ABSTRACT

Hydrogen burns without directly emitting carbon. The current energy system already mobilizes some, but this hydrogen is carbon-emitting, as it is derived from fossil methane gas (“grey” hydrogen). In the future, to decarbonize uses for which direct electrification is not possible, hydrogen, with its derivatives (ammonia, methanol, e-fuels), will be needed. In the future, it could also contribute to energy storage and to the balancing of electrical systems. It is therefore likely to play a key role in carbon neutrality scenarios, as long as its production becomes decarbonized.

Decarbonization shakes up the entire energy system

France, through its Stratégie nationale bas carbone (SNBC-2, 2019), is aiming for net-zero emissions. This demands, among other things, shrinking the territorial greenhouse gas emissions by a factor of at least 6. Achieving such goals will require a shift from the current primarily fossil-fuel-based energy system to one founded mainly on low-carbon electricity. This is a major change that will redistribute the roles and relative value of the energy carriers: electricity, gas, liquid fuels, wood, etc. It is not always easy to identify which energy carrier should be preferred for each use, in order to achieve carbon neutrality. Today, it is widely established that electricity will be called upon to directly cover the majority of uses. Energy from biomass, as well as hydrogen and its derivatives, are scarcer or more expensive and will essentially cover the uses that electricity will not be able to satisfy – these are the so-called “hard-to-abate” uses.

The French strategy for low-carbon hydrogen, resulting from the France Relance and France 2030 plans, is endowed with 9 billion euros by 2030. “Becoming the leader in green hydrogen”, including the creation of electrolyser gigafactories, is one of the ten objectives of France 2030.

Hydrogen can or will be used, mainly:

- In so-called "specific" uses: production of ammonia, from which nitrogen fertilizers are derived; refining of liquid fuels; iron ore reduction (primary steel production), as a replacement for coal-based processes.
- In "energy" uses: industrial heat; combustion in gas turbines for electricity production; in fuel cells, notably in vehicles; and to produce synthetic liquid fuels (e-fuels), through recombination with a carbon source.

In addition, ammonia, derived from hydrogen and much more easily transported by ship, can be used as a fuel in industrial installations, for example for electricity production, or for naval propulsion.

The dividing line between the relevance of electricity and that of other carriers is still uncertain. This is the case, for example, for long-distance overland transport. However, "no-regret" uses of hydrogen can already be identified. These are essentially the "specific" uses: both the current specific uses and, very likely, the production of primary steel.

Two main use categories for hydrogen

This report calculates abatement costs, i.e. the costs, in euros per ton of avoided CO_2, of using low-carbon hydrogen. These costs are calculated according to the two main use categories identified above: on the one hand, a generic "specific use", in which "grey" (carbon-intensive) hydrogen would have been produced otherwise; on the other hand, a "combustion use" in which hydrogen replaces fossil methane.

In these two main configurations, the use of decarbonized hydrogen avoids, ultimately, the emissions of fossil methane. Additionally, for the "specific uses" case, it avoids having to first convert this methane into hydrogen, with costs and above all a loss of energy due to the conversion efficiency: the production of hydrogen from methane only retains 76% of the initial energy content. Thus, given a certain quantity of low-carbon hydrogen, it is more advisable to use it to replace "grey" hydrogen whose production will have required more methane, rather than using it to replace its energy equivalent in methane. One kilogram of hydrogen produced by any low-carbon technology, and whose production will have emitted less than 3kg of CO_2, avoids 10kgCO_2 when it is dedicated to a specific use, and 7.6kgCO_2 when it is dedicated to a generic combustion use. For a given production cost of hydrogen, the abatement costs are therefore lower in the first case.

Abatement costs: what are they about?

Following the Paris Agreement, France has set the objective of net-zero emissions by 2050. This ambitious target implies, for part of the emission reductions, deploying costly technologies. The question then emerges as to which technologies to deploy, and when to do so. The canonical answer to this question is to calculate the cost of reduction of each ton of CO_2-equivalent emissions, expressed in €/tCO_2-eq. and called abatement cost of a decarbonisation action. The lower the abatement cost, the "easier" the action will be economically. In order to select and prioritize the actions that are useful to the community, the abatement costs must be compared with one another but also with the measure of the gains of the action. The latter is given by the "climate action value", set in France at 120€/t CO_2-eq, rising progressively until 2050, and passing by 250€/t CO_2-eq in 2030.

After setting this recommended Value for Climate Action in 2019, the "Quinet Commission"[1] noted that "it is essential to establish a clear and shared methodological framework for assessing the socio-economic abatement cost of the various actions". To this end, a commission chaired by Patrick Criqui and supported by the CGDD, the DG Treasury and France Stratégie was established. Its work is also part of the follow-up to the Stratégie nationale bas carbone (SNBC-2) and the preparation of the SNBC-3. In addition to discussing methodological aspects, this commission identifies and establishes the abatement costs (in €/tCO_2-eq avoided) related to different actions and technologies in the transport, electricity, building, industry, hydrogen and agriculture sectors.

Several production routes for low-carbon hydrogen

Several routes, generally identified by colors, can be used to produce hydrogen. The first two, which emit CO_2, are widely used today ("black" and "grey" hydrogen), while the following ones can contribute to decarbonization:

[1] Quinet A. (2019), *The Value for Climate Action: A shadow price of carbon for evaluation of investments and public policies*, report, France Stratégie, February.

Possible typology of the main hydrogen production routes, carbon-based (black and grey) or low-carbon

Input	Process	Color
Coal, oil	Gasification, etc.	Black
Natural gas	Methane reforming	Grey
Natural gas	Reforming with CCS	blue
Natural gas	Methane pyrolisis	Turquoise
Renewable electricity	Water electrolysis	green
Nuclear electricity	Water electrolysis	Purple
Low-carbon électricity mix	Water electrolysis	Rainbow ?
Solar radiation	Water thermolysis Photocatalysis	Extremely distant readiness
Very-high-temperature nuclear heat	Water thermolysis	

CCS: Carbon capture and (geological and final) storage

Source: Criqui commission

There are thus two main categories of processes that can produce low-carbon hydrogen:

- processes that, like the current carbon intensive "grey" hydrogen, use fossil gas as an input, but avoid emitting most of the carbon and ensure its storage;
- water electrolysis, where electricity separates water into (di)hydrogen and (di)oxygen.

The last two lines of the table remind us that hydrogen could theoretically be produced by thermolysis of water, from very high temperature low-carbon heat delivered by very advanced concentrating solar power or by high temperature nuclear power; or even by artificial photosynthesis.

Blue or even turquoise hydrogen, or paths for the short and medium term?

"Blue" hydrogen is similar to "grey" hydrogen, but it adds CO_2 capture and geological storage (CCS). It requires a very strong focus on residual emissions, including methane leaks and the uncaptured CO_2 fraction. It also implies moving towards CCS, which, although not yet implemented on a very large scale, represents in many international studies (e.g. those of the International Energy Agency) a substantial part of the emission reductions for deep decarbonization. The additional costs of blue hydrogen over grey hydrogen are sufficiently limited to be acceptable, as early as today, according to the normative "climate action value" (CAV) used in France. This conclusion is robust to the costs of fossil gas, since it relies on a difference between two solutions both based on this fossil gas - the issue of gas availability is more likely to weaken it. This is particularly the case in the context of the gas price crisis in 2021 and the war in Ukraine in 2022 and their consequences. Thus, blue hydrogen, defined in the strict sense (capture of all CO_2 flows, storage of this CO_2, optimization of the climate balance), is theoretically a relevant technology in the short term to replace the present-day carbon-intensive hydrogen productions.

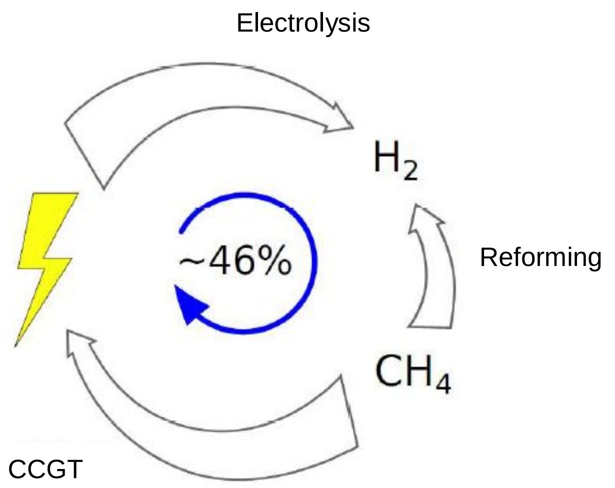
"Turquoise" hydrogen is a route relatively close to blue hydrogen, but not yet ready. It also consists of transforming methane, but by pyrolysis rather than by reforming. The related economic calculation cannot yet be made, due to a lack of information on costs, but it seems at first glance to be less favourable than the one associated with the "blue" route, because of the methane and electricity consumption. Nevertheless, this turquoise route would have the advantage of being more appropriate for decentralized implementation, and of storing carbon as "black carbon" rather than as CO_2, which geological storage may raise concerns and is yet to be developed on a large scale.

Electrolysis, the electricity-intensive path

Electrolysis comprises several technologies: alkaline electrolysis, which has been used industrially in the 1920s; proton exchange membrane electrolysis, which is more recent; and high-efficiency electrolysis, which is currently in the prototype phase.

What these technologies have in common is that they reverse the hierarchy of energy carriers, relative to the current carbon-based system. Today, fuels, including gas, are massively converted into electricity, with a substantial loss of conversion efficiency, which presumes that electricity is much more valuable than gas, in accordance with the thermodynamic view that a joule of mechanical work is worth more than a joule of heat. Inversely, electrolysis converts electricity into gas, also with efficiency losses. This inversion of the hierarchy of carriers, although new, is not absurd since, in a deep decarbonisation context, the most abundant energy sources are no longer fuels, but carbon-free electricity sources.

The inversion of the hierarchy between energy carriers implies that in order to obtain hydrogen that is significantly less carbon-intensive than the current grey hydrogen, highly decarbonised electricity must be sourced. Ex-coal electricity would produce hydrogen that is five times more carbon-intensive than grey hydrogen, and even ex-fossil-gas electricity would produce hydrogen that is twice as carbon-intensive as grey hydrogen. This means that low-carbon electricity production is at least twice more useful when it avoids fossil electricity production than when it produces hydrogen. Thus, if the electrolyser is fed by the electrical system, it is necessary, in a perspective of decarbonisation and of good optimization of the energy system, that no fossil fuel-based electrical production be in operation at the same time as the electrolyzer.



Legend: If we convert methane (CH4) into electricity by using the most efficient technology, and then extract hydrogen from it, through electrolysis, we will have transformed methane into hydrogen, which is what the current "grey" hydrogen process already does by reforming, and with a consumption of methane that is at least twice as low!

Source: Criqui commission

The costs of electrolysis: adding the fixed costs of the electrolysers and the cost of electricity supply

This situation - as well as the desire to produce hydrogen directly from electric renewables, for example in the most favourable areas – leads to considering the economics of intermittent electrolysis.

It is often argued that electrolysers should operate at high load factors, i.e. almost continuously in order to amortise the initial investment (the CAPEX). This type of reasoning is in fact based on high CAPEX electrolysers, associated with small-scale pilot projects, producing hydrogen at particularly high costs, in the order of 10€ per kg compared to 1.5€/kgH_2 for "grey" hydrogen – excluding the situation of gas price crisis since 2021 and the war in the Ukraine in 2022[1].

[1] At a fossil gas cost of 100€/MWh, a level sometimes reached or exceeded by European spot prices since October 2021, and almost continuously since the outbreak of the war in Ukraine, the cost of hydrogen exceeds 5€/kg.

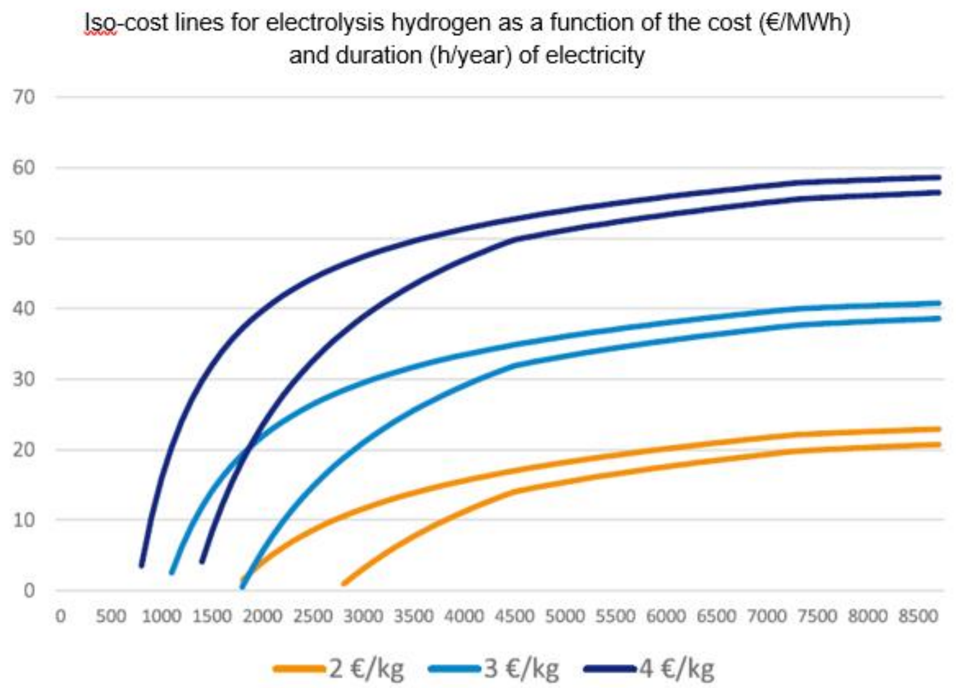
In the context of the socio-economic and prospective calculation made here, it is advisable to not retain the current costs of the pioneer projects, but the level of costs expected if the technology is deployed on a large scale. This means setting up a framework of analysis in which the larger costs at the beginning of the technological trajectory are justified by reasoning from the economics of innovation – particularly the search for learning effects – and from industrial policy, reasoning which underpins strategic "upstream" investments, for the development and industrialisation of technologies. For the calculation of the abatement cost associated with an electrolysis installation, it is thus the anticipated costs of the electrolysers that are considered. A CAPEX of 640€ to 700€/kWe is thus assumed. This level of costs has been identified as early as 2019 by the IEA as being achievable from 2030 under the hypothesis of a deployment sufficiently large to obtain learning effects. The very strong acceleration of hydrogen plans around the world since 2020 could even push this bar sooner[1].

The first challenge in obtaining hydrogen from electrolysis at a controlled cost will in fact be to mobilise low-carbon electricity at very low cost. For example, to produce hydrogen at 3€/kg, which is still twice the price of "grey" hydrogen under normal conditions[2], electricity at less than 40€/MWh (or even less if it is not available "continuously") seems indispensable. Such a cost level is not yet reached by any means of electricity production in France (network costs included), even if it could correspond to a value anticipated in the medium term for large-scale photovoltaics.

[1] Lower CAPEX hypothesis can therefore be considered. For the majority of the calculations here, sticking to the "prudent" assumption ensures that the results for the low load factors (see below) remain robust to future changes in cell CAPEX.

[2] That is, before the gas price crisis from 2021 and before the war in Ukraine in 2022.

Socio-economic cost of hydrogen, including storage, depending on the load factor of the electrolysers and on the cost of electricity



Note: the two curves in each colour refer to two different hypothesis as to the shape of the costs of electrolysis.

Source: Criqui commission

However, relatively low load factors, down to about 20% (i.e. 1,750 hours per year), may be sufficient to amortize the CAPEX of the installations – although the hypothesis we have retained for these CAPEX is less optimistic than many recent projections. This result takes into account, but with substantial uncertainty, the cost of hydrogen storage that would become necessary if an intermittent electricity supply is mobilized. This storage is geological, the only route whose costs appear to be affordable.

The resource-pooling allowed by the electricity system is key to the economical infeed of electrolysers

Considering the relationship between the cost of low-carbon electricity, the electrolyzer load factor and the full cost of the hydrogen that results, no means of electricity production that can be developed in the medium term in Metropolitan France, if taken in isolation, leads to an performing result.

It is in fact the resource-pooling made possible by the electricity system that allows electrolysis to access to favorable electricity supply costs. In an electricity system where the main low-carbon productions (nuclear, wind, photovoltaic) are rigid, like the majority of consumption, it is actually legitimate, in economic analysis, to consider a low cost of electricity supply to electrolysis. The same mechanism leads to low or zero electricity prices in the presence of an abundance of rigid productions. Electrolysis then finds its place thanks to its flexibility, by making use of fatal electricity generation, in periods of overproduction.

But this is only achievable if the electricity system is already largely low-carbon, which is not yet the case at European level. The result is a techno-economic vision in two stages, in which the development of low-carbon electricity production must primarily contribute to the decarbonisation of the electricity system. Indeed, one MWh of low-carbon electricity is at least twice more efficient in reducing CO_2 emissions, when it avoids fossil fueled electricity production rather than when it powers electrolysis[1], and the associated abatement cost is usually less than 100€/tCO_2[2].

In a second phase, the electricity system will be able to present significant surpluses. When these surpluses exceed for a significant part of the year (about of 2,000h/year) what other flexibilities (time shifting of consumption, flexibility of the hydroelectric facilities, possible batteries, etc.) can absorb, then these surpluses will allow the production of hydrogen by electrolysis in satisfactory conditions. From today's point of view, uncertainties remain high, in terms of both costs and quantities. In 2020, RTE's calculations showed only a small and uncertain potential by 2035, under the hypothesis of production volumes and consumption volumes that prevailed in 2020.

As France is more advanced in the decarbonisation of its electricity system than the European average, a choice exists between a vision based on technical optimization at the European level, which would take advantage of complementarities between countries, and a more autarkic vision for France, but one that would to slow down the decarbonisation of Europe.

Production costs, abatement costs

After taking all these elements into account, the calculations show the following orders of magnitude for different routes for hydrogen and its derivatives.

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[1] Under conditions of high gas prices, this approach remains unchanged, as it looks for ways to save as much gas as possible.

[2] Still under "ordinary" gas price conditions, and using forward-looking costs for RES. This abatement cost can become highly negative (i.e. very favourable) under high gas price conditions. On the other hand, the costs of the end of the decarbonisation path of the electricity systems are higher: see Criqui P. (2022), *Abatment Costs. Part 3 - Electricity*, report of the commission on abatement costs, January.

Synthesis of production and abatement cost estimates for the main hydrogen production routes examined, in the medium to long term, in Metropolitan France

Process	Color	Production costs	**Abatment cost** (specific uses of hydrogen)	**Abatment costs** (energy uses of hydrogen)
Natural gas reforming	Grey	Approx **1,6€/kgH_2**	Carbon pathway	Carbon-intensive pathway
Reforming with CSC	Blue	Approx **2,2€/kgH_2**	Approx **100 €/tCO_2**	Approx **250 - 300 €/tCO_2**
Natural gas pyrolysis	Turquoise	(n.d)	(n.d)	(n.d)
Electrolysis of dedicated electricity production (renewable or nuclear)	Green or purple	**> 3,5€/kgH_2**	**> 200€/kgH_2**	**> 400€/kgH_2**
Electrolysis of low-carbon surpluses	Rainbow?	Decreasing, uncertain floor → **pot 2,0€/kgH_2**	Decreasing, uncertain floor → **pot 100€/kgH_2**	Decreasing, uncertain floor → **pot 250€/kgH_2**

Note: These estimates take into account the anticipated costs in the 2030 decade, in metropolitan France. For fossil gas supply, they take into account "ordinary" prices, not including the price crisis and the war in Ukraine. Very high prices would lower the abatement costs of the two electrolysis routes. A storage cost is taken into account when production is intermittent.

Nota Bene: these results are derived not only from the figures of 10 and 7.6kgCO_2 saved per kgH_2, but also from the residual emissions of the low-energy production routes including an hypothesis of 2.8 kgCO_2/kg/H_2 for "blue" hydrogen; and the cost of substituted grey hydrogen and the lower cost of substituted methane fuel. The interaction of these factors produces the abatement costs displayed, which can be compared with the "climate action value" estimated at 250€/t in 2030 and 500€/t in 2040.

Source: Criqui commission

Even if the comparison of abatement costs with the "climate action value" indicates that all technical options could eventually be compatible with this VCA, the results need to be carefully analyzed.

As shown above, "blue" hydrogen emerges as the lowest cost decarbonisation route, relevant in the short term – under the essential condition of a proper optimization of its overall climate balance and of ensuring the security of its gas supply. The turquoise route seems potentially interesting, with pros and cons compared to the blue route, but it is not possible, at this time, to make complete calculations.

The massive production of hydrogen by electrolysis, although it appears to be dependent on the very strong prior development of low-carbon electricity production, emerges as the most desirable and potentially least costly way forward. Thus, the limited volumes of electrolysis hydrogen accessible in the short term, does not diminish the R&D and industrialization investments needed to lower costs, to establish a position for the French industry and ensure that the industrial system for conversion of surplus electricity into hydrogen is actually set up at the time when it can be massively solicited.

The figures presented here assume, for both the blue route and for electrolysis, large industrial installations, with in addition, for electrolysis, massive geological storage of hydrogen. Uncertainty factors arise in particular from costs of definitive geological storage of CO_2 (for “blue” hydrogen) and the costs of temporary geological storage of hydrogen (for electrolysis hydrogen).

Beyond these calculations, conducted for metropolitan France and the medium term (2030-2040), the hypothesis of significant imports should also be examined, particularly from a European perspective. The analysis and evaluation will depend on both the hypotheses about low-carbon options abroad as well as on the assessment of their context and geopolitical constraints. The fact that hydrogen is difficult to transport over long distances would be critical. The economic calculation would presumably highlight: firstly, imports through easily transportable hydrogen products, such as steel (or pre-reduced iron ore); then ammonia, for specific uses (nitrogen fertilizers especially) and then for fuel supply of industrial port sites (peak electricity production, ship propulsion, etc.); and finally synthetic liquid fuels (e-fuels). The opportunity of such imports should also be examined in the light of economic sovereignty considerations, which the calculation does not directly indicate.