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PERSPECTIVES ON A HYDROGEN STRATEGY FOR THE EUROPEAN UNION

Cédric PHILIBERT

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Center for Energy & Climate

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Executive Summary

Hydrogen currently produced in the world comes from fossil fuels - natural gas in the European Union (EU) - with a significant carbon footprint. Its use is limited to refineries and chemical plants. Thanks to a successful mobilization of industrial stakeholders, work by leading institutions and ambitious decarbonisation targets, there is now a wide understanding that larger use of clean hydrogen in future can be an important mean to achieve decarbonisation of the European economy.

For the purpose of accelerating the energy transition, hydrogen used needs to be low carbon, and zero carbon for achieving carbon neutrality by 2050. For the sake of simplification in this paper, clean hydrogen encompasses low carbon and zero carbon hydrogen but an EU strategy would need to make this distinction clear.

A robust, cost-effective European hydrogen strategy could become a pillar of an EU economic recovery plan which should, in line with the Green Deal, accelerate the decarbonization of European economies. The challenge for the upcoming EU strategy is to identify the most important future uses of cost-effective clean hydrogen, ensure sound scale-up through efficient public support schemes and system approaches driving significant cost reductions. Opportunities to maximise the economic benefits for the European economy in terms of jobs, value creation and competitiveness will also matter. And, of course, effective decarbonisation.

Comprehensive studies have been conducted on the potential of clean hydrogen but some issues are still up to debate. Important R&D efforts are underway across several industrial segments. Yet the European hydrogen industry is now largely ripe for a progressive scale up that needs to be planned for the coming 20 years. Industrial cycles require strategic action now, where appropriate and beyond the low hanging fruits. It is of paramount importance to carefully align future supply and demand at the level of European geographic or industry clusters notably.

While clean hydrogen will be indispensable, it comes with technical and economic challenges. There is an undisputed potential for decrease, but costs and availability of energy inputs, as well as transport and distribution systems, and an enabling policy environment, matter as much or more than simple scale-up. Clean hydrogen deployment bears huge economic and decarbonisation benefits but deployment policies must also maintain the competitiveness of European industries.

The EU will have to take stock of strategies developed by other countries. Japan and South Korea have robust industrial strategies that push carbon intensive hydrogen in the automotive, residential and power sectors with strong public support. Japan actively pursues a strategy of procuring low-carbon hydrogen from abroad. The United States and notably California are developing the production and end use of low carbon hydrogen, notably for mobility. China has now added hydrogen to its strategy of transport electrification. The United Kingdom is particularly active in transforming gas networks. Australia, Chile, Morocco and other countries, notably in the Middle East, are considering ways of exporting hydrogen to countries with more limited or expensive renewable resources. In most cases, public money and support are underpinning strategies. Decarbonization is not always the primary objective. Those strategies have not delivered yet: while the scale of stakeholder commitment can be assessed, their effectiveness cannot be clearly measured yet.

The European Commission will also have to take into account the strategies developed by EU member countries, some being particularly active in this area. *A minima*, there will have to be an effort of jointly discussing and coordinating aspects of these strategies, noting that of course, each country will want to build on its perceived advantages, for example CCS opportunities, offshore wind potentials, nuclear power plants or existing gas infrastructure and industry.

When considering future end-uses for clean hydrogen in the EU, the physical characteristics of hydrogen matter – its lower density notably.

- The current demand for hydrogen in fuel refineries and to produce ammonia and methanol for agriculture, mining and industry purposes figures at the top of the possible demand for clean hydrogen.
- Moreover, steel making in the industrial sub-sector is most likely to create considerable demand for clean hydrogen in complement to scrap recycling. Other industries may use hydrogen to cover high-temperature heat needs.
- In the transport sector, clean hydrogen could be primarily used for long-haul trucking and coaches. European products exist and deployment is already underway. Long-haul trucks and coaches may demand significant amounts of clean hydrogen, with some complements from other terrestrial transport means although the European carmakers prioritise battery electric cars and light duty vehicles. For hydrogen fuel cell vehicles and supporting infrastructures

(distinct for heavy duty and light duty vehicles), the challenge is of cost reduction through upscaling and mass production.

- Deep sea shipping is a sub-sector in which ammonia as a fuel is most likely to generate considerable additional demand for hydrogen. Aviation is a sub-sector that may call for large amounts of clean hydrogen in various forms unless offsetting emissions with verifiable carbon storage is available at scale and more competitive.
- Space heating and cooking might demand some clean hydrogen to complement efficient electrification in specific countries and circumstances.
- Clean hydrogen may be used to achieve full decarbonisation of the power sector as an inter-seasonal option, via sector coupling with the gas infrastructure – but this will probably not be needed before 2035 in the large, interconnected European power system, and not be the case for all EU member countries.

Clean hydrogen can mainly be produced from electrolysis of water with low carbon electricity generation, from natural gas steam reforming with carbon capture and storage, and from natural gas pyrolysis. The clean hydrogen production comes with costs/challenges: hence why future demand must be carefully identified and prioritised.

The costs of clean hydrogen production vary according to the technology chosen to produce it, the availability and cost of low-carbon electricity, water cost, the prices of gases used, the possibilities and costs of carbon dioxide disposal, and the value of by-products.

Compressed or liquefied, hydrogen is costly to store except in underground saline cavities, to transport except in pipelines, and to distribute to end-users.

International trade of low-carbon hydrogen-rich fuels and feedstocks (ammonia, methanol, synthetic hydrocarbons and hot briquetted irons) that are easier to store, transport and distribute could develop on these cost differences.

The use of low-carbon hydrogen-rich fuels and feedstocks as mere carriers of hydrogen to be used as such is less likely to develop due to the efficiency losses and costs of the double transformation needed.

A sound hydrogen strategy for the EU should initially:

- *Assess* all available reference studies and international developments in terms of system benefits and costs, certainties and uncertainties, primary and secondary priorities, timelines as well as strengths and weaknesses of the European industry.
- *Deploy* progressively and cost-efficiently clean hydrogen for the applications where it has a potential proven advantage over competing solutions for decarbonisation to evaluate merit in terms of EUR/CO2 of each application under different assumptions (current uses in chemical industry, primary steel making, deep-sea shipping);
- *Support* hydrogen clusters at city or territorial/ regional levels were production, demand and distribution can be effectively organized into systems that allow scale up, job creations, cost reductions and decarbonisation;
- *Organize* the scale up of demand and competition over supplies via regulation, IPCEIs in providing clarity over future needs/timelines;
- *Develop* roadmaps and demonstration projects for clean hydrogen-based solutions where the possibility of hydrogen proving a superior solution for decarbonisation is high enough, such as long-distance trucking or aviation; or where the need for hydrogen in the future is likely but less urgent, such as in the power sector;
- *Protect* EU hydrogen industry stakeholders at all levels and seizes from takeovers from external competitors as the industry is burgeoning.
- *Ensure* a level playing field for clean-hydrogen and hydrogen-rich fuels and feedstocks both within the EU and externally when there is a global market and competition, via regulatory tools (for example, eco-design prescriptions or REDII standards) and/or via a carbon border adjustment mechanism.

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Introduction

A Hydrogen Strategy for the European Union (EU) should be part to its broader environmental and industrial strategies, which pursue the primary goal of decarbonising its economy while ensuring economic development.

The Commission's communication "The European Green Deal" of 12 December 2019 defines the objectives of "climate neutrality" by 2050 and of greenhouse gas (GHG) emission reductions targets by 2030 by at least 50% vs. 1990 levels and working towards achieving a 55% reduction. European GHG emissions are currently at 77% of 1990 level.

This communication refers to hydrogen in a few occasions: it mentions "hydrogen networks" among "smart infrastructures" and "clean hydrogen fuel cells" among the priority areas for breakthrough technologies. "Clean hydrogen" is also mentioned as a topic for research and innovation.

The Commission's communication "A New industrial Strategy for Europe" of 10 March 2020 sets out the aim of building "a globally competitive and world-leading industry – an industry that paves the way to climate neutrality". There are two references to hydrogen in this communication:

- "All carriers of energy, including electricity, gas and liquid fuels will need to be used more effectively by linking different sectors. This will be the aim of a new strategy for **smart sector integration**, which will also set out the Commission's vision on **clean hydrogen**."
- "Where identified as necessary, the approach of **industrial alliances** could be the appropriate tool. (...) Clean Hydrogen is a prime example of where this can have a real added value. It is disruptive in nature and requires stronger coordination across the value chain. In this spirit, the Commission will shortly propose to launch the new **European Clean Hydrogen Alliance** bringing investors together with governmental, institutional and industrial partners. The Alliance will build on existing work to identify technology needs, investment opportunities and regulatory barriers and enablers."

While both communications from the Commission spell out many other considerations of relevance for the context in which a Hydrogen Strategy would be deployed, a full analysis is beyond the scope of the present document, and the reader is invited to refer to the original communication documents.

If both documents are rather succinct in explicit mentions of hydrogen, an EU Strategy will likely build upon several other achievements and publications.

The Commission has demonstrated a long-standing interest for hydrogen, which dates to the early 2000s. The European Strategic Energy Technology (SET) Plan identifies fuel cell and hydrogen technologies as crucial technologies contributing to reaching the ambitious goals of the integrated European energy and climate policy with a time horizon of 2020 and beyond.

The European Hydrogen and Fuel Cell Technology Platform was launched under the 6th Framework Programme for Research (2002 – 2006) as a grouping of stakeholders, which indicated a way forward with strategy papers (research agenda, deployment strategy, implementation plan). A Council Regulation on 30 May 2008 established the Fuel Cell and Hydrogen Joint Undertaking (FCHJU) as a public-private partnership between the European Commission, European industry and research organisation to accelerate the development and deployment of fuel cell and hydrogen technologies.

In 2014, the Council agreed to continue the FCHJU under the EU Horizon 2020 Framework, and its second phase (FCH 2 JU) is set up for a period lasting until end 2024. It has a focus on "energy and transport applications" and aims at overcoming barriers to deployment, pooling resources, with a market focus and the intent to tackle market failures.

In 2014, the EU's State Aid Modernisation initiative provided guidance as to the criteria the Commission will apply for the assessment under State aid rules of public financing of important projects of common European interest (IPCEIs), which may be considered to be compatible with the internal market according to Article 107(3) of the Treaty on the Functioning of the EU.

Responding to a call of the Commission, stakeholders have recently presented hydrogen IPCEIs for a cumulative amount of over Euros 60 billion for the next 5 to 10 years. IPCEI funding comes from the Member States; there is no EU IPCEI budget. Most importantly, hydrogen in IPCEIs needs to be green, i.e. from renewable energy, blue or grey hydrogen not complying with the IPCEI rules (phase out harmful environmental subsidies).[1] Hydrogen refuelling stations or acquisition of fuel cell electric vehicles can be funded by Member States based on, respectively, the Guidelines on State aid for Environmental protection and Energy, or the General Block Exemption Regulation – not the IPCEIs.

Meanwhile, the EU is elaborating a list of economic activities assessed and classified based on their contribution to EU sustainability related policy objectives: the "taxonomy", which aims to encourage private investment in sustainable growth and contribute to a climate neutral economy. The Taxonomy Regulation was adopted at the political level in December 2019 and will be supplemented by delegated acts which contain detailed technical screening criteria for determining what an economic activity can be considered sustainable.

A Technical Expert Group on Sustainable Finance had been mandated to provide advice in the matter. Its final report and technical annex were published in March 2020. They suggest a maximum of 5.8 t CO_2eq/tH_2 as direct emissions or via electrolysis of water (with a maximum of 58 MWh/tH_2 of electricity with at most 100 gCO_2eq/kWh). This criterion would allow, for example, natural gas reforming with capture of the sole more concentrated process-related CO_2 flux, leaving unabated the energy-related CO_2 emissions, more costly to capture. It remains to be seen how long this criterion can be deemed fully compatible with an objective of zero net emissions.

The CertifHy project "Designing the 1st EU-wide Green and Low Carbon Certification System" has developed a Green and Low Carbon Certification pilot that has led to the issuance of 76 000+ Guarantees of Origin, of which 3600+ have already been used so far". Financed by the FCH 2 JU, it is undertaken by a consortium led by HINICIO, a consulting firm. It has published in March 2019 its "hydrogen criteria", stating that "CertifHy Green hydrogen is hydrogen from renewable energy that additionally fulfils the criteria of CertifHy Low-carbon hydrogen". The latter is hydrogen from a production batch or sub-batch having a GHG footprint equal or lower than a specified limit that will be defined based on requirements from the Recast to 2030 of the Directive on renewable energy (RED II), but has provisionally be set at 36.4 gCO_2eq/MJ (low heating value), i.e. about 131 g CO_2eq/kWh.

Hydrogen Europe, a.k.a. the European Hydrogen and Fuel Cell Association represents more than 160 industry companies, 78 research organisations as well as 21 national associations and partners with the FCH

1. D. Spatharis, "Potential IPCEI on Hydrogen: Opportunities and Limits", *Hydrogen for Climate Action*, Brussels, DG Competition, 15 January 2020.

JU. It has recently launched the "2x40 GW" initiative, with the aim of promoting a massive increase of electrolyser production. Half should be deployed inside the EU and half in the Ukraine and Northern Africa.

This paper offers strategic perspectives on a future EU hydrogen strategy, building on existing literature and studies[2], industry developments in the EU and abroad as well as stakeholder discussions of current and future opportunities and challenges. The paper does not claim to cover all aspects of the future hydrogen use, nor to make definitive, undisputable assessments. It is aimed at providing food for thought for public and private decision-makers as they prepare for this indispensable strategy.

2. Notably the following studies: Hydrogen Council, "Path to Hydrogen Competitiveness", 20 January 2020, available at: https://hydrogencouncil.com; FCH 2 Joint Undertaking, "Hydrogen Roadmap. Europe", January 2019, available at: www.fch.europa.eu; IEA, "The Future of Hydrogen: Seizing Today's Opportunites", June 2019, available at: www.iea.org; IEA, "Renewable Energy for Industry", November 2017, available at: www.iea.org; Hydrogen for Climate Action, "2x40 GW Green Hydrogen Initiative", available at: www.hydrogen4climateaction.eu; Bloomberg New Energy Finance, "Hydrogen Economy Outlook", 30 March 2020.

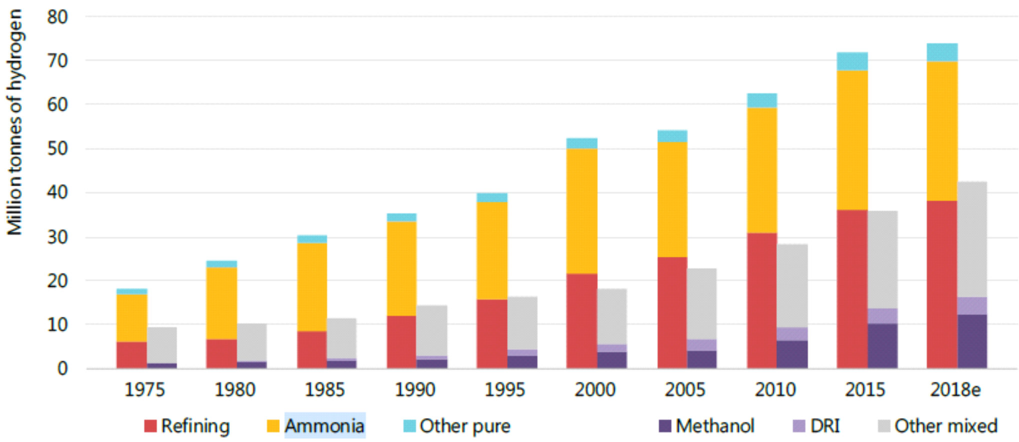
Using Clean Hydrogen

A European strategy for hydrogen should be built on an assessment of the potential for effective uses of clean hydrogen to decarbonise various sectors and sub-sectors, and in comparing the possible use of hydrogen with other ways of achieving decarbonisation. In this section the various uses are thus ranked by a criterion of necessity: the uses of hydrogen that appear the most indispensable given a lack of alternative. Nevertheless, costs and benefits and timing for introduction and deployment are discussed as important considerations.

Current uses of hydrogen

About 70 Mt of pure hydrogen gas or dihydrogen (H_2) are produced annually "on purpose" for industrial use in the world. The largest use is now for refining – cleaning and upgrading – fuels. The production of ammonia (NH_3) constitutes the second largest use of on-purpose hydrogen production. NH_3 is a feedstock in the production of nitrogen fertilisers and of mining explosives and is also used as a cleanser and a refrigerant, with a yearly production of ~180 Mt. On top of this production of pure H_2, another 45 Mt/y of hydrogen is produced in mix with other gases, often carbon monoxide (CO). This production can be either on purpose, mostly for producing methanol, a major feedstock for the chemical industry, and for steelmaking through direct reduction of iron, or as a by-product of economic activities, notably steelmaking in blast furnaces (Figure 1). The EU represents about 9% of global current hydrogen demand.

Figure 1 : Evolution of the annual global demand of hydrogen



Source: IEA, 2019, The Future of Hydrogen. DRI stands for direct reduction of iron in steelmaking.

About 98% of H_2 is currently produced from fossil fuels, via coal partial oxidation in China, or steam methane reforming (i.e. natural gas) in other countries, with a mere 1-2% from electrolysis, mostly of sodium chloride solutions to produce chlorine and sodium hydroxide. Hydrogen production from coal produces about 20 t CO_2/t H_2, production from natural gas close to 10 t CO_2. A fraction of this CO_2 is captured and used in the fertiliser industry to be form urea in combination with NH_3. Direct emissions from the production of hydrogen in in industry are 830 Mt CO_2, but about 130 Mt CO_2 from hydrogen production and encapsulated in urea are released soon after its use in the crops and accounted for as agricultural GHG.

These uses of hydrogen that had originally nothing to do with the need for decarbonising the economy logically come on the top of the list of uses for green and low-carbon hydrogen. The markets are already here. They have been constantly growing thus far but their future is uncertain.

- The demand for mining explosives, currently absorbing ~20% of ammonia production, will likely grow with energy transition and its higher demand for metals.
- Meanwhile, nitrogen from fertilisers ends up in large proportions (~80%) in the ecosystems rather than in the food, creating negative disruption. Even if the global demand for food increases, there is a large room for efficiency improvement in the use of nitrogen fertilisers, and some countries are trying to implement policy objectives of zero growth (China, India) or reduction (France) of synthetic fertiliser use, which may eventually prove effective.

There are other uses of pure hydrogen in industry, as a shielding gas in welding, as the rotor coolant in electrical generators, in the semiconductor industry, in metal alloying, in flat glass production, etc. In any case, a well-thought hydrogen strategy has to address the decarbonisation of all current hydrogen uses.

Novel industrial uses

Combustion of hydrogen is often suggested to replace direct fossil fuel uses in energy-intensive industries. This suggestion deserves closer examination as these fossil fuel uses could also be replaced by electrification. Meanwhile, hydrogen use seems to have no competition in the coming decades for a role of reductant of iron ore in steel making.

Steelmaking

Iron and steelmaking is the sub-sector most likely to create considerable additional demand for low-carbon hydrogen in a world striving for decarbonisation. Iron and steel production is one of the largest sources of GHG emissions, accounting for about 8% of total global fossil fuel CO_2 emissions, with over 3.3 Gt CO_2/y for a global production of 1.8 Gt crude steel, of which 2 Gt CO_2 are direct emissions from within the sector, and the remainder indirect emissions from the generation of electricity being used by the sector. Direct emissions stem from the use of fossil fuel as energy sources, but also as reductants of iron ores turning them into metal.

The blast furnace – basic oxygen furnace (BF-BOF) route accounts for 70% of the total production and is based on coking coal (or partially charcoal as in Brazil). The remainder is produced via the electric arc furnace (EAF) route. It uses scrap steel but also direct reduced iron (DRI) so that DRI-EAF contributes for 5% of total steel production, or 7-8% of total primary steel. DRI is operated with syngas, a mixture of carbon monoxide and hydrogen produced from natural gas (e.g. in Iran, Russia) or coal unsuitable for blast furnaces (e.g. in India).

Hydrogen-based DRI (H-DRI) is currently being developed by the Swedish iron and steel industries (*Hybrit*) but has already existed at commercial scale at the Circored plant in Trinidad and Tobago, 1999-2005. Other routes to low-carbon steelmaking are currently explored, notably carbon capture and storage (CCS) on BF-BOF (limited as requiring several CCS systems) and fossil-based DRI routes; smelting reduction using coal (not coking coal), easing CCS (*HIsarna*); injection of H_2 in blast furnaces (limited in scope); and direct electrolysis (Siderwin).

As the cost of renewable electricity is rapidly declining, the two routes H-DRI-EAF and direct electrolysis appear to be the most interesting ones besides scrap recycling that should see its role increase significantly in a "well bellow 2°C" scenario. Direct electrolysis would be 30% more efficient and possibly more flexible, but its technology readiness level is much lower than that of H-DRI-EAF. The latter appears to be the first option for achieving a significant level of decarbonisation of steelmaking in the next two decades at least.

The EU (UK included) is the second largest producer of steel far behind China, with 167.6 Mt steel in 2018, representing 9.3% of the global output, of which 41.5% in EAF, essentially from scrap steel. DRI production was 669 kt providing for 1% of steel production, vs. 15% in the US, 40% in India, 60% in Africa and 100% in the Middle East.

Other industrial uses

The industry sector is a large consumer of fossil fuels as heat sources, at various temperature levels. Three-quarters of the energy used in industry is process heat; the rest is for mechanical work and specific electricity uses. About 30% of process heat is low temperature (below 150°C), 22% is "medium-temperature" (150 – 400°C) and 48% is high temperature (above 400°C). About 10% of process heat is estimated to be electricity based.

It is commonly acknowledged that electrification of low and medium temperature heat loads can be done with commercial technologies, from Joule effect to more efficient industrial heat pumps and mechanical vapour recompression machines. As a result, low-carbon hydrogen appears to be the main option for decarbonising high temperature processes.

Things may not be that clear cut, though. There is no physical law that prevents electricity to deliver high temperature heat. Indeed, plasma technologies allow deliver heat at temperature higher than the combustion temperature of all fuels, including hydrogen. Emerging high temperature processes (direct resistance, induction, dielectric heating, electron beam, electric arc and others) are already used in industry despite costs of electricity being usually higher than fossil fuels. The greater energy efficiency of some of these processes, which can often be applied more directly to the material to be transformed, as well as indirect benefits for working conditions, faster process and/or better product quality, justify these higher costs.

The limitation for electrification is thus not so much the temperature level per se, but rather the insufficient scale of some of these technologies for application to large industrial plants. Electrification of e.g. cement factories is being explored in Sweden. It could be associated with CCS for process emissions which could be reduced but not avoided. Electrification of ethylene crackers is also being developed by a consortium of European companies, with the ambition to substitute significant amounts of petroleum products currently used as energy source and feedstock to produce olefins and other base chemicals. The process will likely involve significant quantities of H_2 and CO_2 as feedstocks.

Scaling up electric processes for high temperature heat may not be an insurmountable problem, so the two options of direct electrification and using hydrogen as a fuel will probably be in competition to each other. Most likely, the less costly technology will not be the same for all sub-sectors and applications, and it seems difficult or counter-productive to select either electricity or hydrogen as the fuel that will respond to all industrial needs for high-temperature heat.

Apart from delivering heat, H_2 is also being used already or considered for some industrial mobility applications, notably forklifts in warehouses and haul truck in mines. The intensity of the uses, often 24/7, is the main driver of a possible preference for hydrogen over electricity for these applications. Haul trucks carrying up to 450 t of rocks are responsible for about half the energy consumption of mining and are already "hybrid", associating a diesel generator and an electric traction chain. One option for decarbonisation is to replace the generator with a H_2 fuel cell, another is to install overhead catenaries in the mines and pantographs on the trucks. Hydrogen may still have a role to play in this case, as very often mine owners produce all or part of their electricity and are developing solar and wind capacities to reduce their use of oil and associated GHG emissions. For continuous operations, they would need to also install stationary electricity storage capabilities, such as batteries and H_2 cylinder tanks.

Transportation uses

While short distance transportation can be electrified on land and water bodies, aviation and long-distance shipping are beyond the possibilities of batteries and hydrogen-rich fuels such as ammonia or synthetic hydrocarbons have no other rival than biofuels of limited supply. For long-haul land transportation, H_2 fuel cell electric vehicles (FECV) such as trucks and coaches offer higher range, higher payload, higher flexibility and shorter refuelling times than battery electrical vehicles (BEVs), unless the latter can be supported by some electric road systems.

Shipping

Shipping represents 2.5% of global GHG emissions, which are expected to grow by 50 to 250% by 2050. Short sea shipping's GHG emissions are usually part of national GHG inventories and under the control of national authorities. A significant fraction of it can be electrified, as the current dynamics of ferry electrification in the Nordic countries demonstrates. Hydrogen fuel cell ships are being developed and may serve to propel some vessels on somewhat longer trips (e.g. in Greece).

Deep sea shipping is responsible for over 80% of GHG emissions from shipping, and is mostly international, and as such, not part of the nationally determined contribution to global climate change mitigation agreed upon at COP-21 in Paris, 2015. In 2018 the International Maritime Organisation (IMO) has adopted a target "to peak GHG emissions from international shipping as soon as possible and to reduce the total annual GHG emissions by at least 50% by 2050 compared to 2008 whilst pursuing efforts towards phasing them out".

No modal shift to, e.g. land-based transport means, can help reduce global emissions, as maritime transportation, especially on large ships, is the most energy efficient freight mode. However, efficiency improvements, speed management and wind assistance can all contribute to reduce GHG emissions. Nevertheless, many stakeholders and analysts consider that the IMO target can only be achieved if a progressively growing fraction of large vessels – tankers, bulk carriers and containerships – are propelled with zero carbon fuels. Liquefied natural gas (LNG), an option chosen by some shipowners as it complies easily with another IMO regulation regarding Sulphur oxide (SO_x) emissions enforced since the beginning of this year, would at best offer a 20% reduction of GHG emissions.

The low energy density of batteries does not allow these large ships to be electrified given the long distances they are travelling. Biofuels and synthetic fuels made from hydrogen and biogenic or atmospheric carbon is an option that would require minimal adaptation of the ships and their propulsion but the uncertainty on available supply and costs loom large given the likely limits to sustainable biomass harvesting and the competition from other sectors, in particular aviation. Compressed or, rather, liquefied hydrogen, would require entirely novel propulsion chains on board based on large fuel cells with a current low technology readiness level (TRL) and the deployment of an entire new supply and bunkering chain.

Hence most analysts and stakeholders – shipowners, shipbuilders, engine manufacturers, certification companies, naval architects, maritime universities – now turn their attention to ammonia, the only possible fuel with hydrogen (and electricity) that does not contain carbon atoms.[3] Ammonia is liquid at -33°C or under a pressure of 1 MPa (10 bars), and is already traded internationally, mostly on some specific tankers. It is already used as a refrigerant on many more ships. Many commercial ports around the world already have NH_3 loading, unloading and storage facilities – although they would need to be scaled-up considerably.

While some fuel cells can be fed directly with ammonia, they lack power density and load response capability and are expensive. Others can only be run on pure hydrogen, but extracting and purifying H_2 from NH_3 on board looks too complex. The large low-speed, two-stroke Diesel engines that currently propel large ships can be adapted to run on NH_3 at the costs of more cautious bunkering operations, larger fuel tanks, safe fuel preparation systems, and replacement of injection devices. The use of a pilot fuel for 5% of the energy will also be required to support the combustion of the less flammable NH_3.

Although less efficient than fuel cells (efficiency ~60%), these internal combustion engines are currently the most efficient fossil-fueled prime movers of all sorts, with efficiency ~50%. The risk of excessive emissions of nitrogen oxides (NO_x) will also require the use of selective catalytic recirculation of exhaust gases, with NH_3 itself being the catalyst. All these changes can be made on a significant proportion of the existing fleet, which represent a considerable advantage over other options for the rapid conversion of the sector as requested by the IMO decision.

Mostly depending on the traffic growth in the coming decades, the demand for low-carbon fuels from the shipping sector could by 2040 reach 6.5 million barrels of oil equivalent per day (Mboe/d) from current need of 5 Mboed/d and plateau at ~8 Mboe/d from 2055 on. If a shift to NH_3 was to deliver 80% of the required emission reductions to achieve the IMO objective, the demand from international shipping would reach 650 Mt NH_3/y, requiring the production of ~115 Mt H_2/y, more than its current production for all uses.

3. See, e.g., N. Ash and T. Scarbrough, *Sailing on Solar – Could green ammonia decarbonize international shipping?,* Environmental Defense Fund, London, United Kingdom; T. Brown, "Ammonia-fueled ships: entering the design phase", 2019, available at: www.ammoniaenergy.org; N. de Vries, *Safe and effective application of ammonia as a marine fuel*, C-Job & TU Delft, Hoofddorp, Netherlands, May 2019; Llyod's Register and UMAS, *Zero Emission Vessels 2030,* London, United Kingdom, 2017; MAN Energy Solutions (MAN ES), *Engineering the future two-stroke green-ammonia engine*, Copenhagen, Denmark, 2019; K. Kim, *et alii*, "A preliminary study on an Alternative Ship Propulsion System Fuelled by Ammonia: Environmental and Economic Assessments", *Journal of Marine Science and Engineering,* 8:183, March 2020; Korean Register, *Forecasting the Alternative Marine Fuel – Ammonia*, Busan, Korea, January 2020; W. Tan, *Hydrogen: The Economics of Powering Ships*, BNEF, London, United Kingdom, 27 March 2020.

Aviation

Aviation is responsible for 2.4% of global GHG emissions and perhaps 5% of global anthropogenic radiative forcing due to high altitude nitrogen oxide and soot emissions leading to contrail formation and aviation induced cloudiness. GHG emissions from flights departing and/or landing within the EU have roughly doubled since 1990 and kept growing as traffic growth constantly exceeded economic growth by factor four or more – at least until the Covid-19 breakout.

Aviation, like shipping, is partly regulated by national authorities and, with respect to international segment, by an intergovernmental organisation, the International Civil Aviation Organisation (ICAO). The ICAO's main objective today is of a "carbon-neutral growth from 2020 to 2040". Meanwhile, the International Air Transport Association (IATA), which represents the global airline industry, has adopted a target to reduce net aviation CO2 emissions by 50% below 2005 levels by 2050.

The ICAO has set up the "Carbon offsetting and reduction scheme for international aviation" (CORSIA), in a voluntary phase until 2026 and a mandatory phase thereafter. This market-based mechanism to ensure carbon-neutral growth beyond 2020 uses lower carbon aviation fuels and carbon offsetting from a variety of projects in other sectors. The ICAO does not consider any measure aiming at keeping the growth of air traffic under control, including through modal shifts, although many analysts consider that the doubling of air traffic to 8.2 billion passengers a year by 2037 (which the IATA expected before the Covid-19 outbreak) would make the objectives significantly more difficult to reach.

Given the low power density of batteries, direct electrification of aviation is likely to remain marginal, extending to small aircrafts (e.g. training aircrafts) for very short haul commercial flights – liaising urban centres to airports for a handful of passengers for example; the use of hydrogen fuel cells as range extenders is conceivable in such applications. The largest contribution of electricity to aviation decarbonisation may remain grounded to cold ironing and taxiing, maybe take-off roll (catapults or tugs).

However, medium and long-range commercial aircrafts flying on pure H_2 (through combustion or fuel cells and propellers) seem out of reach with current technologies. While the specific power (i.e. power per weight) of H_2 is highest, its power density is low, and the reservoirs and machinery necessary to keep it liquid (at – 253°C) and keep boil-off to acceptable levels have considerably more weight than the gas itself. On-board regasification before combustion would be an extraordinary safety challenge for a commercial aircraft. Using compressed hydrogen would further increase the storage volume.

Alternative fuels such as ammonia (not containing carbon) or methanol (containing carbon) would be too heavy for commercial aviation. Commercial long-distance airliners may have 45% of their weight at take-off made of fuel, hence fuels with 2 to 3 lower specific energy would drive a weight-compounding effect. Their lower energy density would be another issue, increasing drag and decreasing efficiency.

"Drop-in" aviation fuels would be used in current aircrafts exactly like fossil-fuel based jet fuels. They could be biofuels or synthetic fuels such as synthetic paraffinic kerosene. Some biofuels have already been qualified for use in aviation in blend up to 50%. Their share in the total fuel use is currently less than 1 ‰ and expected to reach ¼ to ½ of 1% by 2024. While there are expectations it could reach 20% of aviation fuel demand by 2050, such achievement cannot be given for certain.

Synthetic fuels would considerably expand the possibilities. They would presumably be produced through the Fischer-Tropsch (FT) process already developed at commercial scale in coal or gas to liquid plants. The process combines carbon from CO or CO_2 and H_2 into a variety of hydrocarbons, including synthetic paraffinic kerosene (SPK). Provided the carbon is sourced from the biomass of the atmosphere, they would be zero carbon on a life-cycle basis.

Direct air capture is under development using various processes but is energy-intensive and expensive, although a large fraction of the required energy could come from the FT process itself in integrated plants. A cheaper option would be to use carbon from the biomass, and more specifically in capturing the concentrated CO_2 fluxes from biofuel plants. The biomass is richer in carbon than in energy, and the production of biofuels uses only about a fourth of the biogenic carbon.

Combining the production of biofuels and of synthetic fuels in integrated "power&biomass-to-liquid" plants would deliver three to four times more sustainable fuels from the same biomass basis – a promising option for aviation. SPK produced from biomass and low-carbon hydrogen could even prove largely superior to conventional kerosene as its combustion entail slightly less NO_x and much less soot emissions, possibly reducing the actual contribution of aviation to climate change beyond CO_2.

Depending on growth patterns, the amount of hydrogen required to sustainably fuel aviation could reach amounts similar or larger than that for international shipping. However, the current policy framework for mitigating the GHG emissions from aviation strongly rests on the development of the CORSIA. Offsets are quite cheap for now (at around 5$/t) but this may represent limited low-hanging fruits or options that are being challenged, notably by environmental NGOs, for their hard-to-demonstrate additionality.

Carbon storage in underground caverns would provide a much safer and provable option at a higher cost but still, the cost of conventional fuels plus carbon storage would be significantly lower than the cost of synthetic fuels (the capture of carbon from either biomass or the atmosphere being the same in both options). Hence the option of offsets, even if made more stringent and provable through carbon storage, would likely represent an important share of mitigation action, as long as aviation companies remain free to chose between sustainable aviation fuels or offsets – thus largely reducing the aviation market for hydrogen-based fuels.

Terrestrial transportation

Terrestrial transportation is the largest fuel consuming and GHG emitting sub-sector. It has long been the focus of most attention from the companies interested in the development of hydrogen as a fuel, and a few models of hydrogen fuel cell electric vehicles (H-FCEVs) are on the market, while hundreds of refuelling stations have been or are being built already. However, there is a growing consensus in the automobile industry that electrification of most cars is likely to dominate the shift from petroleum-fuelled cars to low-carbon mobility on this market segment in the EU. The attention is moving to other vehicles types: taxis, busses, commercial light-duty vehicles with intensive use, for which the long refuelling times of batteries, shorter range and lower payload makes electrification less straightforward, and long-haul transportation, notably trains on non-electrified lines, coaches and long-haul trucking.

Other low-carbon options include biofuels, already used in blends but which can hardly be scaled-up to sustainably cover such a large demand. Hydrogen-based synthetic fuels would be costly, even if the low efficiency of their entire cycle from electricity to mobility could be partly compensated by a production in regions with best renewable resources. Ammonia is often considered too hazardous for such a wide distribution. Methanol in blend would be close to a “drop-in” fuel and could be an option for part of the trucking, provided its carbon is sourced from biomass or the air, and its hydrogen low carbon. All in all, these alternative fuel options could be part of the picture but are unlikely to compete massively with electricity and hydrogen fuel cells

The rapid development of electrification options competes with the hydrogen-based solutions. Battery electric busses are less expensive, trolley busses have a long-proven history of service. "Frugal" electrification of railway lines with relatively low traffic avoid all costly-to-electrify difficulties – tunnels, bridges, crossings, stations – thanks to relatively small on-board batteries. On the other hand, fuel-cell electric bus may prove superiority on long routes, routes with frequent services, hilly terrain and steep grades, or extreme weather conditions, and offer greater flexibility. Hence some cities now tend to equip their fleets with fuel cell electric buses in complement to their battery electric buses.

Electric trucks are being announced with range characteristics allowing them to serve significant portions of the freight demand. Electric road systems are being tested, that would also be used for long portions of journeys while on-board batteries would give the required flexibility to reach electric roads or highways from departing points or reach endpoints from electric roads. Catenaries would only serve trucks and coaches, while ground power supply could also serve cars on long distances. Inductive supply is less efficient and much more expensive than conductive rail, possibly the most promising option currently tested in Sweden[4].

On the hydrogen side, significant cost reductions of production, transport and distribution of low-carbon H_2, refuelling stations and fuel cells are expected from learning by doing and research, mass production and upscaling. Important first step would be to reach consensus of the on-board storage technology (compressed or liquid?) and to adopt a protocol for heavy duty refuelling stations. Other elements weighting in favour of hydrogen over direct electrification may be the greater ability to control the cost and carbon content of the electricity used to produce green hydrogen, compared to the lower flexibility of battery electric vehicles with intense use, and the possibility to also use blue hydrogen from natural gas with carbon capture and storage (see below).

One difficulty for both battery electric and hydrogen fuel cell options are "chicken and egg" problems, with expensive refuelling stations uneconomic with low use and consumers reluctant to procure either type of vehicle anticipating difficulties to find convenient refuelling opportunities or facing high costs.

Japan and South Korea emphasise H_2 mobility, with large state subsidies and support to develop the refuelling infrastructure and for

4. See on: https://eroadarlanda.com.

purchasing the fuel cell electric vehicles (FCEVs).[5] They benefit from being islanded territories - cars can hardly cross their borders. Long-range distance is a key advantage of FCEVs or FCE Buses (over 500 km for the Hyundai Nexo or 300 km for city buses). Moreover, refuelling time is fast. Drawbacks are the costly infrastructure, the costly refilling operation and costly vehicles. While Japan and Korea's automotive industries bet on H_2 and consumers enjoy generous state subsidies, European car makers are rather absent from that segment and keep focussed on the battery electric vehicle transition. EU member countries have so far prioritized to support the roll out the battery electric mobility. Lastly, hydrogen powered trucks are being developed including in Europe. For example, Daimler and Volvo have in April 2020 announced their intent to create a common subsidiary to develop heavy duty H2-FCEVs they expect to put on the market by 2025.

Developing a H_2 infrastructure would not require installing refuelling systems at each current gasoline station. It can be started at clusters of captive fleets such as city buses, along roads used by trucks, in ensuring that there is a non-discriminatory access to the infrastructure so that a fraction only of the existing network could be needed to have a significant coverage of a territory. Cities and H_2 stakeholders will have to play a key role in scaling up that infrastructure. While the electric mobility is a priority and will remain so, especially following the current economic and financial crisis that will put a strain on available public resources for low carbon subsidies, it is worth also supporting a targeted, specific development, at regional level in coordination with several countries, of the H_2 mobility: first based on trucks and other transport vehicles (city buses, trains) where appropriate. This could then, in a later stage, pave the ground for the H_2 passenger car mobility to grow, when conditions allow and the network of filling stations and clean H_2 supplies has expanded.

Buildings

Space heating and cooking could be the major applications of hydrogen in building. The competition is again with electrification, notably as efficient electric heat pumps offer on average a much greater efficiency than the hydrogen chain if it starts with electricity. The apparent "efficiency" of a heat pump with a seasonal performance factor is about six times higher than that of turning electricity into H_2, compress and distribute it to end-users, and turn into either heat or heat and power in a fuel cell.

5. S. Kan, "South Krea's Hydrogen Strategy and Industrial Perspectives", *Edito Energie*, Ifri, 25 March 2020, available at: www.ifri.org; M. Nagashima, "Japan's Hydrogen Strategy and its economic and Geopolitical Implications", *Études de l'Ifri*, Ifri, October 2018, available at: www.ifri.org.

However, space heating is a large contributor to peak demand of electricity. Electrifying more space heating may increase the height of the peaks, leading to additional investment in electricity peak capacities, transport and distribution, while H_2 could potentially reuse existing natural gas networks.

Furthermore, the efficiency of heat pumps decreases with the outside temperature – precisely when electricity demand peaks. The carbon content of electricity increases at these times, as fossil-based peaking thermal plants step in, especially in low wind and low sunshine periods. If these plants are fuelled with stored hydrogen produced at times of lesser demand and higher renewable availability, in future fully decarbonised power sectors (see below), then the overall efficiency from solar and wind power to heat delivery becomes comparable or even lower than using H_2 at endpoints.

Gas networks can serve to transport and distribute H_2 in three different ways: in blend with natural gas, with pure H_2, or with synthetic methane (CH_4). Blending is limited to a few percent in energy. It is difficult to support the re-carbonisation of H_2 through methanation at a time of massive use of NG-based steam methane reforming to produce H_2. As for sustainable aviation fuels, if carbon is taken out from the atmosphere or the biosphere, it is simpler and less costly to store it underground, than to combine with low-carbon H_2, whether the latter has been produced from electrolysis or SMR with CCS.

A fully-fledge "gas change" for pure H_2 thus might be the best option and it is being deployed in Northern England. There are safety risks, though, due to the high flammability of H_2 and the impossibility to detect leaks with human senses. It seems difficult to add an odorant to the gas – as is done for natural gas – without compromise its ability to feed membrane-based fuel cells.

The UK's Committee on Climate Change advocates for deploying hybrid space heating systems with an electric heat pump and a hydrogen burner, to avoid overbuilding the power generation, transport and distribution system and takes advantage from the existing gas network. However, the exact level at which H_2 use would become preferable to further electrification of space heating is hard to determine at this point. Lastly, public acceptance and safety will be key issues.

Furthermore, better insulation levels in homes (through renovation for existing buildings and strengthened building codes for new built) would reduce the overall need and the height of the demand peak, making the double investment in heat pumps plus hydrogen burners less cost-effective.

In some cases, solar thermal heating devices can be plugged onto heat pumps, both devices increasing their respective efficiencies in this combination. Solid biomass can also serve as complement during cold peaks.

Power sector

Decarbonising the power sector goes through the deployment of renewable electricity generation and, where possible, the extension of existing nuclear power plants, the building of new ones if costs can be kept in check, as well as the roll-out of carbon capture and storage or other zero-carbon options for thermal plants with the possible need of negative emissions through, for instance, biomass with CCS. However, as the share of variable renewable electricity generating technologies increases, the question of maintaining the reliability of power systems becomes important, especially in power systems with relatively low hydropower capacities.

Integrating larger shares of variable renewables can be facilitated on various levels, such as system-friendlier deployment of renewables (wind turbines with lower specific energy and higher capacity factors, westward orientation of solar panels, different power electronics, etc.), better weather and output forecasts, more electricity networks and interconnections, development of time-based demand response and others. Ultimately though, more electricity storage will have to step in.

Batteries can provide storage for a few hours' duration. Pumped-storage hydropower plants can provide electricity storage for some tens of hours and can be further developed in Europe contrary to other hydropower capacities. However, only in the specific circumstances of cascading hydropower can pumped-storage hydropower be developed and extended to weeks of storage. Inter-seasonal storage would rest on the transformation of electric power into chemical power. Zero-carbon fuels could then substitute natural gas in balancing and peaking thermal power plants (which in any case will remain necessary throughout Europe), competing with thermal plants with carbon capture and storage, depending on the expected capacity factors.

H_2 is one of the main contenders for such a role in zero-carbon fuels, although depending on the geological possibilities. In areas where underground caverns or salt deposits suitable for H2 storage are absent, further transformation in NH_3 may be preferred – which would also facilitate the import of additional renewable energy from regions with better and larger renewable resources.

While this use of hydrogen appears quite likely in the future, it does not need a fast deployment. Deploying renewable energy to directly substitute electricity from coal-fuelled baseload plants and load-following natural gas plants has a significantly stronger effect in mitigating GHG emissions than it has in substituting natural gas with hydrogen for delivering peak power, whether in large-scale fuel cells or gas turbines compatible with H2 combustion, with capacity factors of 10% or lower. The French transport operator RTE does not identify a need for hydrogen before 2035 at the earliest. This time horizon is probably valid for the EU as a whole, unless proven otherwise, so that no firm plans should be made at this stage beyond preparing the availability of potential technologies through R&D efforts.

However, for islanded power systems such as islands and remote communities and economic activities such as extractive industries, the need for storage may appear much earlier, while the cost of traditional load-following power on fossil fuels (usually diesel gensets) is usually high, the use of H_2 storage on top of batteries may rapidly prove necessary to shoulder decarbonisation and back-up solar and/wind electricity-generating capacities. Similarly, gen-sets running on hydrogen in fuel cells or some hydrogen-rich fuel (ammonia, methanol, e-diesel among the main contenders) in engines could replace diesel-run gen sets that represent a large global capacity, providing back-up to renewable capacities on mini-grids, safety back-up to specific grid-connected users, shouldering weak grids or fully supporting isolated small and large customers, from telecom relays to agricultural pumps to mines.

One special case is Japan: confronted with particularly high renewable energy costs, low CCS potential and the stalling of its large nuclear power basis after the Fukushima Daishi disaster, the country is preparing to import green or blue hydrogen, notably as ammonia, from Australia and the Middle East, to feed its current coal and gas power plants. The amounts mentioned for the power sector's use by 2030 in the Government's Basic Hydrogen Strategy are three to four times larger than the hydrogen demand expected from the country's 800 000 FCEVs targeted at that date and the gap would further widen.

Supplying Clean Hydrogen

Differences in hydrogen production costs throughout Europe and the world rest on the differences in the resources available to generate low-carbon electricity, the prices of natural gas, the possibilities of carbon dioxide disposal, and the value of by-products. Hydrogen is widely seen as an option for energy storage, but actual H_2 storage costs vary greatly according to geological possibilities. Costs of transport and distribution may be high as well. International trade is more likely for hydrogen-rich fuels and feedstocks.

There are three major options to produce pure low-carbon hydrogen: electrolysis of water run on low carbon electricity, steam-methane reforming with carbon capture and storage (SMR-CCS), and natural gas pyrolysis run on low carbon electricity.

Other options are not detailed in this paper as they seem to be either

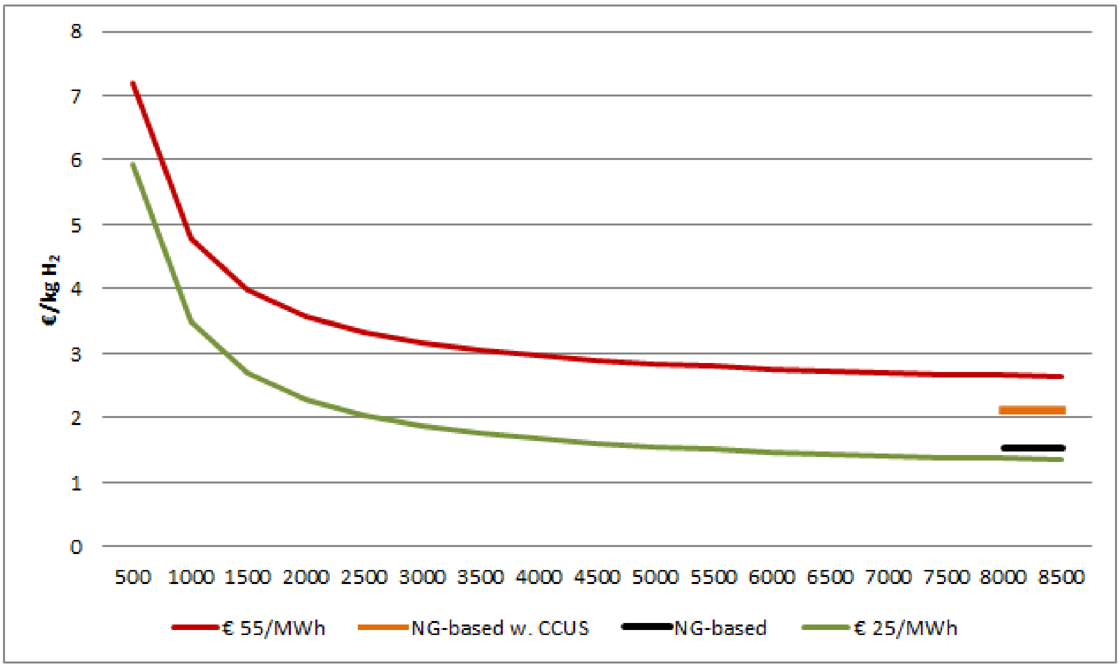
- insufficiently effective in lowering carbon emissions (e.g. coal-based hydrogen production with CCS),
- insufficiently energy efficient and/or at lower technology readiness level (e.g. solar-run thermosplitting or photosplitting of water or natural gas), or
- not the best way to go in the broad context of decarbonisation. For example, extracting hydrogen from biomass seems to be less useful than *adding* low-carbon hydrogen to biomass in order to produce carbon-neutral (on a life-cycle analysis) methanol and hydrocarbons as fuels or feedstocks. Steam reforming of biomethane would be another option making full sense for the use of hydrogen as feedstock, for example in ammonia plants. However, for this option to prove advantageous over directly using biogas as a fuel easier to store and distribute, it would need to be coupled with centralised CCS, thereby delivering negative emissions.

Water electrolysis

Electrolysis decomposes water into hydrogen and oxygen. There are three types of electrolysers: alkaline electrolysers (AEM), proton-exchanging membranes (PEM) electrolysers, and solid oxide electrolyser cells (SOEC). Large-scale (>100 MW) alkaline electrolysers have been around for long, notably in Norway in all-electric ammonia plants that delivered most nitrogen fertilisers to Europe during the XXe Century. All-electric ammonia plants were also built in Canada, Chile, Egypt, Iceland, India, Peru and Zimbabwe. Except for that in Peru, they have all been decommissioned by now.

Contrary to widely held belief, very large-scale uninstalled electrolysers would not be very costly at €400/kW, as they do not require precious materials. As a result, provided their capacity factor (or rate of utilisation) is not less than 3000 full load hours (FLH) equivalent per year, and if possible greater than 5000 FLH, the cost of electrolysis is dominated by the cost of electricity, not that of electrolysers. With low costs electricity, hydrogen from electrolysis can start competing with NG-based electrolysis with CCS (Figure 2).

Figure 2: Cost of hydrogen from electrolysis



Source: Adapted from C. Philibert, Renewable Energy for Industry*, IEA, Paris, 2017.*
Assumptions: Capex uninstalled alkaline electrolysers €400/MW + 30% installation + 20% provisions for stack replacement, WACC 7%, technical lifetime 30 years, efficiency 70% (lhv), NG price 7.3 $/MBtu.

The flexibility of electrolysers and the fact that electrolysis is not considerably more expensive with an utilisation rate of 50% or more allows to stop its work when the cost and carbon content of grid electricity become too high, or to feed them with electricity from dedicated solar and wind capacities.

In either case, this would allow electrolytic hydrogen to qualify as "green" hydrogen according to the current European standard requiring a carbon content of less than 100 gCO_2/kWh (see in Introduction).

- Grid-based electrolysis: for smaller load factors, such as based on limited "excess" of variable renewable electricity otherwise curtailed, the relative cost of electrolysers becomes predominant. Even if significant cost reductions of the electrolysers open that door, using green hydrogen to decarbonise end-use sectors would likely require adding more renewable electricity-generating capacities to the grid. This may lead to public acceptance issues especially for large PV or wind farms that are needed to reach low levels of electricity prices. These new loads, however, would be flexible, so that they would not contribute to the demand peaks. Although highly variable, solar and wind electricity generating technologies can be attributed a "capacity credit", representing the amount of fully dispatchable capacity that is not necessary anymore to maintain the reliability of the power system. Small or inexistent for solar PV in temperate climates, this "capacity credit" may range between 5 to 20% for onshore wind power plants and up to 30% for offshore turbines. As more capacities are added, their marginal capacity credit plummets but their total capacity credit increases, thus reducing the need for storage and back-up thermal plants. More importantly perhaps, the increase in electricity demand with greater flexibility reduces the curtailment of variable renewables and thus increase their value, equivalent to reducing their production cost. In sum, electrification of end-use sectors through hydrogen and possibly other means (e.g. battery electric vehicles with well-managed charging, electric heating with heat storage) can ease the integration of variable renewables. However, in areas with fair solar and wind resources, the cost of green H_2 would still be too high to compete with H_2 from natural gas, even with CCS.
- Dedicated solar and wind capacities: green H_2 cost competitive with blue H_2 would be produced from dedicated solar and wind capacities in world's best resource areas such as Australia, some Eurasian countries, North Africa, Southern Africa, Middle East and parts of China Latin America and North America. The combination of solar and wind power, provided their levelised cost of electricity are sufficiently close, would allow sustain the capacity factor of the electrolysers. If freshwater is not available in sufficient quantities, desalination of seawater could be needed in coastal areas, adding small costs to hydrogen production. Studies have shown how to optimise the respective solar and wind capacities relative to that of electrolysers depending also on the nature of a possible back-end plant

turning green hydrogen into hydrogen-rich fuels or feedstocks, such as ammonia, methanol, synthetic hydrocarbons or hot briquetted iron. Hydrogen as such is costly to transport, notably over the oceans, while these products can be easily stored and shipped.

Electrolysis of water produces oxygen along hydrogen. This by-product can have a significant market value, thereby reducing the cost of electrolytic hydrogen. In a broad decarbonisation perspective, oxygen can serve for gasification of solid biomass or oxycombustion of fuels ("oxyfuel"), which is a way of facilitating CCS in increasing the CO_2 concentration of exhaust gasses.

Scaling-up and mass deployment will help reduce costs of hydrogen production, with variable effects for diverse situations. For electrolysers run from dedicated solar and wind capacities, say at a cost of €25/MWh and load factor 50%, even a division by factor four of the current cost of large alkaline electrolysers (€570/kW) will only reduce the cost of hydrogen by 22%. Increases in the efficiency of the electrolysers, and further decreases of the solar panels and wind turbines (due to scale-up and mass deployment for all purposes), are more important drivers of hydrogen cost reductions in this case.

For electrolysers on the grid with the role of avoiding curtailment of "excess" solar or wind production at times, say 1000 hours a year at a cost of 15 €/MWh, then a division of the costs of electrolysers by four would more than halve the cost of hydrogen (-57%).

SMR with CCS

Another option for low carbon electrolysis is that of coupling steam methane reformers (SMR) and or autothermal reformers with CCS. Steam reforming uses water as an oxidant and source of hydrogen and requires high temperature heat; partial oxidation (e.g. of coal) uses oxygen in the air as the oxidant and releases excess heat. Autothermal reformers (ATR) use natural gas and combine steam reforming with partial oxidation so it does not require nor release heat. ATR, sometimes combined with SMR in integrated plant, facilitates carbon capture as both energy-related and process-related CO_2 formation take place in the same reactor, leading to a more concentrated and homogenous CO_2 off gas.

This "blue" hydrogen could significantly accelerate the decarbonisation of the broad economy in making more low carbon hydrogen available sooner. Notably, as explained above, renewable-based electricity has greater GHG mitigating effects in replacing coal-based, then NG-based electricity, than in making fuels, including hydrogen, given efficiency losses. Even if green hydrogen may be the future of hydrogen, blue hydrogen may prove very helpful during the next few decades and maybe more if the CO2 capture rate can be lifted from ~90% currently to 99% without significant cost increase. It could increase low carbon hydrogen availability for many of its applications.

Methane pyrolysis

Electricity-driven pyrolysis of natural gas to produce hydrogen and solid carbon instead of CO_2. Natural gas here only serves as an energy-rich feedstock and is not combusted. The minimal electricity requirement is 8 times lower than that of electrolysis, however, the high temperature level (>3 000°C)[6] reached originates important heat losses and the commercial process is more likely to be use 4 or 5 times less electricity than electrolysis – thanks the energy potential of methane.

This technology has already been proven at scale at the *Kvaerner Hydrogen Plasma Black Reactor* from 1998 to 2007 in Quebec, Canada. The firm Monolith Materials is currently building a commercial plant in Nebraska, aiming primarily at producing carbon black, based on a process developed at Mines ParisTech. The by-product hydrogen will initially be sent to a reconverted 125-MW coal plant of the Nebraska Public Power District. Other institutes and companies are working on various pyrolysis technologies, notably the Hazer Group in Australia, the Dutch TNO, the German BASF and Russia's Gazprom.

One advantage of this other form of blue hydrogen could be to help increase the availability and perhaps affordability of low carbon hydrogen in countries that have expressed strong reluctance to carbon dioxide storage or do not have the suitable geology, but do not enjoy sufficiently large and cheap renewable energy resources. As methane travels more easily than hydrogen, even in pipelines, the pyrolysis would presumably take place close to the place of consumption.

6. See e.g. F. Fabry and L. Fulcheri, "Synthesis of Carbon Blacks and Fullerenes from Carbonaceous Wastes by 3-phase AC Thermal Plasma", 6th International Conference on Engineering for Waste and Biomass valorisation, Albi, May 2016, available at: https://hal-mines-paristech.archives-ouvertes.fr.

Strategic Perspectives for the EU Hydrogen Strategy

A sound hydrogen strategy for the EU as part of a broader decarbonisation strategy could distinguish two main categories of applications. These are the following:

- Applications where clean hydrogen is the only viable decarbonisation solution or where it has a proven advantage over all competing solutions for decarbonisation. These applications include:
    - current feedstock uses in chemical industry, notably ammonia and methanol,
    - feedstock use in iron and primary steel making industry,
    - fuel use in deep-sea shipping,
    - and some storage uses in islanded power systems.
- Applications where the possibility of hydrogen (as H2 or as H-rich fuel/feedstock) proving to be a superior solution for decarbonisation is relatively high, or very high but only in the future. These include:
    - Fuel use in aviation (main competitor: offsetting with carbon storage)
    - Fuel use for long-distance trucking and coaching (main competitor: direct electrification with batteries and electric road systems)
    - Some uses in building to complement electrification (main competitor: electrification efficiency improvements)
    - Storage use in the interconnected power systems of continental Europe (after 2035).

The hydrogen strategy could aim at to *deploy* progressively and cost-effectively, low carbon hydrogen use for the applications of the first category, and to *develop* hydrogen use technology through R&D and demonstrations following a clear technology roadmap for the applications of the second category.

The deployment of the applications of the first category can be supported through regulation such as eco-design, RED II, incorporation mandates, procurement, the Emission trading scheme or other ways of implementing a carbon price.

The amounts of clean hydrogen required to respond to the growing demand of the first category of application would be largely sufficient to support the development of the production of both green and blue hydrogen, within the European territories and abroad, with imports of easy to store and transport hydrogen-rich fuels and feedstocks.

EU's strategy here should not be to favour one production technology over another but rather to have competition among different clean hydrogen sources while maintaining fair competition across energy fuels. While EU money should not come in support of one specific technology, the EU should though allow member countries to choose if they wish to support a specific technology given their local circumstances and provide conditions for such support. Overall, most funding and efforts so far have gone into electrolysis, less into pyrolysis. This is a major responsibility of the industry to beef up efforts and investments in this field. The EU strategy should seek to support carbon capture and storage technologies, which are lagging back and will be part of the solution for different purposes e.g. not only for hydrogen, but also decarbonisation of the industry and power.

The gas infrastructure could play a role in deploying clean hydrogen systems. But its role must be carefully weighted to avoid stranded or costly investments which will ultimately be paid back by end-consumers. Where optimal, the transformation of segments of the gas infrastructure into hydrogen pipelines/storages should be validated. Turning entire gas networks into hydrogen networks at this stage is a challenge given high costs and safety issues. One interesting option, as highlighted above, would be to continue using part of the gas infrastructure to ship natural gas that will then be transformed into hydrogen close to demand sites if technologies to produce zero-carbon hydrogen from natural gas prove affordable. That requires reducing fugitive methane emissions along the gas value chain and close cooperation between gas suppliers, hydrogen producers and end-users and probably, long term gas for hydrogen power purchase contracts which would transform the interdependence with EU's external suppliers. Yet part of the existing gas infrastructure would need to be decommissioned though.

The hydrogen strategy should aim at creating clean hydrogen clusters in gathering stakeholders at regional level, coordinating end users with suppliers and transport&distribution operators, facilitating feasibility studies for developing hydrogen systems and access to finance for their deployment.

It is not very likely, however, that some of them would be imported within Europe as mere carriers from which pure hydrogen would be massively extracted on arrival, as the cost difference with local H_2 production would largely be offset by the costs and efficiency losses of the transformations required at both production and consumption places.

With respect to the second category of applications, support to research and development should now remain the principal lever of European institutions and Member States.

Nevertheless, hydrogen fuel cells vehicles and refuelling stations are already being deployed. A sound strategy could be to partially support this deployment in complementing private investments from, say, freight companies or city bus companies, in ensuring that not only information gained but also access for all, including direct competitors, is guaranteed, so as to ensure positive network effects. The hydrogen strategy could coordinate local, national at regional efforts and aim to develop hydrogen stations corridors across EU's main transport arteries.

The EU's strategy should also design safety regulations and standards for hydrogen value chain equipment.

It should also seek to protect EU industry stakeholders from external takeovers as global competition for production, distribution and end-use technologies is strengthening, involving actors that are often largely directly or indirectly backed by states. Moreover, it will be paramount to plan the deployment of clean hydrogen in the industry in coordination with a carbon border adjustment mechanism or with regulation that can provide a level playing field at international level. Otherwise, the EU risks putting the competitiveness of its industries at risk and loose on all fronts: jobs would be lost here and industries could be relocated abroad.

Lastly, the EU's strategy should have various external dimensions: seek to showcase benefits from clean hydrogen deployment in industry in emerging & developed economies; assess to what extend domestic demand could be matched by domestic supplies under different scenarios towards 2050, in order to identify how much would need to be imported from abroad and how the competition between EU clean hydrogen supplies of various forms could evolve with supplies from abroad; lay the ground to improve the business climate, trade environment for hydrogen-rich fuels and feedstocks production and export notably from Africa, which is a condition to reduce the risks environment for investments, and limit their costs; and as mentioned, deploy protective measures against unfair competition from producers that would stick to highly GHG-emitting production processes.

Conclusion

Clean hydrogen has a strong role to play to decarbonise our economies, and its massive deployment also represents important opportunities for economic development. As it needs to be manufactured, it is likely to remain a more expensive fuel than those that need only to be extracted, and its low energy density makes it more expensive to shore and ship. However, green hydrogen will soon be able to compete with fossil-based hydrogen, with or even without carbon capture and storage.

Clean hydrogen is primarily a tool to reduce greenhouse gas emissions of the industry and transport sectors where it is most difficult, that is, the sectors most difficult to electrify directly or in full, chemicals and steel in first place; and trucks, ships and planes, as ammonia for ships, as synthetic fuels for planes. Hydrogen can also help achieve the decarbonisation of the power sectors, starting with small islanded systems.

Scaling-up and mass deployment will contribute to reduce costs, perhaps more on the hydrogen handling and end-use sides than on the production side. Developing the use of co-products, from oxygen to solid carbon in many forms, can also contribute.

An enabling environment conducive to investment is required for these promises to materialise, with a credible and predictable carbon price. If carbon taxes are deemed too difficult from a political standpoint, an emissions trading scheme with a corridor of prices would work. Financial support is necessary to initiate deployment but, as Bloomberg New Energy Finance recently noted, “policy measures are generally focused on expensive road transport applications” while “the more promising cases in industry are only funded with one-off grants for demonstration projects”. The stimuli that the European governments will put in place for the post-lockdown economic recovery provide an opportunity for clean hydrogen and other decarbonisation technologies that should not be missed, nor wasted.

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