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Review Article

Hydrogen as a viable decarbonization enabler for critical sectors: A comprehensive review

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ABSTRACT

Global hydrogen demand reached approximately 100 Mt in 2024, yet low-emission hydrogen accounts for less than 1% of supply, and the viable project pipeline has contracted from 49 to 37 Mtpa year-on-year. This review provides a structured, sector-by-sector assessment of where hydrogen is a viable decarbonization enabler and where it is not, spanning refining, ammonia, steelmaking, transport, power generation, and — uniquely among hydrogen economy reviews — aerospace and hypersonic propulsion. Hydrogen delivers value in sectors that resist direct electrification (steel, shipping, aviation, long-duration storage) but remains marginal where batteries already dominate. Hydrogen-based direct reduction of iron ore emerges as the most compelling near-term growth sector, while hydrogen's thermophysical properties (2.8× the gravimetric energy density and 7.2× the specific heat capacity of kerosene) make it the leading fuel for scramjet propulsion above Mach 8, where no hydrocarbon offers a comparable fuel-and-coolant capability. Five priority research directions are identified.

Contents

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1. Introduction

The accelerating urgency of global decarbonization, driven by the Paris Agreement's mandate to limit warming to 1.5 °C above pre-industrial levels [1], has placed hydrogen in a central role in energy transition strategies worldwide. Global hydrogen demand reached approximately 100 million tonnes (Mt) in 2024, yet less than 1% was produced using low-emission technologies, with the vast majority derived from unabated fossil fuels, primarily via steam methane reforming and coal gasification [2]. This paradox—hydrogen as both a pillar of the clean energy future and a persistent source of carbon emissions—defines the challenge of the current decade. In response, over 60 national governments have adopted dedicated hydrogen strategies [3], committing billions in public funding and regulatory incentives such as the United States' Section 45V Clean Hydrogen Production Tax Credit [4] and the European Union's REPowerEU plan [5]. More than 1700 hydrogen projects have been announced globally since 2020, backed by substantial public and private capital, yet only a fraction have reached final investment decision, and the pipeline of expected low-emission production by 2030 has begun to shrink [2,6]. This widening gap between ambition and deployment raises a critical question: where, precisely, does hydrogen deliver on its promise under current market conditions, and where does the evidence demand a more sober assessment?

The scale of this gap is now quantifiable. Of this expanding project pipeline, only 510 — roughly 30% — have progressed past final investment decision (FID), representing approximately $110 billion in committed investment and a combined capacity of 6 million tonnes per year (Mtpa), of which just 1 Mtpa is operational [6]. The outlook has deteriorated further: the IEA's 2025 assessment finds that potential low-emission hydrogen production by 2030 has fallen to 37 Mtpa, down from 49 Mtpa projected just one year earlier, driven by cancellations, delays, and the persistent cost gap between low-emission and fossil-based hydrogen [2]. Of this reduced pipeline, only approximately 4 Mtpa is deemed almost certain to materialize by 2030 based on projects that are operational, under construction, or at FID, with an additional 6 Mtpa contingent on effective demand-side policies. Binding offtake agreements cover approximately 3.6 Mtpa — about 60% of committed project capacity but less than 10% of the broader announced pipeline — underscoring the demand uncertainty that continues to stall project financing [6]. Meanwhile, the economics have moved in the wrong direction: falling natural gas prices and higher-than-expected electrolyzer costs have widened the cost gap between green and grey hydrogen, even as policy support through mechanisms such as production tax credits and carbon pricing has expanded.

The existing literature on hydrogen energy is extensive, yet predominantly oriented towards production technologies and their techno-economic optimization. Comprehensive reviews have examined electrolyzer design and performance [7], thermochemical and biological production pathways [8], and comparative lifecycle assessments across the green–blue–grey spectrum [9]. While valuable, these works largely address the supply side of the hydrogen equation. Comparatively fewer reviews have undertaken a systematic, cross-sectoral assessment of where hydrogen is actually being deployed at industrial scale, at what cost, and with what measurable impact. This gap is significant: as the sector transitions from announcement to execution, the defining questions are no longer whether green hydrogen *can* be produced affordably, but whether demand is materializing, which sectors are converting pilot projects into commercial operations, and where hydrogen faces structural barriers that alternative decarbonization pathways may address more effectively. Furthermore, hydrogen's role in aerospace and hypersonic propulsion — where its thermophysical properties appear uniquely enabling — has received limited attention in the broader energy review literature, despite accelerating development activity in both subsonic aviation and scramjet applications [10,11]. This review addresses these gaps by providing a deployment-focused, sector-by-sector assessment grounded in the most recent project data, policy developments, and cost analyses available as of late 2025 and early 2026.

The review is organized as follows. Section 2 surveys the current hydrogen production landscape — supply mix, cost trajectories, and policy drivers — to contextualize the sectoral analysis. Section 3 constitutes the core: a sector-by-sector deployment assessment spanning refining, ammonia, steelmaking, transport, and power generation. Section 4 examines aerospace and hypersonic propulsion as a distinct domain where hydrogen's thermophysical properties are uniquely enabling. Section 5 synthesizes cross-cutting infrastructure, supply chain, and regulatory challenges, and Section 6 identifies priority research gaps. This review does not cover electrolyzer design, hydrogen storage materials, or fuel cell electrochemistry in detail, as these topics are well served by recent dedicated reviews [7,8]. The emphasis throughout is on deployment realities rather than technological possibilities.

1.1. Scope and methodology

This review combines a structured literature survey of recent peer-reviewed scientific work with an evidence-based synthesis of deployment data drawn from international energy agencies and industry consortia. The dual sourcing is deliberate: peer-reviewed journals provide the most rigorous record of technical performance, materials behaviour, and process economics, while institutional trackers (the International Energy Agency Global Hydrogen Review, the Hydrogen Council Global Hydrogen Compass, and IRENA's Renewable Energy Statistics) provide the most current and geographically complete record of project pipelines, final investment decisions, and offtake commitments. We use the former to establish what is technically known and the latter to characterize what is actually being built.

Literature search and selection

The peer-reviewed literature was identified through structured searches in Scopus, Web of Science, and Google Scholar between March 2025 and January 2026. Search strings were constructed sector-by-sector by combining the controlling chemistry or process term with a deployment-oriented qualifier; representative examples include "green hydrogen" AND ("direct reduction" OR "DRI") AND "steel"; "hydrogen" AND ("Haber–Bosch" OR "ammonia synthesis") AND ("green" OR "electrified"); "proton exchange membrane" OR "anion exchange membrane" AND "water electrolysis"; "hydrogen" AND "gas turbine" AND ("combustion" OR "materials"); "scramjet" AND ("hydrogen" OR "regenerative cooling"); "hydrogen" AND "global warming potential"; "hydrogen embrittlement" AND "pipeline"; and "underground hydrogen storage" AND "salt cavern". The timeframe was restricted to publications from January 2020 through January 2026, with the bulk of cited primary sources drawn from 2023–2025 to reflect the state of the art. Foundational works predating this window were retained where they establish canonical physical relationships (e.g., Urzay's 2018 review of supersonic combustion for hypersonic flight [10]) or provide the originating dataset for a still-current claim.

Inclusion was conditional on three criteria: (i) publication in a peer-reviewed journal or peer-reviewed conference proceedings, or — in the case of institutional sources — issuance by a body with established editorial review (IEA, IRENA, Hydrogen Council, EPRI, NASA NTRS); (ii) direct relevance to one of the deployment sectors examined in Sections 3–4 or to a cross-cutting infrastructure topic in Section 5; and (iii) provision of quantitative evidence (cost, efficiency, capacity, technology readiness, or emissions data) rather than purely qualitative claims. We prioritized sources that report measurements, model results benchmarked against measurements, or aggregated project data traceable to underlying announcements. Press releases, advocacy publications, and non-peer-reviewed working papers were excluded except where they were the originating record of a specific project milestone, in which case they were cross-checked against at least one independent source. Across the sectors covered, the final reference base comprises approximately 100 sources, of which roughly three quarters are peer-reviewed scientific articles and the remainder are institutional and policy documents serving the deployment-data role described above (Fig. 1).

Technology readiness level assignment

Technology Readiness Levels reported throughout this review follow the nine-point scale standardized by the U.S. Department of Energy and harmonized internationally by the European Commission [12, 13], in which TRL 1–3 denotes fundamental research, TRL 4–6 denotes laboratory- to pilot-scale validation, TRL 7–8 denotes prototype to demonstration in operational environment, and TRL 9 denotes commercial operation at full scale. Where a published source (typically the IEA Energy Technology Perspectives clean energy technology guide [14] or a sector-specific peer-reviewed review) reports a TRL for the technology under discussion, we adopt that value and cite it explicitly. Where a sector-wide TRL is not reported in a single authoritative source, we assign a range based on the most advanced operating deployment we could verify from peer-reviewed or institutional documentation: for example, hydrogen-based direct reduction of iron ore is assigned TRL 6–8 because pilot plants such as HYBRIT and a 100,000 t/yr ArcelorMittal demonstration unit are operating at industrial scale [15, 16], while no plant has yet reached the multi-million-tonne commercial capacity that would justify TRL 9. Liquid-hydrogen-fuelled commercial aviation is assigned TRL 4–6 based on Airbus's ZEROe program timeline and the H2FLY piloted liquid-hydrogen flight demonstration [17,18]; hypersonic scramjet propulsion is assigned TRL 3–5 based on flight-test data through X-43A, X-51A, and the SPARTAN/DART-AE development program [10,19]. A consolidated cross-sector TRL summary is shown in Fig. 9; the underlying assignments and their primary sources are listed alongside each sector's discussion in Sections 3–4.

Temporal framing

This review reports the hydrogen landscape as it stood in late 2025 and early 2026. Throughout the manuscript we distinguish two classes of conclusion. *Structural* conclusions—such as the thermodynamic preference of liquid hydrogen over kerosene for high-Mach scramjet propulsion, the chemical pathway by which hydrogen-DRI substitutes for blast-furnace coke, or the displacement of OH-mediated methane sinks by atmospheric hydrogen leakage—follow from physics and chemistry, do not depend on current market conditions, and are stated accordingly. *Time-specific* conclusions — project counts, levelized cost ranges, offtake-agreement volumes, and policy-instrument values — depend on the data snapshot and are dated explicitly to the source year. Where a quantitative claim is likely to shift on a one- to two-year timescale (for example, the levelized cost of green hydrogen or the announced pipeline of low-emission production), we report the central value with its source year and, where the literature supports it, indicate the direction of recent change. This separation of structural from time-specific findings is intended to preserve the durability of the review's qualitative conclusions even as the underlying market data evolves.

2. The current hydrogen production landscape

2.1. Production pathways

Hydrogen production is conventionally categorized by its associated carbon intensity, commonly referenced through a colour-based taxonomy. *Grey hydrogen*, produced via steam methane reforming (SMR) or coal gasification without carbon capture, remains the dominant pathway, generating approximately 9–12 kg CO_2 per kg H_2 from natural gas and significantly more from coal [9]. *Blue hydrogen* applies carbon capture, utilization, and storage (CCUS) to these same fossil-based processes, targeting capture rates of 90% or above, though real-world operational performance has often fallen short of this benchmark [9]. *Green hydrogen*, produced by water electrolysis powered by renewable electricity, generates near-zero direct emissions and is widely regarded as the long-term target pathway; the principal electrolyzer technologies are alkaline electrolysis (AEL), proton exchange membrane (PEM), and solid oxide electrolysis cells (SOEC), each at different stages of commercial maturity [7]. Additional pathways under development include *turquoise hydrogen* from methane pyrolysis, which yields solid carbon rather than CO_2 as a byproduct, and *pink* (or *purple*) *hydrogen* from nuclear-powered electrolysis. While these emerging routes attract research interest, none has reached significant commercial scale as of this writing (early 2026), and they are not considered further in this review. The relative contributions of these pathways to the global production mix, and the extent to which low-emission routes are displacing incumbent fossil-based production, are quantified in the following subsection.

Table 1 summarizes the key performance parameters of the three commercially deployed electrolyzer families. This level of detail is justified by the central role that electrolyzer choice plays in the sectoral analyses that follow — particularly steel (Section 3.3) and ammonia (Section 3.2) — where electrolyzer cost, durability, and ramp characteristics largely determine the techno-economic viability of low-emission hydrogen. The emerging fourth family, anion exchange membrane (AEM) electrolysis, is treated separately in Section 2.2, as its performance envelope and supply-chain implications differ substantively from the three established technologies.

2.2. Anion exchange membrane electrolysis

Anion exchange membrane (AEM) water electrolysis is the most significant emerging electrolyzer family of the past five years, and warrants separate treatment because its operating principle combines features of the alkaline and PEM technologies in Table 1 without inheriting their respective penalties. An AEM cell transports hydroxide ions through a solid polymer membrane in a mildly alkaline environment (Fig. 3), allowing non-platinum-group-metal (non-PGM) catalysts — typically nickel-, iron-, or cobalt-based — at both electrodes while

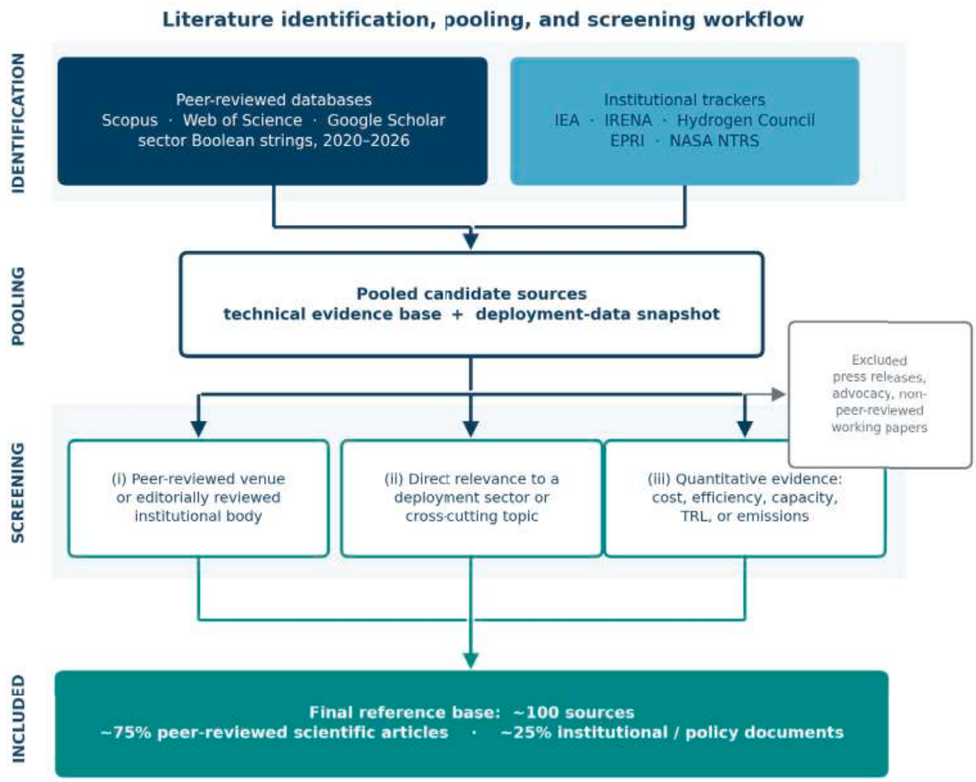

Fig. 1. Literature search and screening workflow used in this review. Peer-reviewed databases provide the technical evidence base; institutional sources (IEA, IRENA, Hydrogen Council, EPRI, NASA NTRS) provide the most current snapshot of project pipelines, final investment decisions, and offtake commitments. Three explicit inclusion criteria were applied to all candidate sources, yielding a final reference base of approximately 100 sources (roughly 75% peer-reviewed scientific articles).

Table 1
Comparison of principal commercially deployed electrolyzer technologies for green hydrogen production. Values reflect representative ranges for the state of the art in 2024–2025 as compiled from the sources cited in the table footer; the emerging AEM family is discussed separately in Section 2.2.
Source: Data compiled from IEA [2,20], Kumar and Lim [7], and DOE Hydrogen Shot [21].

Parameter	AEL	PEM	SOEC
Electrical efficiency (%, LHV)	60–70	55–70	75–85
Current density (A/cm^2)	0.2–0.5	1.0–2.5	0.3–1.0
Operating temperature (°C)	60–90	50–80	700–900
Typical CAPEX ($/kW)	800–1400	1000–1600	2500–4000
Stack lifetime (kh)	60–100	50–80	10–30
Ramp rate	Minutes	Seconds	Hours
Key catalyst material	Nickel	Iridium, Platinum	Nickel, LSM
Water purity requirement	Moderate	High (Type I)	Steam input
TRL	9	8–9	6–7
Dominant deployment region	China, Europe	Europe, N. America	Europe

AEL = alkaline electrolysis; PEM = proton exchange membrane; SOEC = solid oxide electrolysis cell; LHV = lower heating value; LSM = lanthanum strontium manganite; kh = thousands of hours. Operating cost is dominated by electricity consumption (~60% of LCOH) and is largely independent of electrolyzer type at a given power price; stack-replacement cost is reflected in the lifetime row.

retaining the compact membrane-electrode-assembly architecture that gives PEM its high current density and fast dynamic response [22,23]. The practical consequence is a potential pathway to high-current, high-efficiency electrolysis without the iridium and platinum loadings that constrain PEM scale-up (see Section 5.4).

The principal historical limitation has been membrane durability under sustained alkaline operation. Recent peer-reviewed work has substantially reduced this gap. Liu, Miyatake, and co-workers reported a polyphenylene-based AEM (designated QTAF) achieving hydroxide conductivity of 168.7 mS cm^{-1} at 80 °C and stable operation of a non-PGM-anode cell at 1.0 A cm^{-2} for 1000 h with a degradation rate of 1.1 μV h^{-1} [22]. Zheng et al. subsequently demonstrated sustained AEM operation at 10 A cm^{-2}—a current density approaching the long-term economic optimum identified for PEM—for over 800 h with a cell voltage near 2.3 V, representing a five-order-of-magnitude lifetime improvement over earlier high-current-density benchmarks [24]. These results, together with the broader catalyst and membrane-electrode-assembly advances synthesized in Zhang et al.'s 2025 review [23], move AEM from a primarily academic technology towards pre-commercial deployment.

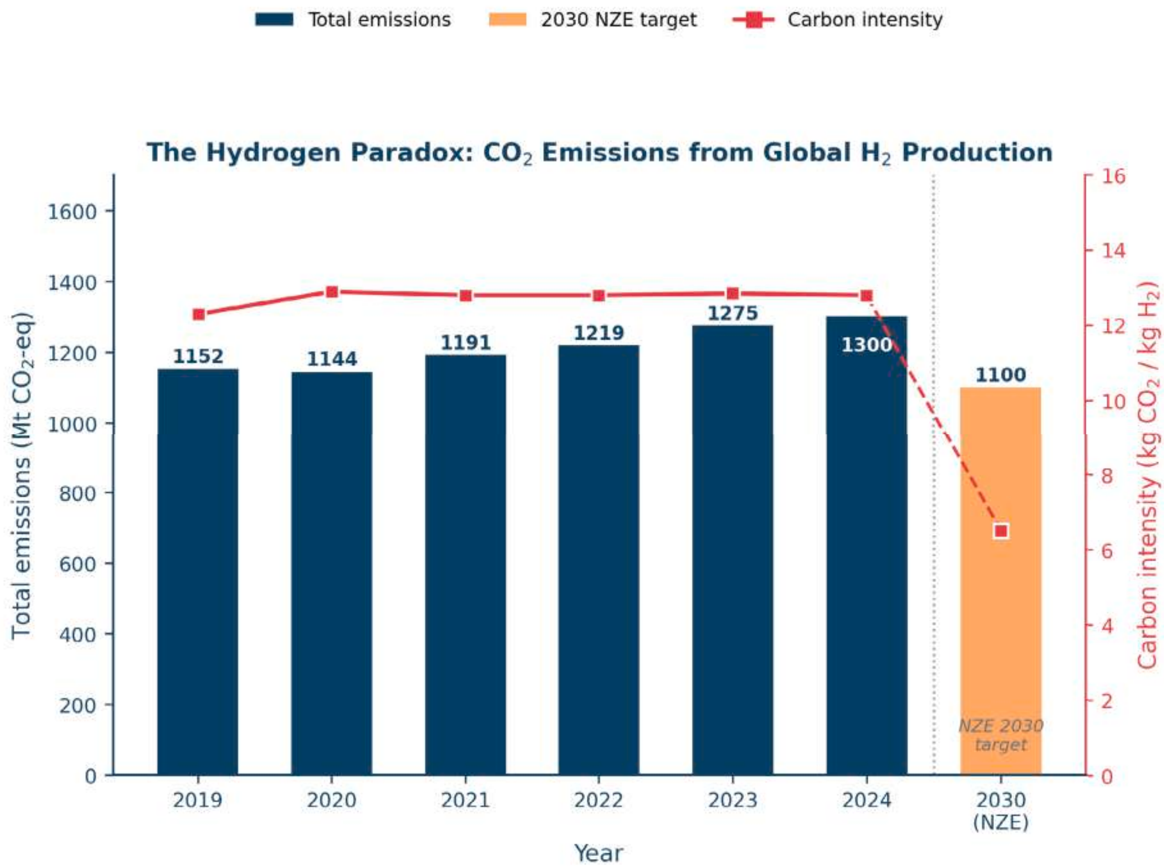

Fig. 2. The hydrogen paradox: total CO_2 emissions from hydrogen production (bars, left axis) and average carbon intensity (line, right axis), 2019–2024, with the 2030 Net Zero Emissions target. Despite over 60 national strategies and 1700+ announced projects, absolute emissions have risen steadily from ~1150 to ~1300 Mt CO_2-eq, while carbon intensity remains flat near 12.7 kg CO_2/kg H_2.
Source: Data from IEA [2] and Hydrogen Council [6].

AEM is currently assigned TRL 5–6: laboratory and single-stack performance has reached parity with PEM on several key metrics, but multi-stack systems, balance-of-plant integration, and field-validated lifetime under variable renewable input remain unproven at the megawatt scale. A recent review bridging academic and industrial AEM stacks underscores this gap: academic cells rarely exceed the 2.5 kW scale, whereas the commercial stacks now entering the market span roughly 2.5 kW to 2.5 MW and have yet to demonstrate the multi-year durability long established for alkaline and PEM systems [25]. We accordingly omit AEM from Table 1, which is restricted to the three families with established commercial deployment, but treat it as a plausible mid-term complement to alkaline and PEM electrolysis should the durability and scaling results of the past two years be reproduced in industrial-scale stacks.

2.3. Global production mix

Global hydrogen production has grown steadily from approximately 90 Mtpa in 2020 to an estimated 102 Mtpa in 2025, yet the fuel mix supplying this output has remained virtually unchanged (Fig. 4). Natural gas without carbon capture accounts for roughly 63% of total production (~64 Mtpa), consuming an estimated 290 billion cubic metres (bcm) of gas annually—equivalent to approximately 6% of global natural gas demand [2]. Coal gasification, overwhelmingly concentrated in China, contributes a further ~20% (~20 Mtpa), consuming roughly 90 million tonnes of coal equivalent (Mtce) per year [2]. Together, these two unabated fossil pathways supply over 83% of the world's hydrogen and are responsible for approximately 1300 Mt CO_2-eq of annual emissions—comparable to the total greenhouse gas output of Japan [2]. The remaining production comprises by-product hydrogen from refinery and petrochemical operations, a small contribution from oil-based routes, and a negligible but growing share from fossil fuels with CCUS. Electrolytic hydrogen, despite its prominence in policy discourse, contributed less than 1% of global output in 2024.

The regional distribution of production mirrors the concentration of heavy industry. China alone accounts for roughly one-quarter of global hydrogen output and dominates coal-based production, while North America and the Middle East rely primarily on natural gas reforming [2]. Europe's production base is comparatively small and increasingly shaped by decarbonization mandates, whereas India's emerging hydrogen economy remains anchored to refinery by-product streams. This geographic concentration carries strategic implications: regions with abundant low-cost natural gas (the Middle East, North America) face different transition incentives than those dependent on coal (China, parts of South and Southeast Asia), a divergence that is already visible in national strategy documents and investment patterns [3].

A telling observation from Fig. 4 is the absence of any visible structural shift in the production mix over the 2020–2025 period. Each fossil pathway has grown in absolute terms roughly in proportion to demand growth, meaning that low-emission hydrogen has not displaced any incumbent production but has merely added a marginal increment on top. This pattern — additive rather than substitutive growth — is the central challenge facing the sector and underpins the emissions trajectory shown in Fig. 2. Whether this pattern can be broken depends critically on the cost competitiveness of low-emission pathways, which is examined next.

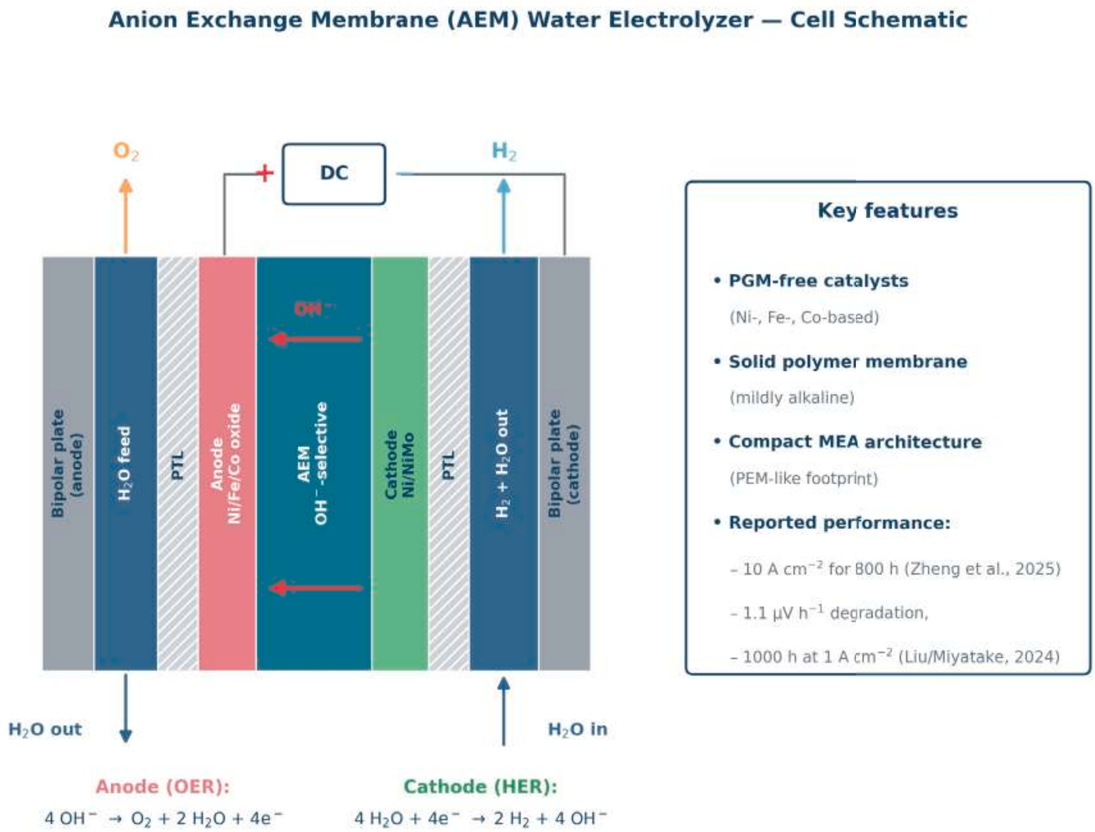

Fig. 3. Schematic of an anion exchange membrane (AEM) water electrolyzer cell. Hydroxide ions (OH^-) generated at the cathode migrate through the solid polymer membrane to the anode, where they are oxidized to oxygen and water. Both electrodes use non-platinum-group-metal (non-PGM) catalysts, eliminating the iridium and platinum requirements of PEM electrolysis while retaining a compact membrane-electrode-assembly architecture. Reported single-cell performance highlights listed at right are drawn from [22,24].

2.4. Cost trajectories and the widening gap

The economic case for low-emission hydrogen has deteriorated since 2022, contrary to the trajectory anticipated by most roadmaps. Fig. 5 presents the levelized cost of hydrogen (LCOH) by production pathway for 2024 and the 2030 Stated Policies Scenario (STEPS). STEPS is the IEA's central reference scenario, which projects an energy-system pathway consistent with policies currently in place or explicitly announced by governments, rather than the more aggressive trajectories required for net-zero alignment [2]. The LCOH from unabated natural gas reforming currently ranges from approximately \$0.9–4.5/kg H_2 depending on regional gas prices and cost of capital, with the lowest costs in the Middle East and U.S. Gulf Coast. This range has narrowed substantially from 2022, when post-invasion gas price spikes pushed the upper bound above \$8/kg in import-dependent markets. Coal-based production, concentrated in China, occupies a similar band of \$1.6–4.7/kg H_2. The retreat of fossil-based costs from their 2022 peaks has restored — and in some regions widened — grey hydrogen's cost advantage over low-emission alternatives [2].

Green hydrogen costs remain far above fossil parity in most markets. Electrolytic hydrogen from onshore wind currently ranges from \$4.1–12.2/kg H_2, from solar PV \$4.0–12.8/kg, and from offshore wind \$5.5–12.7/kg, with the enormous spread driven primarily by differences in renewable electricity prices and capacity factors [2]. Electricity constitutes approximately 60% of LCOH, making the cost floor effectively determined by the local levelized cost of energy [2]. In Western markets, installed electrolyzer system costs average approximately \$1200–1400/kW for alkaline and PEM systems, and have risen due to inflation, supply-chain bottlenecks, and slower-than-expected deployment; the sharp decline in natural gas prices from 2022–23 levels, combined with this electrolyzer cost inflation, has led to a larger cost gap than previously anticipated [2]. China represents a notable exception: electrolyzer CAPEX of approximately \$900/kW in 2024, combined with lower renewable electricity prices and cost of capital, yields green hydrogen costs 40%–45% below European and American benchmarks [2]. Blue hydrogen occupies an intermediate position at approximately \$1.5–5.1/kg H_2, but its competitiveness depends on both gas prices and the capital cost of CCUS infrastructure, and operational capture rates at existing facilities have frequently underperformed design targets [9].

The 2030 STEPS projections in Fig. 5 suggest meaningful but insufficient convergence. Onshore wind-based hydrogen is projected to fall to \$2.4–9.7/kg and solar PV to \$2.6–12.8/kg, with the lower bounds approaching fossil parity in the most favourable locations. The IEA projects that renewable hydrogen in China could become cost-competitive with unabated fossil production by the end of this decade, and that the cost gap in parts of Latin America could narrow to just above \$0.5/kg [2]. However, the upper bounds of the electrolytic range remain stubbornly high, reflecting the reality that many regions lack the combination of cheap renewables and low cost of capital needed to produce affordable green hydrogen. Electrolyzer manufacturing capacity has expanded from 0.6 GW in 2021 to approximately 4.9 GW in 2024, and electrolytic production grew 60% year-on-year in 2024, though it remains on track to reach only 1 Mt by 2025—less than 1% of global output [2]. Solid oxide electrolysis cells (SOEC), with electrical efficiencies exceeding 80% on a lower heating value basis, offer a further cost-reduction pathway if durability and manufacturing-scale challenges can be overcome [7].

The net result is a cost gap that policy must bridge. The Hydrogen Council estimates that green hydrogen LCOH on the U.S. Gulf Coast

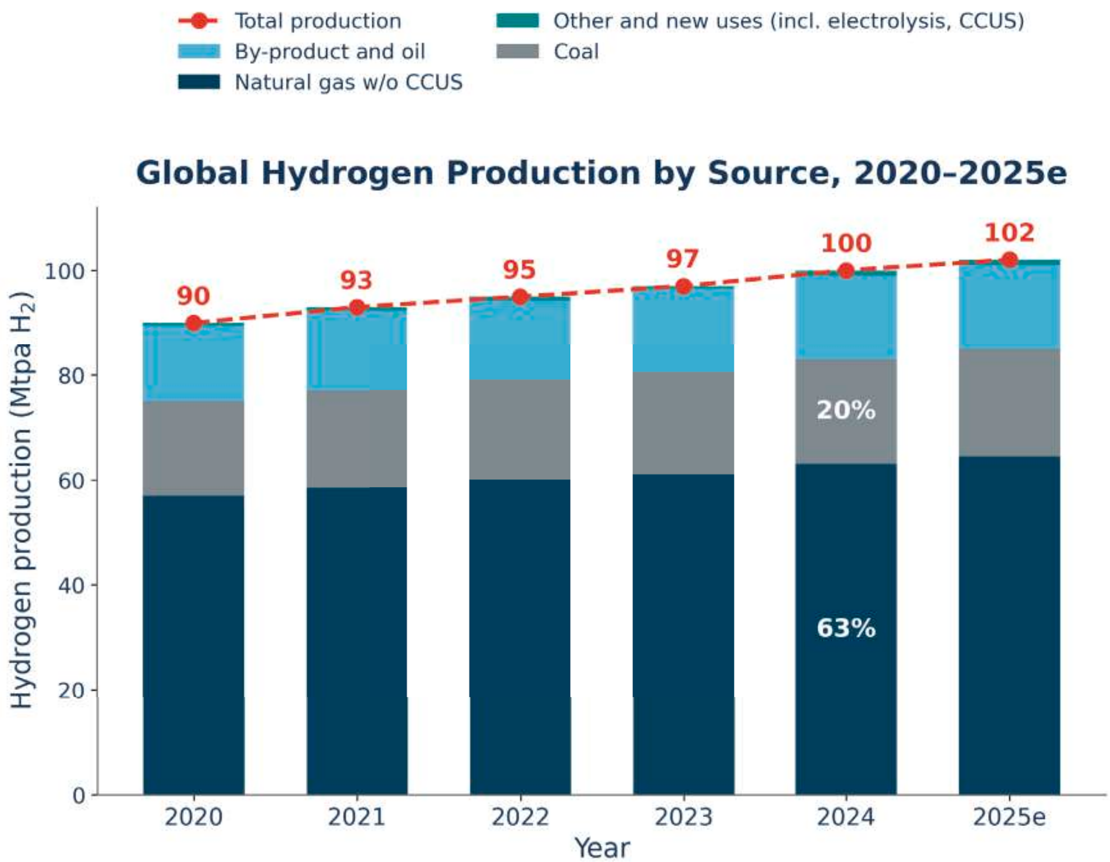

Fig. 4. Global hydrogen production by source, 2020–2025e. Natural gas without CCUS accounts for ~63% of production, followed by coal (~20%). The remaining production comprises refinery and petrochemical by-product hydrogen, a small oil-based contribution, and a category labelled "Other and new uses" that aggregates fossil fuels with CCUS, electrolysis, methane pyrolysis, and nascent low-emission routes; combined, these low-emission pathways remain below 1% of total output. Red markers indicate total production, which grew from ~90 to ~102 Mtpa over the period. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
Source: Data digitized from IEA [2].

has risen from approximately \$2.9/kg to \$5.0/kg since initial project scoping, while grey hydrogen in the same region has fallen back below \$1.5/kg [6]. This gap, now exceeding \$3/kg in many Western markets, is the single largest barrier to final investment decisions and explains the pipeline contraction documented in Section 1. Policy instruments—the U.S. 45V production tax credit of up to \$3/kg, the EU's contracts for difference under the European Hydrogen Bank, and comparable mechanisms in Japan, South Korea, and India—are designed to bridge precisely this differential [4,5]. However, regulatory delays, additionality requirements, and the sheer scale of subsidy needed have slowed disbursement. As of mid-2025, no green hydrogen project in the United States had received a final 45V credit determination [2]. Whether these policy mechanisms can accelerate deployment before investor confidence erodes further is examined in the following subsection.

2.5. Policy drivers and regulatory landscape

The global hydrogen policy architecture has matured rapidly since 2020, with more than 1000 policy measures announced or implemented worldwide and 61 countries having adopted dedicated hydrogen strategies as of September 2025 [2,3]. However, the pace of new strategy publication has slowed — only five new national strategies appeared between the 2024 and 2025 editions of the IEA Global Hydrogen Review — and several countries have begun revising initial targets downward. France, for example, reduced its electrolyzer target from 6.5 GW to 4.5 GW by 2030, while Spain moved in the opposite direction, tripling its target to 12 GW [2]. Both the European Union and Chile missed their near-term electrolyzer deployment milestones for 2024 and 2025, respectively, underscoring the gap between announced ambition and realized capacity [2].

Three broad categories of policy instrument have emerged. On the supply side, production subsidies and tax credits aim to close the cost gap identified in Section 2.4. The U.S. Section 45V clean hydrogen production tax credit, finalized in January 2025, offers up to \$3/kg for hydrogen produced with lifecycle emissions below 0.45 kg CO_2-eq/kg H_2, subject to additionality, temporal matching, and deliverability requirements [4]. The European Union's Hydrogen Bank has deployed contracts for difference (CfDs) through competitive auctions, while Japan is offering 15-year offtake contracts to provide long-term revenue certainty [2]. Australia and India emphasize tax incentives and fixed-premium schemes, respectively, with India's Strategic Interventions for Green Hydrogen Transition (SIGHT) programme now in its second phase [2]. China, by contrast, relies primarily on state-owned enterprise mandates and industrial policy rather than explicit production subsidies, leveraging its dominant position in electrolyzer manufacturing—the country accounts for approximately 60% of global manufacturing capacity and 65% of installed or FID-stage electrolyzer capacity [2]. Announced public funding for low-emission hydrogen has reached a cumulative USD 38 billion globally, though this figure declined by nearly two-thirds compared to the previous year, with almost 90% originating from advanced economies [2].

On the demand side, progress has been slower but is accelerating. A total of 112 demand-side policies advanced in the year preceding the

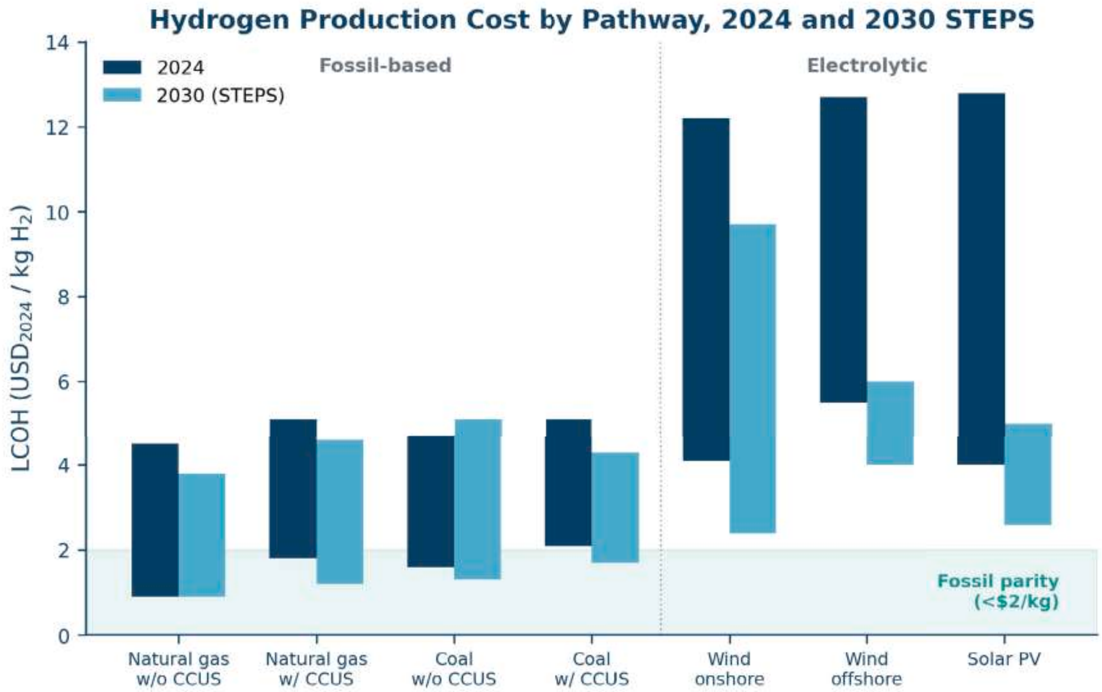

Fig. 5. Hydrogen production cost by pathway, 2024 and 2030 Stated Policies Scenario (STEPS). Bars represent the range of levelized cost across regions. Fossil-based pathways occupy the lower cost range, while electrolytic pathways show wide regional variation driven primarily by electricity cost and electrolyzer CAPEX. The shaded band indicates the approximate fossil parity range (<$2/kg).
Source: Data digitized from IEA [2].

2025 review, frequently in the form of grants and sectoral quotas [2]. The EU's Renewable Energy Directive (RED III) mandates that 42% of hydrogen consumed in industry must be derived from renewable fuels of non-biological origin (RFNBOs) by 2030, creating a binding demand signal for green hydrogen in refining and ammonia production [2,26]. The International Maritime Organization's (IMO) Net-Zero Framework, approved at MEPC 83 in April 2025 but with formal adoption deferred to October 2026, could provide a further demand anchor for hydrogen-based shipping fuels, though near-term uptake may favour LNG or biofuels [2]. Legislated policies could collectively trigger demand for nearly 6 Mtpa of low-emission hydrogen by 2030, while government demand targets add up to 9.5 Mtpa; however, production targets of 27–33 Mtpa far exceed both figures, highlighting a persistent supply–demand policy imbalance—for every USD 1 targeting demand, USD 1.5 supports supply [2].

The third category, infrastructure and certification policy, remains the least developed but is increasingly recognized as essential. Hydrogen transport and storage networks are essential to connect geographically dispersed production sites with demand centres, yet pipeline networks remain limited to legacy industrial clusters. Certification and mutual recognition of hydrogen origin and carbon intensity across jurisdictions are prerequisites for international trade but remain fragmented, with ongoing efforts through the IEA Hydrogen Technology Collaboration Programme and the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) to harmonize frameworks consistent with ISO standards [2]. Without standardized certification, the emerging hydrogen trade risks being confined to bilateral agreements rather than developing into a liquid global commodity market.

Taken together, the policy landscape presents a paradox of its own: the sheer breadth of announced measures is unprecedented, yet the translation of policy into deployed capacity remains slow (Fig. 6). Regulatory delays—exemplified by the multi-year timeline required to finalize U.S. 45V rules and the absence of any credit disbursement as of mid-2025—have left project developers in a holding pattern [2,4]. The challenge for the second half of this decade is not the absence of policy frameworks but their timely and effective implementation.

3. Sectoral demand assessment

Global hydrogen demand reached approximately 100 Mt in 2024, growing 2% year-on-year in line with overall energy demand [2]. This demand remains overwhelmingly concentrated in four established industrial sectors — oil refining, ammonia synthesis, methanol production, and fossil-based direct reduced iron (DRI) — which together account for more than 99% of consumption. Demand from new applications (biofuels upgrading, steel decarbonization, mobility, power generation, and synthetic fuels) grew from a very low base but still constituted less than 1% of the total in 2024 [2]. Table 2 provides a summary of current hydrogen demand, technology readiness levels (TRL), and deployment status across key sectors, and Fig. 7 traces the corresponding production-to-end-use flows. The following subsections assess each sector in turn, evaluating the technical maturity, scale of current consumption, and realistic potential for low-emission hydrogen adoption by 2030.

3.1. Oil refining

Oil refining is the single largest consumer of hydrogen globally, accounting for approximately 37 Mtpa in 2024 [2]. Hydrogen is consumed primarily in hydrodesulfurization (HDS) and hydrocracking processes to meet increasingly stringent fuel quality standards and to process heavier crude slates. From a technology readiness perspective, the use of hydrogen in refining is fully mature (TRL 9); the transition challenge is not one of process innovation but of supply substitution—replacing grey hydrogen produced by on-site steam methane reformers with low-emission alternatives [27].

Approximately 45% of refinery hydrogen is produced via dedicated captive SMR units, more than 35% is recovered as a by-product of

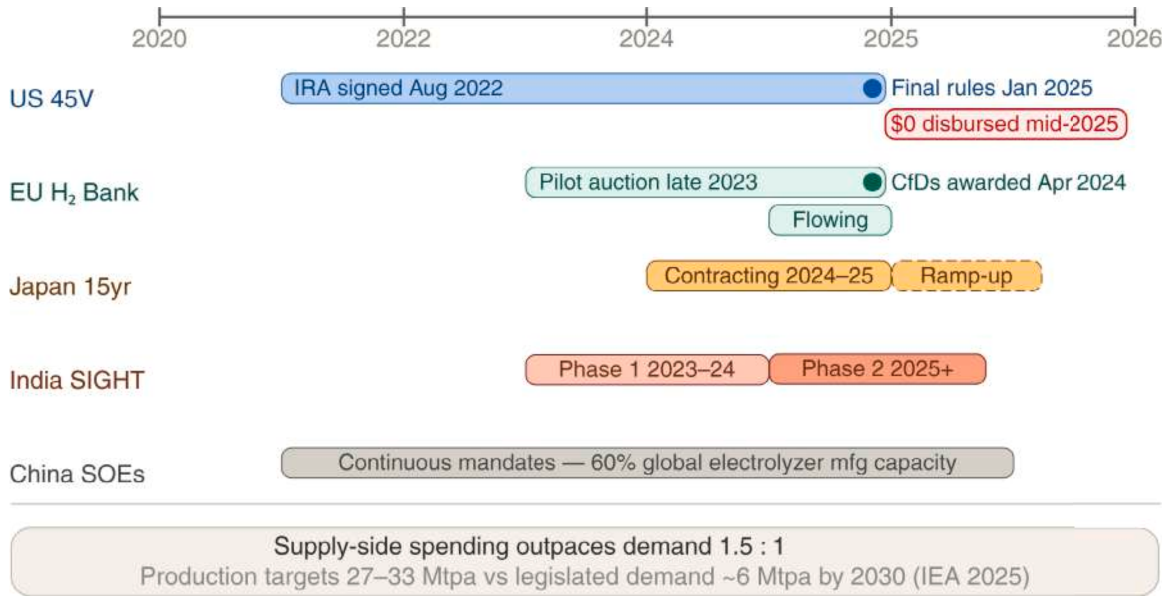

Fig. 6. Hydrogen policy implementation gap: timeline from announcement to operational disbursement. The US Section 45V credit required over 2.5 years from legislation (IRA, August 2022) to final rules (January 2025), with no credits disbursed as of mid-2025. The EU Hydrogen Bank is the only major instrument with funds flowing as of early 2026. China operates through continuous SOE mandates rather than explicit subsidies, controlling ~60% of global electrolyzer manufacturing capacity. Supply-side policy spending outpaces demand-side support 1.5:1 [2,4].

Table 2
Hydrogen demand by sector: current consumption, technology readiness, and 2030 outlook.

Sector	2024 demand (Mtpa)	TRL	Low-H_2 share (%)	Key barrier
Oil refining	~37	9	<1	Cost gap, asset lock-in
Ammonia	~33	8–9	<1	Electrolyzer scale, LCOH
Methanol	~15	8–9	<1	CO_2 source, cost
Steel (DRI)[a]	~5	6–8	<1	H_2 cost, ore quality
Road transport	<0.1	7–9	N/A	BEV competition
Shipping	<0.1	5–7	N/A	Engine availability
Aviation (SAF)	<0.1	4–6	N/A	Cost, certification
Power generation	<0.5	6–8	<1	Turbine readiness, cost

[a] Includes all DRI hydrogen consumption (predominantly natural gas-based); 100% H_2-DRI demand is currently near zero. TRL refers to the H_2-DRI pathway specifically.

catalytic reforming operations, and the remaining ~20% is sourced externally as merchant hydrogen [2]. This structure means that decarbonizing refinery hydrogen requires either retrofitting existing SMR units with CCUS (blue hydrogen) or connecting refineries to external green hydrogen supply—both of which face significant capital expenditure and logistical barriers. TotalEnergies launched the largest private-sector tender for low-emission hydrogen in 2023, seeking to decarbonize hydrogen consumption across its European refining operations, though the average bid price was reported to be substantially above the cost of incumbent grey supply [2].

Refinery hydrogen demand is projected to plateau or decline from the late 2020s onward as electric vehicle adoption reduces demand for refined petroleum products, particularly in Europe and China [2]. This creates a paradox for investment in refinery decarbonization: the sector offers the largest near-term addressable market for low-emission hydrogen (TRL 9, no process change required), yet the shrinking long-term demand outlook weakens the business case for capital-intensive supply infrastructure. Nevertheless, refining remains critical as a "low-hanging fruit" for early adoption, and projects at FID stage could deliver more than 2 Mtpa of low-emission hydrogen to refineries and industrial facilities by 2030 [2].

3.2. Ammonia and chemicals

Ammonia production consumes approximately 33 Mtpa of hydrogen, making it the second-largest demand sector [2]. The Haber–Bosch process, which synthesizes ammonia from hydrogen and atmospheric nitrogen at high temperatures (400–500 °C) and pressures (150–300 bar), has remained essentially unchanged for over a century and operates at TRL 9 [28,29]. Global ammonia production exceeds 180 Mt/yr, with approximately 70% used as nitrogen fertilizer feedstock, making ammonia production indispensable to global food security [30,31]. The sector's carbon footprint is substantial: ammonia synthesis is responsible for releasing approximately 1.6 tonnes of CO_2 for every tonne of ammonia produced and accounts for more than 1% of anthropogenic CO_2 emissions globally, with virtually all hydrogen feedstock derived from unabated natural gas (grey ammonia) or coal gasification [31,32].

The pathway to green ammonia — replacing grey hydrogen feedstock with electrolytic hydrogen — is technologically straightforward (TRL 8–9 for the integrated process) but economically challenging. The Haber–Bosch reactor itself requires no fundamental modification; the transition is determined entirely by the cost and availability of green hydrogen at sufficient scale and purity [31,33]. Life-cycle assessments indicate that replacing grey hydrogen with electrolytic hydrogen

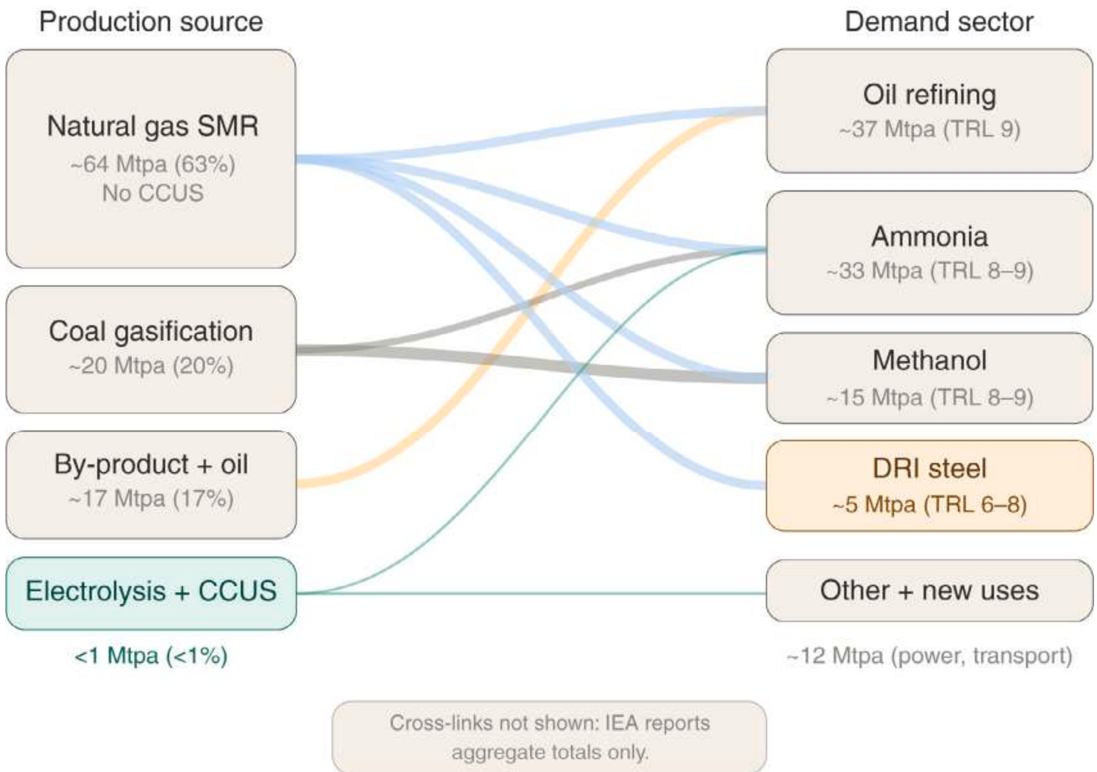

Fig. 7. Global hydrogen production and demand by sector, 2024 (~102 Mtpa). Left: production by source—natural gas without CCUS dominates at ~64 Mtpa (63%), followed by coal (~20 Mtpa, 20%) and by-products (~17 Mtpa, 17%). Electrolysis and fossil fuels with CCUS combined account for less than 1% of output. Right: demand by sector—oil refining (~37 Mtpa), ammonia (~33 Mtpa), and methanol (~15 Mtpa) together consume over 83% of production. DRI steel (~5 Mtpa) is highlighted as the most promising growth sector. Connecting flows are illustrative; source-to-sector disaggregation is not published by the IEA. *Source:* All values from IEA [2].

in a conventional Haber–Bosch loop can reduce ammonia's carbon emissions by up to eight times relative to the incumbent route, with the economics most favourable where low-cost renewable electricity is paired with solid-oxide or proton-exchange membrane electrolysis [31]. A complementary pathway, modelled in detail by Fortunato et al. using Aspen Plus, is the gradual incorporation of green hydrogen into existing natural-gas-fed Haber–Bosch plants; with a partial bypass of the primary reformer to prevent the secondary reformer from overheating, green H_2 incorporation of up to 60% can be achieved while respecting all process constraints [32]—offering a near-term retrofit option that does not require greenfield construction.

Beyond conventional Haber–Bosch, a growing body of work investigates intensified thermocatalytic synthesis under milder conditions to improve compatibility with intermittent renewable inputs. Gu et al. provide a comprehensive review of catalyst, reactor, and process-integration advances aimed at producing ammonia at lower temperatures and pressures, and conclude that thermocatalysis remains the most economically competitive of the emerging routes (electrocatalytic, photocatalytic, and plasma-assisted being the others), but that none has yet displaced conventional Haber–Bosch at industrial scale [29]. A more disruptive long-term possibility is electrochemical nitrogen reduction, which would bypass molecular hydrogen entirely by synthesizing ammonia directly from nitrogen, water, and renewable electricity. Recent reviews of this route report steady gains in Faradaic efficiency and production rate, particularly for lithium-mediated cells, but it remains at laboratory scale with yields and energy efficiencies far below those required to compete with green-hydrogen-fed Haber–Bosch, leaving electrolytic hydrogen the only near-term pathway to low-emission ammonia [34,35]. A practical constraint specific to renewable-powered ammonia is that the rigid operating envelope of conventional Haber–Bosch loops makes them poorly matched to variable wind and solar inputs and forces large hydrogen-storage buffers. A techno-economic analysis by Tully et al. shows that introducing modest reactor flexibility cuts the required hydrogen storage by up to 84% and the levelised cost of ammonia by approximately 22%, opening locations without low-cost salt-cavern storage to economically viable off-grid green ammonia production [36]. Several demonstration projects have validated the integrated concept: Skovgaard Energy inaugurated a plant in Lemvig, Denmark in August 2024, using Topsoe's flexible ammonia synthesis technology with a capacity of 5 ktpa, capable of operating between 5% and 100% load—a critical capability for coupling with variable renewable electricity supply [2]. China's Envision commissioned a 500 MW electrolyzer at its Chifeng project in Inner Mongolia in July 2025, representing the world's largest single electrolytic hydrogen facility and targeting ammonia as a primary offtake [2].

Methanol production consumes a further ~15 Mtpa of hydrogen and follows a similar decarbonization logic: the synthesis process ($CO + 2H_2 \rightarrow CH_3OH$) is well-established (TRL 9), but green methanol additionally requires a sustainable CO_2 source, adding complexity beyond the hydrogen supply challenge [2]. Green methanol has attracted particular interest from the maritime sector, with over 60 methanol-powered vessels operating and nearly 300 on order as of mid-2025, creating a pull-through demand signal for low-emission methanol production [2, 37].

The ammonia and methanol sectors represent the most capital-efficient entry point for low-emission hydrogen deployment after refining: the end-use processes are mature, the demand is large and geographically concentrated, and the product substitution is chemically identical (green ammonia is indistinguishable from grey ammonia). Binding offtake agreements in these sectors account for a significant share of the 3.6 Mtpa of committed hydrogen demand in the global pipeline [6].

3.3. Steel: Hydrogen-based direct reduction

The steel industry accounts for approximately 7% of global CO_2 emissions, with conventional blast furnace–basic oxygen furnace (BF-BOF) steelmaking generating 2.0–2.3 tonnes of CO_2 per tonne of steel produced through the combustion of metallurgical coke [15,38]. Hydrogen-based direct reduction of iron (H_2-DRI), in which hydrogen replaces carbon monoxide as the reducing agent for iron ore pellets in a shaft furnace, offers a pathway to reduce steelmaking emissions by up to 95%, as the reduction byproduct is water vapour rather than CO_2 [15,39]:

$$Fe_2O_3 + 3H_2 \rightarrow 2Fe + 3H_2O \quad (1)$$

The resulting sponge iron (DRI) is subsequently melted in an electric arc furnace (EAF) powered by renewable electricity to produce liquid steel. The H_2-DRI-EAF route requires approximately 50–60 kg of hydrogen per tonne of steel [40], and a 1 Mtpa steel plant would consume roughly 600 MW of electrolyzer capacity [39]—an enormous hydrogen demand that links steel decarbonization directly to the cost and availability challenges discussed in Section 2.4. Detailed mass- and energy-flow modelling by Bhaskar et al. shows that H_2-DRI-EAF can cut specific emissions by more than 35% relative to BF-BOF at present European grid emissions intensities, with electrolyzer efficiency identified as the dominant lever on overall system energy consumption [15]. A concern frequently raised about "green steel" is whether residual hydrogen in the reduced iron causes embrittlement of the final product. Direct measurements by Özgün et al. using thermal desorption spectroscopy show that the hydrogen content of steel produced via hydrogen-based direct reduction followed by arc-furnace melting is 1–2 wppm, comparable to that of conventional steel after vacuum degassing, suggesting that the move to hydrogen reduction does not introduce a new embrittlement risk in the as-cast product [41].

From a technology readiness perspective, H_2-DRI-EAF is the most mature hydrogen-based steelmaking route, assessed at TRL 6–8 as of 2025 [39]. Conventional natural gas-based DRI (using the Midrex or Energiron process) is fully commercial (TRL 9), accounting for over 120 Mtpa of iron production globally; the adaptation to 100% hydrogen operation requires modifications to gas preheating, heat management, and shaft furnace gas distribution but does not demand fundamentally new reactor design [42]. Alternative hydrogen-based steelmaking concepts—including hydrogen injection into blast furnaces (H_2-BF, TRL 5–6) and hydrogen plasma smelting reduction (HPSR, TRL 3–5)—remain at earlier stages of development, with the former limited to approximately 30% coke replacement and the latter still at pilot scale [39].

The flagship project in this space is Stegra (formerly H2 Green Steel), which is constructing the world's first large-scale 100% hydrogen-based DRI steel plant in Boden, northern Sweden. The facility integrates a 700 MW alkaline water electrolyzer — one of the largest in Europe — with a Midrex DRI shaft furnace and EAF, targeting 2.5 Mtpa of near-zero-emission steel, scaling to 5 Mtpa by 2030 [43]. As of late 2025, construction was approximately 60% complete, with over half of the electrolyzer modules installed, and the project had secured approximately €6.5 billion in financing and binding offtake agreements with over 20 major customers including IKEA, Mercedes-Benz, Porsche, and BMW [43]. However, cost overruns and financing pressures led Stegra to launch an additional €975 million fundraising round in October 2025, drawing comparisons with the financial difficulties that led to the bankruptcy of Northvolt, another Swedish green-industry venture [2,43]. The parallel HYBRIT initiative (SSAB/LKAB/Vattenfall) has successfully demonstrated fossil-free hydrogen storage in a 100 m^3 steel-lined rock cavern in Luleå, proving that variable renewable hydrogen production can be buffered for continuous DRI operation with 25%–40% reductions in variable operating costs [44].

Despite these milestones, the sector faces headwinds. ArcelorMittal abandoned plans in June 2025 to produce hydrogen-based DRI at two German sites, citing that green hydrogen was "not yet a viable fuel source" and that natural gas-based DRI was "not competitive as an interim solution" at current economics [2]. The decisive constraint remains hydrogen cost: at \$5/kg, H_2-DRI-EAF costs approximately \$675/t—a premium of ~\$225/t (~50%) over the global BF-BOF average of \$450/t (Fig. 8). This premium may narrow to ~10% if hydrogen prices reach \$1.80/kg, a target consistent with aggressive electrolyzer cost reduction and cheap renewable electricity [45]. A further technical constraint is ore quality: H_2-DRI requires DR-grade iron ore pellets with ≥67% Fe content, and the projected scarcity of such high-grade feedstock may limit the global scalability of the technology [42]. Devlin et al. extend this constraint into a geographic analysis of over 300 candidate locations, identifying regions near the tropics of Cancer and Capricorn—combining high-quality solar resources with supplementary onshore wind, high-grade iron ore, and competitive labour costs—as the most likely sites for cost-competitive green steel, and projecting that fossil-free steel could reach parity with coking-coal-based production from approximately 2030 in favourable locations if coking coal prices remain elevated [16]. A complementary feasibility assessment by Wang et al. examines the deployment trajectory of H-DR technology and concludes that, in the long term, 80%–90% of steel-sector CO_2 emissions can be avoided by full conversion to H-DR, while in the near term the dominant transitional pathway is the operation of existing Midrex- and HYL-type shaft furnaces on H_2-rich gas (55–85 vol% H_2), with full 100% hydrogen operation deferred to a later phase as electrolyzer cost and hydrogen availability allow [46].

Fig. 9 summarizes the technology readiness levels across all hydrogen end-use sectors assessed in this review, highlighting the maturity gradient from established industrial applications (TRL 9) to emerging frontiers such as aviation and aerospace.

3.4. Transport: Road, shipping, and aviation

Transport currently accounts for less than 0.1 Mtpa of hydrogen demand globally, yet it remains one of the most actively debated future applications owing to the sector's scale (approximately 25% of global CO_2 emissions) and the limited decarbonization options available for heavy-duty, long-distance, and high-altitude modes [2]. The technology readiness, competitive dynamics, and realistic hydrogen penetration vary sharply across subsectors, and the following assessment addresses each in turn.

3.4.1. Road transport

Fuel cell electric vehicles (FCEVs) for passenger cars have effectively lost the competition with battery electric vehicles (BEVs). Global FCEV sales totalled fewer than 15,000 units in 2024 (including all vehicle types), compared with more than 10 million BEV passenger cars, and several automakers have scaled back FCEV programs [2,47]. The fundamental disadvantage is thermodynamic: the well-to-wheel energy efficiency of an FCEV (~38%) is less than half that of a BEV (~81%), meaning that for every unit of renewable electricity, direct electrification delivers roughly twice the driving range [48]. Combined with the rapid improvement in lithium-ion battery energy density and the expanding BEV charging network, the FCEV passenger car market has narrowed to a niche role in regions with dedicated hydrogen infrastructure, principally Japan, South Korea, and California.

Heavy-duty trucking represents the remaining viable opportunity for hydrogen in road transport (TRL 7–9). Long-haul Class 8 trucks face a genuine tradeoff between payload capacity and battery weight: a 500-mile BEV tractor requires a battery exceeding 1 MWh, adding several tonnes of weight that directly reduces freight capacity [49]. FCEVs, by contrast, offer comparable range with hydrogen tanks weighing substantially less, and refuelling times of 10–15 min versus multi-hour charging [2]. Despite early commercial deliveries—Nikola shipped 88 TRE fuel cell trucks in Q3 2024 before filing for bankruptcy

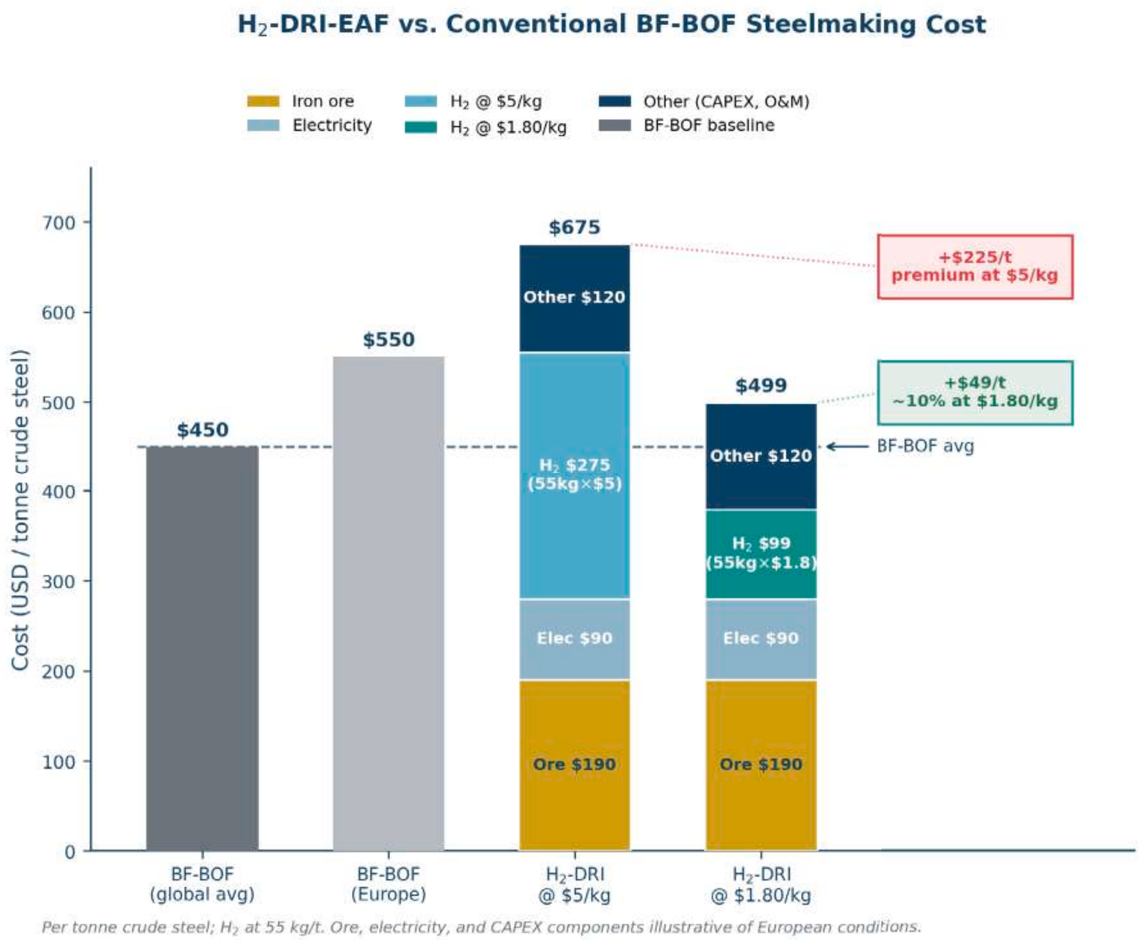

Fig. 8. Cost comparison of H_2-DRI-EAF steelmaking versus conventional BF-BOF. Hydrogen cost calculated as 55 kg H_2 per tonne of steel at the indicated price [39,40]. BF-BOF baselines: $450/t global average, $550/t European average. At $5/kg H_2, the green premium is ~$225/t (~50%); at $1.80/kg, it narrows to ~$49/t (~10%). Ore, electricity, and CAPEX components are illustrative of European production conditions.

in September 2025, underscoring the sector's commercial fragility—deployment remains limited [2]. Hyundai's Xcient has seen modest uptake in South Korea and Switzerland, and Toyota, Mercedes-Benz, and Volvo all have running trials or prototypes [2]. However, total cost of ownership (TCO) analyses consistently show that BEV trucks will reach cost parity with diesel sooner than FCEVs, with the ICCT estimating a ~25% per-mile cost disadvantage for FCEVs relative to BEVs in a 2030 scenario, driven primarily by hydrogen fuel costs [49]. The market consensus is therefore that FCEV trucks will occupy a defined but limited niche — very long haul, high utilization, weight-sensitive routes — rather than displacing BEVs as the dominant zero-emission truck platform.

3.4.2. Shipping

Maritime transport presents a stronger case for hydrogen-derived fuels. International shipping accounts for approximately 3% of global CO_2 emissions, and the International Maritime Organization's (IMO) Net-Zero Framework — approved at MEPC 83 in April 2025 as the first mandatory emissions limit and GHG pricing mechanism for an entire industry sector — provides a powerful regulatory signal for decarbonization [2,37,50]. However, formal adoption was deferred from October 2025 to October 2026, following opposition led by the United States and Saudi Arabia, introducing uncertainty into the implementation timeline [2]. The leading hydrogen-derived marine fuels are green ammonia and green methanol, both of which leverage existing bulk chemical logistics infrastructure. Ammonia-fuelled ship engines are under development by MAN Energy Solutions and Wärtsilä but are not yet commercially available (TRL 5–7); ammonia's toxicity and the risk of NO_x slip and unburned-ammonia emissions during combustion present unresolved engineering challenges [30,37]. A comprehensive review of ammonia dual-fuel marine engines spanning more than three hundred studies concludes that ammonia is presently viable mainly in dual-fuel configurations — paired with a pilot fuel such as diesel or hydrogen for ignition — and that effective exhaust aftertreatment for NO_x and ammonia slip remains a prerequisite before ammonia can displace conventional marine fuels at scale [51]. Green methanol is further advanced in deployment: as of mid-2025, more than 60 methanol-powered vessels were operating and nearly 300 were on order, with Maersk's dual-fuel methanol container ships leading fleet adoption [2]. Supply-chain modelling for green marine fuels indicates that the long transition period in which LNG, methanol, ammonia, and hydrogen coexist, together with substantial substitution between green fuels in response to price volatility, will favour port investments that can serve multiple fuels rather than committing to a single chemistry [37].

Marine fuel bunkering is highly geographically concentrated: Singapore alone supplies approximately one-fifth of global demand, and just 17 ports cover over 60% of the sector's refuelling needs [2]. This concentration offers a pragmatic pathway for hydrogen-based fuel adoption—infrastructure investment can be focused on a small number of strategic ports rather than requiring ubiquitous coverage. However, the IMO framework may initially favour LNG or first-generation biofuels over hydrogen-derived fuels in the short term, given their lower cost and higher readiness [2]. Offtake agreements for hydrogen-based

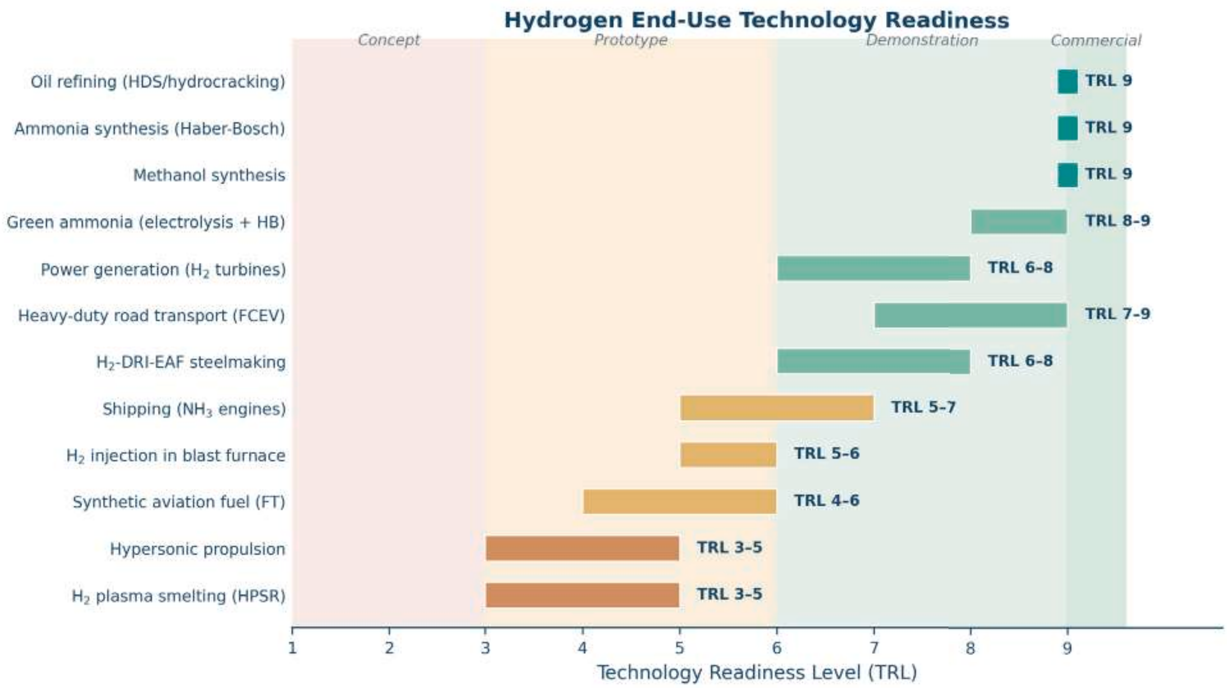

Fig. 9. Technology readiness levels (TRL) of hydrogen applications across sectors, as of 2025. Established industrial uses (refining, ammonia, methanol) are fully commercial (TRL 9), while emerging applications span from early demonstration (aviation, aerospace) to large-scale pilot (H_2-DRI steel, shipping). Compiled from IEA [2,39], and sectoral assessments in this review.

shipping fuels have increased but remain a small share of the 3.6 Mtpa committed pipeline [6].

3.4.3. Aviation: Sustainable aviation fuels

Aviation is the most challenging transport subsector for hydrogen. Direct hydrogen combustion in aircraft requires cryogenic liquid hydrogen storage, a fundamentally different fuel system architecture, and is currently at TRL 4–6 for commercial application; Airbus's ZEROe program targets entry into service no earlier than the mid-2030s [52]. The nearer-term pathway is synthetic sustainable aviation fuel (SAF) produced via Fischer–Tropsch synthesis or methanol-to-jet conversion using green hydrogen and captured CO_2 as feedstocks (TRL 5–7 for the integrated pathway) [53]. Power-to-liquid (PtL) SAF is chemically identical to conventional jet fuel and requires no aircraft or infrastructure modifications, but current production costs of $4–7 per kg render it 3–6× more expensive than fossil kerosene [2,53]. A critical review of the full SAF landscape finds that the most mature pathway, hydroprocessed esters and fatty acids, is already at TRL 9 but that production technologies average roughly 120% higher cost than fossil jet fuel while delivering emissions reductions of at least 27%, and that fewer than 40% of existing policies offer direct monetary incentives—leaving SAF operating at a small fraction of its potential capacity [54]. Global SAF production in 2024 represented only 0.53% of total jet fuel use, the vast majority from waste fats and oils (HEFA pathway) rather than electrolytic hydrogen routes [2].

The EU's ReFuelEU Aviation regulation (Regulation (EU) 2023/2405) mandates increasing SAF blending from 2% in 2025 to 6% in 2030 and 70% by 2050, with a dedicated sub-mandate for synthetic e-fuels rising from 1.2% in 2030 to 35% in 2050 [55]. This regulatory pull, combined with airline net-zero commitments, creates a long-term demand signal, but the required scale-up of green hydrogen production, direct air capture of CO_2, and Fischer–Tropsch synthesis capacity is enormous and will not materially impact aviation emissions before the mid-2030s. Aviation thus represents a critical but longer-horizon application for hydrogen, where the sector's contribution to this review's current snapshot is primarily one of future potential rather than current deployment.

3.5. Power generation and grid balancing

Hydrogen and its derivative ammonia are increasingly considered for two distinct roles in the power sector: dispatchable generation to complement variable renewables, and long-duration energy storage to address multi-day or seasonal imbalances. Together, these applications currently consume less than 0.5 Mtpa of hydrogen globally but are attracting significant policy attention, particularly in Japan, South Korea, and the United States [2].

3.5.1. Hydrogen and ammonia in thermal power

The most advanced near-term pathway is ammonia co-firing in existing coal-fired power stations, championed by Japan as a bridging strategy for its coal-dependent fleet. JERA and IHI Corporation completed the world's first commercial-scale ammonia co-firing demonstration in mid-2024 at the 1 GW Hekinan Unit 4 in Aichi Prefecture, substituting 20% of thermal input with ammonia over a three-month continuous trial [56]. The results confirmed a 20% reduction in CO_2 emissions, NO_x levels no higher than coal-only operation, SO_x reduced by 20%, and negligible N_2O formation, with operability comparable to the coal baseline. JERA plans commercial 20% co-firing operations at Hekinan by FY2027–2028, with 50% demonstration targeted for 2028 and full 100% ammonia combustion envisioned in the 2040s [56]. However, critics note that 20% ammonia co-firing in a coal plant still produces higher specific CO_2 emissions than a modern natural gas combined cycle turbine, and the approach risks extending the operational life of coal assets rather than replacing them [2].

Direct hydrogen combustion in gas turbines is also advancing. Mitsubishi Power's M501JAC turbines, being installed at the Intermountain Power Project (IPP) in Delta, Utah, are designed to operate on a 30% hydrogen–70% natural gas blend from 2025, with incremental increases to 100% hydrogen by 2045 [57]. GE Vernova, Siemens Energy, and Mitsubishi Power have all demonstrated hydrogen blending at various ratios in frame-class gas turbines, with several models now rated for 50%–100% hydrogen operation (TRL 6–8) [2,58]. The primary combustion-stability challenges include managing the higher flame speed and adiabatic flame temperature of hydrogen, which can increase thermal NO_x formation, and adapting dry low-emission (DLE) combustor designs for hydrogen's wider flammability range; recent reviews catalogue micromix, multi-tube, and axially-staged combustor architectures that have been demonstrated to maintain flashback-free, low-NO_x operation at high hydrogen fractions [58]. A less appreciated risk lies downstream of the combustor. Switching from natural gas to hydrogen or hydrogen-rich fuels changes the composition, temperature, and water content of the gas entering the hot section, with consequences for blade and coating durability that have not been systematically characterized at realistic turbine conditions; a recent critical review by O'Connor et al. identifies hydrogen embrittlement of Ni-based superalloys used in fuel injectors, accelerated nitridation, and changes to thermal boundary-layer behaviour from elevated H_2O content as the principal hot-section material concerns [59]. These materials risks are manageable but require an explicit qualification programme that runs in parallel with combustor development rather than after it.

3.5.2. Long-duration energy storage

The case for hydrogen in power is strongest not in baseload generation but in long-duration energy storage (LDES), where lithium-ion batteries face fundamental economic limitations. Battery storage dominates the 2–6 h duration range with round-trip efficiencies of 85%–95%, but costs scale linearly with duration, making multi-day or seasonal storage prohibitively expensive [60]. Hydrogen-based power-to-gas-to-power systems, by contrast, decouple power capacity (electrolyzer and turbine/fuel cell) from energy capacity (storage volume), enabling massive energy reserves at low marginal cost—provided suitable geological storage is available [2].

The flagship demonstration is the ACES Delta project in Delta, Utah—a joint venture between Chevron and Mitsubishi Power Americas, backed by a $504 million DOE loan guarantee [57]. The facility will convert 220 MW of renewable electricity into up to 100 metric tonnes per day of green hydrogen via alkaline electrolysis, storing it in two massive salt caverns with a combined working capacity of 11,000 metric tonnes (approximately 300 GWh of dispatchable energy). For perspective, each ACES cavern stores approximately 150 GWh—more than three times the total U.S. grid-connected battery storage capacity as of end-2023 [57]. The stored hydrogen will fuel the adjacent 840 MW IPP Renewed combined cycle plant, enabling seasonal shifting of excess spring renewable generation to meet peak summer demand—a storage duration of weeks to months that no battery technology can economically provide.

The fundamental tradeoff is efficiency: hydrogen power-to-power round-trip efficiency is approximately 30%–45%, compared with 85%–95% for lithium-ion batteries [60]. This means roughly 2–3 units of renewable electricity are consumed for every unit returned. The economic crossover between the two technologies can be made explicit with a transparent reduced-form levelized-cost-of-storage (LCOS) model. Following the LCOS framework of Schmidt et al. [61], the per-cycle cost of delivered energy as a function of discharge duration t is

$$\mathrm{LCOS}(t) = \frac{a}{t} + b + \frac{P_{\mathrm{el}}}{\eta_{\mathrm{RT}}}, \tag{2}$$

where a is the power-block capital cost amortized over the energy delivered per cycle (and therefore declines with duration), b is the energy-capacity capital cost per unit of delivered energy (approximately independent of duration), P_{el} is the charging electricity price, and η_{RT} is the round-trip efficiency. Lithium-ion systems combine inexpensive power electronics (low a) with costly cells (high b) and a small efficiency penalty ($\eta_{\mathrm{RT}} \approx 0.9$); hydrogen P2G2P inverts this profile, pairing expensive electrolyzer and fuel-cell/turbine power blocks (high a) with near-free salt-cavern storage (low b) but a large efficiency penalty ($\eta_{\mathrm{RT}} \approx 0.35$). Evaluating Eq. (2) with the representative parameters listed in Fig. 10 places the crossover at approximately 13 h, consistent with the independent NREL estimate [62]: below this duration batteries hold a clear economic advantage, while beyond it hydrogen's near-zero marginal storage cost begins to dominate total system economics. The practical implication is that hydrogen storage is not a competitor to batteries but a complement—addressing the tail of the duration curve (days to seasons) where batteries cannot operate, while batteries handle intra-day balancing far more efficiently.

The geological requirement for salt cavern storage limits deployment to regions with suitable formations, notably the US Gulf Coast, Northern Europe, and parts of China. Lined rock caverns (as demonstrated by HYBRIT in Luleå, Sweden) and depleted gas reservoirs offer alternatives but at higher cost and lower technology readiness [44]. The IEA projects that hydrogen-based LDES could become essential for grid reliability as renewable penetration exceeds 60%–70%, particularly in systems with limited hydroelectric or interconnection capacity [2].

Sectoral summary. The sectoral assessment reveals a clear maturity gradient in hydrogen adoption. Established industrial consumers—refining (37 Mtpa), ammonia (33 Mtpa), and methanol (15 Mtpa)—operate at TRL 9 and offer the largest near-term addressable markets, but face an economic substitution challenge: replacing cheap grey hydrogen with costlier low-emission alternatives in processes that require no technical modification. Steel H_2-DRI (TRL 6–8) represents the most promising new industrial application, with flagship projects under construction, though hydrogen cost and ore quality constraints limit near-term scalability. In transport, hydrogen has effectively ceded the passenger vehicle market to batteries but retains niche potential in heavy-duty trucking, and hydrogen-derived fuels (ammonia, methanol, synthetic kerosene) offer the only viable decarbonization pathways for shipping and aviation. Power generation applications — ammonia co-firing and long-duration storage — are technically advancing but remain pre-commercial at scale. Across all sectors, the binding constraint is not technology readiness but the cost and availability of low-emission hydrogen at the volumes required. The following section examines an emerging frontier where hydrogen's unique thermophysical properties — gravimetric energy density, specific impulse, and active cooling capacity — create applications for which no substitute exists: aerospace and hypersonic propulsion.

4. Emerging frontiers: Hydrogen in aerospace and hypersonic propulsion

While the preceding sections assess hydrogen in sectors where it competes with electrification or incumbent fossil pathways, aerospace and hypersonic propulsion represent a qualitatively different category: applications where hydrogen's thermophysical properties are not a marginal improvement but, on current evidence, appear functionally irreplaceable. This section reviews hydrogen's role across the flight-speed spectrum, from subsonic fuel cell aircraft to scramjet-powered hypersonic vehicles, and argues that this domain — though small in current hydrogen demand — constitutes a strategically important frontier that most hydrogen economy reviews overlook.

4.1. Hydrogen as an aerospace fuel: Fundamental advantages

Hydrogen possesses three properties that make it uniquely suited to aerospace propulsion. First, its gravimetric energy density of 120 MJ/kg (LHV) is approximately 2.8× that of conventional kerosene-based jet fuel (Jet-A, ~43 MJ/kg), providing substantially more energy per unit mass—a critical parameter in aerospace where every kilogramme directly impacts payload, range, and structural margins [11]. Second, when used with liquid oxygen in rocket engines, the LH_2/LOX propellant combination delivers a specific impulse (I_{sp}) of approximately 450 s, the highest of any chemical propulsion system and the reason hydrogen powered the Space Shuttle Main Engine and continues to power the RS-25 engines on NASA's Space Launch System [63]. Third,

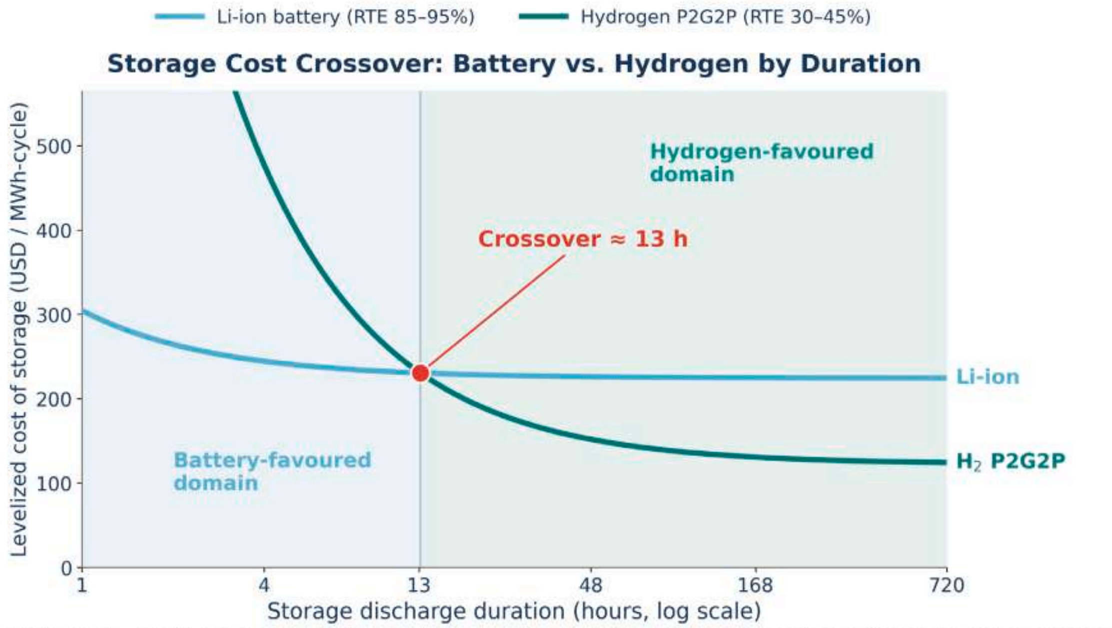

Fig. 10. Levelized cost of storage (LCOS) for lithium-ion battery storage versus hydrogen power-to-gas-to-power (P2G2P) as a function of discharge duration, computed from the reduced-form model of Eq. (2). Parameters: power-block term $a = 80$ and 1420 USD/MWh h, energy-capacity term $b = 180$ and 8 USD/MWh, round-trip efficiency $\eta_{RT} = 0.90$ and 0.35, and charging price $P_{el} = 40$ USD/MWh for Li-ion and H_2 P2G2P respectively; values follow the LCOS framework of Schmidt et al. [61] and salt-cavern storage-cost literature. The modelled crossover at ≈13 h reproduces the NREL estimate [62]: below it batteries are cheaper, above it hydrogen's near-zero marginal storage cost (cavern volume) dominates. The crossover duration is sensitive to power-block CAPEX and round-trip efficiency.

hydrogen's exceptionally high specific heat capacity ($c_p \approx 14.3$ kJ/(kg K) at standard conditions) and its ability to undergo endothermic decomposition at elevated temperatures make it an exceptionally strong active coolant for managing the extreme aerothermal loads encountered in hypersonic flight, where leading-edge stagnation temperatures can exceed 2000 K at Mach 7 and above [64].

These advantages must be weighed against a critical disadvantage: liquid hydrogen's volumetric energy density (8.5 MJ/L) is approximately one-quarter that of Jet-A (~34 MJ/L), meaning that LH_2 storage tanks require roughly four times the volume for equivalent energy content. At cryogenic conditions (20.3 K, 1 atm), boil-off management, tank insulation mass, and the non-conformable geometry of cylindrical or spherical pressure vessels impose significant integration penalties on conventional tube-and-wing airframes [11]. These volumetric constraints diminish in relative importance as flight speed increases, because the fuel mass fraction and cooling requirements dominate vehicle design at hypersonic velocities, precisely where hydrogen's gravimetric and thermal advantages are most decisive.

Fig. 11 compares six key thermophysical properties of liquid hydrogen, kerosene (Jet-A), and liquid methane across the parameters most relevant to aerospace propulsion. Hydrogen's dominance is striking: it delivers 2.8× the gravimetric energy density, 1.45× the specific impulse (with LOX), 7.2× the specific heat capacity, and 7.3× the flame speed of Jet-A—advantages that translate directly into superior range-per-unit-mass, thrust efficiency, active cooling capacity, and combustion reliability in scramjet flowpaths. The sole exception is volumetric energy density (Fig. 11b), where hydrogen's 0.25× disadvantage imposes the cryogenic storage penalty that dominates subsonic airframe design but diminishes in significance at hypersonic speeds where fuel mass fraction governs vehicle performance.

The range advantage of hydrogen over batteries for regional aviation can be understood quantitatively through the Breguet range equation. For a fuel-burning aircraft, range scales with the product of propulsive efficiency, lift-to-drag ratio, and the logarithm of the fuel-to-empty-mass ratio. Hydrogen's gravimetric energy density (120 MJ/kg, LHV) is 2.8× that of Jet-A, but cryogenic tank systems impose a gravimetric index (fuel mass as a fraction of total fuel system mass) of approximately 0.3–0.5 for current technology, compared with essentially 1.0 for conventional wing tanks carrying kerosene [11,65]. Even at a conservative gravimetric index of 0.35, the effective energy per unit fuel-system mass for LH_2 ($0.35 \times 120 = 42$ MJ/kg) matches kerosene, while a more optimistic 0.5 yields 60 MJ/kg—a 40% net advantage that translates directly into extended range or reduced fuel-system weight. For battery-electric alternatives, current lithium-ion cells deliver 200–300 Wh/kg (0.7–1.1 MJ/kg), roughly two orders of magnitude below LH_2 on an energy-per-mass basis [65]. This fundamental disparity confines all-electric aircraft to routes below approximately 500 km, while hydrogen fuel cell systems credibly target 1000–2000 km—sufficient for the majority of regional and short-haul operations that constitute over 25% of European departures [66].

4.2. Subsonic hydrogen aviation

At the subsonic end of the spectrum, hydrogen-electric propulsion using PEM fuel cells is advancing towards certification for regional aircraft. ZeroAvia has completed over a dozen flight tests of its 600 kW ZA600 hydrogen-electric powertrain in a 19-seat Dornier 228 testbed at Cotswold Airport, UK, including a 23-minute flight in 2024 [67]. In September 2025, the company demonstrated a full 250-nautical-mile flight profile (equivalent to London–Dublin) in ground testing of its certification-intent fuel cell system, with the Cessna Caravan as its launch platform targeting FAA/CAA certification by 2027 [67]. H2FLY (a DLR spin-off, now owned by Joby Aviation) achieved the world's first piloted flight of an aircraft powered by liquid hydrogen in September 2023, completing four flights in its HY4 demonstrator including one exceeding three hours, doubling projected range from 750 km (gaseous H_2) to 1500 km with LH_2 [68]. A recent review of hydrogen propulsion architectures for medium-haul aircraft places these demonstrators in the broader technology context, noting that scaling from kW to MW powertrains requires concurrent advances in fuel-cell specific power,

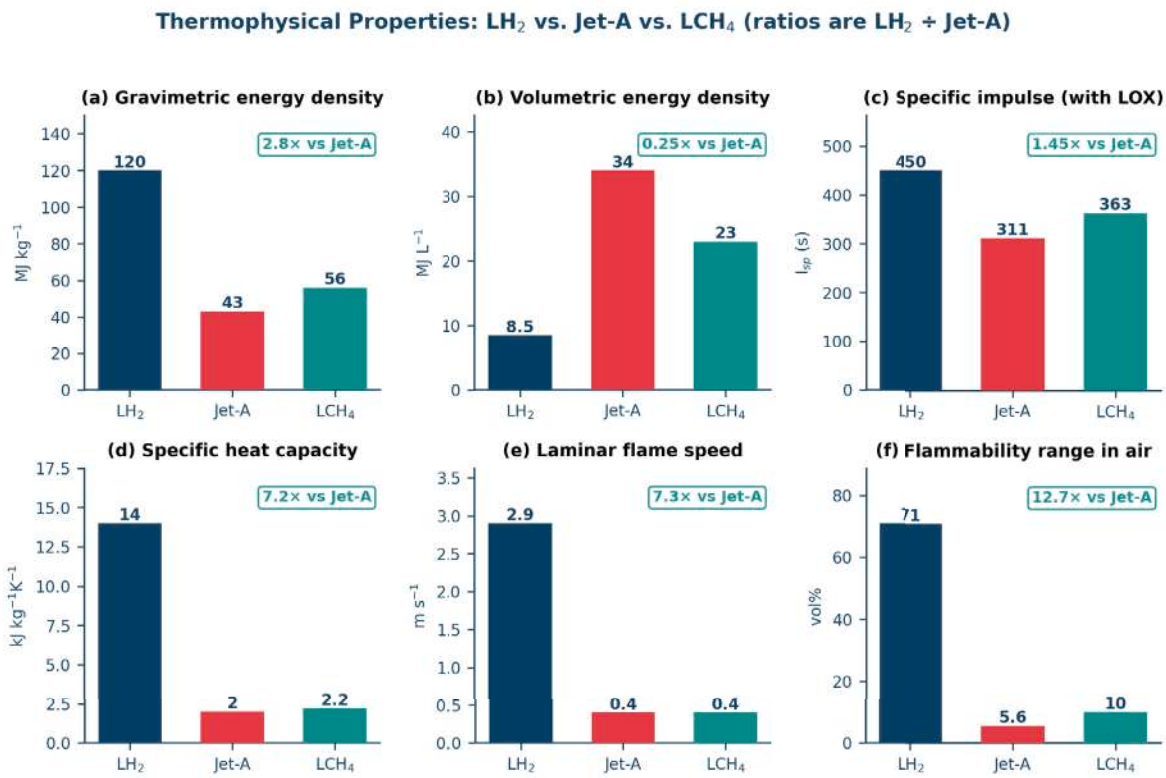

Fig. 11. Comparison of key thermophysical properties of liquid hydrogen (LH_2), kerosene (Jet-A), and liquid methane (LCH_4) for aerospace propulsion applications. (a) Gravimetric energy density, (b) volumetric energy density, (c) specific impulse with liquid oxygen, (d) specific heat capacity, (e) laminar flame speed, (f) flammability range in air. Inset labels indicate the hydrogen-to-kerosene ratio for each property. Hydrogen dominates in five of six metrics; the volumetric penalty (b) is the primary driver of cryogenic storage challenges. Data compiled from Brewer [11], Sutton and Biblarz [63], and NIST standard reference data.

thermal management, lightweight electric machines, and integrated cryogenic cooling, and concludes that hydrogen-electric drivetrains are credible for the regional segment but that direct hydrogen combustion in modified gas turbines retains the edge at higher powers [18]. These achievements place hydrogen-electric subsonic aviation at TRL 5–6, with a credible path to TRL 8 by the late 2020s for aircraft up to 20 seats.

Airbus's ZEROe program targets larger airframes (100–200 seats) using direct LH_2 combustion in modified turbofan engines, with entry into service projected no earlier than the mid-2030s [52]. The concept requires fundamental airframe redesign—a blended wing body or modified fuselage to accommodate rear-mounted cylindrical LH_2 tanks—and an entirely new airport refuelling infrastructure. A comparative emissions and cost analysis by Karpuk, Freund, and Hanke-Rauschenbach for medium-range and long-range aircraft entering service around 2050 indicates that hydrogen fuel-cell aircraft can achieve in-flight emissions reductions of approximately 24% relative to hydrogen-combustion aircraft on long-range missions, but at an estimated operating-cost penalty of about 30% and a 22%–30% increase in fuel burn—driven by the lower specific power of fuel-cell systems and the cooling and tankage penalties [17]. The implication is that the choice between fuel-cell and combustion architectures is not settled at the long-range segment and will be sensitive to future gains in fuel-cell power density and to the carbon intensity of the hydrogen supply. The EU's Clean Aviation Joint Undertaking is funding multiple Phase 1 (2022–2026) projects addressing hydrogen combustion, fuel systems, and cryogenic tank technology, with total program funding exceeding €1.7 billion [69]. The FAA published its Hydrogen-Fuelled Aircraft Safety and Certification Roadmap in December 2024, signalling regulatory preparation for hydrogen aircraft entry within the next decade [70].

4.3. Hypersonic propulsion: Scramjets and active cooling

Between the subsonic programs described above and the hypersonic regime discussed below lies a notable gap: at transonic and low supersonic speeds (Mach 1–5), conventional turbofan and turbojet engines remain competitive, and hydrogen offers insufficient performance benefit to justify the cryogenic infrastructure penalty. Hydrogen's aerospace value proposition is therefore bimodal, and it is at the hypersonic extreme — above Mach 5 — that the case becomes not merely strong but exclusive.

At the opposite extreme of the flight envelope, hydrogen is the enabling fuel for air-breathing hypersonic propulsion. Supersonic combustion ramjets (scramjets) operate at flight speeds above Mach 5, where the incoming air is compressed by the vehicle's own shockwave system and enters the combustor at supersonic velocity. At these conditions, hydrocarbon fuels cannot ignite and sustain combustion within the millisecond residence times available in the engine flowpath; hydrogen, with its wide flammability limits (4%–75% in air), low ignition energy (~0.02 mJ), and high flame speed (~2.9 m/s laminar, turbulent flame speeds an order of magnitude higher), is widely regarded in the propulsion literature as the only practical fuel for sustained scramjet operation above approximately Mach 8 [10,64,71]. The fundamental difficulty in achieving robust supersonic combustion is well summarized by Urzay's review: in a scramjet combustor the airflow autoignites at temperatures of order 1000–1400 K produced by the shock train, but typical autoignition delay times are of order 10–100 μs, comparable to the residence time of the flow in the combustor, so a significant fraction of the flowpath would remain chemically frozen unless deliberate flame-anchoring mechanisms are provided [10]. Practical scramjet engines therefore operate in a dual-mode regime, transitioning from ramjet-like subsonic combustion at the lower end of the Mach 4–6 window to pure supersonic combustion above Mach 6 (Fig. 12) through

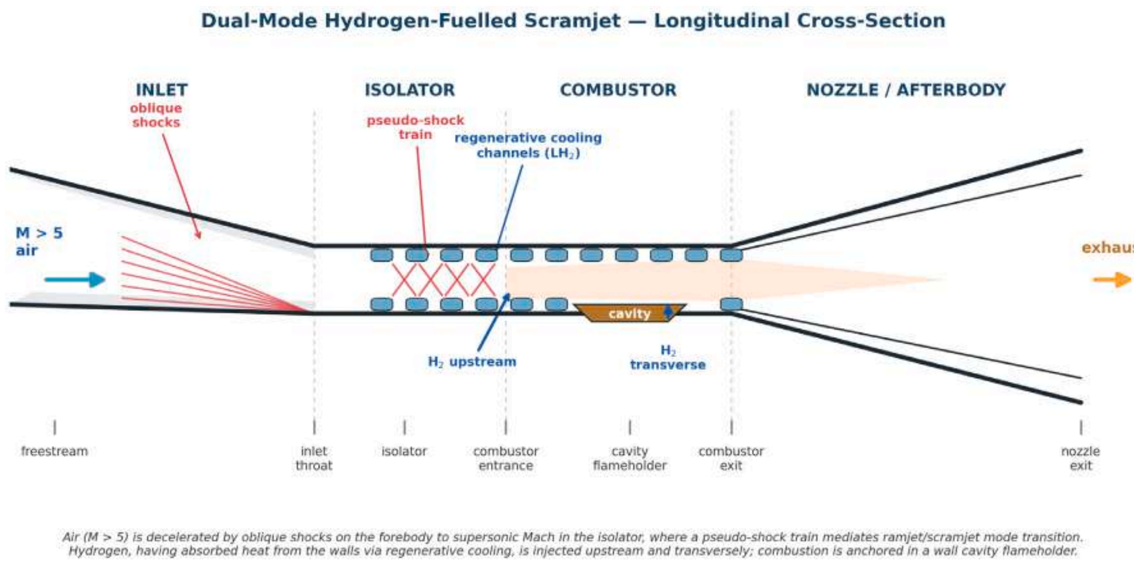

Fig. 12. Longitudinal cross-section of a dual-mode hydrogen-fuelled scramjet, showing the four functional sections: inlet (forebody compression via oblique shocks), isolator (pseudo-shock train mediating ramjet/scramjet mode transition), combustor (cavity flameholder with upstream and transverse hydrogen injectors), and nozzle/afterbody (expansion). Cryogenic hydrogen circulates through wall-embedded regenerative cooling channels, absorbing aerothermal heat from the combustor walls before being injected into the flowpath as fuel; this dual fuel–coolant role is fundamental to all current scramjet concepts. Schematic adapted from the architectural features described in [10,19,72,73].

a combination of variable-geometry isolators, cavity flameholders, and — in flight-tested HyShot and HIFiRE configurations — the "radical-farming" technique in which a shock train generates hydroxyl and hydrogen radicals upstream of the combustor to seed the reaction zone [10,19]. A synthesis of the open scramjet experimental database covering ground-test and flight programmes from the 1990s onward indicates that, while ground facilities can replicate stagnation enthalpies representative of Mach 5–7, replicating flight conditions above Mach 10 reliably is not yet possible, which makes flight testing indispensable to scramjet qualification [19].

Mixing and combustion efficiency in a scramjet combustor are controlled primarily by fuel injection strategy. Transverse injection of hydrogen from the combustor wall is the simplest implementation but suffers from limited fuel penetration into the core flow. Detailed numerical simulations by Bezerra et al. of a dual-injection mode in a generic scramjet combustor show that adding upstream injectors to a baseline single-injection configuration increases the global fuel penetration from 27.9% to 33.8% of the duct height and raises the combustion efficiency from 10.3% to 22.0%, with only a modest additional total-pressure loss [74]. These figures illustrate how sensitive scramjet performance is to injection-system design choices and underscore that scramjet combustor development cannot be separated from the broader airframe–engine integration problem.

Equally important is hydrogen's dual role as both fuel and coolant in hypersonic vehicles. At Mach 7, aerodynamic heating generates heat fluxes exceeding 1 MW/m^2 at vehicle leading edges, and total enthalpy conditions approach those of atmospheric re-entry [64]. The scaling of stagnation-point heat flux with flight Mach number, calculated from the Sutton–Graves correlation as a function of leading-edge radius, is shown in Fig. 13. At the X-51A flight condition ($M \approx 4.8$) heat fluxes for a 5 cm leading-edge radius are modest enough that hydrocarbon regenerative cooling suffices; by contrast, at the X-43A flight condition ($M \approx 9.6$) the predicted stagnation-point flux for the same geometry exceeds 2 MW/m^2, and towards the Mach 12 upper limit of the SPARTAN engine's design envelope, it approaches 5 MW/m^2—a regime in which only an active coolant with hydrogen's heat-sink capacity is viable [64,72].

Regenerative cooling, in which cryogenic hydrogen circulates through channels in the engine walls and leading-edge structures before being injected into the combustor, simultaneously manages thermal loads and pre-heats the fuel for more efficient combustion. This dual-role architecture is fundamental to the thermal management of all current scramjet concepts and has no viable substitute at flight speeds above Mach 6 [71,72]. The flight-test record illustrates how decisive regenerative cooling is in extending operating times: NASA's X-43A, which relied on passive thermal protection, sustained powered flight for less than 10 s, whereas the X-51A, fitted with regenerative cooling using JP-7 hydrocarbon coolant, sustained scramjet operation for approximately 140 s at Mach 4.8 and over 300 s in a follow-on test [72]. Hydrogen is a stronger active coolant than hydrocarbon fuels on a per-mass basis. Its specific heat capacity at standard conditions is approximately 14.3 $kJ\,kg^{-1}\,K^{-1}$ (from NIST tabulated data), and additional latent heat is available from endothermic dissociation at elevated temperatures, giving hydrogen a cooling capacity that the open scramjet literature consistently identifies as exceeding that of practical hydrocarbon coolants such as JP-7. The corresponding price is the volumetric penalty of cryogenic storage and the requirement to manage supercritical hydrogen flow through narrow cooling passages, where heat-transfer deterioration and channel optimization remain active research problems [72].

A specific engineering issue that warrants attention is mode transition and the role of the isolator. Practical scramjets operate as dual-mode combustors that must function as ramjets at the lower end of their flight envelope (subsonic combustion behind a thermally-choked shock train) and transition to supersonic combustion above approximately Mach 6. The isolator, a constant- or slightly diverging-area duct between the inlet and the combustor, contains the shock train that mediates this transition. Ground-test and flight data show that the back-pressure that the isolator can sustain before unstart sets a fundamental limit on combustor heat release, and that this limit becomes increasingly restrictive as flight Mach number rises and combustor entry conditions move from oblique-shock-train to pseudo-shock behaviour [19,73]. This constraint is tightened by hydrogen's combustion characteristics: its high flame speed and heat release raise the back-pressure the isolator must contain, so the mode-transition margin and the hydrogen injection schedule are coupled. Mode transition is therefore not merely a control problem but a constraint that propagates back into airframe-engine integration: vehicles intended to

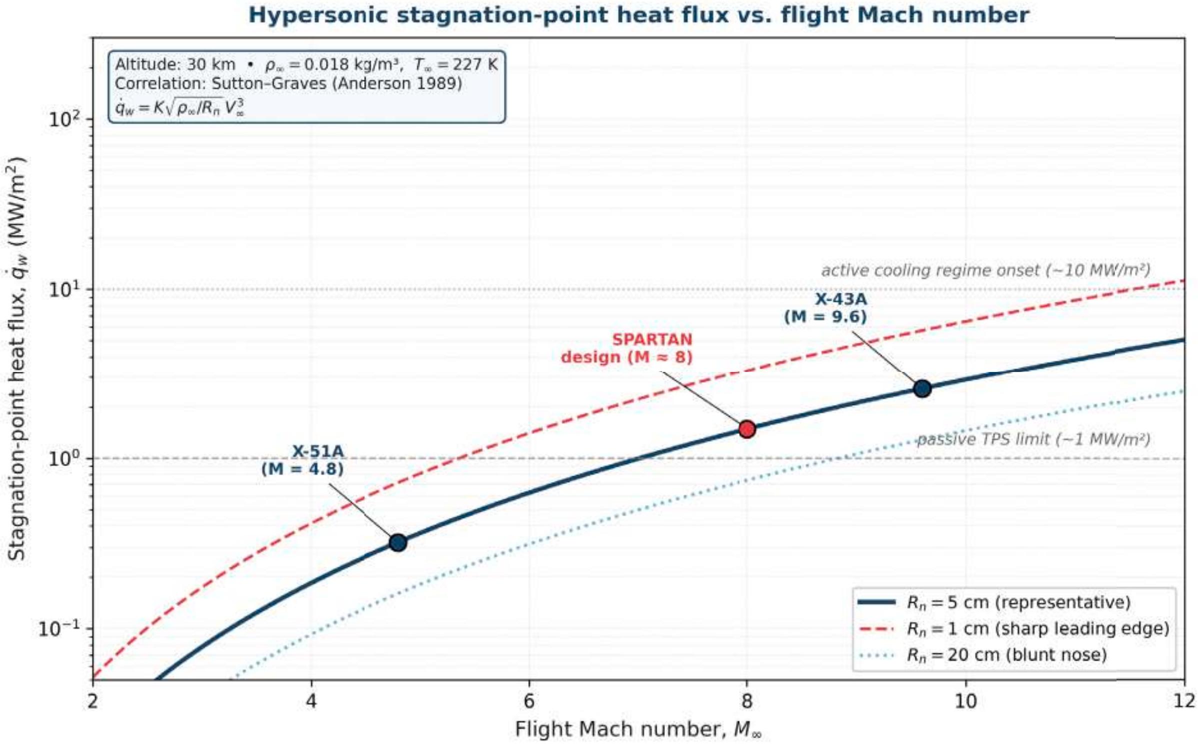

Fig. 13. Stagnation-point heat flux on a hypersonic leading edge as a function of flight Mach number, evaluated at 30 km altitude using the Sutton–Graves convective-heating correlation ($\dot{q}_w = K\sqrt{\rho_\infty/R_n}\,V_\infty^3$, $K = 1.7415 \times 10^{-4}$ in SI units; see Anderson [64]). Three curves are shown for leading-edge radii of 1, 5, and 20 cm, bracketing the design range of practical scramjet vehicles. Markers indicate the flight conditions of X-51A (M = 4.8), X-43A (M = 9.6), and the SPARTAN engine design point (M ≈ 8). Above approximately Mach 7 with representative leading-edge geometry, the stagnation-point heat flux exceeds the ~1 MW/m^2 limit typically achievable by passive ceramic thermal protection systems, motivating active regenerative cooling with hydrogen as coolant.

span the Mach 4–12 range either require variable-geometry inlets and combustors, which add weight and sealing complexity at hypersonic conditions, or accept reduced performance over a portion of the flight envelope through fixed-geometry compromise—the path taken by the SPARTAN engine [73,75].

Active cooling sets the second constraint on sustained scramjet operation, and the cooling-channel design problem is fundamentally coupled to the combustion problem because the coolant becomes the fuel. The available heat sink per unit fuel flow is bounded by the specific heat of the coolant, the maximum allowable wall temperature, and the channel geometry. Luo et al.'s review shows that supercritical hydrogen flow in milled rectangular cooling channels can exhibit heat-transfer deterioration when the wall temperature rises faster than the bulk fluid temperature, an effect attributed to the strong variation in thermophysical properties near the pseudo-critical point [72]. Channel optimization work, including the use of high-aspect-ratio sections, additive-manufactured internal structures, and bifurcated networks, can recover much of this deterioration but at the cost of increased pressure drop and manufacturing complexity [72]. The implication for vehicle design is that the regenerative-cooling system and the combustor cannot be developed independently: heat-flux distribution, fuel-flow ratio, and injection conditions are part of a single coupled-thermal-fluid optimization, and recent work using high-fidelity coupled simulations and machine-learning surrogates aims to make this multi-disciplinary optimization tractable for vehicle-scale design [72,73]. The integrated architecture, with liquid hydrogen serving as both active coolant and fuel, is shown in Fig. 14.

The technology readiness of scramjet propulsion has advanced significantly in recent years. NASA's X-43A demonstrated hydrogen-fuelled scramjet operation at Mach 9.6 in 2004, achieving the record for air-breathing powered flight that stood for over a decade [76]. The Australian-led Hypersonix Launch Systems has developed the SPARTAN engine, a fifth-generation, 3D-printed, fixed-geometry hydrogen scramjet capable of operation up to Mach 12, powering the DART AE—a 3.5 m autonomous hypersonic demonstrator [75]. As of February 2026, Hypersonix has secured $46 million in Series A funding (backed by Australia's National Reconstruction Fund, Saab, and QIC), and has announced a launch window for the first DART AE flight test at NASA's Wallops Flight Facility in Virginia, launched via Rocket Lab's HASTE suborbital booster under the US Department of Defense HyCAT program [75]. This flight, designated *Cassowary Vex*, will constitute the first flight demonstration of a hydrogen scramjet engine manufactured entirely by additive engineering, and will evaluate propulsion, materials, and guidance systems under sustained hypersonic conditions [75].

The contrast with hydrocarbon-fuelled scramjets clarifies why hydrogen is pursued at the high-Mach end of the envelope: hydrocarbon systems such as those demonstrated in free flight in 2022 are practical to approximately Mach 5–6, whereas hydrogen's combustion and cooling properties extend sustained air-breathing operation to Mach 8 and beyond, while its regenerative-cooling capacity is what makes reusable — rather than single-use — hypersonic platforms physically plausible [71].

4.4. Challenges and outlook

Despite these advances, hydrogen aerospace applications face formidable barriers. Cryogenic LH_2 storage imposes volume and insulation penalties that limit airframe integration options; boil-off rates of 0.1–1%/day require either robust venting systems or zero-boil-off cryocooler technology still under development [11]. Certification of hydrogen-fuelled aircraft requires new regulatory frameworks—the FAA's 2024 roadmap identifies gaps in fire detection, crash survivability standards, and airport operations protocols [70]. For hypersonic

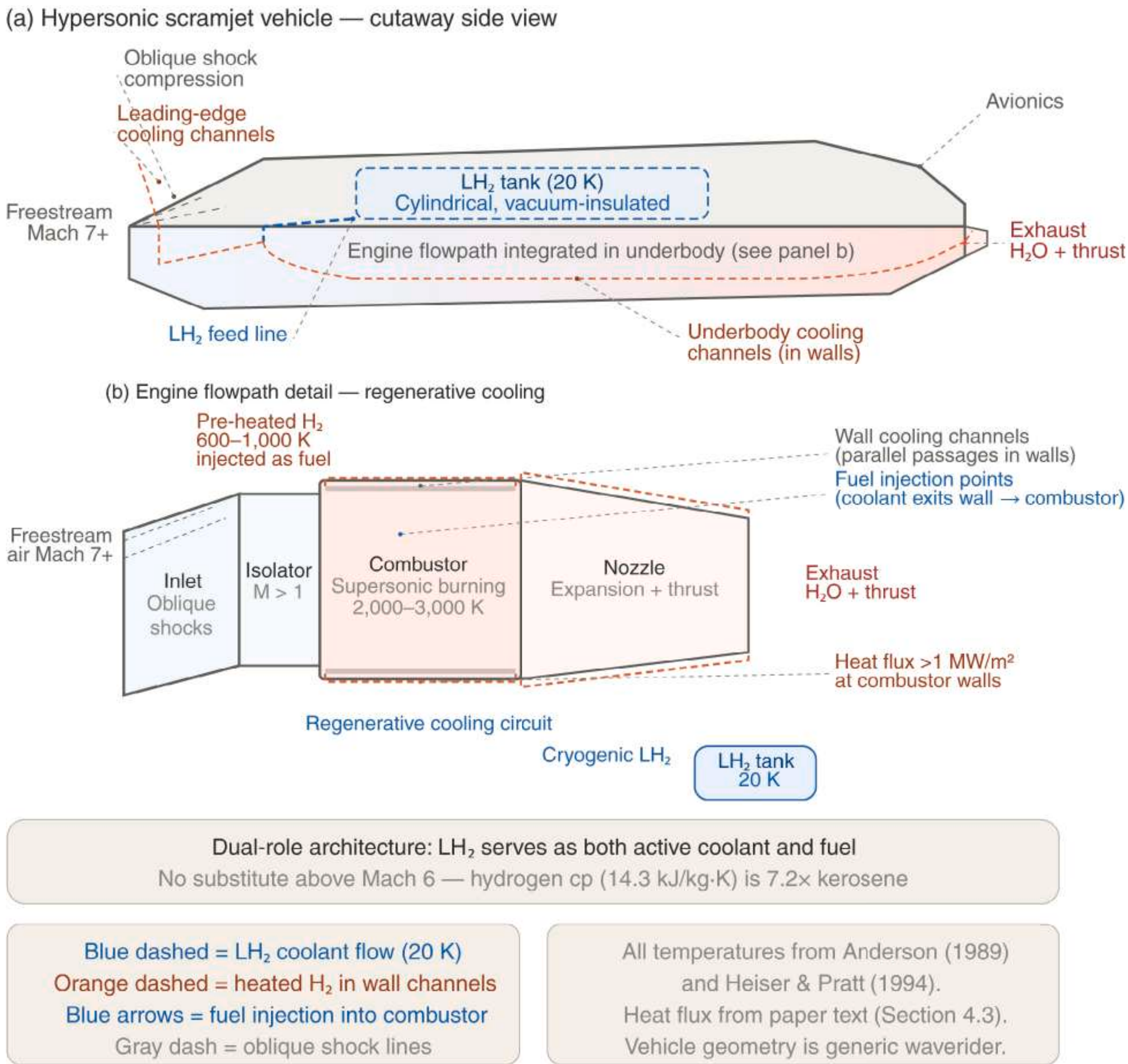

Fig. 14. Hydrogen-fuelled scramjet with regenerative cooling. (a) Cutaway side view of a generic waverider-type vehicle showing the internal LH_2 tank, engine flowpath integrated into the underbody, and cooling channel routing through the vehicle skin and leading edges. (b) Engine flowpath detail showing the regenerative cooling circuit: cryogenic LH_2 (20 K) flows from the tank through wall cooling channels in the combustor and nozzle, absorbing aerothermal heat fluxes exceeding 1 MW/m^2, before being injected into the combustor as pre-heated fuel (600–1000 K). This dual-role architecture — hydrogen as both active coolant and fuel — has no viable substitute above Mach 6. Temperatures from Anderson [64] and Heiser and Pratt [71]; heat flux from Section 4.3; vehicle geometry is a generic waverider.

systems, the transition from ground-test to sustained free-flight at Mach 7+ remains a fundamental engineering challenge: replicating true flight enthalpies in ground facilities is impossible above approximately Mach 10, making flight testing essential and expensive [64].

Fig. 15 maps the current technology readiness of hydrogen aerospace programs against flight Mach number, revealing two distinct clusters separated by a "supersonic desert" between Mach 1 and 5 where no hydrogen projects currently exist. In the subsonic regime (Fig. 15a), fuel cell aircraft (ZeroAvia, H2FLY) and synthetic SAF occupy TRL 5–7, with a credible trajectory towards the certification target zone (TRL 7–8) by the late 2020s; Airbus ZEROe remains at TRL 3–4, reflecting the longer timeline for large-airframe LH_2 integration. In the hypersonic regime (Fig. 15b), the imminent DART AE flight test (TRL 4–6) represents the critical bridge between ground-validated scramjet technology and sustained hypersonic flight—a frontier that only NASA's X-43A has previously reached. The Mach 1–5 gap is notable: at transonic and low supersonic speeds, conventional turbofans remain competitive, and hydrogen offers insufficient benefit to justify the cryogenic infrastructure penalty. Hydrogen's aerospace value proposition thus exhibits a bimodal character—compelling at subsonic speeds (where zero emissions drive adoption) and essential at hypersonic speeds (where no alternative fuel exists)—with limited relevance in the intermediate regime.

Although hydrogen aerospace demand is negligible today, an order-of-magnitude estimate reveals its potential scale. Global commercial aviation consumed approximately 290 Mt of jet fuel in 2024 [2]. The IEA estimates that regional, short-haul, and medium-haul flights — those most amenable to hydrogen propulsion — account for roughly 95% of departures but approximately 50%–58% of fuel consumption [77]. If hydrogen aircraft captured 25% of this addressable segment by 2050 (a moderate scenario consistent with fleet renewal timelines and the mid-2030s entry into service projected by Airbus [52]),

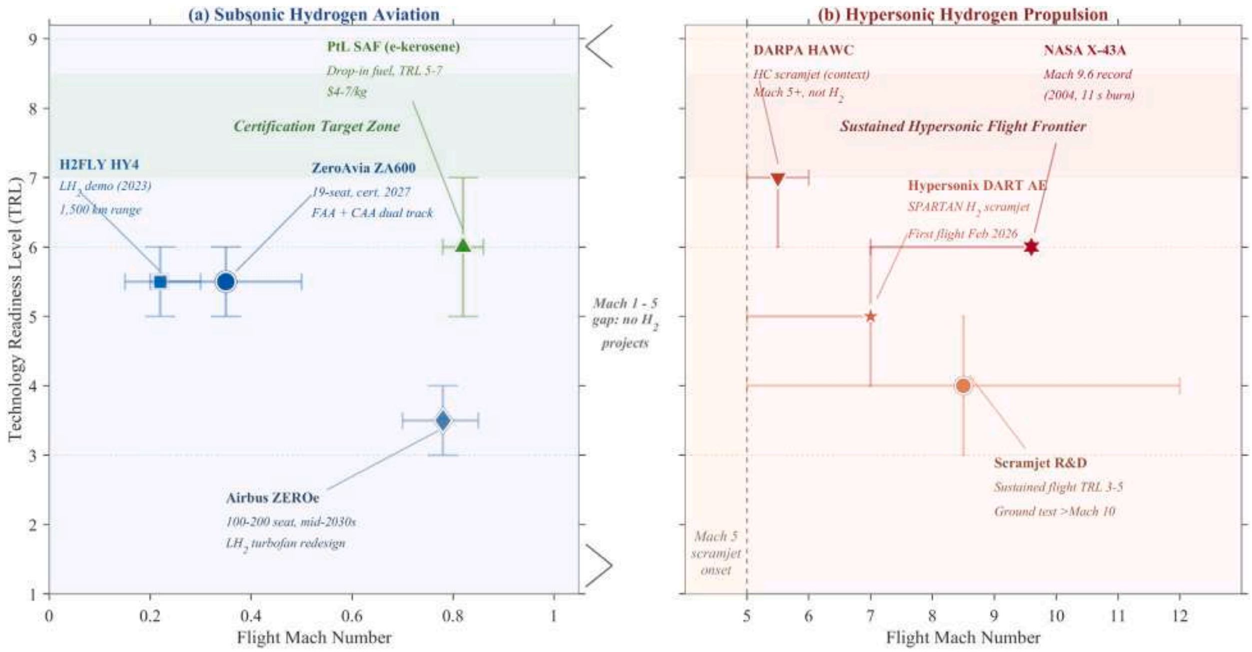

Fig. 15. Hydrogen aerospace technology roadmap: technology readiness level (TRL) versus flight Mach number for key programs and demonstrators, as of early 2026. (a) Subsonic hydrogen aviation, showing fuel cell aircraft and synthetic SAF programs approaching the certification target zone (green band, TRL 7–8). (b) Hypersonic hydrogen propulsion, showing scramjet demonstrators relative to the sustained flight frontier (red band). Error bars indicate TRL and operational Mach ranges. The Mach 1–5 gap between panels reflects the absence of hydrogen-specific aerospace programs in the transonic and low-supersonic regimes. DARPA HAWC (hydrocarbon scramjet) is included for context. Compiled from program data cited in Section 4. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

and accounting for hydrogen's 2.8× gravimetric energy advantage offset by a ~20% efficiency penalty from cryogenic storage and airframe drag [65], the resulting hydrogen demand would be approximately 10–15 Mtpa—comparable to current global methanol hydrogen demand (15 Mtpa) and sufficient to constitute a strategically significant offtake sector. In the nearer term, if only sub-20-seat fuel cell aircraft enter service by the late 2020s, initial hydrogen demand would remain below 0.1 Mtpa, scaling with fleet penetration through the 2030s. Hypersonic applications, while transformative, would consume orders of magnitude less hydrogen given the small vehicle and fleet sizes involved. The aerospace sector thus represents a long-term demand anchor rather than a near-term volume driver for the hydrogen economy.

Nevertheless, hydrogen's role in aerospace is qualitatively distinct from its role in the terrestrial sectors assessed in Section 3. In refining, ammonia, and steel, hydrogen competes with electrification, CCUS, or process alternatives; in hypersonic propulsion, there is no alternative. The convergence of three trends — advances in additive manufacturing enabling complex scramjet geometries, the global build-out of green hydrogen production infrastructure, and intensifying geopolitical competition in hypersonic capabilities — suggests that aerospace may emerge as a strategically critical, albeit volumetrically small, hydrogen demand sector in the 2030s. The imminent DART AE flight test and ZeroAvia's certification timeline place hydrogen aerospace at an inflection point between laboratory demonstration and operational deployment.

5. Cross-cutting challenges

The sectoral analyses in Sections 3 and 4 reveal that technology readiness varies widely across hydrogen applications, but a common set of infrastructure, logistical, regulatory, and supply chain constraints cuts across all sectors and will ultimately determine whether announced projects translate into operational capacity. This section addresses six such challenges: hydrogen transport infrastructure and pipeline repurposing (Section 5.1), large-scale geological storage (Section 5.2), safety standards and public acceptance (Section 5.3), electrolyzer supply chains and workforce development (Section 5.4), water requirements for electrolysis (Section 5.5), and the emerging concern of hydrogen leakage as an indirect greenhouse gas (Section 5.6).

5.1. Infrastructure and transport

Delivering hydrogen from production sites to demand centres requires dedicated infrastructure that largely does not yet exist. The European Hydrogen Backbone (EHB) initiative envisions approximately 28,000 km of pipeline corridors by 2030, expanding to 53,000 km across 28 countries by 2040, with roughly 60% comprising repurposed natural gas pipelines and 40% new construction, at an estimated investment of €80–143 billion [78]. Transporting hydrogen 1000 km via this backbone would cost €0.11–0.21/kg—competitive with any alternative mode at scale [78]. However, repurposing existing steel pipelines introduces the challenge of hydrogen embrittlement: dissolved hydrogen atoms degrade the ductility and fracture toughness of carbon steel, particularly at weld seams where residual stresses concentrate hydrogen accumulation, increasing embrittlement coefficients by over 75% in some configurations [79]. The ASME B31.12 pipeline code, which applies to hydrogen concentrations above 10 mol%, imposes substantially stricter material, welding, and fracture toughness requirements than the B31.8 code governing conventional natural gas systems [79]. Qualifying existing pipeline segments for hydrogen service thus requires individual integrity assessments that may preclude repurposing of older, higher-carbon-content vintage pipe.

Beyond pipelines, port infrastructure for hydrogen-derived fuel imports remains minimal. Ammonia can leverage existing bulk liquid terminals, but dedicated cracking facilities to reconvert ammonia to hydrogen at import terminals are not yet commercially deployed at scale, adding cost and energy penalties of 7%–18% to the delivered hydrogen price [2].

5.2. Storage

Matching intermittent renewable hydrogen production with continuous industrial demand requires large-scale storage. Compressed gaseous storage (350–700 bar) and liquefaction (20.3 K) serve point-of-use applications but are prohibitively expensive for bulk seasonal storage. Underground storage in solution-mined salt caverns has emerged as the most technically mature and cost-effective option for large-scale hydrogen buffering. Salt formations offer low permeability, chemical inertness towards hydrogen, self-healing mechanical properties under cyclic loading, and rapid injection/withdrawal rates [80,81]. Operational experience exists: the Chevron Phillips Clemens Terminal in Texas has stored hydrogen in a salt cavern (160 ft diameter, 1000 ft height, 2520 metric tonnes working capacity) since the 1980s, and the UK Teesside facility has operated since 1972, storing 95% pure hydrogen at 4.5 MPa [80,81]. The ACES Delta project in Utah, discussed in Section 3, represents the next scale: two caverns with 11,000 metric tonnes of working capacity [57]. Salt cavern storage reduces costs by 70%–90% compared with above-ground tank systems [80], with comparative levelised costs of underground hydrogen storage in the range of ~\$1.2–1.3/kg H_2 for depleted reservoirs and salt caverns [81]. A recent techno-economic model that resolves the cost by formation type reports a levelised cost of hydrogen storage of approximately 4.97 RMB/kg for salt caverns, 6.01 RMB/kg for depleted gas reservoirs, and 6.55 RMB/kg for lined rock caverns at annual cycling, confirming that salt caverns remain the lowest-cost option where the geology permits [82], but suitable geological formations are geographically constrained, leaving regions without salt deposits dependent on costlier alternatives such as lined rock caverns or chemical carriers (ammonia, liquid organic hydrogen carriers). Chemical carriers trade geological independence for a round-trip energy penalty—ammonia requires an energy-intensive cracking step (7%–18% of delivered hydrogen; Section 5.1) and liquid organic hydrogen carriers incur dehydrogenation losses—making both better suited to long-distance transport than to bulk cyclic storage. Country-scale assessments of coupling salt-cavern storage with renewable electricity show that the principal engineering challenges — wellbore integrity, cushion-gas management, and microbial activity in saline environments — can be addressed within existing salt-cavern gas storage practice but require dedicated site characterization and monitoring programmes [83].

5.3. Safety, standards, and public acceptance

Hydrogen's physical properties — flammability limits of 4%–75% in air (versus 5%–15% for natural gas), minimum ignition energy of approximately 0.02 mJ, invisible flame, and tendency to leak through seals due to its small molecular size — demand rigorous engineering controls at every point in the value chain [84]. ISO/TC 197, the international standardization body for hydrogen technologies, has published 21 standards as of 2024 covering fuelling stations, fuel quality, dispensing protocols, and basic safety considerations, with active ballots on cryogenic and heavy-duty vehicle dispensing standards progressing through 2025 [84]. National codes including ASME B31.12 (pipelines), NFPA 2 (hydrogen technologies), and CGA G-5.6 (pipeline systems) provide regulatory frameworks, but gaps remain—particularly for novel applications such as ammonia co-firing in power plants, hydrogen-fuelled aircraft (addressed by the FAA's 2024 roadmap [70]), and residential hydrogen blending above 20 vol%.

Public acceptance remains an underappreciated barrier. Community opposition to hydrogen infrastructure siting, fuelled by unfamiliarity and association with historical incidents, can delay permitting timelines as effectively as technical obstacles. Transparent safety communication and visible demonstration projects — such as Stegra's green steel operations in Boden [43] and ZeroAvia's flight test programme [67] — play an important role in building social licence.

5.4. Supply chain and workforce

The electrolyzer manufacturing supply chain faces a scaling challenge of unprecedented magnitude. Global installed electrolysis capacity must grow from approximately 1 GW in 2023 to hundreds of gigawatts by 2030 to meet announced green hydrogen targets [2]. European electrolyzer manufacturing capacity stands at approximately 1.75 GW/year, with commitments to scale to 17.5 GW/year, but order books remain thin amid project delays and uncertain offtake agreements [20].

Critical mineral constraints pose a longer-term threat. PEM electrolyzers rely on iridium for anode catalysts, yet global iridium production is only approximately 7.5 tonnes per year—a by-product of platinum mining concentrated overwhelmingly in South Africa [85]. At current catalyst loadings (1–3 mg_{Ir}/cm^2), scaling PEM electrolysis to meet even moderate deployment scenarios would consume a substantial fraction of annual iridium supply [85]. Two mitigation pathways are advancing: catalyst loading reduction (Toshiba–Bekaert demonstrated 90% iridium reduction in 2024; startup Bspkl achieved 25× lower iridium and platinum loadings [20]) and high-efficiency recycling targeting 95%–97% recovery rates from end-of-life stacks [85]. Alkaline electrolyzers avoid PGM dependence entirely, using nickel-based electrodes, and currently represent the majority of installed capacity, providing a hedge against PEM-specific supply chain risks.

Finally, workforce development constitutes a binding constraint that receives insufficient policy attention. The hydrogen economy requires technicians trained in cryogenic handling, high-pressure systems, electrochemical engineering, and fuel cell maintenance —skill sets that overlap with but are distinct from conventional oil and gas or power sector competencies. Without parallel investment in vocational training and university curricula, labour shortages risk becoming as constraining as capital shortages in determining the pace of hydrogen deployment.

5.5. Water requirements

Electrolysis requires approximately 9 l of ultrapure water per kilogramme of hydrogen produced based on reaction stoichiometry alone; when water purification, process cooling, and system losses are included, practical consumption rises to 10–22 L/kg H_2 for commercial systems [86–88]. This is comparable to or lower than the 20–40 L/kg consumed by conventional steam methane reforming when upstream water use in natural gas extraction is included [87]. At a global scale, producing the Hydrogen Council's high-demand 2050 scenario (660 Mt H_2/yr) entirely by electrolysis would require approximately 13 billion m^3 of water annually — roughly 0.3% of current global freshwater withdrawals — suggesting that water is a design constraint rather than a fundamental barrier to the hydrogen economy [86].

However, this global average obscures critical regional tensions. Many of the regions best suited for low-cost green hydrogen production —the Middle East and North Africa, the Australian interior, and parts of Chile and Namibia—are among the most water-stressed on Earth. Locating gigawatt-scale electrolyzer facilities in these regions without dedicated water supply strategies risks competing with agricultural and municipal demand [89]. Seawater desalination via reverse osmosis (RO) provides a proven solution at negligible additional cost: modern RO plants consume approximately 3–5 kWh per cubic metre of permeate, adding less than 0.2% to the energy requirement of electrolysis and no more than \$0.01–0.02/kg to the levelized cost of hydrogen [86,88,90]. A comprehensive review of seawater treatment for electrolysis by Mika et al. confirms that established desalination technologies — reverse osmosis, multi-effect distillation, and multi-stage flash — can deliver feedwater of the required ASTM Type I or Type II purity, with reverse osmosis the most economically attractive option for new green-hydrogen plants [88]. A critical review of seawater electrolysis and desalination reaches the same conclusion, finding that integrating established desalination with electrolysis is the most practical near-term route to green hydrogen in coastal water-scarce regions, while direct seawater splitting remains constrained by chloride-induced corrosion and competing chlorine evolution [91]. Australia's 2024 National Hydrogen Strategy update and Namibia's Hyphen project licensing both now require developers to source water from desalination or recycled streams, establishing an emerging regulatory norm. Nevertheless, the additional infrastructure, brine disposal challenges, and permitting requirements associated with coastal desalination should not be underestimated, particularly in regions lacking existing RO capacity [89]. Water stewardship is increasingly recognized as a prerequisite for social licence and should be integrated into project design from the outset rather than treated as an afterthought.

5.6. Hydrogen leakage as an indirect Greenhouse gas

An emerging concern that has received increasing attention since 2022 is the indirect climate impact of molecular hydrogen leaked into the atmosphere. While H_2 is not itself a greenhouse gas in the conventional radiative sense, atmospheric hydrogen reacts with hydroxyl radicals (OH), reducing the availability of OH for oxidizing methane (CH_4). This extends methane's atmospheric lifetime and thereby amplifies its warming effect. Hydrogen also contributes to increased tropospheric ozone and stratospheric water vapour formation, both of which exert additional positive radiative forcing [92–94].

A multi-model ensemble study by Sand et al. (2023) estimated the 100-year global warming potential (GWP_{100}) of hydrogen at 11.6 ± 2.8 relative to CO_2 on a per-mass basis [92]. Subsequent work using more comprehensive photochemical models has produced somewhat lower central estimates ($GWP_{100} \approx 8$–9), though the range remains under active investigation [94,95]. Yang et al. have shown that current global chemistry models overestimate global OH concentrations and underestimate OH reactivity; correcting these biases lowers the modelled GWP_{100} of hydrogen by approximately 20%, indicating that the canonical value remains sensitive to chemistry-model assumptions [96]. A sensitivity study using a chemistry transport model further indicates that the hydrogen GWP_{100} is largely insensitive to the magnitude and location of plausible future leakage and to changes in atmospheric composition expected by 2050, provided emissions occur in regions with active soil sinks [97]. A recent comprehensive assessment in *Nature* reports a consensus range of $GWP_{100} = 11 \pm 4$ for hydrogen [98]. The 20-year value is materially larger — approximately three times the 100-year value — reflecting hydrogen's short atmospheric lifetime and the longer time horizon on which methane and ozone responses unfold [99].

The practical significance depends on the leakage rate across the hydrogen value chain. Measurements remain sparse, but modelling studies suggest that at a 1% leakage rate, the indirect warming effect offsets approximately 0.4% of the CO_2-equivalent emission reductions achieved by replacing fossil fuels with hydrogen—a manageable penalty. At a 10% leakage rate, the offset rises to approximately 4%, which would materially erode the climate benefits of the transition [93,99]. These figures underscore the importance of leak detection, pipeline integrity management (cf. Section 5.1), and system design standards that minimize fugitive emissions throughout production, transport, storage, and end-use. As the hydrogen infrastructure scales from pilot to industrial volumes, establishing a robust emissions monitoring framework analogous to those now being deployed for methane in the oil and gas sector will be essential to ensure that the climate case for hydrogen remains sound.

6. Conclusions and future outlook

This review has assessed the global hydrogen economy as it stands in early 2026—a system defined by the tension between extraordinary ambition and stubborn deployment realities. The central finding is that hydrogen is best understood not as a universal clean energy solution, but as a *viable decarbonization enabler for a defined set of critical sectors*: transformative where no viable alternative exists, marginal where electrification already dominates, and everywhere constrained by the same binding variable—the cost and availability of low-emission hydrogen at scale.

The production landscape reveals the depth of this constraint. Global hydrogen demand reached approximately 100 Mt in 2024, yet low-emission hydrogen accounts for less than 1% of supply. Of more than 1700 announced projects, only 510 have reached final investment decision, representing roughly 6 Mtpa of capacity of which just 1 Mtpa is operational. Green hydrogen costs ($4.1–12.8/kg) remain well above those of grey hydrogen ($0.9–4.5/kg), and the gap is widening as falling natural gas prices coincide with rising electrolyzer costs. The announced project pipeline has contracted from 49 to 37 Mtpa in the past year, signalling that the market is entering a rationalization phase in which only projects with secured offtake, policy support, and favourable geography will proceed.

The sectoral assessment produces a clear maturity gradient. Established industrial consumers—refining (37 Mtpa) and ammonia/chemicals (33 Mtpa ammonia, 15 Mtpa methanol)—operate at TRL 9 but face an economic substitution challenge requiring either carbon pricing or sustained production subsidies to close the cost gap. H_2-DRI emerges as the most compelling near-term growth sector, with Stegra's 700 MW Boden facility demonstrating industrial-scale feasibility despite a ~$225/t green premium at current hydrogen prices (~50% over the global BF-BOF average). In transport, hydrogen has effectively ceded passenger vehicles to battery electric drivetrains (fewer than 15,000 FCEV versus more than 10 million BEV sales in 2024), but retains defensible niches in heavy-duty trucking, maritime shipping (green ammonia and methanol), and aviation (synthetic SAF)—sectors where energy density or operational constraints limit battery penetration. Power generation applications are technically advancing but remain pre-commercial, with hydrogen's economic advantage over batteries emerging only beyond approximately 13 h of storage duration.

The aerospace and hypersonic propulsion domain represents a qualitatively different category: hydrogen is not competing with alternatives —it is, on present evidence, the leading and likely the only practical option. Its gravimetric energy density (2.8× Jet-A), specific heat capacity (7.2× Jet-A), and wide flammability limits make it favourable for scramjet propulsion above Mach 8 and well-suited to zero-emission subsonic flight. The technology roadmap reveals a bimodal structure: hydrogen-electric aviation (TRL 5–6) approaching certification by the late 2020s, and hydrogen scramjet demonstrators (TRL 4–6) preparing for first flight, separated by a Mach 1–5 gap where hydrogen offers insufficient advantage. The imminent DART AE flight at NASA Wallops and ZeroAvia's FAA/CAA certification programme represent inflection points for the decade ahead.

Cross-cutting challenges — pipeline embrittlement, salt cavern geographic constraints, iridium supply bottlenecks, regulatory gaps, and workforce shortages — are individually manageable but collectively formidable. Two emerging concerns warrant particular attention: water stewardship in arid regions hosting large-scale electrolysis, and hydrogen leakage across the value chain ($GWP_{100} \approx 11 \pm 4$), which could erode climate benefits if leakage rates exceed a few percent.

Five priority research directions emerge from this assessment:

1. Achieving green hydrogen production costs below $2/kg through next-generation electrolyzer designs, iridium thrifting below 0.5 mg/cm^2, and integration with low-cost renewable electricity.

2. Improving ammonia cracking efficiency and developing commercially viable cracking units at import terminal scale to unlock intercontinental hydrogen trade.
3. Establishing comprehensive hydrogen embrittlement datasets for the full range of pipeline steel grades and vintages to enable safe, large-scale infrastructure repurposing.
4. Advancing cryogenic LH_2 storage and zero-boil-off technology for aviation applications.
5. Extending scramjet combustor durability from seconds-scale demonstration burns to the minutes-to-hours regime required for operational hypersonic platforms.

The hydrogen economy now stands at the transition from announcement to deployment. The evidence reviewed here suggests that hydrogen's highest-impact roles lie not in displacing electrification where batteries already win, but in decarbonizing the sectors that cannot electrify — steel, shipping, aviation, ammonia, long-duration storage — and in enabling capabilities that no other fuel can provide, from zero-emission regional flight to sustained hypersonic propulsion. The question is no longer whether hydrogen has a role in the energy transition, but whether the policy frameworks, infrastructure investments, and supply chains can materialize fast enough to fulfil it.

CRediT authorship contribution statement

Moaz Bilto: Writing – review & editing, Writing – original draft, Visualization, Methodology, Formal analysis, Data curation, Conceptualization. **Tanay Sıdkı Uyar:** Supervision, Conceptualization.

Declaration of generative AI in scientific writing

During the preparation of this work, the authors used Claude (Anthropic) for language editing and formatting assistance. The authors reviewed and edited all AI-generated output and take full responsibility for the content of this publication.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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