IEA and EC Workshop on electro fuels, Brussels, 10 September 2018
Background document, updated 10 October 2018

Electro fuels: Status and perspectives

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Introduction

"A **fuel** is any material that can be made to react with other substances so that it releases energy as heat energy or to be used for work. " (Wikipedia)

A broader definition still would be needed to take account of the fact that fuels can also be used as feedstock or reagent in various industries. This is notably the case of fossil fuels in the chemical industry.

The recent and rapid cost reduction of solar and wind power technologies has created a strong interest in the prospects of further electrification of end-use sectors as a pathway towards the decarbonisation of the global economy. Where direct electrification appears difficult, however, notably for long duration storage and long haul transportation services, and perhaps for very high temperature heat needs, indirect electrification could be achieved through water electrolysis to produce hydrogen, and the synthesis of storable and transportable fuels.

While it is often argued that this could help harness variable renewable power in turning "excess" power into storable fuel forms, the production of these fuels would more likely take place in areas with abundant and excellent renewable resources which may otherwise remain "stranded" for lack of local demand (Philibert, 2017). Often termed "electro fuels", they form a subset of an array of concepts termed "Power-to-X", which include in particular "power-to-heat", not considered in the present note. Power-to-X is widely considered as a means to help integrate large amounts of variable renewable power such as solar and wind power.

Electro fuels can be gaseous, liquid or even solid, and most of them are rich in hydrogen. Almost all hydrogen currently produced on purpose is used in industry as feedstock or a reactant, and not as a fuel. It is produced from fossil fuels, and entails CO_2 emissions in the order of a billion tonnes per year. This production could be "greened" to significant extent (up to ~90%) with carbon dioxide capture and use or storage (CCUS). Still, the focus of this note is on electro fuels produced with carbon-free electricity most likely through water splitting by electrolysis but also possibly with electric methane splitting.

The first section of this note aims at concisely describing possible electro fuels and giving some basic information relative to their production, transport, storage, distribution and uses. The second section discusses the role of carbon in these electro fuels and its possible sources, the procurement of green electricity, and other sustainability criteria. The third section considers their possible uses as feedstocks, reagents or fuels in various end-use sectors, following a variety of production and delivery paths. A fourth section brings about elements of energy and economic analysis. A final section discusses short term options for jump-starting this industry.

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[1] The author is grateful to Till Bunsen, Pierpaolo Cazzola, Araceli Fernandez, Hiroyuki Fukui, Peter Levi and Uwe Remme for useful inputs and comments.

1. Diversity of electro fuels

A majority of electro fuels will be fluids, i.e. gaseous or liquids[2]. Hydrogen gas and methane can be liquefied for convenience in transport and storage, but they are most frequently handled as gases. Ammonia is gaseous at normal temperature and pressure, but as a fuel it would be more likely handled as a liquid, given that it liquefies at – 33°C and remains liquid under moderate pressure (1 MPa). A more important distinction with respect to their ability to mitigate greenhouse gas emissions is whether or not they contain carbon atoms or not. While most often people only think of hydrocarbons (and alcohols) as electro fuels, this paper intentionally widens the perspective, as Table 1 shows.

Table 1: Electro fuels

	Without carbon	Containing carbon
Gaseous	*Hydrogen gas* (H_2)	*Methane* (CH_4)
Liquids	*Ammonia* (NH_3)	*Methanol* (CH_3OH) *Hydrocarbons* (C_xH_y)

a. Fluids containing hydrogen but no carbon

Hydrogen gas

The hydrogen gas is the dihydrogen (H_2) or diatomic hydrogen, a.k.a. molecular hydrogen. Often called “hydrogen”, it should not be confused with the chemical element of symbol H and atomic number 1 – the lightest element on the periodic table.

At present, about 70-80 Mt H_2 are produced annually for industrial uses, mostly for refining oil products (removing sulfur) and producing ammonia, itself feedstock of nitrogen fertilizers, explosives, detergents and refrigerant. Its current use as a fuel is marginal, in rockets and some thousands of hydrogen vehicles. It is mostly (95%) produced from fossil fuels (coal gasification in China, natural gas steam reforming in most other places, and as a by-product in catalytic naphtha reforming), with only a small contribution of electrolysis, mostly as a by-product in chlorine and caustic soda production. Some metallurgic industries also produce hydrogen, on purpose or as a by-product, most often as part of syngas mostly made of carbon monoxide and hydrogen. Steam crackers also produce significant quantities of hydrogen, which is used for hydro treating co-products and possibly sent to the refinery and blended with fuel gas.

The hydrogen gas is not an energy source, but a possible energy vector. It has a very high specific energy (or gravimetric energy density), but a rather low (volumetric) energy density. One kilogram of hydrogen has the same energy content of one gallon (i.e. 3.785 l) of gasoline, but its volume is over seven times larger when compressed at 700 bars, and almost four times larger when liquefied.

Hydrogen with no or low greenhouse gas emissions at its production stage could be produced in different ways. The most important are the following:

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[2] The theoretical possibility of using powders of iron, silicon or other element is not considered here.

- From fossil fuels (steam reforming of natural gas, partial oxidation of oil products, gasification of coal), with carbon dioxide capture and use or storage (CCUS);
- From biomass in various states (methanisation, pyrolysis, etc.);
- From electrolysis of water.
- From natural gas by thermal cracking (splitting), a.k.a. pyrolytic hydrogen, with solid carbon as a by-product, used in industry or stored; this would potentially be another form of CCUS, although the concept is usually employed about gaseous CO_2.
- With concentrating solar heat running thermochemical reactions such as reduction – oxidation (redox) cycles.[3]

The first option is often termed "blue hydrogen", the three others "green hydrogen". This paper only considers using biomass to produce fuels containing carbon together with hydrogen produced from an electric process, justifying their labelling as electro fuels (or electro biofuels). Electrolysis and methane splitting would ideally be run on non-carbon electricity, as further discussed below. High-temperature thermochemical reactions run on concentrating solar heat currently have a lower technology readiness level and are not further discussed here.

Storing hydrogen is no simple matter. Small amounts are usually stored as compressed gas, usually at 35 to 70 MPa. Embrittlement of metals by H_2 dictates specific choices of materials. On-board vehicles and stationary storages for building blocks or refuelling stations (up to about one tonne) would use metallic or composite-reinforced polymer tanks. Other stationary options include metal hydrides, which store H_2 in a solid under moderate temperature and pressure that gives them a safety advantage. But they are heavy and can only store 1.8% hydrogen by weight.

Large amounts of hydrogen gas can be stored in underground salt caverns, at various pressure levels. Air Liquide operates the world's largest (300 000 m^3) such storage in Texas. In Europe, a number of smaller salt caverns currently storing natural gas could be adapted for hydrogen storage. Hydrogen can also be stored as a liquid, although liquefaction at minus 253° C is a complex and energy-intensive process. Maintaining the fuel at low temperature requires continuous energy use.

Transporting hydrogen is also difficult. Its low volumetric density makes transport mode relatively energy-intensive in pipelines. Transport over long distances in large amounts would presumably take one of the three roads identified by the Japanese cross-ministerial strategic innovation promotion program "Energy carriers": cryogenic, liquid hydrogen; bound with carbon atoms in organic hydrides[4], or bound with nitrogen in ammonia.

The distribution cost of gaseous hydrogen (compressed) by trailers can be assessed at USD 1 to 4/kg – roughly doubling the price from large hydrogen producing plants. This may justify decentralized production from electrolysis, even if small-scale is more costly than large-scale. Another option is to inject hydrogen in mix with natural gas in existing natural gas networks,

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[3] See, e.g., SolarPACES 2015, and Mission Innovation's Converting Sunlight Innovation Challenge.

[4] For example, toluene would be hydrogenated into methyl-cyclohexane for hydrogen exports. After dehydrogenation it is converted back to toluene, shipped back to the place of hydrogen production. Both products are liquid at normal temperature and pressure, facilitating shipping.

also benefitting from existing natural gas storage capacities. However, the implied decarbonisation remains limited.

The high inflammability of hydrogen creates difficulties for direct combustion if not in mixes. Its best energy use is in fuel cells for electricity generation (see below).

Ammonia

Anhydrous ammonia (NH_3) associates one atom of nitrogen with three atoms of hydrogen. This chemical bonding takes place over a catalyst in efficient Haber-Bosch loops, and ammonia contains 88% of the energy of the hydrogen it embodies. Ammonia has a boiling point of -33.5°C and quickly turns to a gas when exposed to air. But ammonia is easily and indefinitely stored as a liquid at about 1 MPa, a very low pressure which does not require special high pressure tanks. It is sometimes termed “the other hydrogen”, in part as its liquid form contains more hydrogen than the liquid form of dihydrogen, as reflects their relative energy densities: 15.37 MJ/L for NH_3 vs. 9.98 MJ/L for H_2. However, its specific energy is significantly lower than that of most hydrocarbon fuels.

Ammonia has been used as a refrigerant for 170 years, and as a feedstock for nitrogen fertilizers for a century. Storage and transportation at all scales in industry are routine. Ammonia is toxic for lungs and eyes, but its pungent smell is an important safety feature. While ammonia is usually converted to urea and other nitrogen-based fertilisers, it is routinely used by farmers in Midwestern United States who inject it directly in the soil. Although accidents are infrequent, the risks associated with handling ammonia would likely restrict its uses to various professional environments, with training and specific equipment.

Table 2: storage of liquid hydrogen and liquid ammonia

	NH_3	H_2
Temp to form liquid at atmospheric pressure	-33°C	-253°C
Energy density MJ/L	15.37	9.98
Storage vessel size	4 500 to 60 000 t	Up to 900 tonnes
Tonnes stored/tonne steel	41-45 tonnes	-

NH_3 can be combusted in gas turbines, industrial furnaces or internal combustion engines, most likely after partial or complete thermal cracking into nitrogen and hydrogen to balance out its high ignition temperature – a positive safety feature.

A concern frequently expressed relates to the formation of nitrogen oxides (NO_x) which the presence of nitrogen in ammonia could increase. However, the formation of NO_x depends on the temperature and pressure during combustion, the stoichiometry of the mix, etc. Furthermore, ammonia (safely converted into urea) has a known ability to convert NO_x into diatomic nitrogen and water in selective catalytic reduction process. This property is widely used to reduce the NO_x emissions due to combustion of fossil fuels in industrial boilers, gas turbines and diesel engines of all scales. Hence prospects for low-NO_x combustion of ammonia are high and start being demonstrated with various experiments undertaken in Japan, the UK and other countries.

Ammonia can also be used as a mere hydrogen carrier, both for large-scale long haul transportation (e.g. in oceangoing tankers) and for distribution e.g. to refueling stations for vehicles. However, full dehydrogenation, i.e. chemical and physical separation of species to produce hydrogen of extreme purity ("fuel cell grade") is currently associated with significant losses. New dehydrogenation processes are being developed in Australia, Japan or the United Kingdom (Crolius, 2018). Direct use of ammonia in alkaline fuel cells is possible, though, and commercialized by at least one company, CellGen, targeting the off-grid generation sector (Gabriel, 2018).

b. Fluids containing hydrogen and carbon

Methane

Methane associates one carbon atom with four hydrogen atoms. It is the main constituent of natural gas. Synthetic methane would be produced with the Sabatier reaction of methanation: CO_2 + 4 H_2 gives CH_4 + $2H_2O$. This reaction is the inverse of the steam methane reforming process completed with water gas shift reaction. Although half of the hydrogen atoms involved in the reaction end up as constituent of the water molecules, the reaction is relatively efficient and the resulting methane contains 83% of the low heating value (lhv) of the hydrogen.

Methane would need to be based on green hydrogen, but the origin of the carbon atom also matters – this sustainability criterion is discussed below in section 2. One appealing option could be to enhance the production of biogas: hydrogen from electrolysis would be reacted with the CO_2 formed in the methanisation process, thus increasing the use of the carbon atoms captured by the biomass.

Methanol

Methanol is the simplest alcohol (CH_3OH). Dominantly produced from fossil fuels, it is primarily used as a feedstock in the chemical industry. However, its energy uses, in gasoline blending or after transformation in dimethyl ether (DME) or gasoline now accounts for about 40% of its global demand of about 80 Mt/y. Although its combustion forms CO_2, it forms much less air pollutants than gasoline or diesel fuel burning.

Methanol is liquid at normal temperature and pressure, and thus very easy to store and ship. It is usually produced from fossil fuels through catalytic reactions to associate carbon monoxide and hydrogen. This process leads to the emissions of large amounts of CO_2. Alternatives include CCUS, biomethanol, and the hydrogenation of CO_2 with renewables-based hydrogen.

Methanol can be produced from CO_2 in one or two steps. In the latter case, CO_2 is converted to CO with the reverse water gas shift (RWGS) reaction, followed by hydrogenation of CO into methanol. In one step, these two reactions take place simultaneously with direct methanol synthesis. The resulting product mixes methanol and water that needs then to be distilled.

Carbon Recycling International in Iceland produces carbon-neutral renewable methanol using the almost entirely decarbonized electricity from the Icelandic grid and CO_2 captured in geothermal power plant, which would otherwise be vented (Stefansson, 2017). The potential for expansion is however limited. Sunfire is producing methanol in Dresden in co-electrolysing carbon dioxide and water in solid oxide electrolysers to deliver syngas, thus bypassing the reverse water gas shift reaction otherwise necessary – recycling CO_2 from industrial fluxes (Hauptmeier & Aldag, 2018).

Like ammonia, methanol is considered as a relatively easy target for decarbonisation of chemicals. As it has similar heating value and air/fuel ratio in combustion, the use of a mix of ammonia and methanol is also considered, notably at Xiamen University in China (Wang, 2016).

Hydrocarbons

A variety of hydrocarbons and blends can be produced from hydrogen and carbon. Their production could take several paths: the first is based on methanol and oil, which is then converted and upgraded in gasoline, kerosene or diesel; another uses the Fischer-Tropsch (FT) process. The FT process directly produces hydrocarbons which can be further upgraded into the same fuels. Most of these processes are proven or even commercial today, although based on fossil fuels other than oil, i.e. gas to liquid and coal to liquid technologies. A third path is the hydro treatment of vegetable oils, animal fat or waste cooking oil – usually designated as hydro treated vegetable oils (HVO) or renewable diesel.

While synthetic liquid hydrocarbons are often categorized as “drop-in” fuels, i.e. fuels that could replace oil products with no change in the customer applications, the reality is more complex. Commercial fuels are usually complex blends, and end-use applications may have different levels of flexibility in accommodating possible variations, even minor, in the fuel composition. While methanol-based biodiesel must be blended with petroleum-based diesel, renewable diesel can fully substitute it – and renewable jet fuel is accepted in 50% blend in aviation, at least in Europe. Still, a very significant advantage of “drop-in” fuels is that they could use all or most existing logistics, including transportation, storage and distribution systems, on top of final application. In this respect, synthetic methane too should be considered a “drop-in” fuel in current applications for natural gas.

2. Sustainability issues

a. The origin of carbon

While hydrogen gas and ammonia do not contain carbon atoms, other electro fuels such as methane, methanol, higher alcohols and higher hydrocarbons rest do contain carbon. As a result, their combustion creates large volumes of CO_2 that are usually emitted at the atmosphere, and, in several possible usages such as transport, cannot be captured. Hence the origin of carbon is of importance with respect to the contribution of electro fuels to climate change mitigation.

Carbon recycled from fossil fuel burning or process emissions

One possible source of carbon atoms in synthesizing hydro carbons with green hydrogen is capture of otherwise-emitted CO_2. Even if this CO_2 is of fossil origin, re-using the carbon of the original hydrocarbon might be useful as it avoids another emission.

However, a complete analysis would have to consider possible alternative uses of the electricity invested into green hydrogen production. For example, Abanades et al. (2017) argue that it would be more effective to store underground all CO_2 captured and to use carbon-free electricity to displace more coal-fired power plants. The argument makes sense if the power sector is not already decarbonized, and provided the electricity is not produced in remote areas from where it can only be shipped in some chemical form.

Still, using fossil carbon to make synthetic hydrocarbons may lead to serious inconsistencies and shortcomings. Let us consider the following scheme: from steam reforming methane hydrogen with carbon capture, both flows of CO_2 and H_2 are re-combined to produce "synthetic methane", to be used in an application incompatible with further capture. This absurd scheme would offer no advantage over the original natural gas and only cost more energy and capital.

Now let us consider a slightly different scheme: to reduce CO_2 emissions an ammonia producer introduces CO_2 capture on a steam methane reformer and offers the CO_2 for sale. Another industrialist then recombined this CO_2 with H_2 from water electrolysis to form synthetic methane.

It would of course be much simpler and cost less in energy and capital to direct the hydrogen from electrolysis to the ammonia plant, and to use natural gas as it comes. However, such a situation may result from piling up a series of well-intended incentives:

- incentives to electrolyze water with green power,
- incentives to capture and reuse carbon dioxide from industry plants, and
- incentives to produce electro fuels with carbon of whatever origin.

In any case, policies should prioritise the more straightforward and simple actions. Electrolysis of water should be applied first to decarbonize ammonia production, while CCUS should be prioritised, whether as a source of CO_2 for synthesizing artificial hydro carbon, or simply for storage – in sectors where no electricity based substitution exists, such as cement making. In short, only "unavoidable emissions" should be considered for CCU. Of course, these leaves room for discussion of what emissions are avoidable or not, and in what timeframe.

To achieve full decarbonisation, however, the emissions of all carbon of fossil origin (including process emissions from limestone calcination in cement making), even if used and recycled several times, will need to be compensated with some negative emissions.

CCU from biomass combustion

There are several options for using atmospheric carbon. One is to capture carbon dioxide from a plant that burns biomass. The emissions of carbon dioxide from such a plant, usually considered carbon-neutral as the carbon was originally captured from the air by photosynthesis, would then be eliminated and the overall process would result in larger emission reductions. Although this carbon as part of an electro fuel would then be actually emitted at the atmosphere at the time of combustion, it would do so in replacement the emission arising from the combustion of some fossil fuel. This would help reduce emissions as much as would be the case if carbon from biomass was stored immediately after its capture – as long as there are avoidable emissions. However, only bioenergy plus carbon capture and storage (BECCS) would actually constitute "negative emissions" that could compensate for persistent, unavoidable emissions as well as to compensate any temporary "overshoot" of carbon emissions in deep decarbonisation scenarios.

Direct Air Capture

Direct air capture (DAC) of CO_2 would ensure the carbon neutrality of electro fuels and thus mitigation of CO_2 emissions from burning fossil fuels. Due to relatively low CO_2 atmospheric concentrations, DAC is more energy intensive than carbon capture from off gases of power plants or industrial facilities, or capture of nitrogen from air in ammonia plants. DAC units require electricity and heat at about 100°C for CO_2 capture and regeneration. DAC is already an industrial reality by Climeworks in Switzerland. In the production of electro fuels, exothermic back-end conversions such as FT can provide most of the required heat, thus reducing the efficiency losses (Fasihi et al. 2016).

Enhancing biogas and biofuels production

Another option for procuring atmospheric carbon in the production of electro fuels is to associate it with the production of biogas or liquid biofuels. In both cases indeed, the processes only convert CO into biogas or hydrocarbons, while CO_2 is also formed but vented. Reacting this CO_2 with an external source of hydrogen, with catalytic or biologic agents, allows increasing the production of methane and liquid biofuels by up to 100% or more (Hannula, 2016; Ademe, 2016; Bassani, 2017). The association of biogas production with synthetic methane production is already experienced in various places in Europe, notably Germany. Finally, HVO associate, by definition, hydrogen and biomass.

b. The origin of electricity

Turning electricity into electro fuels is associated with significant conversion losses, from electrolysis to further conversion steps, transport and distribution, whether its end use is heat, electricity, mobility or otherwise. According to Malins (2017), fuels produced with current grid average EU electricity would have greenhouse gas intensity approximately three times higher than liquid fossil fuels. Even relatively low carbon content of the electricity may entail relatively high carbon footprint of the electro fuels. For the carbon footprint to be sufficiently low, electrolysers and the backend process turning hydrogen into electro fuels need to be run on zero or near-zero emission electricity. Besides nuclear power in a limited number of countries, the major option seems to be renewables[5]. Two different types of situations must be considered: “local” procurement, and dedicated renewable assets.

“Local” procurement

During the negotiations of the revised EU Directive on Renewable Energy it was suggested that only fuels produced in plants directly linked to renewable capacities could be considered renewable fuels. An alternative view was that a proper framework could ensure that any electricity of fossil origin absorbed in the production of electro fuels would be properly compensated for by truly additional renewable electricity production. A related concern is the risk of double counting of the renewable energy production and the multiplication of incentives.

“Remote” procurement

One of the possible advantages of electro fuels is their ability to help harness vast renewable energy resources otherwise “stranded” by being situated in areas far from large consumption

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[5] Using electricity from fossil fuel plants with CCS could be considered for decentralized production of hydrogen, but is unlikely to represent a valuable option for large-scale production as it would be more complex than direct hydrogen production from fossil fuels with CCS.

centers, from where they could be shipped in ocean-going tankers or land pipelines. Hence one basic assumption is that the bulk or totality of the electricity used by the electrolysers and the back-end plant, will be from dedicated renewable assets. Fulfilling the sustainability criterion of the additionality of renewable electricity generation may thus appear easier – but this also depends on the boundaries of its definition. As notes Frontier Economics (2018), very strict definition of additionality, for example "it must first be ensure that electricity demand in the production country is already covered by renewable energy", might be impossible to satisfy in most potential production countries even in the medium term.

c. Other sustainability criteria

Besides the criteria regarding the CO_2 cycle for methane, methanol and hydrocarbons, and the additionality of renewable electricity generation, a number of other sustainability criteria have been suggested. For example, Frontier Economics considers the following ones:

- "Sustainable use of land", notably considering competition for food production and forested areas; this criterion is perfectly legitimate, however it is important to consider that deployment of renewables such as solar and wind are proving compatible with many other land uses and activities, and request significantly less land than the production of biofuels;
- "Sustainable economic development in production countries"; criteria for sustainable development could include the requirement to make additional investments, reduce poverty levels, and/or transfer new technologies.
- Preservation of water in dry climate zones; the water required for the electrolysis "should be sourced from seawater desalination plants and not from the existing water supply" (Frontier Economics). This requires only relatively small amount of power compared to electrolysers, and seems possible in various dry regions. Some regions with excellent resources, such as the Western provinces of China, are not particularly at risk of water shortage.

3. Using hydrogen-rich chemicals and fuels

a. Non-energy uses

As the bulk of hydrogen produced today is used in industry, the first use of green hydrogen should likely to replace "brown hydrogen" in its current uses. Furthermore, hydrogen may also have other feedstock/reagent application to help green the industry, such as in steel making. It could be used to reduce iron ores in replacement of carbon from either coal or gas, and thus have a very important role in reducing industry CO_2 emissions (Philibert, 2017).

Non-energy uses are not the focus of the present note. However, their development could provide an important impetus to the development of energy uses of hydrogen in electro fuels, in scaling up the research, development and dissemination of electrolysers and other relevant technologies for handling, transporting, distributing and storing hydrogen in whatever form.

b. Energy uses

In power systems and large industrial furnaces

Using electro fuels to complement other renewable electricity generating technologies is considered in islanded systems of various sizes, where the cost of fossil fuel delivery is usually high, thus making alternatives more attractive. This even applies to large islands such as Japan. This application will be consuming most hydrogen in Japan's hydrogen strategy, and justifies procurement from abroad: by 2030 Japan may consume about 300 000 t/y of hydrogen in the power sector (with a dedicated capacity of about 1 GW), four times more than the expected consumption of hydrogen fuel cell vehicles by 2030 (GoJ, 2017). At a later stage, imports would be raised to 5 to 10 million tonnes/year). Special combustor technologies would be develop; meanwhile, Japan aims to mix ammonia with coal at coal power plants by around 2020 and use ammonia for gas turbines by around 2030" (GoJ, 2017).

The preferred option in this role might indeed be ammonia, easier to transport and store than hydrogen gas while containing no carbon. In a professional, industrial environment, its specific risks can be controlled with a very high level of security. Ammonia is less flammable than current fuels, a positive safety feature but an issue for combustion engineers. Meanwhile, hydrogen gas is more flammable than current fuels. A pragmatic solution seems to be a partial cracking of ammonia, fueled from the wasted heat of combustion, so that boilers or gas turbines would use a blend of nitrogen, ammonia and hydrogen of good flammability.

In smaller industries and buildings

Injection in existing gas grids, in mix with natural gas, would be a relatively easy first step to develop the use of some hydrogen in buildings and industries, etc. connected to gas distribution grids. Although in the past town gas (resulting from coal gasification) was widely used and contained 50% or more hydrogen gas, it is not exactly clear which proportion could be injected today with no or very minimal changes at users' level. Current regulation limit the share of hydrogen to 6% in France (in volume), or even 2% in Germany, while some studies and tests suggest 20% could be achieved. These percentages apply to volumes, but given the lower energy density of hydrogen compared to methane, they should be divided by three to represent the energy content of the mix – thus ranging from less than 1% to about 7% in the best case.

ENE-Farms: the World's largest fuel cell achievement so far

Over 200 000 fuel cells producing electricity and heat have been installed in Japanese homes, with government support to reduce the cost, which is around 20 000 USD per unit. The programme aims to install up to 5 or 6 million of them, in part to get around the difficulties of the electric grid and centralised electricity production.

ENE-farms use gas, either city gas or LPG. Each unit associates a reformer and a fuel cell. They are efficient as both heat (mainly for water heating) and electricity are valued. But the CO_2 is vented. Still, the cogeneration schemes allows for a reduction of about one third of primary energy use, and close to one half in CO_2 emissions. However, co-generation from distributed generators may prove almost as effective but cheaper.

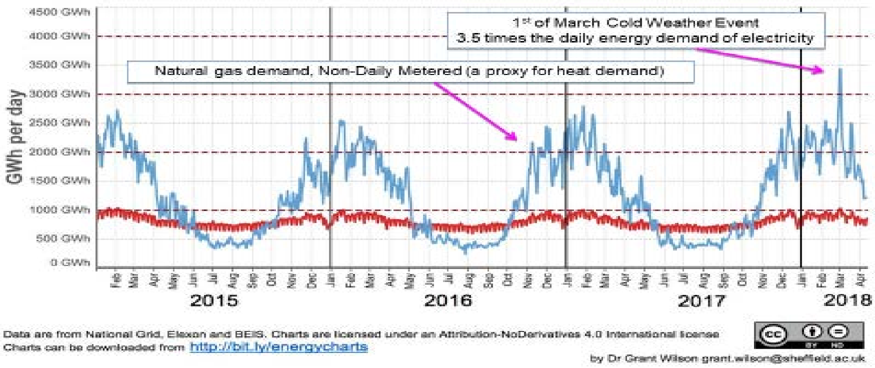
This experience may not be transposable in Europe or many other places. Japan only procures LNG, which is cleaner and purer than the gas Europe receives. This allows the reformer to deliver pure-enough hydrogen to PEM fuel cells – the first generation of ENE-Farms. The second generation uses simplified reformers and solid oxide cells, which are more tolerant to CO. Another advantage is that they are more efficient (60% vs. 45%), so that they deliver more electricity than heat, which owners found of interest when a change in law allowed them to sell power to their neighbours.

Larger-scale ENE-farms – for a building block, or a shopping mall – may in a not-too-distant future be run on green ammonia, with part of the heat provided by solid oxide fuel cells fuelling the catalytic cracking of ammonia.

Beyond this threshold, there are two options. The natural gas could be replaced with synthetic renewable-based methane or biogas or a mix of both. Alternatively, a “gas change” would allow pure hydrogen gas to flow through the gas network. This is a complex and costly operation, which will be experienced in Leeds (UK). The issues relate to embrittlement of some steel pipes, leaks, absence of smell (risk factor), difficulty to add an odorant tolerable by fuel cells, and the need to convert most applications (Dodds and Demoullin, 2013).

Given efficiency losses in the conversion, one may wonder if using renewable electricity would not be a better choice to cover all heating needs in buildings. With an average coefficient of performance of three, heat pumps would need six times less electric power than producing hydrogen with electrolysers for heating purposes.

Figure 1: Variations of power demand addressed to Great Britain’s Energy Vectors



Source: Dr. Grant Wilson, University of Sheffield; data from National Grid, Elexon and BEIS.

However, in temperate and cold countries there is a large seasonal imbalance in the use of natural gas in buildings, as Figure 1 shows. This suggests that electricity networks would have to be largely upgraded for seasonal peaks if all heat demand were satisfied with electricity. Furthermore, peak heat demand occurs in the coldest days, when the performance of air-source heat pumps degrades significantly. There might thus be an economic advantage in the continued use of existing gas networks to shave seasonal power demand peaks as much as possible. Still, a trade-off must be found between this advantage and the lower efficiency of the power-to-hydrogen cycle.

Transport applications

Terrestrial vehicles

Hydrogen vehicles associate a fuel cell, an electric battery and electric traction chain. The battery is necessary to deliver sufficient instantaneous power at high loads and to recuperate energy during breaking. The respective sizes of the fuel cell and the battery can lead to different combinations: fuel cells could be providing the bulk of the energy, or be used as a mere “range extender" in a plug-in electric vehicle. The use of hydrogen is most competitive to ensure long ranges, limiting the volume and weight needed for on-board storage. Hydrogen also lowers the demand for critical materials required for battery manufacturing for transport vehicles, while still allowing zero emission mobility. Battery storage has a clear advantage in terms of energy efficiency, it benefits from very sizable investments from the consumer electronic industry to improve technologies and achieve cost reductions thanks to large production volumes, and faces much lower investment risks for energy supply.

The deployment of hydrogen vehicles has been so far hampered by the classic "chicken and eggs" problem: owners of hydrogen vehicles have access to few refueling stations, while the building of refueling stations is made uneconomical given the scarcity of hydrogen vehicles. This limits the deployment of vehicles and the possibility to scale up production and benefit from economies of scale and technology learning. In addition, no hydrogen distribution infrastructure exist today, and reducing risks to allow its build up requires the presence of sizable demand. This problem is less relevant for battery electric and plug-in hybrid vehicles thanks to the possibility to align the timing of the investments on the vehicle and the power supply, the much greater development of power distribution, and the lower investments required for charging points.

Challenges for hydrogen might best be resolved progressively based on the combination of refueling stations for captive fleets of hydrogen vehicles (e.g. taxis, buses, trucks and waste collectors), – providing they are open to all potential customers - urban or sub-urban refueling hubs and the roll-out of network of refueling stations along major transportation axes.

Some of the options allowing making hydrogen available at the refueling points include:

- Transporting hydrogen on trucks;
- Distributing hydrogen in gas networks;
- Building dedicated hydrogen distribution networks (pipelines);
- Producing hydrogen at the station with electrolysis and compression in-situ.

While trucking and distributing hydrogen in pipelines enables to tap into the economic advantage of large-scale electrolysis, in-situ production does not allow doing so. On the other hand, the cost of trucking hydrogen is quite high, as the low energy density of highly compressed hydrogen makes trucking inefficient: currently 30 tonnes of steel must be moved back and forth to deliver one tonne of hydrogen, with an energy content of 33 MWh. Using gas pipelines comes with the need to recondition them to make them suitable for hydrogen transport and therefore requires sizable investments (and the need to handle associated risks). Using dedicated pipelines also requires sizable demand to justify investments, and comes with significant risks.

Hydrogen could also be extracted from ammonia at the refueling stations. Trucking ammonia is much less expensive than trucking hydrogen. In this case, electrolysis could extract hydrogen from ammonia for a fraction of the electricity expense of producing ammonia in the first place.

Drop-in fuels – synthetic renewable carbon-neutral gasoline or diesel fuel – would not face the refueling stations-and-vehicles chicken-and-egg problem type. They would not only filled current vehicle fleet but also use existing storage, distribution and refueling assets. However they would likely suffer an equivalent or perhaps even greater efficiency gap than hydrogen vehicles. Arguably they could – like ammonia – be produced in remote regions with excellent renewable resources; this could partly compensate for the cost difference, if direct air capture comes at acceptable costs or appropriate sources of recycled carbon can be identified.

The production of other electro fuels may offer other possibilities. If neutral carbon procurement is an issue, ammonia could be a candidate but acceptance might be an issue, due to its smell and risk perception, although it has been argued it would be less dangerous than gasoline or diesel oil. Liquid electro fuels, whether methanol or perfect "drop in" fuels, offer greater ease in distributing and handling the fuel on board than synthetic methane. They might optimally complement electrification of plugged-in hybrid vehicles and extend their range. However, the low efficiency of the entire cycle would not argue in favor of a mere replacement of current fuels with electro fuels. Frontiers Economics (2018) estimates the overall efficiency from renewable power to movement at 69% with batteries, 26% with fuel cell vehicles, and 13% with liquid fuel and internal combustion engines.

Maritime transportation

Green ammonia today appears as the prime candidate for replacing maritime fuels in long haul ocean-going ships. The Llyod's register together and the University of Maritime Advisory Services (2017) show that biofuels and green ammonia are better option to green long haul maritime transportation than green hydrogen and electricity, which may be considered for shorter trips.

Biofuels likely represent the least costly option for ship owners, as they require virtually no change in the ship machinery and storage. However, uncertainties on the actual amount of sustainable biofuels suggest that they may need to be primarily directed where other solutions may not work. This could the case of part of terrestrial transportation, in complement to direct electrification, and for aviation, as considered below.

While ammonia is heavier and bulkier than fossil fuels and biofuels, this inconvenience may not be as problematic on ships as it might be on aircrafts. Additional storage tanks would not actually create significant inefficiencies or reduce the useful load. Existing internal combustion engines could use ammonia as a fuel with relatively minor modifications.

While some other studies suggest hydrogen gas and fuel cells would be the best choice, they usually do not consider the ammonia option, which may limit their relevance.

Aviation

Aviation is the transport mode in which the specific energy of the fuel, i.e. its ratio energy over weight, matters the most. This could in theory favor hydrogen over other electro fuels, if not for the very low density of hydrogen, hence its low volumetric energy density. Conversely, compressed hydrogen still requires four to seven times the space of jet fuel, and the storing cylinders are not really light.

Therefore, the most likely use of hydrogen gas on board seems to be for running the auxiliary power units (APU) which deliver electricity on board when aircrafts are on the ground in airports. The consumption of APU is not negligible, and they create significant air quality issues in and around airports, so the benefits of running them on hydrogen should not be underestimated.

Nevertheless, aviation seems to be the area where moving away from hydro carbons might be the most difficult, and thus, where biofuels and electro fuels might prove the most useful.

As of today, the methanol pathway has not undergone the American Society for Testing and Materials (ASTM) approval procedure, while FT-based pathway has been approved for use in commercial aviation in blends of up to 50% with conventional jet fuel (Schmidt et al., 2018). Jet fuels are complex blends, and some more development will be required for electro fuels and biofuels to perfectly mimic them. While competition between electro fuels and biofuels should been seen favorably, their association as “enhanced biofuels” or “electro biofuels” could prove a pragmatic way of producing more carbon-neutral renewable fuels from any amount of sustainable biomass.

IV –Economic considerations

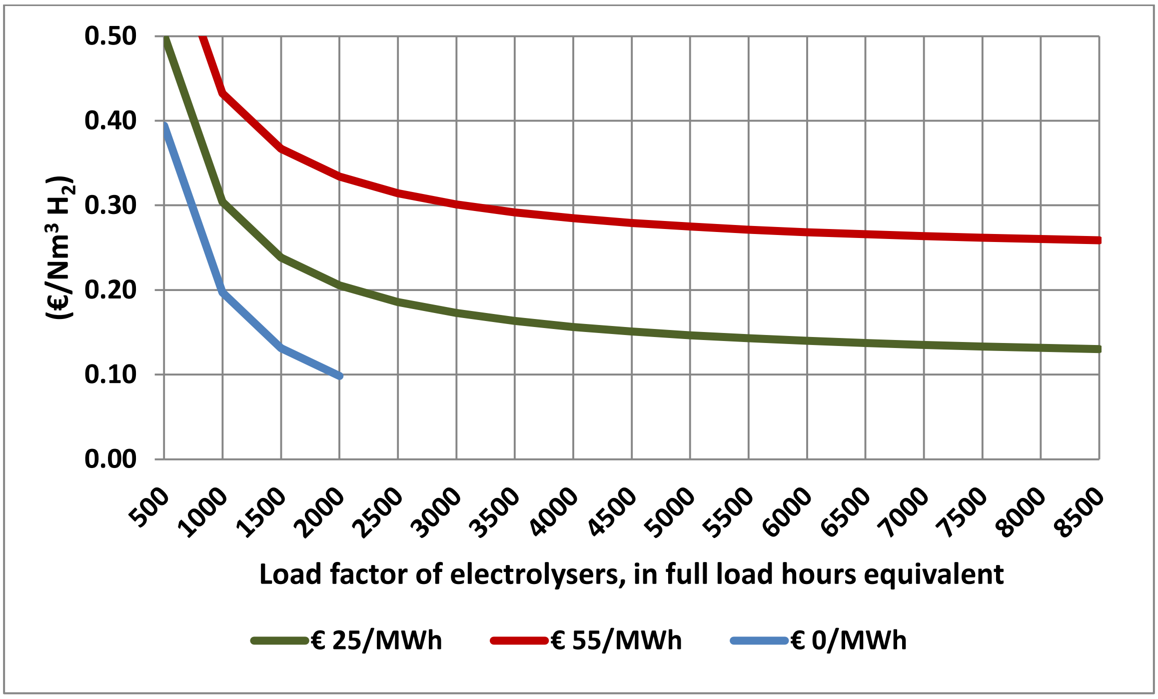
a. Green hydrogen and ammonia production

Green hydrogen production with electricity constitutes the main building block of the manufacturing of all electro fuels. Electrolysis of water would be the working horse of a large extension of production, but thermal splitting could be an interesting bridge technology.

Electrolysis

In case of electrolysis of water, the major costs are those of electricity and of the electrolysers. The cost of electrolysers especially matters for capacity factors below 30%, while for higher capacity factors the cost of electricity is the predominant factor.

Figure 2: Cost of hydrogen from electrolysis for different electricity costs and load factors



Assumptions: Capex electrolysers USD 450/kW$_{in}$*+30% installation +20% Opex; lifetime 30y; Weighted average capital cost 7%; efficiency 70%.*

Figure 2 is based on the cost of commercially available large-scale alkaline electrolysers. The blue line symbolizes "surplus" electricity supply from variable renewables, otherwise curtailed and thus assumed to be "gratis". The red line represents the unsubsidized cost of onshore wind power or utility-scale PV plants in areas with good but not exceptional resources. The green line represents the possible cost of solar and wind power in world's best resource areas in the coming years, based on most recent auctions results. The analysis shows that the cost of hydrogen could be EUR 1.7/kg or lower with "gratis" electricity with at least 1300 full load hours; with electricity at USD 25/MWh, a capacity factor of about 50% would be needed for the same hydrogen production cost.

Excellent solar and wind resources – or preferably a combination of both – can be found in various areas, often remote from large consumption centers. They may not suffice, though. Very low costs of renewable power are usually achieved under excellent financing conditions, thanks to long term power purchase agreement with large, renowned off-takers. First-of-kind electrolysers plants run on dedicated variable renewable assets may not benefit from similar financing conditions due to the combination of technology and market risks, especially if the electricity can hardly find a different off-taker.

Nevertheless, it seems that if large amounts of hydrogen are needed in the future to decarbonize the industry, including steel making, and the other end-use sectors, turning "surplus" variable renewables into hydrogen in average resource areas may contribute but may not prove sufficient – while other uses of otherwise wasted "surplus" electricity may be used more efficiently e.g. in providing storable heat to buildings and industry. Conversely, the conversion into hydrogen and other, easier to handle and ship electro fuels, of large "stranded" renewable resources may prove over time a more important contributor.

Methane splitting

Another option may prove a useful bridge technology: methane splitting. This is a technology based on alternative-current three-phase plasma that uses methane as a feedstock, electricity as energy source, and produces hydrogen and solid carbon, thus not requiring to store gasous CO_2. The technology, developed over 25 years at Mines Paris Tech, is now being used by Monolith Materials[6] (Fulchéri, 2018) to operate a pilot in California. This US firm is now building an industrial plant in Nebraska, which will ultimately be run on CO_2-free electricity.

Methane splitting consumes significantly less energy than water splitting, but operates at high temperature in plasma, with significant thermal losses that reduce its efficiency advantage. Still, it uses three to five times less electricity than electrolysis for the same amount of hydrogen produced. It prevents CO_2 emissions of two origins: methane steam reforming, and the production of carbon black. It incurs additional expenses in natural gas but benefits from two streams of revenues: sales of carbon black is likely the largest, being used in rubber, tires, printers, plastics and others; and hydrogen, which in the case of the Nebraska plant will be sold

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[6] Another technology co-producing graphene is proposed in Australia by the Hazer Group.

to the Nebraska Public Power District which will convert in 2019 a 125-MW coal plant to burn hydrogen instead of coal.

The global carbon black market is expected to increase from 12 Mt/y to 16.4 Mt/y in the next five years. If all was produced from methane splitting this would represent over 5 Mt of hydrogen, or about 8% of the current global on-purpose hydrogen production. Markets for other exotic forms of solid carbon - carbon nanotubes, carbon fibers, graphene – are one to two orders of magnitude smaller than that of carbon black but could grow rapidly with the expansion of batteries or carbon-reinforced concrete (Dagle et al. 2017). Other solid carbon markets, although less effective from a climate mitigation standpoint as the carbon in the products is emitted as CO_2 in final use, are significantly larger and may provide other options for relatively cheap hydrogen production from electricity and natural gas (Hanson, 2018).

Steam methane reforming with CCS

Considering "blue" hydrogen production from fossil fuel with CCS is useful as a benchmark. The IEA Greenhouse gas technology collaboration programme has published the most detailed techno-economic cost studies for both "merchant" hydrogen plants, and for steam methane reforming units integrated into methanol or ammonia/urea plants (IEA GHG 2017 a and b). Under the assumptions made for the cost of natural gas, it showed in the first case an increase in the cost of hydrogen from EUR 0.9/kg without CCS to EUR 1.7/kg for the most effective CCS option, allowing 89% emission reduction at an avoided cost of EUR 60/t CO_2. The cost of avoided CO_2 emissions from steam methane reforming (SMR) units integrated into methanol or ammonia/urea plants is slightly higher[7], ranging from EUR 70 to 86/t CO_2. Note that in case of methanol, the carbon content of the fuel is of fossil origin, so that CCS only marginally reduces its footprint.

b. Ammonia, methanol and hydrocarbons

Based on the costs of hydrogen from electrolysis on Figure 2 and that of natural gas reforming above, Figure 4 compares the cost of producing ammonia from natural gas with those of producing ammonia from electrolysis. Natural gas reforming is presented with and without CCS mentioned, or with a carbon tax setat EUR 120/t as by 2040 in the Sustainable Development Scenario (SDS) of the World Energy Outlook 2017 (WEO 2017) of the IEA. The price of natural gas is assumed to represent the European market. The conditions for electrolysis illustrate two situations, "average" renewable resources at EUR 55/MWh, and world's best.

Figure 3: Cost of green ammonia from NG reforming vs. electrolysis of water

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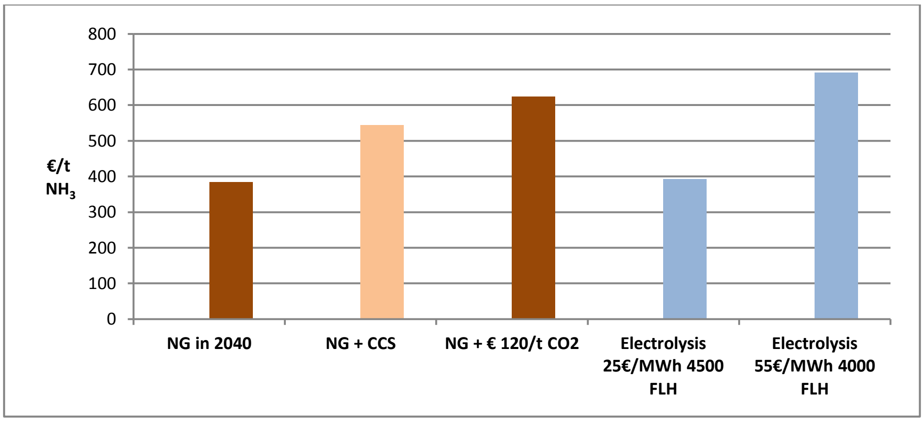
[7] In SMR one distinguishes two fluxes of CO_2: the process CO_2, very concentrated and easy to capture, and the CO_2 from natural gas combustion, more diluted and costly to capture. In most ammonia and all methanol plants the concentrated flux is used to form urea or methanol, and thus not emitted to the atmosphere. As a result, reducing further the CO_2 emissions of these plants requires the capture of a more diluted CO_2 flux, at a higher cost and not a lower cost, contrary to an often-repeated error.



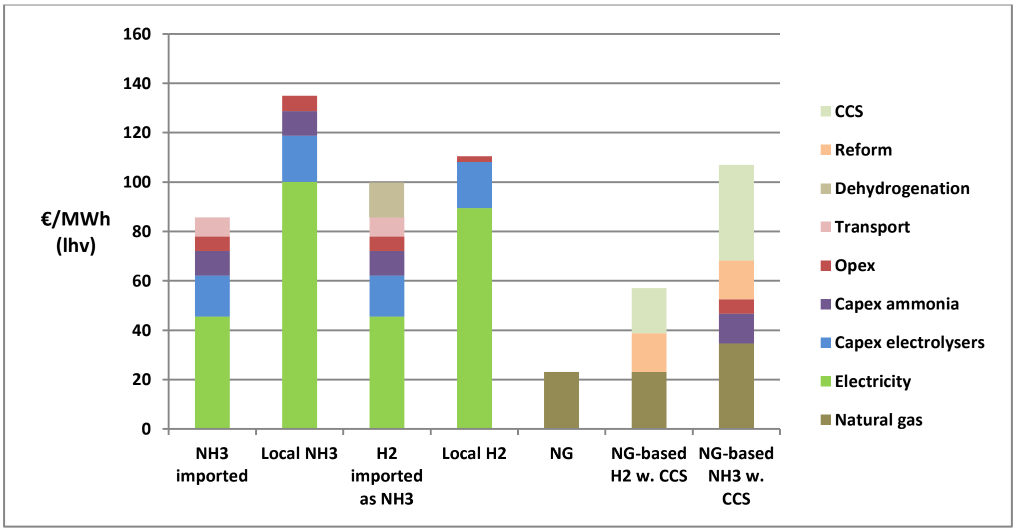
The analysis suggests that producing ammonia from renewables in world's best resource areas can compete with natural gas reforming in Europe, especially if carbon emissions are constrained or taxed.

Ammonia can be used as a fuel, or simply as a carrier of hydrogen. For some of its application, it would be dehydrogenated, with additional losses. Figure 4 allows comparing the energy of natural gas and hydrogen (low heating value) delivered in Europe in various ways:

- renewable-based ammonia imported from best resource areas and used as a fuel;
- renewable-based ammonia produced in Europe and used as a fuel;
- hydrogen extracted from imported renewable-based ammonia;
- renewable-based hydrogen produced in Europe (with average renewable power price)
- natural gas used as fuel at European gas prices
- hydrogen from natural gas reforming with CCS at European gas prices
- ammonia as a fuel from natural gas reforming with CCS at European gas prices.

This analysis bears several interesting conclusions. If ammonia is needed for its own sake, e.g. as feedstock for industry, or because a long-duration storage is needed, imports from best renewable resource areas dominate over local production and (as seen above) natural gas reforming. However, if hydrogen gas is required either as feedstock or energy carrier for most fuel cells, the costs of turning it into ammonia, transporting it and turning it back to hydrogen gas significantly reduce the price advantage over local hydrogen production from renewables. Furthermore, both are outcompeted by natural gas reforming with CCS.

Figure 4: costs of energy of hydrogen from various sources and in natural gas



A number of recent studies have provided a range of techno-economic analyses of the costs of other electro fuels, from methane to methanol to gasoline, diesel fuel, jet fuel and others. Hannula and Reiner (2017) provide a framework for comparing biofuels, electro fuels and battery electric vehicles in function of the ranges, distinguish first-of-kind and Nth-of-kind plant costs and suggest to consider carbon-neutral synthetic fuels (CNSF) targets to benefit from scale-up. Brynolf et al (2018) calculations result in production costs in the range of EUR 200–280 /MWh in 2015 and EUR 160–210 €/MWh in 2030 using base cost assumptions from the literature review. Frontier Economics similarly assesses the cost of synthetic methane and oil between EUR 200/MWh and 300/MWh but believes costs can fall to EUR 100/MWh by 2050 if the global capacity of Power-to-Gas and Power-to-Liquid reaches around 100 gigawatts. The authors clearly acknowledge the benefits for Germany of procuring electro fuels from better resource areas. Meanwhile, some industry representatives believe costs could be lower based on redirecting existing refinery assets to manufacture electro fuels. Unfortunately, these studies ignore or at best briefly mention ammonia as a possible fuel or energy carrier but do not analyse its production costs.

V – Where could this start from, and why?

There is no winner-takes-all pathway and we will need of portfolio of technology options. Wherever possible, direct electrification and electricity storage will be favored over electro fuel production thanks to much higher efficiency. However, long duration storage, long haul transportation services and high temperature heat may require other fuels that are closer to the conventional fuels already in use today. These can be synthetized from water and electricity, and nitrogen or carbon from the air.

Non-carbon fuels offer a simple way of decarbonising the economy, and can respond to a great variety of needs. Ammonia is more easily liquefied, transported, stored and distributed than hydrogen, at least for a large part of the supply chain. Ammonia is also likely to continue to cost less than electrofuels containing carbon and produced with direct air capture, if only because carbon is about 2 000 times less abundant than nitrogen in the air. Ammonia has good chances to prevail over carbon fuels when carbon neutrality is required, unless transportation and distribution costs offset its lower production cost in comparison with electrofuels containing carbon (the latter can benefits from transportation and distribution infrastructure that is, to a large extent, already existing). Another exception is that of uses for which ammonia's toxicity or its lower specific energy constitutes major impediments for its success.

Carbon fuels produce CO_2 at combustion, but they can still reduce the overall carbon footprint of fossil fuels when recycled from a first fossil fuel use. They can be carbon neutral if they use carbon captured in the air, directly or indirectly through photosynthesis, and are as effective in climate change mitigation as negative emissions, as long as there are fossil fuel uses that they can substitute – but not beyond.

Governments will have to consider many trade-offs. There are infrastructure decisions that government or sub-national jurisdictions may have to take, e.g. concerning “changing gas” in large gas networks, vs. developing synthetic methane to keep gas assets as they are. In road transport, electro fuels are one option competing with the direct use of electricity in battery electric vehicles, the use of hydrogen with fuel cell vehicles, and other options, including to the possibility to electrify some highways with overhead lines for feeding hybrid trucks on the move.

This indicates the complexity of the task for governments. They might have to play, alongside industry, customers and markets, a very significant role not only in orienting and supporting research and development efforts, but also in deciding structural investments. And they have to do so in line with many subnational authority levels, but also with some level of international coordination, to create broader markets and network synergies.

The clock is ticking for climate change; in the same time, there is still a long way to go in most jurisdictions to replace fossil fuels with renewable heat, electricity and transport fuels. Electro fuels can contribute to this, complementing other renewable energy vectors possibly reaching their limits in terms of sustainability (bioenergy) or practicability (renewable heat and electricity). The need is somehow more immediate in hard-to-decarbonise industrial sectors, starting with those that already use hydrogen on a massive scale. While a great variety of experimental developments in all sectors is welcome, governments must first address the decarbonisation of current hydrogen uses and perhaps, as recently did the French Government, set ambitious targets for this.

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