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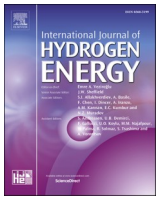

Optimising hydrogen carrier pathways for industrial decarbonisation: A techno-policy framework for readiness in infrastructure and governance

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ABSTRACT

Industrial decarbonisation is a major route to net-zero emissions, and hydrogen is emerging as a key energy carrier for hard-to-abate sectors. This work applies a techno-policy readiness framework which encompasses infrastructure compatibility, regulatory institutional alignment, technological readiness, and market readiness, to improve hydrogen carrier pathways for industrial purposes. The framework uses comparative assessments of production routes, transport and storage pathways, and policy instruments to assess the techno-economic performance and governance readiness to support each hydrogen carrier pathway. The findings indicate that ammonia and liquid organic hydrogen carriers (LOHCs) have the highest readiness for long distance transportation, while compressed hydrogen and liquid hydrogen can still be used for shorter distances or niche markets. The analysis also indicated that successful hydrogen rollout will depend as much upon governance and infrastructure alignment, and not only on technical readiness. Overall, this research provides realistic pathways for policymakers and industry actors to expedite their hydrogen uptake into industrial systems, and ultimately enable a quicker transition to global decarbonisation goals.

1. Introduction

Industrial decarbonisation is a critical element in the realisation of global climate goals, as outlined in the Paris Agreement and reinforced by national commitments and policy frameworks [1]. Steel, cement, chemicals, and refining industries, in particular, account for approximately 25–30 % of global greenhouse gas (GHG) emissions. Decarbonising these sectors represents one of the most technically challenging and economically demanding aspects of the global energy transition [2]. These industries feature intense heat-based manufacturing processes, locked-in production lines, and long capital stock turnover, which together create fundamental constraints on the feasibility of traditional forms of renewable energy. Within this context, hydrogen and its by-products emerged as viable energy carriers with the potential to serve as feedstock and fuel. Its use enables on-site decarbonisation in industrial sectors that are otherwise hard to decarbonise [3,4]. Hydrogen, especially the type generated from renewable energies known as "green hydrogen," provides several advantages, including carbon-free combustion and the potential to serve as a versatile intermediary in various chemical and energy systems [5]. However, the successful integration of hydrogen into industrial applications necessitates careful consideration of various carrier options, such as compressed hydrogen, liquid hydrogen, ammonia, methanol, and synthetic hydrocarbons, each with distinct advantages, technical challenges, and infrastructure needs. Although there has been substantial research on the thermodynamic and economic aspects of different carrier options, much less focus has been placed on how prepared these systems are, in terms of infrastructure compatibility, regulatory alignment, institutional coordination [6].

As hydrogen applications evolve from specialised to large-scale deployment, the integration of technological innovation with policy frameworks becomes increasingly critical—particularly where technological potential must align with governance structures and infrastructure capabilities. Historical energy transitions have often been less constrained by technological limitations than by institutional

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misalignments, fragmented policy incentives, and insufficient planning for infrastructure development [7]. Therefore, evaluating hydrogen carrier pathways should extend beyond conventional metrics such as energy efficiency, cost, or carbon intensity. It requires a holistic readiness framework that properly accounts for the multifaceted interactions between technological maturity, infrastructure readiness, rule-making support, and socio-political acceptance. Furthermore, recent advances in machine learning, particularly physics-informed and data-driven optimisation algorithms, have shown promise in supporting the techno-policy alignment of hydrogen deployment strategies. These approaches help evaluate carrier trade-offs dynamically under changing energy scenarios and policy constraints [8]. This study aims to address a significant gap by applying a techno-policy framework to the assessment and design of hydrogen carrier pathways for industrial applications, ultimately supporting decarbonisation in hard-to-abate sectors. Rather than focusing solely on the techno-economic feasibility of promising hydrogen carriers, the analysis is situated within a holistic readiness framework. This framework incorporates a comprehensive review of the policy instruments, infrastructure readiness, regulatory barriers, and institutional cooperation mechanisms [9]. Through the integration of techno-economic and governance analysis, this study provides actionable insights to policymakers, industry stakeholders, and investors for informed strategic decisions in hydrogen infrastructure deployment.

A central argument of this study is that effective industrial decarbonisation through hydrogen hinge on the coordinated interplay between policy interventions and technological advancement. This is particularly evident in the context of hydrogen carrier pathways, which complex and multi-layered value chains, including production, storage, transportation, conversion, and integration into end-use applications. Each step in this value chain faces different policy frameworks and technical standards, as well as investment risks. For instance, ammonia offers high volumetric energy density and benefits from established global trading infrastructure. However, its deployment raises significant concerns related to safety, toxicity, and energy-intensive reconversion processes, necessitating dedicated regulatory oversight. Similarly, methanol offers opportunities for carbon recycling; yet its viability as a decarbonisation vector relies heavily on harmonized carbon accounting frameworks to ensure lifecycle integrity. In addition to technical performance, the choice of hydrogen carrier profoundly influences local energy policies, international trade dynamics, and industrial competitiveness. The infrastructure associated with each carrier pathway, such as ammonia terminals, methanol synthesis plants, or hydrogen pipeline network, is largely site-specific and non-transferable, resulting in long-term lock-in effects and path dependencies [10]. Consequently, infrastructure investment decisions need to be guided not only by the prevailing economic considerations, but also by adaptive policy frameworks that account for evolving market conditions, technological breakthroughs, and shifting geopolitical landscapes.

The inherent uncertainty and complexity of hydrogen transitions underscore the growing recognition of the need for adaptive policy-making. While static policy instruments are often used in the early stages of market formation, they frequently prove inadequate in addressing the rapid evolution in technologies and business models within the hydrogen sector. In response, this study proposes a readiness-based approach that embeds flexibility, modularity, and cross-cutting learning into the planning and implementation of hydrogen carriers strategies [11]. This framework draws on lessons from prior energy infrastructure transitions, particularly in natural gas, electricity, and biofuels, while accounting for the distinct techno-economic and regulatory characteristics of hydrogen systems. This study introduces a holistic readiness evaluation framework structured around four interdependent dimensions: “infrastructure compatibility and investment”, “regulatory and institutional coherence”, “technological maturity and scalability”, and “market and social acceptance”. These dimensions are assessed using a set of qualitative and quantitative indicators derived from stakeholder consultations, policy documents, and empirical research. The multi-criteria approach facilitates comparative assessment of hydrogen carrier pathways, enabling evidence-based strategic decision-making. This framework is applied across diverse regional contexts, revealing that optimal hydrogen carrier strategies vary significantly based on local resource availability, industry infrastructure, regulatory environments, and geopolitical factors. For example, resource-rich but demand-constrained regions may favour export-oriented carriers such as ammonia, whereas regions with established petrochemical infrastructures are more likely to prioritise synthetic fuels or methanol. Framing hydrogen pathway optimisation through both sectoral and regional lenses enhances the granularity and policy relevance of the analysis. This study ultimately promotes a holistic techno-policy perspective that aligns innovation with implementation, aiming to make hydrogen’s role as a decarbonisation facilitator both practically achievable and policy-relevant.

This study is organised as follows: Section 2 reviews hydrogen production, contrasting renewable and non-renewable feedstocks. Section 3 evaluates transportation options focusing on pricing, storage conditions, and technical specifications. Section 4 analyses how the legislative and policy frameworks instruments, such as carbon pricing, subsidies, and international agreements, facilitate the hydrogen transition. Section 5 integrates cross-disciplinary insights on infrastructure, governance, and social acceptance to address key challenges and opportunities. Finally, Section 6 presents forward-looking policy and research recommendations for accelerating hydrogen deployment in industrial decarbonisation.

2. Hydrogen production methods

Hydrogen can be produced using a range of techniques, each associated with its own set of distinct advantages and limitations regarding energy efficiency, cost, and carbon emissions. Broadly, these production methods are classified into renewable-based and fossil-based (non-renewable) pathways [12].

2.1. Renewable energy-based hydrogen

2.1.1. Electrolysis

Electrolysis is a process that splits water into hydrogen and oxygen utilising electricity. When powered by renewable sources such as solar or wind energy, this process enables the production of green hydrogen with minimal carbon emissions [13]. There are three main types of electrolysers: alkaline (AEL) electrolysers, proton exchange membrane (PEM) electrolysers, and solid oxide (SOEC) electrolysers, each operates under different temperature and pressure conditions, utilises distinct materials, and offers varying levels of efficiency, capital cost, stack durability, and system scalability. AELs are the most mature and commercially deployed, offering low capital costs but lower current density. PEM electrolysers provide faster dynamic response and compact design yet require high-purity water and expensive catalysts. SOECs achieve the highest efficiency under high-temperature operation, making them suitable for integration with industrial waste heat, though they pose challenges in material stability and thermal management. [14]. As summarised in Table 1, these technologies involve trade-offs across multiple dimensions, including electrolyte type, efficiency, operating temperature, material requirements, and commercial maturity [15,16].

2.1.2. Biomass gasification

Biomass gasification is a thermochemical conversion technique that transforms biomass feedstocks, such as wood residues or agricultural waste, into a hydrogen-rich synthesis gas (syngas), which can subsequently be reformed to produce hydrogen. [18]. This process typically involves the controlled application of heat, steam, and oxygen in the absence of complete combustion. If the biomass is sourced sustainably, gasification can approach carbon neutrality; however, the process is energy-intensive and may generate additional pollutants. It is an

Table 1
A Comparative characteristics of major electrolyser technologies for green hydrogen production.

Electrolyser Type	Efficiency (% LHV)	Operating Temp	Electrolyte	Typical Materials	Benefits	Drawbacks	Commercial Maturity	Ref
Alkaline (AEL)	60–70 %	60–90 °C	Aqueous KOH (25–30 %)	Nickel-based electrodes	- Low capital cost - Proven, mature technology - Tolerant to water impurities	- Low current density - Bulky system - Slow dynamic response - Gas crossover risk	Commercial	[15]
Proton Exchange Membrane (PEM)	50–70 %	50–80 °C	Solid polymer electrolyte	Platinum-group metals (Pt, Ir)	- Compact design - High current density - Fast response to load changes - Safer at high pressures	- High material cost (Pt, Ir) - Requires high-purity water - Shorter stack lifetime than AEL	Commercial	[16]
Solid Oxide (SOEC)	70–90 %	700–900 °C	Ceramic oxide	Perovskite or cermet-based electrodes	- Highest efficiency - Uses waste heat - Co-electrolysis of CO_2 and H_2O	- High operating temperature - Complex thermal management - Material degradation and sealing issues	Demonstration/ Pilot	[17]

established technology that employs a controlled process using heat, steam, and oxygen to convert biomass into hydrogen and by-products, without full combustion. Because biomass absorbs carbon dioxide (CO_2) during growth, its use in gasification can result in minimal net emissions, particularly when coupled with long-term carbon capture, utilisation, and storage (CCUS) strategies. Commercial and pilot-scale biofuel gasification facilities are already in operation, offering valuable experience and best practices for hydrogen production [11,18,19].

2.2. Non-renewable energy-based hydrogen

In addition to renewable-based pathways, global hydrogen landscape remains heavily reliant on non-renewable sources, particularly steam methane reforming (SMR), coal gasification, and the increasingly explored nuclear hydrogen production. These methods offer advantages in terms of energy efficiency, cost-effectiveness, and scalability, making them dominant contributors to global hydrogen supply. However, their environmental impact remains a concern, without the integration of carbon capture and storage (CCS) technologies, these processes are associated with substantial carbon emissions. Consequently, their long-term viability in a decarbonised energy system hinges on the effectiveness of emission mitigation strategies. A clear understanding of the technical principles, operational challenges, and decarbonisation potential of these conventional approaches, particularly as they relate to national energy infrastructures and transition strategies, is essential to assessing hydrogen's realistic position during the energy transition. The subsections that follow provide a detailed assessment of the three major non-renewable hydrogen production pathways, examining their characteristics, limitations, and potential for cleaner integration.

i. Steam Methane Reforming (SMR) is currently the most widely used method for hydrogen production, accounting for the majority of global hydrogen output [19]. In this process, natural gas, primarily methane, reacts with steam at a high temperature (typically 700–1,000 °C) in the presence of a catalyst to produce hydrogen and CO_2. SMR is considered cost-effective compared to other small modular reactors (SMRs). However, without the integration of carbon capture and storage (CCS) technologies, it results in significant CO_2 emissions, thereby limiting its suitability in decarbonisation strategies [21].
ii. Coal gasification is a thermochemical process that converts coal into syngas, primarily a mixture of hydrogen, carbon monoxide (CO), and CO_2. While similar in principle to biomass gasification, coal gasification operates in a closed chamber at a high temperature (typically 800–1,200 °C) using steam and oxygen as reactants. The resulting syngas can be used for chemical synthesis, the generation of electricity, or further processed to extract hydrogen [7]. Coal gasification is often considered a viable pathway in regions with abundant coal reserves and limited access to cleaner energy resources [20]. It can improve energy security and reduce reliance on gasoline imports; however, its long-term sustainability remains uncertain without robust emissions control policies. As Mohideen et al. [12] argue, the future viability of coal-based hydrogen depends largely on the efficiency and accessibility of CCS technologies, and their integration into broader low-carbon energy systems. Considering the above factors, it is crucial to recognise that coal gasification remains a carbon-intensive pathway for hydrogen production. Both SMR and coal gasification release a substantial amount of CO_2 as a by-product [21]; in particular, coal gasification results in even higher CO_2 emissions than traditional combustion or SMR when CCS is not implemented [22]. The integration of CCS technologies is essential to reducing environmental impacts and aligning with decarbonisation targets. However, widespread CCS deployment requires significant capital investment and faces notable technical and regulatory challenges.
iii. Nuclear hydrogen production utilises thermal or electrical energy from nuclear reactors to generate hydrogen, offering a low-carbon option compared to fossil fuel-based methods [23]. One of the most promising pathways is high-temperature electrolysis (HTE), which achieves greater efficiency than conventional electrolysis by leveraging both thermal and electrical inputs [24]. When coupled with advanced high-temperature nuclear reactors, such as advanced gas-cooled reactors (AGRs) [25] and molten salt reactors (MSRs) [26], HTE can theoretically reach efficiencies exceeding 80 % [27], substantially reducing the total energy input to generate hydrogen [27]. Nuclear hydrogen offers constant, mass-scale production and can enable grid decarbonisation, but cost considerations, public acceptance, and regulatory approval of next-generation reactor systems continue to face challenges [28]. Beyond traditional performance metrics, the integration of digital optimisation tools is gaining importance in enhancing the adaptability and efficiency of existing hydrogen production systems. Across the spectrum of non-renewable hydrogen production technologies, including SMR, coal gasification, and nuclear systems, there is growing interest in integrating artificial intelligence (AI) tools to support plant optimisation and decision-making. For instance, AI-driven predictive maintenance algorithms and residual carbon emission estimators are increasingly utilised to enhance the operational

reliability and performance assessment of retrofitted hydrogen plants, particularly under scenarios involving fluctuating carbon prices or partial CCS integration [8].

3. Hydrogen carrier pathways and supply chain options

Once Hydrogen is produced, it must be efficiently transported and stored before reaching end users, introducing additional complexity of the hydrogen value chain [29]. There are other ways to move hydrogen, such as compressed hydrogen gas, liquefied Hydrogen, and carriers like ammonia or liquid organic hydrogen carriers (LOHCs) [29]. Each option has individual technical and economic factors to consider with regards to energy density, required infrastructure, and losses during conversion. For example, liquefaction increases density, yet requires a high input of energy; ammonia, meanwhile, provides easier storage at the price of later reconversion. As Cvetkovska et al. [30] note, optimal choice depends on factors including distance, scale, and desired application.

3.1. Gaseous hydrogen

Gaseous hydrogen transportation is possible through pipelines or overland transportation using compressed gas vehicles, each presenting distinct advantages and limitations. Pipeline transportation is considered the most cost-effective way to transport large amounts of hydrogen over long distances, particularly in the case of centralised production combined with extensive distribution [31]. Nonetheless, the adaptation of current natural gas pipelines for hydrogen conveyance is not devoid of some challenges. Hydrogen can induce embrittlement in some steel alloy types, leading to safety concerns and questioning the long-term structural integrity of pipelines. Based on this, material strengthening, interior coatings, or even replacement of pipelines is possible for secure operation at high pressures [32]. These modifications may significantly increase retrofit costs, impacting overall economic feasibility. Moreover, operational fluctuations in hydrogen flow can also impose additional mechanical stress on pipeline systems. In real-world deployment scenarios, particularly in offshore wind-to-hydrogen projects, accurately forecasting hydrogen production based on wind variability allows for better control of pipeline pressure, thereby reducing flow surges and mitigating structural risks.

For applications in smaller distances or in the early stages of pipeline installation before infrastructure is built, compressed hydrogen gas transportation is efficiently done using gas cylinder trucks or high-pressure tube trailers. It offers some flexibility and requires a lower initial capital outlay; nevertheless, it is limited by the relatively low energy density of compressed hydrogen, which is often stored at pressures up to 700 bar. The low energy density results in increased transportation costs and limits the amount of energy that is transferred in a single journey [33]. With the growth of the hydrogen economy, gaseous hydrogen transportation will increasingly depend on a combination of infrastructure investments, scale, and demand. In this context, integrating hydrogen transportation planning with predictive analytics and AI-based optimisation could significantly improve operational efficiency, especially in decentralised or early-stage hydrogen distribution systems. For instance, machine learning models for route scheduling, demand forecasting, and dynamic load balancing may help minimise system-level costs and enhance reliability, a strategy particularly valuable in distributed hydrogen networks or localised renewable-hydrogen integration scenarios.

In addition to the physical infrastructure, evidence shows that AI-enabled predictive maintenance and route optimisation models may also increase the reliability of hydrogen pipeline systems. Machine learning methods including anomaly detection and Bayesian predictive analytics have been applied to natural gas pipelines and are being transferred to hydrogen systems to assess brittle structures and predict the best route and flow given changing demand [34]. For example, AI-assisted pipeline monitoring in European pilot projects produced a reduction of unplanned outcome greater than 15 %, providing clear evidence that these types of tools will increase hydrogen distribution efficiency at scale.

3.2. Liquid hydrogen

Liquid hydrogen (LH_2) transport is considered an effective solution for long-distance transportation, largely owed to its vastly superior energy density when compared to that of compressed gases. Maintaining hydrogen in the liquid state requires the upkeep of cryogenic temperatures, around −253 °C, necessitating the use of advanced insulated tanks to minimise heat ingress and boil-off losses. Hydrogen is transported in bulk by cryogenic tankers at an affordable price, especially in areas where pipelines do not exist or the construction of pipelines would be economically infeasible [35].

The liquefaction process is fraught with many challenges. Perhaps most notably, it is extremely energy-intensive, requiring about 30–40 % of the energy contained in the liquefied hydrogen itself. Such a large energy requirement has a drastic effect on the total cost of the hydrogen supply chain while, at the same time, decreasing efficiency. Boil-off losses are also a big challenge when it comes to the transportation and storage of hydrogen. Even with the use of high-quality insulation, temperature input from the environment causes hydrogen to constantly evaporate from the system, resulting in continuous loss of energy and product. Safety is a crucial factor, as liquid hydrogen necessitates meticulous management due to its extremely low temperature and flammability. Cvetkovska et al. [30] indicate that while liquid hydrogen presents advantages for global and long-distance transport, its economic viability will hinge on progress in liquefaction technology and storage systems aimed at reducing losses and costs.

Dynamic scheduling techniques in large scale LH_2 shipping, using AI modelling of renewable output forecasts can significantly reduce idle and boil-off times in this application. A key demonstration of this was in the Japan–Australia hydrogen supply chain pilot project with AI based scheduling of port times and vessel routing, where not only did shipping idle times decrease, but liquefaction plant utilisation also increased [36]. These examples illustrate how AI is providing a link between intermittent renewable generation and concrete shipping progressions and times, and helping to lower costs logistics.

Liquid hydrogen (LH_2) shipping provides hydrogen in its pure form directly at the import site. Currently, LH_2 shipping costs are elevated (for instance, the route from Saudi Arabia to Japan was approximately USD 15/kg in 2020), but with sufficient scale, they have the potential to decrease to USD 1.7/kg by 2030. Indeed, the technology resembles that which justifies investment in hydrogen production and transmission [37]. Achieving such cost reductions would require significant scale-up, including the expansion of shipping vessel capacity from 160 to 10,000 tonnes, and liquefaction plant output from 10 to 50 tonnes/day to 500 tonnes/day [38]. Fig. 1 presents illustrations of possible shipping routes along with comprehensive end-to-end costs for LH_2 shipping. It is important to recognise that these values are highly sensitive to scaling up, and there is still uncertainty regarding the potential for cost reductions. To optimise these large-scale maritime LH_2 operations, dynamic scheduling algorithms based on renewable output forecasts, such as wind power prediction models, could enhance port-side liquefaction efficiency and minimise idle boil-off [39].

3.3. Hydrogen carriers

Hydrogen carriers have a critical function in enabling effective, secure, and cost-effective transportation and storage of hydrogen over long distances. Two of the most viable carrier options are ammonia and LOHCs, both with a specific set of advantages and disadvantages (Table 2). Ammonia is produced via the Haber-Bosch process, where hydrogen reacts with nitrogen at high pressure and temperature in the presence of an iron-based catalyst. It has a higher volumetric energy

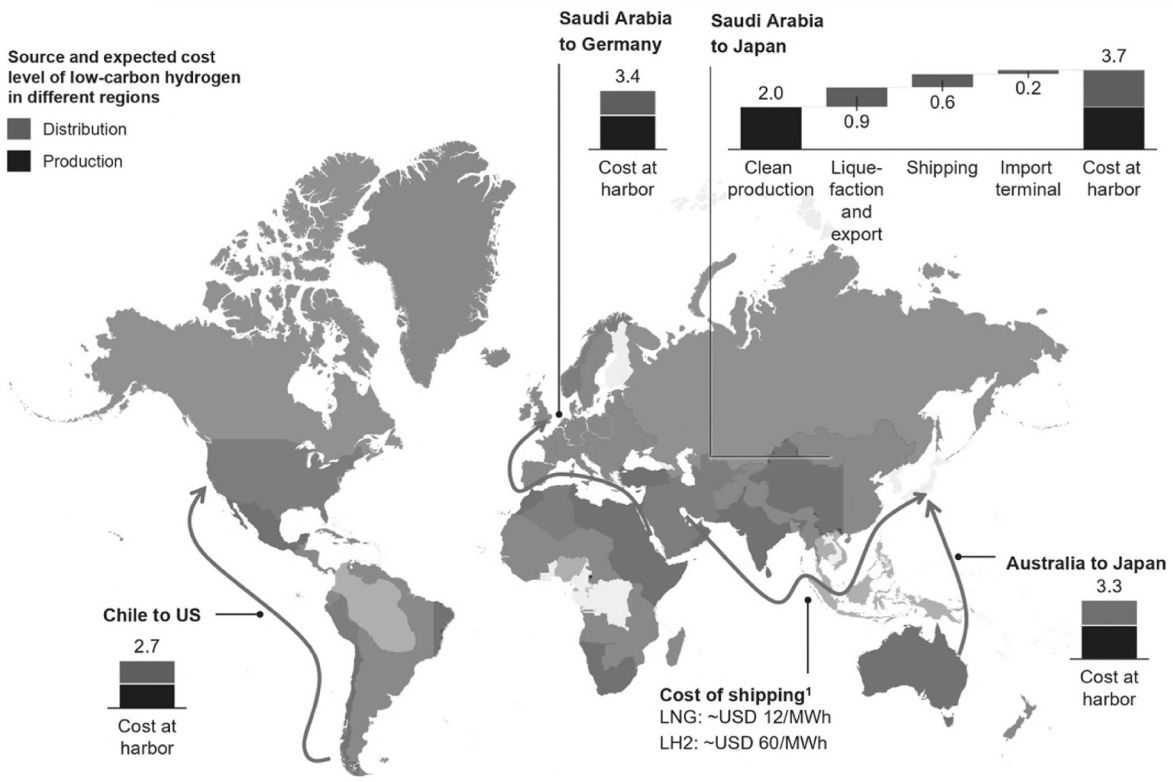

Fig. 1. The projected cost of transporting liquid hydrogen across various regions in 2030 will be quantified in USD per kilogramme [40].

Table 2
Assessment of alternatives for transport and storage of hydrogen. Note: The "Energy Density" column is relative, indicating categories (low, medium, high) based on volumetric energy density (MJ/L) values reported in the literature. All values are based on the lower heating value (LHV) of hydrogen. Approximate reference ranges include compressed hydrogen at 700 bar (4–5 MJ/L), liquid hydrogen (8–10 MJ/L), ammonia (12–13 MJ/L), and representative liquid organic hydrogen carriers (LOHCs), e.g., methylcyclohexane (6–7 MJ/L).

Method	Transport Distance	Energy Density	Advantages	Disadvantages	References
LOHCs	Long	Medium	Safe, convenient	Energy-intensive hydrogenation/ dehydrogenation	[43,47]
Ammonia	Long	High	High energy density, established infrastructure	Energy-intensive conversion/reconversion	[48–50]
Liquid Tankers	Long	Medium	Higher energy density than compressed gas	Energy-intensive liquefaction, boil-off	[51]
Compressed Trucks	Short	Low	Flexible, readily available	High transport costs	[52]
Gaseous Pipeline	Long	Low	Economical for large volumes	Infrastructure costs, material compatibility	[31,53]

density than liquefied hydrogen and can be kept in a liquid state at relatively moderate conditions (−33 °C, atmospheric pressure), hence easily transported using current infrastructure in a more economically feasible manner. Ammonia is currently traded globally as a fertiliser, which also augments its feasibility as a hydrogen carrier. However, the extraction of hydrogen requires the decomposition of ammonia into hydrogen and nitrogen, a process that is energy demanding and is still in the midst of developments towards better efficiency for large-scale industrial use [41].

Utilising Ammonia as a hydrogen carrier allows for the effective use of existing infrastructure for worldwide distribution. Furthermore, the process of converting hydrogen to Ammonia is a recognized technology. When Ammonia is the intended end use, transporting Ammonia is the preferred choice; however, it necessitates cautious handling by certified operators because of its toxic nature. Nonetheless, if the final application necessitates pure hydrogen, an extra reconversion step is needed, which is presently in the initial phases of development. Furthermore, reconversion would necessitate access to affordable clean energy at the arrival port if the goal is to produce a low-carbon or renewable hydrogen product. This reconversion step often reintroduces cost and complexity, especially in regions lacking affordable clean energy at the point of use. Depending on the evolution of technology and local conditions, this reconversion step may contribute an additional USD 1 to 2/kg, in addition to conversion and shipping costs [42].

LOHCs are organic compounds that have the ability to take up and release Hydrogen through chemical reactions. LOHCs provide a secure and dependable means of transporting Hydrogen, thus eliminating the need for high-pressure or cryogenic conditions. Both the processes of adding Hydrogen (loading) and removing Hydrogen (unloading) need a lot of energy and depend on catalysts, which affects how well the whole system works [43]. LOHCs shipping, which uses various chemical compounds, like toluene or methylcyclohexane, capitalises on established shipping architectures and facilitates the transfer and storage of hydrogen in liquid form. Similar to Ammonia, the dehydrogenation process presents a problem that necessitates large-scale development and substantial energy input at the import location. Unlike ammonia LOHCs require the carrier liquid to be shipped back after dehydrogenation, thereby increasing logistics complexity. Moreover, the existence of numerous LOHCs technologies hinders economies of scale until they achieve worldwide standardization [44]. Due to the nascent stage of the technology, cost projections for LOHCs and cycle rates remain very unpredictable and necessitate further research and development. To

address some of the inherent logistical and efficiency challenges, integrating LOHC logistics with AI-based route planning and reconversion optimisation systems offers promising potential. In particular, predictive modelling approaches, such as those developed in industrial energy scheduling research, can align carrier liquid availability with downstream hydrogen demand in real time, thereby reducing inefficiencies in return cycles and improving economic viability. Such digital tools, when deployed at scale, may accelerate LOHC system readiness despite current cost uncertainties [45].

It should be recognized that the designation of LOHCs as "medium" energy density in Table 2 is primarily based on benchmark systems such as toluene/methylcyclohexane, which contain ~6-7 wt% hydrogen, resulting in gravimetric energy densities less than ammonia (~17.6 wt% hydrogen) but greater than compressed hydrogen. Other LOHC candidates such as dibenzyltoluene or perhydro-N-ethylcarbazole, are also in this range (5–8 wt%), which may have a small effect on energy density classification. Nevertheless, LOHCs can collaboratively be considered "medium" in energy density when compared to competing carriers, a categorization derived more from current techno-economic consensus than a lone compound.

AI-based optimisation has also been examined for controlling the complexity of LOHC logistics. Predictive modelling approaches such as reinforcement learning and hybrid optimisation frameworks are capable of synchronising hydrogenation and dehydrogenation cycles to accommodate fluctuations in industrial demand [36]. In simulation studies, these predictive modelling designs improved the turn-around of carrier liquids by about 20 %. Similarly, European research programmes such as H_2Haul are underway to pilot AI-enabled route planning for hydrogen trucking, demonstrating the real-world feasibility of digital optimisation in chemical carrier networks [8].

This study did not conduct a definitive cost analysis. The least costly shipping technology will depend on end applications, necessary onshore transportation, scalability, and technical advancements. If Hydrogen is the intended use, LH_2 appears to be the most advanced option within the value chain and the most economical solution by 2030, but substantial scaling will be necessary for achieving cost reductions [46].

While shipping infrastructure is an important element to consider, another important consideration is the existence of pre-existing ammonia pipeline networks, which already are used for large-scale distribution of ammoniacal fertiliser across areas such as the United States and parts of Europe. These pipeline systems could potentially be designed or adapted to distribute bulk hydrogen in the form of ammonia with significant cost savings in comparison with designing and building completely separate hydrogen pipelines. The toxicity and associated safety requirements with ammonia require stringent operational protocols [49]. However, established systems for transporting ammonia demonstrate that moving ammonia through pipelines is technically feasible. Future research is needed to determine whether such infrastructure is also adaptable to LOHCs, Liquid Organic Hydrogen Carriers [54]. It should be noted that there are additional complexities in logistic operations to consider with LOHCs, given that LOHCs usually require return of the carrier liquid based on the dehydrogenated temperature, which would add additional modal logistics complexities of using established ammonia distribution systems. Nevertheless, these considerations provide an example of how preexisting chemical infrastructure can be repurposed to speed hydrogen deployment while also identifying avenues to reduce capital costs within carrier-based hydrogen transport.

3.4. Techno-economic analysis

A comprehensive techno-economic analysis of hydrogen carrier pathways is essential for identifying the most cost-effective and efficient methods for enabling large-scale industrial decarbonisation [12,30]. This analysis should encompass the complete hydrogen value chain, starting from production and including transportation, storage, and delivery to final end-use applications. The key elements in this context include capital expenditures (CAPEX), operational expenditures (OPEX), energy efficiency, infrastructural needs, scalability, and compatibility with current systems. Hydrogen carrier selection, spanning from compressed gas, LH_2, and ammonia to LOHCs, plays a major role in both the economic viability and technological readiness of the supply chain [43]. Geographical location, the supply and demand dynamic, and the particular industrial use for consideration are crucial in this situation. Examining all the related factors enables techno-economic assessments, which in turn inform decisions and investment planning that guide both policy and industry action towards promoting hydrogen technologies for a low-carbon future. These assessments can be further strengthened by integrating real-time forecasting models, such as those applied in wind power output and energy storage scheduling within smart microgrids, to capture cost fluctuations and enhance operational decision-making.

3.4.1. Levelized Cost of Hydrogen (LCOH)

Levelized Cost of Hydrogen (LCOH) is a key metric for comparing the economic viability of different hydrogen production processes. It is the cost of producing 1 kg of hydrogen on average over the lifespan of a production plant and takes into account factors like CAPEX, OPEX, energy input, plant efficiency, and finance [55]. The general formula for LCOH is depicted in Equation (1). Where t, n, r, and $H_{2_}\text{Produced}_t$ refer to year, project lifetime, discount rate, and hydrogen produced in year t, respectively.

$$\text{LCOH} = \frac{\sum_{t=1}^{n}\left(\frac{\text{CAPEX}_t + \text{OPEX}_t + \text{EnergyCost}_t}{(1+r)^t}\right)}{\sum_{t=1}^{n}\left(\frac{H_{2_}\,\text{Produced}_t}{(1+r)^t}\right)} \quad (1)$$

LCOH varies extensively with production methods, cost of inputs, and local conditions [56]. Green hydrogen produced at present by electrolysis typically has a greater LCOH than SMR grey hydrogen. However, with the diminishing cost of renewables and more sophisticated electrolysers, the LCOH for green hydrogen is set to fall appreciably [56].

Key factors influencing LCOH include [57–59].

- Capital costs (CAPEX): the most prominent costs for early-stage green hydrogen projects and with electrolyser costs being the most prominent.
- Operating costs (OPEX): the ordinary expenses, such as maintenance, water, labour, and CCS for blue hydrogen.
- Energy/fuel input costs: the largest cost components for green hydrogen, driven by renewable electricity price levels.
- Plant efficiency: determines how much hydrogen can be produced for a unit of energy input.
- Capacity/utilisation factor: the number of full-load hours in a year tend to strongly impact unit costs.
- Discount rate and project life: the financial assumptions that affect cost recovery.

For purposes of clarity, this study assumed a project life of 20–25 years, discount rates of 6–8 %, and capacity factors consistent with regional renewable availability, and these assumptions align with the benchmarks presented in recent techno-economic assessments.

The value of LCOH is that it provides a normalised, comparable metric for comparing hydrogen production pathways, (grey, blue and green). Grey hydrogen (SMR without CCS) has the least LCOH today but has the greatest carbon emissions [60,61]. Although blue hydrogen reduces carbon emissions it introduces greater CAPEX and OPEX due to the inclusion of CCS. Green hydrogen presently has a greater LCOH, but it is expected to drop considerably as renewable electricity prices drop and the electrolyser technology matures and scales. Therefore, LCOH plays an essential role in allowing both investors and policy makers to

consider trade-offs between options.

3.4.2. Transportation and storage costs

Transport and storage are key elements of the hydrogen supply chain, with a major impact on the overall economic efficiency of hydrogen distribution. Pipeline transportation is generally the most cost-effective way for continuous, bulk transportation of hydrogen over short-to medium distances. Nonetheless, it necessitates a substantial initial investment in specialised hydrogen pipelines and compression facilities. Long-distance or international transport typically converts hydrogen into high-energy-density carriers, like LH_2, ammonia, or LOHCs. These approaches enhance volumetric efficiency but incur higher costs due to energy-intensive processes involved in liquefaction and chemical transformation [62]. The total transport and storage cost (C_{ts}) can be represented as Equation (2). Where C_{trans}, C_{stor}, and C_{conv} refer to transport cost (like pipeline, shipping), storage cost (like tanks, insulation), and energy and infrastructure costs for conversion (like liquefaction or chemical bonding), respectively.

$$C_{ts} = C_{trans} + C_{stor} + C_{conv} \quad (2)$$

Hydrogen pipelines constitute the most efficient means of transportation for extensive and long-distance distribution. Nevertheless, the expenses associated with dedicated hydrogen pipelines are considerably greater than those for natural gas, attributable to material limitations and operating difficulties [63]. Hydrogen exhibits significant diffusivity and can induce embrittlement in steel pipes, requiring the use of specialised alloys or interior coatings to avert leakage and structural deterioration [60]. The expense of pipeline infrastructure is contingent upon the feasibility of repurposing existing natural gas pipelines or the necessity of constructing new hydrogen-specific pipelines. Hydrogen pipeline costs, as indicated by infrastructure cost models from prior studies, fluctuate according to width, pressure, and regional labour expenses [64]. Repurposing existing natural gas pipelines can decrease expenses by 50–70 % relative to constructing new hydrogen pipelines. The viability of retrofitting is contingent upon the compatibility of pipeline materials, as hydrogen embrittlement poses a significant technological challenge. Table 3 [65] presents a comparative analysis of hydrogen pipeline costs derived from existing case studies. The cost-effectiveness of hydrogen pipelines increases with elevated utilisation rates, rendering them more feasible in areas with concentrated industrial hydrogen demand [66]. Nonetheless, in situations of reduced demand, alternate transit modalities should be evaluated.

Liquefied hydrogen shipping is a critical factor in international trade and large-scale transportation [67]. To achieve a liquid state, hydrogen requires cooling to −253 °C, a process that utilises 30–40 % of its energy content [51]. The substantial energy demand, along with the necessary specialised infrastructure for liquefaction, storage, and regasification, markedly increases costs. The CAPEX for liquefaction plants varies between $300 million and $1 billion, contingent upon size and technological efficiency. OPEX is primarily influenced by electricity costs and the maintenance of cryogenic systems. Transporting LH_2 incurs boil-off losses, generally ranging from 0.2 to 0.4 %/day, contributing to increased operational expenses over extended distances. Table 3 [6] also presents a cost comparison of liquefied hydrogen transportation. Considering the cost structures, LH_2 transport is economically viable for distances exceeding 2000 km, at which point pipelines are no longer practical. High liquefaction costs and energy losses render this option feasible solely when integrated with low-cost renewable energy sources at the hydrogen production site.

Transporting compressed hydrogen is suitable for short-distance delivery and small-scale distribution; however, it becomes prohibitively expensive over longer distances [37]. Table 3 presents the cost structure related to compressed hydrogen trucking. The cost structure for compressed hydrogen trucking is influenced by storage pressure (350–700 bar), trailer capacity, and fuelling infrastructure. Higher pressures reduce transport costs per kilogramme of hydrogen; nonetheless, they raise capital costs for reinforced composite storage tanks [68]. Trucking serves as the most efficient approach for local hydrogen distribution across distances ranging from 200 to 500 km. Beyond this range, pipeline transport or LH_2 shipping proves to be more economically viable.

To address hydrogen's storage and transportation constraints, chemical carriers like ammonia and LOHCs provide an alternate method for long-distance hydrogen transfer. These technologies facilitate the transportation of hydrogen in ambient conditions, hence diminishing the expenses associated with compression and cryogenic storage. Nonetheless, they necessitate conversion and reconversion infrastructure, hence incurring an additional economic burden. Although ammonia and LOHCs diminish direct hydrogen management expenses, the energy losses incurred during reconversion render these alternatives less efficient than direct LH_2 transportation [69]. Table 3 also delineates the synthesis, transportation, and reconversion costs for ammonia and LOHCs indicating that ammonia has reduced transportation costs (0.30–0.70/kg H_2/1000 km) relative to LOHCs (0.50–1.00/kg H_2/1000 km), while both encounter substantial reconversion costs (up to $1.50–2.50/kg H_2). Ammonia is becoming a prominent contender for hydrogen trade because of its existing shipping infrastructure and storage convenience [70].

Compressed hydrogen storage is a prevalent technology for short-term and transportable applications, especially in fuel cell vehicles, industrial facilities, and transit logistics. Hydrogen is generally kept at elevated pressures between 350 and 700 bar to enhance its energy

Table 3
Comparative hydrogen transport costs ($/kg H_2).

Transport Method	Subtype/Carrier	CAPEX ($/km)	Synthesis/Compression ($/kg)	Transport Cost ($/kg/1000 km)	Reconversion ($/kg)	Capacity/Pressure	Losses (%)
Pipeline	New hydrogen pipeline	$1.0–2.0 million	0.10–0.15	0.05–0.10 (est.)	–	100–500 t/day	0.5–1
Pipeline	Repurposed gas pipeline	$0.3–0.6 million	0.07–0.10	0.05–0.10 (est.)	–	50–300 t/day	1–2
Liquefied H_2	Large-scale ship	N/A	1.5–2.0 (liquefaction)	0.50–1.20	–	–	0.2–0.4 (boil-off)
Liquefied H_2	Small-scale barge	N/A	2.0–3.0	1.00–2.00	–	–	0.3–0.5 (boil-off)
Compressed H_2	High-pressure tube trailer	N/A	0.5–1.0	2.00–5.00	–	350–700 bar	Negligible
Compressed H_2	Cryo-compressed truck	N/A	1.0–1.5	1.50–3.50	–	250–400 bar	Negligible
Hydrogen Carriers	Ammonia	N/A	1.0–1.5 (synthesis)	0.30–0.70	0.75–1.50	–	Negligible
Hydrogen Carriers	LOHCs	N/A	1.2–1.8 (synthesis)	0.50–1.00	1.00–2.00	–	Negligible

density. Nevertheless, the need for specialised materials capable of enduring high-pressure conditions substantially increases storage expenses. Table 4 presents a detailed analysis of the costs associated with hydrogen storage. Even though compressed storage is flexible and widely used, the high costs of building tanks, the energy needed for compression, and the wear and tear on materials over time create significant financial challenges. This approach is most appropriate for temporary storage applications and localised hydrogen delivery systems [71].

Storing LH_2 allows for more energy to be packed into a smaller space than storing it as a gas because it is cooled to −253 °C, which means we can keep more hydrogen in a smaller area. The energy expenditure for liquefaction is considerable, necessitating roughly 30–40 % of the hydrogen's overall energy content [51]. Furthermore, sustaining cryogenic conditions necessitates ongoing cooling, hence increasing operational expenses. Table 4 also shows a detailed cost comparison of LH_2 storage, including the initial investment (CAPEX of 1800–4500/kg H_2), yearly operating costs (OPEX of 45–110/kg H_2/yr), and losses from evaporation (0.1–0.5 %) for both small and large cryogenic tanks [67]. The main challenge to widely using LH_2 storage is the high energy costs linked to liquefaction and boil-off losses, making it better suited for long-distance transport and large hydrogen facilities rather than for smaller.

Underground geological formations, including salt caverns, depleted gas fields, and aquifers, provide economical solutions for extensive seasonal and long-term hydrogen storage. These storage techniques offer the advantages of minimal running expenses and substantial capacity, making them especially appropriate for industrial applications and grid stabilisation [72]. Moreover, when integrated with AI-driven demand forecasting and real-time operational scheduling, such storage methods could further optimise dispatch timing in hybrid energy systems, particularly where hydrogen serves as a seasonal buffer in wind-solar microgrids [73]. Table 4 summarises the economic and technical features of underground hydrogen storage, including CAPEX (0.15–1.20/kg H_2), OPEX (0.02–0.18/kg H_2/year), and storage capacities between 10,000 and 1,000,000 tonnes. Salt caverns demonstrate the most economical costs (CAPEX: $0.15–0.60/kg H_2) and elevated cycle efficiency (75–95 %), underscoring their appropriateness for seasonal energy storage [74]. These approaches necessitate comprehensive geological evaluations, regulatory approvals, and prolonged monitoring to mitigate leakage and contamination hazards.

Table 4
Overview of hydrogen storage costs.

Storage Type	CAPEX ($/kg H_2)	OPEX ($/kg H_2/yr)	Other Metrics	Efficiency Loss/Cycle Efficiency
Compressed Hydrogen Storage				
350 bar steel tank	650–1200	6–12	Pressure: 350 bar	5–10 %
700 bar composite tank	1200–2000	9–18	Pressure: 700 bar	10–15 %
High-capacity cylinders	1800–2700	12–22	Pressure: 700 bar	10–20 %
Liquid Hydrogen (LH_2) Storage				
Small-scale LH_2 tank	2500–4500	55–110	Boil-Off Loss: 0.3–0.5 %	–
Large-scale cryogenic tank	1800–3800	45–85	Boil-Off Loss: 0.1–0.3 %	–
Underground Hydrogen Storage				
Salt cavern	0.15–0.60	0.02–0.07	Capacity: 10,000–100,000 tons	Cycle Efficiency: 85–95 %
Depleted gas field	0.30–0.90	0.03–0.12	Capacity: 50,000–500,000 tons	Cycle Efficiency: 75–90 %
Aquifer storage	0.40–1.20	0.04–0.18	Capacity: 100,000–1,000,000 tons	Cycle Efficiency: 70–85 %
Other Hydrogen Storage Options				
Ammonia (NH_3)	1.2–1.80	0.35–0.80	Reconversion Cost: 0.80–1.70 $/kg H_2	25–40 % efficiency loss
LOHCs	1.5–2.2	0.55–1.10	Reconversion Cost: 1.20–2.50 $/kg H_2	30–45 % efficiency loss
Metal hydrides	2.2–3.5	0.90–1.80	Reconversion Cost: 1.70–3.20 $/kg H_2	35–50 % efficiency loss

Chemical storage methods, including ammonia, LOHCs, and metal hydrides, facilitate hydrogen storage at ambient pressure and temperature, thereby minimising the requirement for costly high-pressure tanks or cryogenic facilities. These methods entail supplementary energy and conversion expenses linked to hydrogen release and reconversion [75]. Figs. 2 and 3 illustrate the annual operating costs per kilogram of hydrogen across various storage technologies. Underground storage options, particularly salt caverns and depleted gas fields, offer the lowest OPEX, benefiting from natural containment and minimal active management. In contrast, chemical storage options and cryogenic LH_2 systems exhibit elevated OPEX due to continuous cooling, reconversion energy, and additional system requirements. These disparities further highlight the importance of lifecycle cost optimisation in selecting hydrogen storage solutions for different industrial applications. Table 4 shows the costs of making hydrogen, which are 1.2–1.80 per kg for ammonia, 1.5–2.2 per kg for LOHCs, and 2.2–3.5 per kg for metal hydrides. Reconversion costs significantly increase expenses, amounting to 1.70/kg Hydrogen for ammonia, 2.50/kg Hydrogen for LOHCs, and 3.20/kg Hydrogen for metal hydrides. Efficiency losses, which range from 25 % to 50 %, exacerbate economic challenges [55].

Fig. 2 compares the yearly operating costs (OPEX) for different compressed hydrogen storage systems: 350-bar steel tanks, 700-bar composite tanks, and high-capacity cylinders. The OPEX range shows that while higher storage pressures bring greater energy density, the materials and maintenance become increasingly costly. This information offers insight into the best storage options for mobile and small-scale industrial hydrogen applications. Stakeholders should consider both the performance of the systems they are selecting, the lifecycle operating costs of the system, and the risks of material degradation.

As demonstrated in Fig. 3, underground hydrogen storage, specifically in salt caverns, has the lowest OPEX when compared to all other storage technologies discussed. Salt caverns have both low OPEX and

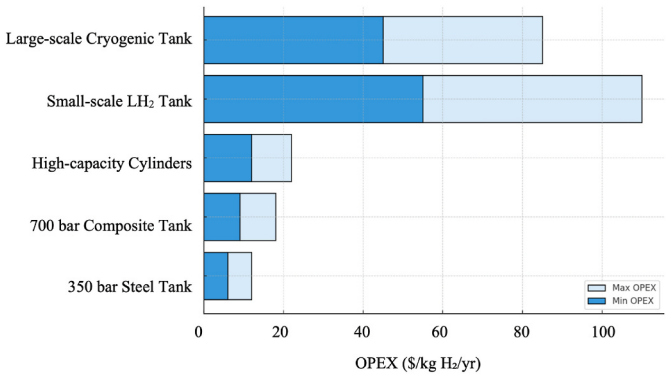

Fig. 2. Opex range of compressed hydrogen storage types.

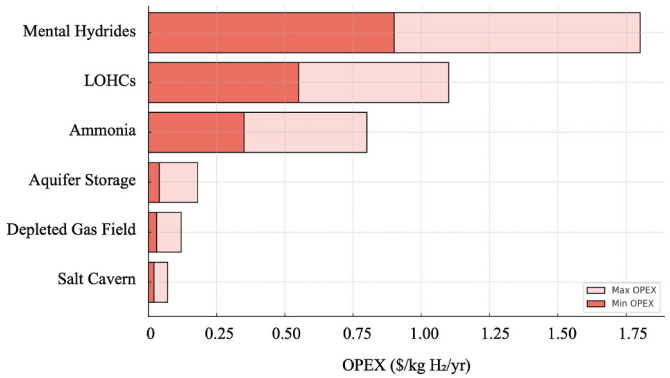

Fig. 3. Opex range of underground hydrogen storage types.

high cycle efficiency; thus, they are ideal for seasonal and long-duration storage. While aquifers and depleted gas fields have excellent capacity, they may also have more expensive monitoring and regulatory costs. Therefore, this finding highlights the need to connect the geological feasibility of storage with policy incentives in tandem, necessary for the continued deployment of low carbon, large volume hydrogen for the long term.

Fig. 4 presents the proportion of energy lost during a complete storage-release cycle for various hydrogen storage methods. Underground options such as salt caverns demonstrate high cycle efficiency (up to 95 %) due to minimal conversion losses. Fig. 4 emphasises the efficiency trade-offs between different storage types, with subterranean options (particularly salt caverns) associated with the least amount of energy loss and therefore best suited for grid stabilisation and seasonal storage. In contrast, LOHCs and metal hydrides suffer the worst reconversion losses, with losses in excess of 30–50 %. While hydrogen storage efficiency is an obvious concern, there is a need to make this efficiency tradeoff against the benefits of flexibility and safety, particularly in the case of regions where subterranean formations are not available. Therefore, policy and R&D should target efficiency improvements on reconversion technology for chemical storage systems in particular.

Figs. 5 and 6 provide a more granular breakdown of CAPEX costs associated with each storage method identified in Table 4. Underground storage options (particularly salt caverns) demonstrate significantly lower investment requirements compared to compressed gas or cryogenic storage. Chemical storage methods, including LOHCs and metal hydrides, exhibit the highest CAPEX due to reconversion complexity and system design requirements. These insights reinforce the need for application-specific optimisation when selecting hydrogen storage pathways.

Fig. 5 depicts the capital expenditure (CAPEX) across types of storage tanks and pressure classification for compressed hydrogen storage. The costs associated with compressed hydrogen storage tanks at higher

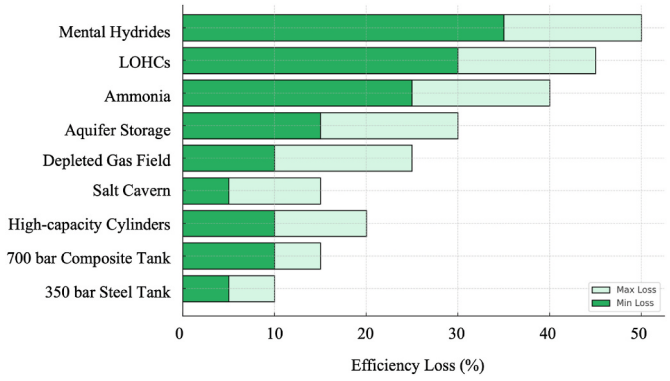

Fig. 4. Efficiency loss per cycle for hydrogen storage types.

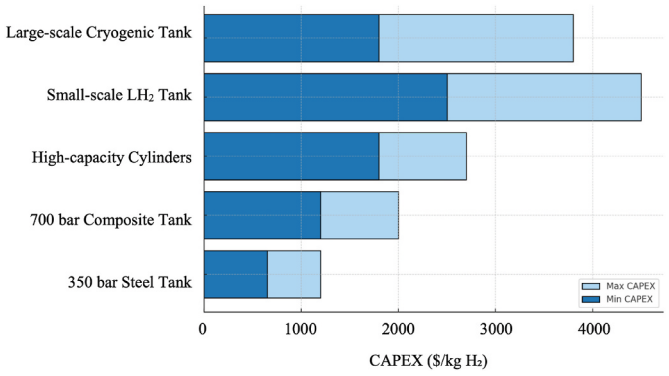

Fig. 5. Capex range of compressed hydrogen storage types.

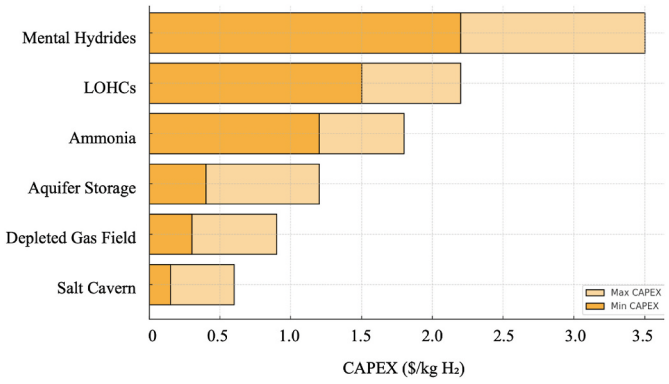

Fig. 6. Capex range of underground hydrogen storage types.

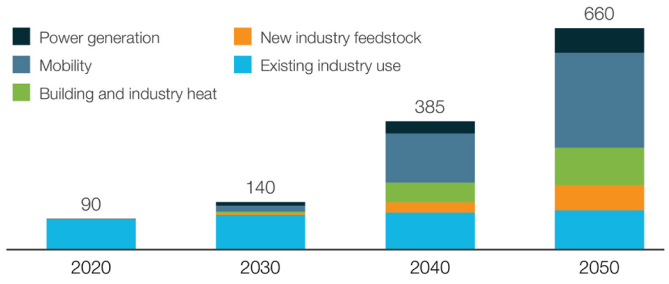

Fig. 7. Projected global hydrogen demand by sector till 2050. Sixty metric tonnes of hydrogen will be required annually by 2050 to achieve net-zero emissions, representing a 22 % increase from 140 in 2020–2030 [40].

pressures (700 bar) will be exorbitant due to the appropriate safety regulations and required tank reinforcement. Financial limitations related to CAPEX will typically restrict the potential markets for hydrogen storage tanks, as budgets impose constraints. Regardless, compressed hydrogen will still offer short-term, decentralised, and mobile hydrogen storage options. Future financial models and production innovations related to processes within composite tank manufacturing will lower start-up costs to allow entry into various new hydrogen markets.

Fig. 6 shows the capital investment needed for underground storage technologies, where salt caverns are the cheapest, followed by depleted gas fields and aquifers. The low CAPEX investments, coupled with large capacity (high efficiency), mean that salt caverns have potential for industrial scale and seasonal applications. However, they are geographically limited and therefore require site assessments and regulatory approvals. The situation demonstrates the importance of integrated planning and public-private partnerships in identifying and

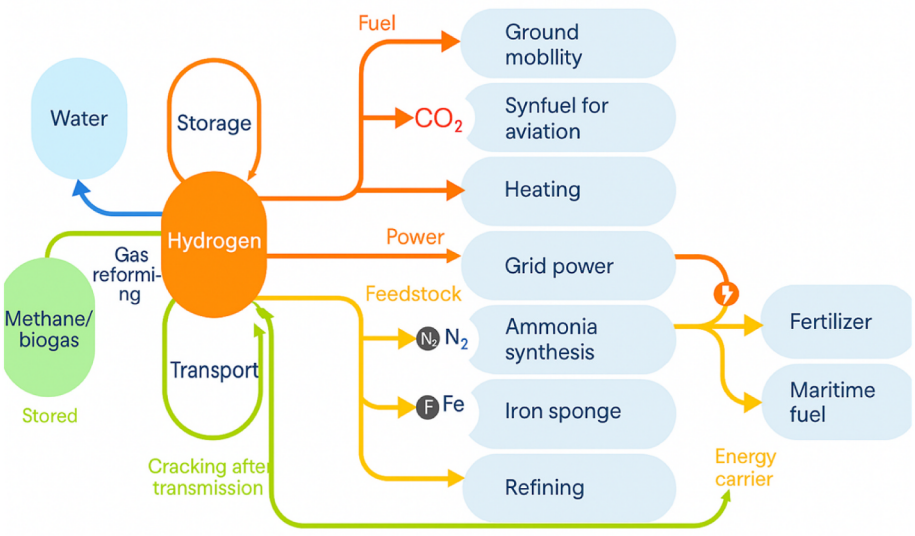

Fig. 8. Hydrogen trajectories within the energy framework [40].

developing potential scenarios for scalable hydrogen storage infrastructure.

Three primary factors influence the cost of hydrogen storage: capital investment in infrastructure, maintenance and energy input OPEX, and energy losses during storage and retrieval. For instance, as indicated in Table 5, gas storage under compression necessitates the use of high-pressure tanks operating at 350–700 bar, which demand expensive composite materials. This leads to a CAPEX of between $1200 and $2700 per kilogramme of hydrogen (kg H_2), in addition to energy-intensive compression processes that consume 0.5–1.0 kWh/kg H_2. LH_2 storage, characterised by its elevated energy density, justifies the substantial CAPEX) of $1.5–2.0/kg H_2 for cryogenic chilling to −253 °C, which leads to daily boil-off losses ranging from 0.2 to 0.5 %. Underground storage in salt caverns presents a cost-effective option for large-scale hydrogen use, with CAPEX ranging from $0.15 to $0.60 per kg of Hydrogen; however, its feasibility is limited by geographic factors. Besides losing 25–50 % of energy, chemical carriers like ammonia LOHCs also have extra costs for making and converting them back ($1.0–1.8/kg H_2 and $0.75–2.50/kg Hydrogen, respectively), which helps in transporting hydrogen using current systems. Energy losses differ by method: LH_2 and chemical carriers experience losses of 25–50 % due to boil-off or inefficiencies in reconversion, while compressed gas systems incur losses of 10–15 % of stored energy. The identified trade-offs underscore the necessity of aligning storage solutions with specific applications, including short-term mobility (compressed gas), long-distance transportation (LH_2), and seasonal storage (salt caverns).

Table 5
Economic and performance attributes of hydrogen storage technologies.

Storage Method	CAPEX ($/kg H_2)	OPEX ($/kg$H_2$/ year)	Energy Loss (%)	Typical Applications
Compressed Gas (700 bar)	1200–2700	9–18	10–15	Short-term storage for mobile applications
Liquid Hydrogen (LH_2)	1800–3800	45–85	25–30	Long-distance transport and export
Salt Caverns	0.15–0.60	0.02–0.07	5–10	Seasonal or bulk-scale storage
Ammonia (NH_3)	1.0–1.80	0.35–0.80	25–40	Hydrogen carrier for international trade
LOHCs	1.2–1.80	0.55–1.10	30–45	Medium-term centralized storage
Metal Hydrides	2.2–3.5	0.90–1.80	35–50	Niche applications with compact requirements

3.4.3. Capital and operational expenditures (CAPEX and OPEX)

3.4.3.1. Capital expenditures. Capital investment in hydrogen production plants includes the price of electrolysers or SMR units, auxiliary equipment, site preparation, and grid or pipeline connections. The production via electrolysis entails elevated CAPEX due to the nascent development of large-scale electrolyser technologies [76]. Alkaline and PEM electrolysers are the top choices in the market, with PEM systems being pricier but offering better efficiency and flexibility for using renewable energy that varies in availability. The cost to build blue and grey hydrogen plants mainly depends on the size of the SMR units and, for blue hydrogen, the use of CCS technologies [77]. Table 6 shows a detailed look at the costs to build green hydrogen plants, which range from $1500 to $2500/kW for 1 MW plants and drop to $800–1500 per kW for 100 MW systems. In contrast, blue hydrogen CAPEX ranges from $900 to $1500 per kW for 1 MW installations, reducing to $700–1000 per kW for 100 MW systems. Grey hydrogen maintains the lowest CAPEX, recorded at $500–800 per kW for large-scale plants [78]. The CAPEX for green hydrogen includes the costs for electrolyser stacks and other necessary equipment, like cooling systems, rectifiers, water purification, and hydrogen compression, as well as the setup of renewable

Table 6
Estimates of capital expenditure (CAPEX) for hydrogen production technologies across different plant scales.

Production Method	CAPEX (1 MW) ($/kW)	CAPEX (10 MW) ($/kW)	CAPEX (100 MW) ($/kW)
Green hydrogen (Electrolysis)	1,500–2,500	1,200–1,700	800–1,500
Blue hydrogen (SMR + CCS)	900–1,500	800–1,200	700–1,000
Grey hydrogen (SMR)	700–1,000	600–900	500–800

Notes: Capital expenditure (CAPEX) values represent indicative ranges contingent upon project scale and economies of scale. Green hydrogen estimates pertain to proton exchange membrane (PEM) and alkaline electrolysis systems. Blue hydrogen is produced through steam methane reforming (SMR) combined with carbon capture and storage (CCS), achieving capture rates of 90–95 %. Grey hydrogen is defined as conventional steam methane reforming (SMR) without carbon capture and storage (CCS).

electricity sources. Economies of scale can lead to substantial cost reductions, with larger 100 MW installations exhibiting costs up to 40 % lower/kW than 1 MW units. The capital costs for blue hydrogen include traditional SMR units, but adding CCS technology can raise these costs by 20–40 % CCS infrastructure requires extra pipelines to transport CO_2 and places to store it underground permanently, which raises costs, especially in places without existing storage options. Grey hydrogen exhibits the lowest CAPEX, as it can utilize existing refineries and industrial hydrogen production facilities with minimal modifications [60]. Regulatory changes that implement carbon pricing mechanisms may diminish its cost advantage in the long term.

3.4.3.2. Operational expenditures. OPEX includes regular maintenance, manpower, energy usage, and, particularly for blue hydrogen, costs associated with carbon capture and sequestration. Green hydrogen demonstrates little maintenance expenses due to the simple design of electrolyser units; yet electricity costs substantially affect its long-term feasibility. The expenses associated with electricity for green hydrogen production vary significantly depending on the accessibility of renewable energy sources [9]. A substantial fraction of production expenses is ascribed to electricity consumption, with projections suggesting that electricity might account for 50–70 % of overall OPEX. Table 7 illustrates the operational expenses, indicating that the OPEX for green hydrogen varies from 0.04 to 0.09 per kg of hydrogen or 1 MW plants and from 0.02 to 0.06 per kg of hydrogen for 100 MW systems, thereby highlighting cost efficiencies associated with bigger systems [60]. Ensuring a steady provision of economical renewable electricity is crucial for reducing the expenses linked to green hydrogen. Water consumption represents a minor but substantial aspect of operational expenses, as electrolysis requires roughly 9 L of purified water for per kg of hydrogen generated. For blue hydrogen, the principal elements of OPEX include the acquisition of natural gas and carbon management. The efficacy of CCS is vital, as systems that achieve high carbon capture rates need augmented energy consumption and substantial capital inputs [79]. The operating costs related to carbon sequestration infrastructure, including compression, transportation, and long-term monitoring, add complexity to the financial analysis [80]. The prices of natural gas significantly affect the operational costs of grey hydrogen, whereas worldwide methane markets dictate its economic feasibility. Current maintenance and operational expenses are minimal; however, environmental concerns and the growing implementation of carbon levies may result in an increase in OPEX in the future. In this context, the integration of machine learning-based predictive models for electricity price forecasting and electrolyser scheduling can further optimise OPEX, especially in green hydrogen systems relying on variable renewable inputs.

3.4.4. End-use application costs

End-use application costs are the cost of modifying or replacing current infrastructure to utilize hydrogen as a source of energy. These costs are probably enormous and wildly varying by industry and level of integration. For industrial applications, this cost entails CAPEX to install or retrofit equipment, and changes in OPEX For example, for the case of direct reduced iron (DRI) steelmaking, a changeover from natural gas to hydrogen involves hefty investments in hydrogen-compatible DRI facilities. But such costs can also translate to reduced OPEX over the long term thanks to decreased carbon pricing liabilities and better sustainability [81]. Overall cost (C_{total}) and be given as Equation (3). Where: C_{CapEx}, C_{OpEx}, and $C_{Carbon\ Savings}$ refer to capital cost of new infrastructure, ongoing operational costs, and cost savings from emissions reductions, separately.

$$C_{total} = C_{CapEx} + C_{OpEx} - C_{Carbon\ Savings} \quad (3)$$

Compressed hydrogen and liquid organic hydrogen carriers (LOHCs) are generally regarded as highly flexible and safe options. In contrast, ammonia and liquid hydrogen, despite their higher costs and additional energy requirements for conversion, tend to be more cost-effective solutions for long-distance transportation. This comparison underscores that there is no universally optimal hydrogen carrier; rather, the choice should be tailored to specific industrial applications, geographical conditions, existing infrastructure, and end-use requirements. Table 3 summarises these key insights and provides strategic guidance for decision-making throughout the hydrogen value chain.

Table 7
Operational Expenditure (OPEX) for different hydrogen production methods across varying plant capacities. (All values in USD per kg of H_2 produced).

Production Method	OPEX (1 MW)	OPEX (10 MW)	OPEX (100 MW)
Green Hydrogen	$0.04 – $0.09	$0.03 – $0.07	$0.02 – $0.06
Blue Hydrogen	$0.07 – $0.12	$0.06 – $0.10	$0.05 – $0.09
Grey Hydrogen	$0.06 – $0.10	$0.05 – $0.09	$0.04 – $0.08

3.5. Demand drivers for hydrogen: sectoral needs and carbon reduction potential

3.5.1. Global demand forecast and carbon reduction potential

Hydrogen is an essential decarbonisation agent that has the potential to integrate and transform the existing power, gas, chemical, and fuel sectors. Hydrogen can serve a crucial function in assisting nations and sectors in achieving their net-zero emission objectives by 2050. Although hydrogen is not a comprehensive solution for reducing emissions across all sectors, it distinctly enhances and facilitates other decarbonisation strategies, including direct electrification, energy efficiency initiatives, and biomass-derived fuels [40]. In a net-zero scenario, the demand for clean hydrogen might near 660 million metric tonnes (MT) by 2050, constituting 22 % of global final energy demand and preventing annual emissions of 7 gigatons (GT) of CO_2 (Fig. 4). The annual abatement potential of 7 GT in 2050 corresponds to around 20 % of the emissions if the world continues on its present global warming track. By 2050, clean H_2 has the potential to reduce a cumulative total of 80 gigatons of CO_2, or double the current yearly human emissions [60]. The cumulative CO_2 abatement potential of 80 GT by 2050 is approximately 11 % of the emissions reductions necessary to remain within the carbon budget of 420 GT, which is essential for limiting global warming to 1.5–1.8 °C.

3.5.2. The role of energy system hydrogen

Hydrogen plays a pivotal role in enabling decarbonised energy systems by facilitating electrification, supporting renewable energy integration, and enhancing overall energy system flexibility. It enables long-duration energy storage and system balancing, contributing to grid resilience. It can enable the long-distance piping and shipping of clean energy, releasing "stranded" renewable resources. It can also transform the chemicals, fuels, and metals industries and link them to the electricity sector. Hydrogen's systematic function enables faster, cheaper, and more comprehensive decarbonisation across sectors and regions.

3.5.2.1. Storage of energy. In deep salt caverns, hydrogen can store significant amounts of energy for later use. Heating during unexpectedly cold winters or supplying hydrogen to industrial operations are examples. Hydrogen can be stored in pipelines through "line packing," or increasing pressure, to increase storage volume and energy security.

3.5.2.2. Energy system resilience. Hydrogen has many energy system resilience benefits. Hydrogen stabilises demand peaks and troughs by storing excess low-cost energy when it's available and releasing it when necessary to maintain grid operations. It also encourages energy resource diversification across regions to use the most cost-effective resources rather than overbuilding locally. Data centres and hospitals use backup generators powered by it.

3.5.2.3. Energy transmission. Hydrogen can enable regional and global energy transmission by moving clean energy from attractive energy resources to less attractive domestic ones. Regional pipes and lorries distribute hydrogen. Pipelines can carry 10–20 times more energy than power transmission networks and provide big volumes of energy across vast distances cost-competitively. Pipelines might transport renewable energy from southern Europe to demand centres in the north. Large industrial users like steel and ammonia factories will need pipelines to get hydrogen, as on-site supply is unavailable. Compressed or liquid hydrogen trucks can provide refuelling stations, remote generators, building sites, and smaller industrial customers cost-effectively. Ship hydrogen long distances. It connects low-cost hydrogen production locations like Australia, Latin America, and the Middle East with demand centres like Europe, the West, Japan, and Korea. It can be supplied as pure liquefied hydrogen, processed into ammonia or liquid organic carriers for end-use applications, or "cracked" back into hydrogen. Hydrogen can unlock very competitive "stranded" renewable energy potential in remote, sparsely inhabited areas. Many renewable resources offer high volumes and quality (i.e., high load factors and low cost), but establishing energy transmission lines to demand centres has been impossible until recently. Hydrogen allows the energy system to tap into these resources and send them to demand centres with less attractive energy resources, delivering low-cost, clean energy. By opening up previously inaccessible resources, it can speed the energy transition and prevent renewable energy shortages.

3.5.2.4. Sector coupling. Beyond system functions, hydrogen connects industries in new ways. Hydrogen can transform electricity into gas and other end-products, connecting and reshaping gas, power, chemicals, and fuel markets with clean energy (Fig. 8). Clean hydrogen for steel or aircraft comes from renewable energy, natural gas, or biogas with carbon capture. Hydrogen links the clean power and energy market to the metals, fuels, chemicals, and petrochemical industries. Ammonia, used for fertiliser and other industrial purposes, might be used as a fuel for shipbuilding, power generation, or as a clean energy carrier for worldwide electron transmission in clean molecules. Future energy systems incorporating hydrogen could benefit from predictive optimisation algorithms, such as those applied in smart microgrids for renewable dispatch and storage scheduling, to enhance hydrogen deployment in sector-coupled and dynamic grid environments.

4. Policy and regulatory framework

Strong and enabling policy and regulatory framework is essential to speeding up the innovation and uptake of hydrogen technologies in sectors. In the view of [82] as well as [83], effective governance needs to span the whole value chain of hydrogen, from production and transport to storage and end-use applications. This includes creating clear safety standards, simplifying permitting, and providing financial incentives like subsidies or tax credits to minimise investment risk. Regulatory equivalence between regions is also critical to facilitate cross-border trade of hydrogen as well as infrastructure. Long-term policy stability is also necessary to stimulate private sector investment and innovation. Strategic planning must also involve alignment with renewable energy infrastructures and carbon pricing mechanisms so that hydrogen plays its role in overall decarbonisation goals. In total, an enabling policy landscape will have the final say to shape an economically viable, sustainable hydrogen economy.

4.1. Carbon pricing

A carbon pricing policy a carbon tax or a cap-and-trade system can serve as an anchor policy instrument to guide decarbonisation by internalising greenhouse gas emission externalities. By putting a price on carbon emissions, a carbon pricing policy renders carbon-emitting activities more expensive, thus making low-carbon options like green hydrogen more financially appealing [84]. The features of this market-based policy not only incentivize capital investment towards clean-tech sectors but also enable the transition to clean energy systems. Possible areas of further research may include considerations of the optimal price levels needed to encourage meaningful green hydrogen uptake, the impacts of sectoral carbon pricing on consumption of hydrogen, and the interplays between carbon pricing and other subsidization or regulation methods in order to inform the establishment of sound and equitable policy regimes [85]. Cross-jurisdictions comparative analysis could also identify best practices and common challenges to be avoided in implementing carbon pricing, hence driving advancement in the hydrogen industry.

Fig. 9 illustrates how increasing carbon fees can significantly lower CO_2 emissions over time. The left illustrates that beginning with a high fee ($35 per tonne) increasing by 5 % annually results in much lower emissions compared to lower fees or no fees. The right illustrates that fee increases have a large impact, with even modest initial fees sending a powerful price signal in the market over time. These findings highlight that carbon pricing must send a powerful price signal and also rise over time to continue reducing emissions, particularly to spur hydrogen use in difficult-to-clean-up industries.

4.2. Subsidies and incentives

Governments have the ability to drive the promotion of hydrogen technologies by providing financing and incentives to targeted parties. The facilitation can be done through investments made in research and development, tax incentives related to levels of low-carbon hydrogen consumption and production, and guarantees of loans aimed at financing critical infrastructure projects. These fiscal policies are intended to reduce investment risks, increase private sector participation, and encourage innovation along the entire hydrogen value chain. The efficiency of the consumption of hydrogen can be improved by performance-based incentives, as well as encouraging reductions in emissions [87]. Performance-based incentives can enhance hydrogen utilisation efficiency and encourage emissions reductions in end-use sectors. Future research should focus on evaluating the effectiveness of different subsidy schemes, identifying optimal incentive structures tailored to various regional contexts, and assessing their alignment with broader decarbonisation goals. Additionally, combining the deployment of hydrogen subsidies within end-to-end decarbonisation policy structures, such as renewable portfolio standards and carbon prices, can guarantee policy coherence, as well as optimal long-term sustainable outcomes. Further research on additional areas of international cooperation can also assist in reducing market distortions and developing a global and highly competitive hydrogen market.

Besides direct subsidies, alternative financing vehicles such as green bonds, carbon contracts for difference (CCfDs), and blended finance become increasingly relevant. These products de-risk early-stage investment in infrastructure and employ private capital. Future policies need to combine these financial products in a hybrid of policies to catalyse investment on the scale required for industrial hydrogen transitions. Additionally, integrating predictive analytics or AI-based financial risk modelling, such as those used in smart grid investment planning—may support more accurate targeting of subsidy allocation and improve project bankability under uncertainty.

4.3. Standards and regulations

Adjudicated strict codes and regulations that encompass the manufacturing, transportation, and storage of hydrogen are important in order to offer protection, encourage environmental friendliness, and enhance public acceptability. The standards should specifically encompass fuel cell efficiency according to the purity of hydrogen, pipeline safety in order to prevent leakage, and tank design in an effort to

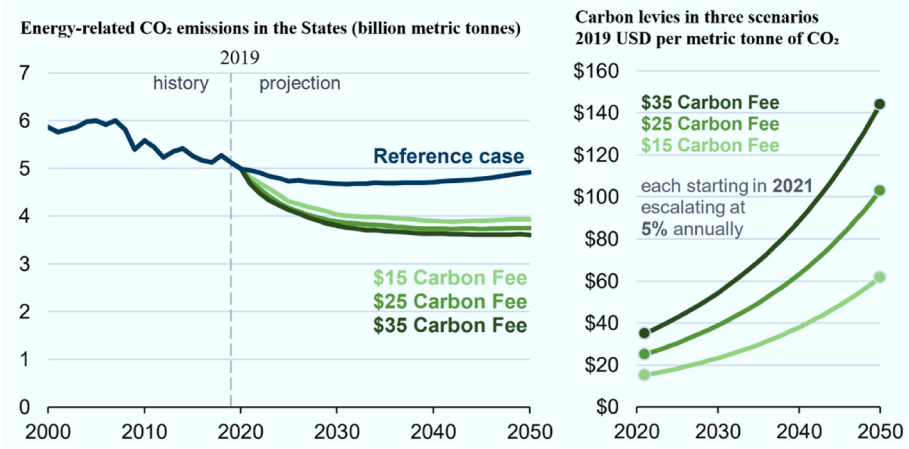

Fig. 9. Projected U.S. energy-related carbon dioxide emissions (left) and implied carbon fee trajectories (right) under three carbon fee scenarios ($15, $25, and $35 per metric tonne CO_2, each rising at 5 % per year from 2021 to 2050). The figure illustrates that more carbon prices lead to greater emissions savings over time [86].

minimise the risk of explosions [82]. Without international standardization, differences could limit cross-country trade and interoperability of technologically related systems. Moreover, regulatory frameworks must evolve alongside technological progress, incorporating novel materials and digital monitoring systems, including AI-based leak detection and predictive diagnostics where applicable. Although all aspects are important, special focus should be on pipeline safety because of the high diffusivity and in flammability of hydrogen, which requires special safety requirements. Strong standards in this area can significantly reduce the chances of accidents and increase the confidence of stakeholders, hence their uptake of these technologies.

4.4. National hydrogen strategies

National hydrogen strategies are important drivers that reflect the commitment of a country to gaining a low-carbon future. National hydrogen strategies are full-fledged plans outlining aims and legislative arrangements, as well as financing avenues needed to produce hydrogen, build infrastructure, and employ it across the various economic sectors. Good country plans are based on stringent climate goals, which drive investments, drive innovation, and encourage multi-sectoral collaboration. Current plans, however, lack the needed detail, especially regarding long-term implementation and capacity to integrate with country energy policies [82]. National plans should focus on cross-country convergence, integrate greenhouse gases along the whole cycle of their lifetime, and build strong financing schemes to ensure better efficiency overall. It is important to have high priority towards infrastructure, mainly in the areas of storage solutions and distributed networks, as well as refuelling systems, to be able to meet this goal. Without coordinated infrastructure planning, hydrogen deployment may become fragmented and inefficient, impeding commercial scalability and complicating international trade. In this context, data-driven infrastructure modelling tools and AI-enabled demand forecasting could assist governments in dynamically adapting strategies and investment priorities.

Many countries have made hydrogen strategies that are useful guides. Germany's National Hydrogen Strategy for 2020 was all on making green hydrogen and making electrolysis work on a larger scale. Japan wants to import hydrogen and use fuel cells to move it around, whereas Australia wants to export hydrogen via ammonia infrastructure. The examples show different techniques that are in line with national interests and show how important it is for technical and regulatory standards to be in line across borders [60].

4.5. International cooperation

In the progress of hydrogen technology, international cooperation is necessary, which calls for information exchange, standards convergence, and the unification of respective capabilities [88]. Mutual frameworks allow resource-sharing or aggregation, eliminate research and development redundancy, and enhance interoperability between multiple systems through the implementation of common regulatory standards. In addition, international cooperation provides the mechanism to stimulate investment by reinforcing market stability and lowering barriers to global businesses looking to enter new economies. A few examples of such kinds of collaboration include joint research projects involving several countries, inter-state policy pacts, and cross-country experimental projects. Despite this, differences in technological capabilities between countries, as well as their respective policy structures, might present barriers to coordinated actions. It is necessary to underscore the requirement of synchronisation and unification of regulatory structures, as these elements are instrumental to the transfer of technology and unification of global economies. Well-defined and widely accepted standards regarding safety, efficiency, and certification which cut across countries can efficiently drive investment and trade within the industry of hydrogen technology [88]. Emerging AI-enabled platforms for global data sharing, techno-economic benchmarking, and cross-border infrastructure optimisation are also beginning to support more transparent and synchronised international hydrogen development.

5. Results and discussion

5.1. The development of infrastructure for integrating industrial hydrogen

Integration of industrial hydrogen systems (Fig. 10) requires robust and networked infrastructure for production, transport, storage, and end-use connectivity. Specific technical and economic factors govern the integration of these components, which is crucial for the economic and large-scale hydrogen economy [62].

Hydrogen production plants must be co-located with renewables in order to reduce the levelised cost of hydrogen (LCOH) as well as to reduce transmission losses. As evident from Table 6, the CAPEX of electrolysis equipment can be reduced by up to 40 % when scaled up from 1 MW to 100 MW capacities, highlighting the necessity for high-capacity, centralised hubs near industrial demand zones [89]. Rather than viewing each infrastructure segment in isolation, developers must treat the hydrogen system as a coordinated network of production nodes, transport links, storage assets, and industrial off-takers. This

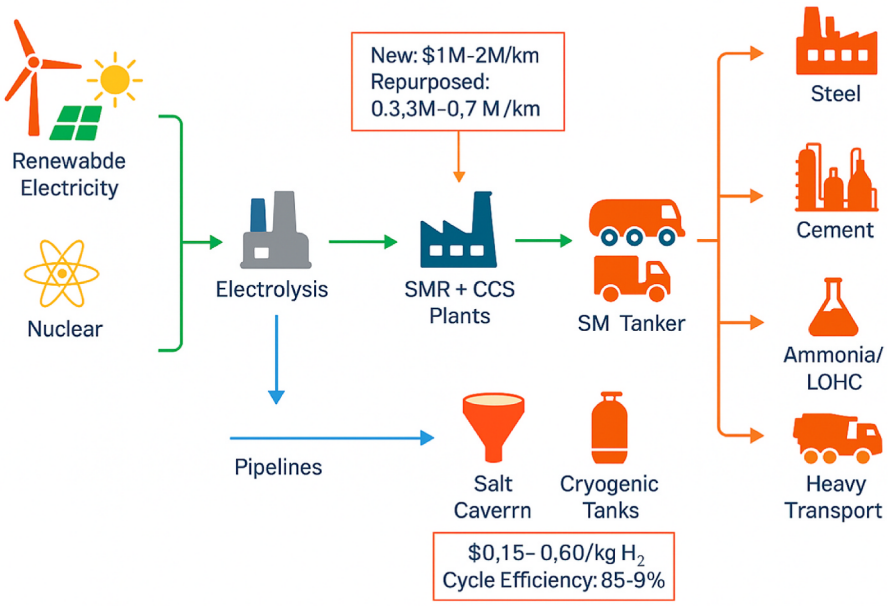

Fig. 10. The integrated hydrogen infrastructure framework for industrial decarbonisation [64,72].

holistic system architecture is illustrated in Fig. 7, which depicts the flow of hydrogen from clean power inputs (such as renewables and nuclear), through electrolysis or SMR + CCS plants, and on to downstream industrial sectors including steel, ammonia, and heavy transport. The diagram also highlights infrastructure costs, such as new hydrogen pipelines ($1–2 million/km) and the cost advantage of repurposed natural gas lines ($0.3–0.7 million/km).

Pipeline infrastructure is fundamental for bulk transportation over long distances. While new hydrogen pipelines cost a lot to install ($1M–$2 M/km), even up to 70 % of CAPEX can be saved by using existing natural gas pipelines (Table 3). However, issues such as hydrogen embrittlement and diffusion require high-level alloy coatings and leak-prevention solutions [53,62]. Hydrogen storage (or storage) facilitates system flexibility and reliability. Among the options, underground salt caverns are the cheapest way to store hydrogen ($0.15–$0.60/kg H_2) and are very efficient (85–95 %), making them the best choice for balancing energy needs throughout the seasons [62,90]. Liquid hydrogen tanks, while costlier in CAPEX, remain viable where space is a constraint and still high energy density is an issue. Together, these infrastructural elements form a closed-loop system of hydrogen deployment, as illustrated in Fig. 7. The figure indicates an optimised flow of hydrogen from renewable production to industrial use via nodes for combined transport and storage.

While each component is critical, pipeline infrastructure demands the most earnest and long-term attention. Pipelines are the backbone of the hydrogen-based economy, creating bonds between producing and consuming areas on both local and nationwide levels [30]. Without an optimally planned and well-conceived network, even the most advanced systems of production and storage stand little chance to function effectively at large scales [60]. In short, the construction of strong infrastructure for hydrogen on the basis of pipeline networks, along with investment in facilities to produce and secure storage, will be pivotal in creating a scalable, safe, and economically sound supply chain of hydrogen.

5.2. Governance and societal dimensions

The transition to a hydrogen economy necessitates significant governance and social factors that must be meticulously integrated to ensure equity and fairness. In the implementation of hydrogen technologies [19], it is essential to establish inclusive institutions characterised by public engagement, openness, and accountability. The decision-making should engage the host communities directly, especially the historically excluded or disproportionately affected by energy transition, to ensure their involvement. There must be equitability in the access to the promises from the use of hydrogen, clean energy, employment, and infrastructure development across places and social groups. Also, policy direction and regulation coordination must be established to steer the development of the industry to avoid inequalities or environmental injustices. Social acceptability and societal uptake of the technology will also depend on the degree to which such considerations have already been factored in from the onset. As [91,92] stress, early consideration towards social equity is critical to the sustainable development in the transition to the hydrogen economy.

5.2.1. Public participation

Getting the public involved is vital for making hydrogen projects work smoothly. It helps build trust and acceptance. By maintaining open lines of communication, we can dispel any misunderstandings about hydrogen technologies, clarify safety procedures, and alleviate environmental concerns. When stakeholders take part in discussions, it ensures that different opinions are heard, and getting the local community involved helps create a sense of ownership and reduces pushback. Good ways to engage the public include holding meetings, running information campaigns, and working with local leaders. These approaches help people make better decisions and support the projects in the long run [93].

5.2.2. Human capital advancement

A robust and proficient workforce is essential for the long-term development of the hydrogen business. As hydrogen technologies proliferate, the requirement for professionals in manufacturing, infrastructure, safety, and applications is increasing. Investment in specialised education and vocational training programs is essential for cultivating this talent pool [94]. Governments, academia, and industry stakeholders can collaborate to facilitate curriculum creation and provide on-the-job training in response to changing industry requirements. Enhancing the skills of existing employees in cross-industry sectors, such as oil and gas, can expedite workforce preparedness and ease the transition to energy. Furthermore, fostering STEM education at an early

level will facilitate long-term talent acquisition. Neglecting to prioritise workforce planning will render the industry susceptible to a shortage of competent labour, delaying project timelines and compromising safety and innovation. According to Ref. [94], labour development is not merely supplementary but essential to realising a hydrogen economy.

5.2.3. Energy justice

Energy justice provides that the transition to a hydrogen economy is equitable and just. With expanding hydrogen technologies, the priority should be to avoid exposing low-income communities and racialised communities to disproportionate environmental or economic harm [91]. This involves refraining from situating hydrogen infrastructure in underprivileged communities without enough consultation or equitable benefit-sharing. Policies should prioritise community engagement, transparency, and fair access to clean energy advantages, including employment opportunities, improved air quality, and affordable energy [91]. Furthermore, financial resources and assistance must be allocated to historically marginalised populations to ensure they are not excluded from transitioning to a sustainable economy.

5.3. Opportunities

The transition to a hydrogen industrial economy is a unique blend of opportunities and challenges that affect the pace and efficiency of global decarbonisation [95]. Hydrogen can decouple energy systems from carbon use, particularly in industries that are hard to abate such as steel, cement, and heavy transport. However, to realize these benefits, technology, economic, regulatory, and social barriers must be overcome. Strategic investments, effective policy environments, and public-private partnerships will be critical in managing these complexities and unlocking the full potential of hydrogen [82].

5.4. Challenges

One of the greatest obstacles to widespread adoption of hydrogen is the cost of producing low-carbon hydrogen, particularly green hydrogen by electrolysis. The capital expense of electrolysers remains high, and although the expense of renewable energy, albeit diminishing, is still significant. In addition to that, operational expense in the shape of maintenance and water treatment adds to the overall cost. This makes green hydrogen at the moment less economical compared to fossil fuel-based options without subsidies or carbon-pricing policies [96].

Lack of dedicated hydrogen infrastructure heavily limits its scalability to date. Existing natural gas pipelines are largely incompatible with hydrogen due to material embrittlement risks and leak problems. Moreover, there is not enough hydrogen refuelling stations, storage terminals, and compression facilities, especially in the absence of pilot project areas. This defector fragmented infrastructure environment deters investment and delays the establishment of reliable supply chains needed for industrial-scale deployment of hydrogen [53].

Lack of coherent policy guidance and lack of harmonized rules are the other key challenge. Support mechanisms for the long term, carbon pricing, and safety standards are unclear to investors and developers. While some areas have hydrogen strategies, others lack clear roadmaps, resulting in an unlevel playing field. Lack of international certification and trading standards for clean hydrogen also complicates the development of markets and cross-border coordination [97].

Social acceptance of hydrogen technology is presently mixed, namely due to assumed safety risks and low levels of public knowledge. The occasional hydrogen leak or explosion accidents have raised apprehension. Environmental protesters will also protest against fossil-fuel-based hydrogen projects (i.e., blue or grey hydrogen), as they may question their climate legitimacy. Active communication, stakeholder engagement, and strict safety norms will be needed to develop public trust and gain society's acceptance for hydrogen infrastructure and roll-out [97].

5.5. Opportunities

Decarbonisation Potential: Hydrogen presents a breakthrough opportunity to decarbonise hard-to-abate industries, such as steelmaking, chemical manufacturing, refining, and heavy transportation, where direct electrification is either technically difficult or economically unviable. As a clean energy carrier, green hydrogen, produced via renewable electricity, can replace fossil fuels in industrial processes, slashing greenhouse gas emissions dramatically. In sectors like ammonia and methanol production, where hydrogen is already a feedstock, a shift from grey to green hydrogen is a direct pathway to carbon neutrality. Furthermore, the pairing of hydrogen with carbon capture and storage (CCS) in the blue hydrogen pathway can provide a transitional decarbonisation option [98]. As governments implement more ambitious climate policies and carbon pricing, hydrogen's decarbonisation role becomes increasingly critical to the success of net-zero emission targets. Hydrogen is at the centre of future low-carbon energy systems because of its versatility and clean nature, which complement renewables and solve seasonal energy storage and grid balancing requirements.

5.5.1. Economic growth

The establishment of a global hydrogen economy offers tremendous economic growth opportunities. Investment in the production, infrastructure, and end-use technology of hydrogen is expected to stimulate industrial activity and create high-skilled employment in engineering, manufacturing, maintenance, and research sectors. The hydrogen industry can generate trillions of dollars in economic value by mid-century, according to global projections. Nations endowed with abundant renewable resources can become large exporters of green hydrogen, and the industry has the potential to transform their economies. Additionally, the entire process of making electrolysers and moving hydrogen around can help revive industries, especially in countries moving away from fossil fuels [99]. With targeted policy support and public-private cooperation, it can crowd in innovation and infrastructural development, making hydrogen a central pillar of an inclusive and fair green economy. By building out local supply chains and innovation ecosystems, hydrogen can drive long-term economic resilience and competitiveness in the global clean energy economy.

5.5.2. Energy security

Hydrogen enhances energy security by enabling countries to diversify their energy mix and be less dependent on imported fossil fuels. As hydrogen can be produced from different domestic sources, water through electrolysis, natural gas with CCS), biomass, or even waste, countries can tailor production to local conditions, increasing self-sufficiency. Furthermore, hydrogen is a flexible energy carrier with the potential to store excess renewable energy and help balance electricity grids, making power systems more resilient. Geostrategically, hydrogen trade will be more geographically diversified than oil and gas, potentially reducing the geopolitical conflicts associated with energy supply disruption. Hydrogen also enables the building of decentralised energy systems to the benefit of remote and rural areas [100]. As energy systems become more integrated and interdependent, hydrogen offers an important buffer, strengthening energy security aspirations while being aligned with climate aspirations and providing resilient supply chains less susceptible to global shocks.

5.5.3. Technological innovation

The hydrogen economy development is a powerful driver of technological innovation in several fields. Improvements in water electrolysis technologies like proton exchange membrane (PEM), alkaline, and solid oxide electrolysers are making green hydrogen production more efficient and cheaper [9]. Fuel cell innovations are improving performance, durability, and scalability in industries ranging from transportation to backup power systems [77,101]. At the same time, hydrogen storage in compressed, liquid, or solid-state research is

addressing basic concerns of safety, energy density, and infrastructure compatibility. Progress is also being achieved in hydrogen pipelines, refuelling infrastructure, and smart grid integration. As these technological developments form the foundation of hydrogen's viability, they also create spill over benefits for other clean technologies. R&D funding, pilot programmes, and scale-up initiatives are key to unlocking these innovations. Lastly, the hydrogen economy can serve as a hub for high-impact research and entrepreneurship, fostering a continuous cycle of improvement and technological leadership.

5.6. The role of AI in hydrogen route optimisation

AI is developing as an essential enabler of hydrogen supply chain optimisation. In contrast to traditional stochastic optimisation models, AI methods such as reinforcement learning, physics-informed neural networks, and multi-objective genetic algorithms can manage inherent uncertainties of renewable-based hydrogen systems [102]. AI is ideally suited for the purpose of hydrogen because of its capability to make real-time routing, storage scheduling and reconversion dynamic decisions, and as such provide flexible integration of into complex industrial ecosystems.

There are already practical applications from existing demonstration projects. An application of AI is embedded in the Japan–Australia LH_2 corridor for shipping and port logistics, and the EU's H_2Haul uses AI-enabled planning for hydrogen trucking and refuelling. At the microgrid level, predictive AI models have been used to synchronise delivery of hydrogen storage to the predicted forecasts of wind and solar generation, enhancing resilience, and to manage the cost of imbalance [8].

All of these examples show that AI should not be viewed as simply a complementary tool but rather as a cross-cutting enabler that advances the techno-policy readiness of hydrogen carriers. Integrating digital optimisation into the planning of infrastructure and governance, will contribute to more cost effective, flexible, and resilient hydrogen delivery pathways for policymakers and industry actors [103].

6. Conclusion and recommendations

Hydrogen is a viable clean energy carrier for decarbonizing industrial processes [60]. Optimisation of the hydrogen carrier route needs an overarching techno-policy framework that deals with technical challenges, encourages the development of infrastructure, and sets enabling policy mechanisms. From the industrial application analysis, evaluation of hydrogen carrier alternatives, and deployment of mitigation alternatives, the smooth integration of hydrogen into industrial systems can be ensured [104].

The followings are recommendations geared towards facilitating the hydrogen economy and getting us to a low-carbon future for governments, business, and scientists [105]. Through commitment to planning, policymaking, and innovation, the true potential of hydrogen can be maximised and contribute to global decarbonisation [106]. (1) Fund R&D to reduce the cost of low-carbon hydrogen production and develop the infrastructure required. (2) Develop national hydrogen plan with clear goals, policies, and overall national strategy. (3) Create carbon pricing systems that would reward firms for cutting their greenhouse gas emissions. (4) Encourage the development and marketing of hydrogen technologies by offering fiscal and other incentives to the industries. (5) Adopt strict regulations and standards on hydrogen production, transportation, and storage. (6) Encourage international cooperation to speed the development and availability of hydrogen technologies. (7) Engage the public and incorporate safety and environmental concerns into the decision-making process. (8) Invest in training the workforce to prepare them to work in the hydrogen sector. (9) Keep hydrogen projects from harming poorer societies by considering their effects on them. Those political and entrepreneurial leaders who adhere to such principles can assist the transformation of the industrial economy to hydrogen, the cleaner and more sustainable alternative.

Future research should focus on: Achieving maximum efficiency and lowering the cost of green hydrogen production via advanced electrolysis and photoelectrochemical water splitting [96]. Uncovering new hydrogen storage materials such as metal-organic frameworks (MOFs) and nanomaterials to increase energy density and lower storage cost [107]. Examining the possibility of reuse of the current natural gas pipelines for hydrogen transmission and the creation of new pipeline materials that are hydrogen compatible [108]. Carrying out detailed life cycle analysis of various hydrogen carrier pathways to analyze their environmental effects and determine the areas that need improvement [56]. Examining the socio-economic impacts of the hydrogen economy, such as job creation, economic growth, and distributional implications [1]. Additionally, the integration of AI-based predictive optimisation models, such as those demonstrated in recent research on energy system scheduling and hydrogen carrier logistics, holds promise for enabling data-driven planning of route design, storage dispatch, and demand alignment in industrial hydrogen systems, thereby supporting more cost-effective and scalable deployment.

CRediT authorship contribution statement

Somtochukwu Godfrey Nnabuife: Writing – review & editing, Writing – original draft, Visualization, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Jinyan Yang:** Writing – review & editing, Writing – original draft, Visualization, Formal analysis, Data curation. **Boyu Kuang:** Writing – review & editing, Supervision, Project administration, Funding acquisition. **Eunice Ngozi Akpala-Okoroafor:** Writing – review & editing, Supervision, Conceptualization. **Peter Azikiwe Onwualu:** Writing – review & editing, Visualization, Supervision, Resources, Conceptualization.

Data availability statement

The authors declare that the data supporting the findings of this study are available within the article.

AI tools usage declaration

The authors used OpenAI's ChatGPT (version GPT-4o) solely for improving the clarity and grammar of the manuscript text. All content was carefully reviewed and approved by the authors to ensure accuracy and integrity.

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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Optimising hydrogen carrier pathways for industrial decarbonisation: a techno-policy framework for readiness in infrastructure and governance

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