NATIONAL ACADEMY OF TECHNOLOGIES OF FRANCE

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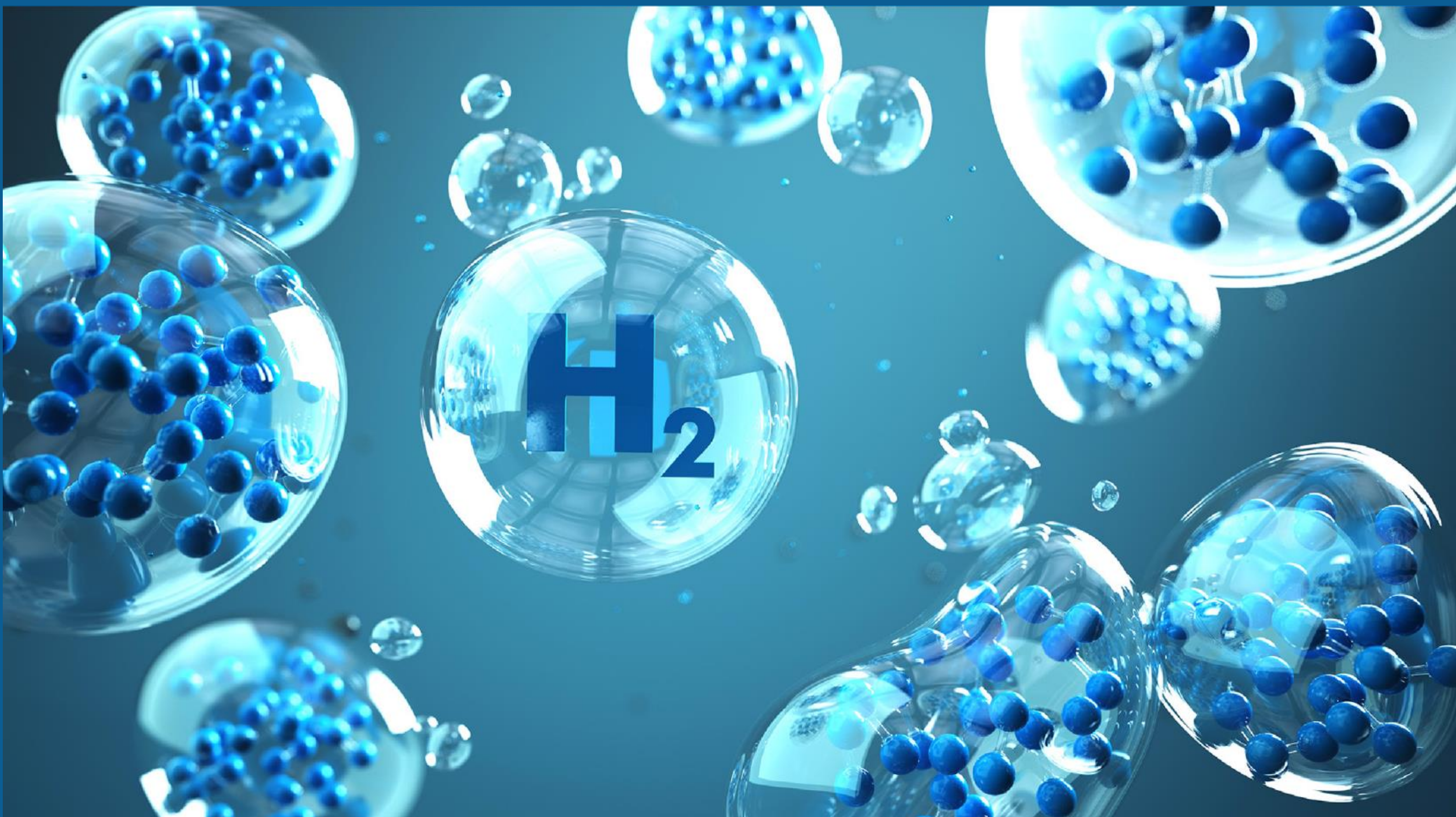
The Role of Hydrogen in a Decarbonised Economy

Report of the National Academy of Technology of France



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"Yes, my friends, I believe that water will one day be employed as fuel, that hydrogen and oxygen which constitute it, used singly or together, will furnish an inexhaustible source of heat and light, of an intensity of which coal is not capable"

Jules Verne "The mysterious island" 1874

Table of contents

Summary of the report

Hydrogen is in the universe as simple an atom as it is abundant. Its chemical and energetic properties are manifold, which sometimes gives it the nickname "Swiss Army Knife". Hydrogen is widely used in industry ("raw material" hydrogen, hereafter in this report referred to as "*Material hydrogen*"), particularly in refineries to produce light or desulphurised fuels, in chemistry to produce ammonia and fertilisers, potentially in the steel industry to produce steel by reducing iron ore, etc. France produces and uses 922,000 tonnes of hydrogen per year and has several private hydrogen transport networks, more than 300 km long. World production, which is growing, is close to 70 million tonnes.

The objectives of drastic reduction of CO_2 emissions, or even carbon neutrality in 2050, are causing in many countries, including France, renewed interest in energy applications of hydrogen whose combustion does not emit CO_2 or fine particles. New "energy" uses of hydrogen are being considered, such as injection of up to 20% into natural gas networks, conversion into methane or liquid fuels (e-fuels and in particular synthetic fuels for air transport), electricity by direct conversion into stationary (powering eco-districts or buildings) or vehicle-mounted fuel cells (FCs). Hydrogen is sometimes referred to as a storage vector for intermittent solar and wind energy, after production by electrolysis and then reconversion into electricity in FCs (*Power-to-Gas-to-Power*).

The objective of the academy's report is to present the possible roles of hydrogen in the ecological transition, to propose an amplification of research and development (R&D) efforts in certain areas and to recommend areas for industrial development. It includes an international benchmark.

The hydrogen value chain.

Production

Most of the hydrogen is currently produced by steam reforming of hydrocarbons. The processes are mature, but highly CO_2-emitting. Production processes using electrolysis (alkaline, or with proton exchange membranes "PEM") are mature, but significantly more expensive than steam reforming. Hydrogen produced by electrolysis is a decarbonised carrier only if the production of electricity is also decarbonised.

The costs of electrolytic hydrogen are determined by the price of electricity (75% of the total cost), far ahead of the depreciation of the installations if they are used at least 3,000 to 4,000 h/year. Electrolytic hydrogen produced with renewable electricity will remain consistently more expensive (€5-8/kg) than reforming hydrogen (€3.0-4.5/kg including CO_2 capture and storage) as long as market prices for natural gas remain low. Exploiting the energy properties of hydrogen produced by electrolysis can only be justified if the price per tonne of CO_2 avoided is significantly above €100/t.

The energy content of the hydrogen needed to decarbonise a significant proportion of French final energy consumption would mobilise more than 275 TWh of electricity if the hydrogen were produced exclusively by electrolysis. This increase of more than 50 % in annual electricity production would require doubling the current installed capacity, if carried out solely by intermittent renewable energies (variable and non-controllable).

It seems more realistic to envision hydrogen production (1) by electrolysis of water with nuclear electricity to ensure a high load factor of the electrolysers), (2) by electrolysis of water with intermittent electricity, and (3) by steam reforming with CO_2 capture and storage (CCS). French know-how in this field is significant, making it possible to envisage the development of an industrial sector. But it will only develop in France if it is accepted by society, and if the penalty for the tonne of carbon emitted (EU-ETS price) increases significantly.

Transport and storage

Currently hydrogen must be compressed for transportation and storage. These operations have a direct impact on the hydrogen economy. For short distances, transport is carried out in pressurised tanks (currently 220 bar). Hydrogen pipelines are possible for large distances and quantities. On-board storage of hydrogen for mobility (700 bar) has progressed thanks to carbon fiber composites (or others) that make the tanks lighter. However, their shape is cylindrical, which does not facilitate their integration into vehicles.

Utilisations

In this context where hydrogen presents multiple attractions, but also costs, its use should primarily concern **two sectors, "Material hydrogen" for industry and "Energy hydrogen" for mobility.**

The most obvious and immediate need is the **substitution of carbonated hydrogen** from reforming processes with decarbonised hydrogen produced by electrolysis. This can be done quickly for **the territorially dispersed chemical industry**, which pays a high price for hydrogen due to the lack of real competition between suppliers and the high cost of packaging and transport. In addition, new uses need to be promoted for decarbonising certain industries (iron and steel and possibly cement plants).

Hydrogen-based mobility provides a range that battery-based-only mobility cannot provide. Some forms of mobility (boats, trains, trucks and buses) cannot be decarbonised by electric batteries whose density per mass and volume is too low.

It is reasonable to assume that hydrogen mobility will initially develop only from a limited number of distribution points, effectively reserving its use for heavy transport and local vehicle fleets. Finally, rail traction and ships (for short distances, but also stationary in port) will be able to use hydrogen as a substitute for hydrocarbons and in particular for heavy fuel oil.

The injection of decarbonated hydrogen into existing gas infrastructures as a substitute for natural gas should be a third lever to boost demand and create reliable sources of production, as the IEA points out [32]. Admittedly, the cost of avoided CO_2 is high, but this is because natural gas is cheap and has low CO_2 emissions.

The massive use of hydrogen as an intermediate storage of intermittent electrical energy (wind and solar) in the **Power-to-Gas-to-Power** chain faces daunting obstacles due to the large volumes required for the underground storage of hydrogen and the low load factor of the electrolysers and fuel cells in the "conversion-storage-conversion" chain, which places a considerable burden on costs.

The various possible uses of hydrogen will be in competition, since production capacities by electrolysis are necessarily limited. For example, producing the hydrogen currently consumed in France (922 kt) would require nearly 50 TWh of electricity; this hydrogen could alternatively power some 10 million light electric vehicles, i.e. about a third of the total number of light vehicles in France; hydrogen could also be used to decarbonise certain industries or to produce gas and synthetic fuels. These different uses could require nearly 300 TWh of electricity, which would far exceed the intermittent electricity surpluses of a 100% renewable mix. The different electricity, gas and hydrogen sectors are interdependent and a systemic approach to the production and uses of hydrogen is needed.

The development of the hydrogen sector will require the creation of considerable infrastructures for its production, delivery to vehicles, transformation into methane or synthetic liquid fuels or, after storage, into electricity, etc. These investments will have to be made when there is no demand: only the State will be able to assume this risk.

Security

The deployment of hydrogen outside the industrial sector will be associated with consumer uses, increasing the potential for accidents, particularly in the mobility, residential and tertiary sectors. This new risk will have to be taken into account and existing standards and regulations that are based on significant feedback from experience acquired in another context will have to be adapted.

Operations for demonstration purposes; research and development

We must take advantage of the strong motivation of the territories to initiate "demonstrators". Some projects are part of larger research and development programmes. But others aim essentially to be showcases for known and often imported technical solutions; they must be supervised at the national level, and a periodic and transparent assessment of these operations must be carried out.

French public research has identified many promising technologies with variable Technology Readiness Levels (TRLs), such as high-temperature reversible electrolysers, plasma torches, native hydrogen, hydrogen from bacterial activity and/or 2nd generation biogas-type processes, all of which are promising avenues; the development of these technologies is insufficiently supported, and their passage to the industrial pilot stage should be encouraged. The same is true for transport techniques where French R&D is present, but sometimes not on the national territory due to a lack of an adequate regulatory framework.

Towards a French/European Hydrogen Industry

The key technologies (electrolyser, fuel cell, on-board hydrogen reservoirs, etc.) exist; almost all of them are mature and can be industrialised.

The French ecosystem of equipment manufacturers is alive and well and covers these key technologies and provides the required components (connectors, valves). Nevertheless, these companies are small or even very small enterprises and will find it difficult to apprehend the market, which, being global, implies very high commercial prospecting costs. Consolidation of the sector will impose itself sooner or later; in the meantime, small players will need the support and credibility of more powerful actors, while avoiding drying up their creativity and agility. This ecosystem must benefit from targeted calls for tender in France and Europe to help companies grow. Furthermore, as at this stage of development these companies are confronted with the well-known problems of growth management and difficult access to equity capital, such support is an opportunity for France to develop a new industry in a timely manner.

The major French integrators (Air Liquide, Engie, EDF, Total, etc.) are present, particularly in terms of the orders they place and the operations - some of them of significant size - that they often initiate or announce with the support of public authorities. Their knock-on effect on French and European industry is not always sufficient.

International Benchmarks

Many countries are committed to the hydrogen challenge with a national strategy, stimulation of the demand for decarbonised hydrogen, incentives for hydrogen mobility, risk coverage for early investors and research programmes. Among the most dynamic countries and in descending order of effort outside Europe: Japan, Korea, China, the United States (California in the lead), Australia; and in Europe: Germany, the Nordic countries, France and the United Kingdom.

Several of these countries (Germany, Japan, Korea, etc.) consider that they have limited potential for national production of decarbonised hydrogen, and are considering, despite the difficulties of maritime transport of hydrogen, its massive import from countries that would produce it from natural gas or coal and capture of CO_2 (Australia for Japan, Russia for Europe), or from electrolysis in countries where renewable energies can be very competitive.) The geostrategic implications of these policies are complex.

Recommendations

Based on these observations developed and supplemented in the report, the main recommendations of the National Academy of Technology of France are as follows. Barring duly noted exceptions, they are addressed to the public authorities.

RECOMMENDATION 1: Prioritise and promote hydrogen applications for the energy transition by considering the cost per tonne of carbon that is avoided in this way.

1.1: Decentralised production of hydrogen by electrolysis for uses in territorially dispersed industries, rather than by natural gas reforming, has a positive carbon balance at no additional cost to the consumer. It should be made a priority.

1.2: The Academy recommends making the distribution of hydrogen for mobility the subject of a national policy like in Germany. Heavy transport (trucks, buses and coaches, rail, river and sea transport) and local urban and suburban vehicle fleets should have priority. This calls for the establishment of a national co-ordination structure for public and private actors from all sectors of the hydrogen industry. Priority should also be given to equipping the vicinity of major regional capitals, especially where there are logistics centres. The network will further develop along the main corridors and as a fleet of hydrogen vehicles develops. Particular attention must be paid to safety issues.

1.3: France has an extensive natural gas network. The Academy recommends that, in a phase of development of the hydrogen economy, the injection of decarbonised hydrogen into gas networks should be encouraged, despite the high cost per tonne of CO_2 thus avoided, to sustain demand and in this way benefit from economies of scale in production.

1.4: The Academy recommends the development of industrial demonstrators for 100% hydrogen storage and distribution systems, especially for energy supply to non-interconnected areas (NIAs) or for export. However, the massive storage of hydrogen for huge amounts of electricity generation in the Power-to-Gas-to-Power logic has no convincing business model by 2050.

RECOMMENDATION 2: Develop a supportive policy framework

2-1: Like the major countries with which it is in competition, France must have a vision and an ambitious, shared and clear hydrogen industrial policy. The initiatives of the territories, and in particular the regions, often involve industrial demonstrators. The Academy recommends encouraging these initiatives with the aim of contributing to the industrial development of the French hydrogen industry: hydrogen policy cannot result from the mere aggregation of regional initiatives and must be driven and supervised by the government at the national level.

Public authorities could, in full transparency and independently of hydrogen promotion bodies, assess the coherence of the overall policy and the results achieved.

2-2: The Academy recommends that public authorities, in liaison with industry, universities and research laboratories, should produce System Analyses and overall scenarios, coupling in particular the electricity and gas sectors, including hydrogen and the CO_2 emissions, and thus making it possible to appraise the opportunities, costs and time horizons of the various options.

2-3: Pre-normative, normative and regulatory efforts should be continued, particularly for the safety of consumer or semi-consumer applications at European level. In continuing current practices, regulatory work must involve the administration and all stakeholders (fire brigades, technical centres, equipment manufacturers, operators, users, etc.).

2-4: The European Union must establish a classification of the different types of hydrogen during its production. The qualification of green hydrogen must be reserved for decarbonised hydrogen (electrolysis with decarbonised electricity).

RECOMMENDATION 3: Promote a French and European industry encompassing the entire hydrogen chain.

Beyond the electrolyser, the main elements are storage, transport, distribution and consumption. These elements interact to form a system, the operation of which is dictated by the intermittency of certain renewable sources of electricity (variable and non-controllable) and the fluctuation of consumption.

3.1: There are mainly two modes of production of decarbonised hydrogen:
- hydrocarbon reforming and water reduction with CO_2 capture and storage or utilisation (CCUS);
- electrolysis of water by decarbonised electricity.
The reforming/CCUS path should be developed when the economic conditions are right, especially since France has players of international stature.

It is up to the public authorities to promote a French and European electrolyser/fuel cell industrial sector with a view to reducing costs and achieving the required functionalities (variable electrolyser load, etc.).

3.2: A policy of business support should be put in place in all areas of the hydrogen sector, especially the value-added links in the chain, giving priority to French equipment manufacturers by stepping up equity investments, equity support, repayable loans and cash flow support, and by encouraging cooperation between French or at least European-based and -governed players.

3.3: Demonstration, pre-deployment and deployment operations organised by the territories create demand. They must be valorised by ensuring that they do not have as their main consequence the importation of equipment produced in Asia or North America.

3.4: The exploration for native geological hydrogen must be encouraged.

RECOMMENDATION 4: Preparing for the future through an increased French and European R&D effort

4.1: Research and development must be stepped up to help launch the industrial sector and the emergence of French groups with global ambitions. The entire chain must be supported in parallel: hydrogen production (many alternative processes are possible) transport, storage and use, particularly for mobility. Public funds should be made available to support as a priority the potential levers for change at the intermediate (3 to 6) or low TRL (*Technology Readiness Levels*). This should be done in order to build prototypes and then move on to pilots and industrialisation.

Report of the National Academy of Technology of France

1. Introduction

Hydrogen, by virtue of its simplicity, the multiplicity of its uses and modes of production, and its potential to be a clean energy source, has attracted the attention and fascination of people from Jules Verne (The Mysterious Island) to today's political leaders.

In the 1970s, after the first oil crisis, governments entrusted the International Energy Agency (IEA) with setting up Hydrogen and Fuel Cell Collaborative Programmes. In the 1990s, a few major countries and regions (Japan, European Union, Canada), motivated by initial concerns about climate change, launched large-scale operations to support the development of hydrogen. In the 2000s these expressions of interest were extended, notably by the United States, which launched the *International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE)* in 2003, amplifying the action of the IEA. However, this wave of interest came to an end with the move away from Peak Oil, and the conviction that the cost of the infrastructure required by electric vehicles was much lower than that of hydrogen.

Today, however, the interest in hydrogen appears to be more widespread and profound. More than half of the G20 countries have defined a hydrogen strategy including production, uses, transport, storage and an associated industrial policy. The main drivers of this renewed interest are climate change and the energy transition. It is recognised that a massive development of renewable energies requires the storage of electricity surpluses over several weeks or even months, which can be expected from the hydrogen vector. Hydrogen would subsequently be used in mobility or directly in gas networks.

Hydrogen is therefore the subject of growing interest in Europe as well as in Asia and the United States, with all countries adopting a strategy and launching large-scale projects. In France, for example, since 2015 in Paris, we have seen an increase in the number of azure blue hydrogen taxis, Hydrogen buses in several provincial towns, and Hydrogen bicycles here and there, for example in Biarritz.

The Paris agreement of 2015 aims to contain global warming; and in France the 2017 climate plan aims to achieve carbon neutrality by 2050. They oblige us to explore all avenues to achieve these ambitions. Decarbonised hydrogen, whether as a raw material or energy, must be evaluated as one of the means to achieve carbon neutrality while enabling the creation of a French/European industrial sector.

This report aims to establish the potential of decarbonised hydrogen, to point out the promising paths but also the bad good ideas, to identify the roadblocks and to propose recommendations to create a French/European dynamic. It is aimed both at the general public who wish to be informed about the challenges of hydrogen and at the public authorities who must implement a policy of research, development and industrialisation.

This report consists of eight chapters; the first chapter positions the subject and announces the outline of the report.

The second chapter presents the main physical and chemical characteristics of hydrogen and introduces its two main modes of use: today essentially "*Material hydrogen*" used for its chemical properties, mainly in refineries (hydrocracking and desulphurisation) and in the chemical industry (production of ammonia and fertilisers); and in the future "hydrogen energy" used for its energy properties, either in combustion or to produce electricity in a fuel cell.

The third chapter reviews the hydrogen technology value chain from production to storage and distribution (the use is discussed in Chapter 2). In particular, the main current production method (methane reforming) and electrolysis as envisaged in France for future production are examined.

The fourth chapter is devoted to safety issues (ignition and explosion), the progress made in this area, in particular for use by the general public or semi-general public, and the developments required, particularly with regard to regulation.

The fifth chapter analyses this industrial sector's economic costs and the progress that needs to be made in order to achieve competitiveness. This will only be achieved if the cost per ton of carbon avoided by the use of decarbonised hydrogen is valued; evaluations of this cost are proposed according to the different uses.

The sixth chapter is devoted to emerging technologies and the research and development required; some technologies are emerging, such as the exploitation for native hydrogen deposits.

The seventh chapter presents the hydrogen plans of a few large countries, or intermediate countries similar to France (United States, China, Japan, Spain, United Kingdom). It shows that despite similar intentions, ambitions can be very different depending on the specific situation in each country.

The eighth chapter presents the French industrial sector, including small companies or *start-ups* that are positioning themselves on this emerging market, and some major French groups.

The conclusion given in Chapter 8 sets out the academy's findings for hydrogen to play its role in the energy transition with the support of a rational public policy aimed at developing an industrial sector.

2. Why be interested in hydrogen?

Hydrogen, with atomic number 1 and symbol H, is the simplest element in the universe. It is also the most abundant: 75% by mass and 92% by number of atoms of stars, nebulae, gaseous planets and interstellar gas[I]. It is present in the atmosphere only in trace amounts (0.55 ppm)[II]. However, it is massively present in water and therefore in the oceans; associated with carbon, it is the main constituent (in number of atoms) of all living matter. For example, hydrogen is present in 63% of molecules and constitutes 10% of the mass of the human body[1].

The dihydrogen molecule (later to be called "hydrogen") was identified in 1766 by Cavendish; Lavoisier demonstrated that it combined with oxygen to form water and gave it his name (1783). This atom has two other isotopes, deuterium and tritium, the latter being radioactive and unstable.

Hydrogen was used as an energy source for transportation in the late 19th and early 20th centuries before being supplanted by liquid hydrocarbons. It nevertheless remained very present in Europe until the 1960s, since the "town gas" produced in the 19th century by anaerobic pyrolysis of coal and then by carbo-reduction of water by coal contained up to 50% hydrogen.

The physical, chemical and energy properties of hydrogen are particularly remarkable. They are briefly presented below as they condition the production and uses of hydrogen; they are detailed in Annex 1.

The melting and boiling temperatures of hydrogen are very low (- 259.14°C/- 252.87°C) and hydrogen is therefore mainly used in gaseous form. It is very light (density of 0.083 g/l at 20ºC and 1 atmospheric pressure) and must therefore be stored at high pressure. Hydrogen can be combined with most simple compounds. With carbon, it forms hydrocarbons and is the basis of organic chemistry; in combination with metals, it forms hydrides which are a way of storing hydrogen. These properties make *Material hydrogen* an indispensable element in many chemical processes.

Hydrogen has a high calorific value, 2.5 times that of methane per unit mass. Hydrogen is therefore envisaged as an energy carrier in the future, or even an energy source[2]. However, due to its low density, its calorific value per unit volume is low. Used as a substitute for methane in gas networks, three times the volume of hydrogen is needed to provide the same energy as methane.

2.1. Hydrogen today: essential uses in the petrochemical and chemical industries

The global hydrogen market is estimated at approximately $135 billion in 2018 with a prospect of reaching $200 billion in 2023, with a growth rate of 8% differing from one geographic region to another[3]. World production in 2018 was around 70 Mt/year of pure hydrogen from 273 Mt of hydrocarbons (mainly methane) to which must be added 40 Mt/year of hydrogen co-produced with carbon monoxide and used in chemical processes. Annual French production is slightly less than 1 Mt/year.

The main distributors of hydrogen in the world are: Air Liquide (France), Air Products and Chemicals (US), Praxair (US), Iwatani (Japan), Linde (Germany), Messer Group (Germany), etc.

[I] This result was established in 1923 in her thesis by Cecilia Payne-Gaposchkin (1900 - 1979), although it was not really admitted until it was confirmed in another way by Henry Russel in 1929; Russel, however, admitted Cecilia Payne's anteriority.

II ppm : part per million. In one cubic metre of air, there is the equivalent of 0.55 cm3 of hydrogen.

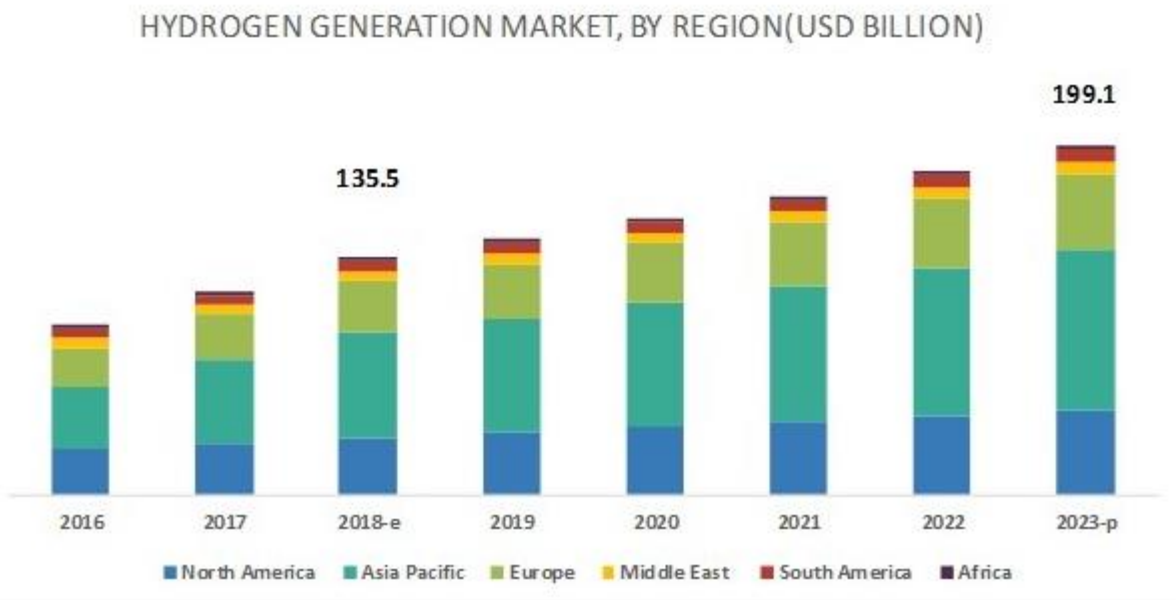

Figure 1 — World Hydrogen Market - Markets and Markets® - 2018

Pure hydrogen is mainly used for its chemical properties[4]:

- The primary use (nearly 50% of world demand) is to convert heavy petroleum fractions into light products and to desulphurise the final products. Environmental requirements have greatly increased the demand for desulphurisation. The hydrogen sulfide produced by the process accounts for the bulk of the world's sulfuric acid production.
- The second use (nearly 45% of world demand) is the production of ammonia (NH3 gas), which is used for the production of fertilisers for which demand is growing.

Hydrogen is also used for the production of other molecules (methanol, ethanol, amides, H_2O_2, ...). Finally, the reducing properties of hydrogen are used in various industries (iron ore reduction, metallurgy, glass, welding, electronics, etc.).

The bulk (95%) of the world's hydrogen production is carried out by chemical processes that emit CO_2: Steam Methane Reforming (SMR) according to the reaction: $CH_4 + H_2O \rightarrow CO + 3\ H_2$ which produces synthesis gas, then $CO + H_2O \rightarrow CO_2 + H_2$ (Water Gas Shift Reaction - WGSR), or coal gasification followed by a WGSR reaction. However, these endothermic processes, which require high temperatures (700-1100°C), emit large quantities of CO_2 (about 10 kg of CO_2-eq per kg of hydrogen produced by SMR; even more when using coal[III]). The energy contained in the hydrogen produced by SMR is only 2/3 of the energy consumed; the hydrogen produced by this route is not "green" (or "decarbonised").

Other chemical processes for the production of hydrogen are in operation or under development and are presented in the remainder of this report, some of which emit CO_2 while others do not; the

[III] Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming - National Renewable Energy Laboratory – United States - 2011. This reference indicates 11.9 g/kg, but it should read 11.9 kg of CO_2 per kg of hydrogen. *See Large-scale Hydrogen Production* - Jens R. Rostrup-Nielsen and Thomas Rostrup-Nielsen - Topsoe technologies - 2001 which gives 8.1 tonnes CO_2 per tonne H_2 for process operation alone, without a full life cycle analysis.

expected multiplication of these sources suggests that traceability must be put in place to distinguish green hydrogen (produced without CO_2 emissions) from blue hydrogen (produced from hydrocarbons, but with CO_2 capture) and grey hydrogen (Chapter 3.1.6).

2.2. Tomorrow's hydrogen: decarbonised production and valorisation of its energy properties

In the future, *Material hydrogen* will remain indispensable for many chemical and industrial applications; however, this hydrogen will have to be decarbonised; one way is its production by electrolysis using decarbonised electricity.

Hydrogen has the advantage of not producing waste when converted directly into electricity in a fuel cell. *Eneregy hydrogen* produced from hydrocarbons with CO2 capture or by electrolysis is therefore a clean energy carrier that emits neither harmful gases nor fine particles. This hydrogen can be valorised directly, or used in fuel cells (FCs) to produce electricity that can be used in mobile or stationary installations. It should be noted, however, that the combustion of an air-hydrogen mixture produces nitrogen oxides; to avoid this, combustion must take place in the absence of nitrogen (oxy-combustion) or at low temperature in the presence of a catalyst.

a. Material hydrogen for industry

The most obvious and immediate need is the substitution of carbonated hydrogen from gasification or reforming processes with decarbonised hydrogen.

Decarbonised hydrogen, whether produced by reforming with CO2 capture and storage, by electrolysis from decarbonised electricity or by other more prospective processes, will represent an additional cost for industry. The hydrogen deployment plan for the energy transition of July 1, 2018 ("Hulot" plan) has set the objective, which is actually modest, that 10% of French hydrogen be produced by electrolysis in 2023, and 20% to 25% in 2028. The technologies exist, and Air Liquide, for example, has announced the construction in Canada of the world's largest PEM (Proton Exchange Membrane) electrolyser, with a capacity of 20 megawatts (MW) for the production of decarbonised hydrogen[5]. This facility located in Bécancour will benefit from very low electricity prices in Quebec.

b. Hydrogen energy uses

Hydrogen, if its production is decarbonised, can become a clean energy carrier. It can be produced by steam reforming with CO_2 sequestration, from biomass or by electrolysis. It is the latter mode of production that is currently causing a real frenzy in many European countries, on the assumption that intermittent excess production capacity (solar or wind) could be used to produce and store hydrogen; this hydrogen would be drawn from storage and converted into electricity when the demand for electricity exceeds production capacity. Chapter 5 shows that the production of hydrogen from surplus renewable energy alone would not be sufficient to ensure the development of a hydrogen economy, and that additional electricity generation based on hydrogen demand must be considered.

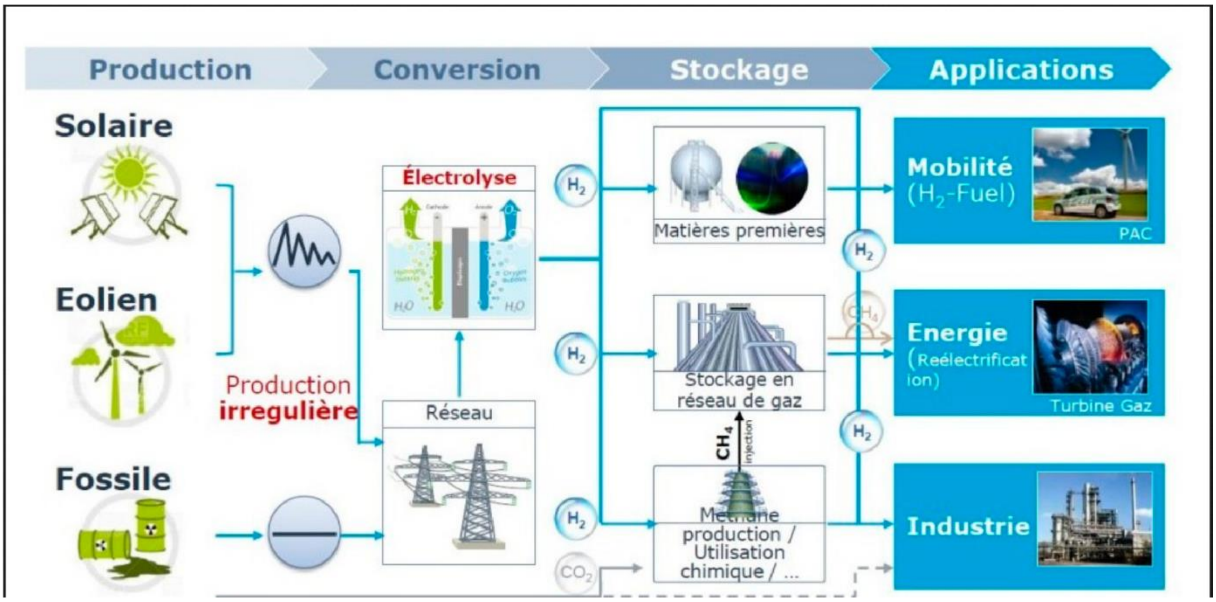

Figure 2 — Hydrogen Value Chain - According to GRT Gaz - 2014

c.1. Stationary use

Energy hydrogen can be used directly by combustion, subject to the emission of nitrogen oxides. It can be mixed with methane up to a concentration of about 20% by volume, the main advantage of which is to use existing gas infrastructures that are largely amortised. It can also be used in stationary fuel cells to generate electricity locally. It can equally be used in gas turbines in direct cycle or supplemented by a steam turbine (combined cycle). Current turbines, which can achieve up to 60% efficiency in the combined cycle, accept only a small proportion of hydrogen as fuel, and natural gas - a CO_2 emitter - remains the main fuel. However, they have a longer service life and higher power output than FCs. Some manufacturers are developing 100% hydrogen gas turbines (Mitsubishi, Siemens, General Electric); however, they are not envisaged before 2030.

These different perspectives of use and their economic quantification are detailed in Chapter 5.

c.2. Hydrogen for mobility

Hydrogen-based electric mobility benefits from greater autonomy and a much shorter recharging time than battery-based electric mobility. The energy density of the hydrogen system (tank, fuel cell and hydrogen) per unit of mass and volume compared to its battery equivalent makes it a good candidate for heavy and long-distance transport.

In addition, the conversion of hydrogen into electricity does not generate harmful gases (SOx, etc.) or fine particles, which makes hydrogen mobility also well suited to urban use.

A hurdle: the distribution of hydrogen

The development of hydrogen mobility requires the distribution of fuel to users. Individual mobility requires a highly meshed network: there are about 11,000 fuel distribution points in France. Even accepting a mesh reduced to 20 km by 20 km, 2,500 distribution points would be needed.

Yet, hydrogen distribution stations require investments significantly in excess of €1 million and must either be supplied - by trucks at present, possibly by pipeline in the long term - or produce their hydrogen on site by electrolysis (they are then about 80% more expensive). Beyond the few existing demonstrators, such installations can only be profitable with large distributed volumes. The development of a network, prior to the sale of vehicles, is hardly conceivable without public support.

Individual mobility

The uses of hydrogen for mobility are developed in Section 5.4. It should be noted at this stage that the cost of the on-board system, which includes on-board electricity production (hydrogen tank, fuel cell, intermediate storage battery) and the electric propulsion chain, is substantial. Considerable reductions are expected from improved cell performance and a strong series effect[6],[7].

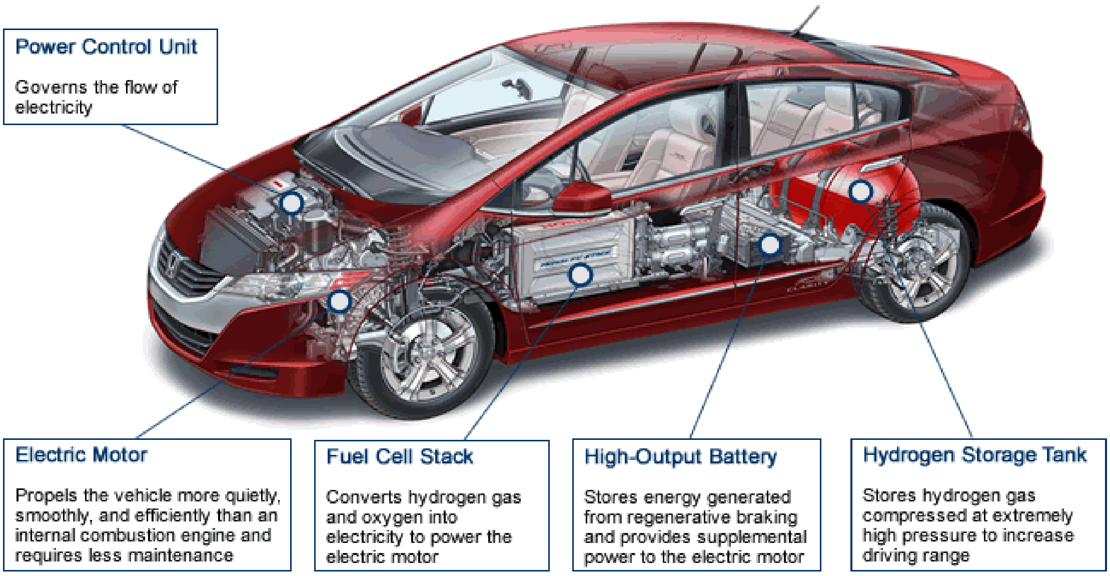

Figure 3 — Transparent view: Hydrogen Vehicle Components
https://i.pinimg.com/originals/a5/47/93/a54793c5c18f3eb8e928ac9be29bd009.gif

The hydrogen deployment plan for the July 1, 2018 energy transition envisages 20,000 to 50,000 light commercial vehicles[IV], 800 to 2,000 heavy vehicles and 400 to 1,000 distribution stations by 2028. In relation to the number of vehicles, these stations would be under-utilised. It is therefore reasonable to expect that hydrogen mobility will initially develop only from a limited number of distribution points (filling stations), effectively reserving its use for targeted fleets. The example is Hype[8] with its hydrogen taxis in the Paris region, but also bus fleets (Pau, Versailles, etc.).

Beyond that, one can think of long-distance road transport for which batteries are not a viable solution. A few distribution points on the busiest roads could help decarbonise a sector that contributes significantly to carbon emissions.

However, in view of the number of vehicles envisaged, it is clear that equipment and system suppliers will not contend with the French market but will have to aim for a global market: support policies must be conducted with this vision in mind. The international benchmark makes it possible to apprehend the variety of approaches of different Western and Asian countries, including South Korea, which is particularly ambitious.

[IV] It is interesting to note that the hydrogen plan concerns all light commercial vehicles and not only individual mobility vehicles.

Transport of passengers or goods

Figure 4 — A Toyota truck https://cleantechnica.com/files/2018/04/DSC03596.jpg

Figure 5 — Alstom fuel cell trainset - SNCF Operations - © Alstom
https://fuelcellsworks.com/news/france-climbs-aboard-hydrogen-train-revolution-with-order-of-15-trains/

Finally, trains (cf. Alstom) or even ships (for short distances) could use hydrogen without first requiring the deployment of a large number of distribution points.

Figure 6 — A Norwegian ferry – European Union aid - Commissioning 2021
https://flagships.eu/2019/10/04/presenting-the-flagships-h2/

Commercial vehicles with hydrogen-powered range extenders

Since the end of 2019, Renault has been producing battery-electric light commercial vehicles with a hydrogen-powered range extender, the heart of which is a low-power fuel cell (5 kW, 20% to 25% of what would be needed for normal vehicle propulsion). The range extender allows the battery to be recharged even when the vehicle is stationary. The Kangoo extends its range from 230 km for the battery electric version to 370 km for the hydrogen version. The Master achieves a range of 350 km compared to 120 km without hydrogen.

The hydrogen chain for these vehicles is currently being produced in an artisanal way, to test the market before industrial production.

Figure 7 — Light commercial vehicles Renault Z.E. 33 H2 Hydrogène
https://i0.wp.com/hydrogentoday.info/wp-content/uploads/2019/10/21234886_2019_-_V_hicules_Utilitaires_Z_E_33_H2_HYDROGEN.jpg?ssl=1

Hydrogen filling stations for the delivery of hydrogen to vehicles are above ground, the storage can be closed, but at ground level[V]. These installations require, if they are supplied by an electrolyser, a water treatment plant, ventilation of the system, compression at 350 or 700 bar, and their footprint is significant.

[V] Order of 22 October 2018 relating to the general requirements applicable to installations classified for environmental protection subject to declaration under heading No. 1416 and Order of 12 February 1998 relating to the general requirements applicable to installations classified for environmental protection subject to declaration under heading No. 4715

Summary and Conclusions

The hydrogen production industry is well developed; the main uses are in the petrochemical and chemical industries (*Material hydrogen*). France has a world-class player, Air Liquide.

Most of the world's hydrogen production is based on hydrocarbons. The development of renewable energies opens up the prospect of producing decarbonised hydrogen by electrolysis.

Energy hydrogen can be a clean energy carrier for the energy transition. The energy contained in stored hydrogen - whether produced from hydrocarbons or electrolysis - represents about 2/3 of the energy needed to produce it.

The potential uses of *Energy hydrogen* are manifold; their technical and economic feasibility is assessed in Chapter 5:

- direct use for injection into gas networks;
- conversion of hydrogen to synthetic methane by combining it with CO2;
- use of hydrogen in biogas plants to improve efficiency) or in e-fuels (kerosene, etc.);
- use for mobility in vehicles: hydrogen is converted into electricity via fuel cells (FCs). These applications can concern heavy land transport, river or sea transport, long-distance light transport, etc. The production of electricity in fuel cells generates only water, and therefore no harmful gases or fine particles;
- storage of intermittent renewable electricity and transformation into electricity in stationary FCs, for powering buildings or neighbourhoods, or for feeding into the electricity transmission grid (Power-to-Power).

3. The technological value chain: production, transport, storage

3.1. Hydrogen production

3.1.1. Hydrogen as by-product

More than half of France's annual production of hydrogen, which is about 900,000 t, is byproduct hydrogen, i.e. it is produced in association with industrial processes that do not have hydrogen production as an objective.

The chlorine industry that uses brine hydrolysis produces 51 000 t of hydrogen per year, or 6% of national production. Coke ovens produce about 126 000 t (14%) and refineries about 360 000 t (40%). Refineries use this *Material hydrogen*. Other industries use this hydrogen in combustion or release it into the atmosphere.

3.1.2. Reforming

96% of the world's hydrogen production is produced by reforming hydrocarbons or by coal gasification with CO_2 emissions, which in most cases are not captured.

SMR wet method

49% of world production is by Steam Methane Reforming (SMR).

The main material hydrogen production process used today is wet reforming (SMR) which requires an external energy input or autothermal (ATR) which uses energy from a fraction of the methane treated according to the reactions:

$CH_4 + H_2O \leftrightarrow CO + 3\ H_2$ endothermic reaction, at high temperature (840 to 920 °C), moderate pressure (20-30 bar) and in the presence of a catalyst (Ni);

$CO + H_2O \leftrightarrow CO_2 + H_2$ exothermic reaction in the presence of water is the WGSR (*Water Gas Shift Reaction*);

The overall yield is 72 to 82%, half of the hydrogen comes from methane and half from water; 10kg of CO_2 is emitted per kg of H_2, and the energy contained in the hydrogen produced is about 2/3 of the energy needed for the reactions.

SMR facilities are typically large, with about 100 tonnes per day of hydrogen for the larger facilities worldwide and up to 600 tonnes for the largest in the United States and Asia.

Oxidation of petroleum fractions

29% of the world's production is made by partial oxidation of petroleum fractions.

This process is suitable for heavy oil fractions with a yield of 53 to 67% on lower calorific value.

The principle is the same as steam reforming of methane to form synthesis gas but the oxidation of the hydrocarbon is done by dioxygen instead of water.

The reaction is exothermic, at high temperature (900 to 1000 °C), higher pressure (20-60 bar) and generally without catalyst.

This process is used to provide synthesis gas with an H_2/CO ratio specific for petrochemicals in the absence of light hydrocarbons, or to destroy heavy hydrocarbon residues with low valorisation potential.

Coal gasification

18% of the world's production is made by "carbo-reduction of water" by coal (i.e. coal gasification).

It is the reaction between incandescent coal and water to produce gas from water: $C + H_2O \leftrightarrow CO + H_2$ followed by: $CO + H_2O \leftrightarrow CO_2 + H_2$, i.e. the WGSR (Water Gas Shift Reaction)

Almost 100% of the hydrogen produced comes from water with the result that the CO_2 emitted per kg of hydrogen is much higher than that of the SMR process.

In Australia, a major project for the production of hydrogen by coal gasification using lignite has been launched to export this hydrogen to Japan (see next paragraph).

3.1.3. Reforming or coal gasification with CO_2 capture and storage

However, as a continuation of the current production of hydrogen from methane or coal, large projects combine the production of hydrogen from carbon-based energies with CO2 storage in order to produce hydrogen, sometimes called blue hydrogen to indicate that it does not emit CO_2 during the complete manufacturing cycle. The cost of CO_2 capture is in the order of €10-20 per tonne of CO_2[9] (€100-200 per tonne of hydrogen); the cost of capture is therefore lower than the trading value of emission permits on the EU-ETS market and is a cost-effective operation.

CO_2 capture processes are widely used in industry. They are efficient, although they can probably be improved. The change from grey to blue H_2 is mainly in terms of CO_2 storage. Research in this area was very active in the 2000s, particularly with EPICs (public establishments of an industrial and commercial nature) such as IFPEN (French Petroleum Institute, New Energies) and BRGM (French Geological Survey), and a pilot project was carried out, thanks to TOTAL, around the depleted Lacq deposit. In addition, there is national and worlwide exported know-how in underground gas storage such as Storengy, Teréga, Geostock. Nevertheless, research projects are being carried out at a snail's pace because there is currently no business model for CO_2 storage and underground activities have little political support in France

An interesting example is provided by a project involving the Australian government and the Japanese firm Kawasaki Heavy Industries. Australia has large quantities of lignite in the Latrobe Valley. The project consists of using lignite for coal gasification. The hydrogen will then be transported by truck to the Australian port of Hastings and then by hydrogen tanker to Kobe in Japan. The approximately $400 million pilot project is being funded by the Australian government and the State of Victoria for the facilities and by Japan for the ship. The project started in 2019. If it expands, it is planned to achieve capture and storage of the CO2 emitted (CCS). The developers of the project consider that the Gippsland Basin lignite deposit in the Latrobe Valley has the capacity to store CO2, which is confirmed by the Global CCS Institute. The hydrogen produced must be transported to a liquefaction plant at the port of Hastings and then transported to Japan. The economic balance of the project has not been demonstrated, but the Australian government, the State of Victoria and Kawasaki have chosen to take this risk[10].

Another major project is led by Chiyoda, the hydrogen produced by steam reforming in Brunei would be transported by boat using an organic medium (toluene hydrogenated into methylcyclohexane) in Japan[11].

In the United Kingdom, the H21 project in Leeds is under development. It aims to transform methane by steam reforming, inject CO_2 into depleted reservoirs and use the pipeline network to transport the hydrogen.

Total has been involved from the outset in the Norwegian CCS technology centre in Mongstad. It has contributed to projects at the Sleipner and Snoviht production sites. With Shell, Total is developing an original project to capture CO_2 from industrial facilities in Oslo (cement plant, incineration plant, etc.) and to store the CO_2 in the North Sea. Each of these projects stores more than 1MT of CO_2 per year. Sleipner has been operational since 1996. Finally, Total, in conjunction with IFPEN, has just launched a demonstration project on new CO_2 capture technologies at Dunkirk.

These projects are interesting and encouraged by natural gas producers. Their technical and financial feasibility depends on the proximity of storage capacities and their operating costs.

If the hydrogen economy develops on a large scale, this type of opportunity can play a role in the hydrogen market and change the balance.

For the development of the hydrogen sector, as for the continuity of other industries, we will probably not be able to ignore CO_2 capture. The above examples and a survey of international policies (details available in the French version of this report) show that several countries and private companies are seriously investing in research to develop the production of blue hydrogen, thus storing CO_2. The Academy hopes that France will not abandon research and know-how in this field.

3.1.4. Production by steam reforming of biomethane

This mature solution requires biogas treatment to remove the sulphur and carbon monoxide that poison the catalysts that are used. These treatments are already in place to transform the biogas from the digesters into biomethane that can be injected into the network.

3.1.5. Water electrolysis

Currently, the only process available to produce decarbonised hydrogen in industrial quantities is the electrolysis of water, provided that the electricity itself is decarbonised. Three main processes coexist:

- electrolysis of water with the addition of an alkaline solution (usually KOH) to improve the conductivity of the medium at low temperature and pressure (about 30 bar). The efficiency (ratio between the theoretical energy needed and the energy required is a little over 70%);

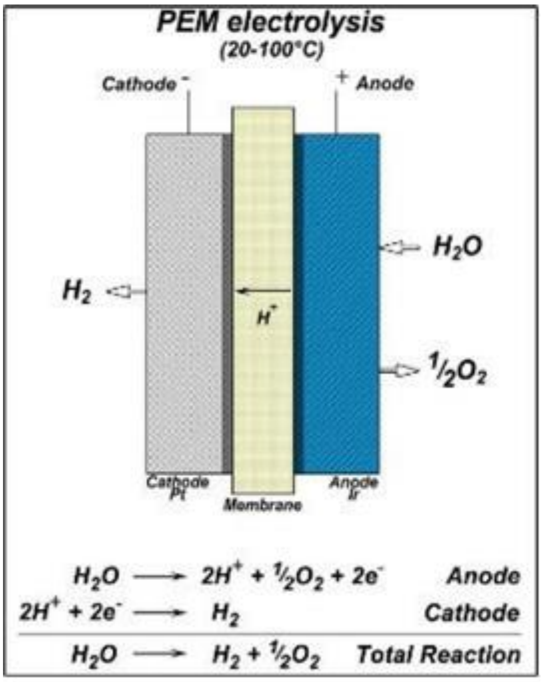

Figure 8 — Principle of a PEM electrolyser

- electrolysis with proton exchange membrane (polymer-electrolyte membrane or proton-electrolyte membrane PEM). The concept of polymer membranes can be used in electrolysers as well as in fuel cells (FCs). It is sometimes considered to be the concept of the future. The efficiencies achieved are 60% and the aim is to exceed 70%. However, the market will ultimately decide between alkaline and PEM solutions;
- high temperature electrolysis (Protonic Ceramic Fuel Cell (PCFC) or Solid Oxide Electrolysis Cell (SOEC)), which requires high temperatures, is therefore not very flexible, but has a better efficiency if heat can be recovered and valorised. Some of these electrolysers could be coupled with waste heat sources, but also with cogeneration nuclear reactors or concentrated solar power plants: developments are long-term. The CEA (Commissariat à l'énergie atomique et aux énergies alternatives - Atomic Energy and Alternative Energy Commission) has developed a concept - Sylfen - in which a membrane system can be used alternatively to electrolyse water, or to produce electricity by operating as fuel cell. This system, which is currently being tested, can smooth the variability of renewable energy production in a large building.

Alkaline electrolysers have lower investment costs than PEM. The French company AREVA H2gen specialises in PEM technology, while the other French company McPhy operates a PEM process (stacks supplied by the American company Giner) and an alkaline process (following the acquisition of a German company).

The renewed interest in the development of a hydrogen economy has motivated the development of more efficient electrolysers over the last ten years. Many foreign countries (United States, China, Korea, Japan, Germany, etc.) and France have increased public research efforts and initiated demonstrators. This interest has grown with the generalisation of policies to control and reduce CO_2 emissions and the deployment of intermittent energies (renewable energies - RE - wind and solar, for the most part). Electricity systems that make extensive use of these non-regulatable means experience significant periods when production exceeds demand; it must be curtailed or used to ensure its storage in chemical form (batteries or hydrogen). Electricity is difficult to store in electrochemical form (batteries); storage in the form of hydrogen is the basis of the "Power-to-Gas" chain. The diagram below shows the principle. Depending on the demand, hydrogen can be:

- used as such in stationary installations or for mobility;
- transformed into CH_4 by combining it with CO_2 that would have been captured beforehand (e.g. CO_2 from industry as in the case of the Jupiter 1000 pilot at Fos-sur-Mer), the synthetic methane thus produced can easily be injected into the network ;
- transformed into a liquid synthetic fuel, for transport applications (especially air transport), by combining it with carbon from biomass.

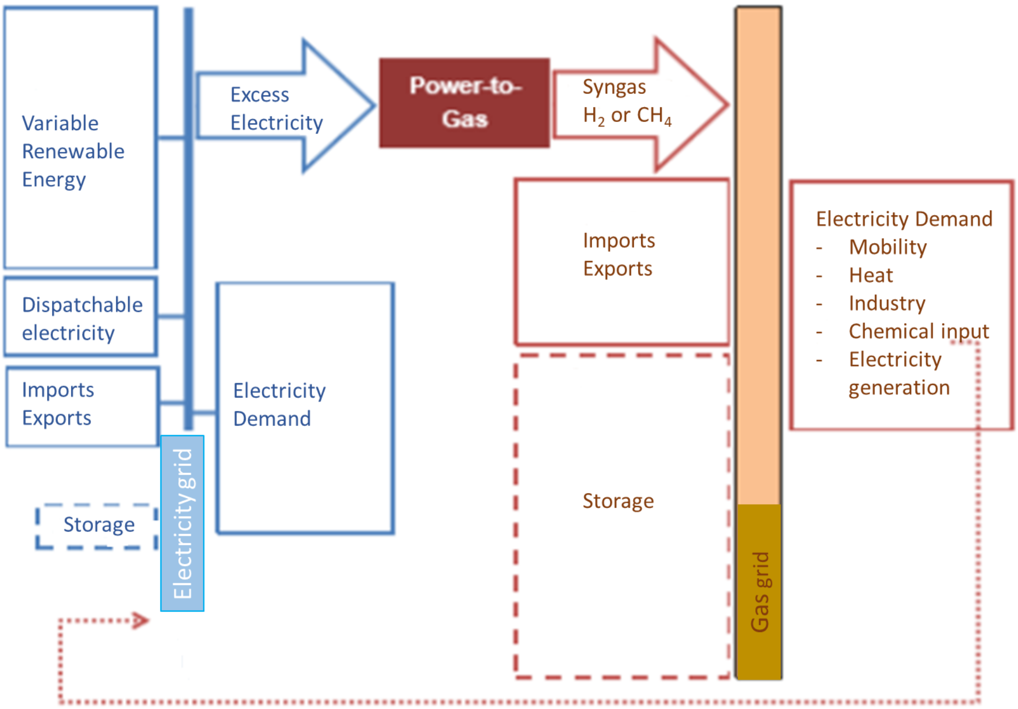

Figure 9 —Power-to-gas concept[12]

Electrolysers and fuel cells can be designed in a modular way:

- each elementary module (or cell) consists of a stack of plates;
- the cells that make up a functional unit are stacked in series to form stacks. The stacks can be connected in series or in parallel depending on the desired application.

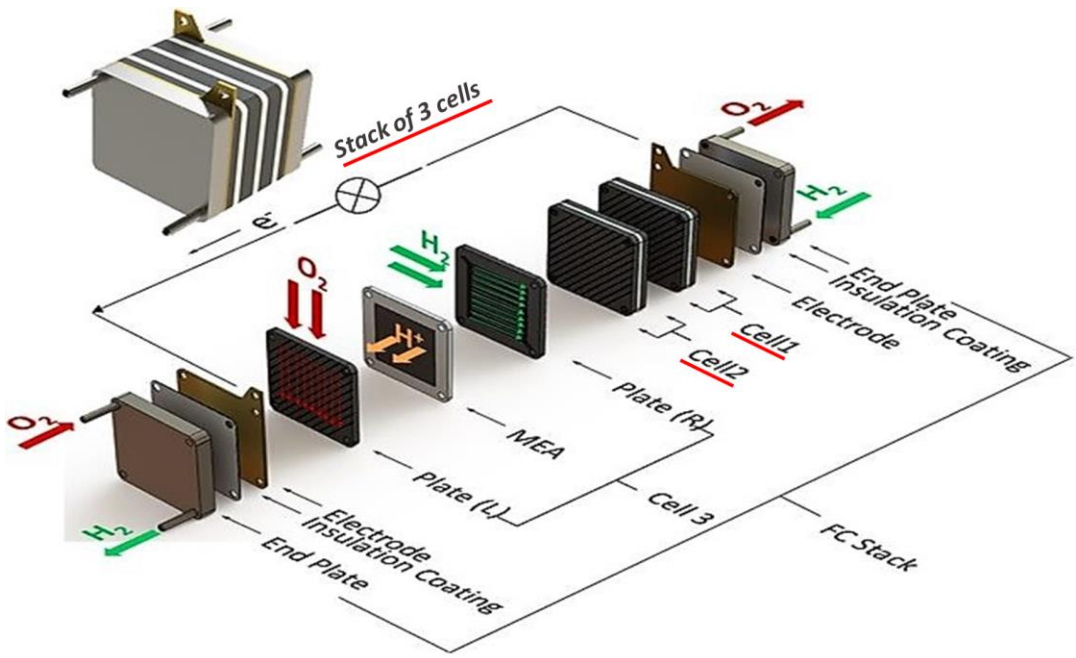

Figure10 — Schematic presentation of a fuel cell stack

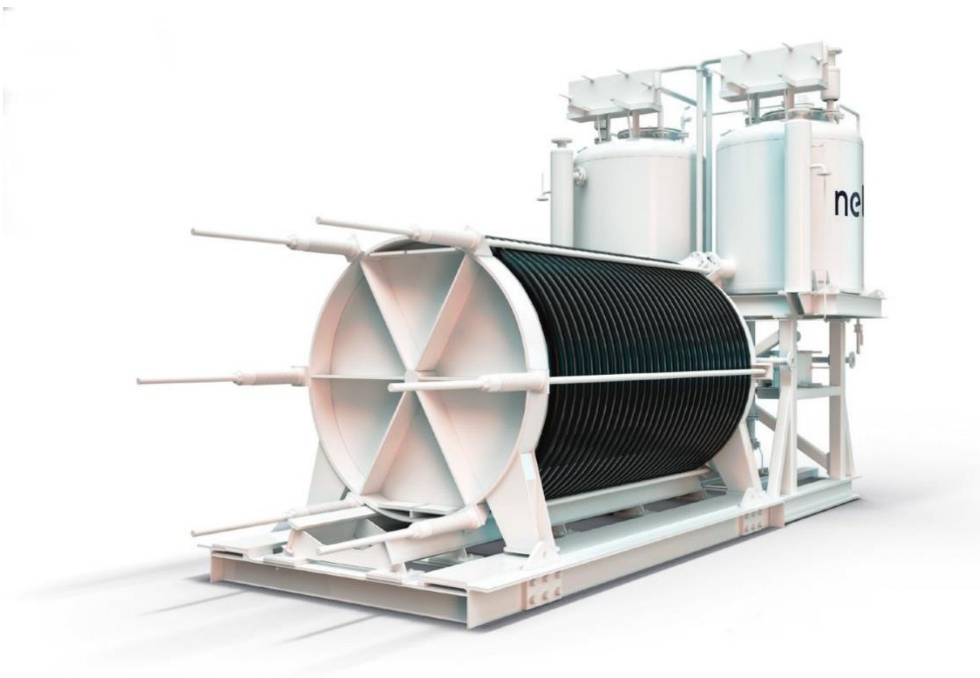

Figure 11— High pressure electrolyser - 1 MW - © Neel

There are three types of electrolysers, all mature:

1. low-pressure alkaline electrolysers whose technology is close to the chlor-alkali electrolysers used for chlorine production. The hydrogen produced must be compressed. Thyssen is the world leader in this field and has installed hundreds of MW worldwide;
2. new generation alkaline electrolysers, 30 bar in output, McPhy type. The power of the stacks is 2 MW maximum, diameter from 1 to 2 m;

3. PEM electrolysers, output at 60 bar. The power of the stacks is a maximum of 1 MW; the diameter is of the order of a metre and the length is a few metres.

The power of the stacks is limited by their mass. Beyond a certain limit, they can no longer be transported by road or rail but must be assembled on site, which is a disadvantage. The stacks are assembled in series and/or parallel depending on the desired installation.

One of the performance criteria of the stacks is the current density (Faraday's law) measured in g of hydrogen produced per cm^2 of electrode.

PEMs have a higher density than alkalines but a loss by Joule effect. As a result, alkaline electrolysers have a better efficiency.

To avoid compressing the hydrogen at the outlet of the electrolyser, the pressure within the electrolyser must be increased, but this requires thicker steels; in addition, dimensional stability of the cells must be ensured.

In fact, a global techno-economic optimum is sought and proposed by manufacturers.

Beyond the electrolyser presented above, the main elements are storage, transport, distribution and consumption. These elements interact to form a system, the coherence of which depends on the different aspects mentioned above, but also on the flexibility of the electrolysers, i.e. their ability to operate with variable electrical power. This flexibility allows the electrolyser to decrease or increase its power according to the electrical power available as a result of variations in intermittent electrical production and the variability of its consumption.

3.1.7 Other ways of producing hydrogen

The other modes of hydrogen production are described in detail in the section on research in this document because they are still not very developed, even though some are quite mature from a technological point of view and the first pilots are in development. From hydrocarbons, carbon can be separated from hydrogen in a plasma torch without producing CO_2, this is the path being explored by the major natural gas producers, but there is also native hydrogen that can be exploited and finally some bacteria and algae generate hydrogen from biomass or solar energy.

Conclusion on hydrogen production

The use of the energy properties of hydrogen is non-polluting (except if combustion takes place at high temperature); the challenge is to produce it without emitting CO_2.

Most hydrogen is currently produced from hydrocarbons. The processes are mature, but highly CO_2 emitting. Different CO_2 capture processes are available, storage processes are under development and their implementation should be encouraged by raising the price of CO_2 emission permits. Electrolysis from decarbonated electricity uses existing production processes, but it is now significantly more expensive than production from hydrocarbons. Nevertheless, electrolysis is rapidly evolving to reduce its cost and increase its efficiency. Electrolysis is a large consumer of electricity, the price of which weighs on the profitability of the sector. Production from biogas or biomass processing will also be greenhouse gas (GHG) free, but the maturity of these processes is still low (pyrolysis and plasma torch) – and then there is still the underexplored native hydrogen.

3.1.6. Hydrogen certificates of origin

Hydrogen can be produced by many processes, some of which emit greenhouse gases (GHGs) and some of which emit little or no GHGs. The hydrogen market is growing in Europe and worldwide. The objectives of reducing greenhouse gas emissions make it necessary to differentiate production processes according to the quantities of GHG emitted and not only according to the economic cost of production.

An outline of a European classification

Directive (EU) 2018/2001 revised on 11 December 2018 introduces a guarantee of origin system for hydrogen similar to that applicable to renewable energies. Under this system, a guarantee of origin (GO) certificate is issued by a producer, certified by a state-designated body and used to prove the characteristics of the electricity or gas sold by the supplier to the final consumer. These certificates circulate on the market (Powernext), so that the final supplier can buy them if he does not have the electricity or gas with the characteristics to which he has committed himself; double counting is not possible and the certificate disappears when the electricity or gas is sold to the final customer. With this system, a customer who acquires a "green" hydrogen cylinder has the guarantee that such a quantity of hydrogen with this characteristic has been produced somewhere, but it will generally not be this hydrogen that will be delivered to him.

However, this system requires a classification of the different production chains; so far no agreement has beenreached on a European classification.

The CertifHy GO certification system developed by the Fuel Cells and Hydrogen Joint Undertaking - FCH JU[VI, VII, VIII] benefits from European support, but is not yet a standard. It is presented as an example.

It identifies three types of hydrogen:

[VI] https://www.fch.europa.eu/page/certifhy-designing-first-eu-wide-green-hydrogen-guarantee-origin-new-hydrogen-market
[VII] https://certifhy.ca/Green%20and%20Blue%20H2.html
[VIII] https://www.iea.org/commentaries/the-clean-hydrogen-future-has-already-begun

grey hydrogen from hydrocarbons without CO_2 capture, **blue hydrogen**[IX] from non-renewable sources but with a low CO_2 impact (60% reduction in CO_2 emissions compared to methane reforming), **green hydrogen** whose production respects the CO_2 ceiling of blue hydrogen and is derived from renewable energies. It is typically hydrogen from electrolysis **if a significant part of the electricity is of renewable origin**.

This classification has the merit to exist and to be a first step towards certifications of origin, but it is flawed on different points: the CO2 emissions which remain significant with green hydrogen, the limit between green and blue, the fact that it does not take into account hydrogen having other sources than those mentioned above and finally the fact that it does not take into account the routing of the hydrogen to its point of use and more globally a complete life cycle analysis.

Emissions of green hydrogen: the production of green hydrogen, as well as blue hydrogen, can emit - and in practice will emit since blends are allowed - 40% of the CO_2 that would have been emitted by steam-reforming production (SMR) without CO_2 capture. Taking into account the conversion efficiency and the respective calorific values, it is shown that, per unit of energy contained, green hydrogen emits 65% of the CO_2 that would be emitted by natural gas.

Blue/green: if one were to stick to an impact-based definition in terms of GHG emissions, hydrogen from electrolysis from nuclear electricity should be considered green. But nuclear power is not qualified as renewable, and electrolysis using this technology produces blue, not green, hydrogen. And some non-governmental associations are even advocating that this qualification be removed and that it be considered grey. This is a subject that can have substantial commercial consequences. Moreover, it is surprising that the term blue hydrogen is widely used when CO_2 capture, transport, use and storage (Carbon Capture Utilisation and Storage: CCUS) is still in a research and pilot phase (excluding storage in depleted oil or gas wells). In practice, there is currently no real blue hydrogen, except if it is produced by nuclear electricity.

The plasma torch process may suffer from the same narrow approach to the concept of renewables; it will be considered blue and not green because it uses methane as a raw material, although it emits no CO_2.

Native hydrogen should be classified as green if the hydrogen generation is indeed due to a water/rock interaction, such as hot fluids from geothermal energy.

Hydrogen as by-product also falls, in this colourful but fuzzy classification, into a no-man's-land. If one makes chlorine by electrolysis with non-green electricity it should be classified grey but being a by-product one could just as well classify it as green, or at least not attribute a carbon balance to it as a proportion of what it represents in this process, i.e. not much. Its local use in short circuits also has other environmental and societal benefits.

Hydrogen resulting from bacterial activity or algae will undoubtedly and rightly be classified as green.

The German proposal

In its hydrogen strategy adopted on 10 June 2020, Germany proposes a different classification. Green hydrogen is obtained by electrolysis of water with renewable (non-nuclear) electricity. Blue hydrogen is produced by reforming with CO_2 capture and use/storage. Grey hydrogen is produced by reforming without CO_2 capture. A turquoise category is added; this hydrogen is also produced by cracking

[IX] Blue hydrogen is a registered trademark of Air Liquide, which corresponds to another definition.

methane at high temperature (pyrolysis, plasma torch) and the residue is carbon black. The electricity used must be renewable, non-emitting CO_2.

This brief synopsis highlights, if there is still a need, that the classification of the impact of human activities using as sole gauge "renewable" which excludes nuclear energy, which does not emit CO2, or even "greenhouse gas emitters" is not the only relevant one. Electrolysers and fuel cells contain non-renewable metals, and the life cycle analysis of a product must be systematically carried out from A to Z.

Some economic or political players may find it advantageous to have sectors classified as virtuous or not. It is relatively easy to simplify the vision of a process to achieve partisan objectives. It is much more complex to do a complete and comprehensive life cycle analysis. For example, the environmental cost of a hydrogen that is produces, trucked, liquefied and transported by ship, then regasified, compressed and trucked again (the Australian-Japanese project) is not the same as the environmental cost of just producing it. The Academy would like the classification of the different types of hydrogen to be based exclusively on an analysis of the CO2 emitted during the life cycle and up to the point of distribution.

Ammonia as a hydrogen carrier: production, transport, storage.

Consideration is being given to converting hydrogen into ammonia (NH3), which is easier to use than hydrogen and can be an alternative energy carrier.

At room temperature and atmospheric pressure ammonia is gaseous, but liquefies at -33°C. It can be stored and transported in a liquid state at ambient temperature but under pressure or at -33°C and normal atmospheric pressure. Its main use today is in the production of nitrogen fertilisers. The United States operates 5,000 km of dedicated ammonia pipeline. Its energy content is relatively high (6.5 KWh/kg or 3 KWh/l). It is produced by the Haber-Bosch process from nitrogen and hydrogen and can therefore be decarbonised if the hydrogen is produced in a decarbonised manner. It can be considered as a hydrogen storage system. It is then dissociated into N2 + 3H2 between 400 °C and 800 °C using catalysts. It can also be used as a fuel in combustion engines, turbines (such as the X15 rocket engine in the 1960s, combined with oxygen), and Proton Ceramic fuel cells. It can be mixed with hydrogen to improve burner performance and gas turbine efficiency. In February 2020, the Royal Society published a report on this subject[X]. Japanese universities are very active. Despite the security problems, this topic seems promising.

3.2. Hydrogen transport

Due to its very low density, hydrogen must be conditioned to allow for its transport and storage. This conditioning can be done by compression, liquefaction, but also by reversible adsorption of the hydrogen by solid bodies that are easier to handle. At equal pressure, the same volume of hydrogen contains three times less energy than natural gas.

Today, the transport of hydrogen is associated with the production from the reforming of fossil methane and therefore corresponds to a logic that will be modified at least partially by the production of hydrogen of non-fossil origin. The mode of transport depends on the quantity of

[X] https://royalsociety.org/topics-policy/projects/low-carbon-energy-programme/green-ammonia, hydrogen to be transported, the distance to be covered and the geographical location of the route, whether land or sea.

3.2.1. Pipeline transportation

Hydrogen pipelines are not significantly different from methane pipelines. They are made of conventional steels or polymer composites. However, hydrogen tends to weaken the metal of the pipe and the welds. Operating pressures vary according to the networks between 21 mbar and 3 to 4 bar for distribution and 60 to 100 bar for transport. The diameters vary between 10 mm and 300 mm. The adaptation of the methane distribution network to the transport of hydrogen seems possible for the transport of a methane-hydrogen mixture - named Hythane™ by Engie - in a proportion that varies from 11% to 12.5%. European research has concluded that the hydrogen concentration can reach 20% without any particular problem. However, if on the user side pure hydrogen is needed, a separation process is required which is expensive and makes the transport of hydrogen as a mixture unattractive.[13].

To avoid the phenomenon of embrittlement of pipeline metal, the steel must be mild steel. Many of GRTgaz's (Gestionnaire Réseau Transport de gaz - Gas Transmission Operator) pipelines are of this type, but the most recent ones are made of alloy steel, whose behaviour must be validated prior to the transport of hydrogen.

The transport of pure hydrogen by pipeline is being developed in some parts of the world. The United States has a network of more than 2,600 km, much of it between Texas and Louisiana. Northern Europe has a 1,600 km hydrogen pipeline network, including more than 610 km in Belgium, operated and mostly owned by Air Liquide.

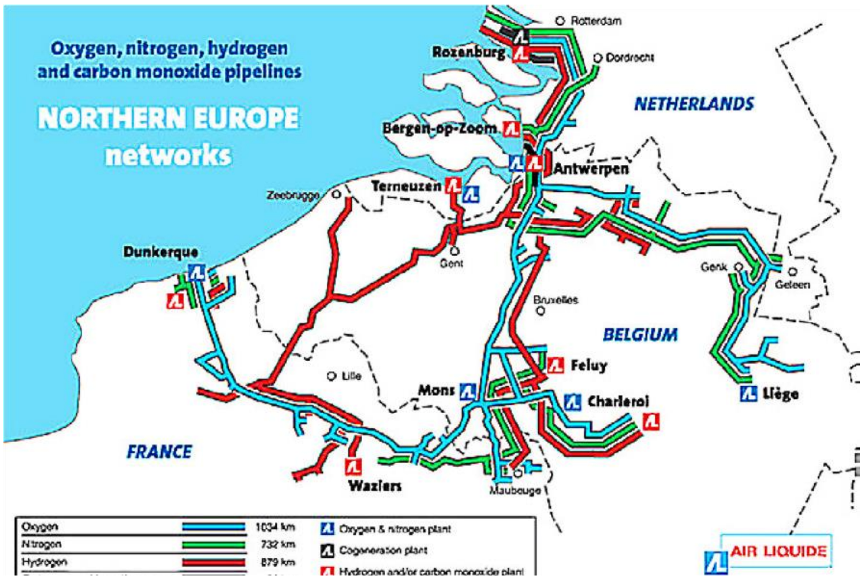

Figure 12 — Gas transmission network in France and Benelux [14]

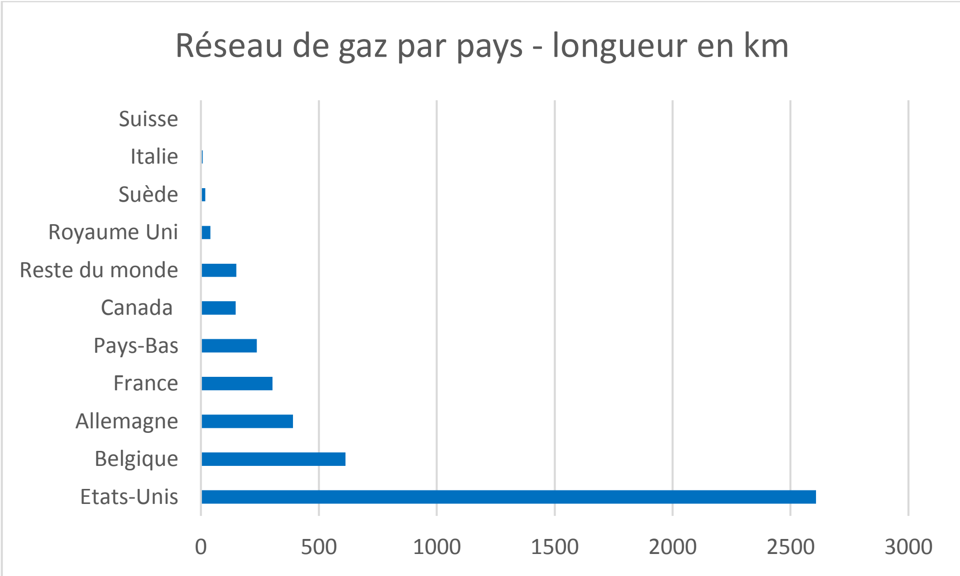

Figure 13 — Gas networks of the main countries (km) - Same source

The length of the European gas pipeline network for the transport of natural gas is approximately 200 000 km. It continues to develop towards the gas fields of Russia, Kazakhstan etc. It is much cheaper to transport energy in the form of methane than in the form of electricity. Moreover, the development of these networks meets little opposition, at least so far, and is perceived less negatively by the populations concerned than 400 kV power lines. Moreover, the "tubes" can be buried in the seabed without interruption.

If it takes a large amount of hydrogen consumption to justify investment in a pipeline, the existence of a pipeline can help bringing down the price of hydrogen and thus develop its uses. Will uses pull the networks or the other way around? Both hypotheses are valid, and it can be postulated that both options will develop in parallel, depending on local circumstances and needs. The most likely scenario is that the uses will lead to the installation of new networks.

In June 2019, nine gas companies, including GRTgaz and GRDF (Gaz Réseau Distribution France - Gas Distribution Operator), published a report on the technical and economic conditions for injecting hydrogen into the natural gas systems. This report concludes that it is possible to integrate a significant volume of hydrogen into the gas mix by 2050 with limited infrastructure adaptation costs. This integration implies the coordinated use of blending, methanation and deployment of 100% hydrogen clusters on certain grids by converting structures or creating new networks.

In the short term, the rate of 6% by volume of hydrogen is achievable in mixtures in most networks, in the absence of sensitive structures or installations at customer sites.

By 2030, operators recommend setting a target capacity for the integration of mixed hydrogen in networks at 10%, then 20% beyond that, in order to anticipate the adaptation of equipment, particularly downstream.

The report indicates that by 2050 there will be areas of complementary relevance for the three injection routes of blending, methanation and 100% hydrogen clusters.

In the short term, to enable the implementation of the first projects for injecting hydrogen into the networks and to develop genuine competitive hydrogen logistics, French infrastructure operators have identified a list of 10 recommendations that they wish to share with the Minister of State, Minister for Ecological and Solidarity Transition.

3.2.2. Road or rail transport of hydrogen

Hydrogen can be transported to its point of use in cylindrical steel cylinders in racks at a pressure of 200 to 250 bar. A 33-tonne semi-trailer truck loaded with cylindrical steel cylinders **transports 300 kg of hydrogen**. On the return journey, it also carries 33 tonnes but empty, the weight of the hydrogen transported being insignificant compared to the total weight of the truck with the empty steel cylinder racks.

This mode of transport is evolving thanks to the development of on-board hydrogen tanks for mobile use in vehicles of all types. These lighter composite tanks make it possible to store hydrogen at pressures of up to 700 bar.

For example, the Linde Group has developed trailers with 100 storage elements and transporting 1,100 kg of hydrogen.

These same assemblies can be installed on wagons and operated as rail freight or on barges and can be integrated in pushed convoys on wide-gauge canals.

3.2.3. Maritime transportation

The transport of hydrogen has similarities with the maritime transport of LNG, but also fundamental differences: methane liquefies at -160°C and hydrogen at -253°C. In Japan, a ship with a capacity of 1,250 m^3 was built by Kawasaki[15]. It will be capable of carrying 90 tons of hydrogen. Liquid hydrogen loading-unloading technologies are also being developed. The development of LNG tankers has changed the economics of methane on the planet, as it offers an alternative to the bilateral contracts that generally govern the use of gas pipelines. The boil-off (evaporation) rate can be very close to zero, particularly depending on the insulation. These ships give resilience and consistency to the gas market. Perhaps this will be the case one day with hydrogen. With GTT (Gaztransport & Technigaz), France has a world champion in the transport of liquefied gas at very low temperatures. Nearly one out of every two LNG carriers circulating around the world has been built under license from GTT. This company should be motivated and supported in the development of a solution dedicated to the transport of liquid hydrogen.

Figure 14 — World's first liquefied hydrogen carrier launched in Japan.
This ship of 120m will carry 90t of hydrogen.

3.2.4. On-board-vehicle transport

Small on-board-vehicle gas storages, especially for mobility purposes, should be of low volume for reasons of vehicle space requirements. There is a trend towards composite and aerospace-derived tanks (e.g. carbon fibre, fibreglass and kevlar with epoxy resin with a liner made of very high-density polyethylene or polyamide which provides hydrogen tightness). Aluminium is used for applications up to 350 bar, for example for buses. The order of magnitude of the thickness of the tank is around 50 mm.

In this configuration 5 kg of hydrogen can be stored in a 100 kg tank. The maximum possible pressure is 900 bar, beyond which there is no technico-economic optimum; but regulations limit this pressure to 700 bar.

Conclusion for the transport of hydrogen

The development of hydrogen use will gradually change transport methods. Part of the gas network could be dedicated to hydrogen rather than methane, but this raises difficult technological issues. This is a hypothesis that Gazprom in Russia is raising, although there are still open questions about the compatibility of materials: we know how networks behave up to a 20% hydrogen content - above that, local demonstrators, transport and distribution operators are working together within GERG (European Gas Research Group) with the HYReady and ThyGA projects, but their performance at 100% hydrogen content remains to be validated and will vary depending on the country and the age of the networks[16].

The development of hydrogen pipelines is fairly fast because it is a relatively simple technology and the deployment of a gas pipeline is generally viewed positively by the populations concerned. In the United Kingdom, the replacement of the entire steel pipeline network with composite materials, which has been underway for several years for safety reasons, is already more than half complete and makes it compatible with hydrogen. Because of this speed and relative simplicity, the deployment of hydrogen networks could be fairly rapid.

Hydrogen tankers would change the game by creating a global market. It is difficult to predict when maritime transport of hydrogen could have a significant impact on prices.

1 GERG – Launch of the THyGA project -
https://www.gerg.eu/wp-content/uploads/2020/01/THY_WP6_002_Press-release_01.pdf
HYReady: https://www.gerg.eu/media-centre/publications

3.3. Compression, liquefaction, storage

All these processes involve compression, possibly liquefaction of the hydrogen, and then return to a state that allows its use. The energy-related cost of compression is substantial, especially since the waste heat is generally not recovered.

The 700 bar compression used in hyperbaric tanks enables a hydrogen density of 42 kg/m3 to be achieved.

Filling a vehicle tank up to 700 bars, the initial state of which is 0.5 kg and 30 bar (pressure at the electrolyser outlet and in the buffer tank) requires about 2 kWh/kg (source Air Liquide and the American manufacturer RIX) by staged compression with a piston compressor. This solution is satisfactory for storing relatively small quantities of hydrogen, for example in the on-board tanks of light vehicles.

It should be noted that the advent of centrifugal compressors would mark a step forward in terms of operation and maintenance, but materials technology still requires further development.

Cryogenic storage in the liquid state at 20 K increases the density of hydrogen (1 kg of liquid hydrogen occupies 15 litres compared with 24 litres at 700 bars). Liquefaction consumes about 9 kWh/kg today (for a unit of a few dozen tonnes/day) and the target is 7 kWh/kg in 2030 (source: Air Liquide), i.e. 20% to 30% of the energy content (33 kWh/kg) of liquefied hydrogen. To regasify the hydrogen, 1 kWh/kg is needed (almost zero cost if a free hot spring is available - sea water, river). These 9 to 10 kWh used to liquefy the hydrogen and return it to a gaseous state are to be compared to the 55 kWh used for its production.

Hydrogen in its liquid form has the advantage of making the optimisation of logistics easier and it is therefore necessary, in particular for mobility applications, to study the complete chain (liquid hydrogen brings savings on the investment and operating costs of service/distribution stations).

3.3.1. Solid storage

Other solutions consist of storing hydrogen in a solid or liquid state. Some compounds absorb hydrogen and can release it. Metal hydrides allow a higher storage density than liquid hydrogen. Hydrogen is absorbed at a pressure of a few dozen bar. "*The desorption reaction is endothermic and self-limiting: in the event of an accidental leak, the temperature of the tank drops rapidly to equilibrium temperature, interrupting the release of hydrogen*."[17] A magnesium hydride is ground with a transition metal at a nanometer scale to create highly reactive powders. The hydriding reaction is highly exothermic, which requires optimal thermal management with heat recovery[18]. One of the disadvantages of metal hydrides is that they are very sensitive to moisture. R&D aims to lower the desorption temperature, currently significantly above 120°C, and reduce the energy required for desorption (up to 30% of the hydrogen content) while reducing the weight of storage. The French company McPhy was created in 2018 to develop a solid storage offer based on CNRS patents. After completing several pilots, it stopped marketing this technology in 2018[19].

3.3.2. Liquid storage on support

Another route developed in Japan uses the reversible cycle route of the hydrogenation reaction of toluene to methylcyclohexane: i.e. transporting this cheap liquid and then dehydrogenating it in the presence of a catalyst to release hydrogen.

However, this solution will remain reserved for transactions between professionals because of the very high toxicity of toluene and methylcyclohexane to aquatic life.

AREVA and the German company Hydrogenious are working separately on the hydrogenation and dehydrogenation of dibenzotoluene (oil). Less efficient than toluene, DBT has the advantage of very low toxicity. Another advantage is that DBT is a commercial oil commonly used as a heat transfer fluid. Finally, oil hydrogenation technologies are fully mastered in the food industry.

A great deal of ongoing research concerns storage, using, among other things, formic acid, the family of amino-boranes, molecular storage in platinum or fullerene "sponges". For the latter, the cost aspect will be a determining factor.

The French company HySiLabs is developing a process based on liquid silicon hydrides (polysilanes). It has raised €1.5 million in 2018.

3.3.3. Underground storage

a. storage solutions and field experiments

Underground methane storage is a mature solution, in aquifers as well as in salt diapirs. The high solubility of salt in water allows the excavation of large cavities in salt formations by dissolution from the surface, and the specific properties of the salt guarantee the long-term stability and watertightness of these cavities. These large cavities are created by dissolution in situ. Sites have been exploited for a century. There are 300 natural gas storage sites in Europe and 2,000 worldwide.

In France, Storengy and Géostock, together with others in Geodénergie, are competent industrialists in this field.

One of the pioneering studies on this subject, conducted in the United States by the Gas Technology Institute [20], had concluded that saline cavities were the most appropriate storage method compared to other geological reservoirs (aquifers and depleted hydrocarbon deposits) and that large quantities of gas could be safely stored due to the available volumes and high storage pressures. The ability to handle large flow rates with rapid injection/drawdown cycles makes saline cavities the most satisfactory option.

Hydrogen has been stored in several caverns in Teesside (UK) since 1972, in caverns near the Texas Gulf Coast since 1983, and in Germany. These in situ experiments demonstrate the feasibility of storing hydrogen in salt cavities over long periods of time and without the occurrence of accidental events. Several aquifer storage facilities also exist, including Lobodice in the Czech Republic and Dademe in Argentina. These storages are possible because hydrogen is very poorly soluble in water at low temperatures and pressures[21].

The European HyUnder project, "Assessment of the potential, the actors and relevant business cases for large scale and seasonal storage of renewable electricity by hydrogen underground storage in Europe", involving Germany, the Netherlands, Spain, France, Romania and the United Kingdom, submitted a report in 2014. It concludes that the solution of storing hydrogen in a saline cavity is feasible when the geology is suitable and indicates a price in the order of magnitude of 40-60 €/m3 for a cavity of more than 500,000 m3 , i.e. about 0.5 €/kg (see § 5.2.2).

b. the risks associated with underground storage

Since the storage of hydrogen in saline cavities under high pressure remains much less common than that of natural gas, knowledge of the specific risks associated with such storage remains patchy. Feedback has shown that there are three main types of risk[22]:

1. Leakage of gas at the surface, either in a sudden form (blow-out type) or as a slow, diffuse leak from the cavity, well or surface facilities (cf. the accidents at Aliso Canyon in California in 2016, Moss Bluff in Texas in 2004, Hutchinson in Kansas in 2001). These leaks may be induced by defects in well integrity (defective cementing, casing corrosion), the absence or malfunction of barriers (valves, plugs, etc.) or external damage to the wellhead. The main dangerous phenomena that may result are gas ignition or explosion;
2. Contamination of drinking water aquifers by compounds resulting from chemical or biological reaction with hydrogen;
3. Appearance on the surface of disorders of geomechanical origin, following an inadequate operating pressure of the cavity inducing excessive creep or wall damage.

The analysis of the feedback also shows that the riskiest phases in the life of a gas storage facility are well interventions, during which the main barriers for well safety can be rendered inoperative and replaced by temporary barriers. It should also be noted that underground hydrogen storage differs from other underground gas storage facilities in a number of ways:

- hydrogen has a high mobility that induces a greater possibility of leakage, whether through salt, equipment or wellheads;
- conversely, because of its chemical reactivity, hydrogen can recombine with many elements in the subsoil and not remain available in gaseous form in storage;

- the potential chemical or biochemical reaction of hydrogen with well equipment can lead to its embrittlement;
- under certain conditions in aquifers, hydrogen can cause microbial reactions leading to a change in the composition of the stored gas;
- the risk of explosion or ignition may be greater than for natural gas;
- damage to the cavity walls can be amplified by increased frequency of pressure cycles.

These risks do not call into question the feasibility of underground hydrogen storage since the operational sites that have existed for thirty years have not experienced any major accidents.

However, one of the indispensable conditions for the development and acceptability of underground hydrogen storage, in a societal context that is not very conducive to the use of the subsoil, is the identification and evaluation of these risks as early as possible in order to take appropriate reduction or control measures to make these risks acceptable (in particular monitoring measures).

c. regulatory and societal aspects of underground storage

Another challenge of underground hydrogen storage is that, to date, there is no specific legislative and regulatory safety and environmental framework for this type of activity, in particular for testing to verify the integrity of the structures and associated facilities. The framework specific to underground storage of natural gas could be used as a reference and could be transposed, in part, to hydrogen storage. However, this implies significant changes to the mining and environmental codes, which should be prepared as early as possible to allow the development of the sector.

Seeking a positive social perception of hydrogen storage will involve the definition of rules for the design and dimensioning of sites as well as for the required safety and monitoring devices. The emergence of a new industrial sector in the energy landscape will also have an impact on other sectors. Therefore, before considering the integration of hydrogen solutions into gas and electricity grids, it is necessary to accurately assess the capital needs and expenditure in multiple infrastructures for the different streams involved (electricity, CO2, methane, hydrogen, heat) and to study how to manage them jointly.[23]

Conclusion on storage

Compression and storage have a direct impact on the hydrogen economy. On-board storage and tank storage have progressed through technologies using carbon (or other) fibres and resins that make tanks lighter and safer. However, the shape of the tanks is cylindrical and does not facilitate their integration into vehicles of any kind.

Large-scale underground storage can allow the management of large volumes of hydrogen, as is the case for large-scale methane. Potential geological sites are recognized, and excavation methods are known. The good behaviour of the cavities remains to be demonstrated, particularly during transients. The legislative and regulatory framework needs to be adapted.

The integration of hydrogen stored in cavities must be subject to a full assessment of the system into which it is inserted.

Research on different forms of solid or liquid storage that also facilitate transport deserves more support from public authorities.

1

4. Hydrogen and safety

4.1. Hydrogen properties

As is the case for any energy product (electricity, petrol, natural gas, lithium, etc.), the use of hydrogen poses problems in terms of safety of use and must be subject to regulations and good practices. Precautions for the use of hydrogen are linked to its ease of inflammability and its wide range of explosiveness when mixed with air. The use of hydrogen, which is in gaseous form under usual conditions, can be similar to that of natural gas, which is widely used.

Hydrogen is a substance with a high energy density by mass, but low energy density by volume. In order for it to ignite or explode, the following conditions must be met simultaneously:

- A hydrogen concentration in the air between 4% and 75 %[XI]. In an open environment, this condition can only be met in a small volume,[XII] due to the exceptional lightness and high diffusion speed of hydrogen, which results in rapid dilution in air. In a confined environment, an accumulation of hydrogen can occur, resulting in a concentration in the above range.
- Presence of a source (spark, hot spot) whose energy locally exceeds the minimum ignition energy of hydrogen (which varies according to the concentration of hydrogen and oxygen and may be as low as values obtained by human origin electrostatic discharges). Although hydrogen heats up when it expands (this is the inverse Joule-Thomson effect), this effect is too small to really influence the risk of explosion.

  The combustion of hydrogen creates a very hot flame, over 2000°C, but almost invisible in daylight. This aspect must obviously be taken into account in rescue operations.

  The ignition of a gas cloud formed during a leak in a pipeline or storage facility can, in certain configurations, lead to an explosion. This explosion is a sudden release of energy leading to the propagation of a flame front and an pressure surge wave.

Explosion regimes: two different explosion regimes are possible:

- deflagration: in this case, the flame front moves at subsonic speed. Volume expansion causes the fresh gases at the flame front to be compressed (piston effect). This results in a continuous increase in pressure surge. For hydrogen in air at stoichiometric conditions (for each hydrogen molecule there is half a molecule of oxygen), the deflagration velocity is 2.6 m.s-1. In the presence of oxygen, the velocity can increase up to 11-12 m.s-1, a value which can increase further depending on the containment (e.g. explosion in a tube);
- detonation: the speed of the flame front is supersonic, the hydrogen/fuel mixture is compressed under almost adiabatic conditions resulting in the formation of a shock wave. The range of detonability of hydrogen varies according to the geometry of the

[XI] at room temperature and pressure

[XII] The explosive volume depends mainly on the flow rate but also on the impact of the jet, so it is not always only a small volume. The accident at a service station in Norway in July 2019 also prompts us, while awaiting its final conclusions, to put this statement into perspective containment, the ignition energy and the ratio of the mixture. Examples of detonations occurring at hydrogen concentrations of 11% or less are cited in the literature.

But hydrogen also has very favourable characteristics in terms of safety:

- low radiation intensity of its flame, which in the event of fire considerably limits the risk of propagation by the effect of heat radiation;
- absence of toxicity (in case of contact, inhalation...);
- rapid diffusion. It dilutes four times faster in air than natural gas and twelve times faster than gasoline vapours, reducing the risk of explosive accumulations.

For figures on the characteristics of hydrogen under different conditions of temperature, pressure, mixture, etc., refer to Afhypac safety data sheets 7.1 & 7.2.

4.2. What risks are associated with mobility?

The use of hydrogen in industry has been well known for several decades and the related risks are well controlled, both with regard to its production (chemical industry) and its use (main applications are ammonia synthesis, petrochemicals or space; as an example of other applications, alternators in power plants use hydrogen to facilitate their cooling thanks to its high calorific conductivity) and current regulations apply to these installations.

The remainder of this chapter will therefore focus on the consumer aspects of hydrogen use, and in particular on road transport, both from the vehicle and filling station perspective. The use of hydrogen is going to be decentralised.

The low volume density of hydrogen gas means that it is often necessary to store it under high pressure to reduce the size of the tanks. Pressure levels in gaseous hydrogen storage systems for hydrogen energy applications typically range from a few tens of bar to 900 bar in filling stations for mobility applications.

Hydrogen fuelling stations are now operational in a number of countries (see safety annex) and supply the daily needs of the first users of hydrogen for mobility (road vehicles, hydrogen fuel cell scooters or bicycles, shuttles).

The precautions for the use of hydrogen are related to the quantity stored, the flow rate or even the quality of the hydrogen[XIII].

Scenarios to be averted are those in which hydrogen could be released. For this hydrogen is then likely to :

- create a inflammable mixture with air;
- and then produce a flame or an explosion that causes severe damage.

According to the recommendations of the authoritative Ineris (Institut national de l'environnement industriel et des risques - National Institute for Industrial Environment and Risks), the ministerial

[XIII] In Korea in 2018 the malfunction of an electrolyser (too high oxygen content in the hydrogen) caused two deaths and six injuries. (https://www.youtube.com/watch?v=igPIGvO7ibM) order of general prescription for the design of H2 stations, the dominant scenario retained is a rupture of the filling hose with the formation of a horizontal flaming dart.

4.3. Good practices, standardisation and regulations for "consumer" hydrogen stations

4.3.1. Good practices

Ademe, in collaboration with Ineris and members of Afhypac, has published two documents[24] regarding good practices on the safety of distributed generation facilities and hydrogen refueling stations.

4.3.2. Conception

The practices developed for risk management aim first and foremost to avoid as far as possible any risk of hydrogen leakage.

The appropriate design level of the components of a hydrogen installation, such as a high-pressure storage tank, is validated and certified by extremely severe testing during qualification tests. The nature and level of stresses to which the system is subjected during these tests far exceed what it will have to withstand during its operational life. For example, for a gaseous hydrogen storage tank, at a working pressure (WP) of 700 bar, the test pressure is 1 050 bar (1.5 x WP) and the burst pressure is 2 100 bar (3 x WP).

In the event that a hydrogen leak should nevertheless occur within the installation, means of minimising the consequences are provided for: detection, supply interruptions (hydrogen, electricity, etc.), ventilation, etc:

- the immediate and systematic detection by hydrogen sensors of an abnormal hydrogen content is put in place;
- - System components that may be exposed to a release or leakage of hydrogen shall be completely isolated from ignition sources.

Ventilation is the central element of the safety device. It is the best way to rapidly dilute hydrogen in the ambient atmosphere and reduce the possibility of the formation of flammable or explosive clouds. Today, access to tunnels and car parks is allowed for hydrogen vehicles. However, preparations for standardisation are underway at European level[25].

Adequate and specific safety for the use of hydrogen must be systematically integrated into the design of components and systems, in the same way as for the use of natural gas or petrol (also valid for regulations applying to service/filling stations and for vehicle design).

4.3.3. Use

Like any energy system, a system using hydrogen must receive special attention during its operational life cycle: operation, maintenance, servicing, repair, rest, storage, etc.

As a result, manufacturers have made every effort to establish good practices and to translate them into documents for users. It is thus necessary to follow the precautions for use/storage/transportation/preventive maintenance... issued by the manufacturers and, if necessary, to ensure adequate marking.

The companies in charge of servicing or maintaining these systems receive dedicated training and they use appropriate equipment that enables them to intervene in complete safety.

Discussions are continuing between Afhypac experts and the administrations concerned in order to address the issue of the presence of hydrogen vehicles in underground car parks (currently the parking of hydrogen vehicles in underground car parks is not prohibited: the Civil Security simply recommends to avoid doing so) and in tunnels (CETU). In France, there are no regulations on the circulation of hydrogen vehicles in tunnels, but their use does not anticipate any particular difficulty[26].

4.3.4. Standardisation

Without having the force of law, standardisation is an incentive to use the best manufacturing and control techniques. It defines solutions, levels of quality and standardisation that make it easy to comply with regulations.

In France, standardisation is under the authority of AFNOR.

The service station standards are the European and national versions of international ISO norms. They are prescribed to implement the 2014 European directive on alternative fuel supply infrastructures, which encourages the deployment of hydrogen filling stations along the road networks of the European Union, in particular to guarantee the safety and interoperability of equipment. There are three founding voluntary norms. The first, NF EN 17127 (ISO 198801:2020(en)) applies to filling stations dispensing gaseous hydrogen. The second, NF EN 17124 (ISO 14687-2), specifies the quality characteristics of commercially available hydrogen and the corresponding quality assurance to ensure product consistency for use in fuel cell equipped road vehicles. The third, NF EN ISO 17268, covers connection devices for the refuelling of land vehicles with gaseous hydrogen to define the design, safety and operating characteristics. All three were published in the Afnor collection between January 2017 and November 2018.

4.3.5. Regulation

To ensure good practice in the design and use of a hydrogen installation or system, it is necessary to have appropriate regulations and to establish a platform for standardisation.

The current regulations apply to centralised hydrogen production facilities in the chemical industry.

A specific regulation for hydrogen used as an energy carrier is being put in place at national and/or European level. For the French case, a presentation in June 2017 provides an update on French regulations (Journées Hydrogène dans les Territoires - Hydrogen Days in the Territories)[27].

A ministerial order[28] n°0246 regulates the design and operation of gaseous hydrogen distribution stations in order to guarantee total safety for the user. It limits the distribution pressure to 700 bar and the flow rate to 120 g/s[XIV], which means that cars can be recharged in less than a minute, since a

[XIV] The Ministerial Order sets the normative framework that limits the flow rate to 60 g/s for fillings at 700 bar; 120 g/s is reserved for trucks/buses at 350 bar.

light vehicle consumes just over one kilogram of hydrogen per 100 kilometers. It prescribes minimum distances from other equipment (5 metres from electric vehicle charging stations and from charging stations for other fuels).

4.4. Good practice, standardisation and regulation for hydrogen vehicles

4.4.1. Good practices

Ademe, in collaboration with Ineris and Afhypac members, has published a document[29] of best practices on the safety of hydrogen vehicles.

4.4.2. Conception

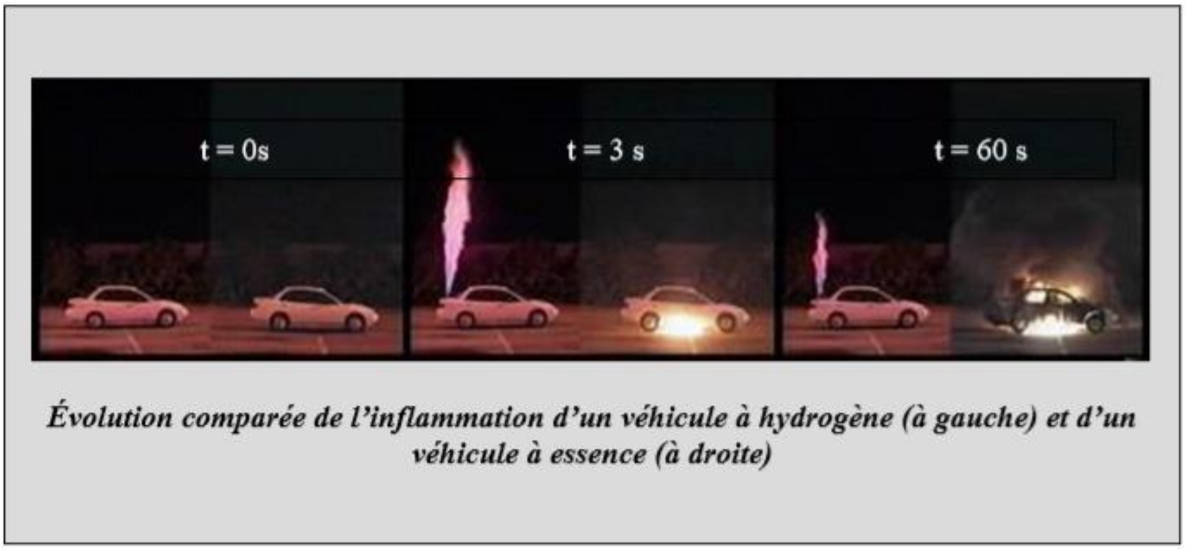

Figure 15 — The flame due to a hydrogen leakage is strictly vertical and does not radiate much[XV]

The manufacturer shall ensure in particular that the hydrogen components and system:

- operate correctly and safely and that they reliably withstand electrical, mechanical, thermal and chemical operating conditions without leakage or visible deformation during their expected service life;
- are protected against overpressure;
- use hydrogen-compatible materials if they are to come into contact with hydrogen;
- résistent de façon fiable à une plage de températures de fonctionnement fixée dans les mesures d'exécution du règlement[XVI].

XV This image is given as an illustration of the low horizontal diffusion of hydrogen but it should be noted that no manufacturer today foresees the opening of the TPRD (Thermally activated Pressure Relief Device) upwards.
[XVI] Mesures d'exécution du règlement EC n°79/2009

4.4.3. Standardisation

Numerous international norms are applicable to hydrogen vehicles, including the ISO 23828:2013 norm on measuring the energy consumption of hydrogen vehicles; the current NF EN ISO 17268 norm on connecting devices for the refuelling of land vehicles with gaseous hydrogen; the ISO 19881:2018 norm on on-board tanks.

4.4.4. Regulation

Hydrogen-powered cars have been certified in France since December 2011.

New models of hydrogen vehicles undergo severe tests before they are put on the market (crash tests) https ://www.youtube.com/watch ?v=W3QNNF4ptl4 .

In addition to conventional certification rules for internal combustion vehicles and rules related to the electrification of the propulsion system, fuel cell vehicles are subject to specific European regulations, including EC Regulation 79/2009 and its implementing Commission document 406/2010 applicable to the approval of hydrogen vehicles.[XVII]

These two regulations require, in particular, proof of the operating safety of the hydrogen system as well as a "type approval" for the most sensitive (where pressure of gaseous hydrogen is greater than 3 MPa) components (or technical entities) , guaranteeing their safety by means of test cycles.

Thus, in addition to the containers with their mountings, regulators, valves or solenoid valves, pressure-, hydrogen temperature- and flow sensors of the high pressure part, hydrogen hoses; the entire filling line, pressure relief valves, sensors, detection probes and hydrogen leakage detectors are subjected by regulation to a set of tests for pressure cycles, tightness, wear and tear and corrosion resistance.

4.5. In the event of an accident: intervention and rescue services

In parallel with the development of safety regulations governing the use of hydrogen, appropriate procedures for intervention by the emergency services have been established.

Training courses for firefighters are already in place, based on practical knowledge of these uses. In particular, the National Superior School for Fire Fighting Officers (ENSOSP) based in Aix-en-Provence provides training for intervention on hydrogen fires for emergency services worldwide.

These training courses were developed as part of the European HyResponse programme involving seven French (the consortium leader ENSOSP, Air Liquide, AREVA SE), English and Italian partners. The aim of this project, which ran from June 2013 to September 2016, was to develop a real training platform dedicated to hydrogen risk for first interveners, the firefighters. Financed within the

[XVII] The regulations will be replaced on 2022/01/05 by: REGULATION (EU) 2019/2144 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 27 November 2019 on type-approval requirements for motor vehicles and their trailers, and systems, components and separate technical units intended for such vehicles, as regards their general safety and the protection of vehicle occupants and vulnerable road users, amending Regulation (EU) 2018/858 of the European Parliament and of the Council and repealing Regulations (EC) No 78/2009, (EC) No 79/2009 ….https://eur-lex.europa.eu/legal-content/fr/TXT/?uri=CELEX:32019R2144 framework of the FCH JU, simulation workshops or simulation exercises in virtual reality enabled the validation of a good practice guide and the definition of a training offer in this field.

It should be noted that the fire brigades of the Manche department are equipped with hydrogen-powered vehicles for their daily interventions.

Hydrogen-powered vehicle for the Channel fire brigade

souce : https://www.automobile-entreprise.com/Les-pompiers-de-la-Manche-roulent,4593

Training in intervention on hydrogen fires at the Ecole nationale supérieure for Fire Brigade Officers (ENSOSP - Aix-en-Provence)

Figure 16 —Hydrogen vehicle and Intervention on hydrogen fire

Summary and Recommendation

Hydrogen has been used industrially for many years with a very satisfactory level of safety despite its potential risks of ignition and explosion.

Existing standards and regulations will have to be adapted to the increasing number of uses, particularly by the general public, and to take account of feedback from experience, it being recognised that the technologies to prevent and limit risks are available. Pre-normative, normative and regulatory efforts should therefore be continued at the European level, in particular for the safety of consumer or semi-consumer applications. In pursuing current practices, regulatory work must involve the administration and all stakeholders (fire brigades, technical centres, equipment manufacturers, operators, users, etc.).

Under this condition, safety issues are not prohibitive for the development of hydrogen.

5. Hydrogen economy and business models

There is no shortage of publications proposing economic models or cost estimates for a hydrogen sector, with sometimes contradictory conclusions. Cost calculation methods may reveal incompatibilities in the conditions of use of the technologies, the basic data may be unclear (old sources or poorly supported prospective sources), etc.

The purpose of this section is to identify established sources for economic data, or failing that, to propose order-of-magnitude comparisons for evaluating options. The ambition is not to achieve the rigour of real economic models, but to identify the cost determinants of the main uses considered and their margins of evolution.

5.1. Hydrogen production costs

The following graph (based on Hosseini et al., 2016[30]) offers a comparison of hydrogen production costs. Although the evaluations are based on homogeneous and consistent assumptions, many parameters are not explicit.

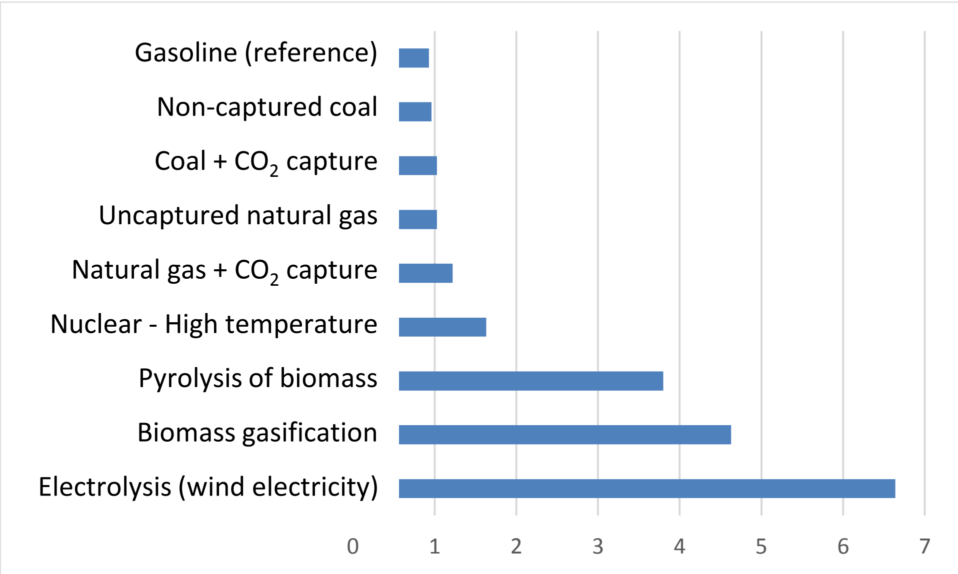

Figure 17 — Costs of the different modes of hydrogen production (US$/kg H2)

The following paragraphs will explore the factors governing these costs and assess their potential for change.

5.1.1. Cost of production by gasification or reforming

Gasification and reforming are established technology streams, with relatively little cost detail provided by industry. Most of the references put forward production costs for reforming in the order of 1.5 to 2 €/kg of hydrogen, which is higher than the figures quoted by Hosseini S.E. et al.

The dissociation of a methane molecule by vaporeforming provides four molecules of dihydrogen (see 2.1, hydrogen today); by mass, 2 kg of methane form one kilogram of dihydrogen and 5.5 kg of carbon dioxide. However, methane is both raw material and energy source for the process: most references refer to carbon emissions of 9 to 10 kg per kilo of hydrogen, which means the use of about 3.5 kg of CH_4 /kg H2.

The price of natural gas varies greatly depending on the country, producer or importer, and the conditions under which it is transported by pipeline or LNG tanker: the IEA[31] in its report on hydrogen expects \$3 to \$11 per million BTU (British Thermal Unit), i.e. from €11 to €34/MWh[XVIII]. The average figure for Europe is ~22.4 €/MWh (0.34 €/kg), which represents a raw material and energy cost for reforming of between 1 and 1.2 €/kg hydrogen. To this must be added the costs of amortisation and operation of the installations: in total for France, the cost of one kg of hydrogen from reforming is between 1.5 and 2 €/kg; countries that are better endowed with natural gas resources can go down to less than 1 €/kg.

Gasification refers to slightly lower costs due to a cheaper raw material, coal. However, gasification requires the management of solids (coal and ash), which is more demanding to manage than gas.

Carbon capture could reduce emissions from gasification or reforming by up to 90%, at an extra cost of 50% on investment and 10% on fuel, which would add ~€0.5 / kg to the price of hydrogen: capture becomes profitable if the cost of CO_2 (emission certificates) is above ~€60 per tonne and even less in the case of gasification. However, this assessment only takes into account the extra cost of CO_2 capture: it does not say anything about the possible costs of storing or reusing it.

Data provided by Total indicate a range of €100 to €250/tonne for all CO_2 capture, transport and storage (CCS) processes. In relation to the cost of hydrogen, this means an additional cost of €1 to €2.5 per kg, or for France, hydrogen by SMR with CCS of €2.5 to €4.5/kg, well above the IEA's estimates.

In a nutshell:

- **Production costs:** 1.5 to 2 €/kg of hydrogen for France, 2.5 to 4.5 €/kg with capture and storage.
- Mature installations (except transport, storage or use of CO_2).
- Main determinants for the evolution of costs:
    - gas (or coal) price,
    - cost per tonne of CO_2.

5.1.2. Cost of production by electrolysis

The production cost for the three available technologies (alkaline, PEM and SOEC, see subsection 3.1.3) is conditioned by:

a. the cost of the electric kWh and the efficiency of the electrolyser

According to an inventory of devices installed in 2017 (see table from Buttler et al., 2018[32]), the electricity consumption of alkaline and PEM technologies is 55 to 70 kWh/kg H_2 produced, and 41 to

[XVIII] Considering an exchange rate of 1.1 USD for 1 €.

43 kWh/kg for high-temperature technologies (which require a heat source, often considered as waste heat and therefore not accounted for).

	AEL	PEMEL	SOEL
Operation parameters			
Cell temperature (°C)	60–90	50–80	700–900
Typical pressure (bar)	10–30	20–50	1–15
Current density (A/cm^2)	0.25–0.45	1.0–2.0	0.3–1.0
Flexibility			
Load flexibility (% of nominal load)	20–100	0–100	−100/+100
Cold start-up time	1–2 h	5–10 min	hours
Warm start-up time	1–5 min	< 10 s	15 min
Efficiency			
Nominal stack efficiency (LHV)	63–71%	60–68%	100%[a]
...specific energy consumption (kWh/Nm^3)	4.2–4.8	4.4–5.0	3
Nominal system[b] efficiency (LHV)	51–60%	46–60%	76–81%
...specific energy consumption (kWh/Nm^3)	5.0–5.9	5.0–6.5	3.7–3.9
Available capacity			
Max. nominal power per stack (MW)	6	2	< 0.01
H_2 production per stack (Nm^3/h)	1400	400	< 10
Cell area (m^2)	< 3.6	< 0.13	< 0.06
Durability			
Life time (kh)	55–120	60–100	(8–20)[c]
Efficiency degradation (%/a)	0.25–1.5	0.5–2.5	3–50
Economic parameter			
Investment costs (€/kW)	800–1500	1400–2100	(> 2000)[c]
Maintenance costs (% of investment costs per year)	2–3	3–5	n.a.

[a] Operating at thermoneutral voltage.
[b] Including auxiliaries and heat supply (SOEL).
[c] High uncertainty due to pre-commercial status of SOEL.

Table 1 — Synthesis of electrolysis production yields and costs, ref. Buttler et al (2018).

The favourable value of 55 kWh/kg H_2 for electrolysers is generally accepted.

This production efficiency must be coupled with the price of electricity, both current and future, to obtain an order of magnitude of the cost of hydrogen. At market prices, electricity has varied between €40 and €50/MWh in recent years, in line with the Arenh[XIX] tariff, which pays EDF €42/MWh for its nuclear production.

[XIX] L'Arenh (Accès régulé à l'électricité nucléaire historique - Regulated access to historic nuclear electricity) is a scheme allowing electricity suppliers competing with EDF in France to repurchase part of EDF's nuclear electricity generation at a rate of €42/MWh.

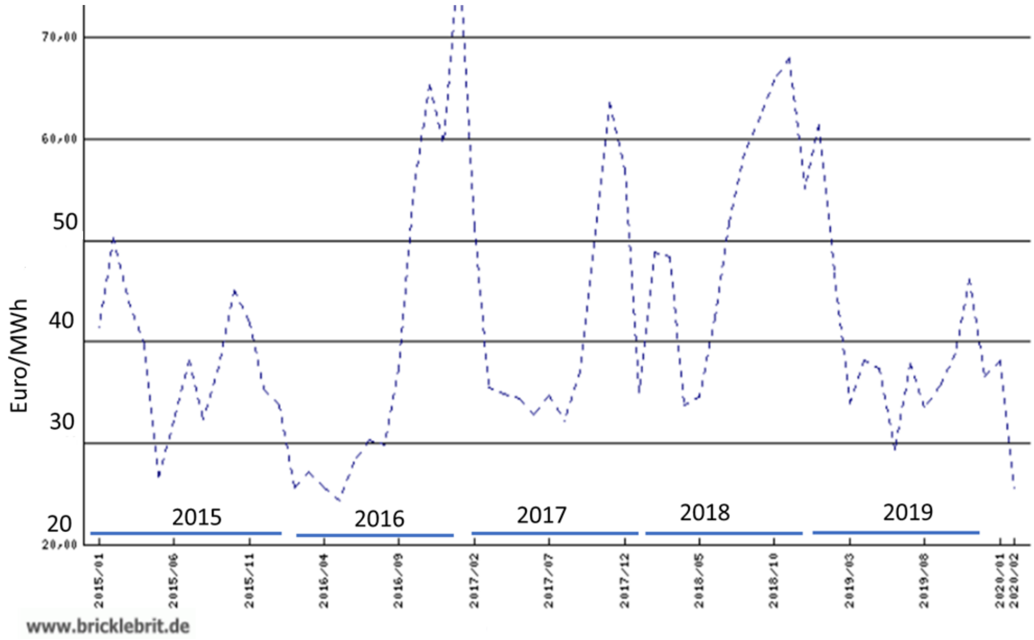

Figure 18 — Average electricity price per MWh on the EpexSpot market, from 2015 to early 2020
http://bricklebrit.com/epex.html

In terms of production costs, the French Court of Auditors[33] referred to nuclear electricity at €59/MWh in 2014 but including amortisation of the reactors. The current production costs of amortised nuclear power are more or less 32 €/MWh[34], taking into account major refurbishment operations. The production price target for the EPR, initially 70 €/MWh, is now estimated at between 80 and 100 €/MWh.

As regards RE in metropolitan France, the Court of Auditors[35] in 2018 indicates floor prices of €65/MWh for ground-based photovoltaic plants, €74/MWh for onshore wind, and more than €200/MWh (reduced to ~140 €/MWh in 2019[36]) for *offshore* wind, €110/MWh for small hydropower. Large hydropower in France is already used as storage to peak load peaks: it does not need to be considered at this stage.

Electrolysis using carbon-based electricity is ruled out, because even if it is competitive it will still emit more CO_2 than reforming. The IEA points out in this respect that, in terms of carbon emissions, electrolysis is only of interest compared to reforming for electricity mixes emitting less than 185 g CO_2/kWh.

It can be noted that high-capacity facilities will undoubtedly find it easier to negotiate the lowest electricity rates (see box on the example of aluminium).

The example of aluminium

Aluminium, like hydrogen envisaged in the future, is produced by electrolysis, i.e. with a high consumption of electricity, of the order of 15 kWh/kg of Al. Oleg Deripaska, CEO of Rusal, says that aluminium is solid electricity. Hydrogen producers might say hydrogen will be gaseous electricity.

For this reason, aluminium smelters negotiate hard on the price per MWh. In most countries, they obtain prices below market prices (€26/MWh in the United States, €50/MWh in China...). They develop international projects, generally large hydroelectricity powered projects, with contracts that sometimes impose a very low MWh price at the outset, which gradually increases when the amortisation of the electrolysers and the supply chain is sufficient in their view. In recent decades, such projects have been carried out in Mozambique, Guinea, Iceland, Canada, Cameroon, etc., and are now being developed in other countries.

Aluminium smelters do not easily tolerate drops in electrical production to avoid cooling of the electrolysis cells, whereas PEM electrolysers accept it.

The fundamental difference between the two materials lies in the issues of transport and storage, which are much more complex for hydrogen than for aluminium.

At 55 kWh/kg of hydrogen, the electricity component in the final cost is :

- 1.75 €/kg of hydrogen with amortised nuclear;
- 3.5 €/kg of hydrogen for ground-based PV;
- 4 €/kg of hydrogen for onshore wind power;
- 7.7 €/kg of hydrogen for offshore wind.

These values are the current lower bounds for each of the modes of electricity generation: up to 30% more is required for lower electrolysis efficiencies. In practice, the actual cost of hydrogen is likely to result from the combination of the different production costs, i.e. :

- 2.2 to 2.75 €/kg of hydrogen with electricity at market price; 4.2 €/kg of hydrogen for an industrial installation connected to the high-voltage grid;
- 8.4 €/kg of hydrogen at the basic electricity tariff for consumers.

It should be emphasised that these are costs excluding transport and taxes. Transport alone (Turpe) potentially adds 10 to 15 €/MWh for large capacity installations, i.e. +0.5 to +0.8 €/kg of hydrogen. Large electrolysers can be qualified as electro-intensive and benefit from a Turpe reduction. However, a macroeconomic analysis must take into account the cost of the necessary reinforcement of the transport and distribution networks - reflected by the Turpe - even if it is not borne by the electrolyser operators but by the other consumers.

b. amortisation of the installation

Buttler A. et al. 2018[XX], quote costs of 800 to 1,500 €/kW of installed power for alkaline electrolysis and 1,400 to 2,100 €/kW for PEM, and more hypothetical costs for SOEC that is still not industrially mature.

[XX] See supra ref.

For installations of more than 5 MW the Academy's hearings indicated a range of 500 to 1,000 €/kW for alkaline and 1,000 €/kW to 1,500 €/kW for PEM with long-term prospects similar to that of alkaline at 500 €/kW. Here, ~7% per year of the investment cost should be added to take account of operation and maintenance operations.

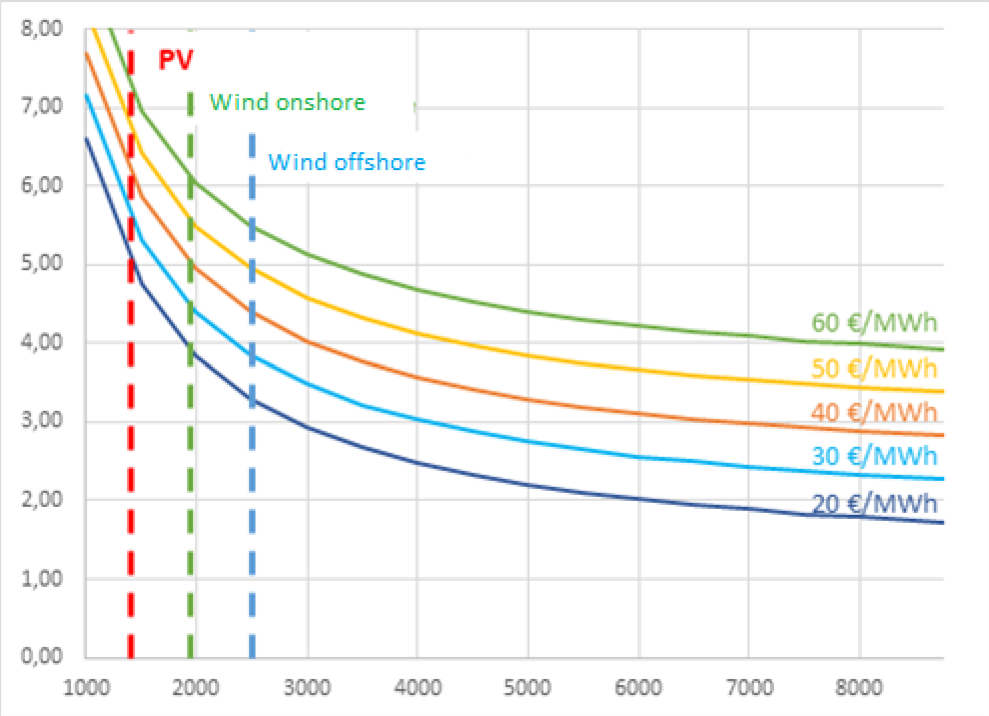

Figure 19 —Hydrogen cost (€/kg) versus Load factor (operating hours per year - Capex of the electrolyser :€1,000/kW)

The impact of this investment on the production price depends on the total quantity of hydrogen produced, i.e. the operating time of the installation or its load factor.

Buttler A. et al. 2018 distinguish the life of the electrolytic installations (30 to 50 years for alkaline, 20 years for PEM and SOEC) from the life of the "stacks" that constitute the heart of the systems: 55,000 to 120,000 h for alkaline electrolysis and 60,000 to 100,000 h for PEM, less than 20,000 h for SOEC, still under development. It is always possible to renovate or replace the stacks to extend the life of the installation (depending on the source, the costs quoted) are of the order of 30% to 50% of the initial investment.

Assuming 100,000 hours (a very favourable value for both alkali and PEM), this means 12 to 14 years of operation for a standard industrial plant (80 to 90% load factor). If only variable RE is to be used (in metropolitan areas, load rate ~15% for PV, ~23% for onshore wind), the amortisation period is determined by the system and not by the *stacks*.

Under these conditions, and on the basis of 1 000 €/kW for electrolysers, one can calculate terminals for the amortisation and operating costs of the electrolysers, referred to the kg of hydrogen:

- 0.5 to 1 €/kg H_2 with grid electricity (80 to 90% charge rate) ;
- 5 €/kg H_2 for PV on the ground (15% load rate);
- 3 €/kg H_2 for onshore wind (25% load rate);
- 1.9 €/kg H_2 for offshore wind (40% load rate).

As for the cost of electricity, these values are lower bounds, in the case of electricity production based exclusively on the means indicated: depending on the utilisation cases, the amortisation may be a composite value. These costs are to be halved if the investment for electrolysers falls to 500 €/kW.

c. cost balance of electrolytic hydrogen

In total, the current cost of producing electrolytic hydrogen is:

	Cost of electricity	Load factor	Turpe[1]	Cost/Price hydrogen[2]	
				1 000 €/kW	500 €/kW
Amort. nuclear	32 €/MWh	90 %		2,75 €/kg	2,25 €/kg
New nuclear	80 à 100 €/MWh	90 %		5,4 à 6,5 €/kg	4,9 à 6 €/kg
Ground PV[3]	65 €/MWh	15 %		8,5 €/kg	6 €/kg
Onshore Wind	74 €/MWh	23 %		7 €/kg	5,6 €/kg
Offshore Wind	140 €/MWh-*70 €/ MWh*[4]	40 %		9,6 €/kg-*5,7 €/kg*	8,6 €/kg-*4,8 €/kg*
Market Electricity	40 à 50 €/MWh	90 %	included	3 à 4 €/kg	2,5 à 3,25 €/kg
Industrial Tariff	77 €/MWh	90 %	included	5,2 €/kg	4,7 €/kg
Basic rate	152,4 €/MWh	90 %	included	9,4 €/kg	8,9 €/kg

1 Turpe (Tarif d'utilisation des réseaux publics d'Électricité - Tariff for the use of public electricity networks) is not accounted for if hydrogen production is assumed at power generation sites.
2 Price calculated for current PEM (1 000 €/kW) or alkaline (500 €/kW) electrolysers.
3 By making the most of cost hypotheses in the sunniest areas of the planet, we could eventually imagine a hydrogen produced from photovoltaics at a little less than 3 €/kg in production output.
4 Costs per MWh for some recent offshore wind tenders, including grid connection. It is not clear that these costs could be applicable for France.

Table 2 – Current cost of electrolytic hydrogen production

Electricity is the primary determinant of the cost of hydrogen, accounting for about 75% of the cost of electricity. Only at low charge rates and/or low electricity prices does the amortisation of the electrolyser become important.

In a nutshell:

- costs: 2.5 to 9.5 €/kg of hydrogen;
- mature (alkaline), maturing (PEM), industrially prospective (SOEC) facilities;
- main determinants of cost evolution:
  - price of electricity, for 75% if the load factor is sufficient (about 4,000h minimum),
  - amortisation of the installations (depending on the load factor).

According to *Future cost and performance of water electrolysis*[37], 2017, which seeks to establish the margins of progress for the electrolysis industry, the figures used above are rather at the limits of the state of the art, still far from being generalised. Alkaline and PEM technologies will compete over the next decade, depending on their price and other characteristics (e.g. flexibility); SOEC is not expected to be massively introduced before 2030. The expected progress relates more to the investment cost and lifetime of electrolysers than to efficiency, which is expected to improve only slightly for as long as SOEC is not widely deployed on an industrial scale.

5.1.3. Other modes of hydrogen production

In this study, no publications proposing costs for prospective production methods such as plasmas, biomass pyrolysis, photosynthesis or bacterial route, or native hydrogen extraction were identified.

From an energy point of view alone, the production of hydrogen by plasma requires only a quarter of the energy needed for electrolysis, i.e., according to the previous cost assumptions, between 0.5 and 1 € of electricity per kg of hydrogen. To this must be added the consumption of methane, which represents between 0.8 and 1 €/kg H2. The greatest uncertainty weighs on the cost of the installations, their efficiency and their lifespan: if we imagine costs at least equivalent to those of electrolytic installations, this means at least 1 €/kg H2 and much more at the beginning. However, the process generates as a by-product carbon black, which today has an economic value that varies according to its purity. This value would drop if production were to exceed demand. *Ultimately*, the cost per kg of hydrogen could approach that of reforming.

Photosynthetic or bacterial pathways entail other types of challenges: they require little or no raw materials, but their production intensity will be low, requiring large areas of "cultivated" land and the collection of hydrogen is likely to be complicated. These technologies are still very much in the early stages of research, and no order of price is available. Bacterial production may also meet the need for CO2 neutralisation or waste treatment, as is the case for biogas, and thus have another economy.

With respect to native hydrogen, exploration and extraction techniques are well known to the gas industry and, therefore, the price of hydrogen at the wellhead could be equivalent to that of methane. Questions are more related to the accessibility of this resource and the long-distance transport of hydrogen, except in cases of local use for which the costs may be very low (see 6.2.1.b. Native hydrogen production).

In a nutshell:

- costs: potentially 2 to 3 €/kg of hydrogen for plasma technology, to be defined for the other routes ;
- totally prospective;
- main determinants of the evolution of costs:
    - price of electricity or gas depending on the heat source used,
    - amortisation of the installations (load factor).

5.2. Costs of hydrogen logistics

The scientific and technical literature refers less to the costs of hydrogen logistics than to the costs of production or use. The cost issues related to logistics involve technologies that are not a priori very specific to hydrogen (e.g. compression and liquefaction), and to challenges that are more industrial than academic.

In the absence of homogeneous references on these costs, one is often left with using orders of magnitude on the basis of physical processes.

5.2.1. Compression or liquefaction costs

Most of the applications looked at consider hydrogen in the form of gas under pressure at 200, 350 or up to 900 bars (the tanks of light vehicles have a working pressure of 700 bars, but the buffer tanks upstream are calibrated at 900 bars). Current electrolysis installations deliver hydrogen at a pressure of between 10 and 50 bars according to the following processes.

Compressing hydrogen from 30 bar (electrolyser outlet) to 700 bar consumes about 5% of its energy content: assuming a consumption of 2 kWh per kg of hydrogen (see section 3.3) and an average electricity price between 40 and 50 €/MWh, this translates to about 0.1 €/kg H2.

Liquefaction requires about four times as much energy, i.e. €0.4 per kg before even taking into account the amortisation of the liquefaction unit. Once liquefied, the hydrogen evaporates (*boil off*) at a rate of 1% per day, a large part of which is recovered and reliquefied.

5.2.2. Hydrogen storage costs

The main options for mass storage of hydrogen are in compressed and liquefied forms. Leaving aside temporary storage after production or before consumption (of small capacity and which can be managed without any particular constraints of mass, volume, etc.), the dimensioning requirements relate to three types of use:

- storage for its transport, local or long distance; this requirement is discussed below in the transport section;
- storage for use in mobility -

The requirement consists in storing up to 6 kg of hydrogen at 700 bar, corresponding to a range of 500 - 600 km for a private vehicle. The 2014 France Stratégie report put forward the price of €2,000 for such a tank, matching a DOE[38] estimate for 2020 (€350/kg of hydrogen).

Over 10 years and 150,000 km (conventional assumption for electric vehicles), this cost added *pro rata* to the fuel price increases the cost per kg of hydrogen by about ~1.3 €;

- storage for later use -

  This requirement refers to the seasonal difference in electricity production and use and thus primarily to the need for interseasonal storage. In 2014, the European study[39] estimated the cost of storage in salt caverns at less than 0.5 €/kg[XXI].

5.2.3. Transport and distribution costs

a. hydrogen transport

Over long distances, hydrogen can be transported by pipeline or ship, in gaseous or liquid form or after conversion to ammonia or another suitable liquid. Compression costs, conversion losses and losses during transport (leakage, *boil-off*) are added to the cost of the transport itself.

For distances greater than 3,000 km, maritime transport of liquid hydrogen or of hydrogen in the form of ammonia or on organic solvents seems the best option if it is possible, with an additional cost of $2 to $3 per kg of hydrogen transported. For shorter distances, and provided the solution is feasible, the pipeline is more economical, with additional costs of $1.5 to $2.5 per kg of hydrogen[40].

The IEA considers[41] that "in general, it will be more economical to produce hydrogen [by SMR with CCUS] on its own territory than to import it"[XXII]. Indeed, even with imported natural gas, the cost of raw material and energy for SMR is still less than €1.5/kg of hydrogen. In the case of production by electrolysis, the additional cost for transporting a hydrogen produced in a remote location where solar or wind power would be very economical can quickly offset the additional costs of domestically produced electricity: each euro of cost for transporting one kg of hydrogen wipes out almost 20 euros saved on 1 MWh of electricity. Even with RE at less than 20 €/MWh in the most favourable areas of the planet, production close to the areas of consumption would remain competitive with electricity between 40 and 80 €/MWh.

For local transport, i.e. for distances of less than 500 km, the pipeline remains the most economical solution (less than €1/kg or even less than €0.5/kg) but requires sufficient flow rates to amortise the investment (cf. 3.2.1). As a result, local transport is most often by road transport of compressed hydrogen, with costs of 0.5 to 2 €/kg increasing with distance.

In the case of long-distance transport, it will generally be necessary to cumulate the costs of long-distance transport with those of local transport in order to reach the places where hydrogen is actually used.

[XXI] HyUnder concluded that, with regard to the entire value chain (in particular the cost of electricity and the cost of the electrolysers), the storage of excess electricity capacity is not justified.

[XXII] "the relatively high cost of hydrogen transmission and distribution means that it will generally be cheaper to produce hydrogen domestically rather than import it. This is because the cost of transport will outweigh differences in the cost of electricity production from renewable sources, or differences in natural gas prices and the cost of CCUS"

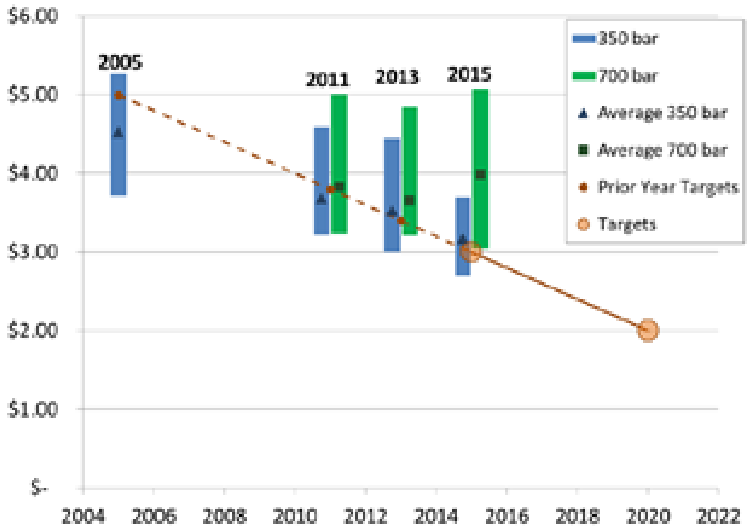

Figure 20 — Cost of supplying and distributing hydrogen from a central production facility - DOE, Quadrennial Technology Review 2015

The IEA thus concurs with the U.S. Department of Energy estimates[42] for 2015, with a total transportation cost of \$3 to \$5 per kg of hydrogen, and a target of \$2 per kg.

b. delivery

For mobility, hydrogen needs to be made available to a large number of consumers.

The IEA suggests costs of \$0.6 to \$2 million for a hydrogen filling station to supply a fleet of vehicles, depending on the throughput of the station. In terms of kilograms of hydrogen delivered, distribution adds between 0.2 and 1.5 €/kg.

In summary:

Process within the H_2 chain	Cost
Compression	
700 bar	0,1 to 0,2 €/kg
Liquefaction	0,4 €/kg
Storage	
Mobility	1 €/kg
In caverns	0,1 to 0,5 €/kg
Transport	
Local	0,5 to 2 €/kg
Long distance	1 to 3 €/kg
Distribution	0,2 to 1,5 €/kg

Table 3 — Additional costs for handling hydrogen

5.3. Hydrogen-to-electricity conversion costs

Thermal generation of electricity using hydrogen will not be economically evaluated here because the efficiency of existing hydrogen turbines is not better than that of fuel cells, while their capital cost is much higher. If hydrogen is combined with natural gas in CCGT facilities, the proportion of hydrogen in the mixture is small and does not significantly change carbon emissions.

For "stationary" fuel cells for power generation, the references identified (including the IEA report on hydrogen in 2019) suggest costs of €1,500 to €2,000/kW with long-term prospects of around €500/kW. However, the units currently installed are of low power, not exceeding 5 MW each, even if recently announced site projects target 10 or even 20 MW. These relatively low capacities seem to be orienting fuel cells towards local uses, with questions about the amortisation of installations very similar to the reasoning behind electrolysers (cf. § 5.1.2.b): it seems very difficult to make the investment profitable for uses other than "baseload".

For mobile uses, the cost of a fuel cell for light vehicles currently on the market would be between 160 and 190 €/kW (Papageorgopoulos 2019[XXIII] cited by the IEA op. cit.), with the prospect of going down to 70 €/kW through effects of scale on production. It should be emphasised that these scale effects will only impact the cost of the processes, not the price of the raw materials needed to manufacture FCs, for example platinum.

The large difference in cost per kW between fuel cells designed for mobile use and those designed for stationary power reflects very different needs and therefore different performance. Fuel cells for mobility are designed for a lifetime of the order of 5,000 h, which is sufficient for the life of the vehicle, whereas stationary fuel cells exceed 70,000 h, with a high charge rate: the structure, materials, etc. have nothing to do with the ensuing impact on costs.

For on-road mobility, DOE estimates that the combination of 80 kW units can meet all needs with one unit for passenger vehicles and four units for heavy transport. This results in a fuel cell cost of €14,000 for a current light vehicle to €6,000 if manufactured in volume (production of more than 100,000 units per year).

In the classical hypothesis of a passenger car amortised over 10 years and 150,000 km, the cost of the fuel cell in relation to the cost of hydrogen increases the cost of hydrogen by €9/kg, potentially falling to €4/kg when the FCs can be produced in volume.

5.4. Costs of different uses of hydrogen

The use of hydrogen is most often mentioned in the following three main categories: industrial production, energy storage and mobility. On the basis of the elements calculated above, it is possible to propose cost estimates of the main options for each of the identified services, and relate them to the common issue of the cost per tonne of carbon avoided.

As a reference and order of magnitude, it should be recalled that EU Emissions Trading Scheme (EU ETS) allowances are traded at around €25/tonne. This value is generally considered to be too low to ensure the objective "to keep global warming below 2°C" defined by the Paris agreement.

[XXIII] 181 to 210$/KW according to sources: Papageorgopoulos D., Fuel cell R&D overview, April 2019, https://www.hydrogen.energy.gov/pdfs/review19/plenary_fuel_cell_papageorgopoulos_2019.pdf

In 2019, *France Stratégie* has proposed a much higher "tutelary value of CO_2"[43], but there is no European consensus on this. It is up to politicians to decide between these elements.

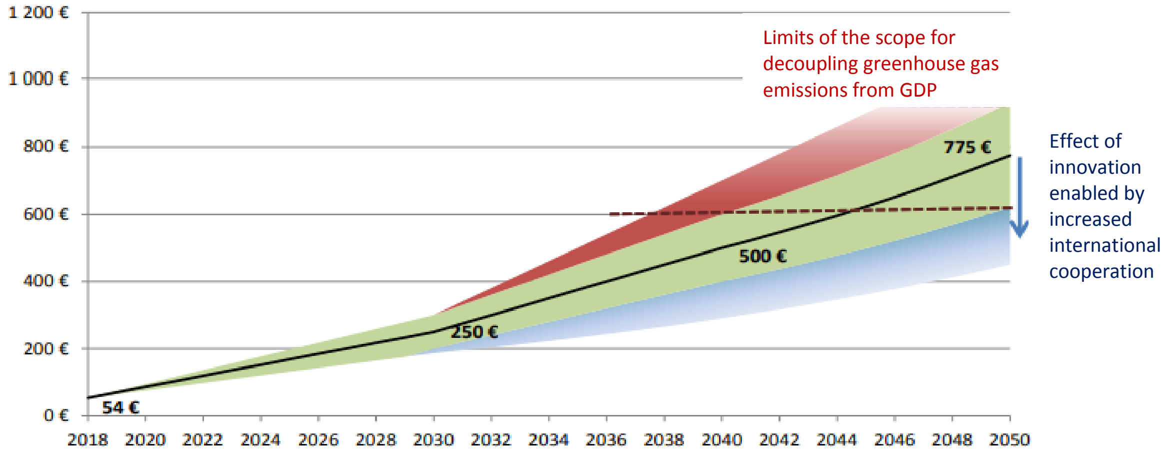

Figure 21 — Constraining value of CO_2 - France Strategy - February 2019

5.4.1. Industrial Uses

a. chemical uses of hydrogen

In its current industrial uses, hydrogen is a raw material: its energy content is not valorised. The issue at stake is the impact of the additional cost of "clean" hydrogen on final production costs.

Decarbonised hydrogen brings just one economic benefit: avoiding the cost of carbon emissions. At a rate of ~10 kg of CO_2 produced per kg of reformed hydrogen, the extra cost of production will be compensated for carbon prices of:

- reforming with capture and storage: 100 to 250 € per tonne of CO_2 avoided;
- electrolysis from decarbonised electricity: 100 to 750 € per tonne of CO_2 avoided.

Chemical uses of hydrogen	Costs per kg of hydrogen	Cost of CO_2 avoided
Reforming with capture *with storage and sequestration*	1,5 to 2 €/kg *3 to 4,5 €/kg*	*100 to 250 €/t*
Electrolysis with decarbonised electricity		100 to 750 €/t

b. local hydrogen production

Declining costs of hydrogen production units may permit local production and thus avoid transportation costs. Investment costs become significantly more favourable for plants from 5 MW upwards, which, however, require a hydrogen consumption of at least two tonnes per day (if we imagine, for example, a use for mobility, this allows refuelling of more than 300 light vehicles per day, i.e. the equivalent of a filling station for internal combustion vehicles).

On the basis of an electricity price of 77 €/MWh (tariff for industrialists, including the Turpe), the cost price of locally produced hydrogen is around 5 €/kg. As long as the cost of transporting hydrogen does not fall below 2-3 €/kg, the option remains competitive with the best possible prices for a centrally produced decarbonised hydrogen (reforming with carbon capture or electrolysis using existing nuclear power).

Local production of hydrogen	Costs per kg of hydrogen	Cost of CO_2 avoided
Electricity at 77 €/MWh (industrial tariff, with Turpe)	5 €/kg	

c. synthetic methane production

The 2018 National Hydrogen Plan mentions for industries that emit a lot of CO_2, the possibility of "valorising the latter with hydrogen by producing synthetic methane"[44]. By mass[XXIV], 1 tonne of CO_2 and 182 kg of H_2 will make it possible to synthesize 364 kg of CH_4 with an energy content of 5.6 MWh (GCV[XXV]: 15.4 kWh/kg).

To valorise 1 tonne of CO_2 therefore requires the consumption of between €450 and €1750 of electrolytic hydrogen[XXVI] (€2.5 to €9.5/kg) to produce the equivalent of €180 of methane (at the market price, based on the average price of natural gas in Europe (cf. § 5.1.1.) of €10 per million BTU). The investment and operating costs of the methanation plant, as well as the cost of the CO_2 itself (capture system and loss of plant efficiency) would also have to be taken into account. Depending on the origin of the electricity, the economic interest of the operation would only start at carbon prices of between €260 and €1600 per tonne of CO_2.

The energy cost of the methane produced as calculated here is at least 220 to 310 €/MWh, consistent with Brynolf et al (2018)[45], who propose a broader and more complete review of the cost of "electrofuels". The authors estimate probable costs between 200 and 280 €/MWh for the whole range of synthetic fuels, specifying that methane is the least expensive among them (taking into account the whole set of scenarios considered, synthetic methane is estimated at between 150 and 650 €/MWh, the value of 200 € being the most realistic).

Production of synthetic methane	Costs per kg of hydrogen	Cost of CO_2 avoided
1 t CO_2 + 182 kg d'H_2 → 364 kg CH_4		260 to 1600 €/t

5.4.2. Storage of renewable energies

Hydrogen produced by electrolysis (or potentially eventually by plasma technologies) could make it possible to absorb - or compensate for - the periods of decoupling between production and consumption resulting from the introduction into the network of intermittent renewable energies. This form of "electricity storage" would allow the storage of large quantities of energy over long periods of time.

In 2018, France experienced eleven hours of negative electricity prices, compared to more than one hundred and forty for Germany[46]. These periods can multiply as the share of RE in the electricity mix increases. However, they do not justify the hypothesis sometimes put forward of energy storage powered solely by surplus electricity. The investment cost of electrolysers is high and they cannot simply operate exclusively during periods of electricity oversupply; the profitability of intermittent

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[XXIV] Sabatier reaction: $CO_2 + 4H_2$ " $CH_4 + 2H_2O$, with molar masses of 44 g for carbon dioxide, 2 g for dihydrogen and 16 g for methane.
[XXV] Gross Calorific Value
[XXVI] It would make little sense to use reforming hydrogen, even with CCSU, for such a purpose.

energy production implies that it is sold on average at a price equal to its Leverage Cost of Electricity, which is taken into account in the evaluations below.

It is therefore appropriate to take into account the real cost of renewable electricity as proposed by the Court of Auditors in 2018, increasing the cost per kg of hydrogen from €7 to €9.5. If pertinent, storage costs (compression, tanks, etc.) of between €0.5 and €1/kg must be added.

As a borderline hypothesis for France, a calculation based on electrolytic hydrogen from wind or solar electricity at 5 €/kg will also be proposed. The calculations in 5.1.2.c. showed that this prospect remains very hypothetical.

Three approaches to hydrogen storage are considered:

a. direct injection of hydrogen into gas networks

Hydrogen can be injected into natural gas networks up to a proportion of 6 to 20% by volume, the maximum currently authorised in France. The gas network thus provides a storage and regulation function for variable RE production.

When used as a fuel, hydrogen provides 39.4 kWh/kg (GCV) of thermal energy under the best conditions. Hydrogen produced from intermittent energies therefore has a cost of 180 to 240 € per thermal MWh, after deduction of the cost of natural gas avoided, i.e. ~34 €/MWh.

Combustion of 364 kg of natural gas produces 1 tonne of CO_2: it takes 142 kg of hydrogen to provide the energy equivalent without emitting CO_2 if the electricity is completely decarbonised. The cost of the carbon avoided is therefore between 800 and 1,200 €/tonne of CO2.

Assuming a hydrogen from RE at €5/kg, the cost of carbon avoided amounts to €520/tonne of CO2. Despite this high value, injection into gas networks remains to be considered as part of a proactive policy to develop hydrogen. Indeed, it requires only very limited investment by benefiting from an existing natural gas network and provides an outlet as long as other uses requiring more important infrastructures (mobility, synthetic fuels) are not developed.

This booster role is also emphasised by the IEA, particularly in its recommendations on public policies, but also in its assessment of the short-term opportunities that countries with gas infrastructure can take advantage of.

	Cost MWh	Cost of CO_2 avoided
Hydrogen injection into gas networks	(GCV H_2)	
Hydrogen from RE: 7 to 9.5 €/kg	180to 240 €/MWh	800 to 1 200 €/t
if hydrogen from RE at 5 €/kg	*127 €/MWh*	*520 €/t*

b. methanation then injection into gas networks

Methanation was explored in the previous sub-section: if only renewable energy is used for this production, the tonne of carbon avoided costs €1,000 to €1,600.

Assuming a hydrogen from RE at 5 €/kg, the cost of avoided carbon amounts to about 720 €/tonne of CO_2.

	Cost MWh	Cost of CO_2 avoided
Methanation, then injection into gas networks	(GCV synthetic methane)	
Hydrogen from RE: 7 to 9.5 €/kg	220 to 310 €/MWh	1000 to 1600 €/t
if hydrogen from RE at 5 €/kg	*162 €/MWh*	*720 €/t*

c. conversion to electricity

In addition to the uses for mobility mentioned below, the logic here is to be able to store hydrogen over more or less long periods of time in order to produce electricity at the times when it is most in demand.

The efficiency of a fuel cell at room temperature is 55-60%; the efficiency is higher with a high-temperature fuel cell, but requires energy for warm-up, which in some cases can be waste heat, but which must be accounted for if it is not.

To evaluate the cost of the electrical MWh output from the fuel cell, it is necessary to take into account:

- The cost of hydrogen produced from renewable electricity (7 to 9.5 €/kg),
- Compression and storage costs (0.5 € /kg in the best case),
- Fuel cell amortisation.

This last point depends mainly on the utilisation rate of the fuel cell: at best 50% in day/night storage; probably 10 to 20% if we consider inter-seasonal storage or at least a few weeks to compensate for windless periods. This amortisation can lead to an additional cost of 2 to 5 €/kg of hydrogen.

Under these conditions, the MWh produced by a fuel cell using hydrogen from renewables is between 500 and 800 €/MWh. The main option for reducing the cost of this electricity from storage would be to use the same device as an electrolyser and as a fuel cell: this is what French start-up Sylfen, for example, is proposing. In this case the MWh produced could be between €400 and €550/MWh, or even less given the more favourable efficiencies of high-temperature electrolysers.

Assuming a hydrogen from RE at €5/kg, the cost of electricity withdrawn from storage could fall to €450/MWh.

Based on the hypothesis, which generally applies, that thermal solutions (gas or coal) compensate for the variability of renewables, they produce between 0.429 t CO_2eq/MWh for gas and 0.986 t CO_2eq/MWh[47] for coal. The tonne of CO_2 avoided by fuel cells therefore amounts to between €1200 and €1900 (gas) and €500 and €800 (coal).

It should be emphasised that all these costs require electrolytic installations of several MW, i.e. the power of an onshore wind turbine or a few hectares of PV panels. At the same time, current PEM (potentially SOEC) electrolysers and fuel cells are devices with a unit power of less than 5 MW. While it is still possible to combine several units on the same site, the prospect of exceeding a few tens of MW of power still seems remote. While this may make sense for isolated areas not connected to a grid, the orders of magnitude do not allow us to see this as a viable interseasonal storage solution for France.

Conversion to electricity		Costs MWh elec.	Cost of CO_2 avoided
	Hydrogen from RE: 7 to 9.5 €/kg	500 to 800 €/MWh	500 to 1900 €/t
	if hydrogen from RE at 5 €/kg	*450 €/MWh*	*455 to 1 050 €/t*

d. general perspective on the storage of variable RE

In any case, storing variable renewable electricity in the form of hydrogen results in conversion losses of 70%, eventually perhaps only 40% or 50%. In an environment with large gas or electricity grids, the prospects of profitability for these solutions seem very remote, at carbon price levels much higher than they are at present.

This is not the case for sites or areas not connected to the grid or for isolated grids, which depend for their energy on what can be produced locally or on supplies that are often made at great expense. These needs may drive research, which may foreshadow more efficient systems, particularly with SOEC.

5.4.3. Hydrogen based mobility

a. fuel cost and comparison with other mobility alternatives

An average passenger vehicle or light commercial vehicle needs about 15 kWh to 20 kWh to travel 100 km, or about 5 to 7 litres of hydrocarbon or 1 kg of hydrogen. On the basis of ~1.5 € incl. taxes per litre of petrol, this means about 4 € excl. taxes per 100 km, comparable in order of magnitude to the best hydrogen production prices.

On the most realistic assumption of decentralised production (installation of sufficient size for an electrolyser cost of around 1,000 €/kW), supplied by electricity at the industrial rate (77 €/MWh, including Turpe) the kg of hydrogen costs ~5 €. The additional cost of €1 compared to hydrocarbons makes it possible to avoid the emission of about 15 kg of CO_2, bringing the cost of avoided carbon to €67/tonne, which corresponds roughly to the initial level of the carbon tax on petroleum products planned for 2020 (set at €44/t of CO_2 in 2019).

Hydrogen-based mobility, which moreover allows a longer range than purely electric vehicles, can be competitive with hydrocarbon mobility for a price attributed to the tonne of carbon avoided that would remain reasonable.

Alstom data on the hydrogen train show a consumption of 35 kg of hydrogen per 100 km compared with 170 to 200 litres of diesel: the price per tonne of carbon avoided is comparable to that of a private vehicle.

b. full cost of ownership for a hydrogen vehicle

The previous subsection considers only the cost of the "fuel" (fuel, hydrogen or electricity); of course, the cost of owning and using the vehicle must be considered for a full comparison. Or, at least, the cost of the elements that change between the different modes: engine, tank, fuel cell, batteries, electronics...

Such work far exceeds the ambitions of this report. One will simply refer to the many studies that offer such comparisons (see IEA example below), emphasising however that the calculation assumptions are not always explicit or jointly applicable (and relevant in the case of France). The studies consulted for this report generally predict long-term parity between hydrogen and battery-powered vehicles.

Figure 54. Total cost of car ownership by powertrain, range and fuel

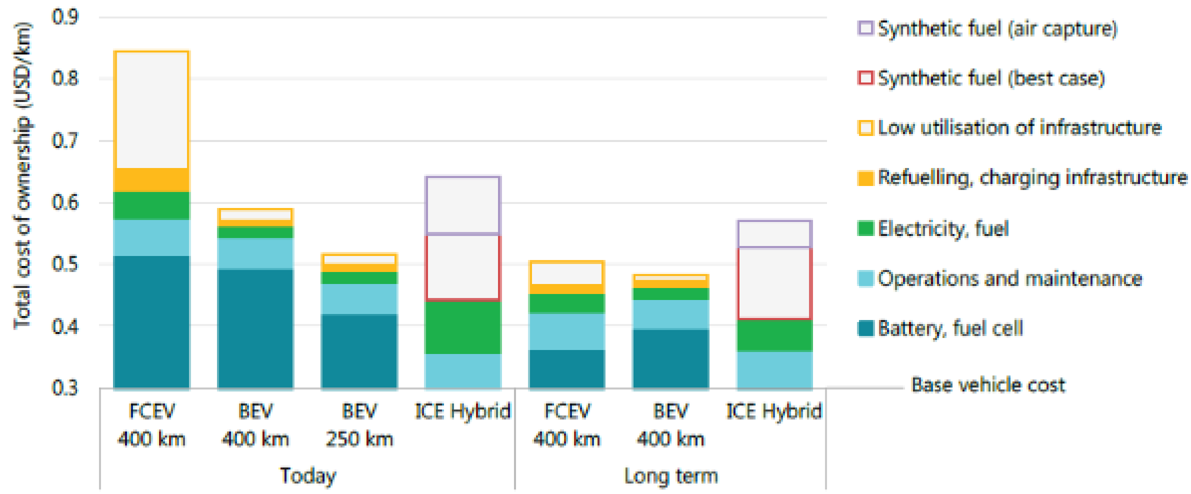

Figure 22 — IEA 2019: Cost per km of hydrogen (FCEV), battery (BEV) and thermal hybrid (ICE) vehicles

To frame the ideas, the following points should be borne in mind: the powertrain of a current internal combustion vehicle represents around 25% of its cost (10% for the engine alone), i.e. from €2,500 to €10,000 for the small and medium ranges. The essential components of a hydrogen engine currently amount to more than €15,000, with the prospect of reducing this by 50% through technical developments and mass production effects. Batteries, which are the main cost item for electric vehicles, currently cost between €10,000 and €20,000 depending on the vehicle, with the prospect of cutting these costs in half.

5.4.4. Summary of the costs of potential uses of hydrogen

	Costs	Cost of CO_2 avoided
Hydrogen for industry	kg of hydrogen	
Chemical uses of hydrogen		
Reforming with capture *with storage and sequestration*	1,5 to 2 €/kg *3 to 4,5 €/kg*	*100 to 250 €/t*
Electrolysis with decarbonised electricity		100 to 750 €/t
Local production of hydrogen		
Electricity at 77 €/MWh (industrial rate, with Turpe)	5 €/kg	
Production of synthetic methane		
1 t CO_2 + 182 kg d'H_2 → 364 kg CH_4		260 to 1600 €/t
Storage of renewable energies	Cost MWh	

Hydrogen injection into gas networks		(GCV H_2)	
	Hydrogen from RE: 7 to 9.5 €/kg	180 to 240 €/MWh	800 to 1 200 €/t
	if hydrogen from RE at 5 €/kg	*127 €/MWh*	*520 €/t*
Methanation, then injection into gas networks		(GCV synthetic methane)	
	Hydrogen from RE: 7 to 9.5 €/kg	220 à 310 €/MWh	1000 à 1600 €
	if hydrogen from RE at 5 €/kg	*162 €/MWh*	*720 €/t*
Conversion to electricity		(MWh electric)	
	Hydrogen from RE: 7 to 9.5 €/kg	500 to 800 €/MWh	500 to 1900 €/t
	if hydrogen from RE at 5 €/kg	*450 €/MWh*	*455 to 1 050 €/t*
Hydrogen for mobility			
	Passenger car or light commercial vehicle: 15 kWh/100 km	5 €/100 km	67 €/t

Table 4 — Example of estimated costs of potential hydrogen uses

The costs of electrolytic hydrogen are primarily determined by the price of electricity, as long as the installations are used at their optimum. Electrolytic hydrogen will therefore remain more expensive than reformed hydrogen in the long term, even with carbon capture.

De facto, the development of a hydrogen industry in the years to come will have to be based on reforming, currently at capacity, but offering only a shift in carbon emissions (except for CCUS, which is still hypothetical), and on electrolysis, for which the increase in capacity should be supported.

From both an economic and environmental point of view, mobility seems to be the usage that can drive the development of a hydrogen industry. The cost of vehicles will certainly have to rise, but the cost of fuel is already of the same order of magnitude as for internal combustion vehicles, while providing greater autonomy than battery-powered vehicles. Captive fleets of company vehicles, trucks, trains and even boats seem to be the preferred targets for this development. In this respect, the availability of economical and largely decarbonised electricity gives France an invaluable asset for developing a hydrogen industry.

In addition, the storage of renewable electricity in the form of hydrogen can open up niche markets (particularly for areas not interconnected to the grid), for France or internationally. However, the economics of this option are handicapped by amortisation periods that are currently longer than the service life of the equipment.

5.5 The place of hydrogen in the mix, and energy scenarios

5.5.1. A potential of several million tons of decarbonised hydrogen

To play a role in the French mix, we need to produce on the order of a million tonnes of decarbonised hydrogen or more.

France produces about one million tonnes of hydrogen per year, according to Afhypac, of which less than 50,000 tonnes are produced by decarbonised methods. To illustrate the challenges, let us give a few orders of magnitude:

- Converting all of the annual production of renewable, non-dispatchable electricity (~35 TWh) into hydrogen would produce approximately 640,000 tonnes of hydrogen;
- converting a quarter of the passenger car fleet to hydrogen would lead to a consumption in the order of one million tons per year;
- one day's electricity consumption in winter represents approximately 1.8 TWh. Given the conversion efficiencies, this requires nearly 90 000 tonnes of hydrogen to be produced and stored, equivalent to eight of the hydrogen tankers like the one presented in paragraph 3.2.3. The totality of current photovoltaic production converted into hydrogen would represent two days of winter electricity consumption, five days for wind power.

The order of magnitude of a significant hydrogen sector in the French energy system is therefore a few million tons per year. In comparison, the largest electrolytic installations currently in operation in the world are ~100 MW for alkaline and less than 10 MW in PEM, i.e. less than 1,500 tonnes of hydrogen per year.

Producing one million tonnes of hydrogen per year by electrolysis requires a production capacity of 6 to 7 GW used full time, fuelled by 55 TWh of electricity. This is well within the reach of the electrical system and the capacities of French industrialists, but it is a significant challenge. Moreover, and even anticipating significant gains in the economy of electrolysers and fuel cells, hydrogen will only be able to develop if a high price is given for the tonne of carbon avoided (over €300/tCO_2).

It should be recalled that Germany considers that the price per tonne of CO2 avoided should be set by the EU-ETS (European Trading Scheme) market, which is currently in the region of €20/t. It is opposed to a tax on emissions. The French domestic tax on the consumption of energy products (TICPE) before the yellow jackets crisis was 50 €/tonne. The price needed for the development of the hydrogen economy without subsidies would be an order of magnitude higher than the TICPE.

5.5.2. Hydrogen in 2050

The production of hydrogen by electrolysis for the main intended uses requires very large quantities of electricity. The table below presents the projections of the authors of this report for 2050, compared to the projections of the McKinsey consulting firm for the same horizon. The McKinsey projections were prepared at the request of Afhypac[48] and its main results were included in the "Hydrogen Deployment Plan for the Energy Transition" (Hulot -2018).

Uses of hydrogen in 2050 versus electrical energy required for producing this hydrogen by electrolysis			
National Academy of technologies of France		*McKinsey*	
Decarbonisation of ½ of material hydrogen (applications for the production of fuels for mobility are expected to be reduced). New uses (methanol, DRI)	45 TWh	Decarbonisation of the totality of material hydrogen. New uses (methanol, DRI)	80 TWh
Energy for Industry	10 TWh	Energy for Industry	35 TWh
Electricity generation and storage	nm	Electricity generation and storage	21 TWh
One quarter of light mobility - three quarters of heavy goods vehicle and public transport mobility	180 TWh	18% of passenger and freight vehicles. Approximately 10% of light passenger vehicles; 20% to 25% of large vehicles and heavy goods vehicles, and 35% of commercial vehicles [XXVII]	72 TWh
Injection of 20% hydrogen into the network	40 TWh	Heating and electricity in buildings (not directly comparable to the injection of 20% hydrogen)	67 TWh
Rail (replacement of diesel engines)	A few TWh	Rail (replacement of diesel engines)	A few TWh
Naval	A few TWh	Naval	A few TWh
Total	> 275 TWh	Total	> 275 TWh

Table 5 — Order of magnitude of the main uses of hydrogen in 2050, converted into the electrical energy required for the production of this hydrogen by electrolysis

Beyond the differences in the segmentation and evaluation of uses, it should be noted that the orders of magnitude of these evaluations are similar. Established independently, they are confirmed. No doubt they are both underestimated (underestimation of industrial uses by the Academy and of mobility by McKinsey. In both cases, rail and sea transport were not taken into account). A hydrogen plan that meets the challenges of energy decarbonisation probably requires more than 300 TWh of electricity per year.

It should be remembered that annual electricity consumption in France for uses other than those mentioned in Table 5 is around 475 TWh per year; these 300 TWh would therefore represent an

[XXVII] According to the McKinsey study - Hydrogen scaling up - conducted for the Hydrogen council - 2017. The French McKinsey study and the APHYPAC study as taken up by the National Hydrogen Deployment Plan 2018 are inspired by this first study.

increase of 2/3, in addition to other needs. The large transmission (HV) and distribution (MV and LV) networks should be increased accordingly.

Producing hydrogen with an energy content of 300 TWh with a load factor for RE of approximately 28% (weighted average of offshore, onshore, and solar wind load factors) would require an additional 125 GW of installed capacity: in total, at least doubling of current production capacity. The power of the electrolysers would be approximately 90 GW (9,000 times the capacity of the largest current installations). The load factor of these electrolysers would be significantly less than 40%, which would not allow such large investments to be profitable, all the more so as the electricity produced exclusively for this need will obviously not be free.

The demand for electricity for the production of hydrogen will be added to other uses of electricity already mentioned: decarbonisation of industry, and in particular of the iron and steel industry, for which electricity and hydrogen can compete, the chemical industry, heating, decarbonisation of mobility. "Getting out of nuclear power" will lead to a very significant demand for hydrogen, which would have to be added to these assessments. The McKinsey projections, which envisage about 21 TWh for this purpose, whereas eight times more would be needed, do not take this hypothesis into account.

A holistic approach that couples the electricity and gas systems on the one hand, and the assumptions on the means of electricity production and competition of uses on the other hand, is necessary. It is a complex task, but it is essential because the investments to be made are in the order of hundreds of billions of euros. The Academy of Technologies invites energy economists (universities, academies, companies, opinion groups) to contribute to it.

Without anticipating all the consequences of these evaluations, a decarbonisation of the energy system based essentially on intermittent renewable energies and hydrogen does not seem feasible either economically or even physically. This is the reason why some countries (Germany, Japan) are considering massively importing hydrogen from countries well-endowed with renewable energy, following the example of their current imports of natural gas. This assumed energy dependence is not in the French tradition, and raises major geostrategic questions. An alternative will be, for those countries that accept it, the use of nuclear energy coupled with hydrogen to drastically reduce the energy use of hydrocarbons. The evaluation of this coupled system remains to be done; the cost per ton of carbon avoided should be significantly lower than that of an "all-hydrogen" system; the share of nuclear and hydrogen will be significant.

6. Industrial research and development

6.1. Emerging technologies and the need for hydrogen research

Currently, the hydrogen sold is often produced from natural gas by steam-reforming and is therefore absolutely not CO_2 neutral. Greening it and making it economical is the main challenge of current research. Research, both privately in large companies and by existing players, as well as with public funds via, for example, in Europe the FCH JU, is focusing on these technologies, some of which, although they are not yet economical, are quite mature: electrolysers and fuel cells. Storage, transport, distribution and safety are other subjects where research efforts are important.

In France Ademe cofinances the 'hydrogen territories'[49] project, seeking above all to help establish the first uses of hydrogen, often around mobility for example in airports, such as at Toulouse or for buses in cities, such as in Pau, or for the installation of stations, such as in the *Zero Emission Valley*. Moreover, this last project is also massively supported by the European Commission and the region, which will accompany the introduction of 1,000 fuel cell cars, 20 hydrogen recharging stations and 15 electrolysers to produce green hydrogen. Ademe is also supporting pilots for a hydrogen/natural gas mixture, as in the Dunkirk region (GHRYD[XXVIII] project). These initial projects are making it possible to test all the links in these new sectors, to familiarise employees and users with these technologies, to test their reliability under operating conditions and, above all, to work to reduce their costs. The ambition is similar for the 600 Hype cabs in Paris (of which a little over a hundred are currently in service) supported by the shareholders Air Liquide and Toyota to familiarise the public, drivers and passengers with hydrogen powered vehicles. It should be noted that many of these deployment projects are federating. There are about twenty partners in Zero Emission Valley (Auvergne-Rhône-Alpes) including industrialists Engie, Michelin, Symbio and the Tenerrdis competitiveness cluster; similarly, the Grhyd project links Engie, GRDF, Ineris, the CEA, etc.

Unfortunately, more disruptive technologies such as plasma technology for the production of hydrogen from methane without generating CO_2, work on microbial hydrogen generation or the exploration of native hydrogen remain niches that have been neglected in France by the public authorities that fund research. The lower TRLs of these technologies should however justify greater public support. A first meeting aimed at federating the French geoscience community in these fields took place at the CNRS headquarters on October 10, 2019. It should be noted that since understanding hydrogen flows is at the heart of understanding the arrival of life on earth, this community is much broader than the one interested in decarbonised energy.

In other words, research is focused on power to gas, and especially power to gas to power, and hydrogen as a source and not as an energy carrier is, in France, but also in Western Europe, neglected. Electrolysis from renewable energy surpluses, as shown in the previous chapters, has limits, especially economic limits, and other sources for a green hydrogen seem to us to be worth exploring rapidly. We will list them below, separating those that could have a completely disruptive impact on a massive production and therefore a massive use of hydrogen from those that will meet a need for local production.

[XXVIII] **G**estion des **R**éseaux par l'injection d'**Hy**drogène pour **D**écarboner les énergies (Network Management by Hydrogen Injection to Decarbonise Energies)

6.2. Large-scale production technologies

6.2.1. Breakthrough technologies for massive hydrogen production:

a. plasma technologies

The principle is quite simple CH_4 + temperature => H_2 + carbon black. France has leaders in this technology; pioneering work has been carried out at the Odeillo solar furnace[XXIX]. The Sophia Antipolis research center (Perseus project) has been working for a very long time on low-temperature plasma processes (around 1,100°C) to directly separate methane into carbon black and hydrogen (Fulcheri and Schwob, 1994)[50]. From a thermodynamic point of view and thus from an energy balance point of view, this reaction is much less expensive than steam reforming and water decomposition (38 - 62 and 285 kJ/mol of hydrogen produced, respectively). This solution therefore has a much higher potential than the others for a massive and inexpensive production of manufactured hydrogen. In addition, carbon black is used as a raw material for the production of ink and various materials such as rubber for tires. The CO_2 balance is potentially excellent since it would allow the

Figure 23 — Torche plasma du centre Persée - Mines ParisTech -Sophia Antipolis

replacement of two operations currently emitting CO_2 (the production of hydrogen by steam reforming and the production of carbon black from hydrocarbon in furnaces) by a non-emitting process.

Figure 23 — Torche plasma of the Persée - Mines ParisTech Centre - Sophia Antipolis

It should be noted that these plasma technologies make it possible to crack hydrocarbons more generally; the input may be other than methane.

At the end of 2000, a Canadian company "Atlantic Hydrogen" embarked on this path and received strong support from National Grid[XXX]; The technical difficulties encountered should not jeopardise this approach. In France, however, few industrialists seem to be interested in it. But the major natural gas-producing countries, the United States and Russia, are launching the first projects. In the United States, Monolith built its first plant in Nebraska after a pilot in California[XXXI] and in Russia Gazprom

[XXIX] https://www.la-clau.net/info/1493/unique-au-monde-le-four-solaire-dodeillo-invente-le-carburant-solaire-1493 ; https://www.franceculture.fr/emissions/science-publique/va-t-enfin-fabriquer-de-lhydrogene-avec-lenergie-solaire

[XXX] https://www.osti.gov/etdeweb/servlets/purl/21396875 ; https://www.cbc.ca/news/canada/new-brunswick/atlantic-hydrogen-bankruptcy-refusal-macfarlane-1.3248312

[XXXI] https ://monolithmaterials.com/innovative-technology/

announces that in 2050 it will be able to supply all the hydrogen that Europe could wish for, using a variant of this technology [51].

France no longer produces natural gas and is only starting to produce biogas. However, natural gas transportation and storage are mature technologies for which all the infrastructures are in place; we believe that an industrial-scale pilot project for this technology to transform natural gas into hydrogen close to the consumer (as Monolith is doing) should be promoted.

b. native hydrogen production

There are many hydrogen emanations on the globe, known for a long time on mid-oceanic ridges, in particular thanks to the work of Ifremer, but also onshore for example in Russia, Oman and the United States (Larin et al., 2014; Zgonnik et al., 2015)[52]. Two accumulations were drilled (by chance), one in Kansas (looking for hydrocarbons) and the other in Mali (looking for water). The one in Mali, is exploited in a relatively artisanal way by Hydroma (ex-Petroma Inc) to make electricity by burning it, and this in small quantities, about 1200 m^3 per day. The hydrogen is almost pure. Accumulation is at a depth of 110 m and the maintenance of pressure at the wellhead despite 5 years of production strongly suggests a continuous recharge (Prinfzofer et al., 2018)[53]. These recent developments show that, contrary to what some people imagined, hydrogen systems operate with generation/migration/accumulation. As for hydrocarbons, surface indications are proof that hydrogen is generated at depth, but the identification of the geological conditions for an accumulation still requires work, the types of possible coverings in particular remain little known apart from salt and certain volcanic rocks which are those, incidentally perfectly impermeable, found around the accumulation of Mali.

The sources studied for hydrogen were: a degassing of the mantle, natural electrolysis in the presence of radioactive rocks and diagenesis phenomena. It is the latter that seems to be the most active, the water/rock interaction that can be seen globally as an oxidation process occurs at the level of mid-oceanic ridges when the mantle rocks come into contact with sea water, leading to all known degassing phenomena at these ridges (the name of the reaction is serpentinisation). These same rocks can continue to oxidise at lower temperatures and thus release hydrogen. It is these reactions that are studied in particular in Oman and New Caledonia, but the Alps, the Pyrenees and other oceanic suture zones could also be prospective. Finally, Proterozoic rocks rich in metals, especially ferrous, and not yet oxidised are the sources envisaged for onshore hydrogen in cratons as in Mali, Russia, the United States or Brazil (see Prinzhofer et al., 2019[54]).

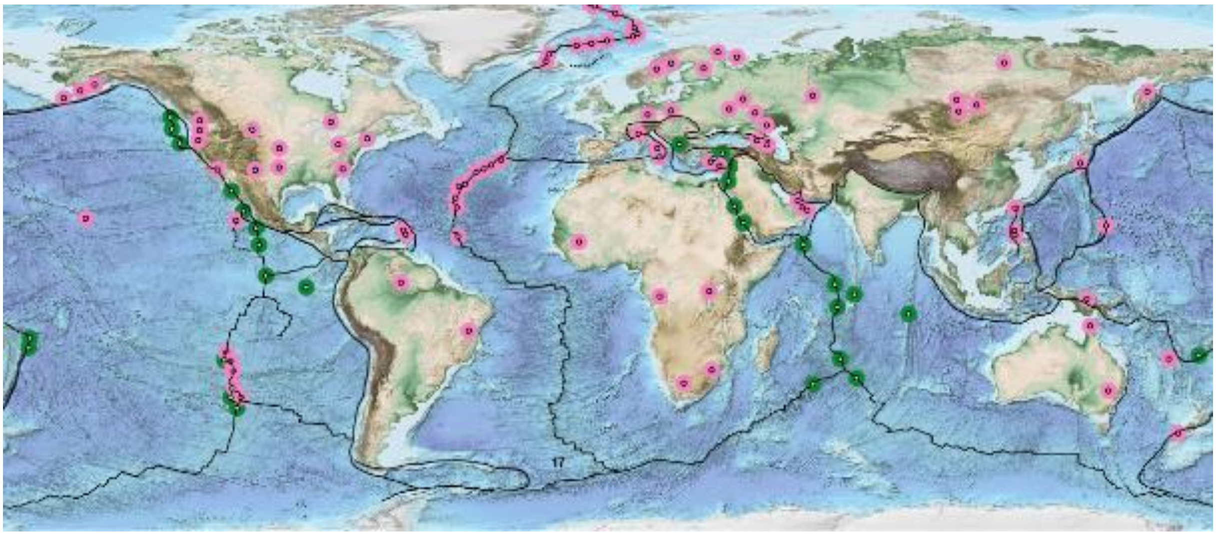

Figure 24 — Already known hydrogen emanations (pink) and abiotic methane derived from H_2 (green).

The first flow-rates measured in Russia, Kansas and Brazil throughout the emanation zones give values between 50 and 800 kg/day/km^2 (Larin et al., 2014[55] ; Prinzhofer et al., 2019). They therefore show a real and considerable global potential. In the marine domain, the flow is continuous, on a geological scale, since there are always active mid-oceanic ridges, the estimates given by Ifremer are between 4,000 and 10,000 t/year/km of ridge. As in the case of hydrocarbons, the portion reaching the surface is very small compared to deep production and recent work (Lopez-Lazaro et al., 2019[56]) shows that at great depths hydrogen is very soluble in water and could therefore migrate over long distances like hydrocarbons for which the source may be more than hundreds of kilometers away from the accumulation. The role of bacteria consuming or emitting hydrogen is also studied in order to better link the surface signal to a deep flux.

Many researchers are now working on the question of hydrogen in cratonic zones. Only hydrogen from the ocean floor linked to serpentinisation had interested the research world in recent years, but from a purely academic point of view. About ten years ago, alerts had been made by B. Goffé (INSU), and researchers from IFPen, but without finding an echo; production in Mali revived everything. Today, in France, IFPen, Ifremer, Isterre in Grenoble, IPGP and UPPA are working, among others, on the subject of native hydrogen, but also Engie as well as start-ups that are being created on this subject such as 45-8. The first industrial chairs are being set up. A TPP (Technical Position Paper) has been produced in the framework of the National Alliance for the Coordination of Energy Research (Ancre) as well as another on underground hydrogen storage.

It should be noted that many countries do not list hydrogen as a natural resource and therefore its production is facing a legal vacuum that should be filled before the issue is hotly debated. The founding president of the Petroma company that became Hydroma obtained the adaptation of Mali's mining code to provide a legal framework for hydrogen production. To consider hydrogen as a natural gas, and thus following a legislation of the type of the production of hydrocarbons, is to our knowledge the way adopted by the United States where the first well with H_2 as a target was drilled in 2019 by Naturel Hydrogen Energy LLC[57]. In France 45-8 is starting to drill for helium, another gas that is very important for new technologies and whose generation and accumulations in the subsoil have similarities with H_2 with which it is sometimes associated. Legislation allowing the exploration and exploitation of these green gases in France would have to be put in place.

6.2.2. Disruptive technologies for local production

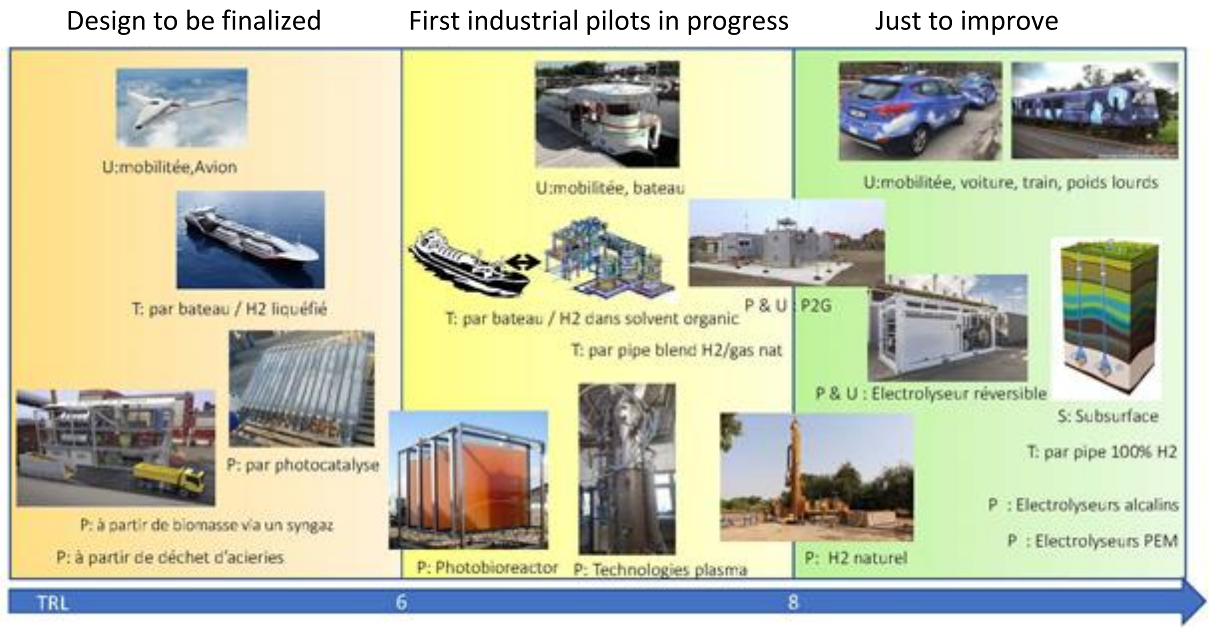

Figure 25 — Maturity of hydrogen technologies

Photosynthesis

Some technologies allow electrolysis to be carried out directly from solar energy and thus to manufacture solar panels that directly deliver hydrogen. Studies and patents exist; the first pilots are under construction in France (TRL 5_6 depending on the model). This type of panel would make it possible to move towards more autonomous homes, with the stored hydrogen then being used at night.

Hydrogen from syngas

This technology makes it possible to produce green hydrogen using much the same process as second-generation biogas. A pyrolysis of dry biomass generates a syngas that contains, among other things, hydrogen and methane, but instead of concentrating the methane as in the biogas process, the hydrogen is then concentrated. This second phase can be done by catalysis or microbial activity. Wood-Hy in the Landes is the most advanced demonstrator project in France in this field. (TRL 6-8 depending on the model).

Production by bacterial or biological activity

If a good part of the bacteria in the subsoil consume hydrogen, hydrogenases, some of them can generate hydrogen if they have another source of energy, which can be biomass or the sun. The possibilities of producing hydrogen from these enzymes had been explored as early as 2003 by BRGM, which at the time concluded that these processes, which are related to photosynthesis, were not very efficient in transforming light energy. Nevertheless, other laboratories have continued the research, the CEA currently has patents on the production of hydrogen from whey in vertical bioreactors and is seeking to make a first demonstrator in a dairy (TRL 2-5 as the case may be).

Algae-based bioreactors have the potential to generate hydrogen, possibly by neutralizing CO_2; there are a few companies, but given the price of algae as a raw material in cosmetics and for certain protein food supplements (such as spirulina sold by Algenol), energy production with these algae is currently an economic nonsense.

Production by oxidation (biomimicry)

The principle is close to what nature does, one oxidises iron in the ferrous state (Fe^{2+}) which releases hydrogen by passing to the ferric state (Fe^{3+}). Research is being conducted, mainly in Grenoble, on catalysts to lower the temperature at which this reaction is effective (Brunet, 2019[58]). Magnetite is a by-product of this reaction and its market value, especially for filters, improves the economy of the system (TRL 2_5 as the case may be).

Overall, these various technologies, the list of which is not exhaustive, can enable hydrogen to be integrated into the energy mix of regions while meeting certain waste treatment needs (steel mills, dairy farms, forests for the three technologies mentioned).

6.3. Improvement of current technologies

6.3.1 Improvement of electrolysers and fuel cells

(TRL 6-9 depending on the model)

At present, alkaline or PEM electrolysers operating at constant power have for the most part an efficiency of around 65%, fuel cells around 50%. Thus, power to gas to power falls to less than 40% and, over time, performance degrades. SOECs have an efficiency of up to 90%, but for the moment a very low life expectancy (between 1 and 3 years). It is therefore very important to improve these performances. The most promising avenue is to raise the temperature.

6.3.2 Transport over long distances

As previously mentioned, one of the killing factors of the hydrogen economy is the cost of transport. It would seem that only Japan and South Korea currently subsidise projects and the transport of hydrogen by sea. If Japan's insularity leaves it little choice, it is clear that if they find an economic solution, those who will master it will have a huge competitive advantage. Others solutions such as on organic solvents are also being tested; to our knowledge French companies, although they had a leading role on LNG carriers fifty years ago, are not participating in these pilots.

A great deal of work is underway on the suitability of gas pipelines for natural gas/hydrogen mixtures, both at the level of the academic world and that of transporters and distributors (GRTG, GRDF). One of the challenges is to ensure the safety of installations using non-destructive methods, given that there are tens of thousands of kilometers of gas pipelines in France. This work is carried out both at the national level and at the European level via European gas associations (Marcogaz, Gerg).

6.3.3 Mobility

All hydrogen mobility is set to develop; French industry already has offers for cars and trains, even if they don't run in France. Work on buses, ships and planes using hydrogen should be encouraged. For aviation, however, the need for high power for the propulsion of wide-bodied aircraft makes a gaseous H_2 solution very unlikely; even compressed to 700 bars, it remains an energy source almost eight times less concentrated than kerosene. Nevertheless, optimizations in the use of hydrogen for aircraft electrical circuits are promising for the medium term.

6.3.4 Carbon Capture and Utilisation – Carbon Capture and Storage (CCU/CCS)

The possible and easy chemical reactions between CH_4/CO_2 and H_2 presented in this document clearly show that the deployment of hydrogen and CCU/CCS should be linked. At Jupiter 1000 the hydrogen is combined with the captured CO_2 and the methane produced is injected into the grid. In some plants the CO_2 from the steam reforming process is used by the food industry. In the Methycentre and HyCONAIS demonstrators, hydrogen is used to boost the production of biomethane by neutralising the CO_2 emitted by bacteria. All combinations of these bricks must be researched; the possibility that hydrogen finally makes CCU economically realistic is not to be ruled out.

7. French strategy, French champions in international competition; a new industrial sector?

The hydrogen sector today employs nearly 2,000 people in France. According to the McKinsey study[48] on the development of hydrogen for the French economy, the prospects for the development of the hydrogen industry in France are as follows. Approximately €8.5 billion in annual revenues in 2030 and €40 billion in 2050 - An export potential of €6.5 billion by 2030 - More than 40,000 jobs in the sector in 2030 and more than 150,000 jobs in 2050 - 10 to 12 Mt CO_2 less in 2030 and 55 Mt in 2050.

7.1. The national hydrogen deployment plan from an industrial perspective

The main objective of the National Hydrogen Plan presented on June 1, 2018 is to reduce our country's greenhouse gas emissions, in line with the Climate Plan and European commitments. Cf Press kit of June 1, 2018[59]

Among the 18 measures in the hydrogen deployment plan[60], six measures numbered from 13 to 18 fall under the heading "development of industrial sectors and support for innovation" and are summarised below:

Measure 13: development through the Investment Programme for the Future of French Heavy/Long-Range Hydrogen Vehicles and Associated Components and Hydrogen Production and Storage Systems;

Measure 14: research programme via the National Research Agency to tackle disruptive technologies;

Measure 15: offer for specific training;

Measure 16: creation of an international center for qualification/certification of high pressure H_2 components;

Measure 17: define the place of hydrogen in the railroad for greening the railways;

Measure 18: reciprocal commitments between companies and public authorities for the elaboration of green growth commitments through the strategic committees of the industry sector.

The financial support schemes are oriented towards players that emit greenhouse gases in the industrial (cement plant in particular), transport and electricity sectors. It is a policy oriented towards integrators (often buyers) in France.

Our country's industrial experience has shown that policies of this type risked inducing the development of imports by keeping only the assembly of equipment and part of the management on our territory. The national research is then little exploited. The Academy would like France to focus its efforts on the industrial players who produce and manufacture essential components (electrolysers, etc.) or elementary components with added or strategic value (membrane, catalyst, etc.), i.e. manufacturers or fabricants of the components of the hydrogen value chain, with the aim of developing their activities on the world market. The Academy would like these manufacturers and fabricants to be fostered and not only the integrators, often large groups which, during demonstration or pre-deployment operations, integrate the lowest cost subcontractors (purchasing policy), or join forces with partners in consortiums to the detriment of French or European suppliers or partners.

In this approach, it is not mandatory to develop the entire industrial chain. It may be preferable to choose certain essential components or elements of this value chain for which France can generate a competitive advantage on the world market. One possibility is to select the technologies for which French industrial players have assets and to support their development whatever the level of advancement of the technology by providing the means to accelerate the industrial commissioning process. This is the choice made by McPhy and by Symbio, which wants to be present throughout the mobility chain. In the case of Symbio, the stack is manufactured in France even if some components come from foreign suppliers due to the lack of French suppliers.

An in-depth economic and industrial **value analysis** would complement and support the following analysis to select key components.

7.2. The Hydrogen Value Chain

The figure 26 (next page) is inspired by an Afhypac publication describing the value chain, its main technological components and the different actors.

The key technologies (electrolyser, fuel cell, on-board tank, etc.) are available. Almost all of them are mature, but they need to be industrialised.

If we take a short time horizon, most of the technologies exist and must be improved through incremental and continuous innovation with the aim of producing the component with reliable quality and lower costs through robotised production.

If we take the bipolar plates of an **electrolyser** as an example: should they be produced by stamping, electro-erosion, machining, 3D printing, etc.? It should be noted that progress in these processes is not necessarily motivated by the H2 market, as manufacturing processes are often cross-cutting in several areas.

The main objective is to lower production costs in mass production. As far as pure performance is concerned, there is no disruptive effect to be expected as the technologies are already close (4 to 5 points) to the thermodynamic optimums.

Also noteworthy is the field of high temperature, where R&D on materials will contribute its share of progress (size of components, durability, robustness, etc.).

Thermal productions	Electrolysis	Storage	Logistics	Charging stations	Fuel cells	Auxiliary components	Intégrators	Industrial users
Fossil fuels Air Liquide Linde Airproducts Total Infcis Arcelor Mittal Exxon Mobil	Areva H2 Ergosup ITW Power McPhy NFI Thyssen Krupp Siemens	**Storage under pressure** Faurecia Plastic Omnium H2ICI Sterela Comp MaHyTec	Air Liquide	Air Liquide CNCIC CNV Atawey Haskel ITM Power McPhy	**Mobilities** Michelin Faurecia Plastic Omnium Safran Symbio Pragma Industries Naval Group Toyota Hyundai	Ad Venta Alcon Alcrys Herose Hawdon Neva Swiss Sertronics Swagelok HP Systems Top Industries	**Upstream Chain** Air Liquide Ataway Engie EDF McPhy	**Mobilities** Dassault Av. Kecks SNCF H2PE Transdev Six
		Hydride Storage McPhy MaHyTec Aaqius					**Mobilities** Green GT Symbio FCI Toyota Naval Group Pragma Ind. Safra	**Stationary** Accor Vicat Vinci Carrefour Engie
Biomass thermolysis Haffner Energy ETIA Engie Crigen		**Cryogenic storage** Air Liquide			**Stationary** Areva SE Sylfen Axane		**Stationnary** PowiDian Sylfen	**Industrial processes** Arkema
Biogas purification								

Multiple suppliers for: electric bipolar plates, membranes, compressors, valves and fittings, electronics, catalysts, metrology, gas treatment, etc.

Research and expertise centres: CEA (Grenoble, Le Ripault, Bordeaux, etc.) - CNRS (TCL lab, LLMIA, Institut Laplace) - Ecole des Mines

Figure 26 — Afhypac - Hydrogen value chain

For **fuel cells**, the approaches are the same; for the cell core, i.e. the "stacks" (plates + membranes), the membranes used for the PEMs are based on a fluorosulphonated polymer (PFSA) whose main properties are watertightness and proton conductivity. Nafion, invented by Dupont (now Chemours), despite an intellectual property that has fallen into the public domain, has a proven quality and know-how, but there are now several producers[61] of "equivalent" polymers (but a narrower range), including Solvay in Europe. The manufacture of the membrane itself (in particular the deposition of charged inks and catalyst) is currently dominated by W.L. Gore (United States), but many smaller and competent companies are positioning themselves on this promising market with a view to setting up national/regional value chains to serve the major automotive players who have invested in fuel cell technology (Toyota in Japan, Hyundai in South Korea, and more recently SAIC in China or Renault-Nissan in Europe). It is to be hoped that a European player of world stature can emerge.

Bipolar plates are easily manufactured by the mainly German stamping manufacturers who work for the automotive industry and manufacture, for example, cylinder head gaskets. Is there a lot of added value, margin to be freed up and jobs located in France?

For **mobility**, it is even more important to break down the constituent elements: the aim is not so much to produce a hydrogen-powered car in France as to produce the constituent elements that are the tanks for various pressures and volumes, on-board or fixed, the fuel cells and their components (membranes, catalysts), the associated power electronics, the controls, the most suitable electric motors (there is a manufacture on French soil of electric motors), the compressors adapted to the different types of storage, the recharging stations, etc. for a world market. In these cases, potential buyers are everywhere in the world, as for today's cars, for which the Tier 1 or Tier 2 "equipment manufacturers" have a global market for the components they produce. Deploying territorial fleets with the help of the State without industrial preparation can again lead to a doping of imports without components designed and manufactured in France.

It will be necessary to create an infrastructure, and public authority is indispensable to initiate and sustain the mobility market (regulatory, fiscal aspects, etc.).

For France, we consider that it is necessary to have the three essential technologies - the electrolyser, the on-board or stationary fuel cell and the tank - and to have a value analysis to specify the key components of these technologies.

In the value chain of hydrogen and the players that are involved in it, a distinction must be made between **industrial fabricants/manufacturers** and **integrators**.

The list presented by the table above (Figure 26) only imperfectly includes technology subcontractors who provide indispensable elements. It would therefore be necessary to go further into the detail of the value chain of each manufacturer of a component in that value chain, as future value creation may be in those elementary components that are currently not very visible. **Afhypac has undertaken an in-depth study on this value analysis.**

7.3. Mobility

No one knows how the distribution between the market for 100% battery electric vehicles and the market for battery/hydrogen hybrid electric vehicles will develop. This unknown concerns the French market, the European market and the world market, distinguishing between OECD countries and emerging or less developed countries. The transition from internal combustion engine vehicles to electric vehicles and hydrogen/electric vehicles is likely to be slow, if only because of the depth of the second-hand vehicle market in Europe and worldwide. This progressiveness poses an industrial problem of market size and infrastructure development. There is a consensus to assume that the first industrial series of components will be for captive commercial fleets and road hauliers who do not have the same financial and economic approach as individual car buyers nor the same rate of use. From this point of view, it is desirable to parallel the development of green hydrogen production and the use of hydrogen of any kind. The use of hydrogen in mobility will focus on areas where autonomy and charging time is predominant and where the size of the energy conversion and storage system is compatible with the size and capacity of the vehicle. This will enable the first series of components to be launched, tested and adapted to the regulations and structure of the vehicles. It is therefore recommended that an oriented ecosystem be created where the technological synergies developed will make it possible to launch the industrial production of systems intended to be embedded in vehicles of all kinds (in particular, hydrogen FCs, Balance of Plant (BOP), battery, storage, if necessary pre-conversion of the primary source, power electronics and controls to ensure operation and safety, and the electric motor). Stationary storage, including underground, centralised or local storage, currently dedicated to "grey" hydrogen is a limited market, but one that will grow. Demonstrators and front-runners are needed for the overall strategy to ensure its credibility and to ensure that all the elements of the system are properly taken into account and industrialised.

7.4. French fabricants/manufacturers/equipment makers

Fabricants/manufacturers are often mid-sized, medium or small companies with growth potential and therefore with a strong need for liquidity to ensure the construction of the top-of-the-range products, salaries and to finance this growth. These fabricants/manufacturers produce essential components (electrolysers, etc.) or elementary components with added value (membrane, bipolar plates, connectors, etc.).

Manufacturers respond to national, European and international calls for tenders and have a commercial policy of global diversification with, sometimes, the handicap of being too small to sustain the necessary commercial and prospecting effort. It is towards them that financial support should be directed.

Consequently, it is essential that aid and support be targeted at these production companies so as to give them more capacity, autonomy and robustness to attack large markets. The objective of this aid is to enable them to grow and to reach a satisfactory level of industrialisation of construction processes regardless of their shareholder. In particular, it is important that manufacturing processes integrate the latest robotics and automation technologies from the design stage, which make it possible to lower production costs and increase quality, but also the potential contributions of new technologies (nanotechnologies for example) to reduce congestion and increase yields.

Fabricants/manufacturers	French Entreprises	Competitors
On-board fuel cell	Michelin (Symbio)	Ballard Power, Toshiba, Panasonic, PLUG Power, Bloom Energy, Fuelcell Energy, Hydrogenics, Doosan Fuel Cell, Horizon, Intelligent Energy, Hyster-

	Pragma	Yale Group, Nedstack, Pearl Hydrogen, Sunrise Power, etc.
Stationary fuel cell	HdF(techno Ballard)	
	Areva SE	
	HELION	
	Axane (Air Liquide)	
Reservoir	Faurecia	Hexagon (United States)
	Plastic Omnium	Doosan (China)
	Mahytec	
	NPROXX	
Electrolysers		
	McPhy	NEL, THYSSEN GROUP, John COCKETILL, SIEMENS, Hydrogenics, GINER, ITM Power etc. + Chinese Companies
	AREVA H2gen	
Connectics	Alcrys	
	AD-VENTA	
Power electronics		
	RAIGI	

Table 6 — French Fabricants/Manufacturers/Equipment Makers

7.4.1. Electrolysers

The electrolyser is at the heart of the value chain. Two French manufacturers are present on the market:

McPhy (in which EDF has just taken a 21% stake) with a range of alkaline electrolysers of 4, 20, 100 MW and more (manufactured in Germany for large power plants). McPhy has opted for a mature technology, but its realisation for high power remains a challenge. Mc Phy supplies the Jupiter 1000 PEM electrolyser.

Areva H2Gen (shareholders: AREVA SE, Ademe, Smart Energies, < 20 employees) offers PEM type electrolysers.

In Europe, the Norwegian NEL Hydrogen Electrolyser, a division of NEL ASA, is the world leader. Also present are the British company ITM POWER, the German companies Thyssenkrupp and Siemens and Hydrogenics, a Canadian company in which Air Liquide has just taken an 18.6% stake and, more recently, Cummins, which took a majority stake alongside Chinese shareholders.

Sylfen (CEA spin off) is preparing the advent of high-temperature electrolysers (850°C) which increase efficiency and can be used reversibly in fuel cells.

Ergosup is developing a high-pressure electrolyser technology with zinc electrochemistry. Ergosup has also developed an innovative decentralised production solution integrating low pressure storage, electrochemical compression and energy restitution.

7.4.2 Stationary applications (fuel cells...)

For stationary applications, the market is dominated, in particular, by the Japanese companies Panasonic, Toshiba...

Hydrogène de France (HdF)

Hydrogène de France has signed an agreement on December 9, 2019 with the Canadian Ballard Power Systems (Chinese shareholder), based in Vancouver and producer of FCs for 40 years (for a total volume of 100 MW today, mainly in the heavy transport market). The agreement provides for a technology transfer - in this case under PEM* solution - from Ballard to HdF Industry so that the French company can manufacture, in the Bordeaux region, FCs corresponding to its needs. That is to say that they can be installed in renewable energy parks.

In practice, the operation could give rise to a factory operational in 2022 with 50 MW of production capacity expected in 2025 and around 100 employees. A €15m project, where the purchase of Ballard FC cores weighs heavily. In addition, the ambition is to carry out co-development with Ballard.

AREVA SE (Helion)

Since July 2019, AREVA SE has been operating under the brand name Helion Hydrogen Power, in order to capitalise (30 patents) on *"twenty years of experience and recognised know-how in the field of hydrogen and fuel cells" (Hélion press release of July 9, 2019).*

This name change is intended to accompany the marketing of new products dedicated to stationary applications (electric generators, emergency power units, hydrogen batteries) and heavy mobility (maritime, river and rail). A production unit dedicated to the automated assembly of battery cores and systems is currently being developed. *"This high-performance industrial tool will make it possible to produce the equivalent of 500 stacks/year from 2022, and will help to divide production costs by three."*

7.5.3. Mobility applications (fuel cells, tanks...)

Michelin and Faurecia (controlled by PSA) have formed a joint venture "Symbio, a Faurecia Michelin, Hydrogen Company" dedicated to the manufacture of hydrogen modules to be integrated into vehicles of various power ratings. Symbio already supplies fuel cells for the Kangoo ZE and Renault Master. The planned investment is €140 million, and the turnover target is €1.5 billion in 2030. The company has 200 employees, 150 of whom are Symbio employees. This company is oriented towards the next calls for tenders in this field. Symbio plans to manufacture all the elements of the chain (plates, membranes, control command, complete modules) excluding tanks. Symbio offers modules with fuel cells with power ranging from 5 kW (Kangoo) to 320 kW.

Safra is an albigensian company that designs and builds buses with all kinds of engines, notably electric and in particular hydrogen with a Symbio fuel cell). With its BUSINOVA hydrogen-powered bus model, Safra has won several calls for tender (Artois-Gohelle transport union, Versailles, Le Mans, Toulouse airport, Auxerre).

Tanks for mobility

Plastic Omnium (PO) has acquired expertise in the field of pressure vessels, particularly 700 bar tanks, by taking control of Optimum CPV in Germany, and in energy management and control in onboard systems through the acquisition of Swiss Hydrogen. In 2016, PO created a joint venture with the Israeli company Celltech. PO has already received orders for 300 bar tanks for buses and has obtained certification for its 700 bar tanks.

Mahytec offers compressed and solid hydrogen storage solutions as well as integrated electrolyser, tank and fuel cell packs.

Stelia Aerospace Composites has got certification for a new generation of very high pressure carbon fibre tanks. In addition, Stelia has signed an exclusive agreement with Faurecia to make available its intellectual property and know-how in the field of hydrogen tanks made of composite materials.

Filling stations,

Atawey is a French start-up offering integrated service stations for hydrogen mobility.

Proviridis is setting up innovative infrastructures for the distribution of clean fuels and energies to meet both the environmental challenges and the economic constraints of consumers: NGV, biomethane, hydrogen and electricity.

Aaqius is developing a refill concept for light mobility using "cans" such as soda cans.

7.5.4. Connectics

Alcrys, the French specialist in high pressure, Alcrys® reinvents gas regulation with an exclusive technology: Alcrysafe®. Alcrysafe is a technology that allows to compose high pressure equipment in the Lego way, by assembling cubic elements and functional cartridges. Zero connections, maintenance in 5 minutes, easy installation, scalability of equipment, compactness, drastic cost reduction... Indeed, this unique and seamless technology offers unrivalled reliability for all gases, even the most sensitive ones such as hydrogen up to 1000 bars.

Ad-Venta is a young, innovative French company specialising in the use of pressurised gases, particularly hydrogen. Ad-Venta benefits from skills based on more than 40 years of experience and provides its customers with turnkey solutions in the following areas: small, cost-constrained, safe, simple and reliable pressure regulators and pressure reducing valves, integrated fluidic devices, mechanical integration of fluidic functions. Today, Ad-Venta has focused its development plan on components and systems for hydrogen energy applications. Ad-Venta has a portfolio of patents and know-how that is regularly expanded.

The French ecosystem described above, even if it is not exhaustive, is considered to be dynamic; nevertheless, these are very small companies which, in order to develop, need to ensure their own commercial prospecting on a global level (at high cost) but also benefit from the support and credibility of more powerful players (backing from ISEs or groups). This ecosystem also needs targeted calls for tender in France and Europe to help them grow. Once the orders have been obtained, these companies need cash flow and growth management (their capitalisation is not always sufficient).

7.4.5. Integrators

Major groups have announced an interest and presented a strategy for hydrogen, but it is slow to materialise in concrete achievements because, as shown in Chapter 5, the hydrogen economy remains largely to be invented. Their objective is to sell the final packaged product worldwide and not necessarily to buy the components and integrated systems (e.g. the hydrogen fuel cell and tank system) from a French manufacturer; these integrators are in a buyer's and cost optimisation logic both in capex and opex to ensure the success of their projects. Nevertheless, local capital investments are appearing, the effects of which should be observed (financial support, support for commercial prospecting, guarantees, etc.).

The participation of a large group in the capital of fabricants or manufacturers can be a solution by providing the capital necessary for the development of technologies, the financing of production launches, the need for cash to finance growth, by making its commercial network available and by providing support in responding to major international calls for tenders on condition that the manufacturer retains its strategic and commercial autonomy to extend its catchment area without any other constraint than its commercial dynamism.

In the field of heavy transport and captive fleets, Renault and PSA are developing strategies in conjunction with equipment manufacturers.

Air Liquide (AL) has exceptional expertise in the entire hydrogen chain: supply, production, distribution, compression and transport. Whether hydrogen is manufactured by vaporeforming, or green or blue with reinjection of the CO_2 emitted, is not the central concern for Air Liquide, which is first and foremost the world specialist in this molecule.

AL targets two markets in countries active in hydrogen, industry and mobility.

AL is the initiator of four consortia (Germany, Japan, South Korea, France) aimed at deploying the hydrogen recharging infrastructure for mobility.

In addition, AL is conducting projects in Europe (600 hydrogen taxis in Paris, CO_2 capture, production of low-carbon steel by partially replacing coal with hydrogen, guarantees of origin for low-carbon hydrogen, etc.), in North America (a 30 t/day station in California to supply 35,000 vehicles, in Canada the construction of the world's largest 20 MW PEM electrolyser, etc.) and in Asia (service stations in China, etc.).

Air Liquide has a minority stake in Hydrogenics, an electrolyser manufacturer, alongside Cummins, the majority shareholder, and Chinese investors.

EDF published a book at Lavoisier on decarbonised hydrogen and took a 21% stake in McPhy. It has created the subsidiary Hynamics to produce and market low-carbon hydrogen for the chemical-, glass-, food processing-, metal transformation industries, refineries but also the mobility market by accompanying local communities. The target countries are France, Germany, the United States, China and the Emirates.

EDF has been selected for the call for mobility and industry projects on two projects. One is the installation of electrolysers near the Penly nuclear power plant in Normandy. The idea often presented by politicians of the use of temporary excesses of green electricity to operate electrolysers is not retained, it seems, by EDF for lack of reasonable profitability.

Engie has bet on hydrogen for its production, marketing and distribution.

Engie, notably via its subsidiary Gnvert, is developing new H_2 refuelling stations and will have 18 stations in operation in France by the end of 2019. Finally, the HyGreen project in association with Air Liquide, in the Durance valley, aims to combine 900 MW of PV with a capacity of 435 MW of electrolysis and hydrogen storage in the salt caverns of Manosque. In the industrial field, Engie associated with Yara and Enaex have the project to introduce renewable hydrogen in the production of NH_3.

Engie is also investing in H_2-related start-ups such as recently in H2SITE[62], which manufactures membranes for H_2 purification.

The GRHYD project (Management of networks by injecting hydrogen to decarbonise the gas) is being developed near Dunkirk, to test the natural gas-hydrogen mixture in the distribution network, this mixture has also been tested as a fuel in buses. Jupiter 1000, a Power to Gas project led by GRTgaz, is based at Fos sur mer with two electrolysers of 500 kW each, PEM for one, alkaline for the other (200 m^3/hour). ENGIE also has several mixed 1st generation biogas and electrolyser projects linked to wind farms to increase the production of biomethane while supplying an H_2 station. Engie is also testing the potential of hydrogen for the energy autonomy of isolated territories in the islands of South East Asia (REIDS project).

Total is interested in the production of hydrogen by vaporeforming and storing the CO2 produced. This solution is being considered in Scotland, Dunkirk and Norway with industrial partners. Total is also active in H2 stations in Germany, Benelux and soon in France. TOTAL's roadmap is currently being redefined.

The major integrators are present in particular through the orders they place and the operations, some of which are of significant size, that they commit or announce. Do they assume the role of driving the French/European industry that could be expected of them?

8. The main international programmes for the production and use of hydrogen

Most OECD countries are more or less actively developing programmes to decarbonise hydrogen production and promote its use. The International Energy Agency (IEA) has published a summary of the hydrogen outlook, which we present briefly, before summarising the policies and projects of a few significant countries (China, Germany, Korea, Spain, United States, Japan, United Kingdom). A synthesis of these policies is presented by major themes (production, use, transport, industrial policy).

8.1 The point of view of the International Energy Agency

A major IEA report prepared at the instigation of Japan[63] considers that, in view of the many national initiatives, the time has come for a change of scale in the place given to hydrogen. After recalling that the main users of hydrogen are refining and fertiliser production, the IEA analyses the main challenges facing the development of hydrogen:

- the higher costs of production from renewable electricity than from hydrocarbons. However, they could be reduced by 20-30%, thanks in particular to the mass production of fuel cells;
- the development of a distribution infrastructure in particular for mobility, which is slow and hinders the penetration of hydrogen;
- the need to recover and store CO_2 from hydrogen production from hydrocarbon sources, which today represents the equivalent of the combined emissions of Indonesia and the United Kingdom. There is a need to rapidly capture and store the CO_2 emitted by these facilities, or to substitute existing production with renewable electricity generation;
- regulations are hampering the penetration of hydrogen. They should be simplified and harmonised at international level.

Faced with these challenges, the IEA makes seven recommendations:

1. establish national development strategies ;
2. stimulate the demand for hydrogen from renewable electricity to achieve economies of scale;
3. make the States assume the risks of the first investors (guaranteed prices, reduced rate loans, etc.);
4. increase research and development, in particular on electrolysers and fuel cells;
5. reduce or eliminate regulatory barriers;
6. encourage international cooperation;
7. focus on a few development areas for the next decade:
    - build on the major ports, where hydrogen-using refineries and fertiliser plants are often located, and turn them into hubs for hydrogen use (import, storage, use);
    - use existing gas infrastructure to inject acceptable concentrations of hydrogen into natural gas;

- support the development of hydrogen for mobility by giving priority to fleets, heavy transport and major routes;
- establish the first international hydrogen transport routes (IEA has in mind the transport to Japan from Australia, the Middle East or Norway).

The main strategies and policies of OECD countries are consistent with IEA recommendations. Rather than a simple summary of the countries reviewed, we group below the main thrusts of their policies according to the different elements of the value chain (production, use, transport and storage). Finally, we group together some remarks on industrial and R&D policies.

8.2 Hydrogen production

The hydrogen production strategies of the different countries reviewed are obviously very dependent on the local hydrocarbon and energy resources. However, there is a consensus to consider that the production of hydrogen by hydrocarbons, even including the cost of CO_2 capture and storage, will in the years to come be significantly cheaper than production from the electrolysis of water. Consequently, decisions on hydrogen production cannot be dissociated from those on CO_2 capture.

Very logically, the countries which have large hydrocarbon resources plan to produce hydrogen by the SMR process, possibly with a transition towards electrolysis in about ten or fifteen years depending on the evolution of the price of electrolysers and electricity: this is the policy followed by China and the United States, the latter country considering the criterion of relative competitiveness of these two modes of production as essential. These strategies obviously involve capturing and storing CO_2 (CCS), but the countries concerned are fairly discreet about their objectives and means in this respect. The United Kingdom, which has significant storage capacities, is also very open to pursuing hydrogen production from SMR. Massive use of the plasma torch process does not seem to be on the horizon but cannot be ruled out in the medium term and would completely change the situation.

On the other hand, in most European countries, the decarbonisation of hydrogen production is based on its production from excess renewable electricity (solar and wind). This is the common point of Spanish and French thinking. Paradoxically, in these countries the development of hydrogen is not based on demand but on supply.

Several countries that have a proactive hydrogen development policy are aware of the inadequacy of their national production capacity and are considering massive imports of hydrogen from countries well-endowed with renewable resources. This is, for example, the case of Germany, which wishes to establish production partnerships in Morocco, Chile or other countries with similar potential.

Particularly noteworthy is the tandem of Australia and Japan considering a long-term partnership coupling Australia's capacity to produce hydrogen from coal with Japan's need to substitute decarbonised gas - in this case hydrogen - for natural gas, which Japan imports on a massive scale. Japan is in a special position because it wants to develop a hydrogen strategy without producing it. To diversify its sources, Japan is also in negotiations with the Emirates (Bahrain, which would use its rich potential for solar energy production) and Norway for hydrogen supplies; the latter plans to produce hydrogen either from surplus electricity or from its hydrocarbons with CCS, and to export hydrogen rather than natural gas. Japan wishes to demonstrate the relevance of its hydrogen strategy for the 2021 Olympic Games. One of the components of this strategy includes the transport of liquid hydrogen by sea from Australia.

Russia, which is the leading supplier of natural gas to Germany and Europe, is preparing for the decarbonisation of the European Union. As a first step, it is proposing to incorporate 20% of hydrogen produced in Russia into natural gas and then to supply all European hydrogen needs. This hydrogen would be produced by Thermal Decomposition of Methane (TDM, i.e. similar to the plasma torch described above) for which Russia anticipates prices much lower than for the electrolysis of water[64] and the pyrolysis of methane. But the TRLs are low.

In Europe, the Spanish situation is interesting to follow. Spain's solar and wind potentials are particularly high, and therefore the country has an exemplary need for peak load mitigation, storage of surpluses and grid stability. The Plan Nacional Integrado de Energia e Clima (PNIEC) 2021-2030 (the equivalent of the national low carbon strategy and multiannual energy programming in France) proposes two competing or complementary paths:

- the realisation of pumped hydroelectric energy storage (PHES). The last Spanish project was commissioned in 2013 (La Muela II). The total capacity of La Muela I & II is 24 GWh of storage and the power is 1,780 MW (the equivalent of Grand-Maison in France). The Spanish PNIEC forecasts stable hydroelectric production in the trend scenario, and a doubling of the PHESs in the voluntary scenario (from 3,337 MW in 2015 to 8,337 MW in 2030);
- the installation of electric batteries: 2.5 GW in 2030 with a capacity of two hours;
- in both cases, the objective is peak-shaving, and not massive storage. On the other hand, hydrogen is not envisaged as a Power-to-Power vector.

It was also mentioned, notably in the German projections, that Chile, which has a very important renewable energy potential, could become an exporter of liquefied hydrogen to Europe. The IEA considers that a transnational hydrogen exchange market can find its place. The main difficulty will be to find the investors who will agree to finance the transport infrastructures when the demand in the importing country has not yet been identified.

8.3 Hydrogen uses

There is a certain consensus among all the countries reviewed that the first priority is to decarbonise hydrogen for industrial use (refineries, fertilisers, iron and steel industry) and several projects for greening current production with the installation of electrolysers on industrial sites are under way (Canada, Hamburg, etc.). The profitability of these greening operations, which are currently rather emblematic, will however only be assured if the price of CO_2 is taken into account in the evaluation of the investments.

8.3.1 Mobility

The countries reviewed are also fairly unanimous in their view that the best candidate for the use of hydrogen is mobility. However, those that have been the most dynamic have been confronted with the development of infrastructures. All these countries are converging towards equipping large regional centres with about ten to fifteen hydrogen distribution stations in each centre, but some report the systematic equipping of hydrogen corridors linking the centres. A very coherent example of such a policy is currently being implemented in Germany with the project to equip a hundred or so vehicle refuelling stations with hydrogen. To this end, the main players in the German market (Air Liquide, Daimler, Linde, OMV, Shell and Total), with the support of car manufacturers (BMW, Honda, Hyundai, Toyota and Volkswagen) and the German government, have joined together in a single H_2 Mobility consortium. They are completing the equipping of the main cities (Hamburg, Berlin, Rhine-Ruhr, Frankfurt, Nuremberg, Stuttgart and Munich) by anticipating demand; a more limited number of stations are installed between these sites. Most of the supply is carried out by road transport with grey hydrogen.

The State of California is supporting a similar project along the N One, in Seattle, San Francisco and the Silicon Valley, in Los Angeles, etc. But the investment in intermediate stations is slowed down while waiting for the emergence of demand. China, Japan and California have similar objectives of one million hydrogen vehicles in 2030 (500,000 for Korea), which is out of all proportion with the French objective (a few tens of thousands). However, their realism is questionable. China, for example, has decided to stop state subsidies for hydrogen vehicles as of 2021; it has in fact found that the subsidies were allocated to many small start-up companies that were unable to reach a critical size.

Several countries (China, Norway, Switzerland) have announced ambitious plans for heavy road transport with hydrogen and fuel cell powered trucks. Some major manufacturers (Hyundai, Toyota, Cummins) as well as start-ups (Nikola) have an offer. The same applies to public transport by bus.

The use of hydrogen in rail transport is also being demonstrated in Germany and the United Kingdom, as well as in France. Hydrogenics (owned by Cummins, an American diesel manufacturer: 81%; Air Liquide: 19%) is the supplier of fuel cells for Alstom's hydrogen trains. 42% of the French rail network is not electrified (48% in Germany). However, these are secondary lines with low levels of utilisation (less than 5% of passenger kilometers). The system can therefore only be developed with significant subsidies; the implicit cost per tonne of CO_2 avoided is high, especially if the hydrogen used is grey, and the carbon balance of many projects is questionable.

The use of hydrogen for ships is beginning to be considered, with industrialists appearing to have the initiative (Ballard and ABB). The aim is to build ships with electric propulsion, hydrogen being produced on board by reforming; the main source envisaged is liquefied natural gas. These solutions are much more expensive than the heavy fuel oil commonly used. But environmental requirements may impose them (Norway).

8.3.2 Energy Hydrogen

The use of hydrogen injected into natural gas networks is being considered in countries equipped with a gas distribution infrastructure; demonstrations are under way in the United Kingdom and France in particular. Germany considers this solution to be expensive in comparison to the simple use of gas. It should be noted that the United Kingdom, a country with a strong gas tradition, is also experimenting with a 100% hydrogen network.

In the perspective of Power to Gas to Power, Siemens benefits from public support to develop a 100% hydrogen gas turbine with the objective of commercialisation in 2030.

8.4 Hydrogen transport and storage

National transport and storage policies are very similar in the different countries examined, except for the specific maritime transport problem in Japan (and perhaps one day in Germany), which is mentioned in paragraph 8.2 – hydrogen production: technical feasibility is assured; on the other hand, demand is not sufficient to justify hydrogen pipelines except for industrial uses (American and European networks presented in sub-section 3.2.1). However, two specific projects can be identified:

- In China, there are discussions about transferring hydrogen from the northwest to the southeast of the country, which would be produced by surplus solar and wind energy in the desert provinces of the northwest, with high wind and sunshine potential, but without population or demand;
- In Germany, the HYPOS Consortium, which brings together a large number of industrial players and research institutes, aims to carry out a demonstration of 100% hydrogen storage in the state of Saxony-Anhalt. This storage will be carried out and operated by the gas operator VNG; numerous demonstrations of the hydrogen chain, in particular production by electrolysis, will be associated with it; after two years passed for the definition of the objectives, the realisation of the storage effectively started in May 2019.

8.5 Industrial policy

We shall refer to the detailed country fact sheets; but we shall note the approach of China which, for the different elements of the industrial sector, implements a classic strategy; import of equipment then creation of joint ventures with the holders of the best technologies with the objective of technological independence in view.

9. Conclusion

As early as 1977, after the first oil shock, the Member States of the International Energy Agency (IEA) asked it to set up a hydrogen and fuel cell collaborative programme. In the 1990s, a few major countries and regions (Japan, European Union, Canada), motivated by initial concerns about climate change and air quality in their cities, launched large-scale operations to support the development of hydrogen. These expressions of interest were amplified, in particular by the United States, which in 2003 launched the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE). However, this wave of interest was brought to an end by the experienced remoteness of "Peak oil" and the recognition that the cost of the infrastructure required for electric vehicles was much lower than that of hydrogen.

Today, however, the interest in hydrogen seems to be more widespread and intense. More than half of the G20 countries have implemented a hydrogen strategy covering production, uses, transport, storage and an associated industrial policy. The main drivers of this renewed interest are climate change, energy transition, but also the falling cost of intermittent renewable energies, electrolysers and fuel cells.

While many countries are interested in hydrogen, close examination shows that the policies they propose are quite different, depending on their national energy context and their ambitions to reduce greenhouse gas emissions. In all countries, including France, the development of hydrogen will result in additional costs. At the beginning of this report, specific recommendations are made for France, which by virtue of its market is a small player on a global scale. In this context, the Académie des technologies recalls three important requirements:

- The development of hydrogen must be underpinned by cost-benefit analyses that take into account the implicit cost of the tonne of CO_2 avoided, taking into account the life cycle of the elements in the hydrogen chain. These analyses are at present not being carried out systematically.
- A few French equipment manufacturers, assemblers and operators are competent in the hydrogen sector. The electrolyser technologies (alkaline or PEM) are mature, each with its advantages. Their support through the implementation of a supply policy is essential. The multiplication of demonstration operations and encouragement of demand is not sufficient in itself.
- The development of the hydrogen sector is a long-term process. Attractive prospects are opening up; but reaching their destination is not a foregone conclusion. It must be accepted that much the development work will only be completed in the decades to come, and the results are uncertain. An energy policy cannot be built on hopes, but on realities.

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Philippe Boucly, président de l'Afhypac (Association française pour l'hydrogène et les piles à combustible) « Filière hydrogène France : le moment est venu de changer d'échelle »

Jean-Pierre Ponssard, directeur de recherche émérite École Polytechnique – CREST Directeur de la chaire Énergie et Prospérité « Politiques Publiques et Économie de l'hydrogène »

Pascal Mauberger, président-directeur général de McPhy « Les grosses plateformes d'électrolyse sont désormais capables de concurrencer le reformage à la vapeur de gaz naturel pour produire de l'hydrogène propre, au service de la transition écologique »

Philippe Lamoine, VP Engineering Symbio « Mobilité hydrogène, déploiement et enjeux »

Fabio Ferrari, directeur technique de Symbio

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Max Julius Hadrich, Institut Fraunhofer « Perspectives allemandes sur l'hydrogène »

Annex 2. Glossary

Ademe	*Agence de la transition écologique* - Agency for the Ecological Transition
Ancre	*Alliance Nationale de Coordination de la Recherche pour l'Energie* - (French) *National alliance for* coordination *of research on* energy
IEA	*International Energy Association*
Aphypac	*Association Française pour l'Hydrogène et les Piles à Combustible - French Association for Hydrogen and Fuel Cells*
Arenh	*Accès régulé à l'électricité nucléaire historique* - Regulated access to historical nuclear electricity
ATR Auto-thermal	Autothermal reforming (ATR) is a process for the production of synthesis gas from the partial oxidation of a hydrocarbon feedstock with oxygen and steam on a catalytic reforming bed.
Boil off	Gas resulting from the evaporation of a liquefied substance
BoP	*Balance of Plant* – It is a term generally used in the context of power engineering to refer to all components and auxiliary systems necessary for operation, other than the core of the production unit itself. These may include transformers, inverters, support structures, etc. By extension, this includes all mechanical, electrical and electronic auxiliaries.
BTU	*British Thermal Unit*
CCS	*Carbon Capture and Storage* traduit
CCUS	*Carbon Capture usage and Storage*
CEA	French Alternative Energies and Atomic Energy Commission
CHP	*Combined Heat and Power*
DRI	*Direct reduced iron*
ENSOSP	*National Fire Officers Academy*
RE	*Renewable Energy* (mostly solar or wind)
EPR	*European Pressurised Reactor*
EU-ETS	*EU Emission Trading Scheme*. https ://fr.wikipedia.org/wiki/syst%c3%a8me_communautaire_d%27%c3%a9change_de_quotas_d%27%c3%a9mission
FC	*Fuel Cell*
GERG	*European Gas Research Grouping*
GHG	*Greenhouse gas*
GRHYD	*Management of Networks by injection of Hydrogen to De-carbonate energies*
GCV	*Gross Calorific Value*
IFPen Energies Nouvelles	*French petroleum institute*, novel energies
Isterre	(French) *Institute of Earth Sciences*
IPGP	*Institute of Earth Physics of Paris*
Ineris	*French National Institute for the Industrial Environment and Risks*
IPHE	*International Partnership for Hydrogen and Fuel Cells in the Economy*

LCOE	*Leveraged Cost of Electricity* traduit en Coût de production d'électricité actualisé
NCV	*Net Calorific Value*
PEM	*Proton Exchange Membrane*
National Hydrogen Plan	National Hydrogen Deployment Plan 2018 presented by the government on 1 June 2018, sometimes referred to as the Hulot Plan.
R&D	*Research and Development*
SMR	*Steam Méthane Reforming*
PCFC	*Protonic ceramic fuel cell*
PHES	*Pumped Hydroelectric Energy Storage*
Royal Society	Royal Society of the UK
SOEC	Solid Oxide Electrolyser Cell
TRL	*Technology Readiness Level* https://fr.wikipedia.org/wiki/Technology_readiness_level
Turpe	Tariff for use of public electricity networks
UPPA	*Université de Pau et des pays de l'Adour*
WGSR	*Water Gas Shift Reaction*

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The availability of increasing amounts of decarbonated electricity, and the falling prices of electrolysers and fuel cells are opening up new prospects for decarbonated hydrogen as a tool for energy and environmental transition.

In the future, hydrogen produced by electrolysis could contribute to greening certain industrial processes; it could also be an energy carrier used in various sectors, including mobility and housing as a substitute or complement to natural gas.

What role can hydrogen play? What price should be paid per tonne of CO2 avoided to make its use a necessity? What competition between batteries and hydrogen to ensure mobility? Can hydrogen ensure inter-seasonal storage of surplus renewable electricity? What research and development avenues will make it possible to lower costs? What disruptive technologies can be expected?

French expertise in hydrogen technologies is strong. How can French players become global players in a nascent industry with strong growth potential?

The report provides answers to these questions, based on well-documented figures, as well as on the contributions of numerous experts and on the analysis of hydrogen strategies proposed by pioneering countries.

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