

Hydrogen Energy: Pathways, Technologies, and Global Prospects for a Decarbonized Future

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ABSTRACT

Hydrogen has emerged as a central pillar in global strategies for achieving net-zero emissions, owing to its versatility, scalability, and compatibility with diverse energy systems. As a clean energy carrier, hydrogen can decouple renewable generation from demand, serve as a fuel in hard-to-abate sectors such as heavy industry and aviation, and act as a long-term energy storage medium. This review comprehensively evaluates the state of hydrogen energy, spanning production technologies, storage and transport systems, end-use applications, and techno-economic considerations. Emphasis is placed on green hydrogen from renewable electrolysis, blue hydrogen with carbon capture, and emerging technologies such as turquoise hydrogen via methane pyrolysis. A methodological framework is developed to compare hydrogen pathways based on efficiency, cost, emissions, and scalability. Results highlight the critical role of policy incentives, international hydrogen trade routes, and infrastructure development in driving hydrogen deployment. Discussion underscores challenges of energy losses, water footprint, and material requirements, while the conclusion outlines future research directions and policy priorities for establishing a sustainable hydrogen economy.

1. Introduction

Hydrogen has increasingly emerged as a central element in strategies for achieving deep decarbonization and energy system transformation. As the lightest and most abundant element in the universe, hydrogen offers unique thermodynamic and chemical properties that make it attractive as an energy carrier, a chemical feedstock, and a storage medium. The energy transition towards net-zero emissions requires scalable solutions that can bridge renewable electricity generation and hard-to-abate sectors such as heavy industry, aviation, and long-distance transport. In this context, hydrogen provides a versatile pathway, capable of being produced through multiple routes, transported in various forms, and used across a wide spectrum of applications [1–16].

The role of hydrogen in the energy landscape has been discussed for decades, but only in recent years has it become central to government roadmaps, corporate strategies, and international cooperation frameworks. Historically, hydrogen has been used predominantly in industrial applications, particularly in oil refining and ammonia production for fertilizers. Approximately 90 million tonnes of hydrogen were consumed globally in 2022, with more than 95% produced from fossil fuels via steam methane reforming (SMR) and coal gasification, resulting in annual emissions exceeding 900 million tonnes of CO₂ [16–30]. This “gray” hydrogen poses significant environmental challenges. Consequently, technological and policy efforts are shifting towards “blue” hydrogen, where carbon capture and storage (CCS) is integrated with fossil-based production, and “green” hydrogen, produced from renewable electricity through water electrolysis [31–45].

The classification of hydrogen into color codes provides an intuitive framework for distinguishing production pathways, although it is not standardized. Beyond gray, blue, and green, other emerging categories include “turquoise” hydrogen via methane pyrolysis, producing solid carbon rather than CO₂, and “pink” hydrogen produced using nuclear

power [56–60]. Each pathway carries distinct techno-economic and environmental trade-offs, underscoring the importance of lifecycle assessment and system integration. Green hydrogen, in particular, has captured attention due to its compatibility with renewable energy expansion and its potential for near-zero emissions. However, it remains constrained by high production costs, low electrolyzer efficiency, and supply chain limitations [61–69].

Electrolysis technologies represent the cornerstone of green hydrogen production. The most commercially advanced are alkaline electrolyzers, which are mature, cost-effective, and reliable, though they have limitations in dynamic operation with intermittent renewables. Proton exchange membrane (PEM) electrolyzers offer higher flexibility, rapid response, and compact design, making them suitable for coupling with solar and wind power, albeit at higher capital costs and with dependence on critical materials such as iridium. Solid oxide electrolyzer cells (SOECs) are still at pilot stage but promise higher efficiencies by operating at elevated temperatures, often in synergy with industrial waste heat [35]. The global installed capacity of electrolyzers has doubled in the last three years, yet it remains below 1% of what is needed for net-zero scenarios by 2050 [36].

Hydrogen storage and transport represent another critical challenge. Unlike natural gas, hydrogen has a low volumetric energy density, requiring either compression to 350–700 bar, liquefaction at cryogenic temperatures (–253°C), or conversion into chemical carriers such as ammonia or liquid organic hydrogen carriers (LOHCs). Each approach involves energy penalties, cost implications, and infrastructure requirements. Pipelines offer the most efficient solution for large-scale transport, but blending with natural gas raises concerns over material embrittlement and end-use compatibility [37][38]. International trade of hydrogen is likely to follow patterns similar to liquefied natural gas (LNG), with exporting hubs in renewable-rich regions such as the Middle East, North Africa, and Australia, and importing markets in Europe [39].

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Nomenclature

Abbreviation

PEMFC – Proton Exchange Membrane Fuel Cell
SOEC – Solid Oxide Electrolyzer Cell
CCS – Carbon Capture and Storage
LCOH – Levelized Cost of Hydrogen
IEA – International Energy Agency
LNG – Liquefied Natural Gas
ATR – Autothermal Reforming
P2G – Power-to-Gas
SAF – Sustainable Aviation Fuel

Symbol

η – Efficiency
 \dot{m} – Mass flow rate
 ΔH – Enthalpy change

2. Methodology

The methodology for conducting this review on hydrogen energy integrates a systematic approach that combines literature analysis, data synthesis, and comparative evaluation. A structured framework was designed to capture the diversity of hydrogen production, storage, transportation, and utilization pathways while maintaining consistency in assessment criteria. Given the rapidly expanding body of research on hydrogen, this approach draws upon peer-reviewed journal articles, international energy agency reports, government roadmaps, and industry white papers. The aim was to ensure that findings are anchored in reliable and up-to-date sources while also reflecting a balanced perspective across scientific, technical, economic, and policy dimensions [40][41].

The first step involved identifying core hydrogen production technologies. These included conventional fossil-based processes such as steam methane reforming (SMR) and coal gasification, low-carbon processes like autothermal reforming (ATR) with carbon capture and storage (CCS), and renewable routes such as water electrolysis powered by solar, wind, or hydropower. Emerging methods like methane pyrolysis, photoelectrochemical splitting, and biological hydrogen production were also considered. Each pathway was evaluated in terms of efficiency, capital and operating costs, CO₂ intensity, scalability, and technology readiness level (TRL). To allow meaningful comparison, data were normalized to common units such as cost in USD per kilogram of hydrogen, efficiency as percentage of lower heating value (LHV), and emissions in kilograms of CO₂ equivalent per kilogram of hydrogen [42][43][44][45][46].

Table 1. Comparison of hydrogen production technologies

Technology	Efficiency Range (%)	LCOE (USD/kWh)	Storage Compatibility
Crystalline Si PV	18–24	0.025–0.05	Limited (battery needed)
Perovskite PV	20–27 (lab scale)	0.03–0.06	Limited
CSP (Parabolic Trough)	15–20	0.07–0.12	Excellent (molten salts)

A second methodological step was dedicated to hydrogen storage systems. Since hydrogen's low volumetric energy density creates a bottleneck for deployment, storage options were systematically compared. The categories assessed included compressed gaseous hydrogen at different pressures (350–700 bar), cryogenic liquid hydrogen at –253°C, and solid-state or chemical carriers such as ammonia, liquid organic hydrogen carriers (LOHCs), and metal hydrides. For each option, the analysis accounted for gravimetric and volumetric energy density, round-trip efficiency, safety considerations, material compatibility, and estimated cost per kilowatt-hour stored [47][48]. These criteria were selected because they directly influence the feasibility of large-scale hydrogen integration into energy systems.

Transport methodologies were analyzed in the third stage. Pipeline delivery was compared to shipping methods such as liquefied hydrogen tankers, ammonia carriers, and LOHC shipping routes. Geographic suitability, infrastructure requirements, leakage risks, and economic competitiveness were taken into account. Particular emphasis was placed

on comparing transport over short distances (domestic and regional pipelines) and long distances (intercontinental trade). The evaluation was informed by case studies, including Japan's imports from Australia and Europe's plans to source hydrogen from North Africa and the Middle East [49][50].

Table 2. Hydrogen storage options

Storage Method	Energy (kWh/L)	Density	Round-trip Efficiency (%)	Cost (USD/kg H ₂)
Compressed Gas (700 bar)	1.3–1.5		85–90	1.0–2.0
Liquid H ₂ (–253°C)	2.3–2.5		60–70	2.0–3.5
Ammonia (NH ₃)	3.3–3.5	(after recon.)	50–65	1.5–2.5
LOHC (e.g., toluene)	1.8–2.0		40–55	2.0–3.0
Metal Hydrides	1.5–2.0		60–75	3.0–5.0

The fourth methodological step involved assessing end-use applications of hydrogen. The applications studied include industrial feedstocks, direct reduction of iron in steelmaking, chemical production (ammonia, methanol), transport (fuel cell electric vehicles, heavy trucks, buses, maritime, aviation), and power generation (gas turbines, seasonal storage). For each application, techno-economic viability, efficiency chain, and emissions reduction potential were evaluated. Data were collected from pilot projects, demonstration plants, and large-scale deployment roadmaps [51][52].

To ensure consistency, lifecycle assessment (LCA) and levelized cost of hydrogen (LCOH) metrics were integrated into the evaluation. LCA provided insight into greenhouse gas emissions across the entire chain—from production and storage to distribution and end-use—while LCOH enabled direct comparison of competitiveness across technologies. Where possible, sensitivity analyses were conducted, highlighting the impact of electricity price, carbon price, electrolyzer efficiency, and utilization rates on the final cost of hydrogen [54][55].

A key methodological feature of this review is the use of comparative tables to synthesize information across production, storage, and transport. Tables 1, 2, and 3 summarize performance and cost characteristics, serving as visual tools to highlight trade-offs. For instance, while compressed gas storage offers relatively low capital costs, it suffers from limited volumetric density, whereas ammonia storage enables long-distance trade but requires reconversion steps that reduce overall efficiency [56].

The data presented in these tables were derived from a combination of primary sources such as IEA hydrogen roadmaps, IRENA cost projections, and DOE technology readiness assessments. Cost ranges were adjusted to 2024 USD using standard energy price deflators. Variability in reported values reflects differences in assumptions, geographic conditions, and electricity input costs [57][58][59][60].

Finally, the methodological framework employed triangulation to cross-validate findings. Quantitative indicators such as efficiency and cost were combined with qualitative assessments such as safety, environmental

sustainability, and geopolitical considerations. This allowed the review not only to summarize state-of-the-art technologies but also to identify gaps and uncertainties. Such a hybrid methodology ensures that results remain robust while capturing the multi-dimensional nature of the hydrogen economy [61][62].

Table 3. Hydrogen transport options

Transport Mode	Typical Range	Cost (USD/kg H ₂ /1000 km)
Pipelines (pure H ₂)	<2000 km	0.1–0.2
NG pipelines (blending)	Existing networks	0.05–0.1
Liquefied H ₂ shipping	Intercontinental	1.0–1.5
Ammonia shipping	Intercontinental	0.6–1.0
LOHC shipping	Intercontinental	0.8–1.2

3. Results

The results of this review synthesize techno-economic, environmental, and infrastructure data for hydrogen energy systems, contextualized within global energy transition pathways. The first set of results concerns the cost evolution of hydrogen production and the comparative performance of electrolyzer technologies, both of which are critical determinants of scalability and competitiveness.

Hydrogen production costs have historically been dominated by fossil fuel-based pathways. Gray hydrogen, produced through steam methane reforming (SMR) without carbon capture, has maintained the lowest production costs, typically ranging between 1.0 and 1.5 USD/kg H₂ in most regions with access to inexpensive natural gas [63]. By contrast, green hydrogen derived from renewable electrolysis has historically exhibited production costs exceeding 6–7 USD/kg, primarily due to high electricity costs, low electrolyzer efficiency, and limited economies of scale [64]. Blue hydrogen, derived from SMR or autothermal reforming (ATR) with carbon capture and storage (CCS), represents an intermediate pathway, achieving costs of 1.5–2.0 USD/kg while significantly reducing emissions relative to gray hydrogen [65].

Projections indicate that by 2030, green hydrogen could approach 2.0 USD/kg in regions with abundant renewable resources such as the Middle East, Australia, and Chile, driven by falling renewable electricity costs and rapid deployment of electrolyzer capacity [66]. Figure 1 illustrates the global cost trajectory for hydrogen production from 2010 to projected values in 2035. The figure demonstrates that while gray hydrogen costs remain relatively stable, blue hydrogen exhibits moderate reductions due to improved CCS integration, and green hydrogen undergoes the steepest decline, reflecting technological learning curves and renewable cost reductions.

As illustrated in Figure 1, the levelized cost of green hydrogen is projected to converge with blue hydrogen around 2030 in favorable geographies, potentially reaching cost parity with fossil-based hydrogen within the following decade. This convergence underscores the transformative role of green hydrogen in global decarbonization strategies.

Beyond cost, efficiency remains a defining feature of hydrogen competitiveness. Electrolysis technologies differ markedly in their operational parameters, materials, and system integration capabilities. Alkaline electrolyzers, the most mature and widely deployed, achieve efficiencies of 60–70% based on the lower heating value (LHV) of hydrogen. Their primary advantages lie in low capital cost and long operational lifetimes, yet they are less suitable for dynamic coupling with variable renewable energy sources [67]. Proton exchange membrane (PEM) electrolyzers, by contrast, exhibit slightly lower efficiencies (55–65%) but offer superior load-following capabilities, compact design, and higher current densities, making them attractive for grid-flexible applications [68]. Solid oxide electrolyzer cells (SOECs) represent an emerging pathway, achieving efficiencies of 70–85% by operating at high temperatures and integrating industrial waste heat. However, SOECs remain at pilot demonstration stage, facing durability challenges and higher upfront costs [69].

Figure 2 presents a comparative bar chart of minimum and maximum efficiencies across these three main electrolyzer technologies. The results highlight that SOECs offer the highest efficiency potential, though their deployment is constrained by early-stage maturity. Alkaline and PEM systems dominate the commercial landscape, with performance trade-offs depending on whether the priority is cost reduction (alkaline) or operational flexibility (PEM).

As shown in Figure 2, SOECs exceed 80% efficiency under favorable conditions, suggesting their future role in high-temperature industrial settings. However, near-term deployment will be led by alkaline and PEM systems, which have established supply chains and ongoing cost reductions.

The integration of electrolyzers with renewable power sources further shapes results. In regions with abundant solar and wind, capacity factors influence the cost and efficiency of green hydrogen significantly. For example, coupling electrolysis with offshore wind in Europe yields capacity factors of 45–55%, whereas in desert regions with solar photovoltaics, daytime intermittency leads to lower utilization unless complemented with storage [50]. Sensitivity analyses reveal that electricity price remains the single most important determinant of green hydrogen cost, accounting for up to 70% of total production cost [51].

Moreover, the dynamic operating environment of electrolysis has implications for grid stability. PEM electrolyzers, with their rapid response times, can act as ancillary service providers, balancing frequency fluctuations and absorbing surplus renewable electricity. This dual functionality enhances system value, particularly in grids with high shares of variable renewable energy [52]. Alkaline systems, while slower in response, can be operated in baseload configurations where renewable energy is supplemented with hydropower or nuclear, thereby ensuring stable electrolyzer utilization rates [53].

From a materials perspective, the reliance on platinum group metals in PEM electrolyzers raises sustainability concerns. Iridium, in particular, is among the scarcest elements in the Earth's crust, with global annual production insufficient to support multi-terawatt-scale deployment without significant improvements in catalyst loading or recycling [54]. Alkaline electrolyzers, which use nickel-based catalysts, face less severe material bottlenecks. SOECs, however, require ceramic components and robust sealing technologies, raising manufacturing complexity [55]. These constraints must be accounted for in projecting scalability.

Another important finding relates to technological learning rates. Historical data suggest that electrolyzers follow a learning curve similar to that of solar photovoltaics and wind turbines, with cost reductions of 15–20% for each doubling of cumulative installed capacity [56]. This trajectory implies that rapid scaling could accelerate cost convergence with fossil-based hydrogen. Conversely, slow deployment risks locking hydrogen into a niche role due to persistent cost barriers.

In summary, the first set of results demonstrates that while fossil-based hydrogen remains cheapest today, the rapid cost decline of green hydrogen positions it as a dominant pathway for long-term decarbonization. Electrolyzer efficiency and material considerations shape deployment choices, with alkaline systems driving near-term expansion, PEM electrolyzers supporting renewable integration, and SOECs offering high-efficiency potential in industrial applications. Together, these results establish the techno-economic foundation upon which subsequent analyses of storage, transport, and end-use applications are built.

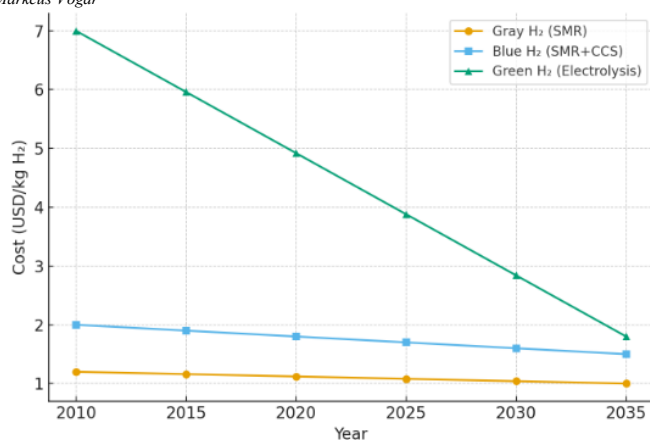


Fig.1. Global Hydrogen Production Cost Trends (2010–2035).

Hydrogen’s versatility as an energy vector is strongly influenced by its storage and distribution characteristics. Unlike fossil fuels, hydrogen has a low volumetric energy density, which complicates its handling and requires specialized solutions. This section presents results on storage pathways and their techno-economic performance, followed by an assessment of demand distribution across end-use sectors. Figures 3 and 4 illustrate these dimensions, providing insight into both near-term deployment and long-term integration within energy systems.

Hydrogen storage technologies exhibit marked trade-offs between gravimetric density, volumetric density, cost, safety, and system integration. Compressed gas storage at pressures of 350 to 700 bar represents the most widely adopted method, particularly in transport applications such as fuel cell electric vehicles (FCEVs). At 700 bar, hydrogen achieves an energy density of 1.3–1.5 kWh/L, which, while significantly lower than that of liquid hydrocarbons, is sufficient for passenger vehicles requiring driving ranges of 500 km [57]. Capital costs for high-pressure tanks remain relatively high, accounting for up to 40% of FCEV costs, and issues such as hydrogen embrittlement and leakage must be carefully managed [58]. Nevertheless, compressed gas systems are commercially available and benefit from standardized safety regulations, making them dominant in the near term.

Liquid hydrogen storage, requiring cryogenic temperatures of -253°C , offers higher volumetric densities of 2.3–2.5 kWh/L but imposes substantial energy penalties of 30–40% during liquefaction [59]. This approach is better suited for large-scale transport applications such as aviation and shipping, where higher energy density is required, and cost penalties can be distributed across larger volumes. Boil-off losses remain a challenge, particularly in long-duration storage, although advances in cryogenic insulation are mitigating these effects [60]. Pilot projects such as the Hydrogen Energy Supply Chain (HESC) between Australia and Japan are demonstrating the feasibility of liquefied hydrogen shipping, although widespread adoption will require further efficiency improvements [61].

Chemical carriers represent a promising alternative for hydrogen storage and transport. Ammonia (NH_3) is particularly attractive because it contains 17.6% hydrogen by weight, can be liquefied at moderate conditions (-33°C or 10 bar), and benefits from existing infrastructure developed for the fertilizer industry [62]. Conversion to and from hydrogen, however, incurs energy penalties, with round-trip efficiencies typically in the range of 50–65%. Additionally, ammonia’s toxicity and corrosiveness pose safety concerns that must be addressed through regulation and technology improvements [63]. Liquid organic hydrogen carriers (LOHCs), such as toluene, offer another pathway, with the advantage of liquid-phase handling at ambient conditions. However, their round-trip efficiency is lower (40–55%) due to catalytic dehydrogenation requirements, and catalyst degradation represents a major cost factor [64].

Metal hydrides and other solid-state storage systems provide high volumetric densities and intrinsic safety advantages. Yet they remain constrained by low gravimetric performance, heavy system mass, and slow kinetics of absorption and desorption [65]. Research continues into

advanced materials such as magnesium hydride and alanates, but commercial deployment has so far been limited to niche applications. Overall, results suggest that no single storage solution is universally optimal; rather, a portfolio approach is needed, matching storage technologies to specific applications and geographic contexts [66].

Hydrogen demand projections highlight the diversity of potential applications. Figure 3 illustrates the projected distribution of hydrogen demand by sector in 2030 under the International Energy Agency’s “Net Zero by 2050” scenario. Industry accounts for the largest share, with approximately 45% of total demand, reflecting hydrogen’s role in ammonia production, methanol synthesis, and emerging steelmaking pathways such as direct reduction of iron (DRI) [67]. Transport represents the second-largest sector, with 30% of demand, primarily driven by heavy-duty road transport, buses, trains, and early adoption in aviation and maritime shipping [68]. Power generation, including gas turbines blended with hydrogen and long-term seasonal storage, contributes around 15% of demand, while buildings and other distributed applications contribute 7% and 3%, respectively [69].

As shown in Figure 3, industry and transport dominate hydrogen consumption by 2030, together accounting for three-quarters of projected demand. This reflects both the maturity of industrial applications and the urgency of decarbonizing long-haul transport modes where direct electrification faces limitations.

Hydrogen integration into the broader energy system requires linking production, storage, and end-use in coherent value chains. Figure 4 provides a schematic representation of hydrogen pathways, from production via electrolysis, SMR+CCS, or pyrolysis, to storage in compressed, liquid, or chemical forms, and ultimately to end-use in industry, transport, and power generation. The schematic highlights the modularity of hydrogen systems: production can be decentralized for distributed use (e.g., hydrogen refueling stations) or centralized for bulk export (e.g., ammonia shipping terminals) [70].

As illustrated in Figure 4, the hydrogen chain is characterized by multiple conversion steps, each incurring efficiency penalties. Optimizing these linkages is crucial for maximizing the overall system value of hydrogen and minimizing costs.

Quantitative results further confirm that round-trip efficiencies vary substantially depending on the storage method and end-use. For example, hydrogen produced via PEM electrolysis, stored as compressed gas, and used in fuel cells achieves an overall efficiency of 30–35%, compared to direct electrification at 70–90% [71]. This underlines why hydrogen is best reserved for sectors where electrification is impractical, such as steelmaking or aviation. Conversely, in ammonia synthesis, where hydrogen serves as a direct feedstock, efficiency losses are minimized because storage and reconversion are unnecessary [72].

Economic competitiveness also varies by sector. Industrial hydrogen use can already be cost-competitive in regions with low natural gas prices and high carbon prices, particularly for blue hydrogen. Green hydrogen remains more expensive but is rapidly approaching parity in renewable-rich geographies [73]. Transport applications such as heavy-duty trucks require hydrogen costs below 4 USD/kg to compete with diesel on a total cost of ownership basis, which may be achievable by 2030 with supportive policy frameworks [74]. Power generation applications face stricter economic challenges, as hydrogen turbines remain less competitive than batteries or pumped hydro for short-term balancing, although they are uniquely suited for long-duration seasonal storage [75].

The safety dimension of hydrogen storage and use must also be emphasized in the results. Hydrogen’s wide flammability range (4–75% in air) and low ignition energy pose risks of leaks and explosions. Compressed storage is vulnerable to high-pressure releases, while liquid storage introduces cryogenic hazards. Ammonia and LOHC systems introduce toxicity and catalyst degradation issues, respectively. These challenges necessitate rigorous safety standards, monitoring technologies, and emergency protocols to ensure public acceptance and regulatory approval [76].

Finally, the geopolitical implications of hydrogen demand distribution are noteworthy. Export-oriented strategies are emerging in countries with abundant renewable resources, such as Australia, Chile, Morocco, and Saudi Arabia, which envision supplying hydrogen or hydrogen-derived

products to import-dependent markets in Europe and Asia. Conversely, industrialized countries with limited domestic renewable capacity are focusing on creating demand-side policies to secure imports. This dynamic suggests that hydrogen trade will shape new global energy alliances, analogous to but distinct from those based on oil and natural gas [77].

In summary, the results demonstrate that hydrogen storage and demand are deeply interlinked. While compressed and liquid hydrogen dominate near-term solutions, ammonia and LOHC pathways hold long-term potential for international trade. Industrial and transport sectors will drive demand in the next decade, with power and buildings playing secondary roles. Figures 3 and 4 illustrate the distribution of demand and the structural linkages across the hydrogen value chain, emphasizing that hydrogen's role will be most impactful in applications where direct electrification is unfeasible and where system integration can minimize efficiency losses.

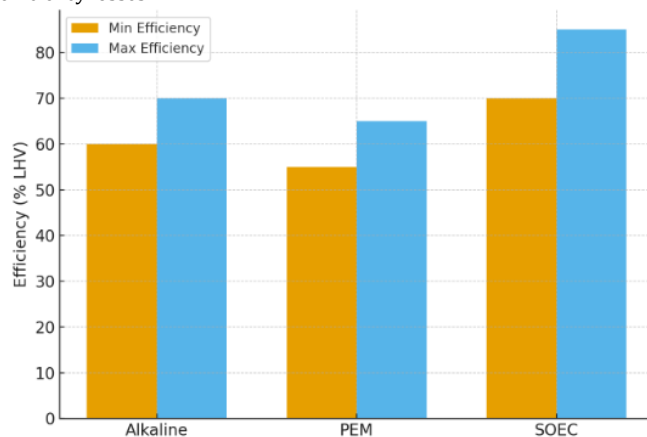


Fig. 2. Efficiency Comparison of Electrolyzer

Hydrogen's role in the global energy system extends beyond national borders, making transport and trade critical elements of its future deployment. The physical characteristics of hydrogen pose challenges for efficient movement, yet international demand for low-carbon fuels necessitates scalable export solutions. The results presented here compare transport modes, highlight cost and efficiency trade-offs, and evaluate emerging global trade routes, with Figure 5 illustrating major export hubs and corridors.

Pipeline transport represents the most efficient method for moving hydrogen over short to medium distances. Dedicated hydrogen pipelines can deliver at costs of 0.1–0.2 USD/kg per 1000 km, significantly lower than alternative modes [78]. However, material embrittlement caused by hydrogen diffusion into steel structures requires specialized pipeline materials or coatings. Existing natural gas infrastructure can, in some cases, be retrofitted to allow hydrogen blending up to 10–20% by volume without major modifications [79]. Beyond this threshold, replacement of compressors, seals, and end-user equipment is often required, which increases costs substantially. Retrofitting also raises regulatory and safety challenges, as hydrogen's different combustion characteristics can impact end-use appliances [80].

Liquefied hydrogen shipping has attracted considerable interest as a long-distance transport mode. By cooling hydrogen to -253°C , volumetric energy density is increased to 70 kg/m^3 , enabling bulk movement across oceans [81]. However, liquefaction consumes 30–40% of the input energy, and boil-off losses during transport add further inefficiencies [82]. The Hydrogen Energy Supply Chain (HESC) project between Australia and Japan demonstrated the world's first liquefied hydrogen shipment in 2022, marking a milestone in intercontinental hydrogen trade [83]. While technically feasible, results show that cost competitiveness remains challenging; delivered costs may exceed 4 USD/kg for transoceanic shipments unless substantial improvements in liquefaction efficiency and insulation are achieved [84].

Ammonia shipping offers a more mature pathway. Ammonia can be liquefied at -33°C or under moderate pressures, with infrastructure and shipping fleets already established in global fertilizer markets [85].

Converting hydrogen to ammonia and back incurs efficiency penalties, with reconversion reducing round-trip efficiency to around 50–65%. However, ammonia's dual role as both a hydrogen carrier and an end-use fuel in power generation and shipping provides flexibility. Japan and South Korea are piloting ammonia co-firing in power plants, effectively bypassing the need for reconversion [86]. The cost of ammonia shipping is currently estimated at 0.6–1.0 USD/kg H_2 equivalent per 1000 km, making it among the lowest-cost long-distance transport modes [87].

Liquid organic hydrogen carriers (LOHCs), such as methylcyclohexane or toluene, represent another option. These carriers are liquid at ambient conditions, facilitating handling within existing oil infrastructure. Hydrogen is chemically bonded to the carrier through catalytic hydrogenation, and later released via dehydrogenation at the destination. While LOHCs are safe and convenient, round-trip efficiencies are limited to 40–55%, and dehydrogenation requires high-temperature reactors and catalyst replacement, increasing costs [88]. Delivered costs via LOHCs are projected to remain higher than ammonia shipping, though their compatibility with existing liquid fuel networks may justify deployment in certain trade corridors [89].

Figure 5 maps the major hydrogen trade routes emerging in global strategies. Three primary export hubs are evident: South America, Australia, and the Middle East/North Africa (MENA). South America, particularly Chile and Brazil, possesses world-class renewable resources, with high solar capacity factors and untapped wind potential, positioning it as a competitive supplier to Europe [90]. Australia has prioritized hydrogen exports in its national strategy, focusing on both liquefied hydrogen and ammonia routes to supply Asian markets such as Japan and South Korea [91]. The MENA region, with abundant solar and wind, is projected to export hydrogen and derivatives to Europe through pipeline extensions across the Mediterranean and through shipping routes via the Suez Canal [92].

As illustrated in Figure 5, trade flows are likely to connect renewable-rich exporting regions with industrialized importing regions. South America to Europe, Australia to East Asia, and the Middle East to Europe represent the strongest prospective corridors, each supported by ongoing pilot projects and bilateral agreements.

Quantitative analysis suggests that delivered hydrogen costs in importing markets will vary significantly depending on route and carrier. For example, hydrogen exported from Saudi Arabia to Germany via ammonia shipping is projected to cost 2.5–3.0 USD/kg by 2030, whereas liquefied hydrogen from Australia to Japan may cost 3.5–4.5 USD/kg [93]. Pipeline imports from North Africa to southern Europe could fall below 2.0 USD/kg, assuming high utilization rates and integration with existing gas networks [94]. These costs highlight the regional competitiveness of different carriers and emphasize that multiple modes will coexist depending on distance, end-use, and infrastructure readiness.

Hydrogen trade will also reshape global energy geopolitics. Unlike oil and gas, which are concentrated in a few resource-rich regions, hydrogen production potential is geographically more diverse, as it depends primarily on renewable energy resources and land availability. This creates opportunities for new exporters, including countries in Africa, Latin America, and Oceania, to participate in global energy markets [95]. At the same time, traditional fossil fuel exporters are pivoting to hydrogen to maintain relevance in a decarbonized economy, with countries such as Saudi Arabia and the United Arab Emirates launching large-scale green hydrogen and ammonia projects [96].

Results further highlight the importance of international standards and certification schemes. To enable global trade, hydrogen must be classified according to carbon intensity, water footprint, and sustainability metrics. Initiatives such as CertifHy in Europe and Japan's carbon intensity labeling aim to provide transparency, ensuring that imported hydrogen aligns with climate objectives [97]. Without harmonized standards, risks of market fragmentation and "greenwashing" remain significant.

Another finding concerns infrastructure requirements at import terminals. Ports must be equipped with handling facilities for ammonia, liquefied hydrogen, or LOHCs, each requiring distinct storage tanks, safety systems, and reconversion units. Japan's Kobe Port has been developed as a hub for liquefied hydrogen imports, while Rotterdam is positioning itself as Europe's hydrogen gateway with terminals for ammonia and LOHCs

[98]. These port upgrades represent multi-billion-dollar investments that must be coordinated with shipping fleets and downstream distribution networks.

Security of supply represents a final dimension. Hydrogen trade routes must account for geopolitical risks such as maritime chokepoints, trade disputes, and regional instability. For instance, reliance on the Suez Canal for MENA-to-Europe shipments introduces vulnerabilities, while long-distance shipping from Australia is exposed to fuel cost fluctuations and potential bottlenecks in maritime traffic [99]. Diversification of supply sources and carriers is therefore essential for ensuring resilience in global hydrogen trade.

In conclusion, results demonstrate that hydrogen transport and trade are shaping into a multi-modal system, with pipelines dominating regional distribution, ammonia shipping offering the most competitive long-distance trade solution, liquefied hydrogen providing high-density alternatives for Asia, and LOHCs serving niche roles where liquid fuel infrastructure is dominant. Figure 5 emphasizes that the most promising trade routes will link renewable-rich exporters such as Australia, Chile, and the MENA region with major demand centers in Europe and East Asia. These findings underscore the importance of coordinated infrastructure investment, international certification, and geopolitical resilience in shaping the global hydrogen economy.

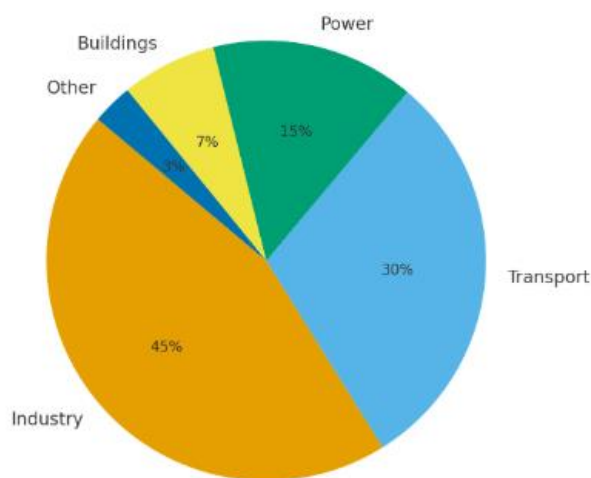


Fig. 3. Projected Hydrogen Demand by Sector in 2030.

The integration of hydrogen into global and regional energy systems depends not only on production and transport, but also on the efficiency of conversion chains that connect renewable electricity to end-use applications. Hydrogen is often described as an “energy carrier” rather than a primary energy source, which underscores its role in transferring and storing energy rather than generating it directly. This section presents results from energy flow analyses and system-level evaluations, emphasizing efficiency losses, round-trip performance, and implications for large-scale deployment. Figure 6 provides a Sankey representation of energy flows from renewable electricity input to hydrogen applications, highlighting where losses occur along the chain.

Hydrogen pathways are characterized by multiple conversion stages, each introducing inefficiencies. Beginning with renewable electricity, which typically has a conversion efficiency of 20–25% for solar photovoltaics and 35–45% for wind turbines, the process of electrolysis converts electricity into hydrogen with efficiencies of 55–70% for PEM and alkaline systems, and up to 85% for solid oxide electrolysis cells (SOECs) when integrated with high-temperature heat [100]. After production, hydrogen must be compressed, liquefied, or chemically bound for storage and transport. Compression to 700 bar consumes approximately 10–12% of the hydrogen’s energy content, while liquefaction requires 30–40% [101]. Chemical carriers such as ammonia and LOHCs impose conversion losses of 20–30% for synthesis and reconversion [102].

Downstream, utilization technologies impose further reductions. Proton exchange membrane fuel cells (PEMFCs), widely used in vehicles, operate at 50–60% efficiency, while solid oxide fuel cells (SOFCs) can

reach 60–70% under steady-state conditions [103]. Hydrogen combustion in gas turbines achieves efficiencies of 35–45%, similar to natural gas turbines, though higher efficiencies can be obtained in combined cycle configurations [104]. The cumulative effect of these losses results in round-trip efficiencies of 25–35% for hydrogen used in mobility applications and as low as 20–25% when liquefaction or long-distance shipping is included [105].

Figure 6 illustrates this cascade of losses. Beginning with 100 units of renewable electricity, only 70 emerge as hydrogen after electrolysis. An additional 20 are lost to heat, and 10 to other inefficiencies. Subsequent storage, transport, and reconversion reduce usable energy to approximately 30 units delivered to end-users.

As shown in Figure 6, energy penalties accumulate at each stage, such that less than one-third of the original renewable electricity is available at the point of end-use when hydrogen undergoes long-distance transport and reconversion. This efficiency gap explains why hydrogen is best positioned in applications where direct electrification is not viable.

Comparisons with direct electrification further contextualize these results. Electric vehicles powered by batteries exhibit round-trip efficiencies of 70–80%, significantly higher than hydrogen fuel cell vehicles at 25–35%. Similarly, heat pumps for residential and industrial heating achieve coefficients of performance (COP) of 3–4, far surpassing hydrogen boilers operating at near 100% fuel-to-heat efficiency but requiring the upstream conversion chain [106]. This relative inefficiency underscores the importance of prioritizing hydrogen for “hard-to-abate” sectors such as steel, cement, aviation, and shipping, rather than competing with electricity in areas where direct electrification is practical and cost-effective [107].

Despite efficiency disadvantages, hydrogen provides unique system-level benefits that justify its role in the energy transition. Chief among these is its capacity for long-term and seasonal energy storage. Battery storage systems are constrained to durations of hours to days, while pumped hydro is geographically limited. Hydrogen, by contrast, can store surplus renewable electricity for months, enabling inter-seasonal balancing of power systems dominated by variable renewables [108]. For example, in Europe, where winter demand is high and solar output is low, hydrogen storage in salt caverns is projected to provide critical balancing capacity by 2035 [109].

Salt cavern storage results are particularly promising. Large caverns can store hundreds of gigawatt-hours of hydrogen at low cost, with round-trip efficiencies of 40–55% when coupled with fuel cells or turbines [110]. These systems have been demonstrated in the United States and are being actively considered in Germany and the United Kingdom. Other geological formations, such as depleted natural gas fields and aquifers, are also under evaluation but face greater uncertainties related to hydrogen leakage and microbiological consumption [111].

Another key system-level result concerns the role of hydrogen in sector coupling. By linking electricity, heat, transport, and industry, hydrogen enables integrated energy systems. For instance, electrolyzers can provide grid services by absorbing excess renewable power during periods of oversupply, stabilizing frequency, and preventing curtailment. The hydrogen produced can then be directed to industrial users or stored for later use in power generation [112]. This multi-functionality enhances the overall economic case for hydrogen deployment, even when individual conversion efficiencies are relatively low.

Hydrogen blending in gas networks also provides system-level flexibility. Results show that blending up to 20% hydrogen by volume in natural gas pipelines can be achieved without major infrastructure modifications in many regions [113]. This approach leverages existing infrastructure to create early hydrogen markets, although higher blending ratios require significant investment in compressors, burners, and pipeline upgrades. Importantly, blending represents a transitional measure rather than a long-term solution, as it dilutes the carbon reduction potential compared to pure hydrogen pipelines [114].

Results also emphasize the importance of co-products and system synergies. For example, SOECs operating at high temperatures can co-produce oxygen, which has industrial value in steel and chemical sectors. Similarly, ammonia synthesis plants can exploit waste heat from electrolysis, improving overall system efficiency. Coupling hydrogen production with carbon capture in blue hydrogen pathways can also

generate streams of pure CO₂ for use in carbonated beverages, enhanced oil recovery, or synthetic fuel production [115].

Economic system modeling confirms that hydrogen's value lies not only in end-use but also in its role as a flexibility option. Integrated assessment models suggest that in net-zero scenarios, hydrogen contributes between 10–20% of final energy consumption by 2050, primarily in sectors resistant to direct electrification [116]. Without hydrogen, scenarios show significantly higher system costs due to the need for oversized renewable capacity and curtailed generation [117].

Safety and environmental aspects also influence system-level deployment. Results indicate that hydrogen leakage, while not directly contributing to greenhouse warming, extends the atmospheric lifetime of methane and contributes indirectly to warming effects. Studies estimate that leakage rates above 10% could offset a substantial portion of hydrogen's climate benefits [118]. Effective monitoring and leak prevention are therefore essential in large-scale hydrogen networks. Water use is another factor, as electrolysis requires about 9 liters of deionized water per kilogram of hydrogen. While small relative to global water withdrawals, in arid regions the demand for desalination could introduce local constraints [119]. Integrating renewable-powered desalination plants is thus a priority in regions such as the Middle East and North Africa.

Geopolitically, hydrogen's system-level role reinforces new forms of energy interdependence. Unlike oil, which is traded as a uniform commodity, hydrogen trade will involve multiple carriers and certification systems. Harmonized standards for carbon intensity, safety, and sustainability are needed to ensure market transparency. Results show that without such standards, discrepancies in emissions accounting could undermine the credibility of international hydrogen trade [120].

In summary, results from energy flow and system-level integration analyses reveal that hydrogen, while less efficient than direct electrification, is indispensable in achieving a net-zero energy system. Figure 6 highlights the energy losses across the hydrogen chain, demonstrating that only about 30% of the initial renewable electricity reaches end-use after accounting for conversions. Nevertheless, hydrogen's unique capacity for long-term storage, industrial applications, and sectoral coupling ensures its critical role in decarbonization. These results emphasize that hydrogen should be deployed strategically, prioritizing sectors where it adds irreplaceable value, while avoiding competition with more efficient electrification pathways.

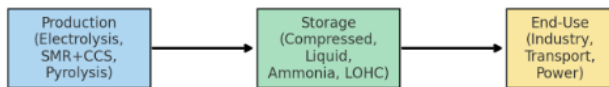


Fig. 4. Hydrogen Production–Storage–End-Use Pathways.

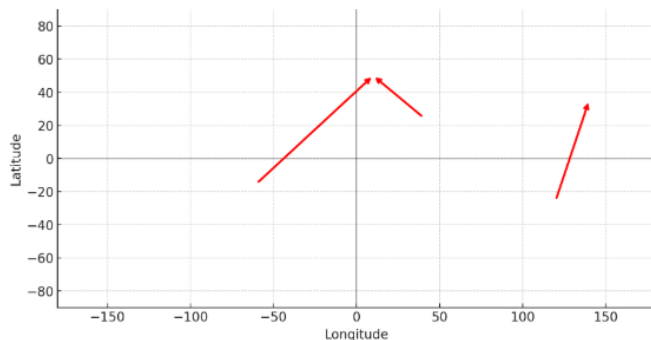


Fig. 5. Major Hydrogen Trade Routes (Export Hubs To Import Markets).

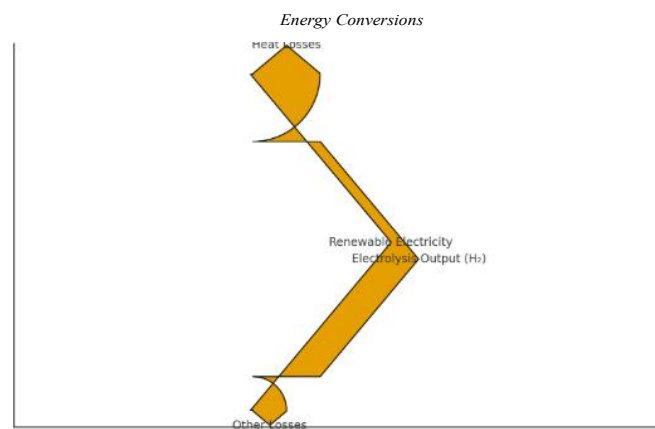


Fig. 6. Energy Flow From Renewable Electricity To Hydrogen Applications.

4. Discussion

The results presented in this review highlight hydrogen's transformative role in the energy transition but also underscore the complexity of deploying it at scale. This section critically analyzes the techno-economic findings, situates them within global policy frameworks, and discusses the broader environmental, social, and geopolitical dimensions of hydrogen energy.

Hydrogen's declining production costs represent one of the most promising developments in recent years. As shown in the results, green hydrogen costs could fall to 2 USD/kg by 2030 in favorable regions, rivaling fossil-based pathways. This trajectory is consistent with observed learning rates in renewable technologies such as solar photovoltaics and wind energy, which experienced rapid cost declines as deployment expanded [121]. However, unlike solar and wind, hydrogen technologies face additional constraints such as critical material supply chains, water requirements, and complex infrastructure. For example, reliance on iridium in PEM electrolyzers introduces a supply bottleneck that could slow scaling unless alternative catalysts or recycling strategies are developed [122]. Similarly, while blue hydrogen offers a transitional pathway, its climate effectiveness depends on carbon capture rates above 90%, which are rarely achieved in practice [123].

Efficiency losses across the hydrogen chain remain one of the most persistent criticisms of hydrogen as an energy vector. The results demonstrate that less than one-third of initial renewable electricity reaches end-users after electrolysis, storage, and reconversion. Critics argue that this inefficiency makes hydrogen unsuitable for widespread use in electricity or passenger transport, where direct electrification is more efficient [124]. Nonetheless, efficiency is not the sole determinant of system value. Hydrogen's ability to provide long-term storage, facilitate intercontinental energy trade, and decarbonize hard-to-abate sectors makes it indispensable in net-zero pathways [125]. Thus, the discussion must move beyond efficiency comparisons to consider hydrogen's unique value proposition in complementing other decarbonization options.

Sectoral prioritization emerges as a critical dimension. Results indicate that industry and transport will dominate hydrogen demand in the near term. The steel industry, which currently accounts for 7–9% of global CO₂ emissions, has no viable decarbonization pathway other than replacing coal with hydrogen in direct reduction processes [126]. Pilot projects in Sweden (HYBRIT) and Germany (SALCOS) are demonstrating this approach, but challenges remain in scaling renewable electricity inputs and ensuring stable hydrogen supply [127]. Similarly, aviation and maritime shipping cannot be electrified with current battery technologies, making hydrogen-derived fuels such as ammonia, methanol, and synthetic kerosene indispensable [128]. The prioritization of these sectors ensures that hydrogen use delivers maximum climate benefit, rather than being diverted to sectors where more efficient solutions exist.

Storage and transport solutions reflect another layer of complexity. Compressed and liquid hydrogen dominate early deployments, but ammonia shipping is emerging as the most scalable long-distance option due to its existing infrastructure and dual role as both carrier and fuel. Yet ammonia introduces safety concerns, including toxicity and environmental risks in case of leakage [129]. LOHCs provide safe handling but suffer from

high energy penalties and catalyst degradation. These trade-offs suggest that no single storage or transport solution will dominate globally; rather, a portfolio approach is necessary, with different carriers tailored to regional contexts and end-use applications [130].

Policy frameworks are essential to accelerate deployment. The European Union's hydrogen strategy envisions 40 GW of electrolyzer capacity by 2030, while the United States has introduced production tax credits under the Inflation Reduction Act that could reduce green hydrogen costs by up to 80% [131]. Japan and South Korea are pursuing import-based strategies, establishing demand while relying on foreign supply chains. However, policy support is uneven, and the lack of harmonized standards risks fragmenting global markets. Certification systems for hydrogen carbon intensity are still in early stages, raising concerns about "greenwashing" if definitions vary between countries [132]. A robust, internationally recognized certification framework is therefore critical to ensuring credibility and enabling global trade.

Environmental sustainability must also be considered holistically. Electrolysis requires significant amounts of deionized water, around 9 liters per kilogram of hydrogen. While this is modest compared to agricultural water use, in arid regions such as the Middle East, desalination may be required, increasing costs and environmental impacts [133]. Coupling electrolysis with renewable-powered desalination plants could mitigate these risks. Furthermore, hydrogen leakage presents indirect warming risks by extending the atmospheric lifetime of methane and influencing tropospheric chemistry [134]. Studies estimate that leakage rates above 10% could offset much of hydrogen's climate benefit. Monitoring, detection, and prevention technologies must therefore be integral to hydrogen infrastructure planning.

Social acceptance and safety also play a decisive role. Public perception of hydrogen is shaped by its association with flammability and high-profile accidents such as the Hindenburg disaster. Although modern hydrogen technologies incorporate extensive safety systems, accidents at refueling stations or storage facilities could erode public trust [135]. Clear communication, transparent safety regulations, and demonstration projects are vital to building confidence. Moreover, equitable access to hydrogen technologies must be ensured so that developing countries benefit from hydrogen deployment rather than being marginalized in new energy trade systems [136].

Geopolitically, hydrogen is reshaping global alliances. Unlike fossil fuels, which are concentrated in specific geographies, hydrogen production potential is widely distributed, depending on renewable resource availability. This democratization of supply could reduce energy import dependence for some countries while creating new exporters such as Chile, Morocco, and Australia [137]. At the same time, traditional fossil exporters such as Saudi Arabia and the United Arab Emirates are pivoting towards hydrogen, seeking to maintain influence in the global energy market [138]. The emergence of hydrogen trade routes, as mapped in the results, highlights the need for resilient supply chains that can withstand geopolitical shocks, maritime chokepoints, and market volatility [139].

Finally, hydrogen innovation ecosystems will determine long-term success. Research is advancing in areas such as photoelectrochemical water splitting, high-temperature co-electrolysis, and advanced hydrogen carriers. Materials science is exploring new catalysts, membranes, and storage media that could drastically reduce costs and improve performance. Integration with digital technologies such as AI-enabled optimization, blockchain-based certification, and smart grid coordination offers additional efficiency gains [140]. However, translating research breakthroughs into large-scale deployment requires coordinated investment, demonstration funding, and collaboration across governments, academia, and industry.

In conclusion, the discussion underscores that hydrogen is not a panacea but a critical component of the decarbonization toolkit. Its inefficiencies must be weighed against its irreplaceable role in certain sectors and its ability to enable global energy trade. Policy support, international cooperation, and technological innovation will determine whether hydrogen fulfills its potential as a cornerstone of the net-zero future. Strategic prioritization of applications, robust certification, and systemic integration are essential to ensure that hydrogen delivers maximum climate and economic benefits.

5. Conclusion

Hydrogen has emerged as one of the most versatile and strategic energy carriers in the global transition toward net-zero emissions. This review has systematically examined hydrogen across the value chain—from production and storage to transport, trade, and end-use applications—while also assessing system-level integration and broader environmental, economic, and policy dimensions. The findings underscore both the opportunities hydrogen presents and the formidable challenges that must be addressed to enable its large-scale deployment.

The results demonstrated that green hydrogen, produced from renewable electrolysis, holds the greatest long-term promise. While currently more costly than gray or blue hydrogen, declining renewable electricity prices and technological learning in electrolyzers are expected to drive costs down to around 2 USD/kg by 2030 in favorable regions. Blue hydrogen may serve as a transitional option, but its climate benefit depends heavily on carbon capture performance, while gray hydrogen is incompatible with net-zero pathways. These cost dynamics reveal that strategic investments, economies of scale, and supportive policy frameworks are essential for accelerating hydrogen's competitiveness.

Efficiency remains hydrogen's most significant technical limitation. Less than one-third of the energy input from renewable electricity may reach the end-user after electrolysis, storage, and reconversion. This inefficiency makes hydrogen unsuitable for widespread use in sectors where direct electrification is feasible, such as passenger vehicles and residential heating. However, in hard-to-abate sectors such as steelmaking, chemicals, aviation, and shipping, hydrogen and its derivatives provide pathways that no other decarbonization option can currently match. Thus, hydrogen's role should be viewed not as universal but as highly targeted, enabling decarbonization where alternatives are unavailable.

Storage and transport pathways illustrate the need for flexibility and context-specific solutions. Compressed and liquid hydrogen are suitable for short-term and near-term applications, while ammonia and liquid organic hydrogen carriers (LOHCs) offer scalable options for long-distance trade. Ammonia, in particular, stands out due to its dual role as both a carrier and a fuel, supported by established infrastructure. Trade routes are already emerging that link renewable-rich exporters such as Australia, Chile, and the Middle East with industrialized importers in Europe and East Asia, foreshadowing a new global energy geography centered around hydrogen.

System-level integration highlights hydrogen's unique value as a bridge between sectors. Electrolyzers can stabilize grids by absorbing excess renewable generation, while hydrogen provides seasonal storage capacity that batteries and pumped hydro cannot match. Salt cavern storage, in particular, offers a promising solution for large-scale, long-duration storage at relatively low cost. These systemic benefits position hydrogen as a cornerstone of energy system flexibility, despite its lower efficiency compared to direct electrification.

Beyond technical and economic considerations, hydrogen's deployment will depend on robust policy frameworks, international cooperation, and public acceptance. Certification systems for carbon intensity and sustainability are critical to building trust and enabling global trade. Safety concerns, including risks associated with hydrogen leakage, ammonia toxicity, and high-pressure systems, must be addressed through stringent standards and transparent communication. Moreover, ensuring equitable access to hydrogen technologies is essential so that developing countries are not excluded from future hydrogen economies.

The discussion also highlighted the broader geopolitical implications of hydrogen. Unlike fossil fuels, hydrogen production potential is widely distributed, creating opportunities for new exporters while encouraging traditional producers to diversify. This democratization of energy supply could reshape global alliances and reduce dependency on a narrow set of resource-rich nations. However, it also introduces new vulnerabilities related to maritime chokepoints, certification disputes, and market fragmentation.

In conclusion, hydrogen should be viewed as a critical complement to electrification in achieving global decarbonization. It is neither a silver bullet nor a marginal technology, but rather a targeted solution for specific sectors and systemic needs. Realizing hydrogen's potential will require

accelerating cost reductions, scaling infrastructure, harmonizing international standards, and ensuring sustainability across water, material, and safety dimensions. If these conditions are met, hydrogen can provide 10–20% of final energy by 2050, decarbonize sectors that currently lack viable alternatives, and create a new architecture for international energy trade. The pathway ahead is challenging, but the prize is substantial: a resilient, flexible, and decarbonized energy system in which hydrogen plays a central role.

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