

# Green Hydrogen for Deep Decarbonization: Technology Progress, Cost Evolution, Infrastructure, and Global Deployment Pathways

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## ABSTRACT

Green hydrogen is increasingly viewed as a strategic option for decarbonizing energy- and carbon-intensive sectors while improving long-term energy system flexibility. Produced by water electrolysis powered by renewable electricity, it offers a low-emission alternative to fossil-derived hydrogen and a potential bridge between variable renewable generation, industrial fuel demand, and emerging clean-fuel markets. This review synthesizes recent progress in electrolyzer technologies, national deployment strategies, cost trajectories, infrastructure development, and market formation. Comparative discussion is provided across major regions including the European Union, North America, Australia, China, and the Gulf, highlighting differences in resource endowment, policy support, and export orientation. The assessment shows that the economics of green hydrogen remain highly location-dependent, but declining electrolyzer costs, larger project scales, and access to low-cost solar and wind resources are expected to narrow the gap with conventional hydrogen. Key barriers persist in water availability, transport logistics, storage, certification, and manufacturing supply chains. Overall, the literature indicates that levelized green hydrogen costs could approach or fall below about \$2/kg in favorable settings by 2030, provided that policy support, infrastructure build-out, and technology scale-up advance in parallel. The paper concludes by identifying research and governance priorities needed to accelerate robust and equitable market growth.

## 1. Introduction

The pace of the global energy transition has intensified as countries confront climate risk, volatile fuel markets, and the need to reduce structural dependence on fossil resources. In that context, hydrogen has re-emerged as an important energy carrier, not because it is universally optimal, but because it can serve applications for which direct electrification remains difficult or inefficient.

Green hydrogen is commonly defined as hydrogen generated through water electrolysis using electricity from renewable sources such as solar, wind, or hydropower. In contrast to grey hydrogen from steam methane reforming and blue hydrogen coupled with carbon capture, the green pathway is designed to minimize lifecycle emissions while offering a route for linking renewable power with industrial energy use, long-duration storage, and synthetic fuel production [1].

Hydrogen is already embedded in the global economy. More than 120 million tonnes are produced annually, primarily for refining, ammonia synthesis, and chemical manufacturing, yet the overwhelming majority of this supply remains fossil-based [2]. The move toward green hydrogen is therefore not simply a matter of introducing a new fuel; it represents a broader effort to decarbonize an existing hydrogen market while expanding its role into new sectors.

Over the last few years, hydrogen strategies have multiplied across major economies. The European Union has set large-scale production and import ambitions, while countries such as Germany, Japan, Saudi Arabia, Australia, India, China, and the United States have launched targeted funding programs, hydrogen hubs, and gigawatt-scale demonstration projects. According to the IEA, announced projects now correspond to a very large pipeline of future electrolyzer capacity, underscoring the speed with which the sector is moving from policy aspiration to industrial planning [3,4].

Despite this momentum, large-scale deployment remains uneven. Green hydrogen still faces persistent constraints related to cost, electricity supply, water demand, transport and storage infrastructure, technology manufacturing capacity, and the lack of harmonized certification frameworks. In most markets, current production costs remain materially above those of conventional hydrogen, meaning that market formation still depends on supportive regulation, carbon pricing, or direct incentives [5].

Against this backdrop, the present review examines the technological, economic, and policy dimensions of green hydrogen deployment by synthesizing recent academic studies, institutional reports, and project-level evidence. The objective is to clarify where progress is most advanced, where critical bottlenecks remain, and how regional strategies differ in their pathways toward scale-up.

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**Nomenclature**

Abbreviation

Al-E	Alkaline Electrolyzer
BEV	Battery Electric Vehicle
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CO <sub>2</sub>	Carbon Dioxide
EU	European Union
FCEV	Fuel Cell Electric Vehicle
GHG	Greenhouse Gas

Symbol

E	Energy consumed or produced
H	Enthalpy of hydrogen
$\eta$	Efficiency

**2. Methodology**

This review adopts a structured evidence-synthesis approach to evaluate the current status of green hydrogen deployment. The analysis focuses on four interconnected themes: electrolyzer technology development, national and regional policy strategies, cost and infrastructure trajectories, and end-use integration across industry, transport, and power systems.

Source collection combined academic literature with grey literature of high policy relevance. Searches were conducted across Scopus, Web of Science, IEEE Xplore, and ScienceDirect, and were supplemented with reports and project databases from organizations such as the IEA, IRENA, BloombergNEF, the Hydrogen Council, and related public repositories. The search window covered material published between 2015 and early 2025, with emphasis on studies explicitly addressing renewable hydrogen production rather than fossil-based pathways.

An initial pool of 318 records was identified. Titles, abstracts, and executive summaries were then screened to remove duplicates, off-topic studies, and publications that lacked empirical, techno-economic, or scenario-based value for the objectives of this review. The final corpus comprised 72 sources, including 42 peer-reviewed articles, 18 institutional or policy reports, and 12 project datasets or white papers.

To support systematic comparison, the selected literature was grouped into five thematic clusters according to its dominant analytical focus.

1. Electrolyzer technologies: studies addressing configuration, efficiency, durability, cost reduction, and deployment barriers for alkaline, PEM, and solid oxide systems.
2. National and regional strategies: publications examining hydrogen roadmaps, investment programs, regulatory instruments, and trade positioning across countries and economic blocs.
3. Cost and infrastructure modeling: studies focused on levelized hydrogen cost, renewable power integration, storage pathways, transport options, and supporting infrastructure requirements.
4. Sectoral use cases: analyses of hydrogen demand and application potential in transport, power balancing, refining, iron and steel, chemicals, and derivative fuel production.
5. Barriers, risks, and governance: literature addressing certification, safety, supply-chain constraints, environmental tradeoffs, and the institutional conditions needed for international market development.

Each source was coded by geographic scope, methodological approach, and reported performance metrics such as electrolyzer efficiency, capital cost, hydrogen output, deployment scale, and levelized cost. This coding framework enabled cross-comparison between studies with very different data structures and purposes.

Table 1 therefore provides a representative cross-section of the reviewed literature, indicating for each theme the principal study or organization, methodological approach, and central finding used in the synthesis.

	Focus	Organization		
[4]	Electrolyzer Technologies	IEA (2023)	Techno-economic analysis	Global electrolyzer capacity to exceed 140 GW by 2030
[5]	Cost Modeling	IRENA (2022)	LCOH simulation	LCOH may fall below \$2/kg in optimal regions
[6]	Technology Comparison	Zhang et al. (2021)	Experimental + LCA	PEM systems offer better dynamic control, but higher CAPEX
[8]	National Strategy	German Federal Government	Policy document analysis	€9B investment with 5 GW domestic goal by 2030
[13]	Regional Deployment	Hydrogen Council (2022)	Industry survey	Gulf countries emerging as green ammonia hubs
[17]	Transport Infrastructure	BloombergNEF (2023)	Infrastructure modeling	Hydrogen pipeline retrofits viable up to 20% blend
[21]	Demand Forecasting	IEA (2021)	Sectoral modeling	Hydrogen demand to reach 530 Mt by 2050 in net-zero pathway
[25]	Barriers & Governance	McKinsey & Co. (2023)	Scenario-based analysis	Lack of harmonized safety and quality standards hinders trade

**3. Results**

The reviewed literature indicates that green hydrogen is moving rapidly from a niche decarbonization option toward an emerging industrial system. Progress is most visible in four areas: declining cost projections, accelerating electrolyzer deployment, expanding sectoral demand expectations, and the early formation of international trade corridors. At the same time, the evidence also shows that scale-up remains highly uneven across regions and strongly dependent on policy design, renewable resource quality, and infrastructure readiness.

**3.1 Levelized Cost of Hydrogen (LCOH) Trends**

Levelized cost remains the principal benchmark for judging whether green hydrogen can compete with conventional production routes. Figure 1 recasts regional cost trajectories as a slope comparison between 2020 and 2030 for Europe, the Middle East, Australia, and North America, drawing on values reported across IEA, IRENA, BloombergNEF, and related techno-economic studies [1–4].

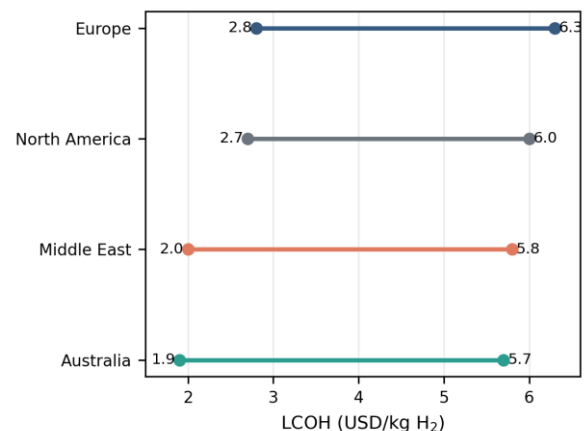


Figure 1. Regional slope chart of projected LCOH decline between 2020 and 2030.

Table 1. Representative Literature by Theme and Focus.

Ref	Thematic	Study /	Methodology	Key Insight
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The revised visual makes two points immediately clear. First, all regions are expected to experience a substantial reduction in LCOH over the decade. Second, the size of the decline differs by geography, reflecting differences in renewable electricity cost, project scale, and financing conditions.

In 2020, most reported values clustered around roughly \$5–6.5/kg H<sub>2</sub>. Regions with strong solar and wind resources, particularly Australia and parts of the Middle East, entered the decade with a relative cost advantage because renewable electricity could already be secured at lower prices than in many import-dependent or grid-constrained markets.

By 2030, the literature generally converges on a markedly lower cost range. Australia and the Middle East are commonly projected near about \$1.8–2.2/kg, whereas Europe and North America more often fall in the broader range of about \$2.5–3.0/kg [5–8].

This decline is primarily linked to falling electrolyzer capital cost, which several studies expect to decrease by roughly 60–75% as manufacturing scales and system design improves [9–11].

A second driver is the increasing availability of low-cost renewable power, especially solar PV and wind in desert, coastal, and high-resource regions [12].

A third driver is operational improvement, including higher system efficiency, better plant utilization, and learning effects in balance-of-plant integration [13,14].

Even so, parity with grey hydrogen is not automatic. In most cases, competitiveness by 2030 still depends on carbon pricing, production incentives, green procurement, or other policy mechanisms that reward low-emission hydrogen relative to fossil-derived supply [15,16].

### 3.2 Technology Deployment: Electrolyzer Trends

Electrolyzer deployment is the main physical indicator of market expansion. Instead of a simple multi-line plot, Figure 2 presents the projected cumulative capacity build-out as a stacked-area chart, which more clearly shows both total system growth and the changing contribution of alkaline, PEM, and SOEC technologies over time [17–20].

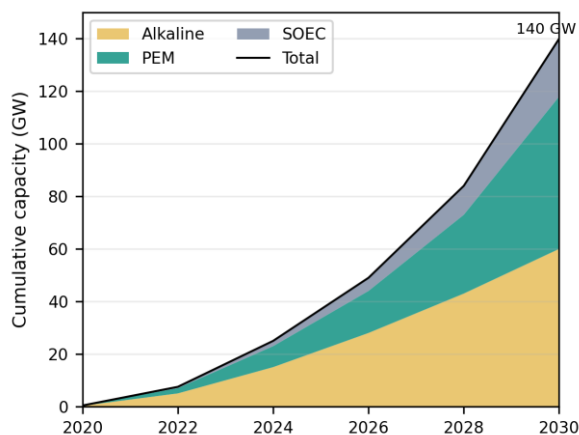


Figure 2. Stacked-area projection of cumulative electrolyzer deployment by technology.

The chart emphasizes the extraordinary scale of the announced pipeline. Global installed capacity was still modest in the early 2020s, but the reviewed literature suggests that cumulative electrolyzer deployment could exceed 140 GW by 2030 if currently announced projects are implemented [21].

Alkaline electrolysis is expected to retain the largest share because it is technologically mature, comparatively less expensive, and already well established in industrial hydrogen applications.

PEM systems, however, are projected to expand rapidly because their faster dynamic response makes them well suited to variable renewable electricity, and because their modular footprint can simplify distributed or flexible plant design.

Additional advantages of PEM include operation at higher pressure and the potential to reduce downstream compression requirements in some configurations [22,23].

SOEC remains less mature commercially, but the literature identifies important long-term opportunities in high-temperature industrial contexts where access to waste heat can raise overall efficiency [24–26].

Regional strategies also differ markedly. China is associated with very large scale-up ambitions and manufacturing-led growth, the EU with a combination of domestic build-out and import partnerships, and Australia and the Middle East with export-oriented hydrogen and ammonia projects [27–29].

In that sense, technology deployment is not only a matter of engineering performance; it is also shaped by industrial policy, supply-chain localization, and the intended position of each region in future hydrogen trade.

### 3.3 Sectoral Demand Forecasts

Demand projections indicate that green hydrogen could become an important input to several hard-to-abate sectors by mid-century, with total global demand under net-zero pathways often reaching roughly 500–600 Mt/year by 2050 [30–32]. Figure 3 replaces the original pie chart with a ranked horizontal bar chart to make relative sector scale easier to compare.

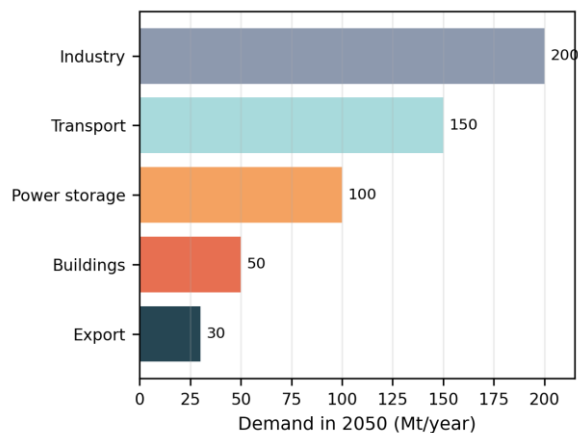


Figure 3. Ranked sectoral demand for hydrogen under 2050 net-zero pathways.

The figure shows that industry is consistently the largest demand center, followed by transport and power-system applications, with smaller but still meaningful roles for buildings and export-oriented trade.

Industrial demand is expected to dominate because hydrogen can directly substitute fossil feedstocks or reductants in sectors such as steel, refining, ammonia, methanol, and synthetic hydrocarbon production [33–35].

Hydrogen-based direct reduced iron is especially prominent in the literature because it can substantially cut emissions from steelmaking when paired with low-carbon electricity [36].

Transport demand is concentrated less in passenger cars and more in heavy-duty trucks, shipping, aviation fuel synthesis, and rail applications where energy density, range, or refueling time constrain full electrification [37–39].

Hydrogen is also increasingly discussed as a flexibility option for electricity systems with high shares of solar and wind, where surplus generation can be converted, stored, and later reused through fuel cells or turbines in power-to-gas-to-power configurations [40,41].

Use in buildings is more contested, but blending into gas networks and dedicated hydrogen heating trials in countries such as the UK and the Netherlands continue to inform the debate over system efficiency, infrastructure compatibility, and end-use practicality [42,43].

A final demand category reflects countries seeking to produce hydrogen or hydrogen-derived carriers such as ammonia for export to industrial importers in Europe and East Asia [46–48].

Taken together, these projections underscore hydrogen's strategic importance, but they also imply the need for massive parallel investment in generation, electrolysis, storage, transport, and downstream conversion assets [49,50].

### 3.4 Global Hydrogen Trade Flows

As the hydrogen economy expands, production and demand are unlikely to be colocated evenly. Regions with low-cost renewable resources, available land, and export-oriented industrial strategies are emerging as potential supply hubs, while densely industrialized or resource-constrained economies are positioning themselves as major import markets. Figure 4 reinterprets this geography using a diverging bar chart that contrasts projected export surpluses and import needs in 2030.

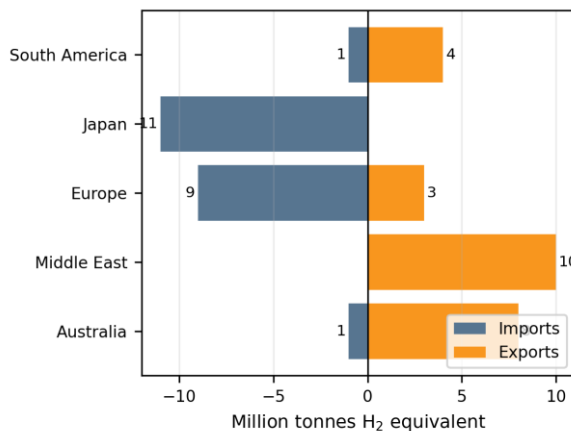


Figure 4. Diverging regional balance of projected hydrogen exports and imports in 2030.

The revised chart highlights the asymmetry of the early trade system: Australia and the Middle East appear as the strongest prospective exporters, whereas Europe and Japan stand out as net import centers.

Australia is repeatedly identified as a likely early leader because of its combination of high solar and wind potential, abundant land, and active project development targeting hydrogen and ammonia shipments to Asian markets [51–53].

The Middle East, particularly Saudi Arabia, Oman, and the UAE, is also strongly positioned through giga-scale projects linked to low-cost renewable electricity and strategic export infrastructure, with NEOM frequently cited as a flagship case [54–56].

Chile and Namibia are likewise attracting attention because their resource quality and port access could support future export platforms tied to global shipping lanes [57,58].

Japan and South Korea have set explicit hydrogen import ambitions within their national strategies, while Europe's REPowerEU agenda combines domestic production targets with substantial expected imports from neighboring and overseas partners [59–64].

North American trade is expected to be more regionalized, with cross-border exchange between Canada and the United States likely to matter more than long-distance maritime imports [65].

Despite the apparent logic of these corridors, large-scale trade still faces technical and institutional barriers.

Carrier choice remains central: compressed hydrogen, liquid hydrogen, ammonia, and LOHC pathways each involve different compromises in energy density, safety, conversion losses, and terminal infrastructure [66–68].

Infrastructure readiness is also limited, as ports, storage systems, pipelines, and receiving terminals often require major upgrades or entirely new construction [69].

At the same time, fragmented certification rules for hydrogen origin, emissions accounting, and product quality complicate the emergence of an integrated international market [70–72].

Even with these obstacles, pilot shipments and bilateral agreements already indicate that the sector is moving beyond conceptual planning toward early-stage commercialization [73–75].

## 4. Discussion

The results collectively suggest that green hydrogen is progressing from policy narrative toward industrial deployment, but not in a uniform or frictionless way. Cost reductions, technology scale-up, and early market formation are all real, yet their pace and depth remain highly dependent on geography, industrial structure, and the policy architecture surrounding hydrogen investment.

Projected LCOH values below about \$2/kg in favorable regions are often cited as a threshold for stronger market uptake, but the review shows that such values are not globally representative. They are most plausible where very low-cost renewable electricity, large project scale, and stable financing conditions coincide [76].

In less favorable contexts, green hydrogen remains exposed to the cost advantage of grey hydrogen unless carbon pricing, contracts for difference, tax credits, quotas, or other supportive instruments shift the market signal. Cost competitiveness is therefore as much a policy question as a purely technical one [77,78].

Electricity price volatility adds another layer of risk, particularly in markets with constrained grids or weak renewable integration. Long-term power purchase agreements and hybrid renewable portfolios are frequently proposed as ways to stabilize production economics [79].

Although alkaline and PEM systems are commercially available, large-scale deployment still depends on the expansion of supply chains for membranes, catalysts, power electronics, and balance-of-plant equipment. Manufacturing capacity is growing rapidly, but the literature suggests that further scale-up is still required to align equipment supply with net-zero deployment pathways [80].

PEM technology illustrates this tension clearly: its operational flexibility is attractive for renewable integration, yet dependence on scarce materials such as iridium introduces both cost pressure and geopolitical vulnerability unless catalyst loading is reduced or substituted [81].

SOEC offers efficiency advantages in high-temperature settings, but lower technology readiness and higher capital intensity continue to limit widespread adoption. Across all major electrolyzer classes, standardization, modularity, and mass manufacturing emerge as critical levers for cost reduction and reliability improvement [82–85].

Green hydrogen is often framed as a clean fuel, but its environmental footprint is not negligible. Electrolysis requires significant volumes of purified water, and the often-cited baseline of about 9 L of water per kilogram of hydrogen does not include the broader requirements associated with treatment, handling, and potential desalination [86].

This issue is especially important in arid export-oriented regions where hydrogen ambitions may intersect with existing water stress. If desalination is required, the carbon and ecological implications of the added water system must also be considered rather than treated as external to the hydrogen pathway [87].

Land demand is similarly consequential. Utility-scale solar and wind capacity dedicated to electrolysis can require large land areas, creating possible conflicts with agriculture, biodiversity protection, or urban development. The literature therefore points toward integrated land-use planning and site-specific environmental assessment as essential components of responsible hydrogen scale-up [88–91].

Hydrogen's low volumetric energy density continues to make storage and transport a major systems challenge. Whether the chosen pathway is liquid hydrogen, ammonia, compressed gas, or an LOHC, each option introduces tradeoffs between energy efficiency, handling complexity, safety, and delivered cost [92].

Liquid hydrogen offers direct use of hydrogen itself but requires cryogenic temperatures and faces boil-off losses during storage and transport [93].

Ammonia is easier to ship using established chemical logistics, yet toxicity, reconversion requirements, and combustion-side NO<sub>x</sub> control complicate its widespread use in some end markets [94].

LOHC systems may take advantage of existing liquid-fuel infrastructure, but their dehydrogenation step imposes an additional energy penalty that affects overall system efficiency [95].

Pipeline transport faces its own limitations because existing gas systems are not universally hydrogen-ready. Blending can provide an interim option in some cases, but deeper conversion often requires

materials upgrades and large capital investment in dedicated infrastructure [96,97].

Hydrogen is increasingly taking on geopolitical significance because countries with abundant low-cost renewables may become strategic suppliers to industrial importers. That raises not only commercial opportunities but also new questions about certification, subsidy competition, and long-term supply security.

A central challenge is definitional: there is still no universally harmonized standard for what qualifies as green hydrogen. Differences in lifecycle boundaries, renewable electricity matching rules, and verification approaches risk fragmenting the market and slowing cross-border trade [98–100].

At the same time, asymmetric subsidy regimes—such as those embedded in the U.S. Inflation Reduction Act or EU industrial policy packages—may accelerate domestic production in some jurisdictions while disadvantaging producers in regions with weaker fiscal capacity [101]. These dynamics mean that trade governance will matter alongside technology development. Diversified import portfolios, credible guarantees of origin, and multilateral coordination are likely to be essential if hydrogen trade is to scale without reproducing new forms of dependency or market fragmentation [102].

Viewed together, the evidence suggests that the main challenge is no longer whether hydrogen has a role in deep decarbonization, but rather how to deploy it selectively, efficiently, and equitably in ways that align engineering feasibility with economic and institutional realities.

The literature also warns against treating green hydrogen as a universal solution. Its value proposition is strongest in sectors where direct electrification is difficult, where molecular feedstocks are required, or where long-duration energy storage has a clear system-level function.

Accordingly, investment strategies that prioritize the highest-value end uses—rather than diffuse deployment across all possible sectors—are more likely to deliver durable emissions benefits and more efficient use of renewable power.

International collaboration will therefore need to extend beyond capital investment to include technology transfer, certification alignment, workforce development, and planning frameworks that account for regional water, land, and infrastructure constraints.

In short, the hydrogen transition is technically promising but institutionally demanding: success will depend on coordination across engineering, policy, finance, and trade.

**Table 2.** Comparative Techno-Economic Indicators for Green Hydrogen in Selected Countries (Projected 2030).

Country	Renewable Electricity Cost (\$/MWh)	Electrolyzer CAPEX (\$/kW)	Projected LCOH (\$/kg)	Primary Renewable Source	Water Scarcity Index
Australia	15–25	300–500	1.6–2.2	Solar PV	Low
Saudi Arabia	20–30	400–600	1.8–2.4	Solar PV/Wind	High
Germany	40–60	600–900	2.8–3.6	Wind/Solar Mix	Medium
Japan	50–70	700–1000	3.2–4.5	Imported RE	High
Chile	18–25	400–600	1.7–2.3	Solar PV/Wind	Medium-Low

**Table 3.** Summary of Green Hydrogen Certification Schemes in Major Economies

Region/Country	Certification Authority	Renewable Source Criteria	GHG Accounting Baseline	Verification Method
EU	European Commission (RED II)	Direct link to new RES, temporal matching	3.38 kg CO <sub>2</sub> /kg H <sub>2</sub>	Mass balance + audit
Japan	METI	Grid mix allowed with guarantees	2.4 kg CO <sub>2</sub> /kg H <sub>2</sub>	Self-declaration + audit
Australia	CEFC + H2 Council	Flexible RE sourcing through PTC-linked RECs	Varies by project	Third-party audit
US	DOE + IRS (IRA Rules)	RE through PTC-linked RECs	Based on GREET model	LCA-based verification

## 5. Conclusion

Green hydrogen has moved from a speculative long-term concept to a central component of many decarbonization strategies for industry, energy storage, and low-carbon fuel production. The literature reviewed here shows that this transition is being driven by converging progress in electrolyzer deployment, renewable electricity expansion, industrial policy, and emerging international trade networks.

A core finding of the review is that geography matters. Regions with excellent renewable resources, available land, and supportive policy frameworks are structurally better positioned to achieve low hydrogen production costs. By contrast, regions facing higher electricity prices, tighter land constraints, or weaker infrastructure must rely more heavily on regulation, imports, or targeted support mechanisms to remain competitive.

Technology choice also remains decisive. Alkaline systems continue to dominate near-term deployment because of maturity and lower capital cost, while PEM and SOEC are important for flexibility and future efficiency gains. Yet none of these pathways can scale at the required pace without parallel advances in manufacturing capacity, materials supply chains, durability, and standardization.

The review further highlights that green hydrogen should be assessed as part of an interconnected resource system rather than as an isolated fuel option. Water demand, land occupation, desalination needs, transport losses, and downstream conversion requirements all influence the true sustainability and economics of deployment, particularly in arid and export-oriented regions.

Policy and governance emerge as equally important. The pace of market growth depends not only on engineering improvement but also on bankable demand signals, credible certification systems, and trade rules that reduce uncertainty for producers and offtakers.

Without greater harmonization of lifecycle accounting, renewable electricity criteria, and guarantees of origin, the international market risks becoming fragmented, with consequences for both trade efficiency and climate credibility.

Infrastructure is another defining constraint. Storage terminals, hydrogen-ready pipelines, ammonia handling systems, liquefaction capacity, and port upgrades require long lead times and substantial capital. This makes coordinated planning essential if production growth is to translate into usable, deliverable hydrogen rather than stranded project announcements.

From the demand side, hydrogen's highest strategic value appears in sectors that are hard to electrify directly, including iron and steel, chemicals, heavy transport, shipping, aviation fuel synthesis, and selected power-balancing roles. That reinforces the need to prioritize applications where hydrogen creates the greatest system benefit rather than deploy it indiscriminately.

The broader implication is that green hydrogen is neither a silver bullet nor a marginal technology. It is a targeted decarbonization vector whose success depends on using it where molecular energy carriers are genuinely needed and where the supporting electricity, water, and infrastructure systems can sustain it.

For that reason, future progress should focus on scaling electrolyzer manufacturing, improving catalyst and system design, integrating hydrogen with high-quality renewable power, reducing infrastructure bottlenecks, and building internationally compatible certification frameworks.

At the same time, a just transition perspective is necessary. Emerging producers in the Global South need access to finance, technical capability, and market institutions if hydrogen development is to avoid reinforcing existing inequalities in global energy trade.

Overall, green hydrogen offers a credible pathway for decarbonizing selected hard-to-abate sectors, but only if technological scale-up, infrastructure development, and governance reform proceed together. The next phase of the transition will therefore depend less on broad enthusiasm and more on disciplined, region-specific implementation.

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