developed for the Hy-Balance project in Denmark (Air Liquide) represents an early large-scale example, integrating electrolyzer operational data with grid-balancing service provision in near real-time [157]. More recently, the European HYGRID project and related Horizon Europe initiatives have advanced multi-site DT architectures that integrate data from geographically distributed H<sub>2</sub> production and storage assets. Commercially, Siemens Energy and ABB are among the industrial actors deploying DT frameworks for electrolyzer fleet management [158,159].

An important consideration is data latency and cybersecurity: DT systems operating in grid-connected environments must meet IEC 62351 cybersecurity standards and IEC 61850 communication protocols to ensure the integrity of control signals passed between the virtual model and the physical asset. As DT fidelity and integration depth increase, the attack surface expands correspondingly, making secure-by-design architecture a prerequisite rather than an afterthought.

## 9. Conclusions

This study has demonstrated that practical, large-scale deployment of grid-scale HESS is contingent on hybrid system architectures, optimized component configurations, and purpose-built infrastructure. For long-duration storage, geological cavern systems offer the most cost-effective solution, complemented by batteries or SMES for fast frequency ramp-up, thereby avoiding the capital burden of oversized PEM fuel cell (PEMFC) stacks.

Commercial-scale realization depends on concurrent advances in electrolyzer and fuel cell efficiency, manufacturing economies of scale, dedicated H<sub>2</sub> pipeline and storage infrastructure, and the standardization of integration and protection protocols underpinned by robust H<sub>2</sub> market structures. These systemic requirements align directly with SDG 9 (Industry, Innovation and Infrastructure), which calls for resilient, sustainable infrastructure and the fostering of innovation as foundations for inclusive industrial development [160]. The digital optimization tools, AI-driven control systems, and digital twin platforms examined in this study represent precisely the class of technological innovation that SDG 9 envisions as enabling sustainable industrialization at scale. Together, these findings indicate that the main barrier to H<sub>2</sub> energy deployment is not any single performance metric, but the combined challenge of electrolyzer costs and insufficient coordination across infrastructure, power, heat, and industrial systems. Closing this system-level gap, rather than focusing only on isolated component improvements, is critical to enabling H<sub>2</sub>'s contribution to decarbonized energy systems.

The capacity of HESS to buffer VRE output across seasonal timescales by reducing curtailment and improving the economic viability of high-penetration solar and wind systems directly advances Sustainable Development Goal (SDG) 7 (Affordable and Clean Energy), specifically Targets 7.2 and 7.3, which call for substantially increased renewable energy shares and improved energy efficiency [161]. By enabling higher VRE penetration without proportional grid reinforcement costs, HESS lowers the long run levelized cost of delivered clean energy, strengthening the affordability dimension of SDG 7 for utilities and end users alike.

Most fundamentally, green H<sub>2</sub> produced via electrolysis powered entirely by renewable electricity eliminates direct carbon emissions from long-duration dispatchable storage, positioning HESS as a measurable contributor to SDG 13 (Climate Action) and the

net-zero 2050 electricity pathways required under the Paris Agreement [162]. When advances in hybrid storage efficiency, digital optimization, and system-wide coordination converge with enabling policy and market conditions, H<sub>2</sub> can evolve from a promising concept to an indispensable enabler of resilient, decarbonized energy grids operating in concert with complementary storage technologies to manage long-duration VRE variability and deliver a concrete, measurable contribution to the global sustainable development agenda.

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## Abbreviations

|       |                                            |
|-------|--------------------------------------------|
| DT    | Digital Twin                               |
| GH    | Green Hydrogen                             |
| LHV   | Lower Heating Value                        |
| SOFC  | Solid Oxide Fuel Cell                      |
| GSES  | Grid Scale energy Storage                  |
| HIL   | Hardware-in-the-loop                       |
| IRA   | Inflation Reduction Act                    |
| PHS   | Pumped Hydro Storage                       |
| VRE   | Variable Renewable Energy                  |
| PSA   | Pressure Swing Adsorption                  |
| GHS   | Green Hydrogen Standard                    |
| TRL   | Technology Readiness Levels                |
| SMR   | Steam Methane Reforming                    |
| SDG   | Sustainable Development Goal               |
| AWE   | Alkaline Water Electrolyzers               |
| AEM   | Anion Exchange Membrane                    |
| HESS  | Hydrogen Energy Storage System             |
| RTEE  | RTEE round-trip electrical efficiency      |
| LOHC  | Liquid Organic Hydrogen Carrier            |
| P2HP  | Power-to-Hydrogen-to-Power                 |
| CAES  | Compressed Air Energy Storage              |
| PEMFC | Proton Exchange Membrane Fuel Cell         |
| SMES  | Superconducting Magnetic Energy Storage    |
| LBESS | Lithium-ion Battery Energy Storage Systems |

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