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Green hydrogen opportunities in selected industrial processes

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Abstract

This document summarises the contributions to the workshop "Green hydrogen opportunities in selected industrial processes" organised on the 26th June 2018 in the Centre Albert Borschette in Brussels. The main aim of this workshop was to assess the technical limitations and the potential benefits for the direct use of green hydrogen in three specific energy-intensive industrial processes: Ammonia production, Steelmaking, and Oil Refining. This focus was complemented by contributions regarding system modelling work relevant to the three technologies, guarantees of origin for green hydrogen and the European legislative context.

1 Introduction

The Joint Research Centre (JRC) of the European Commission, with the support of the Fuel Cell Hydrogen 2 Joint Undertaking (FCH JU) organised a one-day workshop on the 26th June 2018 at the Centre Albert Borschette in Brussels. The title of the workshop was "*Green Hydrogen Opportunities in Selected Industrial Processes*".

The overarching European policy goals of decarbonisation are based both on efficiency improvements and the introduction of renewable energy in different sectors, while at the same time maintaining European competitiveness, the affordability of energy services, and the security of European energy supply. Currently, industry is one of the largest consumers of energy, with ~25% of total European energy consumption ⁽¹⁾. In many of these industries, energy consumption is linked to a large use of fossil fuels as chemical feedstock. In some cases, such as for the ammonia or the oil refining industries, the fossil feedstock employed (mainly natural gas) is used for the production of hydrogen, which is then further consumed in the production process. In other cases, such as for the steel industry, hydrogen can substitute fossil fuels (coal), currently used as a reducing agent.

The main aim of this workshop was to assess the technical limitations and the potential benefits for the direct use of "green hydrogen" in three specific energy-intensive industrial processes:

- Ammonia production
- Steelmaking
- Oil Refining

Since these three industries contribute to a significant fraction of GHG emissions in the European industrial sector, they will need to be a prominent focus of any decarbonisation effort ⁽²⁾. Part of the carbon dioxide emissions in these three industrial processes are associated with the use of fossil resources as feedstock/reactants, and could in principle be significantly and directly reduced by substituting fossil fuels with green hydrogen. Moreover, the use of green hydrogen in industrial processes could also have the advantage of kick-starting the demand for large scale hydrogen electrolyzers, which could have a positive impact on other sectors, such as transport.

In other industries, such as the cement industry, process emissions are intrinsic to the process, and cannot be avoided. Hydrogen could play a role as an electricity storage medium in energy-intensive industries not considered here (e.g. pulp and paper, cement), but this option was considered outside of the scope of the workshop, since in this case hydrogen would not be introduced as a feedstock in a well-established industrial process. Carbon Capture and Storage (CCS) or Utilisation (CCU) were also deemed outside the direct scope of the workshop. This was a deliberate choice in order to limit and focus the number of topics and issues to be covered. There is already extensive literature available on carbon capture, while we believe the direct use of green hydrogen has not yet received the same attention.

The main aim of the workshop sessions was to collect knowledge from invited experts from the three industries and to discuss their views on the feasibility and potential benefits associated with the use of green hydrogen.

The workshop was organised by inviting selected people from industry, associations, academia and governmental organisations. The speakers were asked to prepare a short presentation, and industry participants were asked to complete a questionnaire touching upon the topics discussed below, prior to the workshop. During each session, short presentations from the invited speakers were followed by a moderated debate. The

⁽¹⁾ <https://www.eea.europa.eu/data-and-maps/indicators/final-energy-consumption-by-sector-9/assessment-1>

⁽²⁾ They amount to about 8% of total GHG emissions - <https://www.eea.europa.eu/data-and-maps/data/data-viewers/greenhouse-gases-viewer>

workshop encouraged the discussion between session speakers, modellers, and representatives from industry, research and governmental institutions.

Presentations from the workshop are not available to the general public, but their content is outlined in this document: this report collates and summarises the contributions from the workshop and the questionnaire.

The workshop also included a section dedicated to system modelling. The aim of this part was to frame these new potential production chains employing green hydrogen in a broader energy system context by reviewing the outcomes of techno-economic modelling studies. Considerations put forward during the system modelling session have been included in the relevant industrial session. This includes the contributions from the European Commission, Joint Research Centre/ Rijksuniversiteit Groningen (**JRC/RUG**), E3Modelling (**E3M**), International Energy Agency (**IEA**) and Forschungszentrum Jülich (**FZJ**). The contributions in this session draw extensively from work previously performed by the contributors mentioned above [1-8]. Whilst many system modelling presentations extensively discussed hydrogen production costs and compared them to other options (e.g.: CCS or CCU), they will not be presented in detail in this report. Different scenarios with a 2050 time horizon were presented in the same system modelling session and several GHG reduction options were analysed across these different scenarios. Their findings will be discussed in relation to the relevant industrial session. General remarks derived from the system modelling session will be presented in the "General Conclusions" section.

Introductory presentations, on certificates of origin for green hydrogen and on the European legislative and policy context, preceded the two sessions on system modelling and selected industrial processes. The first two presenters (European Commission, Directorate-General for Energy-**DG ENER** and Hincio-**CertfiHy Project**) framed the subsequent sessions within the context of European policy, defined the nature and requirements of green hydrogen and the methodology for labelling green hydrogen as such.

Sections 4, 5 and 6 of this report contain information on three specific industrial processes (ammonia production, steelmaking, and oil refining) and are based on information provided by industrial participants, supplemented by information from the system modelling session. We have tried to summarise the proceedings of each individual workshop session, which means that there may be some repetition. Our aim is to have a document where the interested reader can access each section as a self-standing source of specific process information. It should nevertheless be kept in mind that some general remarks are valid across industries, but may be presented more extensively in a single section, without being repeated in other sections. For instance, the introduction of electrolysis and related considerations on the associated renewable energy needs, have significant similarities across all the three processes considered, and steam-methane reforming (SMR)-specific considerations provided for ammonia production are in principle also valid for the SMR process used in oil refining, and vice versa. This document will not describe the technical processes or delve into the details associated with each industry. Therefore, the information provided presumes a certain familiarity of the reader with the production processes of the three industries considered. It should be noted that most of the numbers provided should be taken as estimates, and are used to give an idea of the order of magnitude of a specific parameter. They should not be considered as exact quantification.

It was not possible to use the same reporting structure for each session, since the specificities and the information available for the three different industries do not allow for a strict standardised reporting. Nevertheless, we tried to obtain and present information answering the following questions for each of the three industrial processes:

- 1) Are the different industrial players considering the use of green hydrogen as an option for greening relevant industrial processes?

- 2) Is it possible to roughly quantify the potential impact of using green hydrogen on GHG emission reduction?
- 3) How much energy would be required when switching to a process based on green hydrogen?
- 4) Is the switch to a green hydrogen based process economically feasible?
- 5) Is it technically possible to base the production process on green hydrogen? Would a new process based on green hydrogen impact process efficiency and affordability?
- 6) Is there a preferred source or solution for providing the necessary electrical power?
- 7) Which other considerations or future developments can impact GHG emissions from an established production process or affect an established market?

All the information provided is derived from the workshop and the questionnaire filled in by the participants, unless otherwise indicated.

2 Green hydrogen and guarantees of origin

The Fuel Cells and Hydrogen 2 Joint Undertaking (FCH JU) project CertifHy ⁽³⁾ has established a European Guarantee of Origin (GO) scheme covering the hydrogen supply chain upstream of the production site exit gate, at defined quality, and has provided a framework for ensuring transparent information. The project is split into three different phases. Phase one (concluded) deals with defining green hydrogen and GO schemes. Phase two (ongoing) finalises the scheme for GO and runs some pilot projects. Phase three (future) prepares a European wide implementation and finalisation of relevant Regulations, Codes and Standards.

The CertifHy scheme includes two different GO Labels:

- CertifHy **Green Hydrogen** ⁽⁴⁾ (from renewable sources and having a greenhouse gas emission intensity below a defined threshold), and
- CertifHy **Low Carbon Hydrogen** (having a greenhouse gas emission intensity below a defined threshold).

The CertifHy scheme is developed collaboratively, reviewed and improved by means of a multi-stakeholder dialogue across the value chain. The CertifHy scheme is technology neutral and as long as the requirements to comply with the definitions are met, any hydrogen production route is covered. Any technology that can provide evidence that the emission requirements for the amount of hydrogen produced are met is therefore included in the scope of the CertifHy scheme. In addition to technologies specifically designed for hydrogen production, technologies producing hydrogen as a by-product are included in the CertifHy scope, as long as the basis of the GHG emissions allocation complies with the principles of the CertifHy scheme. Relevant GHG emissions allocation methods ⁽⁵⁾ (mass, energy, value or benchmark-based allocation mechanisms) are being discussed within the stakeholder forum which is composed of GO scheme experts (Work Group 1 (WG1)), GO producers (WG2), GO Users (WG3), and Regulatory experts (WG4).

In the near future, the project will test the GO scheme with pilot projects, and then implement the roll-out of the scheme at a European level, involving legislators and standardisation bodies.

⁽³⁾ <http://www.certifhy.eu/>

⁽⁴⁾ From CertifHy *Deliverable 2.4*: " CertifHy Green hydrogen is hydrogen from renewable sources that is also CertifHy Low-GHG-emissions hydrogen. Hydrogen from renewable sources is hydrogen belonging to the share of production equal to the share of renewable energy sources (as defined in the EU RES directive) in energy consumption for hydrogen production, excluding ancillary functions. CertifHy Low-GHG hydrogen is hydrogen with emissions lower than the defined CertifHy Low-GHG-emissions threshold, i.e. 36.4 gCO_{2eq}/MJ, produced in a plant where the average emissions intensity of the non-CertifHy Low-GHG hydrogen production (based on an LCA approach), since sign-up or in the past 12 months, does not exceed the emissions intensity of the benchmark process (SMR of natural gas), i.e. 91.0 gCO_{2eq}/MJ."

⁽⁵⁾ e.g. for a chloralkali electrolyser process.

3 Policy Context

The EU's Energy Union strategy is the frame of reference for the energy policy initiatives at a European level. Its basic aim is "secure, sustainable, competitive, affordable energy for every European". This strategic vision has five leading principles ⁽⁶⁾:

- 1) Energy security, solidarity and trust
- 2) A fully integrated internal energy market
- 3) "Energy efficiency first" (including the transport sector)
- 4) Transition to a long-lasting low-carbon society
- 5) An Energy Union for Research, Innovation and Competitiveness

All these principles impact on the wider future European energy system development, and will therefore also have implications for European industry.

This strategy inspires and informs the legislative initiatives produced in recent years and is translated into targets for renewable energy, energy efficiency, and GHG emissions reduction.

Integrating a growing, but intrinsically intermittent, renewable energy supply will require sector integration and infrastructure development able to increase flexibility and adaptability. The situation is evolving quickly and it will take a more defined structure in the following years.

Industry will increasingly have to be considered as one of the components of a larger system, coupling together the transport, energy, residential and production sectors.

Currently, the most relevant European legislation impacting on the three industrial processes under consideration here, are: the Fuel Quality Directive (98/70/EC), the Renewable Energy Directive (2009/28/EC), and the Emission Trading Scheme Directive (2003/87/EC). These directives, in their current or expected revised form (e.g. RED II), set targets, methodologies, and constraints which directly or indirectly drive the evolution of these three industrial processes towards increased efficiency and reduced GHG emissions.

In particular, the renewable energy share defined in the recast Renewable Energy Directive will have to reach 32% by 2030, by which time GHG emissions are to be reduced by 40% with respect to 1990 levels. The Renewable Energy Directive in its revised form is expected to empower consumers, giving them the possibility to self-produce and store energy, and it should also introduce new targets for fuels in transport, including biofuels and fuels from non-biological origin. The new Electricity Market Design Directive and Regulation will also recognise and regulate the role of storage, as a service for the grid. Transmission System Operators (TSOs) and Distribution System Operators (DSOs) (with some exceptions) will be prevented from owning storage facilities, and TSOs will have to provide non-discriminatory connection of new power plants and energy storage providers.

⁽⁶⁾ https://ec.europa.eu/commission/priorities/energy-union-and-climate_en

4 Ammonia Production

Representatives from **Yara International ASA** and **OCI Nitrogen** took part in the Ammonia session of the Workshop. For both companies the main driver behind the adoption of green hydrogen is decarbonisation of the industrial processes and the reduction of GHG emissions currently associated with ammonia production.

Both companies have activities linked with the development of a more sustainable ammonia and nitrates production chain: a dedicated decarbonisation program reaching from production processes to field applications for **Yara**, and several innovative industrial projects (Power2ammonia/Voltachem projects) and platforms (collaboration within the Dutch Institute for Sustainable Process Technology, Chemelot) for **OCI Nitrogen**.

This section contains consideration of the use of ammonia as a fuel/energy carrier and of OPEX costs originating from the **IEA** presentation.

4.1 Energy requirements

The annual worldwide production of ammonia is about 180-200Mt, and accounts for a demand for about 30-40Mt of hydrogen. China is the biggest world producer with about 1/3 of the world production. European ammonia production is of the order of 20Mt.

In a European context, a tonne of ammonia requires about 8-10MWh (feedstock and energy) if hydrogen is produced using steam methane reforming (SMR). The total energy consumption grows up to 10-12MWh if hydrogen is produced through electrolysis.

When SMR hydrogen production is involved, an average of about 1.6–1.9 tonnes of CO₂ is emitted per tonne of synthesized NH₃. The amount of CO₂ emitted, rises to more than 4 tonnes of CO₂ per tonne of synthesized NH₃ if hydrogen is produced through coal gasification (CG). These emissions could theoretically be completely avoided by the introduction of green hydrogen in the Haber-Bosch process for ammonia synthesis (0.176 (3/17) tonnes of hydrogen are needed for the production of 1 tonne of ammonia).

A standard SMR hydrogen production route consumes about 15% less energy than that required for producing the same amount of hydrogen through electrolysis. About two thirds of the energy consumed by SMR is associated with the conversion of the chemical feedstock. However, if electrolytic hydrogen is used, CO₂ emissions can be close to zero if the electricity source does not carry any significant carbon footprint, i.e. if the electricity is produced by renewable energy.

Greening the hydrogen needed for ammonia synthesis through electrolysis will require a significant and reliable source of renewable electricity. Considering a so-called "global scale" plant producing around 800kt of ammonia per year, the energy consumption of the plant using an electrolyser for hydrogen production will be around 8TWh/year.

An estimate provided by OCI Nitrogen, is that completely greening their annual hydrogen production (more than 1Mt) would require an installed renewable capacity of around 3GW (considering a capacity factor around 50%). This corresponds to the entire currently installed renewable capacity in the Netherlands.

4.2 Technical feasibility

The substitution of fossil fuel derived hydrogen with green hydrogen in the ammonia synthesis process is technically straightforward and does not present any challenge per se. There have been examples in the past (such as the Norsk Hydro Glomfjord plant), and there are currently some ammonia plants running on by-product hydrogen from other industrial processes such as the chlor-alkali process. The thermal balance of the plant does not seem to be critically impacted by the substitution of the SMR step by electrolysis. In particular, steam currently generated as a by-product of SMR can be easily substituted. Water consumption for electrolysis is not deemed to be a limiting

factor for deployment. Water consumption for cooling purposes is estimated to be higher than water consumption for electrolysis.

A significant drawback associated with the production of ammonia from green hydrogen is linked with the intrinsic intermittency of renewable energy production.

Due to the high temperature and pressure involved, the Haber Bosch process (the most commonly used ammonia synthesis route) cannot easily accommodate fluctuations, as it is designed to be run continuously. In order for the installed renewable energy source to constantly sustain the industrial process, it must therefore be oversized as must the capacity of the linked electrolyser. This necessity drives the installed power to values even higher than those discussed above, and/or requires large energy storage options. Using electricity from the grid powered by the current EU-energy mix would significantly drive up GHG emission with respect to a process based on SMR.

The main requirement for the synthesis process is to have a constant nitrogen/hydrogen ratio in the feed. A hybrid (able to run on both fossil and green hydrogen) process would have the advantage of allowing the introduction of hydrogen from renewable sources in a process which is still using fossil fuels as baseload feedstock. Hybridisation could therefore be a first step in the introduction of green hydrogen into the ammonia synthesis process. Electrolysers running on renewable energy could feed a fraction of the total hydrogen demand of a conventional plant. An increase in green hydrogen load can start when renewable electricity is available for the electrolyser, and fluctuations in the supply of hydrogen could be accommodated by using a new overall process design with a high turn-down ratio ⁽⁷⁾.

4.3 Economic considerations

An ammonia plant running on SMR-produced hydrogen attributes around 60% of its CAPEX to the SMR installations. An annual production of about 1Mt of hydrogen would translate to an investment of the order of 1-1.5 billion euros. Switching to hydrogen produced by electrolysis is estimated to require investment up to 4 times higher: electrolysis (depending on the assumptions employed 1.5-3 billion euros) and dedicated infrastructure (about 1 billion euros). However, the CAPEX for electrolysers is on a decreasing trend, and is expected to approach that of a typical SMR installation. This CAPEX does not include renewable energy production infrastructure.

The Levelized Cost of Ammonia (LCOA) produced using green hydrogen is estimated to be 2 to 5 times that of ammonia produced through a conventional process. This costing takes both CAPEX and OPEX into account; OPEX is nevertheless expected to have the biggest impact, and it should be noted that green hydrogen coming from electrolysis is dependent on the renewable electricity cost. From an economic point of view, access to cheap methane makes the production of ammonia particularly convenient in certain areas of the world (such as the US Gulf Coast and the Middle East, with hydrogen reaching a cost of less than 1USD per kilogram), this provides an economic barrier to the market introduction of a product based on the use of green hydrogen. This cost gap becomes insurmountable if GHG emissions are not penalised worldwide and the carbon intensity of the final product is not taken into account by the market in its entirety (this should include all ammonia value chain operators e.g. agriculture, food producers). Ammonia profit margins are small, and without incentives, it is unlikely that ammonia produced using green hydrogen could be economically sustainable in the short to medium term. This situation is nevertheless going to be heavily impacted by the development of CO₂ prices, possible import restrictions on products with high carbon intensities, and the evolution of gas prices in a global context.

Since the cost of a transition to ammonia production using green hydrogen is high, and the profit margin on the product low, without incentives and support for investments,

⁽⁷⁾ The ratio between the maximum and the minimum operational process capacity.

ammonia producers will not be able to face the necessary transition costs and remain competitive at a global level.

4.4 Urea and Nitrates

Another important point to consider is that in conventional ammonia synthesis, based on hydrogen produced from fossil sources, CO₂ emissions can be captured and subsequently used as feedstock for the synthesis of urea. Urea synthesis has the potential to capture and use up to ~70% of the emissions from steam methane reforming. Opportunities for CCU are often already exploited by coupling a SMR-based ammonia production process with urea production.

Urea is the most commonly used fertiliser in the world, but only makes up about 23% of European demand (nitrates account for about 45% of European demand) [9].

The CO₂ is not stored indefinitely in ammonia derived chemical products, but it is released again during product use. The time scale of storage, if CO₂ is captured in urea, is only of the order of 6-12 months, while if other products such as melamine (produced from urea and used as a polymer precursor) are synthesized, the storage time can be 20-50 years.

Urea synthesis, with ammonia production completely based on green hydrogen, will have to be coupled to new, sustainable sources of CO₂. Even if urea production will decrease as a consequence of green hydrogen introduction for ammonia synthesis, this should not be a major issue. There is the distinct possibility that fertilisers based on urea could be replaced by fertilisers based on nitrates in the coming years. However, any shift of this magnitude should be established by taking into consideration several field-application factors impacting the whole fertiliser lifecycle, such as fertiliser efficiency, and land use change, and not be limited to considerations based on its production cycle.

Nitric acid (the base for the production of nitrates) is obtained by oxidising ammonia through the Ostwald process. The oxygen produced as a by-product of water electrolysis cannot be used as a feedstock for the Ostwald process due to its high purity, and would either be released in the atmosphere, or be sold. It should also be considered that a potential stream of oxygen is already available from the air separation-unit used for obtaining the nitrogen employed in the ammonia synthesis process. The Ostwald process is also not designed for variable operation and intermittency must be limited as much as possible.

4.5 Future use of ammonia as Fuel/Energy carrier

The use of ammonia as a synthetic fuel/hydrogen carrier was touched upon as a possible future development. Thanks to the considerable industrial experience available, ammonia could be used as a hydrogen carrier and be thermally decomposed in order to obtain hydrogen. The main advantage of such an option is the significant industrial experience available and the easier storage of ammonia compared to hydrogen. Furthermore, the more efficient capture (with respect to CO₂) of nitrogen from air makes this option more energetically favourable than other CCU pathways involving CO₂ capture (from air or from fumes) and the subsequent production of synthetic fuels. The main drawback of such a choice is the energy efficiency of the whole conversion cycle (electricity-ammonia-hydrogen), and the safety dimension associated with ammonia use in the transport sector.

4.6 Hydrogen/Energy Supply Possibilities

Currently European ammonia plants are built in close proximity to fertiliser production sites, but not necessarily close to sites rich in renewable electricity. Several options could be available for sites which are not in proximity to abundant and available renewable resources. Hydrogen could be produced centrally and transported to the consumption sites. This hydrogen production option could still be based on fossil fuels, provided that

CO₂ emissions can be captured and stored. Alternatively, renewable electricity could be transported to the ammonia production site. If the fraction of renewable electricity distributed by the grid grows, hydrogen production through this option could become increasingly feasible. A third solution could involve ammonia synthesised at new advantageous sites and transported to fertiliser production sites. A fourth hypothetical scenario would involve the partial or total displacement of new ammonia-production and ammonia-consumption (fertiliser production) sites. For the last two options, it is possible that advantageous locations outside European borders could be exploited. If these scenarios materialise, it will be necessary for Europe to provide requirements on the carbon footprint of the imports, so that these are produced according to standards which will provide a "level playing field" and will prevent carbon leakage outside of European borders. Each scenario has specific uncertainties and challenges.

In particular, a scenario involving ammonia production in remote places offering large amounts of available renewable energy, and subsequent transfer to where demand is present, might present other specific hurdles. It was noted that, even if the remote location should favour the direct availability of renewable energy for ammonia production, the lack of infrastructure will likely have a negative impact on this production option. Since production has to be continuous, significant investments in storage will have to be made too. Another remark made, is that Europe does not seem to have many of such sites, and this production opportunity is likely to be located outside European territory.

It seems highly likely that solutions will be developed progressively, and will follow market incentives and possible developments in the use of ammonia as an energy carrier. Probably capacity for green hydrogen will be gradually built up, and process flexibility (electrolysis/SMR) will be privileged, at least in a short to medium time frame.

5 Steelmaking

Representatives from **ArcelorMittal**, **HYBRIT**, **Salzgitter**, and **Voestalpine Stahl Gmbh** took part in the Steelmaking session of the Workshop. **Thyssenkrupp Steel Europe** did not attend, but answered the questionnaire.

For all these industries the main driver behind the adoption of green hydrogen is the achievement of the decarbonisation of the industrial process, and the decrease of GHG emissions currently associated with steel production. The achievement of this goal will require the development of new production processes, significantly different than the existing techniques, which currently do not allow for substantial margins for improvement. The steelmaking process is made up of different integrated steps. The following discussion focuses mainly on the key segments of the whole steel production chain, without considering in detail other important process steps which have a minor contribution to energy consumption and GHG emissions, such as pelletizing and rolling.

Several activities involving the development of a more environmentally sustainable steel production chain are ongoing: SALCOS and GrinHy (FCH JU project) for **Salzgitter**, **HYBRIT** itself is a joint venture between SSAB, LKAB and Vattenfall, H2Future (FCH JU project) and SuSteel for **Voestalpine**, Carbon4Pur and Steelanol for **ArcelorMittal**, and Carbon2Chem for **Thyssenkrupp**.

Since the introduction of significant amounts of green hydrogen in the steelmaking process requires a different production chain from the one currently used, the technical feasibility of a new process employing significant amounts of green hydrogen will be described before any energy considerations for the sector are provided. Despite the different layout from the other sections in this document, this should improve clarity and provide the reader with the appropriate context for the information presented.

This section refers to contributions from **FZJ** and **JRC/RUG**. The presentation from **FZJ** has been used as a complementary source for energy and emissions comparison between conventional and hydrogen-based processes. The presentation from **JRC/RUG** has been used as a complementary source for the section touching upon CCU and CCS and the potential introduction of hydrogen in the steelmaking process.

5.1 Technical feasibility

Reduction of iron ore (iron oxides) is the first step required in steel production. Currently carbon in the form of coke is used as the main reduction agent inside the blast furnace (BF). It is possible, and has been demonstrated, that hydrogen (pure, or present in syngas) or methane can be injected in the blast furnace and act as reducing agents. It is not possible to completely substitute coke with other reducing agents, although a partial decrease in GHG emission from the BF is possible. One estimate suggests that a reduction of about 20% in emissions from the blast furnace is obtained by injecting 27kg of hydrogen per tonne of pig metal produced [10].

It is also possible to reduce the ore through a **direct reduction process**. A Direct Reduction Process (DRP) ⁽⁸⁾, performed for instance with shaft furnaces, can directly use gaseous reductants such as hydrogen or natural gas (producing CO and hydrogen in-situ through reforming) as reducing agents, and completely avoids the use of coal. Our discussion will refer only to technologies (for instance MIDrex, HYL, or ULCORED) where direct reduction is obtained through a gaseous reducing agent, and coal is avoided.

It has to be noted that the CIRCORED plant, an iron ore reduction process based on fluidised bed reactors and designed to be operated with 100% hydrogen, was mothballed

⁽⁸⁾ In this document, DRP instead of the most commonly used DRI-process (Direct Reduced Iron) definition, will be used for consistency with the material presented during the workshop. At present DRI is mainly produced outside Europe, and accounts for about 60Mtonnes/y of worldwide steel production.

by ArcelorMittal in 2017. ArcelorMittal remarked that the plant had several operational and cost issues and never worked with 100% hydrogen.

Reduction of the iron ore with hydrogen is endothermic, whereas reduction with CO (produced by partial oxidation of coke coal) is exothermic. This implies heat must be continuously supplied from an external source during the ore reduction process if hydrogen is used as a reducing agent.

When iron sponge is produced through direct reduction processes, it has to be fed into an Electric Arc Furnace (EAF) for final processing. It is important to note that if 100% hydrogen is used as a reducing agent in the DRP, all the carbon needed for steel production has to be introduced in the final EAF step.

In terms of reducing agents, about 1kg of carbon is needed for the production of about 2kg of liquid metallic iron (BF+BOF process), while 1 kg of hydrogen (DRP+EAF process) is estimated to produce around 15kg of solid metallic iron. These values account for the consumption of real industrial processes.

The use of renewable energy is considered by the steelmaking industry to be a practical option for reducing GHG emissions. A potential advantage of DRP is that the final product is solid (iron sponge), whereas pig iron, obtained at the exit of the BF, is liquid. Considering the intermittent nature of renewable energy production, a solid product in principle allows an easier process management if stockpiling opportunities are exploited when extra production capacity is available.

The DRP process can simultaneously use methane and hydrogen as reducing agents. It is therefore possible to partially substitute one gas with the other, and use varying ratios according to their availability. This option should increase the overall flexibility of the production process and partially decouple the process from the fluctuating availability of renewable energy.

Another possible method for iron ore reduction involves a process based on **hydrogen plasma smelting**⁽⁹⁾. Voestalpine is upscaling a plasma smelting plant in Donawitz. The dimensions of the plant still remain small, with a batch production capability of around 20kg. The maturity of this option is not yet comparable with those mentioned above.

An additional possible use of green hydrogen in the steel production chain is to replace SMR-derived hydrogen currently burned for oxygen removal in inert-atmosphere annealing furnaces, thus preventing air contamination. Any use of green hydrogen in this context will depend strongly on its production cost which should be benchmarked against the current costs of hydrogen obtained through on-site SMR production (around 1.5-2€/kg).

5.2 Energy requirements

The European production of steel is around 168Mt per year. This accounts for about 10% of world production; China is the world leader with a share of ~49%. About 60% of Europe's production capacity is obtained through a consecutive combination of Blast Furnace (BF) and Basic Oxygen Furnace (BOF) technologies. This method is estimated to require about 16-19.8 GJ of energy per tonne of steel produced (4.4-5.5MWh), with almost all of this energy provided by fossil fuel sources (coal) and emitting 1.6-2.2 tonnes of CO₂ per tonne of steel produced⁽¹⁰⁾ (of this about 1.1 tonnes is emitted by the blast furnace). The steel industry is estimated to contribute to about 6-7% of global GHG emissions. Steel can also be obtained from scrap metal using Electric Arc Furnaces (EAF). In this case, electricity is the source of the energy used. In Europe, about 40% of steel production involves EAF use.

⁽⁹⁾ In this technology iron ore is reduced to liquid iron by using an electric arc argon/hydrogen plasma.

⁽¹⁰⁾ Considering the industrial process in its totality

Global steel production has been increasing consistently throughout the years. It is estimated that around 10 tonnes of steel stock are needed for each European person (considering a personal consumption of 400kg of steel/y and a stock lifetime of 20-25 years). Therefore, it seems unlikely that future steel needs will be completely covered without production of new steel.

Any effort aimed at significantly reducing the GHGs emissions of the steelmaking process will have to integrate significant amounts of renewable energy. The highest potential margins for GHG reduction are offered by a steelmaking process based on the combination of DRP and EAF. The two steps of DRP and EAF are at the core of the steel fabrication process, but green hydrogen can play a significant role only in the first case, as a reducing agent, while the rest of the energy required will have to derive from renewable electricity. When hydrogen is produced from electrolysis and renewable electricity, the whole steel production process is estimated to need between 3.5-5.4MWh per tonne of steel; electrolysis will amount to about 2.6-2.7MWh (about 50-77% of the total energy consumption) per tonne of steel. This is a similar, if not lower, energy consumption than the BF+BOF route, and it completely replaces fossil fuels with electricity ⁽¹¹⁾.

The reduction of GHG emissions for the combination DRP+EAF, with respect to the well-established combination BF+BOF, is expected to be significant: about 35%, if only natural gas is used, and 80-95%, if more than 50% of reduction gases are composed of green hydrogen (depending of the green hydrogen share used as a reducing agent). The carbon footprint of the electricity used for both electrolysis and EAF will have a considerable impact on the actual process emissions.

It seems clear that a complete transition from the current steel production process based on a BF+BOF combination, to a new one potentially integrating significant amounts of renewable energy, will require the current legal and economic framework to be changed favourably. The DRP+EAF option is technologically mature, It is expected that a gradual transition will begin to take place in the following years. HYBRIT estimates that between 2025 and 2035 the production of steel on its site will be completely covered by a DRP+EAF process, totally powered through green hydrogen and renewable electricity. By 2045, Sweden has the ambition to be completely fossil-free and all Swedish steel production should be decarbonised by then. It is estimated that for Sweden, a complete greening of the steel production would require around 15TWh/y of available renewable electricity.

Voestalpine estimates an additional requirement of 33TWh/y (100% capacity factor), in order to introduce green hydrogen throughout its steel production.

Salzgitter envisages a gradual replacement of the BF+BOF route with a DRP+EAF route, initially employing mainly natural gas as a reducing agent, and gradually introducing electrolyzers for hydrogen production. This process could start in the 2020s and reach completion by 2050. For a final total reconfiguration of the existing plants and the use of a mix of 55% hydrogen produced by electrolysis and 45% natural gas, the estimated electrical power consumption is 12.4TWh/y (8.8TWh/y used for electrolysis), with an additional requirement of 23PJ/y of natural gas.

A total European steel industry conversion towards a hydrogen-based reduction route, will require 400-500TWh/y for almost total emission abatement (95%), around 260-300TWh/y would be required in order to use a 55% hydrogen and 45% natural gas mixture, resulting in an abatement of about 80% of current emissions.

5.3 Economic considerations

The OPEX for a DRP+EAF based process running on hydrogen is estimated to be about 80% higher than that of the current reference production, that is a Blast Furnace

⁽¹¹⁾ In order to produce steel, some carbon has to be added in the EAF step.

combined with a Basic Oxygen Furnace (BF+BOF), which is based mainly on coal use. OPEX for a DRP+EAF based process running on natural gas is expected to be about 30% more than that of a BF+BOF process.

Currently, the cost of 1kg of carbon is around 0.25€. Since the cost of SMR-derived hydrogen is around 1.5-2€/kg, and electrolytic hydrogen, depending on electricity prices, can be even higher, then hydrogen cost is going to impact its use as a reducing agent. It has to be noted that the carbon-based BF+BOF process (including downstream rolling mills) is usually self-sufficient in its electrical energy consumption, since process off-gases are consumed in on-site power plants. On the contrary, the DRP/EAF process does not produce off-gases suitable for power production. Hence all power consumed has to be provided.

The CAPEX needed for a green-field DRP+EAF installation setting up a flexible (natural gas and hydrogen from electrolysis) production plant based on DRP and EAF, is roughly estimated at around 10 billion euros for a production plant of about 7.5 Mtonnes of steel/y. These costs are lower for brown-field installations already working with DRP-based processes. In both cases these costs do not take into account infrastructure for renewable energy production.

It is estimated that higher OPEX costs will only marginally affect the price of end-products in production chains using steel. Even if the final consumer is only expected to be affected on a comparatively small scale, the decarbonisation efforts of the steel industry will be accelerated if encouraged by incentives and safeguarded by the creation of a European "level playing field".

It seems unavoidable that any transition from the well-established and currently fully integrated and optimised BF+BOF process towards a DRP+EAF process will have to be gradual. Introduction of hydrogen can also be approached progressively, with the readily available natural gas offering a more economic initial solution for reducing iron ore in the DRP.

5.4 CCU and CCS

Alternative decarbonisation approaches involving the steelmaking process have also been envisaged.

One option is the use of captured CO₂ emissions together with methane for a plasma assisted dry reforming step before the obtained syngas is injected in a conventional blast furnace.

Another possibility is the capture and transformation of the carbon emissions (CO and CO₂) from the conventional process (BF+BOF). These emissions can subsequently be combined with either stranded hydrogen from other industries, with hydrogen already available from a conventional steelmaking process (the emissions from a coke plant contain ~64% hydrogen), or with green hydrogen, and used for the production of methanol. Methanol is an important chemical commodity, which can be used directly as a fuel or further transformed to other chemicals. China seems to be extremely active in this field.

Due to a high energy demand, this CCU route has been criticised as a non-efficient way for reducing GHG emissions. Some participants estimate that by using surplus green electricity in a production process, instead of using a fossil fuel based conventional process, the emissions abated by using a functional unit of 1 MWh of electricity with a DRP+EAF combination are about 4 times higher than those of methanol produced following the CCU route and using the same amount of electricity ⁽¹²⁾.

⁽¹²⁾ Salzgitter data based on the methodology of Sternberg, Andre and Andre Bardow, "Power-to-What? - Environmental assessment of energy storage systems". *Energy & Environmental Science*, 2015. 8(2): p. 389-400.

Other participants expressed the opinion that, following a CCU route based on captured emissions coming from a steel plant based on a BF+BOF process might be advantageous. This should be particularly true when the CCU route avoids the flaring of valuable gases such as hydrogen, or when the electricity needed for green hydrogen production would imply that a corresponding amount of renewable electricity cannot be used directly and more efficiently in another sector, without the losses associated with electrolysis ⁽¹³⁾. However, the hydrogen available in the emissions from a BF+BOF process route is not enough to achieve full conversion of the emitted CO₂. Therefore, a CCU route will have to rely on extra hydrogen, either produced by electrolysis or provided by other industrial processes.

In addition to these considerations, it should be noted that the emission captured through a CCU route (e.g. methanol produced by CCU) will only be deferred to another sector or consumer, rather than being completely avoided, unlike with a DRP+EAF route employing green hydrogen.

5.5 Hydrogen/Energy Supply Possibilities

Since the amount of electricity envisaged for reducing GHG emissions from the steelmaking industry is considerable, any new steel production process will require a significant effort in securing suitable amount of generated renewable energy, and it will need substantial strengthening of the electrical grid. Hydrogen supply could be achieved either through on-site electrolysis, or through a purposely developed hydrogen distribution grid. In any case, due to the considerable amount of investment needed, it will be necessary to involve energy providers, transmission system operators and national authorities. The impact on the grid and the possibility to exploit and integrate this industrial process for grid services will have to be carefully planned and considered.

Another possibility considered, is to geographically decouple the production of reduced sponge iron (coming from DRP) and the EAF step. In this way, suitable locations for the production of green hydrogen could be exploited.

⁽¹³⁾ An additional advantage of this CCU route is the exothermic nature of the methanol synthesis reaction. The produced heat could, in principle, be available for CCS purposes, and be advantageous if coupled with a conventional steel-mill.

6 Oil Refining

Representatives from **BP**, **PREEM**, and **Total** took part in the Oil Refining session of the Workshop. Also **Concawe** gave a presentation on the work performed for the "Low Carbon Pathways" project, including a vision for integrating green hydrogen in the EU refining system and its potential use for e-fuels.

The main driver behind the adoption of green hydrogen is the achievement of the decarbonisation of the industrial process, and the decrease in GHG emissions currently associated with fuel production.

Several initiatives are exploring the introduction of green hydrogen in oil refining and fuel production processes. Some examples are the activities of **BP** at the sites of Lingen (D) and the Port of Rotterdam (NL), while **PREEM** is active in several national (Swedish) initiatives and task forces. The FCH JU project REFHYNE which is a demonstration of a 10 MW PEM electrolyser (Polymer Electrolyte Membrane) was also mentioned.

This section refers to contributions from **IEA**, **E3M** and **JRC/RUG**. These presentations have been used as an input on the discussion of OPEX costs and hydrogen consumption options.

6.1 Energy requirements

The European refining capacity amounts to ~14 million barrels per day (equal to roughly 2 Mt of crude) [11]. Currently, hydrogen is used in the refining process to remove the sulphur from the final products, or to maximize the conversion of heavier fractions into more valuable products (hydro-cracking).

Typically, the majority of the hydrogen used for these conversion processes is derived from cracking of the crude hydrocarbons, and it covers between 50 to 100% of the hydrogen required. As an example, a supplementary requirement of about 100kt/y of hydrogen has been roughly estimated for all German refineries, which have a joint overall capacity of 106Mt of crude per year.

A medium conversion refinery with a capacity of 10.4Mt oil/year consumes approximately 50 kt of hydrogen per year. In this case, the ad hoc hydrogen production using SMR is around 30% of the total hydrogen produced by the refinery (¹⁴) [12].

The current need for additional hydrogen is usually covered by steam methane reforming (SMR), which produces ~10 tonnes of CO₂ for each tonne of hydrogen produced. Half of these emissions are not coming from fuel consumption, but are intrinsically associated with the reforming reaction itself, and are linked with the fossil feedstock use. This hydrogen is often produced on-site, but there are examples where hydrogen is distributed by third party operators who produce it away from the refining site.

Ad-hoc hydrogen production accounts for about 15% of the current emissions associated with the European refining industry, including CO₂ coming from SMR and fuel consumption.

Completely replacing the 50kt/y of hydrogen mentioned above would require an approximate installed electrolyser capacity of about 340MW, operated with an estimated yearly energy consumption of about 2.5-2.75TWh.

6.2 Technical feasibility

Tackling emissions associated with hydrogen production is one of the easiest, technically speaking, direct steps for decreasing the GHG emissions arising from the oil refining processes. Hydrogen obtained by SMR can be directly replaced with hydrogen produced by electrolysis. Depending on the assets configuration and taking the ReCAP Project

(¹⁴) Including reforming as process units and ad-hoc SMRs.

report [12] as representative of different refining schemes - from a very simple refinery to a high conversion one - the percentage of hydrogen produced ad-hoc through SMR can range from 0% ⁽¹⁵⁾ up to 50% of the total hydrogen consumption. This is the range which could potentially be replaced by green hydrogen, and does not include the amount produced as a process by-product in the refining processes.

Hydrogen demand in the oil refining process is not really flexible. Hydrogen production must therefore be fairly constant and storage options, if green hydrogen production cannot be continuous, are necessary. An intermediate option would be the introduction of a hydrogen production system where SMR and electrolysis are coupled and used flexibly.

Introduction of significant electrolyser capacity in a refinery environment will also have to be carefully assessed from a safety point of view.

6.3 Economic considerations

The use of electricity rather than fossil fuels for hydrogen production has a significant impact on the production costs of the final products. Currently, hydrogen produced through electrolysis is estimated to be roughly double the price of hydrogen produced through SMR (assuming an electricity price of approximately 35€/MWh).

Due to the high cost of electrolytic hydrogen, the industry proposes that its employment should be incentivised by specific policy measures proportional to the amount of electrolytic hydrogen used in the production of lower life-cycle carbon emissions refinery products.

Ideally, an electrolyser should be used as much as possible, and employ renewable electricity, to minimise both the hydrogen's carbon-footprint and its cost. An electrolyser utilisation of about 40-45% already achieves a significant reduction in hydrogen production cost compared to lower utilisation rates. Beyond this degree of utilisation, the cost of hydrogen can only be significantly lowered by reducing the electricity cost. For utilisation below 35%, the hydrogen production cost increases rapidly with decreasing load factors. There is a general trade-off between electrolyser utilisation and electricity costs. It is possible that the final cost of hydrogen produced through electrolysis becomes comparable in cases with high electricity prices and high electrolyser utilisation, and low electricity prices and low electrolyser utilisation.

6.4 Hydrogen/Energy Supply Possibilities

Different refineries will likely choose different green hydrogen supply paths and utilisation profiles, depending on factors such as their configuration and their local circumstances.

It is unlikely that a constant and large scale utilisation of green hydrogen will occur in the near future. In the beginning, only a small percentage of hydrogen produced through electrolysis will likely be available and exploited in refining processes. Following expected general techno-economic developments, with more and more renewable energy introduced and distributed by a larger, more efficient grid, the fraction of green hydrogen used in fuel refining will have the opportunity to grow and, depending on the scenario considered, potentially reach a steady maximum around 2050.

The fuel production process is going to be significantly impacted by the relevant European legislation and oil refiners would like to get recognition for their efforts to reduce refining GHG emissions with green hydrogen use, since legislation puts them under binding targets. The impending target set by the Fuel Quality Directive (end of 2020) for life-cycle emissions reduction of the produced fuel mix is a 6% GHG reduction with respect to a 2010 baseline. It has been estimated that a total replacement of SMR-produced hydrogen with green hydrogen in Germany (assuming a total external refinery

⁽¹⁵⁾ There are refineries where no hydrogen from SMR is being produced.

demand of 100kt/y of hydrogen) should achieve a 0.37% contribution to the German GHG reduction obligation as defined in BImSchG ⁽¹⁶⁾.

At both European and national legislation level, the use of green hydrogen is currently not acknowledged as a possible method for reducing the life-cycle emissions of fuels. The recognition of the role green hydrogen can play, and legislation introducing a clear methodology such as mass balancing to account for its use in refining processes is needed to support its introduction. It is anticipated that regulations other than the EU European Trading Scheme (REDII for example) will offer higher incentives and therefore will be more relevant for the industry than those associated with the European Emissions Trading Scheme.

Legislation should offer viable options for sites which are not in the proximity of abundant and available renewable resources. Renewable electricity does not necessarily have to be transported directly to the refining site; it is therefore desirable that a well-defined system of Guarantee of Origin (GO) or Purchase Power Agreements (PPA) act as a strong enabler for the introduction of green hydrogen in current oil-refining plants and for the introduction of renewable electricity in an industrial context in general. These options should be regulated. It seems unavoidable that electricity providers, renewable energy producers and authorities responsible for integrated industrial sites will have to be involved in any process aimed at the introduction of green hydrogen.

Hydrogen storage options and integration of the electrolyzers with grid services, in particular during the first introduction attempts, will have to be considered and planned.

Introduction of hydrogen produced through electrolysis in the refining process can be an effective first step, not only towards a more sustainable production process for conventional fossil-fuels, but as an enabler of future low-carbon technologies such as production of biofuels with better yields (carbon efficiency), distribution of hydrogen as fuel for Fuel Cell Electric Vehicles (FCEV), and electro-fuels ⁽¹⁷⁾.

⁽¹⁶⁾ "Bundes-Immissionsschutzgesetz in der Fassung der Bekanntmachung vom 17. Mai 2013 (BGBl. I S. 1274)". <http://www.gesetze-im-internet.de/bimSchG/index.html>

⁽¹⁷⁾ Electro-fuels (e-fuels) can be considered as fuels where hydrogen is combined with other molecules, such as CO₂, in order to produce molecules (e.g.: CH₄, CH₃OH, olefins, etc.) which can then be used as fuels for transport applications.

7 General Conclusions

Despite the individual characteristics of the production processes considered, it is possible to express some general remarks valid across the ammonia production, steelmaking and oil refining sessions:

- Currently the market does not explicitly recognise a higher value for products with a lower carbon footprint. In a **global trade reality**, cost is the main driving force behind product fluxes. Use of green hydrogen is, and will remain for some years, more expensive than hydrogen obtained from fossil fuels. Unless products with low profit margins are granted an added value proportional to their contribution to reduced GHG emissions, they will not be able to compete against the currently available commodities. This seems to be especially relevant for ammonia and refined oil products, somewhat less so for steel.
- Introduction of **flexibility** in the industrial production process seems to be the biggest short term technical hurdle, if green hydrogen is to be employed,. Due to the intermittent nature of renewable electricity, green hydrogen production cannot be continuous. This issue can be mitigated by using hydrogen storage, and by devising process routes fed by hydrogen derived from both fossil fuels and green hydrogen. Designing an adjustable process where SMR-derived and renewable-derived hydrogen can co-exist, is likely to be the main short term challenge in terms of process design.
- The development of processes which are able to integrate green hydrogen, will require significant **CAPEX commitments** from industry. This seems to be highest for the steel industry. Also, the development of a suitable infrastructure capable of harnessing an adequate amount of renewable energy and distribute green electricity and/or green hydrogen to relevant industrial locations will need large capital investment. It is unlikely that industry alone will be able to face these challenges. Public funding and cooperation with TSO and energy providers will be required.
- The amount of **electricity** required for greening the products of the three industrial processes considered, through the use of green hydrogen is significant. Today, part of the energy demand is provided by fossil fuels, considering also their role as feedstock. The overall consumption of energy for total or partial substitution of SMR-derived hydrogen with green hydrogen produced by electrolysis is expected to be higher, in comparison with current processes for ammonia production and oil refining, but lower or the same for steelmaking (DRP+EAF).

For all three industries, a process based completely on the use of green hydrogen requires large amounts of renewable electricity production. For steelmaking, natural gas ⁽¹⁸⁾ seems to be a bridging choice on the path towards exclusive green hydrogen utilisation, while ammonia production and oil-refining are already employing natural gas through SMR.

To give an order of magnitude, the energy needed for producing a MJ of hydrogen ⁽¹⁹⁾ through electrolysis using an EU electricity mix, is estimated to be around four times that required to produce the same amount of hydrogen through SMR [13]. This highlights the fact that, in order to be considered "green", hydrogen has to

⁽¹⁸⁾ Natural gas is a fossil fuel (composed mainly by methane) readily available, but SMR as a technology is based on methane consumption. Discussing possible alternative sources of methane is outside the scope of this report, and options like bio-gas or synthetic natural gas currently do not have the possibility to significantly cover industrial demand.

⁽¹⁹⁾ Based on hydrogen Lower Heating Value (LHV), this is about 8.3 g.

be produced by **renewable electricity** which must be additional to what would be consumed anyway; otherwise renewable energy will be diverted from other direct uses, and it will be replaced by electricity produced by burning fossil fuels. Cross-border effects should be carefully considered and possibly evaluated across the whole European territory.

Access to the required quantities of renewable energy is the first step needed before any new process can be considered viable. Europe could have access to renewable energy like wind from the North Sea, but the expected energy demand for a time horizon around 2050, is of the order of one PWh/y ⁽²⁰⁾, if the total process requirements of these three European industries have to be fully covered by green hydrogen. This comprises the current hydrogen needs of ammonia production and oil refining, and the development of a new fully hydrogen-based DRP+EAF steelmaking process.

- **Legislation** should strive to improve opportunities for products with reduced GHG emissions. Use of green hydrogen should be recognised as a viable means for reducing emissions. Tools such as GO and effective methodologies for allocating GHG credits across the current distribution grids (electricity and gas) will have to be developed, before the introduction of innovative process solutions can begin.
- Suitable **system modelling** approaches are required to evaluate solutions for hydrogen production, transport, and use on a regional and global scale. Currently available energy scenarios can deviate strongly in their hydrogen-related assumptions, and therefore reach significantly different conclusions. Special attention will have to be given and general consensus reached on a set of reasonable, transparent, and well-accepted hypotheses concerning hydrogen use and possible alternative pathways. Some constant outcomes seem to be valid nonetheless:
 - Any **CCU** option will also rely on significant production of electrolytic hydrogen and supply of renewable electricity.
 - Decarbonisation through supply of hydrogen based on methane reforming coupled with **CCS** ("blue" hydrogen) would involve very expensive infrastructure for absorbing the carbon capture capacity required by the three industrial processes considered here.
 - Scenarios involving substantial global decarbonisation (>90% GHG reduction) include significant hydrogen use in industry, but also in other sectors (especially transport), directly, or in the form of synthetic fuels.
 - System modelling based on economic considerations highlights **four main drivers** for large scale green hydrogen uptake: lack of availability of relatively cheap CO₂ storage options (CCS allows use of low-priced fossil fuels and achieves GHG reductions in industrial processes); availability of electricity from renewable energies; decrease in the cost of hydrogen technologies (particularly electrolysis and fuel cells); limited biomass introduction. Hydrogen technologies could become competitive with a decrease in both their CAPEX and OPEX ⁽²¹⁾, or alternatively with a more advantageous ratio between natural gas and electricity prices.

⁽²⁰⁾ For 2016, the total renewable electricity production in EU-28 was around 0.8 PWh.

⁽²¹⁾ OPEX for electrolysis is associated with absolute "green" electricity costs.

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List of abbreviations and definitions

BF	Blast Furnace
BOF	Basic Oxygen Furnace
CAPEX	Capital Expenditure
CCS	Carbon Capture and Utilisation
CCU	Carbon Capture and Storage
CHP	Combined Heat and Power
CO ₂	Carbon Dioxide
CH ₄	Methane
CH ₃ OH	Methanol
DRI	Direct Reduced Iron
DRP	Direct Reduction Process
DSO	Distribution System Operator
EAF	Electric Arc Furnace
ETS	Emission Trading Scheme Directive
FCHEV	Fuel Cell Hydrogen Electric Vehicle
FQD	Fuel Quality Directive
GHG	Green House Gas
GO	Guarantee of Origin
LCOA	Levelized Cost of Ammonia
OPEX	Operational Expenditure
RED	Renewable Energy Directive
SMR	Steam Methane Reforming
Mt	Mega tonne(s)
TSO	Transmission System Operator

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