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H2ignite

Transport sector value chain mapping and segmentation of transport operators

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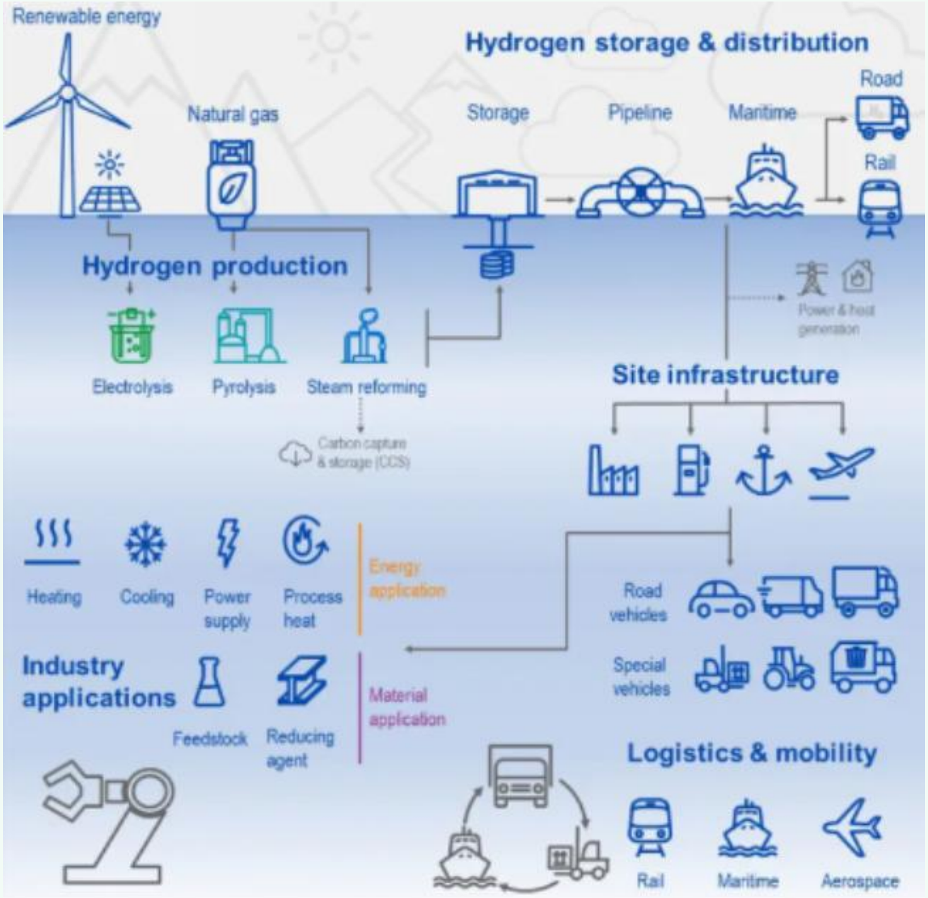
1 Introduction

The hydrogen value chain is traditionally divided into four areas: production, storage, distribution and consumption.



https://www.tuvsud.com/fr-fr/themes/hydrogene/explorez-la-chaine-de-valeur-de-l-hydrogene-

A few important points must be clarified before diving into the hydrogen value chain, from production to end-use. The "H2 Ignite" Interreg project seeks to contribute to the creation of a favorable climate for the **introduction of low-carbon and renewable hydrogen solutions in the transportation industry especially in the heavy-duty transport sector.**

Other hydrogen production pathways, such as those based on **decarbonized electricity** like nuclear or biomass through processes like pyrogasification, should also be examined in order to **completely comprehend how this value chain functions and what is at stake**.

Every production method has pros and cons, both when compared to other clean mobility technologies like batteries and when comparing hydrogen to itself using various production techniques. These variations are evident in production costs, carbon intensity, and infrastructure needs, which differ greatly based on the process and source.

Although low-carbon and renewable hydrogen will be the primary focus of this report, we will also occasionally make reference to "grey" hydrogen, **to give current production volumes and costs as a point of comparison** rather than as a solution for Europe's energy transition.

By considering these factors, we can gain a better understanding of how hydrogen can actually be **incorporated into a larger clean energy mix**, where it can enhance rather than replace other technologies. A “one-size-fits-all" solution is **unlikely** at the European level due to the wide variations in local contexts and resources.

Illustration: generic benefits and challenges of green hydrogen (Gorji, 2023)

Benefits	Challenges
Reduced emissions versus blue/grey hydrogen	Higher production costs versus blue/grey hydrogen
Energy carrier versatility	Intermittent renewables
Storable and transportable	Storage and transport issues
Sustainability contribution	Developing infrastructure
Grid peak shaving	Efficiency losses
Electrolyser advancements	Electrolyser life-cycle
More energy-dense	Less efficient than batteries
Long-range vehicle suitability	Longer refuel time than petrol

2 Key Challenge for Hydrogen production

Today, the world's hydrogen production **is largely dominated by grey hydrogen**, which is made from natural gas through a process called steam methane reforming (SMR will be used in the following paper), and it doesn't include carbon capture.

This type of hydrogen makes up **about 94% of the global output**. While it's relatively cheap at $1-2 per kilogram, it comes with a significant carbon footprint, releasing around 9–12 kg of CO_2 for every kilogram of hydrogen produced: this adds up to roughly 830 million tonnes of CO_2 each year (more than two years of CO2 emissions of France). On the other hand, blue hydrogen is produced with carbon capture and storage (CCS), which helps to lower the carbon emissions to between 1.5 and 6 kg of CO_2 per kg of hydrogen, depending on how effective the capture process is. However, **it still relies on fossil fuels and the long-term sustainability of CO_2 storage sites is a concern**.

Alternatively, green hydrogen, is made through electrolysis powered by renewable energy sources. Right now, **it only accounts for about 0.04–0.1% of global hydrogen production, and its costs are still pretty high, ranging from 3,5€ to 6.5€ per kilogram (**Hydrogen Europe, 2024), (Clerici & Furfari, 2021). It has the greatest potential for reducing carbon emissions, **with almost no direct emissions.** This situation has significant implications for hydrogen mobility: fuel cell electric vehicles (FCEVs) including everything from heavy-duty trucks and trains to inland vessels and buses can only provide meaningful climate benefits if the hydrogen they use comes from low-carbon sources.

A truck powered by grey hydrogen could have a life-cycle carbon footprint that's similar to, or even worse than, that of a modern diesel vehicle (IEA, 2022). So, the challenge we face is twofold: we need to quickly ramp up the production of low-carbon hydrogen and also adapt our infrastructure so that those in the mobility sector can easily access renewable or low-carbon hydrogen (chicken and egg challenge largely underlined in our project). The hydrogen value chain in transportation must be built with this in mind from the very beginning.

3 Hydrogen production from Renewable Energy

To ensure green hydrogen production and therefore use, **renewable energy integration is a necessity**. The following sources are the way how H2 can be called « green ».

3.1. Solar Energy

Solar energy plays a pivotal role in the green hydrogen ecosystem, providing renewable electricity to power electrolysers. With diverse photovoltaic (PV) technologies and deployment configurations, solar energy offers **flexibility and scalability for hydrogen production**. This section explores the integration of solar energy into the hydrogen value chain, focusing on its technical aspects, economic implications, and role in decarbonization.

3.2. Photovoltaic (PV) Systems

PV systems convert sunlight directly into electricity, **which can power electrolyzers to produce hydrogen**. Two primary types of solar PV technologies dominate the market:

1. **Polycrystalline PV Panels:**

- Constructed from multiple silicon crystals, polycrystalline panels are cost-effective but less efficient than their monocrystalline counterparts, with efficiency rates ranging from 14% to 18% (IRENA, 2021).
- Best suited for utility-scale projects in areas with abundant land and moderate solar irradiance.

2. **Monocrystalline PV Panels:**

- Made from a single silicon crystal, these panels offer higher efficiency (19% to 22%) and are ideal for space-constrained projects (Fraunhofer ISE, 2023).
- Widely used in both rooftop installations and high-performance solar farms.
- Their price used to be higher that the polycrystalline technology: it is now most of the time counter-balanced by its higher efficiency.

Emerging PV technologies, **such as thin-film and tandem cells**, are also gaining traction. Thin-film PVs, made from materials like cadmium telluride (CdTe) or perovskites, offer flexibility and lower material costs but require further R&D to improve efficiency and durability (IEA, 2023).

3.3. Concentrated Solar Power (CSP)

CSP systems **focus sunlight using mirrors or lenses to generate heat**, which can then be used to produce electricity or directly drive high-temperature hydrogen production methods like thermochemical cycles. CSP is particularly suited for regions with high direct solar radiation, such as deserts.

Integration into the Hydrogen Value Chain
Solar energy integrates into the hydrogen value chain primarily through electricity generation, but **innovative configurations are expanding its role**.

On-Site Solar-to-Hydrogen Systems

- Small-Scale Installations: rooftop PV systems powering electrolyzers are used for decentralized hydrogen production in remote areas. These systems are ideal for local use cases, such as refueling stations or backup power.
- Utility-Scale Solar Farms: large solar farms connected to centralized electrolyzers are used to produce green hydrogen for industrial hubs or export. Projects like the Neom Green Hydrogen Project in Saudi Arabia demonstrate the scalability of solar-driven hydrogen systems (Neom, 2023[1]).

Solar-Hydrogen Hubs
In regions with abundant solar resources, such as Australia, North Africa, and the Middle East, solar energy is integral to hydrogen hubs. These hubs combine massive PV arrays, grid infrastructure, and hydrogen storage and distribution facilities to supply global markets.

Hybrid Systems
Solar energy is often paired with other renewable sources, such as wind, to balance intermittency. Hybrid systems improve the efficiency of hydrogen production and reduce reliance on battery storage.

3.4. Wind turbines and Hydrogen

Wind energy, both onshore and offshore, plays a critical role in the production of green hydrogen. By converting wind power into electricity that drives electrolyzers, hydrogen can be generated sustainably without carbon emissions. With rapid advancements in turbine technology and declining costs, wind-based hydrogen production is emerging as a cornerstone of the renewable hydrogen economy.

Integration into the Hydrogen Value Chain
Wind energy integrates into the hydrogen value chain primarily through electricity generation for electrolysis. Its variability is increasingly mitigated through hybrid systems and grid interconnections, enabling stable and continuous hydrogen production.

[1] https://nghc.com/news/worlds-largest-green-hydrogen-plant-reaches-80-construction-completion-across-all-sites/

On-Site Wind-to-Hydrogen Systems

- Small-Scale Installations: Local wind turbines powering electrolyzers provide decentralized hydrogen production for rural or island communities. These systems are particularly valuable in areas with limited grid access, supplying hydrogen directly for local use cases such as hydrogen refueling stations (HRS) or backup power
- Utility-Scale and Offshore Installations: Large-scale offshore wind farms are increasingly linked to centralized electrolyzers for gigawatt-scale hydrogen production. Located near coastlines, these projects reduce transmission losses and leverage higher, steadier wind speeds. Flagship developments in the North Sea and along European coastlines demonstrate the scalability of offshore wind-to-hydrogen systems (IEA, 2023).

Wind-Hydrogen Hubs

Regions with abundant wind resources, such as Northern Europe, the North Sea basin, and parts of North America, are developing integrated wind-hydrogen hubs. These hubs combine extensive wind farms, transmission networks, and hydrogen storage and distribution facilities to serve industrial clusters and export markets.

3.5. Hydropower (IPCC, 2022)

Hydropower is one of the most established renewable electricity sources, providing around 16% of global electricity and over 40% of renewable generation. Its high efficiency near 85% and ability to deliver both continuous baseload and flexible peak power make it a valuable partner to intermittent sources such as wind and solar. Through pumped storage, hydropower can also act as **large-scale energy storage**, supporting grid stability and enabling more renewable hydrogen production.

Economically, hydropower remains one of the **lowest-cost electricity options over its 40 – 80 year lifetime**, with relatively low operation and maintenance costs. However, construction costs are highly site-specific and can be significant, especially in remote areas.

The main challenges lie in its environmental and social impacts. Large dams can fragment ecosystems, disrupt sediment flows, and alter water quality. Flooded reservoirs may also emit greenhouse gases.

In the green hydrogen economy, **hydroelectric dams primarily serve as a cornerstone for grid balancing and flexibility**, providing dispatchable, low-carbon electricity that compensates for the intermittency of solar and wind generation. Their main role remains ensuring grid stability and security of supply, which limits the share of hydro output that can be dedicated to large-scale electrolysis. Diverting significant hydroelectric capacity to hydrogen production could reduce the sector's ability to buffer variability and support renewable integration.

For the tidal energy, **it offers a predictable and dispatchable renewable electricity** (since tides follow precise lunar cycles), which makes it valuable for stabilising the grid and supporting integration of variable renewables like wind and solar. However, global installed tidal capacity is still very limited: less than 0.5 GW as of 2023. His contribution to large-scale hydrogen production is constrained more by scale and economics than by technical compatibility.

In the hydrogen value chain, tidal energy would realistically play an opportunistic and complementary role, powering electrolysers during periods when grid demand is low and tidal output is high, without undermining its primary function in grid balancing.

Production method	Energy Input	Carbon Footprint (kgCO2e/kg H2)	Hydrogen color/RFNBO	Estimated Energy Efficiency (%LHV)
Solar PV (poly/mono)	Electricity from photovoltaic panels (14–22% efficiency)	2,5 kg CO_2e / kg H_2 (Stucki, 2024)	Green/ RFNBO if the PV is post 2020	55–65% (electrolysis) × 14–22% (PV) → ~8–14% overall (Fraunhofer ISE (Dr.Simon Philipps), 2025)
Onshore Wind	Electricity from onshore wind turbines (25–35% capacity factor EU average, 30-45% for new ones)	0,5 kg CO_2e / kg H_2 (UNECE, 2021)	Green/RFNBO If new capacity and within same bidding zone	55–65% (electrolysis) × higher output → overall ~30–35% (Wind Europe, 2024)
Offshore Wind	Electricity from offshore wind farms (40–50% capacity factor)	0,75 kg CO_2e / kg H_2 (higher CF than Onshore)	Green/RFNBO	55–65% (electrolysis) × higher output → ~30–35% (Wind Europe, 2024)
Hybrid Solar-Wind	Combined solar PV + wind to stabilize electrolyser operation	Depends on the mix (level of hybridation): more solar = higher footprint	Green/ RFNBO If both assets are new and geographically/temporally matched	Improved electrolyser utilization up to 70–80%, not many results to share (e.g. Neom Green hydrogen project)

Synthesis of the different production methods of renewable energy for green Hydrogen – Author of this table: Pôlénergie

4 Low carbon Hydrogen production

As an alternative for renewable electricity, and as carbon intensity remains a key topic, we have been exploring other potential sources of decarbonized electricity for Hydrogen production.

4.1. Nuclear Power

Nuclear power is a low-carbon and dispatchable source of electricity. It is an excellent strategic complement to intermittent renewables for producing low carbon hydrogen. Nuclear's place in hydrogen value chains could involve different technology readiness levels and national approaches. Its role is often under-represented in public discourse, but as nuclear gains traction in programs and policy and R&D across Europe and other regions, it will become more prominent.

There are two main pathways for producing hydrogen from nuclear energy:

Electrolysis Powered by Nuclear Electricity
The most established method for producing hydrogen with nuclear power involves **using electricity from reactors to run water electrolyzers**. This process offers several advantages:

- Stable production: nuclear power provides continuous baseload electricity, enabling consistent hydrogen output without depending on weather.
- High efficiency: nuclear plants operate at load factors above 90%, improving the performance and utilization of electrolyzers compared to solar or wind systems.
- Low emissions: 0,4 kg CO_2 / kg H_2 (EVOLEN, 2024)

High-Temperature Electrolysis and Thermochemical Cycles
Emerging reactor technologies, such as Very High Temperature Reactors (VHTRs), offer new ways to improve hydrogen production efficiency by using both heat and electricity:

- High-Temperature Electrolysis (HTE): Solid oxide electrolyzer cells (SOECs) operating at 700–900°C can reach efficiencies of up to 80% (US Departement of Energy, 2020)
- Thermochemical cycles: Innovative processes like the sulfur–iodine (S–I) or copper–chlorine (Cu–Cl) cycles use nuclear heat to split water without relying on traditional electrolysis.

These advanced pathways are still at the research or pilot stage, with first demonstrations expected after 2030. They are supported by international efforts such as Euratom and IAEA collaborations.

Production method	Energy Input	Carbon Footprint (kgCO2e/kgH2)	Hydrogen color/Rfnbo	Estimated Energy Efficiency (% LHV)
Electrolysis powered by nuclear electricity	Nuclear-generated electricity	~0,4 (Gan, Ng, Elgowainy, & Marcinkoski, 2024)	Purple/ Not RFNBO	60–65% (alkaline or PEM electrolysis)
High-Temperature Electrolysis (SOEC)	Nuclear heat + electricity (700–900°C)	<0.4 (depending on electricity mix, nuclear-only assumed very low)	Purple/ Not RFNBO	Up to 80% (90% in laboratory) (IAEA Nuclear Energy Series, 2013)
Thermochemical Cycles	Nuclear heat (>800°C)	Near-zero (no fossil input, only process emissions)	Purple/ Not RFNBO	40–55% projected (pilot stage) (IAEA, 2024)

Synthesis of the different production methods of H2 with nuclear power source – Author of this table: Pôlénergie

<u>Integration into the Hydrogen Value Chain</u>

More than ever, nuclear energy is being seen as more than just a provider of baseload electricity. Similar to other low-carbon technologies, nuclear involves high capital cost upfront, but, in return, provides stable and predictable output; ideal for continuous hydrogen production, particularly when compared to variable outputs from wind or solar technologies.

Nuclear-derived hydrogen could compete directly with natural gas-based hydrogen since the nuclear-derived hydrogen's price would not be subject to the volatility component of fuel prices. While uranium represents a small fraction of the total cost in nuclear generation, it is also much more readily available. Uranium does not have as much exposure to market shocks as fossil fuels.

Next generation reactors are looking to reduce costs further, and improve efficiency; but this requires considerable R&D. The prospects of this R&D are only feasible in a world where hydrogen is a large-scale phenomenon.

4.2. White H2

Natural hydrogen, often called “white,” “geologic” or “gold” hydrogen is a molecular H_2 found underground, generated via geological processes such as serpentinization or radiolysis rather than produced industrially. (Owain, et al., 2024)

While its existence has long been suspected, only one site is currently under exploitation: Bourakébougou in Mali. There, a water well drilled in 1987 unexpectedly tapped a nearly pure hydrogen reservoir (98 % H_2), supplying electricity for a village via hydrogen-powered turbines. Geochemical studies confirm that the subsurface dolomitic karst formations enable sustained **hydrogen recharge and trapping (**Maiga, s.d.)

Recently, this discovery has inspired a global surge in exploration: Rystad Energy notes that the number of companies pursuing natural hydrogen rose from 10 in 2020 to around 40 by 2023, with research about H2 mines like in Australia (Gold Hydrogen) or in Europe. If we take France, the resource has been officially recognized in mining law since 2022, with multiple exploration permits issued across regions such as Lorraine, the Pyrenees, and Hauts-de-France. Specifically in Lorraine, FDE (Française de l’Énergie) has confirmed hydrogen concentrations of 15 % at 1,093m depth, and up to 98 % at 3,000m, with a permit already sought for pilot exploitation.

Natural hydrogen extraction remains at an early exploration stage, typically around TRL (Technology Readiness Level) 3 to 4. Only Mali’s site is operational, and all other projects await proof of commercially viable reservoirs. Rystad cites preliminary production costs as low as $0.5 per kg, positioning white hydrogen as more affordable than green or grey hydrogen, but this remains speculative without scale-up (Rystad Energy).

Challenges persist in locating sealed reservoirs, ensuring resource sustainability, and developing extraction, storage, and distribution infrastructures – which could eventually raise H2 price.

Summary table of the different modes of H2 production (RTE, 2024) and other sources (in the table)

Production method	Energy Input	Carbon Footprint (kgCO2e/kgH2)	Hydrogen color	Estimated Energy Efficiency (% LHV)
Electrolysis (grid electricity)	Grid electricity	Highly variable: from 1 to +30 depending on carbon intensity of the grid In France, it's 2,8	Yellow	60–70% (IPCC, 2022) Electrical-to-chemical conversion; losses as heat. Efficiency depends on electrolyzer type (PEM, alkaline, SOEC).
Electrolysis (renewable electricity)	Wind, solar	1,6 (ADEME, 2021)	Green	60-70% (IPCC, 2022) Better efficiency possible with high-temperature heat from reactors
Steam Methane reforming (SMR)	Natural Gaz or Biomethane	11.1 from natural gas 2,13 from biomethane[2]	Green if from biomethane, grey if natural gas	65% Losses due to high-temperature steam generation and reaction inefficiencies. CO_2 emissions are high
Steam Methane reforming + CCU (SMR) (IPCC, 2022)	Natural Gaz or Biomethane	1.0 to 3.6	Blue if natural gas, green if biomethane	70–75% Efficiency (losses due to both high-temperature steam generation/reaction inefficiencies and additional energy demand for CO_2 capture and compression). CO_2 emissions reduced by 85–95% compared to grey SMR, but residual emissions remain from incomplete capture and upstream methane leakage.
Methane Pyrolysis (EVOLEN, 2024)	Natural gas	1 to 3	Turquoise	60% Energy needed to break CH_4 bonds; solid carbon must be managed
Methane Pyrolysis (EVOLEN, 2024)	Biomethane	Near to 1	Green	60% Energy needed to break CH_4 bonds; solid carbon must be managed
Pyrogasification (Bioenergy, 2025) & (IPCC, 2022)	Biomass, Waste	Between 0 and 1	Green	40-60% Depends on feedstock quality
Natural Hydrogen	Naturaly occuring underground	Very low	White	Close to 100%

Author of this table: Pôlénergie

[2] From "base carbone", datasheet with every footprint https://data.ademe.fr/datasets/base-carboner

As a conclusion, every energy source typically has benefits, but also tradeoffs.

- Wind and solar power are low-carbon but intermittent
- Coal can provide cheap-energy but is the most polluting
- Nuclear can provide reliability-type benefit and low-carbon emissions but could raise all sorts of waste and safety questions.

As any future decarbonized economy will be using all the options available to build a strong resilient hydrogen ecosystem (IAEA Nuclear Energy Series, 2013). White hydrogen could also become a true "game changer". Concrete exploitation remains uncertain (technical feasibility to confirm).

5 European electricity production and H2 production perspective

This part will focus on current and future status of electricity production in Europe as well as its consequences for H2 production.

Some key points (Ember Energy, 2024)**:**

In 2023, the European electricity system continued its transformation toward a low-carbon energy mix, driven by policy targets and market incentives. Renewables now contribute to **over two-thirds of total electricity generation**, reflecting a structural shift away from fossil fuels, which accounted for roughly 33% of output, down from nearly 39% in 2022.

Variable renewable energy sources, particularly wind and solar, experienced strong growth in 2023. Solar installations expanded rapidly, increasing the share of solar generation and reducing reliance on fossil fuels. Wind energy also maintained significant output, supported by both onshore and offshore projects. However, **the intermittent nature of these sources introduces challenges for grid stability**, underlining the need for energy storage, demand-side management, and cross-border interconnections.

Electricity demand in the EU declined slightly by 3.4% compared with 2022, driven by **improved energy efficiency and shifts in industrial activity**, as well as responses to high electricity prices. While this decrease helped reduce CO_2 emissions, rising electrification in transport, heating, and industry is expected **to increase overall electricity consumption in the coming decade**. Meeting this growing demand sustainably will require continued investment in renewable capacity and flexible grid solutions. For instance, up to 100 billion Euros for France only by 2040 – a country which infrastructure is considered as rather strong in Europe. Europe estimates that more than 1 000 billion Euros will be necessary for the whole continent[3].

[3] https://energy.ec.europa.eu/news/eu-guidance-ensuring-electricity-grids-are-fit-future-

These trends have important implications for green hydrogen production. Electrolysers depend on low-carbon electricity, and the expanding share of renewables improves the potential for low-emission hydrogen. Yet, variability in solar and wind generation may limit electrolyser capacity factors, making operational flexibility, storage solutions, and grid integration key to ensuring reliable hydrogen production.

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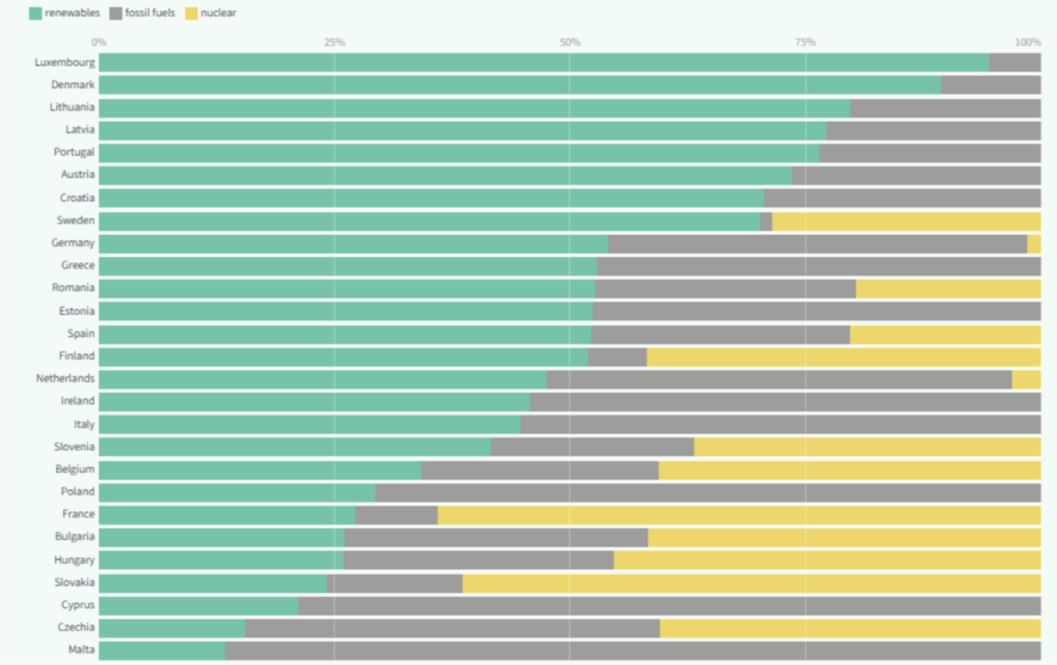
Overall, the EU electricity system is transitioning rapidly, with renewables now forming the majority of generation.

Electricity mix in EU countries (2023)



Source: (European Council)

Net electricity Generation in the EU by fuel type (2023)[4]

[4] Data and text from https://www.consilium.europa.eu/en/infographics/how-is-eu-electricity-produced-and-sold/#0

In 2023 in Europe, 45.4% of electricity was generated from renewable energy sources, 31.7% from fossil fuels and 22.8% from nuclear power.

Fossil fuels in detail:

- Gas: 17%
- Coal: 11.7%
- Oil: 1.4%
- Other: 1.6%

Renewables in detail:

- Wind: 18.5%
- Hydro: 13.5%
- Solar: 9.1%
- Biomass: 4.1%
- Geothermal: 0.2%

Electricity in the EU **is getting greener every year**. The share of renewables in electricity generation has more than doubled since 2004. It will continue to grow in the coming years as the EU has committed to become climate neutral by 2050.

In-depth installed capacity from renewable energy[5] on European Union (27 countries) in 2023:

- Hydro energy: 153,179 GWh
- Wind Onshore: 199,861 GWh
- Wind Offshore: 18,994 GWh
- Solar: 246,072 GWh

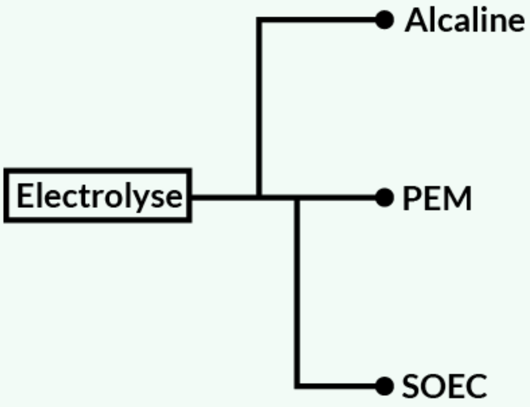
[5] Data from https://ec.europa.eu/eurostat/databrowser/view/nrg_inf_epcrw__custom_17726107/default/table

6 Hydrogen production

Now that we have developed the electricity production part of the value chain, let us focus on the hydrogen production technologies.

6.1. Electrolysis

There are currently three different technologies for producing hydrogen by water electrolysis, grouped in the following graph:



6.1.1. Alkaline electrolysis

$$H_2O \rightarrow H_2 + \frac{1}{2}\,O_2$$

Alkaline electrolysis technology is the **oldest and most mature of the electrolysis technologies.** In a bath of ultrapure water, electrodes, often based on nickel or cobalt, are placed before passing an electric current between them.

The formula illustrates what happens during water electrolysis.

By using electricity, we can split water into hydrogen and oxygen. The hydrogen can then be stored and used as a clean energy source, while oxygen is released as a harmless by-product."

Technology	Operating Temperature	Strengths	Weaknesses	TRL
Alkaline Electrolysis (C, A, T, & Larrazábal)	60-80°C	Mature, cost effective, scalable	Lower efficiency	9

It's reliable and cost-effective for large-scale hydrogen production, more adapted for steady renewable electricity sources.

6.1.2. Proton Exchange Membrane electrolysis

Short for Proton Exchange Membrane electrolysis, this technology uses a liquid solution: the system relies on a special solid membrane made of a high-tech plastic material (like Nafion®). This membrane is both strong and flexible and allows only positively charged particles (protons) to pass through. To make this happen, the setup uses electrodes made of rare and highly durable metals like platinum, iridium, or ruthenium, since the process operates in an acidic environment.

In short, it's a cutting-edge, efficient way to split water into hydrogen and oxygen, perfect for applications needing high-performance hydrogen production.

Technology	Operating Temperature	Strengths	Weaknesses	TRL
PEM Electrolysis (Carmo, Fritz, Mergel, & Stolten)	50-80°C	High efficiency, fast response, compact	Expensive catalysts, sensitive to impurities	7

It's a high-performance option for applications needing rapid hydrogen production, ideal for integrating with variable renewables.

6.1.3. Solid Oxide Electrolysis Cell electrolysis

SOEC is the most recent type of electrolysis and still in the research and development phase. It consists of using high-temperature heat, generally between 400 and 1000 ° C, in addition to the use of electricity to produce hydrogen. The high temperature makes it possible to operate with nickel catalysts, and to obtain better efficiency.

Technology	Operating Temperature	Strengths	Weaknesses	TRL
SOEC (Solid Oxide Electrolysis Cell) (Younus, et al., 2025)	High temperature (400–1000°C), uses nickel catalysts	High efficiency due to heat input, can use waste heat, lower electricity consumption	High-temperature operation requires advanced materials, less mature technology	5

It's promising for industrial-scale hydrogen production with integrated heat but still under development.

6.1.4. Anion Exchange Membrane (AEM) Electrolysis

This technology uses a solid polymer membrane that conducts negatively-charged hydroxide ions (OH^-) rather than protons. The system operates in a mild alkaline environment (or neutral/slightly alkaline) and avoids the high-cost platinum-group metal catalysts typical of PEM electrolysis systems. Instead, electrodes can rely on more abundant metals like nickel, cobalt or iron in an alkaline medium.

In short, it's a promising intermediate technology combining cost-advantages of alkaline electrolysis with the compactness and dynamic response of PEM electrolysis.

Technology	Operating Temperature	Strengths	Weaknesses	TRL
Anion Exchange Membrane (AEM) Electrolysis (Lu, Hongyang, Madani, & Benjamin, 2024)	~30-80 °C (commonly 30-60 °C in current research) (Polymers Basel, 2023)	Lower catalyst cost (non-PGM), possibility of high purity H2 uses alkaline environment allowing cheaper materials	Still limited long-term durability, lower development maturity, ion-conductivity and membrane stability challenges	5

6.2. Methane Pyrolysis

Methane pyrolysis is an emerging technology for producing hydrogen without carbon dioxide (CO_2) emissions. In this process, methane (CH_4) is thermally decomposed at high temperatures, typically between 800°C and 1200°C in the absence of oxygen. This endothermic reaction yields hydrogen gas (H_2) and solid carbon (C), as represented by the equation: $CH_4 \rightarrow C + 2H_2$.

Unlike conventional methods such as steam methane reforming (SMR), which release CO_2 as a byproduct, methane pyrolysis produces gases during hydrogen production. The solid carbon produced can be utilized in various industries, including manufacturing, construction, and electronics, or sequestered to mitigate environmental impact. (INERATEC, s.d.)

Integration into the Hydrogen Value Chain
Methane pyrolysis holds a complementary role within the broader European hydrogen value chain. Its high efficiency, absence of direct CO_2 emissions, and independence from carbon capture infrastructure make it particularly suited for:

- Mid-scale distributed hydrogen production near industrial demand clusters
- Hard-to-decarbonise sectors such as ammonia, fertilisers, and high-temperature industrial processes
- Areas with limited geological capacity for CO_2 storage or where public acceptance of CCS infrastructure is low

Importantly, **methane pyrolysis does not compete with renewable-based electrolysis but** rather complements it within a diversified hydrogen ecosystem. Electrolysis remains the most important way to produce in a fully renewable hydrogen strategy, particularly in synergy with variable wind and solar production. Pyrolysis, in contrast, offers a dispatchable, electrically efficient, and low-emission alternative **where biomethane is available** or where rapid scaling is required without waiting for extensive renewable overcapacity.

Technology	Operating Temperature	Strengths	Weaknesses	TRL
Methane Pyrolysis (Sánchez-Bastardo, Schlögl, & Ruland, 2020)	High temperature (800–1200°C), methane feed, no oxygen	Produces hydrogen without CO_2 emissions, solid carbon by-product, scalable	Requires high temperature, electricity or heat source needed, still emerging	5-6[6]

Complementary to electrolysis, suitable for distributed or hard-to-decarbonize sectors, benefit from a rapid deployment possible without CO_2 capture.

[6] https://pubs.rsc.org/en/content/articlehtml/2025/ee/d4ee06191h ==> Some sources can talk about a 8 or 9 TRL for technologies like cold plasma methane pyrolysis

Summary table of the most mature H2 production technologies

Technology	Operating Temperature	Strengths	Weaknesses	TRL
Alkaline Electrolysis (C, A, T, & Larrazábal)	60-80°C	Mature, cost effective, scalable	Lower efficiency	9
PEM Electrolysis (Carmo, Fritz, Mergel, & Stolten)	50-80°C	High efficiency, fast response, compact	Expensive catalysts, sensitive to impurities	7
SOEC (Solid Oxide Electrolysis Cell) (Younus, et al., 2025)	High temperature (400–1000°C), uses nickel catalysts	High efficiency due to heat input, can use waste heat, lower electricity consumption	High-temperature operation requires advanced materials, less mature technology	5
Anion Exchange Membrane (AEM) Electrolysis (Lu, Hongyang, Madani, & Benjamin, 2024)	~30-80 °C (commonly 30-60 °C in current research) (Polymers Basel, 2023)	Lower catalyst cost (non-PGM), possibility of high purity H2 uses alkaline environment allowing cheaper materials	Still limited long-term durability, lower development maturity, ion-conductivity and membrane stability challenges	5
Methane Pyrolysis (Sánchez-Bastardo, Schlögl, & Ruland, 2020)	High temperature (800–1200°C), methane feed, no oxygen	Produces hydrogen without CO_2 emissions, solid carbon by-product, scalable	Requires high temperature, electricity or heat source needed, still emerging	5-6[7]

Author of this table: Pôlénergie

[7] https://pubs.rsc.org/en/content/articlehtml/2025/ee/d4ee06191h ==> Some sources can talk about a 8 or 9 TRL for technologies like cold plasma methane pyrolysis

6.3. Prospective

Photolysis
Photolysis (or photocatalysis) refers to the splitting of water into hydrogen and oxygen using light energy and photocatalysts, without electrodes or an external current. Chemical reactions are triggered by photon absorption, which initiates water molecule separation. Current laboratory efficiencies remain modest: around 5% for low-cost metallic systems and up to 14% for advanced III–V semiconductor photocatalysts.

The carbon footprint is highly favourable: production is virtually zero-emission if durable materials are used and the process relies entirely on solar energy. Future production prospects are promising, particularly for decentralized applications in under-equipped regions, but technological maturity remains low, with a Technology Readiness Level (TRL) of about 4–5.

Technology	Current TRL	Future production potential	Operational carbon footprint	Promising?
Photolysis	4-5	Decentralised, modular, suitable for remote areas	Near-zero	★ ★

Photoelectrolysis

Photoelectrolysis combines photovoltaic semiconductors and electrolysis in a single cell, enabling direct solar-to-hydrogen conversion. Recent performance data shows solar-to-hydrogen (STH) efficiencies in the range of 8–14%, with a theoretical maximum of 42%. Pilot "lab-to-field" systems currently reach TRLs of 5–6[8]. In terms of carbon impact, operational emissions are almost zero (direct solar electricity), but the embodied emissions from semiconductor manufacturing should be considered. This pathway is seen **as highly promising in the medium to long term,** especially if materials become more durable and cost-effective.

Technology	Current TRL	Future production potential	Operational carbon footprint	Promising?
Photoelectrolysis	5-6	Larger-scale production if costs drop & material durability improves	Very low (direct solar source)	★★★

[8] https://www.horizon-europe.gouv.fr/photoelectrochemical-pec-andor-photocatalytic-pc-production-hydrogen-34759

Radiolysis

Radiolysis uses ionizing radiation (gamma rays, neutrons) to split water molecules and produce hydrogen. Early experiments achieved modest yields, with capacities up to 10 tonnes per day, potentially six times higher with hydrogen atom donors. More recent estimates suggest that combining radiolysis with photocatalysis and nuclear waste heat **could theoretically meet up to 60% of the world's hydrogen demand** (~43 Mt/year) (Vandenborre, Guillonneau, Blain, Haddad, & Truche, 2024). The carbon footprint depends on the nuclear source; if nuclear is considered low-carbon, operational emissions are very low. However, **maturity remains low** (TRL 2–3), with most applications still in experimental nuclear settings.

Technology	Current TRL	Future production potential	Operational carbon footprint	Promising?
Radiolysis	2-3	Significant niche potential using nuclear waste heat	Low if nuclear source is low-carbon	★

Biochemical

Biochemical hydrogen production uses living **microorganisms to generate hydrogen through metabolic processes.** The two primary routes are dark fermentation and photofermentation. In dark fermentation, bacteria such as Clostridium convert carbohydrate-rich feedstocks (food waste, agricultural residues) into hydrogen, organic acids, and CO_2 under anaerobic conditions.

Photofermentation uses photosynthetic bacteria (Rhodobacter) and light to further convert organic acids into hydrogen, often as a second stage to improve overall yields. The carbon footprint is generally low, particularly when using waste biomass, and can be near-zero if powered by renewable heat and light sources. However, **production rates are modest** (typically <5 m^3 H_2/m^3·day in lab settings) and systems are sensitive to contamination and feedstock variability. Current TRL is 4–5 for integrated processes, with future potential focused on integration into wastewater treatment and biorefineries.

Technology	Current TRL	Future production potential	Operational carbon footprint	Promising?
Biochemical	4-5	Modest volumes, best for integration with waste-to-energy systems	Very low to negative (if waste feedstock offsets emissions)	★ ★

<u>Summary table of all the prospective technologies for H2 production</u>

Technology	Current TRL	Future production potential	Operational carbon footprint	Promising?
Photoelectrolysis	5-6	Larger-scale production if costs drop & material durability improves	Very low (direct solar source)	★★★
Photolysis	4-5	Decentralised, modular, suitable for remote areas	Near-zero	★★
Radiolysis	2-3	Significant niche potential using nuclear waste heat	Low if nuclear source is low-carbon	★★
Biochemical	4-5	Modest volumes, best for integration with waste-to-energy systems	Very low to negative (if waste feedstock offsets emissions)	★ ★

Author of this table: Pôlénergie

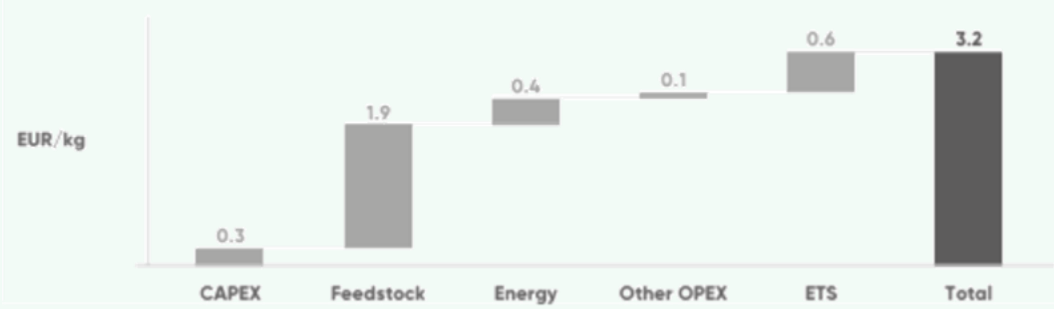
7 Hydrogen price

In this chapter, we will analyse what influences the price of Hydrogen as well as its overall price depending on the way it is produced.

Price determinants: case study from SMR and Electrolysis

SMR

Breakdown of the levelized cost of hydrogen production via SMR in the EU-27 in 2023



Source: (Hydrogen Europe, 2024)

Capital Expenditures (CAPEX)

CAPEX, or capital expenditures, refers to the initial investment needed to design, build, and get a steam methane reforming (SMR) facility up and running. This encompasses the reformer units, pressure swing adsorption (PSA) systems for purifying hydrogen, and all the necessary infrastructure like pipelines, storage, and utility connections. Even though CAPEX is spread out over the plant's operational life, **it can still make up about 10 - 20% of the final hydrogen price**, which varies based on the project's size and financing conditions. Generally, larger plants can achieve a lower specific CAPEX per unit of hydrogen produced, due to the benefits of economies of scale. However, retrofitting an SMR with carbon capture technology to produce blue hydrogen, CAPEX can **jump significantly often by 50 - 100% due to the added costs of capture**, compression, transport, and storage equipment. In 2023, CAPEX accounted for 10.6% of the total cost.

Feedstock

Feedstock is the term used for the natural gas that serves as the main input in SMR. It usually represents the largest single cost factor in grey hydrogen production, **making up about 45-75% of the final price**, depending on the conditions in the gas market. Since producing each kilogram of hydrogen requires around 3-4 Nm^3 of methane, fluctuations in natural gas prices, like those seen during the geopolitical tensions of 2022 – 2023, directly impact hydrogen production costs. For blue hydrogen, the same feedstock requirements apply, but the overall carbon footprint is lessened by capturing and storing CO_2 emissions. In 2023, feedstock **represented 59.3% of the total cost.**

Energy

When it comes to energy, SMR also needs external energy inputs, **primarily heat** for the reforming process and electricity for auxiliary systems like pumps and compressors. While some of the necessary heat is generated by burning a portion of the feedstock, additional energy purchases—especially electricity—add to operational costs. These costs can be affected by local electricity rates, the carbon intensity of the grid, and the efficiency of the plant. In some instances, electricity expenses are relatively minor compared to feedstock costs. In 2023, **energy represented 12.5% of the total cost**.

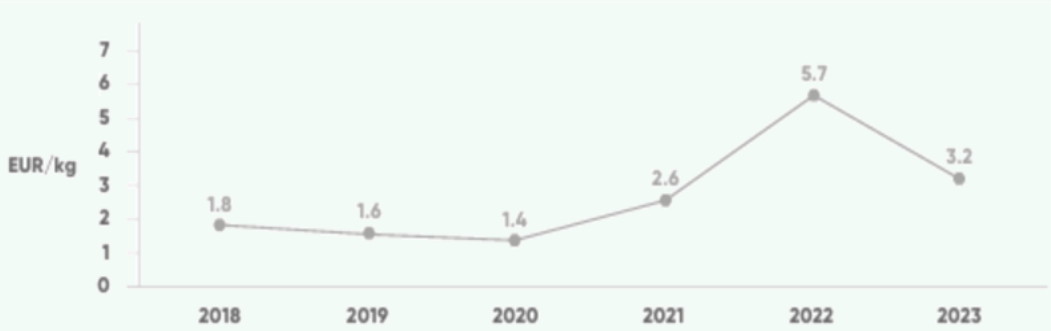
Other Operational Expenditures (OPEX)

When we talk about "Other OPEX", we're looking at a range of costs that keep operations running smoothly. This includes **everything from maintenance and labor to water supply, catalysts, chemicals, insurance, and administrative overhead**. Typically, these expenses account for about **5–15% of the total production costs**, but they play a crucial role in ensuring that operations are safe, compliant, and continuous. One notable expense is catalyst replacement, which can be significant over time since reforming catalysts tend to degrade due to thermal cycling and contaminants in the gas stream. For blue hydrogen production, "other OPEX" also covers the costs associated with running the carbon capture system, including solvent replacement, extra compression, and monitoring. In 2023, "Other OPEX" represented **3.1% of the total cost**.

Emissions Trading System (ETS) Costs

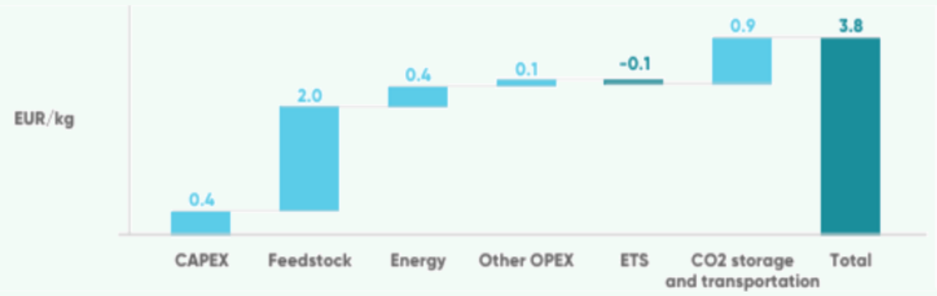
Now, let's dive into ETS Costs. In areas where carbon pricing mechanisms are in place, like the EU ETS, SMR plants face costs for every tonne of CO_2 they emit that isn't captured. With grey hydrogen typically producing 9 -12 kg of CO_2 for every kilogram of hydrogen, and carbon prices soaring above €80 per tonne of CO_2 in 2023, these ETS charges **can add anywhere from €0.70 to €1.00 to the cost of each kilogram of hydrogen**. For blue hydrogen, while ETS costs are lower relative to the capture rate, they still matter unless capture rates hit nearly 100%. Therefore, trends in carbon pricing and tightening regulations have a direct impact on how competitive SMR-based hydrogen is compared to low-carbon alternatives. In 2023, **ETS represented 18.75% of the total cost**.

<u>**Levelized costs of hydrogen production via SMR in the EU-27 in 2018-2023**</u>



SMR + Carbon Capture and Storage

Breakdown of the levelized costs of hydrogen production via natural gas reforming with CCS in the EU-27 (green field plant with ATR technology, 2023 gas prices)



Source: (Hydrogen Europe, 2024)

CAPEX

When it comes to SMR with CCS, the capital expenditures are **notably higher than those for traditional grey hydrogen**. This is largely due to the necessity for carbon capture technology, like amine-based absorption units, CO_2 compression systems, and the integration of these systems into transport and storage setups. In 2023, **CAPEX represented 10% of the total cost**.

Feedstock

The requirement for methane feedstock remains **similar to grey hydrogen**, around 3 to 4 Nm^3 of natural gas for every kilogram of hydrogen produced. However, the efficiency hit from CCS can lead to a slight uptick in consumption, typically around 1% to 5%, due to the energy needed for the capture and compression processes. Consequently, feedstock continues to be the biggest cost driver, but the added demand and reduced efficiency do slightly heighten its effect on the final prices of hydrogen. In 2023, **feedstock represented 52.3% of the total cost**.

Energy

SMR with CCS **demands more energy** than conventional SMR because the processes of capturing, compressing, and pumping CO_2 are quite energy-intensive. This raises electricity needs and might necessitate additional steam generation, which is usually achieved by burning more natural gas or sourcing power from the grid. As a result, the share of energy costs is higher, and in markets where electricity is pricey or carbon-heavy, this can have a significant impact. In 2023, energy **represented 10.5% of the total cost**.

Other OPEX

Operational expenditures are **also higher for CCS compared to grey hydrogen**. This is because CCS systems **require extra maintenance**, solvent or sorbent replacements, and regular inspections of the CO_2 handling infrastructure. The operational complexity ramps up since the plant has to juggle both hydrogen production and CO_2 capture/storage processes. In 2023, “Other Opex” represented 2,6% of the total cost.

ETS (Emissions Trading System) Costs

With regard to the costs associated with the ETS, the outlook for SMR with CCS is considerably more favourable. Because a substantial share of CO_2 emissions is captured and permanently stored, the resulting financial burden is significantly reduced.

CO_2 Storage and Transportation

This is the most distinctive additional cost component for SMR with CCS. Once CO_2 is captured, it needs to be transported, typically through pipelines or ships to a safe storage location, like an old oil or gas field or a saline aquifer. The costs for this can vary based on how far it needs to go and the conditions at the storage site, **usually adding an extra €10–30 per tonne of CO_2** (which translates to about €0.10–0.30 per kilogram of hydrogen). Being close to storage sites can impact the project's financial viability: a facility near an existing CO_2 hub will face much lower costs than one that needs to set up new long-distance transport systems. Plus, there are ongoing expenses related to regulatory compliance and long-term monitoring that can add up over time. In 2023, CO_2 storage and transportation **represented 23.6% of the total cost**.

<u>**Electrolysis from grid energy**</u>

CAPEX

Electrolyser CAPEX primarily covers the cost of the electrolyser stack, balance of plant (water purification, power electronics, gas handling), installation, and commissioning. While the CAPEX for electrolysis has been historically high, recent technological advances and scaling are driving costs down. Typical CAPEX ranges from **€800 to €1,200 per kW of electrolyser capacity,** translating to a significant upfront investment that **must be amortized over 20–30 years**. Larger projects benefit from economies of scale, but the modular nature of electrolysers allows flexible sizing. Unlike SMR, there is no need for carbon capture equipment, so no additional CAPEX for CCS applies here.

Wholesale Electricity Costs

Electricity is the biggest operational expense for electrolysis, often **making up about 60 to 70% of the total cost of hydrogen production**. The electrolyser typically uses around 50 to 55 kWh of electricity for every kilogram of hydrogen it produces, depending on its efficiency, which usually falls between 60 and 70%. This means that **electricity prices play a crucial role in determining competitiveness**. The cost of renewable electricity can vary based on location and time of day, so having access to affordable, low-carbon power sources like solar, wind, or hydropower is essential. Unlike SMR, feedstock isn't an issue here, but fluctuations in electricity prices and the carbon intensity of the grid are key factors to consider.

Network Costs and Taxes

Electricity network fees, taxes, and levies can significantly increase the cost of power supplied to electrolysers. These charges differ from one country to another and among grid operators, and they might include demand charges, capacity fees, or environmental levies. For instance, in some European countries, high grid tariffs can bump up hydrogen costs **by 10 to 20%**. Therefore, it's vital to optimize the location and grid connection agreements to keep this cost in check.

Other OPEX

Operational expenses for electrolysis include water supply and purification, maintenance of electrolyser stacks (which degrade over time and require periodic replacement), labour, insurance, and administrative overhead. Water costs are typically low compared to electricity but must be accounted for. Electrolyser stack replacement cycles typically occur every 5–10 years, influencing maintenance costs. Other OPEX is **generally lower than in SMR+CCS** due to simpler process operation.

Estimated levelized costs of hydrogen production via water electrolysis using grid-mix electricity in Europe in 2023 (excluding any possible transport, storage and conditioning cost)

Source: (Hydrogen Europe, 2024)

Economic Viability of Electrolysis versus CCUS for Hydrogen Production

The profitability of CCUS (Carbon Capture, Utilization, and Storage) technologies **remains uncertain in Europe**, despite carbon prices having reached 50 to 80 €/tCO_2 levels once thought sufficient to drive deployment. Today, significant financial support, such as from the European Innovation Fund, remains necessary due to multiple factors influencing overall cost-effectiveness, including energy prices, carbon quota values, and local conditions.

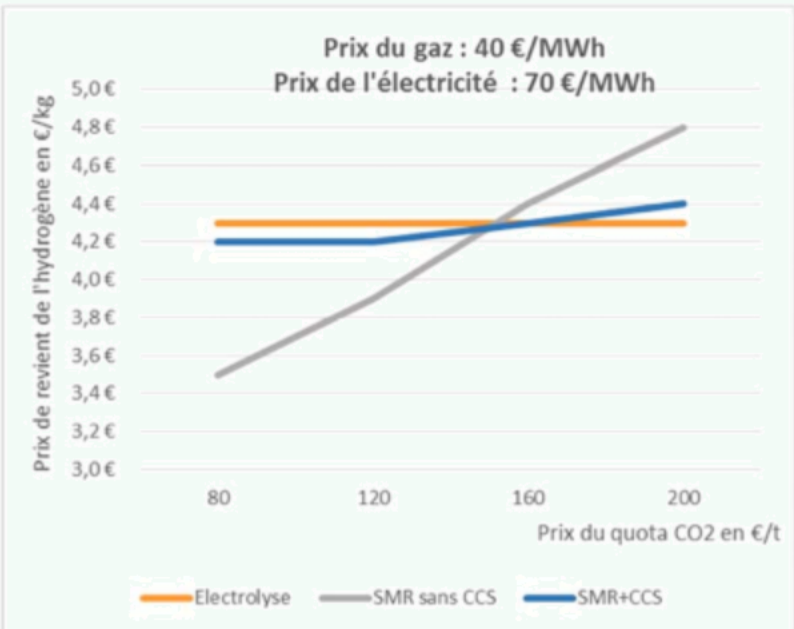
A simplified model (Eden, Equilibre des énergies, 2023) compares three hydrogen production pathways: electrolysis using electricity, steam methane reforming (SMR) without CCS, and SMR combined with CCS, capturing approximately 85% of CO_2 emissions through amine scrubbing.

The competitiveness of these pathways depends on key variables: carbon prices (ranging from 60 to 200 €/tCO_2), natural gas prices (20 to 100 €/MWh), and electricity prices linked to gas prices (60 to 100 €/MWh).

Current findings suggest that at today's carbon price of around 80 €/tCO_2, electrolysis **is only competitive if natural gas prices rise above 80 €/MWh**. Meanwhile, SMR with CCS struggles to be economically viable compared to SMR without CCS unless substantial subsidies are in place. This is largely due to the additional energy consumption required for CCS, assumed here to be 20%, a figure that reflects potential technological improvements compared to the current 40%.

If the carbon price were to increase to 160 €/tCO_2, **electrolysis becomes the preferred option as soon as gas prices exceed 30 €/MWh**. However, SMR with CCS remains uncompetitive unless gas prices fall close to 20 €/MWh. Under more moderate assumption, a gas price of 40 €/MWh and electricity at 70 €/MWh- electrolysis and SMR with CCS exhibit **roughly equivalent costs**, while SMR without CCS remains cheaper only when carbon prices stay below 160 €/tCO_2.

These results highlight that, given the current high fossil fuel prices, CCS-based hydrogen production faces challenges due to the energy penalty from carbon capture. Conversely, electrolysis benefits from the ongoing decrease in renewable electricity costs and the prospect of higher carbon prices. Achieving carbon prices around 160 €/tCO_2 appears critical to ensuring CCS profitability in Europe without heavy financial support.



Source: Eden, Equilibre des énergies, 2023

<u>**Electrolysis from only renewable energy**</u>

Hydrogen production via electrolysis powered by renewable energy **shares many cost components with grid-based electrolysis,** but the **nature and magnitude of these components differ significantly**. **CAPEX remains a major upfront investment**, covering the electrolyser units and supporting infrastructure, similar to grid electrolysis. However, projects relying on dedicated renewable installations (e.g., solar farms or wind parks) face **additional capital costs related to the generation assets themselves**, which must be integrated or contracted alongside the electrolyser. This often increases initial investment but can be offset by lower and more predictable operational costs (IEA, 2019).

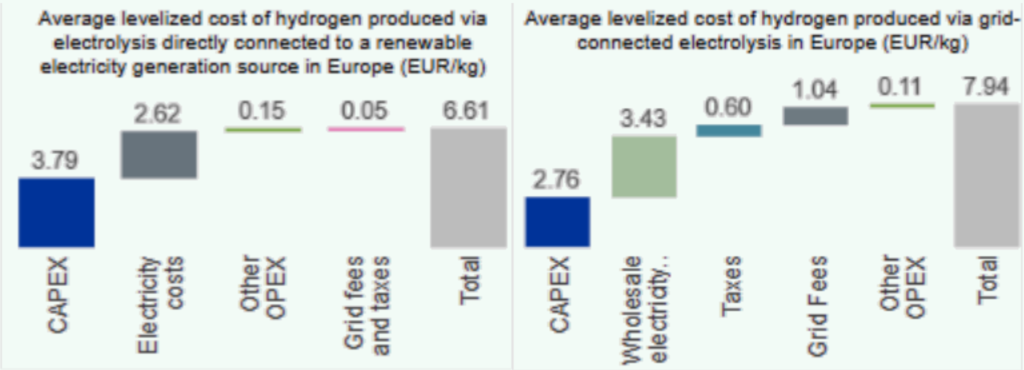
The dominant operational cost for electrolysis powered by renewables **is still electricity**, but unlike grid-based electrolysis where electricity prices fluctuate with market dynamics and grid tariffs, renewable energy cost tend to be more stable and can sometimes approach zero during periods of excess production. This can significantly reduce the levelized cost of electricity for the electrolyser, improving overall hydrogen economics. However, the intermittency and variability of renewables introduce operational challenges: electrolyser capacity factors tend to be lower, leading to underutilization and potentially higher specific CAPEX per kilogram of hydrogen produced. To mitigate this, projects often combine renewable generation with energy storage or grid backup, adding complexity and cost (Hydrogen Council, 2020).

Network costs and taxes differ as well. When the electrolyser is co-located with a renewable plant and operates behind the meter, **grid fees may be minimized or avoided, reducing operational expenses**. Conversely, if renewable power is fed into the grid before reaching the electrolyser, standard network charges and taxes apply, similar to grid electrolysis. Regulatory frameworks regarding renewable energy certification (e.g., Guarantees of Origin) and subsidies also influence the effective cost of power.

Other operational expenditures for renewable-powered electrolysis remain broadly similar to grid electrolysis, including maintenance, water supply, and stack replacement. However, **intermittent operation can affect stack lifetime and maintenance scheduling**, potentially increasing OPEX: When electrolysers run under fluctuating power conditions, their efficiency can drop significantly. Studies show a decline from around 60% to 44% when exposed to variable wind-like profiles, with the energy required per kilogram of hydrogen rising from 67 kWh at full load to as much as 140 kWh at only 30% load (Hydrogeninsight, 2024). This can be explained with the uses of auxiliary systems (pumps for example) that consome proportionally more energy at partial loads. In addition, frequent start-stop cycles accelerate material degradation. (Weiß, Siebel, Bernt, Shen, & Gasteige, 2019)

While the core cost components for electrolysis from renewable energy mirror those of grid electrolysis, key differences arise from electricity sourcing and its variability. Renewable-powered electrolysis offers the potential for significantly lower carbon intensity and, under favorable conditions, lower electricity costs, but these benefits come with challenges linked to intermittency, capital allocation for dedicated renewable assets, and potential underutilization of electrolyser capacity. These factors must be carefully balanced in economic assessments to ensure project viability.

Hydrogen production cost via electrolysis with a direct connection to a renewable energy source in Europe **vary from 4.13 to 9.30€/kg of H2**. Even though H2 production with this way avoids electricity costs like network costs and taxes, the electrolyser capacity factor is limited by the capacity factor of the renewable source it's connected to" European Hydrogen Observatory.



Total H2 cost from grid-connected Electrolysis[9]: 7,94€/kg
Total H2 cost from Electrolysis connected to direct renewable energy: 6,61€/kg

[9] Hydrogen production cost in 2023 from the European Hydrogen Observatory https://observatory.clean-hydrogen.europa.eu/hydrogen-landscape/production-trade-and-cost/cost-hydrogen-production

Summary:

Way of producing H2	LCOE in 2023	Main price Drivers	Advantages	Drawback
SMR	3,76 €/kg	Natural gas prices (largest cost share: 45-75%) ETS carbon price (€80/tCO_2 in 2023 = +8% cost impact) Plant scale and CAPEX efficiency	Mature, widely deployed technology Low LCOE High-capacity factors (>90%)	Very high CO_2 emissions (~9–12 kg CO_2/kg H_2) Vulnerable to gas price volatility Increasing ETS costs under tightening EU climate policy
SMR + CCS	4,41 €/kg	Same natural gas dependency as SMR (+1–5% more due to CCS energy penalty) Added CAPEX for capture, compression, transport, and storage CO_2 storage and transport costs (€10-30/tCO_2) Reduced ETS costs (-2.6% cost impact in 2023)	Significant CO_2 emissions reduction (85-95% capture rates) Leverages existing SMR infrastructure Lower ETS exposure	Higher production cost Still dependent on fossil gas supply CCS adds operational complexity and energy penalty
Electrolysis from grid energy	7,9 €/kg	Electricity cost (60-70% of total) Grid tariffs, taxes, and levies (+10–20% in some EU states) Electrolyser CAPEX (€800-1,200/kW) Stack replacement cycle (5–10 years)	Near-zero emissions if powered by low-carbon grid mix Modular and scalable deployment No fossil feedstock dependency	High LCOE (€7.94/kg in 2023) Emissions depend on grid carbon intensity Exposed to electricity price volatility
Electrolysis from renewable energy	6,61 €/kg	Renewable generation CAPEX (solar/wind farm + integration) Electrolyser CAPEX Capacity factor limited by renewable output Optional grid backup costs	Lowest lifecycle CO_2 emissions Potentially lowest electricity cost during surplus production Avoids grid fees when behind-the-mete	Intermittent supply reduces electrolyser utilization Higher specific CAPEX due to lower load factors LCOE in Europe ranges from €4.13-9.30/kg depending on site

Author of this table: Pôlénergie

Technology	Maturity	RFNBO[10]	CO_2 Emissions [kg CO_2/kg H_2]	1MW Plants		10MW Plants		100MW Plants	
				Uncertainty	**Price [€/kg H_2]**	**Uncertainty**	**Price [€/kg H_2]**	**Uncertainty**	**Price [€/kg H_2]***
Steam Methane Reforming (SMR)	Mature	No	10	X	X	X	X	5 %**	1,5 to 2
SMR with CO_2 Capture	Industrialization	No	3,5 to 7,9***	X	X	X	X	5 %**	2,5 to 4,5
Electrolysis with French Electricity Mix	Industrialization	Usually no, but can be if concerned by AEC (Energy attribute certificate)	3,3	20%	7,3 to 9	20%	5 to 7	50%	5 to 5,5
Electrolysis with Offshore Wind Power	Prototype	Yes	0,8	X	X	X	X	20%	5 to 6 €***
Electrolysis with Electricity from High-Sunlight Countries	Prototype	Yes	2,75	X	X	X	X	25%	3,5 to 5 €

Author of this table: Pôlénergie

Excluding subsidies on CAPEX for green hydrogen production, which reduce costs by approx.* ***0.5–0.7 €/kg H_2*.
** Prices are highly dependent on the price of natural gas.
*** Divergent figures across studies, strongly influenced by the CO_2 intensity of the electricity mix and the technology used.
**** For large-scale installations (several GW), the wind + electrolysis combination can be competitive: **2.50–3.50 €/kg** with an emission factor of 0.8 $kgCO_2/kgH_2$.

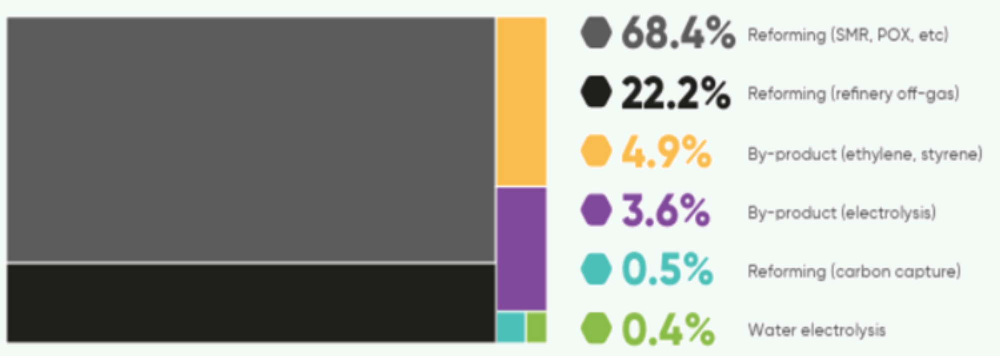
[10] Renewable Fuels of Non-Biological Origin (RFNBO) https://setis.ec.europa.eu/renewable-fuels-non-biological-origin-european-union-0_en#:~:text=Renewable%20Fuels%20of%20Non%2DBiological%20Origin%20(RFNBO)%20are%20synthetic,renewable%20electricity%20and%20carbon%20dioxide.

European green H2 capacity VS transport needs

Current baseline

Installed electrolyser capacity in Europe in 2024 **is still very small**: roughly 385 MW (0.385 GW) of electrolysis capacity installed. This is an order of magnitude increase from a couple of years earlier, but still negligible compared with the scale required for a continent-wide mobility transition. It is important to note that the EU Hydrogen Strategy targeted of deploying 6 GWel by 2024: **this is 15 times lower than what was expected**. Price of the green H2 might be the first reason why the goals were not achieved.

Hydrogen production capacity in 2023 in Europe by production process



Sources: (Hydrogen Europe, 2024)

EU Ambition in 2030

EU-level ambitions commonly quoted include 10 million tonnes (Mt) of domestic renewable hydrogen by 2030. This ambition seems very tricky to reach.

To turn that target into electricity and electrolyser capacity we need to explicit these assumptions:

- Electricity consumed per kg H_2 (electrolyser energy use): 50-60 kWh/kg
- Annual H_2 target: 10 Mt = 10,000,000 t = 10,000,000,000 kg.
- Electricity required = kg × kWh/kg → range 500–600 TWh/year (50–60 kWh/kg).

Results:

⇨ 10e9 kg × 50 kWh/kg = 500 TWh.
⇨ 10e9 kg × 55 kWh/kg = 550 TWh.
⇨ 10e9 kg × 60 kWh/kg = 600 TWh.

Translating hydrogen target into energy terms:

- Typical electricity requirement for electrolysis: 50–55 kWh per kg H_2, based on modern electrolyser efficiencies of 70–80 %
- Delivering 10 Mt/year of H_2 equals 500–550 TWh per year of dedicated electricity.

To calculate necessary electrolyser capacity, we need to consider their capacity factors, which measure actual output versus theoretical maximum:

Variability of the annual capacity factor for a 15 MW electrolyser:

Annual electrolyser capacity factor	Scenario 1 50 MW wind farm	Scenario 2 50 MWac solar farm	Scenario 3 50 MW wind farm + 50 MWac solar farm
Average	69%	28%	80%
Minimum	64%	27%	76%
Maximum	75%	31%	84%
Inter-Annual Variation	3.8%	3.4%	2.2%

Source: (Natural Power)

- ⇨ For a 35% capacity factor (≈3,066 hours/year), it implies 163–180 GW electrolysers;
- ⇨ For a 50% CF (≈4,380 h/year), it implies 114 -126 GW capacity.

Transport needs

Transport hydrogen demand is expected to grow significantly. For heavy-duty trucks alone, some forecasts suggest an emerging market of 45,000+ hydrogen trucks by 2030, which could translate into 1 -3 Mt of hydrogen per year.

The Market for Hydrogen Fuel Cell Heavy-duty Trucks in Europe 2020-2030

Source: (In 2030, over 45000 heavy trucks will run on hydrogen in Europe, Interact Analysis, 2023)

Combine buses, regional rail, and short-sea shipping added demand, and total transport demand could easily reach several million tonnes annually by 2030. Yet, domestic green hydrogen supply, even under optimistic electrolyser deployment, would likely meet only a fraction of this, pointing to an important shortfall.
RMI scenarios project total hydrogen demand (across all sectors) could reach 3.7 Mt to 7.0 Mt by 2030 by RMI[11]— with transport making up a significant yet variable portion.

[11] https://rmi.org/the-case-for-re-calibrating-europes-hydrogen-strategy

However, as of 2024, installed capacity is only 0.385 GW, meaning the EU would need an approximately 300-fold scale-up in 6 years.
While numerous projects are announced or under development, ranging from multi-GW electrolyser hubs in Northern Europe to industrial clusters in Southern Europe, **many are still in early permitting or pilot stages**.

Real-world deployment often faces regulatory, financing, and grid integration challenges, which can delay or downscale planned installations: 2 to 5 years are necessary to build up this type of project and produce Hydrogen, **making the goals even harder (or impossible?) to reach by 2030**.

8 Storage and transport

Storage and transport of H2 is as key as its production as it is an important part of its price and as it determines the availability for potential users of H2.

When there is no need to reduce the storage volume (stationary applications for example), it can be considered in gaseous form at a relatively low pressure (30-50 bars). This inexpensive storage method is perfectly controlled. But mainly, hydrogen must undergo transformations that ultimately allow transport.

Storage method	Volume for 1 kg H_2	Extra energy to prepare	Comparison / use case
Compressed gas (30–50 bar)	~0.25–0.40 m^3 (≈ a large household fridge)	~0.5 kWh (≈ one smartphone charged 50×)	Cheap, well-established, but bulky.
Compressed gas (350 bar)	~0.042 m^3 (≈ a medium suitcase)	2–4 kWh (≈ one washing machine cycle)	Widely used in buses and trucks.
Compressed gas (700 bar)	~0.025 m^3 (≈ a cabin bag)	~3 kWh (≈ two washing machine cycles)	Standard for passenger fuel-cell cars.
Liquid hydrogen (−253 °C)	~0.014 m^3 (≈ a large bucket)	10–12 kWh (≈ a household fridge's 2–3 weeks of use)	Very compact, but costly and requires cryogenic tanks.

Author of this table: Pôlénergie

8.1. Technologies for hydrogen storage for transport

Gaseous Hydrogen Storage (350-700 bar)
High-pressure tanks made from composite materials, such as carbon fiber, dominate this segment due to their balance of weight, durability, and energy density. Ongoing R&D aims to reduce the carbon footprint of tank materials and improve recycling.

Liquid Hydrogen Storage (-253°C)
Primarily used for high-tech applications and long-distance transport. While compact, liquid hydrogen suffers from boil-off issues due to its cryogenic nature, requiring advanced insulation and pressure management.

Solid-State Storage
Metal hydrides provide high volumetric energy density by absorbing hydrogen into their structure. However, their weight limits mobility applications.

Chemical Carriers (Ammonia, LOHCs):
Hydrogen is bound in molecules like ammonia or organic carriers (e.g., methanol, DME, toluene). These solutions offer ease of transport but necessitate additional processing for hydrogen release at the destination.

8.2. Arbitration between local and long-distance

For local and regional supply, **the focus is on efficiency and practicality**. Pipelines, whether purpose-built or adapted from existing natural gas infrastructure, provide a steady, low-loss flow to industrial clusters and refuelling stations. This approach is already being explored in European « hydrogen backbone » initiatives as a way to connect production hubs with demand centres. In areas where demand is smaller or more dispersed, compressed hydrogen delivered by road in tube trailers offers flexibility without the need for heavy infrastructure investment, making it well suited to early market phases. These localised options minimise conversion losses and allow fast deployment.

For long-distance or international trade, **the challenge shifts to moving hydrogen in forms that pack more energy into each shipment**. Liquefied hydrogen, cooled to −253 °C, allows bulk transport by ship but comes with high energy demands for liquefaction and boil-off management (IEA, 2023). Other approaches convert hydrogen into ammonia or liquid organic hydrogen carriers (LOHCs), both of which use existing maritime and fuel-handling infrastructure. Ammonia has the added advantage of being usable directly as a fuel or feedstock, avoiding reconversion losses in some cases, while LOHCs offer easier handling at ambient conditions but require energy-intensive dehydrogenation.

Regardless of the scale, certain challenges remain constant. Transport infrastructure, from pipelines to liquefaction plants and import terminals, demands high upfront investment and long planning cycles. Energy use in conversion and reconversion can erode the overall efficiency of the hydrogen pathway. Safety standards and regulatory frameworks must evolve to manage hydrogen-specific risks across borders. Above all, transport must remain cost-competitive, as delivery costs can represent a significant share of the final hydrogen price, especially in early market stages (IRENA, 2022).

In the broader hydrogen value chain, transport sits between production and end-use, but its influence is felt across the system. The choice of transport mode can shape where hydrogen plants are built, which industries convert to hydrogen, and how integrated Europe becomes in the emerging global hydrogen economy.

Transport Method	Best for	Limitations	Sectors
Liquid Hydrogen (-253°C)	- High-tech applications requiring high energy density	- High energy cost for liquefaction. - Boil-off losses over time.	- Space propulsion (rockets). - **Maritime shipping for international hydrogen supply chains.**
Gaseous Hydrogen (350-700 bar)	- Mobility applications - Short to medium-distance transport. - Localized industrial use.	- Lower volumetric energy density than liquid hydrogen or chemical carriers. - High logistics costs for long distances.	- Road transport for fuel cell vehicles. - Local industrial supply.
Chemical Carriers (Ammonia, Liquid Organic Hydrogen Carrier)	- Long-distance transport with ambient storage. - Industrial processes - Temporary storage.	- Requires processing to release hydrogen. - Additional cost and complexity.	- International transport of ammonia. - Integration into chemical production processes.
Solid-State Hydrogen (Metal Hydrides)	- Stationary storage with high volumetric energy density. - Niche industrial uses.	- Heavy materials limit mobility applications. - Heat management during absorption/release.	- Grid balancing for renewable energy. - Backup power for critical infrastructure.
Pipelines	- Large-scale, continuous supply over medium to long distances. - Regional hydrogen hubs.	- High upfront costs. - Material embrittlement issues.	- Supplying refineries, steel plants, or ammonia facilities. - Regional hydrogen corridors.

Sources: (FFE, 2023) (Negro, Noussan, & Chiaramonti, 2023) (Xie, Jin, Su, & Lu, 2024).

Author of this table : Pôlénergie

Comparison of hydrogen transportation methods:

Method	Pipeline	Compressed H_2 trucks	Liquid H_2 trucks	Liquefied H_2 ships	Chemical carrier	Material carrier
Efficiency	High	Medium	Medium	High	Medium	Medium
Safety	High	Medium	Medium	High	Medium	High
Infrastructure	Low	Medium	Medium	High	Medium	Medium
Flexibility	Low	High	High	Medium	High	High
Cost	Medium	High	High	Medium	High	Medium

Sources: (Gorji, 2023)

Author of this table: Pôlénergie

8.3. Way of Shipping

Multimodal strategies are essential for creating an efficient and scalable hydrogen transport network, particularly given the varying geographical, industrial, and logistical demands. For instance, **hydrogen produced at coastal facilities might initially be transported via maritime routes** using liquid hydrogen or ammonia to reach international markets. Upon arrival, **it could be transferred to rail networks for bulk movement to regional industrial hubs** or further distributed via road transport for last-mile delivery to decentralized consumers, such as refueling stations or small-scale industrial users.

Pipelines, for example, are ideal for stable, high-volume flows between hydrogen hubs but lack flexibility for intermittent or emerging demand while maritime transport can handle large quantities over long distances but depends on specialized port infrastructure. Road and rail provide critical links for shorter distances or variable loads. Multimodality also incorporates ex-works logistics principles, where producers and consumers coordinate transport responsibilities to streamline the hydrogen supply chain. This flexibility ensures that hydrogen logistics can adapt to diverse end-user needs, infrastructure availability, and evolving market conditions.

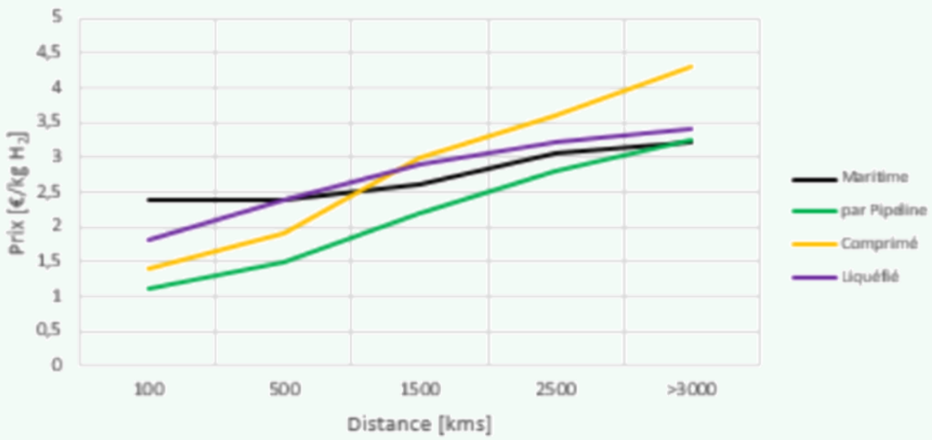
Transport Mode	Best For	Limitations	Examples
Maritime Transport	- Long-distance, large-scale export/import (e.g., intercontinental hydrogen trade).	- High initial costs for cryogenic storage and ship infrastructure. - Energy-intensive liquefaction process.	- Shipping liquid hydrogen from Australia to Europe. - Ammonia tankers for global distribution
Inland Waterway Transport	- Regional distribution connecting hydrogen production sites to nearby industrial hubs via rivers and canals.	- Limited by the geography of navigable waterways. - Requires barge modifications for hydrogen safety compliance.	- Transporting compressed hydrogen via barges on the Seine-North Europe Canal
Rail Transport	- Medium-distance bulk transport. - Linking ports to inland industrial zones or hydrogen hubs.	- Requires specialized rail tankers. - Dependent on existing rail infrastructure.	- Delivering ammonia or LOHCs from coastal terminals to inland factories
Road Transport	- Short-distance or flexible delivery to decentralized consumers (e.g., refueling stations, small industries).	- Limited capacity per vehicle compared to other modes. - High transport cost per unit of hydrogen.	- Trucks delivering gaseous hydrogen to local fueling stations

Author of this table: Pôlénergie

Transport		Cost of H2 [€/kg of H2] depending on distance				
		100 kms	500 kms	1500 kms	2500 kms	>3000 kms
Maritime		X	X	2,4 to 3,1	2,75 to 3,45	2,85 to 3,55
from Pipeline		0,9 to 1,3	1,3 to 1,4	2,2 to 3	2,2 to 3	3 to 3,5
Road	Liquefied	1,8 to 2,6	2 to 2,9	X	X	X
	Compressed	1,4 to 1,5	1,7 to 1,9	X	X	X

Author of this table: Pôlénergie

<u>**Cost of transport of Hydrogen**</u>



« La chaîne de Valeur de l'hydrogène : étude de coût » (Pôlénergie, 2024)

Note: prices have changed, order of magnitude is however similar.

8.4. Hydrogen Refuelling Stations

Hydrogen refuelling stations (HRS) serve as critical infrastructure in the transition to zero-emission mobility. These stations **are designed to dispense hydrogen fuel to various types of vehicles, including passenger cars, buses, and trucks**[12]. The operational capacity and design of an HRS are influenced by several factors, including the intended vehicle types, expected refuelling volumes, and regional demand (France Hydrogène, 2024).

A. Source of Hydrogen

Hydrogen can either be produced on-site via an electrolyzer or delivered from an external source.

- **On-site production:** electrolyzer generates hydrogen directly at the station.
- **Delivered hydrogen:** supplied via truck, cylinder, or tube trailer to the station.

B. Compression

Hydrogen is compressed to a high pressure, up to 1,000 bar (not usual) for efficient storage and distribution.

- **Constant volume + high pressure → higher stored hydrogen quantity.**
- Typical distribution pressures: **350 bar** and **700 bar**.

C. Storage

Compressed hydrogen is stored in high-pressure tanks at the station.

- Storage ensures hydrogen is available for continuous refuelling.

D. Distribution

Hydrogen can be cooled in a heat exchanger before being transferred into the vehicle's tank.

- The station follows specific distribution protocols that define nozzle types and refuelling procedures to ensure safe and efficient delivery.

[12] https://atawey.com/fonctionnement-station-hydrogene/

E. Vehicle Refuelling

The speed of hydrogen refuelling depends on:

- Reservoir size and pressure
- Ambient temperature
- Hydrogen cooling system efficiency

Hydrogen remains in the storage tank until it is converted into electricity by the vehicle's fuel cell.

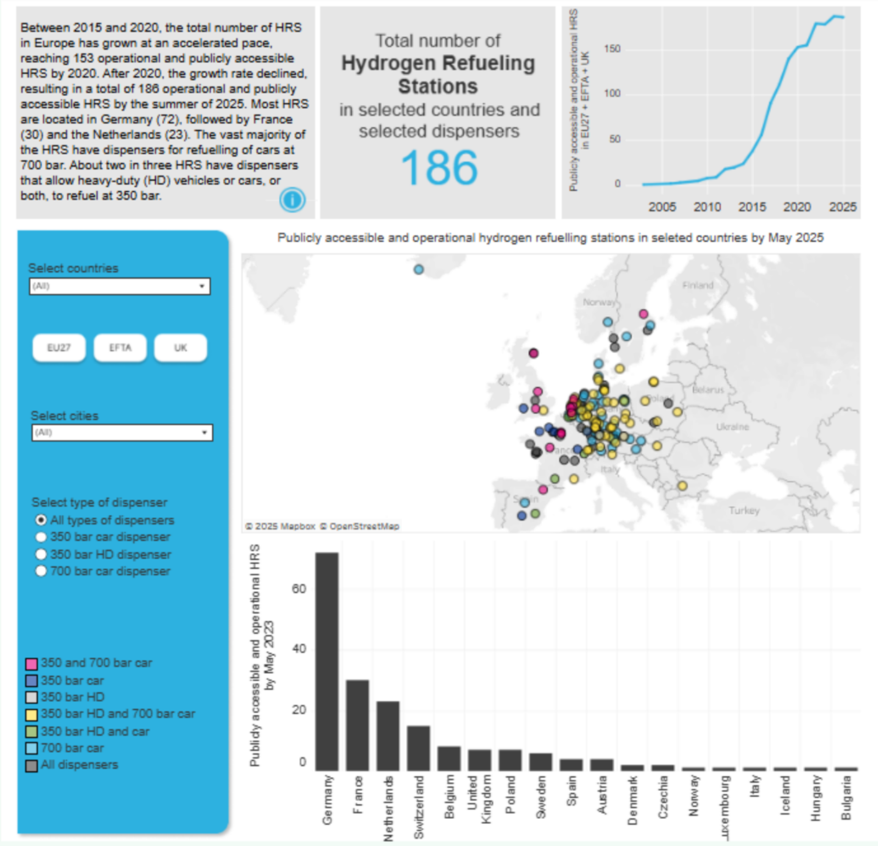
- The vehicle's filling unit determines the final pressure (in bar) of the hydrogen delivered.

"Hympulsion" HRS in Lyon (France)[13]

As of 2024, Europe has made significant strides in establishing hydrogen refuelling infrastructure. **Germany leads the continent with the highest number of operational stations**, followed by France, the Netherlands, and Switzerland. The deployment of HRS is aligned with the European Union's Alternative Fuels Infrastructure Regulation (AFIR), which mandates the establishment of hydrogen refuelling stations every 200 kilometres along major roads and in urban nodes by 2030.

Despite this progress, the number of HRS remains limited compared to the growing fleet of hydrogen-powered vehicles. This disparity underscores the need for continued investment and expansion of refuelling infrastructure to support the widespread adoption of hydrogen mobility.

[13] https://www.hydrogen-refueling-solutions.fr/fr/realisations/station-de-ravitaillement-hydrogene-vert-a-saint-priest-lyon/

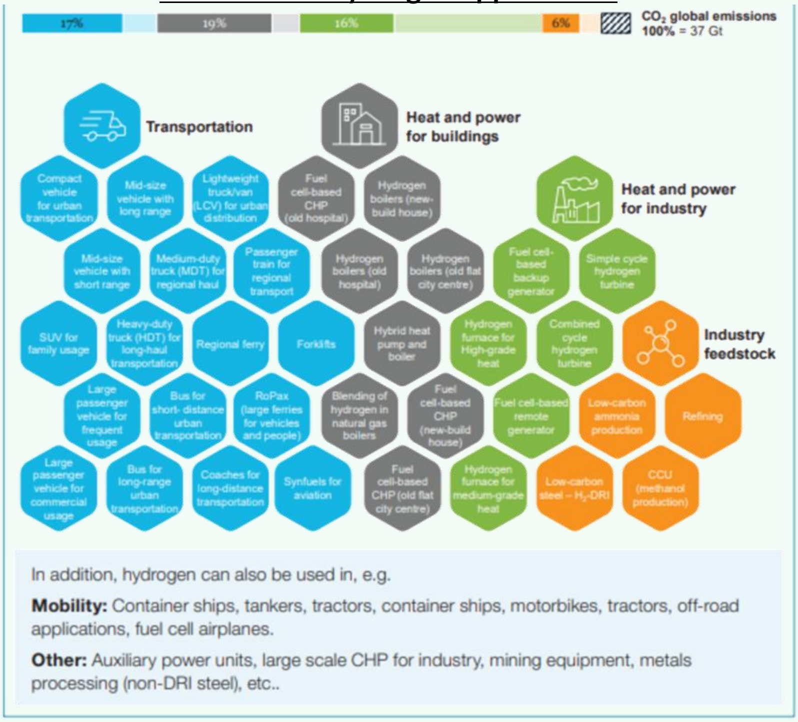


Source: https://observatory.clean-hydrogen.europa.eu/hydrogen-landscape/distribution-and-storage/hydrogen-refuelling-stations

Hydrogen is a versatile molecule whose applications span both industrial processes and energy systems. Its unique properties allow it to serve as a feedstock in chemical manufacturing, a reducing agent in high-temperature industrial processes, and increasingly as a low-carbon energy carrier. While a significant share of current hydrogen production remains grey, driven by fossil fuels, its potential to decarbonize hard-to-abate sectors is gaining momentum. Understanding the diverse uses of hydrogen, from ammonia and methanol production to steelmaking and clean energy provision, is essential for assessing future demand, guiding infrastructure planning, and evaluating pilot projects along strategic industrial corridors (Hydrogen Council, 2021).

Uses:

Overview of hydrogen applications



Source: (Hydrogen Council, 2020)

As a vector for decarbonization

- Steel industry by replacing coke from coal for the iron ore reduction
- The industry as a whole where hydrogen can substitute natural gas to power burner when electrification is too expensive or not possible technically

Industry Impact on mobility?

While this study primarily addresses the role of hydrogen in decarbonizing mobility, **the discussion necessarily extends to industrial hydrogen users due to the strong synergies that exist between these sectors.** Industry remains the largest consumer of hydrogen today, with high and continuous demand for processes such as ammonia and methanol production, refining, steelmaking, and chemical synthesis. Leveraging these existing or planned industrial hydrogen hubs **can create valuable infrastructure opportunities, allowing mobility-focused hydrogen supply chains to benefit from shared logistics, storage, and transport networks**.

Moreover, some industrial sites produce hydrogen on-site, providing potential local sourcing that can reduce transport costs and emissions for adjacent mobility applications. By aligning industrial and mobility hydrogen needs, it is possible to foster integrated regional hubs that optimize both production and consumption, improve the economic viability of hydrogen projects, and accelerate the overall decarbonization of transport. Recognizing these interconnections ensures that mobility-focused planning is grounded in the realities of hydrogen availability, infrastructure, and market dynamics, while also opening avenues for collaboration and scale-up.

Other uses:
Electricity generation

Hydrogen-to-Power
Hydrogen-to-power consist to use hydrogen as a fuel in turbines, engines, or fuel cells. Hydrogen's role in electricity generation remains very limited today, accounting **for less than 0.2% of the global power mix**, mostly in the form of mixed industrial gases rather than pure hydrogen. Yet, technologies to generate power from pure hydrogen are already commercially available, including adapted gas turbines, internal combustion engines, and fuel cells.

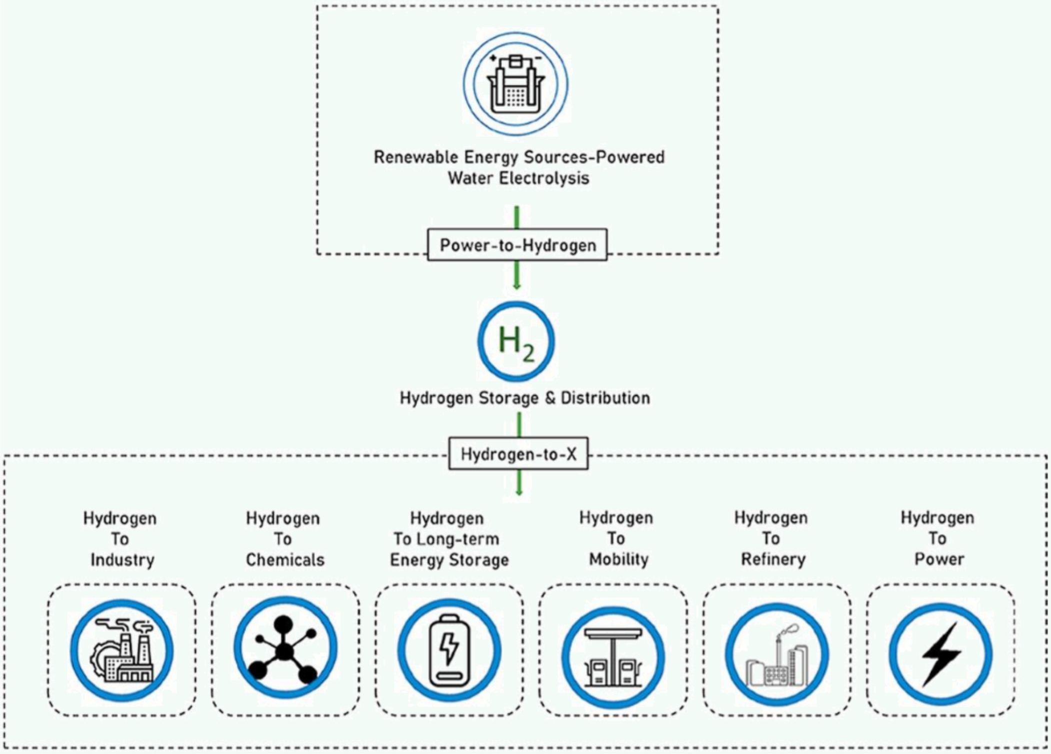
Ammonia, a hydrogen carrier that is **easier to store and transport**, is also attracting attention: successful co-firing trials in coal-fired power plants have been conducted in Japan and China, and in 2022 a 2 MW gas turbine operated on 100% ammonia. These solutions offer significant decarbonisation potential, though controlling nitrogen oxides (NOx) emissions and nitrous oxide (N_2O) in the case of ammonia.

In the near term, **co-firing hydrogen with natural gas or ammonia with coal can lower emissions from existing assets**; in the longer term, fully hydrogen- or ammonia-fuelled plants **could provide valuable system flexibility**, especially when paired with large-scale hydrogen storage from renewable power. By 2030, announced projects could deliver nearly 5.8 GW of installed capacity, 70% of which in gas turbines or combined-cycle plants, 10% in fuel cells, and 3% in ammonia co-firing. "H_2-ready" plants under construction or refurbishment could increase this capacity far beyond that figure, with the technical potential from existing gas turbines alone exceeding 70 GW globally. According to the (IEA, 2023), R&D efforts are now focused on enabling 100% hydrogen or ammonia combustion while minimising pollutant emissions.

Power-to-hydrogen-to-power
Beyond direct hydrogen combustion, the power-to-hydrogen-to-power (P2H2P) approach is often presented as a way to provide long-duration energy storage, complementing batteries and pumped hydro. In theory, it allows excess renewable electricity to be converted into hydrogen via electrolysis, stored, and then reconverted into electricity when needed. This for covering seasonal or multi-day imbalances.

In practice, for every 10 MWh of renewable electricity fed into the system, only 3–4 MWh come back: Europe would need to install three times more solar panels or wind turbines just to deliver the same usable electricity compared with batteries or pumped hydro.

In Europe, pilot projects are emerging in Germany, the Netherlands, and Spain, integrating MW-scale electrolysers with storage and turbines. But unless there are major breakthroughs in efficiency or dramatic cost reductions, P2H2P is unlikely to become a mainstream storage technology by 2030. Instead, its role will probably remain niche—focused on extreme seasonal balancing rather than day-to-day flexibility.



Source: "Power-to-hydrogen and hydrogen-to-X energy systems for the industry of the future in Europe" by (Matteo, et al., 2023)

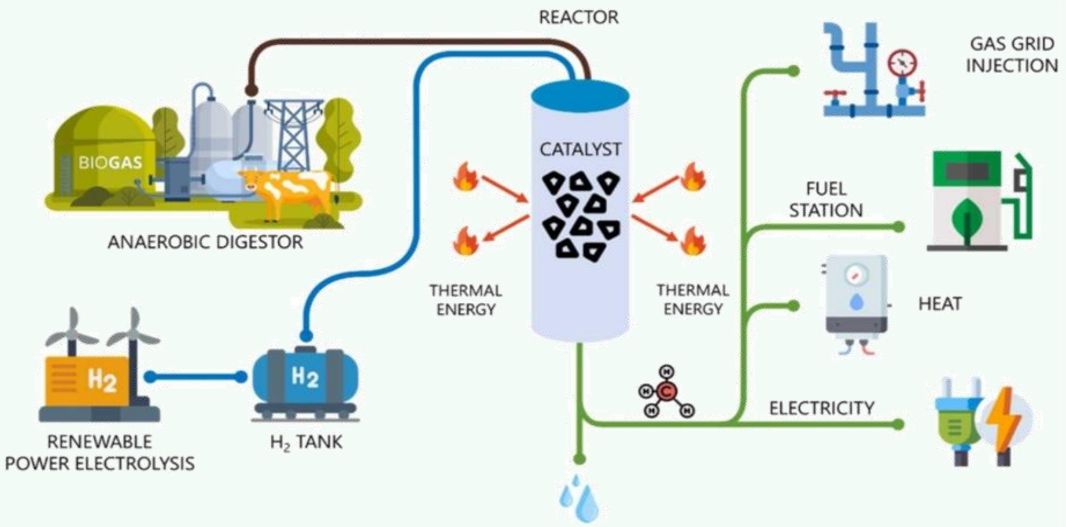
Hydrogen in methane production

Today, methane production, whether fossil-based or renewable, dominates Europe's gaseous energy mix. Hydrogen can play a role in reshaping this sector through synthetic methane pathways, where green hydrogen from electrolysis is combined with captured CO_2 in a methanation process. This creates a drop-in renewable gas compatible with existing methane infrastructure. While technically mature at pilot scale, large-scale deployment depends on two critical factors: **access to low-cost renewable electricity for hydrogen production, and a reliable, concentrated source of biogenic or captured CO_2**. If these conditions are met, hydrogen-based synthetic methane can decarbonize applications that are otherwise hard to electrify, while leveraging Europe's extensive methane storage and transport networks.

Hydrogen and grid injection

Injecting renewable gases into the natural gas grid is already a cornerstone of Europe's energy transition, and hydrogen is increasingly being considered alongside biomethane. Low-percentage hydrogen blending (typically up to 20% by volume in transmission networks) is technically feasible in many parts of Europe without major equipment changes, offering a way to gradually introduce hydrogen into end-use sectors currently dependent on methane. Beyond blending, some regional distribution networks, especially newly built or refurbished ones, are being designed to be "hydrogen-ready," allowing for full conversion in the medium to long term. Using hydrogen in this way enables a gradual, infrastructure-based transition, although its effectiveness depends on coordinated technical standards, regulatory acceptance, and economic viability compared to direct hydrogen delivery via dedicated pipelines.

DIRECT BIOGAS METHANATION



Source: "Advancements in CO_2 methanation: A comprehensive review of catalysis, reactor design and process optimization" by (Tommasi, Degerli, Ramis, & Rossetti, 2024)

Hydrogen for Building Heating

Building heating remains a major consumer of gaseous fuels in Europe, and hydrogen offers a potential low-carbon substitute for methane in this segment. Several EU countries, including the UK, the Netherlands, and Germany, are piloting hydrogen-ready boilers and district heating networks that can operate with pure hydrogen or blends. The advantage lies in using existing gas distribution systems—especially in dense urban areas—while avoiding disruptive retrofits for end-users. However, the efficiency of using hydrogen for direct combustion in heating is significantly lower than electrification via heat pumps, meaning that hydrogen's role is often seen as complementary rather than primary. Most EU decarbonization strategies envision hydrogen heating as a niche or transitional solution in regions where electrification is constrained or where hydrogen infrastructure is already established through industrial or mobility hubs.

8.4. Logistic/mobility application

Hydrogen Propulsion Technologies
Today, hydrogen propulsion in transport relies on two main technological approaches:

Fuel cell electric systems (FCEVs)

Fuel cell electric systems store compressed hydrogen on board, typically at 350 bar for heavy-duty and 700 bar for light-duty applications and convert it into electricity via a polymer electrolyte membrane fuel cell (PEMFC). The electricity powers electric motors, offering silent operation, zero tailpipe CO_2 emissions, and only water vapor as exhaust.

Current commercial FCEVs, such operate with a tank-to-wheel **efficiency of around 50–60%**, which is lower than battery electric vehicles but significantly higher than combustion engines. The technology has reached TRL 9 for road transport, with operational fleets in buses, passenger cars, and trucks in Europe, Japan, and North America. However, large-scale adoption depends on the rollout of refuelling infrastructure, with Europe counting about 230 public hydrogen stations as of early 2024[14]

(Fuel cells and hydrogen joint undertaking, 2019)

Hydrogen internal combustion engines (H_2 ICEs)

Hydrogen internal combustion engines adapt conventional combustion engine architectures to burn hydrogen directly. This allows manufacturers to use existing production lines and maintenance networks, reducing initial capital costs. The technology emits no CO_2 but can generate nitrogen oxides (NO_x), requiring catalytic after-treatment. **Efficiency is generally 25–35%**, lower than fuel cells, but H_2 ICEs **tolerate lower-purity hydrogen and can be more robust in certain heavy-duty or off-road applications**.

There is a lower maturity (TRL 7–8) (IEA, 2023) with early prototypes tested in buses, trucks, and stationary engines by companies such as Cummins and Toyota. Deployment remains limited, but the technology is viewed as a transitional solution for sectors where rapid decarbonisation is required but fuel cell costs remain high.

From a value chain perspective, fuel cells set stricter requirements for hydrogen purity and typically rely on high-pressure gaseous delivery, whereas H_2 ICE can be more flexible in fuel handling.

Both require dedicated storage and refuelling infrastructure and both face the same challenge of scaling green hydrogen production at competitive costs.

(US Department of energy, 2025)

[14] https://www.h2stations.org/statistics/

Technology	TRL	Implications on the Hydrogen Value Chain
Fuel Cell Electric Vehicles (FCEVs)	9 (road transport) 7–8 (Rail, maritime)	Requires high-pressure storage (350–700 bar) Demands high-purity hydrogen, influencing upstream production standards Necessitates dense refueling network with compression capabilities Influences investment in PEM supply chain and maintenance protocols
Hydrogen Internal Combustion Engines (H_2 ICEs)	7-8	More tolerant to hydrogen quality, easing upstream production constraints Compatible with simpler storage formats Can use existing maintenance and repair networks Slower pressure ramp-up requirements for refueling than FCEVs

Author of this table: Pôlénergie

<u>Road mobility - Transport segmentation</u>

<u>Private vehicle:</u>

Relevance: Limited.

Hydrogen faces significant competition from Battery Electric Vehicules (BEVs) due to their **higher energy efficiency and rapidly expanding charging infrastructure**. BEVs are better suited for short- and medium-range trips, which dominate the private vehicle segment. Hydrogen-powered fuel cell electric vehicles (FCEVs) may find niches in regions lacking charging infrastructure or for users needing fast refuelling and longer ranges.

Conditions for viability:

- Infrastructure density: hydrogen refuelling stations must be widely available to match the convenience of existing petrol stations or BEV charging networks.
- Cost parity: FCEVs need to achieve price parity with BEVs and ICEs.
- Use case: particularly viable in regions with abundant green hydrogen production or where long-range driving is common.

Perspective: while technically viable, the high efficiency of BEVs (~70-80% tank-to-wheel vs. ~30% for H2) makes FCEVs less competitive in the short term for private use.

Commercial vehicles:

Relevance: high for long-haul trucking.

For heavy-duty trucks operating over long distances, hydrogen offers advantages over BEVs. BEVs **suffer from heavy batteries and long charging times**, which reduce payload capacity and operational efficiency. Hydrogen refuelling is quicker, and the higher energy density allows for lighter fuel storage systems.

Conditions for viability:
- Long distances: hydrogen is ideal for long-haul trucking where BEVs face challenges with battery weight and long charging times.
- Centralized refuelling: fleet-based operations with predictable routes and centralized hydrogen refuelling points improve feasibility (similar for BEV).

Perspective: hydrogen-powered trucks excel in scenarios where weight, range, and downtime are critical

Buses and public transports:

Relevance: moderate.

FCEVs offer a good alternative for urban and intercity buses, especially on long routes where BEVs would require multiple recharges. However, BEVs dominate shorter routes due to their efficiency and lower operational costs.

Conditions for viability:
- Heavy-duty routes: long-distance or high-frequency routes that strain battery capacity favour FCEVs.
- Government incentives: subsidies for hydrogen adoption and infrastructure can offset initial high costs.

Perspective: hydrogen's long range and quick refuelling make it suitable for high-demand public transport systems, especially where fast turnarounds are needed. Hydrogen buses are a strong alternative to diesel for urban and regional transport, but BEVs dominate shorter, predictable routes due to their efficiency.

Garbage trucks:

Relevance: high.

Garbage collection trucks operate on **predictable routes with frequent stops and high energy demands for waste compaction**. Hydrogen can provide an advantage over BEVs in terms of continuous availability, reducing downtime from charging. However, for short urban routes, BEVs may remain competitive due to their higher energy efficiency and the feasibility of depot charging infrastructure.

Conditions for viability:

- Intensive operations: daily use with minimal downtime for recharging (continuous or multi-shift operations).
- Centralized infrastructure: municipal depots can host H_2 refuelling stations for fast turnaround.
- Vehicle lifespan & TCO: hydrogen trucks must match or beat BEVs and diesel in total cost of ownership over the vehicle's lifetime.
- Green H_2 availability: more viable in regions with reliable, cost-competitive low-carbon hydrogen supply.

Perspective:
Hydrogen-powered garbage trucks are especially attractive for municipalities aiming to eliminate local emissions and noise while maintaining uninterrupted operations. In regions where green electricity is abundant and charging can be done overnight, BEVs will remain more economical. Hydrogen gains the edge when energy density and fast refuelling are critical for 24/7 service.

<u>Industrial vehicles:</u>

Relevance: high for certain applications.

Vehicles like forklifts, mining equipment, and construction machinery benefit from hydrogen where prolonged operation without downtime is required. These vehicles often operate in controlled environments, facilitating hydrogen storage and refuelling infrastructure deployment.

Conditions for viability:

- Extended operating hours: hydrogen is advantageous where continuous operation is required, such as in warehouses
- Safety and storage: on-site hydrogen production or storage infrastructure is essential.

Perspective: offers longer operational cycles and greater flexibility compared to BEVs, which require larger batteries and charging downtime.

<u>Railways mobility:</u>

Relevance: high for non-electrified lines.
Hydrogen is a strong contender for replacing diesel locomotives on non-electrified rail networks. Battery-powered trains are limited by range and charging requirements, whereas hydrogen offers sufficient range and operational flexibility.

Conditions for viability:

- Non-electrified lines: hydrogen trains are a practical solution for regions where electrification costs are prohibitive.
- Regional integration: requires coordinated hydrogen production and refuelling infrastructure.

Perspective: ideal for routes where electrification is uneconomical due to low traffic or geographic constraints particularly for passenger and freight services on medium-range routes.

Boat mobility:

Relevance:
- **Fluvial**: moderate

Hydrogen can decarbonize inland waterways, especially for barges operating in clean zones or regions with green hydrogen production. However, cost and energy losses in hydrogen systems may limit adoption.

- **Maritime**: high for specific cases.

Ammonia and hydrogen are emerging as fuels for decarbonizing shipping. Hydrogen's low volumetric energy density makes it less efficient for large ships, but ammonia or Liquid Organic Hydrogen Carriers (LOHCs) may be used for long-haul maritime routes.

Conditions for viability:
- Effective for regional freight corridors where green hydrogen production can be localized.
- Hydrogen is more suited for short-sea shipping

Perspective: suitable for inland waterways and short-sea shipping. Alternatives like ammonia and methanol may be preferred for long distances

Aeronautic mobility:

Relevance: long-term potential but limited today.

Hydrogen may play a role in decarbonizing aviation through direct use in fuel cells or as synthetic fuels (e.g., e-kerosene). However, challenges with weight, volume, and infrastructure are significant.

Conditions for viability:
- Small aircraft: Hydrogen is more feasible in short-haul or regional aviation due to storage and weight limitations.
- Infrastructure: requires significant advances in hydrogen storage technologies and refuelling infrastructure.
- Technological barrier: limited adoption expected in commercial aviation until significant technological breakthroughs occur.

Perspective: promising for small regional aircraft or auxiliary power units. Large-scale adoption depends on advances in hydrogen storage and aircraft design.

Opening up to other types of mobility

Port and airport operations

Use case: hydrogen-powered equipment for logistics at ports and airports, including forklifts, cranes, and baggage loaders. These are ideal environments for centralized hydrogen refuelling infrastructure.

Benefits: reduces emissions in concentrated areas with heavy equipment use and supports decarbonization goals for large transport hubs.

Military applications

Use case: Mobile hydrogen units for off-grid operations, such as drones, armoured vehicles, or temporary bases.

Benefits: quiet operation, reduced heat signatures, and independence from fossil fuel supply chains make hydrogen advantageous in strategic scenarios.

Personal aviation and urban air mobility

Use case: hydrogen fuel cells for electric vertical take-off and landing, aircraft used in urban air mobility or small regional flights.

Benefits: offers higher energy density than batteries.

Recreational and niche vehicles

Use case: hydrogen for leisure activities like boating, recreational vehicules, and specialty off-road vehicles.

Benefits: supports extended range and quick refuelling in remote areas, complementing the renewable energy goals of eco-conscious consumers.

Hydrogen-powered drones

Use case: industrial or commercial drones for extended surveillance, mapping, or delivery applications.

Benefits: hydrogen fuel cells significantly extend flight time compared to battery-powered drones, particularly for large payloads.

Relevance analysis of H2 for each mode of transportation:

Mode	Relevance	Key Advantage	Main challenges	Condition for Viability	Perspective
Private Vehicles	Low	Fast refuelling, long range, niche potential where charging infra is weak	Low tank-to-wheel efficiency (~30%), high cost, limited refuelling infra	Dense H_2 station network, cost parity with BEVs/ICEs, green H_2 availability	Niche in regions with abundant H_2 and poor charging infra; BEVs dominate overall
Commercial Vehicles (Long-haul trucks)	Can be high for long distance freight	Lighter than BEV for same range, fast refuelling, long range	H_2 infra deployment cost, fuel cost	Long-haul use, centralized fleet refuelling, green H_2 supply	Strong potential where weight, range, and uptime are critical. depending on the level of development of the electric vehicle
Buses & Public Transport	Moderate	Long range, quick refuelling, suitable for high-frequency service + long distance	Higher fuel cost vs BEV, need for depot refuelling infra	Long/high-demand routes, subsidies, low-emission zones	Strong alt. to diesel in long/fast-turnaround routes; BEVs dominate short predictable ones
Garbage trucks	High	Continuous availability, fast refuelling, suited for multi-shift ops	H_2 infra cost, TCO vs BEVs/diesel	Intensive daily ops with minimal downtime, centralized depot refuelling, competitive green H_2 supply	Strong option for emission-free, uninterrupted municipal service; BEVs still more economical for short, overnight-chargeable routes
Rail (non-electrified)	High	Zero-emission replacement for diesel, range & flexibility vs battery trains	Refuelling infra, green H_2 cost	Non-electrified lines, mid-range services, regional infra integration	Ideal for lines where electrification is uneconomical
Boating	Inland: Moderate; Maritime: Case-specific	Zero-emission inland, ammonia/LOHCs possible for maritime	H_2 low volumetric density, cost, energy losses	Regional freight corridors with local green H_2, short-sea shipping	Inland: good potential; Maritime: ammonia/methanol likely for long haul

Author of this table: Pôlénergie

9 Indicators

As part of our analysis, we have been looking at some key indicators per country studied. These countries have been selected to correspond to the location of the project pilots.

Indicator	Notes	Sources	EU	France	Denmark	Netherlands	Sweden
H_2 production (Mt/year)	Installed capacity for H_2 Production (every origin) in 2023	Observatory clean hydrogen	11,23	0,92	0,03	1,48	0,22
Share of green/yellow hydrogen (%)	Hydrogen produced with water electrolysis in 2023	Observatory clean hydrogen	0,4%				
Total Capacity of water electrolysis in operation (MW)	Total Capacity of water electrolysis in 2023	Observatory clean hydrogen	236	17	4	7	30
Total capacity (MW) of water electrolysis projects	Next projects of water electrolysis under construction	Observatory clean hydrogen	1 857	227	99	212	833
Total number of water electrolysis projects	Total number of water electrolysis projects in operation + Under construction	Observatory clean hydrogen	154	21	9	9	7
Hydrogen's Balance of trade in t	X - M hydrogen importation with the world in 2023 in t	Comtrade		+169	- 163	-14 81	+ 1 169
Average LCOH via electrolysis directly connected to a renewable electricity €/kgH2	In 2023	https://www.iea.org/data-and-statistics/data-tools/levelised-cost-of-hydrogen-maps , Observatory clean hydrogen	6,61€	≈ 6,6€	≈ 4,5€	≈ 5,8€	≈ 5,5€
Electricity mix	**Share of production of electricity from renewable sources in 2022**	https://www.consilium.europa.eu/en/infographics/how-is-eu-electricity-produced-and-sold/		27%	89%	47%	70%
Average wholesale electricity price (€/MWh)	Price dates: 24/10/2025	https://euenergy.live/		37,79€	38,05€	36,62€	37,47€ (south of Sweden)
Grid carbon intensity (gCO_2/kWh)	Grid carbon intensity (gCO_2/kWh) in 2023	European Environnement Agency	210	50	94	263	8
H_2 pipeline length (km)		(Lipiäinen, Lipiäinen, & Vakkilaine, Use of existing gas infrastructure in European hydrogen economy, 2023)	1 500				
Number of HRS (public)	Publicly accessible and operational HRS	Observatory clean hydrogen	186	30	2	23	6
Average distance between HRS (km)							
Cost of hydrogen at pump (€/kg)		https://h2.live/en/ https://alternative-fuels-observatory.ec.europa.eu/consumer-portal/fuel-price-comparison		Between 16,5€ and 20€ (Paris) in 2025	No data available	20,139€ (2025)	20.85€ (2025)
FCEV fleet – buses	National deployment of fuel cell buses in 2023	Observatory clean hydrogen	464	27	4	64	2
FCEV fleet – trucks	National deployment of fuel cell trucks in 2023	Observatory clean hydrogen	215			35	
FCEV fleet – passage cars	national deployment of fuel cell passenger cars in 2023	Observatory clean hydrogen	4938	614	232	615	44
FCEV fleet - boats		Lack of informations					
Share of energy from renewable sources used in transport in Europe (%)	**Share of energy from renewable sources used in transport in 2023**	European Environnement Agency	10,1%	9,6%	11,1%	11,2%	29,5%
Expected HRS density 2030							Plan to open 25 more (10 in 2025)
Hydrogen cost forecast 2030 (€/kg)							

Author of this table: Pôlénergie

10 Gap Analysis

As a follow up of the first table, below is an analysis, country per country, of the gaps that has to be overcome for a more competitive hydrogen economy.

Indicator	High / Average / Low	Gap	Consequence	Strategic action
H_2 production (Mt/year)	Netherlands France Denmark, Sweden	Most current production is grey/blue, green share negligible (0.4%)	Risk of dependency on imports or neighbours.	Support national scaling to ≥1 Mt/y per country by 2030; align with import corridors (ports).
Share of green/yellow hydrogen (%)	Denmark, Sweden, France, Netherlands	Installed capacity is <1% of target	Green H_2 scarcity → LCOE remains high, fails decarbonization targets.	Accelerate RES electrolyser coupling; enforce quotas for green H_2 in transport.
Total Capacity of water electrolysis in operation (MW)	Sweden France, Netherlands, Denmark	Installed capacity is <1% of target	Current installed capacity negligible	Fast-track permitting; expand pilot-to-industrial scaling; EU CAPEX support for <100 MW units.
Total capacity (MW) of water electrolysis projects	Sweden Netherlands, France Denmark	EU = 1,857 MW. SE (833) dominates, FR/DE/NL lagging.	Risk of *geographic concentration* → bottlenecks in corridors.	Coordinate EU pipeline (IPCEI, TEN-E); ensure balanced distribution along freight routes.
Total number of water electrolysis projects	France Netherlands, Denmark Sweden	Fragmented landscape: EU total = 154 projects, but most countries in scope are below 15. France has 21,	Fragile pipeline, vulnerable to project delays or cancellations.	Diversify project sizes & ownership (utilities, municipal, private).
Hydrogen's Balance of trade in t	France, Sweden Denmark Netherlands	Very divergent: FR = +169, DK = −163, NL = −14,819, SE = +1,169.	Heavy import dependence (NL) exposes to price shocks & external supply risks.	Secure EU-internal supply contracts; strengthen cross-border trading platform for H_2.
Average LCOH via electrolysis directly connected to a renewable electricity €/kgH2	Denmark, Sweden Netherlands, France	Current costs ×2 benchmark Target ≤ 3 €/kg (Clean Hydrogen JU)	Major competitiveness asymmetry; FR risk of being most expensive	Use RES PPAs for low-cost green H_2; streamline grid fees; cross-border H_2 exchange.
Electricity mix	Sweden, Denmark Netherlands France		Risk of "non-green" H_2. Sweden clearly advantaged.	
Average wholesale electricity price (€/MWh)	Sweden, France, Netherlands, Denmark	Sweden benefits from lower and greener electricity mix, in particular in the north; France has average prices but relies on nuclear instead of variable RES.	High power cost in FR/DK/NL keeps H_2 uncompetitive vs. diesel.	EU auctions to guarantee cheap RES for electrolysers. cross-border balancing with Nordic low-cost green energy
Grid carbon intensity (gCO_2/kWh)	Sweden France, Denmark Netherlands	Carbon-neutral grid 2050	dirty" H_2 risk in NL. Sweden is optimal benchmark.	263

H_2 pipeline length (km)	Netherlands, France Sweden, Denmark	Fragmented infrastructure, early stage, not many data	Chicken and egg problem	
Number of HRS (public)	Netherlands, France Sweden, Denmark	Current density insufficient	Uneven coverage; Denmark & Sweden critically low.	Public-private co-investment; mandate HRS deployment every 150 km in TEN-T corridors.
Average distance between HRS (km)	France Netherlands, Sweden		Range anxiety for FCEV; breaks long-haul corridor feasibility	Coordinated EU corridor HRS siting; focus on HDV routes (RTE-T)
Cost of hydrogen at pump (€/kg)	France Netherlands, Sweden	Pump price ×3 benchmark	High retail prices = low adoption; uncompetitive vs. diesel (diesel ~1.7 €/L).	Subsidize H_2 retail in early markets; CAPEX/OPEX support for HRS; EU excise exemption.
FCEV fleet – buses	Netherlands Denmark, Sweden, France	Very low deployment	Market too small to scale infra; SE critically underdeveloped	
FCEV fleet – trucks	France, Netherlands Denmark Sweden	Pilot stage only	Weak adoption delays HDV corridor viability	Deploy EU HDV subsidy scheme; integrate with logistics hubs
FCEV fleet – passage cars	France, Netherlands Denmark Sweden	Limited uptake, high price barrier	Passenger market not scaling; infra underused.	Focus on captive fleets (taxis, corporate); do not over-prioritize cars vs. HDV.
Share of energy from renewable sources used in transport in Europe (%)	Sweden, France, Netherlands, Denmark	Most countries below target (except SE)	11,1%	Increase blending mandates; allocate RES fuels quota to H_2-based fuels.
Expected HRS density 2030		Plans unclear & not harmonized across countries.	No EU-wide coverage guarantee → risk of fragmented corridors.	EU regulation for minimum coverage density; joint roadmap by TSOs & OEMs.

Author of this table: Pôlénergie

Synthesis country per country

🇩🇰 Denmark – Strong potential but lagging behind on hydrogen

Strengths: 100% renewable electricity mix, low-cost green hydrogen production potential.
Weaknesses: very limited infrastructure and end-use development, few projects deployed to date.
Positioning: a promising outsider. Still in a preparatory phase, but could catch up rapidly thanks to its green electricity and strong renewable culture.

🇫🇷 France – A lot of potential projects but slow industrial rollout as well as interest vs. direct electrification

Strengths: strong infrastructure coverage (pipelines, HRS), nuclear potential for low-carbon hydrogen – high production of electricity.
Weaknesses: limited green hydrogen production (nuclear not recognised as RFNBO), slow scaling-up process, social support.
Positioning: needs to accelerate industrialisation, green the electrolysis process, and better target end-use sectors (industry more than mobility except for some niche application in HDV).

🇳🇱 The Netherlands – Ambitious offensive on H2 but still highly dependent

Strengths: proactive national policy, major hydrogen hubs (Port of Rotterdam), strong public–private coordination.
Weaknesses: carbon-intensive power mix, high costs, dependency on hydrogen imports.
Positioning: a European industrial and logistics frontrunner, yet structurally vulnerable if domestic production fails to take off. H2 is seen as a way to compensate an overwhelmed electric network.

🇸🇪 Sweden – Quiet green leader with limited end-use development

Strengths: low-carbon mix (hydropower + nuclear), advanced industrial projects (e.g. HYBRIT), low production costs.
Weaknesses: limited end-use sectors (mobility, H_2 infrastructure still embryonic).
Positioning: a clean hydrogen production potential champion, but probably lacking a strong local demand. Risk of building a supply chain disconnected from demand. Potential of exportation.

11 Key Market Drivers for Low-Carbon Hydrogen

Expansion of Renewable Energy
The growth of renewable energy will be a key driver for green hydrogen. As wind and solar projects scale up, electricity from these sources is expected to become cheaper, particularly through long-term supply contracts. Since power costs make up a large share of hydrogen production expenses, this downward trend will directly improve competitiveness. At the same time, more renewable generation will provide the low-carbon electricity needed to make hydrogen a credible solution across industry and transport.

Carbon Pricing and Fossil Fuel Volatility
Stricter carbon regulations are making fossil-based hydrogen less attractive. Rising carbon prices in Europe, combined with the volatility of gas markets, put additional pressure on grey hydrogen. This shifting cost balance creates a more favorable environment for green and low-carbon hydrogen, which is increasingly seen as a safer long-term investment.

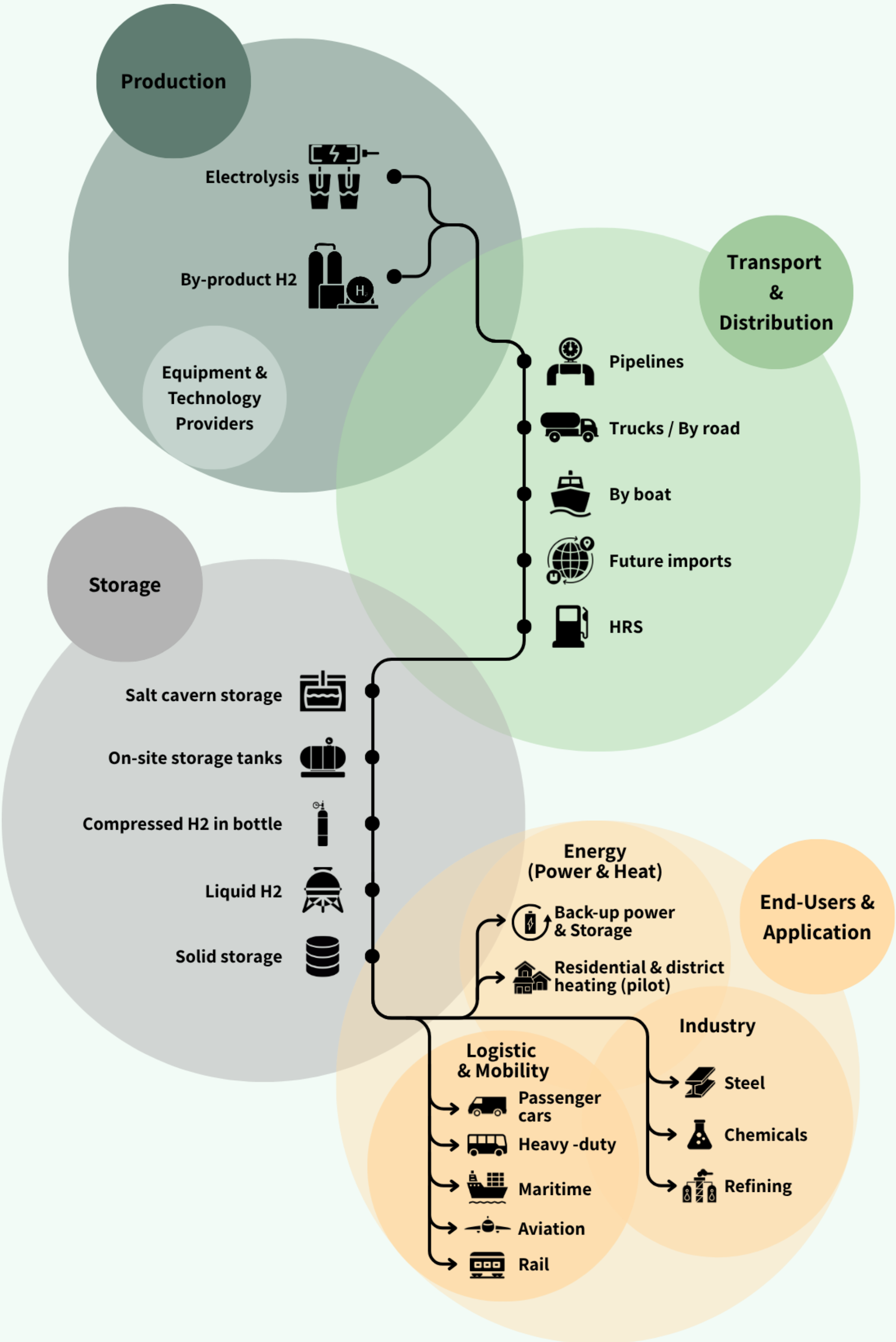
Industrial Scale-Up and Public Support
Government support has accelerated sharply in recent years, with many countries putting hydrogen at the center of their climate and energy strategies. Funding programs, roadmaps, and direct incentives are helping the industry move from pilot projects to large-scale deployment. This scale-up is expected to bring significant cost reductions through economies of scale and technical learning, gradually closing the gap with fossil alternatives.

Equipment Costs and Technology Progress
Hydrogen technologies are becoming more affordable as production moves from small batches to mass manufacturing. Electrolyser prices are expected to keep falling over the next decade, while advances in materials and design are improving efficiency. Similar trends are underway for fuel cells and storage systems, where costs are projected to decline as new solutions reduce the reliance on expensive metals. Together, these developments will make hydrogen increasingly viable in areas where batteries or direct electrification are less suitable.

12 France case study: the Hydrogen value chain

As an example we suggest to deep dive into the French hydrogen value chain. These tables are made to be a source of inspiration for the other pilots of the project.

Hydrogen Value Chain in France



Production

Electrolysis (Green H2)

Air Liquide
Electrolysers in Dunkerque, Normandie, Fos-sur-Mer).

ENGIE
Massyliah project (40MW electrolyzer, with TotalEnergies)

EDF, Hynamics
Several projects linked to industrial sites and mobility hubs.

H2V
Multiple large-scale projects (Dunkerque, Normandie, Fos, etc)

McPhy
Electrolyzer manufacturing (Belfort Gigafactory)

Lhyfe

Equipment & technology providers

Electrolyzers :
McPhy, elogen, Siemens Energy, gen-hy, nel, sunfire, H2B2, John Cockerill

Fuel cells :
PowiDian, CLHYNN, inocel, GenCell, Symbio

Storage tanks :
Air Liquide, OP, Forvia Faurecia, Mahytec

Membrane plant for electrolyzers :
Chemours

Engineering firms :
TEN Technip Energies, VINCI, bouygues

By-product H2

Refineries and chemical plants :
ARKEMA, TotalEnergies, BOREALIS

Carbon capture pilots linked to SMR :
H2 blue roadmap still limited in France

Transport & Distribution

Pipelines

Air Products, Teréga, GRTgaz, Air Liquide

By boat

Air Products
40 foot containers.

Trucks / By road

Air Products, Messer Gases for Life, Air Liquide, Linde
Tube trailers for compressed H2 transport.

Future imports

Feasibility studies for H2 terminals in Fos-sur-Mer, Le Havre, and Dunkerque.

HRS

All types of mobility :
Air Liquide, ataway, McPhy, Proviridis, Air Products, HRS

Light vehicle and commercial vehicles :
pdc, TOP Industrie High Pressure Technology

High-duty vehicles :
Madic group, Hynamics, McPhy, ataway

Storage

Compressed H2 in bottle

FORVIA Faurecia · ROTH2

Salt cavern storage

Terēga · Geostock · storengy

Liquid H2

Absolut Hydrogen · Cryofab · Cryolor

On-site storage tanks

Air Liquide · McPhy · Hexagon Purus

Solid storage

Mahytec · Mincatec Energy

End-Users & Application

Logistic & Mobility

Passenger cars :

hype · HYVIA

Heavy-duty (trucks, buses, coaches) :

Gaussin · Stellantis · SAFRA · hyliko

Trucks & buses in pilot operations.

Dunkerque Grand Littoral · La Région Occitanie · La Région Auvergne-Rhône-Alpes

Regional projects (investing in H2 bus fleets).

Rail :

ALSTOM

Hydrogen trains tested in Occitanie and Bourgogne-Franche-Comté.

Aviation :

AIRBUS zero^e

Research for hydrogen-powered aircraft.

SAFRAN

Turbine and fuel cell R&D.

Maritime :

Chantiers de l'Atlantique · Energy Observer · Sogestran Group · Interreg North-West Europe H2SHIPS

Hydrogen powered ships, ferries, demonstrators.

Industry

Steel :

ArcelorMittal

H2 for direct reduced iron.

Chemicals :

KEM ONE · BOREALIS · ARKEMA

For chemicals processes, substitution of grey H2.

Refining :

TotalEnergies

Use of H2 in hydrocracking & desulfurization.

Energy - Power & Heat

Backup power / storage :

Schneider Electric · EDF · engie

Fuel cells for data centers and critical infrastructure.

Residential & district heating (pilot) :

Projects in GRHYD (Dunkerque) : blending H2 into natural gas grids.

Author of these tables: Pôlénergie

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Project Title:	**Igniting H2 Transport Innovation Ecosystems in the North Sea Region**
Acronym:	H2ignite
Call:	Call 4C (FA)
Priority:	Priority 1. Robust and smart economies in the North Sea Region
Priority specific objective:	Developing and enhancing research and innovation capacities and the uptake of advanced technologies
Start date:	01/09/2024
Duration:	36 Months
Website:	www.interregnorthsea.eu/h2ignite
Consortium:	Ministerium für Landwirtschaft, ländliche Räume, Europa und Verbraucherschutz (MLLEV) - Germany Kiel Institut für Weltwirtschaft – Leibniz Zentrum zur Erforschung globaler ökonomischer Herausforderungen (IfW) - Germany Europa-Universität Flensburg (EUF) – Germany Hafen Hamburg Marketing e.V. (HHM) - Germany Region Sjælland (STRING) – Denmark DFDS A/S (DFDS) – Denmark Københavns Universitet (UCPH) – Denmark Pôlénergie (POL) - France Provincie Drenthe (Drenthe) - Netherlands Lindholmen Science Park AB (LSP) – Sweden Volvo Technology Corp. (VTEC) - Sweden