Hydrogen in the Irish Energy Transition: Opportunities and Challenges

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# Introduction

## Types of hydrogen, value, ambition

Nowadays hydrogen is seen as a potential game changer toward the net zero economy, because it is a clean, reliable, and sustainable energy vector. The key value proposition of hydrogen is to use it as an energy-rich and environmentally friendly substance that enables to facilitate the transport and/or the storage of energy and consequently the possibility of using it at a distance in time and/or space from the primary production site. Furthermore, it can also be used as fuel in transportation applications.

A more hydrogen's widespread usage can potentially give a significant contribution to the decarbonization of the future energy system. The Intergovernmental Panel on Climate Change (IPCC) recommends a reduction in energy demand, decarbonization of electricity and other fuels, greater levels of electrification and complementary carbon dioxide (CO₂) removal activities, to limit global warming to 1.5 °C and achieve net zero carbon dioxide emissions by the year 2050.

The incorporation of hydrogen production and storage into renewable energy and traditional energy systems was shown to be feasible even though more expensive than battery bank approaches.

Hydrogen could play a significant role in decarbonizing the iron, steel, and transport sectors in all the EU countries plus Switzerland, Norway, and Iceland, thereby helping to fulfil tight carbon constraints.

Green hydrogen can be used for electricity generation using a fuel cell, a technology that causes no local pollution because the only by-product is pure water.

Green hydrogen production is seen as a possible driver for the integration of more renewable energy sources in the electricity sector and move towards the ‘100% renewables’ scenarios.

Distributed generation and energy prosumers using electrolysers fed through electricity from the grid can improve load balancing and frequency control. Storage of green hydrogen would contribute to allow grid operators and utilities to delay the installation of extra generation and transmission capacity for grid stabilization.

There are four types of hydrogen, obtained using different production processes. They are: grey, blue, turquoise, and green. Comparison between the diverse types of hydrogen is summarised in table 1.

*Grey hydrogen* is obtained by a steam reforming chemical process using fossil fuels such as coal or natural gas. The production of grey hydrogen produces ten tonnes of CO₂ waste per tonne of hydrogen produced. The cost of grey hydrogen is about 1.5 €/kg [30]. The European Commission has a target of replacing the 8 Mt grey hydrogen demand currently consumed in EU as feedstock by 2030 with clean hydrogen. This would require around 400 TWh p.a. of renewable electric power [48].

*Blue hydrogen* is produced by natural gas steam reforming, a process that involves the separation of natural gas into hydrogen and CO₂. In this case, the CO₂ produced can be stored, avoiding the pollution of the environment. The European Commission considers the CO₂ capture and storage as priority breakthrough technology in its Green Deal [30]. Blue hydrogen is supported by the oil and gas industry because its production can utilise their existing facilities [30]. The economist Dr James Richardson observed that there is a hidden cost associated with the residual emissions of CO₂ to be considered when deciding to produce blue hydrogen, because the CO₂ generated in the production process cannot be fully stored. In UK the Government is supporting a mix of blue and green hydrogen. The cost of blue hydrogen is 2-3 €/kg [30].

*Turquoise hydrogen* is produced by means of the methane pyrolysis, breaking down natural gas into hydrogen and solid carbon. Therefore, in this case there is no CO₂ production at all, and the by-product produced is only solid carbon. Turquoise hydrogen technology is currently still at the development stage.

*Green hydrogen* is obtained by the electrolysis of water using only electricity from renewable energies. In this case, the production process in fully green because there is no CO₂ produced, neither in the electricity generation through renewable sources nor in the electrolysis of water to obtain the hydrogen. The cost of green hydrogen is 3.5-6 €/kg [30]. By 2030, the cost of solar hydrogen will decrease up to 0.7–1.8€/kg due to both solar electricity and water electrolysis costs decreasing fast [79].

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Type of Hydrogen | Production process | Advantages | Disadvantages | Cost |
| *Grey* | *Steam Reforming*  stage1: high temperature (700–1100 °C) endothermic reaction:  CH4 + H2O → CO + 3 H2  stage2: low temperature (360 °C) exothermic reaction:  CO + H₂O → CO₂ + H₂ | Production process is well established and cheap compared to other types of hydrogen | Ten tonnes of CO₂ are generated as waste per tonne of hydrogen produced | 1.5 €/kg |
| *Blue* | *Steam Reforming* with capture and storage of the producedCO₂ or carbon capture and conversion | Low carbon emissions when compared to Grey, cheaper than Green | Residual emissions of CO₂ and fugitive methane are present | 2-3 €/kg |
| *Turquoise* | *Methane Pyrolysis*  the natural gas is broken down into hydrogen and graphite or carbon granules | The production process is carbon free (no CO₂ production at all) | Turquoise technology is at development stage | - |
| *Green* | *Electrolysis of water*  2H2O + electricity + heat → 2H2 + O2  Electricity and heat needed for the chemical reaction to happen are generated from renewable sources. | The production process is carbon free (no CO₂ production at all) | Production requires a renewable plant, solar or wind. Costs are currently higher than Blue. | 3.5-6 €/kg |

Table 1 Comparison of the different types of hydrogen

It is worth to notice that diverse definitions of green hydrogen have been given in the literature, which may be different on the one given in this section and that there are currently characterisation initiatives for green hydrogen worldwide, from diverse regulation bodies. Some of these definitions may focus more on GHG emissions reductions rather than the production pathway. The use of renewable pathways to produce green hydrogen is recommended because it results in zero carbon emissions. The French association for hydrogen and fuel cells requires that green hydrogen is produced using 100% renewables from any renewable pathway, such as electrolysis powered by renewable electricity or biomethane. In UK there has been a consultation process regarding a green hydrogen standard, that was taking a technology neutral approach with the goal of reducing CO2 emissions, but it was abandoned and did not result in an official standard. In California, a Low Carbon Fuel Standard was introduced in 2009, with the objective is to improve the air quality and to reduce the CO2 emissions of the fuel mix of 10% by 2020. When used for fuel cell electric vehicles, green hydrogen produces at least 30% lower GHG and 50% lower NOx emissions than new gasoline vehicles (over the entire vehicle life cycle, from the energy and materials used to produce the fuel to the direct tailpipe emissions). Production technologies suitable for green hydrogen include not only renewable electrolysis, but also SMR of biomethane and thermochemical conversion of biomass. The CERTIFHY body proposed an EU wide guarantee of origin policy that aims at increasing the utilisation of renewable energy sources and reducing the GHG emissions. Green hydrogen produces CO2 emissions at least 60% lower than the baseline SMR carbon intensity, that is 36.4 gCO2e/MJ H2 for the past 12 months. The production process can be any renewable pathway meeting the threshold. This definition has also been adopted in the international standard CEN/CENELEC CLS JCT 6 WG1/WG2. Finally, TÜV SÜD is following a similar approach to qualify green hydrogen in Germany, requiring CO2 emissions 35–75% lower than the SMR baseline depending on the production process, which can be either renewable electrolysis or biomethane SMR or glycerine pyroreforming [114].

In Europe it seems that there has been an attempt to promote the use of the blue hydrogen even more than the green hydrogen, that is probably due to the interests of the fossil fuel industry. Blue hydrogen has more limited benefits on the environment and climate when compared to green hydrogen. It should be highlighted that the production of blue hydrogen involves the presence of fugitive methane, which is not captured and stored. Assuming an emission rate of methane from natural gas of 3.5%, the CO₂ equivalent emissions are only 18%-25% less than for grey hydrogen [31]. The actual amount of CO₂ captured when producing blue hydrogen depends on whether the capture applies only to the steam methane reforming (SMR) process of natural gas or also to the flue gases for the energy that drives the SMR process. Despite its higher production costs, green hydrogen is still appealing because the scalability of the carbon capture and storage technologies has not been fully demonstrated yet. In addition, there is another possibility of transforming the CO₂ emitted into other chemical products according to the carbon dioxide reduction reaction xCO2 + yH­­­++ ne- → CxHyOz + H2O, to determine which chemical is better to make, market research is conducted to find out which chemical products CxHyOz are more likely to give the best profits. Some possible choices are Methanol, Ethanol and Ethylene [44].

Furthermore, if the energy strategy is to prioritise renewable sources, then the investments in blue hydrogen technology will not be likely much incentivised. Moreover, green hydrogen can offer a solution to the intermittency of renewable generation. Business cases should primarily consider the costs associated with hydrogen production, storage and transmission, not much the efficiencies of the conversion processes. In a future power system, green hydrogen technology will enable to install renewable generators in locations where wind speed and/or solar irradiation are stronger, to convert the energy into hydrogen and to transport it to locations where renewables would not generate much power. Energy transportation using hydrogen is facilitated by the higher capacity of a gas pipeline (20 GW) when compared to electricity cables (1–2 GW) and its lower costs, being from 10 to 20 times cheaper to build. Even in case of not-so-high conversion efficiencies, the entire process involving green hydrogen would remain ideally more profitable than installing renewable power generators in locations where their yield would be low.

Integration of hydrogen in the current energy systems is still posing some technological challenges which are going to be addressed by the most recent research.

The concept of “hydrogen economy” has been conceived several decades ago, but only in recent years the hydrogen value chain has proved its commercial value for applications that go beyond the chemical industry. The main reasons that have determined the discovery of possible hydrogen’s use for general energy purposes are the dramatic fall in the cost of solar and wind technologies as well as the progressive improvements of both hydrogen technologies and supporting infrastructure. The active interest shown by countries like Japan, South Korea, China and Germany in promoting the growth of the demand and in creating a supply chain, has helped to drop the cost of the whole hydrogen value chain, making it globally an appealing resource for the decarbonisation of society [33].

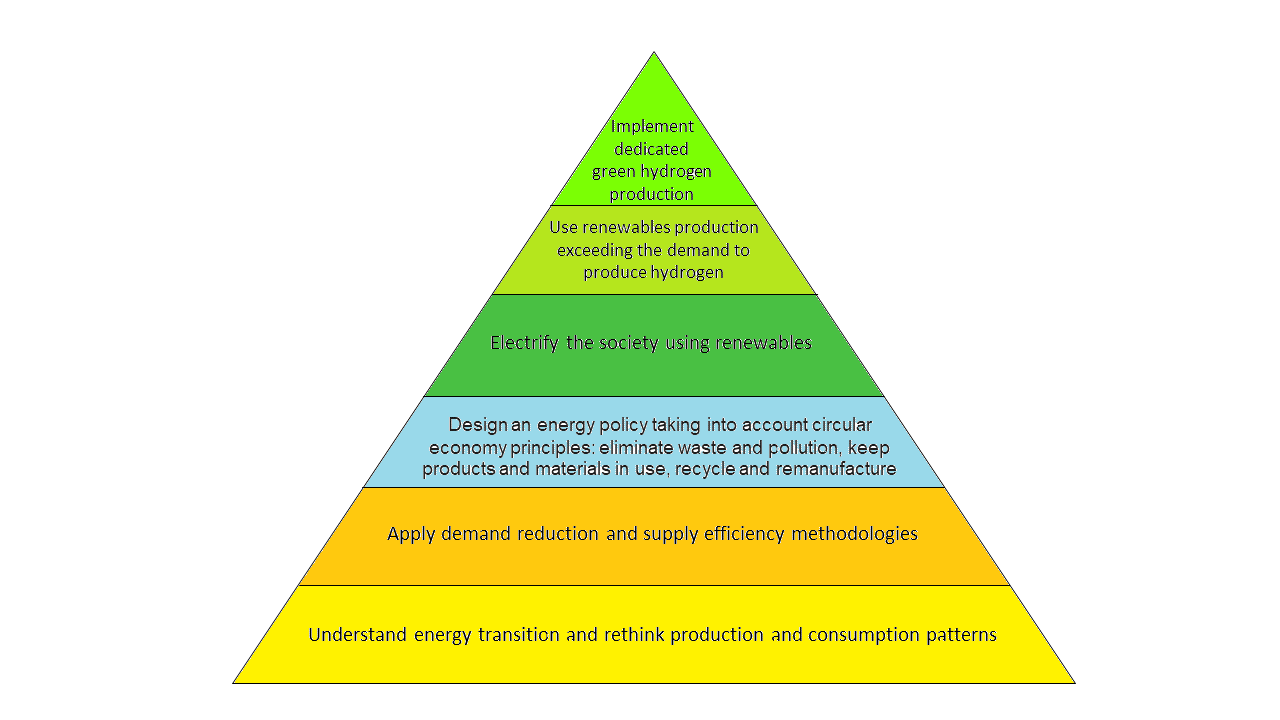


Figure 1 Clean hydrogen triangle

Although hydrogen is undoubtedly a valuable resource for decarbonisation of society, there are other steps that should be given even higher priority before incentivising or developing green hydrogen projects. The whole production of goods and commodities in Europe and the related business models should be revisited to ensure better sustainability, avoid overconsumption, use available resources more efficiently, apply available technologies to reduce energy demand and recycle or remanufacture products. After that this process is complete, the policymakers should incentivise the use of renewables for the electrification of the different sectors. Green hydrogen can be conveniently produced using the excess of power generation capacity, which is not used to supply demand using existing renewable plants. More flexible is the usage of dedicated plants for green hydrogen production. These steps can be represented graphically with the triangle of Figure 1 [49].

## Hydrogen integration in domestic heating, industry, road transport, aviation

According to Chris Train from the UK energy networks association, the decarbonisation of heat remains the greatest challenge. Heating contributes to about one third of the emissions and there are 25 million of homes in UK requiring a low carbon solution. In contrast to the natural gas, the use of hydrogen in combustion boilers of domestic heating systems results in higher heat generation and lower emissions [2]. Hydrogen could be used in domestic heating systems either as a pure fuel or blended with natural gas. While it is believed that blending hydrogen into the existing natural gas infrastructure with concentrations as high as 20%, may result in several advantages related to energy storage, system resiliency, and emissions reductions, the long-term impact of hydrogen on materials and equipment is still unknown. There is clearly a need for some component re-design of domestic gas-fired boilers, especially those which are dependent on hydrogen blending percentage. In fact, to maintain the same thermal load the fuel flow with hydrogen blending must be increased up to more than 3 times and this affects designs of fuel/air mixer and gas valve [3]. Furthermore, if the hydrogen is used as a direct fuel, the combustion velocity is significantly increased with respect to that of natural gas, which makes it challenging the control of the flame in the combustion chamber up to the point that specialized burners are needed to replace those operating with natural gas [2].

Hydrogen has two important applications in industry. It can be used to produce oxy-hydrogen flames and for the reduction of metals from their ores. Oxy-hydrogen flames are obtained from the exothermic reaction of hydrogen with oxygen and are used for welding or cutting non-ferrous metals. Pure hydrogen can be used in a shaft furnace to reduce iron ore thereby reducing emissions from iron and steel production significantly. Moreover, hydrogen reduction is a reliable method to produce a metal precipitating powders from water solutions of metal salts.

Hydrogen is also expected to play a role in decarbonization of road transport, which is today responsible for a high share of CO₂ emissions, plus several other pollutants from the tailpipe, that are harmful to human health. Moreover, road transport is highly dependent on oil-derived fuels and therefore overly sensitive to oil price variations and supply changes. If 80% of road vehicles could be fueled by hydrogen by 2050 the CO₂ emissions would be 50% lower than the usual scenario. However, there are some barriers to widespread adoption of hydrogen fueled vehicles though. The volumetric energy density is lower than gasoline, thus requiring a bulkier hydrogen tank than equivalent gasoline tank to achieve the same range. On the other hand, the efficiency of fuel cells can reach the 50%, whereas that of an internal combustion engine is in the order of 20%, therefore emission reduction could be more than doubled if they were used as a replacement of traditional engines [32]. Compared to battery powered electric vehicles, hydrogen fueled vehicles can be refueled in minutes, whereas charging a battery may require a much longer time (up to some hours, depending on the specific battery technology). However, building an infrastructure for hydrogen production, transmission and refueling is a much riskier and more expensive task than building a recharging infrastructure for battery powered electric vehicles.

In the aviation sector, liquid hydrogen is being considered as a cleaner alternative to kerosene because it produces lower GHG emissions and can be produced from renewable feedstocks. The high-energy content and improved combustion kinetics of liquid hydrogen determine long engine life and low aircraft maintenance costs. On the other hand, because of hydrogen’s low ignition energy and high flame velocity there could be the risk to obtain some traces of unburnt hydrogen during combustion, that could cause metal embrittlement. Finally, there is still some uncertainty on the operating cost of aircraft fuelled by liquid hydrogen because the cost of the fuel depends on the production and storage method and therefore also eventually influenced by specific governmental policies.

The call for evidence will contribute to clarify the current and potential hydrogen utilisation in Ireland for the transportation, industry, and domestic heating sectors (section 4). It will also provide insights on how the stakeholders perceive the benefits of hydrogen consumption with respect to other alternative fuels and energy carriers.

# EU Policy and national policy initiatives on Hydrogen

## The role of European and national policies

The purpose of the EU policy on hydrogen is to foster the good operation of the hydrogen market incentivizing both supply and demand. The policy will have to bridge the cost gap between conventional solutions and renewable and low-carbon hydrogen, also through appropriate State aid rules. Furthermore, the policy is expected to develop a comprehensive support scheme to bridge the gap between market requirements, sustainability and climate requirements, and hydrogen technology development [4].

The policy will increase the EU’s support and will stimulate investments when a sustained expansion of the hydrogen market will take place over a brief period. The EU goal is to establish an open and competitive EU hydrogen market by 2030, removing the obstacles to cross-border trade and enabling a truly efficient allocation of hydrogen supply among the sectors.

The EU also regulates several other aspects that may have influence on hydrogen’s technology diffusion in its Member States and hydrogen EU policy. In fact, the EU sets well defined targets regarding energy efficiency and/or the share of renewable energy in electricity production; it controls the emission trading scheme and in part the European markets for gas and electricity; it also sets minimum levels for energy taxation and subsidizes energy technologies through its regional funds and research projects. Furthermore, the EU has promoted a policy called Trans-European Networks for Energy (TEN-E), which is focused on linking the energy infrastructure of EU countries [96].

The European Green Deal commits Europe to become the world’s first climate neutral continent by 2050. Net-zero requires a full fossil fuel usage elimination. Hydrogen is an opportunity for the gas industry to move to a clean alternative. A 55% emission reduction target in Europe for 2030 is very hard to achieve considering only current renovation rates and the decarbonization of electricity. Hence the importance of a policy which can effectively incentivize the decarbonization of the gas for heating.

At national level, the policy influences the technological diversity, the self-sufficiency, and the secured power generation of a country. In countries with high renewables generation, such as Denmark, the policy target determines whether the country is exporting electricity or hydrogen. In other countries where the main policy target is the self-sufficiency, such as Germany, the hydrogen installed capacity should be increased to meet the target. However, there are countries like Bosnia-Herzegovina, which are highly dependent on energy imports where self-sufficiency would be a target difficult to achieve. In Spain, hydrogen seems not to play a significant role in the power system’s future development; the production exceeding its exogenous demand is exported to other countries. The Spanish strategy is to start with electrification and then use renewables to produce hydrogen only for limited use and in the power system balancing. Portugal plans to decrease its dependency on energy imports from 78% to less than 20% through an increasing utilization of renewable energy. France’s power generation is currently dominated by nuclear therefore diversification of generation technologies is one of the main policy’s targets. Italy has the potential to become a hub for the hydrogen trade because of its central location in the Mediterranean situated between potential major exporters in Africa and the Middle East and the consumers in northern Europe. Italian hydrogen strategy requires up to €10bn of investments between 2020 and 2030 to facilitate the development of a hydrogen-based economy. The goal in Italy is the installation of 5 GW of electrolysis capacity by 2030 and the development of a regulatory framework supporting the green hydrogen production. First experiments regarding the blending of hydrogen in a gas network were conducted in 2019 and they were successful using a percentage of hydrogen by volume of 10% [18].

The TEN-E policy identified nine priority corridors and three priority thematic areas. The goal of the policy is to help EU countries close to priority corridors to collaborate for the development of projects of common interest (PCIs) related to the priority thematic areas (smart grid deployment, electricity highways, cross-border carbon dioxide network), for a better interconnection of energy networks, and to provide funding for new energy infrastructure. The electricity corridors are: the North Seas offshore grid, the North-south electricity interconnections in western Europe, the North-south electricity interconnections in central eastern and south-eastern Europe, the Baltic Energy Market Interconnection Plan in electricity. The gas corridors are: the North-south gas interconnections in Western Europe, the North-south gas interconnections in central eastern and south-eastern Europe, the Southern Gas Corridor, the Baltic Energy Market Interconnection Plan in gas. The oil corridor is the Oil supply connections in central eastern Europe. The Commission has proposed a revision of the TEN-E policy aiming at modernising and upgrading the policy to better reflect the Green Deal objectives and the infrastructure needs to support the development of the clean energy system of the future. Natural gas and oil infrastructures will no longer be eligible for PCI status under the revised version of the TEN-E policy. Hydrogen infrastructures will be among the categories supporting smart electricity grids and low carbon energy solutions.

## The position of the European Parliament and the strategy

The EU Parliament acknowledged that the blue hydrogen has a transition role, even though some members of the Parliament recommend focusing exclusively on green hydrogen. More in general, the importance of carbon capture and storage technologies is recognized, they can contribute to make the heavy industry more sustainable and climate neutral. Moreover, the EU Parliament recommends that the Commission discloses its legal classification of diverse types of hydrogen and that a regulatory framework is established such that hydrogen certification, labelling, origin guarantees and tradability can be readily achieved. The EU Parliament also recognizes the prominent role of hydrogen in the decarbonization of the transportation sector and the related necessity of an adequate refuelling infrastructure [5].

The EU strategy determines short-term vs long-term objectives for hydrogen introduction. Two stages are foreseen, namely objectives to be achieved from 2020 to 2024 and from 2025 to 2030 [1]. The EU strategic objective from 2020 up to 2024 is to install at least 6 GW of renewable hydrogen electrolysers in the EU and the production of up to 1 million tonnes of renewable hydrogen (produced using mainly wind and solar energy). In this first stage, it is foreseen the installation of electrolysers of size up to 100 MW next to existing industrial demand centers such as: larger refineries, steel plants, and chemical plants. They would ideally be powered directly from local renewable electricity sources. Furthermore, hydrogen refueling stations will be used for the uptake of hydrogen fuel-cell buses and, at a later stage, trucks. Electrolysers will thus also be used to locally supply an increasing number of hydrogen refueling stations.

The EU strategic objective from 2025 to 2030 is to make hydrogen an intrinsic part of an integrated energy system with the goal to install at least 40 GW of renewable hydrogen electrolysers by 2030 and the production of up to 10 million tonnes of renewable hydrogen. In this second stage, the plan is to introduce gradually new applications, such as steelmaking, trucks, rail and maritime transport applications, as well as other transport modes. Renewable hydrogen will be used to balance the power system with a high penetration of renewables, by transforming electricity into hydrogen when renewable electricity is abundant and cheap and by transforming back hydrogen into electricity when there is a shortage of electrical power from renewables. Hydrogen’s use for daily or seasonal storage to provide a load balancing function will contribute to improve the supply system’s security in the medium term.

## Initiatives, policies and strategies in European Countries

In UK, the [Government’s Hydrogen Strategy](https://www.edie.net/news/11/UK-Hydrogen-Strategy-published--with-Government-targeting--4bn-of-private-investment-by-2030/) plans to attract up to £4bn of private investment by 2030 in blue and green hydrogen generation, storage and usage and create 9,000 jobs [8]. Large pilot projects underway demonstrate the commitment of the Government in supporting technological developments needed to deploy cost effective hydrogen solutions. The ambition of the Government detailed in the Strategy plans is to scale-up hydrogen production and consumption domestically and supply from 20% to 35% of the whole nation’s energy consumption using hydrogen by 2050, whereas the global average hydrogen utilisation has been forecasted at only 10% [by Bloomberg Intelligence](https://www.edie.net/news/10/Global-hydrogen-investment-to-grow-25-fold-by-2040--Bloomberg-predicts/).

The construction of a new £12.7m hydrogen transmission network research facility starts in 2021 in UK, with £9.07m of funding provided by Ofgem’s Network Innovation Competition and with the remaining amount coming from the other project partners. Ofgem is the Office of Gas and Electricity Markets, a non-ministerial government department and an independent UK Regulatory Authority, recognised by EU Directives. The facility will be making use of several decommissioned assets and will be representative of a gas transmission network. The goal of the trial project is to test hydrogen blending up to 100% at transmission pressures. The testing of the facility will commence in 2022.

Another large project running in UK is HyDeploy [9]. The project will demonstrate the injection of up to 20% volume of hydrogen into Keele University’s existing natural gas network, feeding about 100 homes and 30 faculty buildings, without requiring any modifications of gas appliances.

From a comparative analysis of six EU countries published hydrogen strategies (from Portugal, Spain, France, Germany, Netherlands and Norway), it appears that they differ in scale, sophistication, and ambition level. In the longer term the EU will have to prevent regulatory and competition policy issues, because national hydrogen strategies have the potential to create national or regional hydrogen energy markets, that could easily damage the EU wide hydrogen market and lead some of the countries to a dominant position [21].

# Hydrogen opportunities in Ireland

## Demand & supply reflection and main opportunities

The International Energy Agency published a report that analyses the current state of play for hydrogen and offers guidance for future developments [50]. The report includes data regarding global hydrogen consumption until 2018 showing a million-of-tons steadily increasing demand with super-linear growth. When these data are used for demand forecasting, it can be predicted a total demand covering refining, ammonia and other applications of nearly 200 Mt in 2053 (Fig.2).

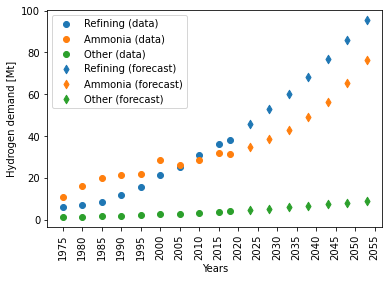


Fig. 2 – Global hydrogen consumption

Ireland is also following this growth pattern being very active in both import and export of hydrogen with other EU countries. Ireland is importing hydrogen from UK, Algeria, France, Belgium and the Netherlands (Fig. 3a) and is exporting it to UK, Germany, Saudi Arabia, Spain and Belgium (Fig. 3b). Ireland was the worldwide 52nd exporter of hydrogen in 2019 with 5.35 M$ exported. In the same year, Ireland was the 40th importer of hydrogen with 23.7 M$ imported. From 2018 to 2019 it was observed a fast growth of [hydrogen](https://oec.world/en/profile/hs92/hydrogen) export markets in Saudi Arabia (413 k$), [Spain](https://oec.world/en/profile/country/esp) (36.2 k$), and [Brazil](https://oec.world/en/profile/country/bra) (33.8 k$) [51].

|  |  |
| --- | --- |
| Fig 3(a) - Ireland import of hydrogen from other countries | Fig 3(b) - Ireland export of hydrogen to other countries |

In addition to existing opportunities in the industry, hydrogen opportunities in Ireland are mainly related to the future development of the electricity generation capacity and the transmission grid to meet the future needs of society [6] and with the transport sector. Pilot projects currently planned in Ireland aim at demonstrating and validating technologies for green hydrogen production, transmission and storage and will involve large operators in electricity and gas as well as high-tech start-up companies.

The policy for hydrogen in Ireland is discussed in the National Energy & Climate plan 2021-2030. The policymaker believes that decarbonisation of the Irish energy system requires to consider coupling between the electricity, heating/cooling, and transport sectors. Green hydrogen may play a prominent role in sectors such as heavy vehicles and maritime traffic, which cannot be fully decarbonised used other means. There is a realistic potential to produce green hydrogen at the scale with a competitive market price, using large scale offshore renewable energy. Blue hydrogen can only be acceptable in case a full capture and storage of the produced carbon can be demonstrated. Grey hydrogen is likely to be considered not good enough to support the transition of the country to a fully decarbonised energy system. The cooperation with other European countries is required to develop the market rules, the safety standards and the cross-border infrastructure required for the development of the hydrogen economy.

Hydrogen could help to integrate elevated levels of variable generation on the electricity system by creating a variable electricity demand that utilises the renewable sources not used to supply other loads to produce green hydrogen, which can be stored in the local gas grid and used for decarbonising domestic heating, transport, and industry sectors.

The national policy supports exploitation of hydrogen technologies to facilitate the integration of variable renewable electricity generation, to mitigate curtailment of wind energy, especially in the electrically isolated regions. Furthermore, the electricity output of waste to energy plants may be used to produce green hydrogen, especially the amount that would be otherwise curtailed because of low demand or high renewable generation. Moreover, there is an opportunity to retrofit existing combined cycle gas turbines to use hydrogen as well as possibility to manufacture hydrogen turbines and use them as backup systems for intermittent renewable sources [107].

Beside hydrogen production, the policymaker considers also important to catch up with the technology development of carbon capture and storage systems. In 2019 a steering group was formed to evaluate the technical feasibility of CCS in Ireland and to develop a relevant policy. There are several sites in Ireland which are suitable for geological storage of CO2; most important ones are the **Kinsale Head depleted gas field** in the North Celtic Sea Basin, the **Portpatrick Basin** in the North Channel and the **Clare Basin** off the west coast.

The Kinsale depleting gas field offers potentially a large storage capacity (330 Mt), which could provide a storage solution for Moneypoint and Cork for up to 50 years. The Kinsale gas field is considered overall a low-risk site, but additional risks apply when considering CO2 storage, such as those ones related to containment and leakage. Leakage risk through existing production wells can be mitigated through application of cement barriers.

The Portpatrick saline aquifer has 37 Mt of effective storage capacity in closed geological structures and up to 2200 Mt of further theoretical storage capacity to be proven up. The 37Mt could be used for Kilroot storage needs for 10 years, which could be extended to 58 years if the 10% of the theoretical storage capacity were available.

Even less explored than Portpatrick is the Clare Basin, since the available geological data do not allow the quantification of the theoretical onshore or offshore storage capacity yet [109]. A Memorandum of Understanding has been recently established between Ervia and Equinor (Norway) and this agreement has received letters of support for a PCI application from various stakeholders: the Dutch Ministry, Athos (Netherlands), Gasunie (Netherlands), Sapling (Scotland), Northern Lights (Norway), UKCCS Research Group, Bellona (Norway) and Port Talbot (Wales). After successfully receiving the PCI status the project applied in Q2 2020 for Connecting Europe Facility (CEF) funding.

The CCS demonstration project has been successfully granted funding under the European Horizon 2020 scheme to develop and assess a carbon capture plant on Ireland’s only oil refinery in Whitegate, Cork harbour. The refinery produces 75000 barrels of oil per day, which cover around 40% of the country’s fuel demand. The refineries contribute about 4% of global CO₂ emissions and are the third sector for CO₂ emission among stationary producers, after power and cement. Refineries will exploit carbon capture technologies to make CO₂ available for either storage (CCS) or use (CCU), allowing to lower the cost of meeting the targets defined in the Paris Agreement by about 40% [110]. The goal of the project is to increase the CO₂ capture from multiple sources in operating refineries, such that 90% CO₂ capture is achieved, and costs are lowered by 30%. Additional funding to allow a study concerning the CO₂ storage potential in the Kinsale Gas Field (and in another potential European location) will be seeked from the H2020 Geological Storage Pilot.

A public consultation regarding CCS has been held with the participation of ESB, Ervia and the Department [108]. ESB has proposed to re-establish the Government’s Interdepartmental Committee on CCS to review the technology from the perspective of Ireland’s low carbon energy future needs. Ervia recommended to ensure that any abandoned wells are plugged such that the reservoir would be suitable for future utilisation as a CO₂ storage or that the need for additional works in relation to the same utilisation is timely determined. The Departments technical advisor agrees that the future CCS potential can only be assessed after carrying out a review of previously plugged wells.

## Hydrogen in electric power generation and supply

The Transmission System Operator (TSO) envisages that many existing peat, heavy oil and coal plants will close over time and will be replaced by gas fired generation, which currently already plays a fundamental role to meet adequacy needs of the country. The Government considers its policy of prohibiting the exploration for and extraction of coal, lignite and oil shale as fundamental to achieve the implementation of a circular economy and has included it as part of Circular Economy Bill 2021 [7]. The growth of combined cycle gas turbine generation quota will determine opportunities for hydrogen blending in the gas grid and the related need of on-site storage of hydrogen. Furthermore, the role of Carbon Capture Utilisation and Storage (CCUS) technologies will be prominent since the Combined Cycle Gas Turbine fleet will be gradually refurbished and the decisions of large investments in new technologies will likely consider also the goal of achieving deep decarbonisation [6]. The roll-out of renewable gas, such as a mixture of biomethane and hydrogen, can reduce the reliance on CCUS, and enable at the same time some decarbonisation of the heat and transport sectors.

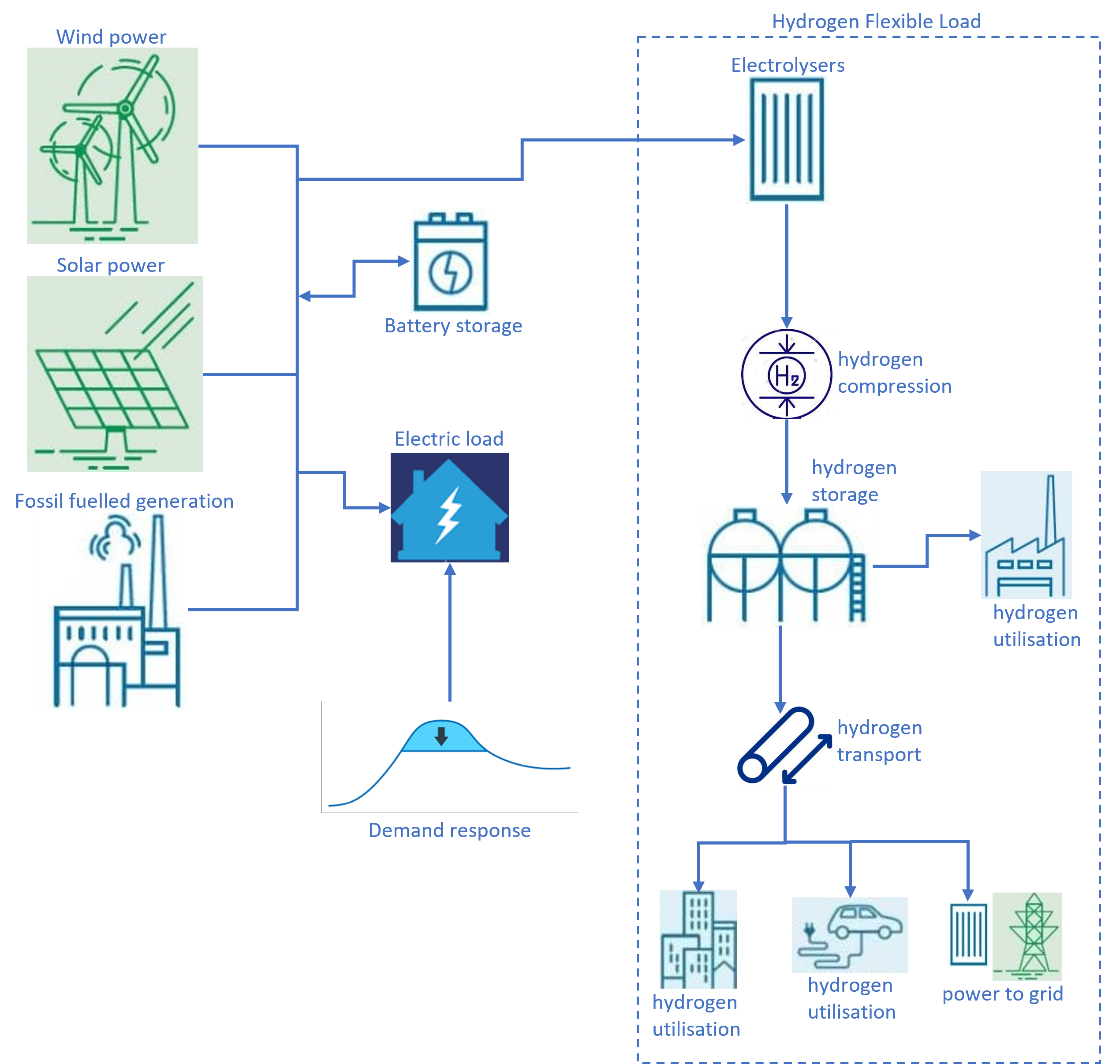


Fig. 4 - Hydrogen production integrated in the electrical grid as a flexible load

The electricity supplier ESB has planned to introduce green hydrogen production and storage in the multi-billion Euro programme Green Atlantic at Moneypoint in County Clare by the end of the decade. The Moneypoint power station is the largest electricity generation station in [Ireland](https://en.wikipedia.org/wiki/Republic_of_Ireland) with an output of 915 MW. It is an only coal-fired power station and the single largest emitter of greenhouse gases in the country. It was commissioned between 1985–87 and it is located on the [River Shannon](https://en.wikipedia.org/wiki/River_Shannon) near [Kilrush](https://en.wikipedia.org/wiki/Kilrush). Green Atlantic is a relatively short-term project which will specifically target the demonstration of hydrogen usage with power generation, heavy good vehicles and multiple manufacturing industries including pharmaceuticals, electronics and cement.

The integration of hydrogen production in the electric grid does not necessarily require the construction of new and dedicated renewable power plants. In fact, electricity that would otherwise be curtailed may be used to supply electrolysers to produce green hydrogen, which can be stored and distributed to the various consumers when demand occurs. In power systems dominated by variable renewable generation supplying both firm and flexible electricity loads the electrolytic hydrogen may represent a new flexible load that can effectively contribute to a better utilisation of the generation assets (Fig. 4). When excess generation capacity is available during most hours, the flexible loads (especially the small ones) can operate at high-capacity factors. The flexible loads such as electrolysis for hydrogen production can contribute to reduce the average cost of electricity by allowing a better exploitation of the generation capacity which was installed for the supply of firm loads. In many system configurations, the variable renewable electricity assets supplying firm loads at current energy costs could supply about 25% or more additional flexible load with 10% or less capacity expansion, reducing at the same time average electricity costs by 10%-20% [95]. On the other hand, the design of a system including hydrogen production using potentially curtailed renewable power is more challenging because if power curtailment occurs only for short periods of time, the electrolysers would work at low-capacity factors when only absorbing the spikes of excess power. Another possibility is to install additional storage to better manage excess generation, resulting in higher equipment costs. The performances of electrolyser plants of diverse capacities with respect to daily hydrogen production using curtailed power are shown in Fig. 5. Fig 5a shows that the amount of hydrogen produced grows with the size of the electrolyser. In order to operate the system exploiting a high amount of curtailed energy, the electrolysers must be coupled with a storage system. The peak size of the storage grows with the size of the chosen electrolyser capacity as shown in Fig. 5b. However, larger electrolysers capacities lead to a better exploitation of available storage capacity as well, with a maximum storage daily utilisation which grows with the size of the installed electrolyser capacity (Fig. 5c). Also, the unused curtailed power decreases when the system size increases (Fig. 5d, 5e). Finally, in Fig. 5f it is shown that utilisation factors of electrolysers decrease when the system capacity increases. There is clearly a trade-off between electrolysers and hydrogen storage implementation costs and the benefits associated with a higher hydrogen production using more curtailed power from renewables. The size of the hydrogen production plant should be determined considering the desired payback time of the investment.

Another short to medium term project is the partnership between ESB and dCarbonX, which will support the development of green hydrogen storage and subsea offshore energy storage technologies in Ireland. dCarbonX Ltd is a geo-energy company based in London and Dublin developing subsurface hydrogen storage, carbon sequestration and geothermal baseload assets to enable the Energy Transition. This partnership will also support the creation of a new ‘Green Hydrogen Valley’ in the Poolbeg peninsula in Dublin.

Many of the existing refining and chemicals production facilities around the world using hydrogen are concentrated in coastal industrial zones, including the North Sea in Europe, the Gulf Coast in North America and south-eastern part of China. These zones and more in general many of the industrial ports could become centres for scaling up the use of green hydrogen. In Ireland, the plan is to build one of the largest green hydrogen facilities of its kind in the world, a 50 MW plant near Aghada, close to lower [Cork Harbour](https://afloat.ie/port-news/cork-harbour-news). The Worley company is going to enter the concept design phase for the plant which will produce green hydrogen by electrolysis using [renewable energy](https://afloat.ie/marine-environment/power-from-the-sea). This facility will have capacity to supply more than 20 tonnes of green hydrogen per day to the local commercial market and to remove 63,000 tonnes of carbon emissions annually [12]. The cost of construction and connection to the electricity grid is expected to be about 120 million euro [20].

Green electric power generation will also be supported by Ireland’s Climate Action Plan through the promotion of all PCI projects under the EU TEN-E policy. In November 2020 Ireland has secured a 360MW hydro-electricity project as one of the EU Projects of Common Interest (PCI) approved by the European Commission. The project will be realised by the Silvermines Hydro in county Tipperary and will enable to supply green electricity to 200,000 homes by means of a pumped hydro storage technology [97].

|  |  |
| --- | --- |
| Fig 5a – Average daily hydrogen production | Fig 5d – Percentage of unused curtailed power |
| Fig 5b – Hydrogen storage capacity required | Fig 5e – Curtailed energy used by the electrolyser |
| Fig 5c – Maximum daily utilisation of hydrogen storage | Fig 5f – Utilisation factors of electrolysers of diverse capacities |

Fig. 5 - Hydrogen production using curtailed wind power (EirGrid data).

## Hydrogen in the transportation sector

The transport sector is the second highest contributor to greenhouse gases emissions in Ireland. For this reason, the green hydrogen produced by electrolysers powered by renewable energy, can play a key role to achieve zero emissions when uses as fuel for heavy goods vehicles and in combination with battery EVs for cars and lighter commercial vehicles. A new company, Hydrogen Mobility Ireland was formed in 2019 by a group of other companies that want to develop fuel cell transport in Ireland. The company is based in Ireland, but it is also working with stakeholders from Northern Ireland. They are testing a hydrogen powered bus on various routes in Dublin. The bus testing involves Bus Éireann, Dublin Bus, Dublin City University (DCU) and Dublin Airport and will be performed from early November to mid-December. The bus is the H₂. City Gold bus manufactured by the Portuguese company CaetanoBus. The bus will be fuelled using green hydrogen produced in Dublin by BOC Gases Ireland [16]. A nationwide hydrogen fuel supply chain (HFSC) including renewable hydrogen production, transportation, and dispensing systems for fuel cell electric buses (FCEBs) could become soon a reality in Ireland. The hydrogen for fuel cell vehicles can be generated by electrolysers located at each existing wind farm using either curtailed or available wind power and by on-site photovoltaic (PV) arrays. The flexibility of the generation power system is enhanced using lithium-ion batteries. The sizing of the electrolyser, PV array and battery can be optimised to minimise the levelized cost of hydrogen. With the current technology, the fuel cost from a distributed hydrogen supply chain may range from 5 to 10 euro/kg. It can be envisaged that the same cost for diesel and H₂-fuelled bus can be achieved by 2030 in Dublin [17]. On the other hand, some concerns exist among the various stakeholders about the fact that wind farms are located far away from most urban centres where H₂ demand for transport is arising. The daily transportation of large volumes of H₂ via diesel trucks through rural roads creates some risks and comes with quite a high carbon footprint; for that reason it may not encounter the full endorsement of the local communities.

## Vision for hydrogen production, transportation and usage in Ireland

The vision for short- medium- and long-term opportunities for hydrogen production, transportation and usage in Ireland should originate from availability of renewables and potential to deploy additional renewable plants, and from the industries that are established in the country.

At European level, there is still a debate on whether low carbon production processes would be still appealing for hydrogen production, in other words the question is whether the blue hydrogen (produced capturing and storing the carbon dioxide emitted in the natural gas steam reforming process) may represent a cheaper alternative to the green hydrogen in the short- to medium- term (since the long-term policy should value only a fully green production based on renewables).

Given the abundance and the potential of renewables in Ireland, it would not be surprising whether the policymaker would prioritise only the green production based on renewables. However, in the medium term the blue hydrogen could be used to stimulate the demand and develop all the end-user services, until more green hydrogen facilities are developed. However, the longer-term vision for green hydrogen and the drop of electrolysis technology prices thanks to scale economy [14], tends to discourage investments in blue hydrogen in Ireland, despite the low prices of natural gas and of the production process.

Long term opportunities of implementing a green hydrogen economy are related to the large-scale deployment of wind and solar energy [11]. An estimation of the amount of feasible wind energy in Ireland gave a figure up to 10 times higher than the country electricity demand, which was 55.4 GWh in 2018 [10]. On the other hand, the utilisation of wind power in 2018 was only 16% of the demand. These considerations about the potential of implementing more wind power plants suggest that wind-hydrogen systems will become a very appealing technology in Ireland. The idea is to use the surplus of wind power exceeding the regional or scheduled demand to electrolyse water and to use the produced hydrogen as a fuel in transportation or to generate again electricity using fuel cells [15].

The environmental goal of a substantial reduction of CO₂ and other harmful emissions, calls obviously for a widespread use of hydrogen in the transport sector in Ireland. As already mentioned, beside using electricity from renewables another possibility to produce hydrogen is through steam reforming of fossil gas. The price of this blue hydrogen is influenced by the evolution of the fossil fuels market and the environmental costs associated with the unwanted residual emissions of the production process. Therefore, the convenience of green hydrogen obtained from renewables’ electricity will be eventually determined by its price difference with the blue hydrogen.

The large potential for green hydrogen production in Ireland could determine a significantly larger utilisation of hydrogen than the global utilisation forecast of 10% by 2050, that would result in a similar scenario for Ireland with respect to UK. However, there are some uncertainties related to political decisions regarding the strategy that will determine the success of hydrogen’s economy in Ireland. The political decisions will also depend on complex factors, such as the electricity market evolution and the successful deployment of infrastructures for road vehicles refuelling.

Blending of hydrogen in natural gas will allow to use the existing natural gas infrastructure consisting in millions of kilometres of pipelines. Gas Networks Ireland has set as one of the 2050 goals the introduction of hydrogen gas into the network and the development of Carbon Capture and Storage (CCS) processes [13]. The plan is to inject 50% of hydrogen into the network thereby replacing half of the natural gas required to meet consumer demand. The CO₂ emissions produced by the remaining 50% of natural gas will be captured and stored using CCS processes. However, the Department of Foreign Affairs has expressed so far strong concerns with respect to the blending of hydrogen with methane in natural gas infrastructure though.

The call for evidence will be used to identify possible regulatory enhancements and the current technology state of the art in Ireland for the different sectors (transportation, industrial, domestic heating). Section 1 will be used to further clarify how a national policy could foster the production and consumption of hydrogen in Ireland according to the stakeholders’ different point of view, what the perceived barriers are, what the expectations or wishes with respect to required proof of concepts and incentives are. It will also be used to understand which application areas are to be prioritised in the short, medium and long term. Sections 2, 3 and 4 are used to gain evidence about production, transportation/distribution and consumption of hydrogen in Ireland and to generate insights about future scenarios.

# System thinking and mapping on hydrogen

## Primary hydrogen stakeholders and their behaviour

The term “stakeholder” indicates an individual, entity or group of people that has an interest, involvement or investment in a certain activity.

Main stakeholders of the hydrogen value chain are: the government, the hydrogen’s producers and the hydrogen’s consumers. In addition, when considering a company producing green hydrogen there are more stakeholders who interact with each other and show an interest in the company’s activities and outcome [21]. The interest of stakeholders goes beyond the profit of the company and involves its interactions with the community and ethics, including the responsibility of improving the climate on the earth. Internal stakeholders are the company’s employees and engineers. The formers are usually selfish but necessary to perform vital tasks for the company’s operations and development. Engineers may be more passionate for their work than other employees and be more involved with their technical projects on hydrogen. Furthermore, there can be other stakeholders who provide funding for project realisation beside the government, such as investors and shareholders.

The main role of the government is that of promulgate an effective policy to reduce greenhouse gases emissions from fossil fuels. In order to incentivise the production of hydrogen by means of a capital incentive paid to hydrogen producers, the government needs to gather taxes from both producers and consumers. Moreover, the government sustains a cost proportional to the health impact of energy and fuel production and utilisation. This cost is reduced when using green hydrogen as a replacement of the natural gas and fossil fuels, because of the low environmental impact of its production process and the zero harmful emissions, when used as a fuel in road transport. Ideally, the government’s goal would be that of minimizing the amount of expenses per unit of GHG emissions reduction considering the incentives paid to hydrogen’s producers.

The green hydrogen producers invest in the electrolysis equipment and in the renewable production infrastructure and operates the system. They receive a revenue that is the sum of revenue from selling the green hydrogen product to the consumer and the incentives received from the government. The green hydrogen producers contribute to the reduction of GHG emissions by producing green hydrogen and at the same time pay a tax to the government which is proportional to their profit. Ideally, the green hydrogen producers want to maximize their profit by investing in the production infrastructure and selling the product to the consumers.

The hydrogen’s consumers are willing to contribute to the reduction of GHG emissions by replacing in part the natural gas used for building heating with hydrogen, and to use road vehicles fuelled by hydrogen. In doing so, each hydrogen’s consumer wants to minimise the additional costs associated with hydrogen’s utilisation with respect to conventional natural gas and fossil fuels. These additional costs may be determined by the charging/refuelling infrastructure, the purchase of hydrogen instead of conventional gases or fuels and a hydrogen tax paid to the government.

A good government intervention should determine a higher capital incentive offered to companies which produce green hydrogen. This way, more producers can enter the market and the price of hydrogen for end consumers can be lowered thanks to market competition and possibly scale economies. Moreover, in a future scenario the government could introduce a regulatory policy for the transportation sector penalising through a suitable taxation the manufacturers or importers of vehicles using diesel or gasoline fuels, with respect to zero-emissions electric vehicles using batteries or hydrogen fuel-cells.

From an analysis of the behaviour of each stakeholder, it is evident that each player will try either to minimise its costs or maximise its profit. In order to incentivise the utilisation of hydrogen, the government will have necessarily to increase the related taxes. Further incentivisation of hydrogen can be obtained by applying higher taxes to conventional gases and fuels than those applied to hydrogen. Also, the promotion and detaxation of scientific research related to hydrogen could help to obtain more efficient production processes, that will eventually determine a lower cost of hydrogen for the consumers.

## Interactions between society stakeholders influencing the hydrogen success

The hydrogen economy success depends on its socio-political, market and community acceptance. The different stakeholders bring diverse perspectives thanks to their knowledge and expertise, which can influence decisions and eventually policies applicable to hydrogen [22].

Socio-political acceptance of hydrogen is determined by public sector stakeholders and policymakers. These actors usually perceive hydrogen as an environmentally friendly substance that can replace fossil fuels. Furthermore, industrial use of hydrogen has determined in some countries an expansion of business activities and the creation of new jobs. These factors have a positive influence on the stakeholders of the public sector.

The residents living in a community or neighbourhood, the local authorities, local agencies, or organisations are the stakeholders that determine the community acceptance of hydrogen. These stakeholders are influenced by aesthetical factors, environmental impact, distributive benefits, and shared costs. They can have a direct influence on the discussion, planning and execution of a hydrogen project.

The consumers, suppliers, investors, firms, and other market players are the stakeholders that determine the market acceptance of hydrogen. These stakeholders are positively influenced by technology demonstration projects showing cost-effective hydrogen solutions. Firms and investors drive the hydrogen technology commercialisation and influence the policymakers in developing favourable policies to their endeavours.

Stakeholders agree on the factors that determine the success of hydrogen industry and therefore can work together to develop them: availability of infrastructures, engagement with local communities, development of regional skills and capabilities, benefits distributed to the community and safe utilisation of hydrogen by the community [22].

An effective governmental intervention at the early stage of the hydrogen economy development could foster the development of pilot projects through incentives and work to make them socially acceptable and well received from the local communities. That way, investors and firms would be more stimulated to make the technology commercially viable. Further incentives could support the subsequent hydrogen industrialisation and allow scale economies to make green hydrogen competitive with alternative technologies and available to everybody.

The different hydrogen stakeholders could contribute to the development of a hydrogen economy showing commitment towards the environment and the reduction of harmful emissions, and their preference of green solutions for the energy consumption and transportation needs when they are made sufficiently accessible and affordable to be used. Stakeholders such as policymakers, industry players, and investors realise that the transition towards the hydrogen economy will not happen spontaneously and are keen to undertake combined and coordinated efforts to overcome the existing barriers related to the legal and policy framework, the environmental impact, available infrastructures, safety, and societal factors [111-112]. Policymakers and industry representatives may work together to define long-term pathways for decarbonization in all the sectors by defining targets for end applications, such as targets for emission of vehicles or targets for the decarbonization of domestic heating, and to determine the necessary infrastructure for energy generation and distribution. Industry stakeholders should work closely with policymakers to develop a strong national market and establish the hydrogen value chains across the EU. They can also cooperate with other industries located in other markets, such as those in the Asian countries to foster technology development and mitigate risks. Moreover, policymakers should also work with gas companies setting targets for renewable products used in the gas grid or regulatory measures such as feed-in tariffs and incentives for green hydrogen utilisation. Moreover, regulations applicable to hydrogen blending into the natural gas grids should be harmonized across different EU countries, whereas hydrogen blending should be promoted through tax exemptions.

Policymakers, transmission system operators (TSOs) and industry should collaborate to establish power balancing markets, where the existing spinning reserves provided by gas turbines are replaced by carbon neutral alternatives, such as flexible green hydrogen production. The development of a fully decentralized power-to-gas market in Europe through stakeholders’ cooperation will determine lower production costs, while establishing more stable prices in the sector, adequate capabilities to manage seasonal power imbalances and a reduced need to curtail renewable generation. At same time stakeholders should explore technical feasibility and opportunities for seasonal and long-term storage, because hydrogen storage comes with a lower footprint than pumped hydro, batteries, or compressed air storages.

Policymakers and regulators should work with industries of the automotive sector to develop the transport sector through coordinated actions promoting a harmonic development of regulations, refuelling infrastructure and vehicles. Relevant regulations include incentives, the public procurement of FCEV buses, fleet regulations applicable to truck, coach, and taxi operators, as well as nonmonetary incentives for FCEV drivers. Sector’s regulations incentivise industry investments in product development such as trucks, buses, vans, and larger passenger vehicles, as well as in their maintenance. If the regulatory stakeholder envisages that with the FCEV number growing the investments in hydrogen refuelling stations will be more profitable and appealing, they should set as a priority the support to product development; on the other hand, if the regulatory stakeholders see the lack of an adequate refuelling infrastructure as an obstacle to the expansion of the FCEV market, they should provide a direct support for the infrastructure development [113].

In the industrial sector, policymakers and industry players should work together to promote the transition from grey to green hydrogen across all the major uses of hydrogen, respectively creating new regulations and implementing the technology for green hydrogen production. Regulations needed by industry should ensure that low carbon targets are applied to chemical processes using hydrogen in industry and that the carbon-free hydrogen production contributes towards renewable targets. Furthermore, stakeholders should develop a standard related to green hydrogen to guarantee that it meets some essential criteria related to requirements for hydrogen production to label it as “green”, the boundaries associated to hydrogen production and utilisation and transportation routes; the chain of custody; the applicable emission intensity thresholds; and the eligibility of production pathways and technologies. Currently, a comprehensive standard does not exist yet, and green hydrogen is sometimes generically associated with production using low carbon energy sources and/or with low environmental impact [114].

Development of more hydrogen and fuel cell applications, as well as plans for their scale up require joint work of industry and policy stakeholders. Such applications include hydrogen utilisation in trains, shipping, and cogeneration in the residential and commercial sectors. Policymakers are expected to establish policies for replacing diesel trains with hydrogen fuelled ones and to set decarbonization targets for ports, rivers, and lakes (target for ocean shipping is set by the International Maritime Organization). Also, policies for energy efficiency in buildings should consider the use of the blended hydrogen and its benefits with respect to natural gas.

All the stakeholders should engage with activities that foster end-users' awareness, information, education, training, addressing thoroughly their safety concerns and knowledge gaps about technology and legal framework. In order to gain end-users' hydrogen acceptance, they also need to contribute to regulations, codes and standards for safety, such as the European CEN/CENELEC/TC 6 standard [112].

The call for evidence will provide further insights about stakeholders’ knowledge and expectations of hydrogen utilisation in different application sectors. The knowledge produced by the call for evidence can be used to further improve the understanding of stakeholders’ expected behaviour and of how they can work together, balancing the different interests, to develop a hydrogen economy in Ireland.

# Innovation, scaling and cost-effectiveness

## Hydrogen technologies for innovation

### Evolution of green hydrogen production technologies based on electrolysis

Electrolysis is commercially a well-established technology that was initially developed for oxygen generation in closed environments, such as crewed space missions and submarines. Most of the electrolyser product development has focused on scale and assembly. On the other hand, fuel cells prototype development deeply requires material optimization, because it is believed that an enormous potential for cost and performance improvements can be seen from current lab and subscale experiments.

The scaling pathways of hydrogen production, storage and utilisation key technologies can be predicted analysing the evolution of prototypes towards commercial products as well as the scale up of the already available commercial products. A distinction between different proposed technologies must be made because they have not reached the same level of maturation and marketability readiness level [29].

Older electrolysis systems operate at low temperature and use as the electrolyte in water, the concentrated potassium hydroxide (KOH). These systems have been built up to the multi-megawatt size and are still in use for niche applications in some large-scale industrial markets. However, they need to operate at balanced pressure and require either mechanical compression of the generated hydrogen or generation of oxygen at elevated pressure. For this reason, electrolysis systems based on potassium hydroxide present additional safety risk related to the high pressure of gases. Furthermore, these systems use a corrosive electrolyte as the circulating fluid and can work with lower operating current densities with respect to most recent systems using a solid electrolyte.

Most recent solid-state-electrolyte-based systems use membranes instead of potassium hydroxide as electrolyte, such as the proton exchange membranes (PEM). These systems can generate electrochemically compressed hydrogen while maintaining the oxygen loop at ambient pressure and can operate at higher current densities than the KOH systems, typically in the range 1.5–2 A/cm2 instead of less than 0.5 A/cm2.

The electrolysis systems based on PEM were available in 2004 in the 40 kW size, whereas 1 and 2 MW systems were released in 2014. After 10 more years, it is foreseen that they would eventually reach the 100 MW scale.

New prototypes are being developed using the Anion exchange membrane (AEM) instead of the PEM. AEM technology is currently less mature than PEM but has potentially some advantages related to the fact that the membrane conducts hydroxide ions rather than protons. This determines a higher pH locally and enables to use a significantly broader range of cell materials and catalyst. The AEM systems have the advantages of both liquid KOH systems and membrane systems: low-cost materials, noncorrosive electrolyte, and low-pressure operation. Since existing stack platforms and balance of plant systems available for PEM technology can be leveraged by AEM, it is foreseen that AEM will mature quickly when suitable materials will be available and that commercial low temperature membrane systems will be a mix of PEM and AEM.

Yet another promising technology for electrolysis cells are the solid oxide electrolysis cells (SOEC) that use an oxide or ceramic material as the electrolyte. These systems operate at much higher temperatures typically 600–1000 °C vs the 50–100 °C of the PEM technology in fuel cell mode, and typically 700–1000 °C vs the 20–100 °C of the PEM in electrolyser mode. The higher operating temperature enables a broader fuel flexibility for the fuel cell and higher efficiency for both the fuel cell and electrolysis operation due to low activation polarization at the catalyst. The efficiency range is of 60-70%, instead of 40-50% of the PEM technology when operating in fuel cell mode, and 81-86% vs 62-82% when operating in electrolyser mode. Furthermore, a non-precious catalyst can be used in the cell compared to the other technologies. When operating in fuel cell mode, the cell generates high quality heat that makes it suitable for combined heat power applications. When operating in electrolyser mode, it can use heat as power supply, which is much cheaper than electricity. On the negative side, the manufacturing a SOEC is more complicated because it requires higher quality materials and sealing. There are few commercial SOEC systems to date, especially used in stationary applications. Preconditions to scale-up these systems and favour their market growth, is to leverage the knowledge of existing commercial fuel cell systems using similar materials with respect to SOEC technology to further develop the SOEC technology. On the other hand, there are differences with the fuel cell and electrolysis requirements as well as with the balance of plant, which does not share the piping and instrumentation layouts and electrical and controls definition used by the low temperature membrane-based electrolysers. Overall, it can be optimistically hypothesized that these systems will have a growth like that of low-temperature systems at best.

### Novel technologies for green hydrogen production using solar energy

Green hydrogen production technologies relying on solar energy are: photoelectrochemical and solar thermochemical. A photoelectrochemical cell combines the functions of a traditional photovoltaic solar cell with an electrolysis cell. This type of cell includes a semi-conductor electrode (the photoanode) that absorbs light and enables to split electrochemically water. The main drawback of this technology is that the photo electrode requires quite a large energy from the solar flux to win the energy band gap and provide the electrical potential required for water splitting, and the electrode surfaces must enable both the absorption of solar light and to catalyse the hydrogen and oxygen chemical reactions. Developed prototypes with size of less than 100 cm2 demonstrated that these devices operate at a low current density, in the order of 10 mA/cm2. The scale up of the photochemical technology is therefore difficult, also considering that no balance of plant has been developed yet at any scale. An optimistic prediction is to achieve 100 kW scale in 10 years and 5 MW scale in 20 years. On the other hand, a solar thermochemical hydrogen plant uses concentrated solar power to heat a receiver and thermally split water at high temperature (about 2000 °C). Solar radiation can be concentrated via heliostat mirrors. Some prototypes of these systems have been developed, but there are currently no commercialization pathways. The preconditions to scale the innovation brought by solar thermochemical hydrogen is to continue the experimentation and improve the understanding of system configuration, standard tests, operating conditions. Solar thermochemical hydrogen technology is considered even less mature than photoelectrochemical, in lag of some years in terms of development. In order to evaluate the effectiveness of using solar energy for hydrogen production, one needs to determine the area of photo-voltaic (PV) panels required to supply the considered demand. This issue is particularly important for the transportation sector, because ideally one wants to generate the hydrogen needed by a refuelling station in a close location such that the costly transportation of hydrogen from remote locations is avoided. Comparing the energy content of hydrogen with that of conventional fuels, it can be estimated that a single refuelling station would require 1000 kg of hydrogen per day, when considering an efficiency of 65% for the electrolysis process and the lower heating value of hydrogen, this quantity corresponds to 51 kWh of electric energy. Considering that 10 sqm of PV panels with 10% efficiency can deliver approximatively 1kWp and that a PV can produce energy for 5 hours/day we obtain that the operation of a refuelling station of hydrogen would require 102000 sqm of PV to be independent on a hydrogen distribution network [40].

### Research on carbon capture and conversion

When analysing the development of hydrogen related technologies, it is worth to mention the fact that carbon capture enables not only its storage, but also the conversion into chemical products. In fact, the CO2 storage using the earth as a huge reservoir may have long term ecological and environmental impacts which are currently not well-understood yet. Moreover, current adsorbents materials technology shows some limitations. Even though various adsorbents have been developed to capture and store CO2, their high regeneration temperatures and/or limited CO2 adsorption capacities still limit the development of such technologies. The alternative strategy is CO2 capture and conversion (CCC), that involves capture and subsequent conversion of CO2 into high valuable chemicals and fuels. Metal–organic framework (MOF)-based materials are emerging as new promising adsorbents and catalysts for CO2 capture and conversion showing excellent capabilities for selective CO2 capture in the presence of N2, CH4, and H2O and other gases. Among the various products that can be obtained by converting CO2, there are intermediate products used to produce engineering plastics, electrolyte solvents for lithium-ion batteries, polar aprotic solvents, degreasers, and fuel additives [46]. Another promising CO2 adsorbent material is the graphite [47]. To conclude this brief discussion about CCC technologies, it can be said that without their development the mission of regulating the CO2 emissions will fail. Therefore, hydrogen policies should not be limited to the green hydrogen only.

## Infrastructure development and scaling pathways for the hydrogen economy

### Hydrogen consumption pathways

The Hydrogen Council, the largest industry-led hydrogen association launched in January 2017 at the World Economic Forum, has set goals and pathways to scale-up hydrogen economy by 2030 and by 2050 in five areas: transportation, industry energy, building heat and power, industry feedstock, energy system [23].

In the transportation sector, one of the main innovations brought by hydrogen are the Fuel Cells Electrical Vehicles (FCEVs) which will become a complement of the Battery Electric Vehicles to achieve deep decarbonisation of the transportation sector. FCEVs will become convenient with respect to BEV because of longer ranges and faster refuelling time. Fuel cells technology will become commercially available in medium-sized/large cars, buses, trucks, vans, trains, and forklifts. However, FCEVs will enter slowly in the automotive market because they are more expensive, may have low quality than other types of vehicles and are perceived as a market entrant technology by many people. It is foreseen that they will gain first success in niche markets, prove their added value to potential clients, reduce their costs, and eventually move into the larger markets [26]. In 2030, there will be globally 10 to 15 million cars and 500,000 trucks powered by hydrogen and 1 in 12 cars in Germany, Japan, South Korea, and California will be fuelled by hydrogen. Trains and passenger ships powered by hydrogen will be deployed. These figures will be significantly increased in 2050, with up to 400 million passenger vehicles, 15 million buses and 5 million trucks powered by hydrogen. In 2050, 20% of diesel trains will be replaced by hydrogen powered trains. The massive usage of hydrogen as a replacement fuel in transportation will result in 20 million barrels of oil replaced per day and 3.2 Gt CO₂ abated per year. The scaling-up of FC from prototypes to commercial products requires that a sufficient capital return and a net positive life cycle assessment are achieved. An analysis of the current technologies reveals that the current manufacturing cost of fuel cells is higher than the cost of internal combustion engines, whereas their operating costs can be much lower than those of competing technologies (e.g., IC engines or boilers) because of a higher thermal efficiency of fuel cells. On the negative side, low reliability of fuel cells results in high repair and maintenance costs and may determine a cost increase up to 60% as well as a reduction of availability [28]. FCEVs will follow a commercialisation pathway from 2020 to 2050 prioritising in a first phase the light duty vehicles, followed by freight vehicles and cars. FCEVs will be improved leading to more cost-effective solutions and their market share consolidation [34].

In industry energy supply, hydrogen is the main option to provide decarbonised heat required by the industrial processes. Green hydrogen is the alternative to post-combustion carbon capture and storage. In 2030, 4 million tons additional hydrogen will be used in industry globally, which correspond to 0.6 EJ of energy. It is foreseen that one in ten steel and chemical plants in Europe, North America, and Japan will be using hydrogen. In 2050, the 12% of global industry energy demand will be met using hydrogen, corresponding to 16 EJ of energy. Hydrogen usage will determine the abatement of about 1 Gt CO₂ per year.

Hydrogen will also be used to decarbonize building heat and power in regions with existing natural gas networks. In 2030, 6.5 million households will be heated with blended in concentrations of up to 20% with natural gas or pure hydrogen using about 3.5 million tons and 0.5 EJ of hydrogen. Fuel cell combined heat and power units will be used by 10% of users connected to the hydrogen natural gas network. In 2050, hydrogen will supply the 8% of global building energy demand of heat and power, corresponding to 11 EJ of energy. The amount of CO₂ abated per year will be about 700 Mt. Furthermore, the commercialisation of fuel-cell co-generation units for buildings will begin in 2030 and in 2050 the co-generation units will cover 5% of the residential demand and 1.5% of the services demand [34].

Hydrogen is currently used in industry as feedstock in refining, fertilization, and chemical production processes. The commercialisation pathway of hydrogen’s use in industry will begin in 2030 and in 2050 the 8-11% of crude oil steel production and the 15% of chemical and petrochemical industry will come from hydrogen. In 2050, hydrogen will also be used for iron smelting [34]. Innovations in hydrogen production can lead to the decarbonisation of 55 million tons of grey hydrogen used by the global industry. Steel plants will use about 100,000 tons hydrogen in hydrogen reduction for zero-carbon iron making in 2030. In 2050, about 200 million tons of crude steel (10% of the global production) will be produced using hydrogen, leading to 190 million tons CO₂ savings per year. Furthermore, in 2030 about 2.5 million tons hydrogen will be used to produce from 10 to 15 million tons of methanol and derivatives, including olefins and aromatics. The quantity of methanol and ethanol derivatives produced using hydrogen will be increased up to 30% in 2050 enabling a reduction of 360 million tons of CO₂ per year. Chemical and refining industries will begin the demonstration of green hydrogen use by 2030 and will fully decarbonise their feedstock by 2050, eventually saving 440 million tons of CO₂ per year.

Hydrogen enables cost-effective long-term storage in underground salt caverns. By 2030, 250 to 300 TWh of excess solar and wind power will be converted into hydrogen and 200 TWh will be stored. The excess solar and wind power converted to hydrogen will raise to 500 TWh in 2050, which correspond to 1.5 EJ of hydrogen energy, whereas the storage will be 3,000 TWh of hydrogen (18 EJ) in 2050. The power plants will produce from 100 to 200 TWh of dispatchable power using green hydrogen by 2030, whereas the predicted production in 2050 is 1,500 TWh from 9 EJ green hydrogen. Ships will transport 100,000 tons hydrogen per year overseas in 2030 and 55 million tons (8 EJ) in 2050.

The achievement of these ambitious targets will be determined by a significant development of the hydrogen infrastructure, with a foreseen market of 2.5 trillion dollars for hydrogen and fuel cell equipment and globally employment for more than 30 million people.

### Hydrogen production pathways

Innovation in hydrogen production may affect several aspects such as: source, system, service, scope, staff, scale-up, safety, scheme, sector, solution, stakeholder, standardization, subsidy, stimulation, structure, strategy, support, and sustainability. These aspects were named the 18s concept in [24]. An innovative system should achieve sustainability performances by improving efficiency, cost-effectiveness, resources use, design and analysis, energy security, environment [25].

The worst sources in terms of harmful emissions to obtain hydrogen are the coal and natural gas. On the other hand, wind, solar, and hydro sources give the lowest emissions. However, coal and natural gas are the most mature and commercialized technologies with better process efficiencies and lower costs than wind, solar, and hydro. When considering multiple criteria, such as emissions, efficiencies, cost, renewability and multigeneration, the best performing sources are geothermal and biomass, followed by hydro and solar. Coal, nuclear and natural gas are the sources that overall perform the worst.

Pathways in hydrogen production are determined by several criteria related to: cost minimization, emissions reduction, system size decrease, improvement of reliability and durability, improvements of service, training, and maintenance programs, improvements on safety, standardization and certification, increased efficiency, better quality of produced hydrogen. Lowest emissions are achieved by photonic hydrogen production systems whereas thermochemical has the highest emissions. Thermochemical processes have the lowest costs, whereas photoelectrochemical systems have the highest. Thermolysis has the highest efficiency, whereas photocatalysis has the lowest efficiency. When the multiple criteria are considered, thermo-chemical systems are the best performing, followed by photo-fermentation and artificial photosynthesis. The lowest performances are achieved by photoelectrochemical systems, followed by photocatalysis and thermolysis.

Successful transition to hydrogen energy systems depends on the success of hydrogen service sectors. The potential of the different pathways to support an increasing demand of hydrogen are shown in Table 2 [59]. Note that the preferred production pathway supported by the EU policy is the electrolysis powered by renewable electricity. Green hydrogen’s cost was $6.00 (€5.09) per kilogram in 2020, whereas the predicted cost for 2030 is $2.50 (€2.12) per kilogram, thanks to the high European wind energy productivity [60].

Interesting and worth to mention is the waste pathway towards hydrogen which uses thermochemical and biochemical processes to produce hydrogen from wastes. Waste can produce hydrogen yields up to 33.6 mol/kg and hydrogen concentrations of 82%. Biochemical methods based on fermentation techniques can produce hydrogen up to 418.6 mL/g [77]. A waste-to-hydrogen project has been planned in the island of Martinique to power buildings and municipal buses. Two companies, a global supplier of renewable hydrogen systems (Ways2H), and a Caribbean ecological and energy solutions provider (Valecom) have engaged into the transformation of 9,000 tons of waste per year into clean hydrogen [78].

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Hydrogen production pathway** | **Production processes** | **Advantages** | **Disadvantages** | **Predicted Impact** |
| Thermal-chemical  Pathway (grey/blue) | Natural gas steam methane reforming (SMR) with carbon capture and sequestration (CCS), coal gasification CCS, and biomass gasification CCS | Can achieve low carbon emissions at a low production cost when CCS is available | If CCS is not available in the in the near- or mid-term then CO₂ emissions reduction will not be achieved | High impact on demand fulfilment because the production process is well established |
| Electrolysis powered by renewable electricity | Onshore/offshore wind, ground-mounted or rooftop solar PV and hydropower used to supply power to an electrolyser | Potential to achieve zero carbon emissions. | Technology not mature yet and/or production costs high. Intermittency and variability of renewable energy sources and integration challenges with the electricity grid and energy systems at large scale. | Potentially high because of no carbon emissions and abundance of renewables |
| Solar photo-electrochemical (PEC) pathway | A photo-electrolytic cell is a device using the light incident on a [photosensitizer](https://en.wikipedia.org/wiki/Photosensitizer), [semiconductor](https://en.wikipedia.org/wiki/Semiconductor) (photocatalytic) or aqueous [metal](https://en.wikipedia.org/wiki/Electrical_conductor) immersed in an electrolytic solution to directly produce [electrolysis of water](https://en.wikipedia.org/wiki/Electrolysis_of_water) | Potential to achieve zero carbon emissions. | Technology not mature yet and/or production costs high | Low |
| High-temperature electrolysis powered by nuclear or solar energy | Reverse reaction of the [solid oxide fuel cell](https://www.sciencedirect.com/topics/engineering/solid-oxide-fuel-cell) (SOFC) technology, using higher temperature (800–1000°C) to split water and consumes lower electricity. | Potential to achieve zero or near-zero carbon emissions. Advanced nuclear reactors are ideal to produce cheap and clean hydrogen on a large scale. | Technology not mature yet and/or production costs high. No significant progress in the R&D and deployment of nuclear reactors in more than 20 years. Solar energy requires areas with abundant land resources and good solar irradiance. | Low to medium |
| Thermal water splitting powered by nuclear or solar energy (thermolysis) | Sunlight is concentrated onto a reactor tower using a field of mirror "heliostats,". High-temperature heat (500°–2,000°C) drives a series of chemical reactions that produce hydrogen. The chemicals used in the process are reused within each cycle, such that only water is consumed and hydrogen and oxygen produced. | Potential to achieve zero or near-zero carbon emissions. Advanced nuclear reactors are ideal to produce cheap and clean hydrogen on a large scale. | Technology not mature yet and/or production costs high. No significant progress in the R&D and deployment of nuclear reactors in more than 20 years. Solar energy requires areas with abundant land resources and good solar irradiance and costs are high. | Low, because more research is needed for robust reactor design and improve process efficiency and durability of materials. |
| Biological pathway | Microorganisms such as green microalgae or cyanobacteria use sunlight to split water into oxygen and hydrogen ions (also known as photo-biological method). Hydrogen ions are recombined with electrons and released as hydrogen gas.  [*Artificial photosynthesis*](https://en.wikipedia.org/wiki/Artificial_photosynthesis) is a production process replicating the natural process of photosynthesis, that converts sunlight, water and carbon dioxide into carbohydrates and oxygen. This has been recently used to split water into hydrogen and oxygen using an artificial compound called [Nafion](https://en.wikipedia.org/wiki/Nafion).  *Photo-fermentation* is the conversion of organic substrate to [biohydrogen](https://en.wikipedia.org/wiki/Biohydrogen) using fermentation produced by [photosynthetic](https://en.wikipedia.org/wiki/Photosynthesis) [bacteria](https://en.wikipedia.org/wiki/Bacteria). | Zero carbon emissions produced. | Still in the early scientific research and laboratory testing stage. Low rates of hydrogen can be produced. Water splitting using the photobiological method also produces oxygen that quickly inhibits reaction for hydrogen production.  Photo-fermentation is limited to the difficulty of maintaining a constant temperature for the bacteria in the bioreactor. | Very low |
| Waste pathway | thermochemical (gasification and pyrolysis) and biochemical (fermentation and photolysis) processes applied to wastes | Positive environmental impact, carbon cutting potential, and low Global Warming Potential, reduction of waste to landfill or incineration, alternative to fossil fuels. | High costs of production and operations, inconsistent feedstock, low efficiencies, inadequate management and logistics, and lack of policy support | Low to medium |

Table 2 Comparison of the different pathways for hydrogen production

### Hydrogen transportation pathways

The pathway for scaling-up hydrogen consumption will require the development of an adequate infrastructure for hydrogen transportation. Hydrogen can be transported in different manners, using gas pipelines, marine terminals, shipping, truck loading and by means of rail transportation [52].

Currently, the liquefied natural gas (LNG) can be transported using LNG tankers from the production zones. Gas unloading is performed using specially designed pipelines withstanding very low temperatures (-160°C) and cryogenic tanks for storage. Subsequently, LNG can be converted back to gas in facilities called LNG terminals. Such sea-side LNG terminals can be adapted to hydrogen transportation and be multipurpose. In other cases, hydrogen can be transported in gaseous or liquid form, using respectively gas cylinders or specialised containers or carriers.

Hydrogen can be embedded in liquid organic hydrogen carriers to reduce the need for pressurized tanks for storage and transport. Alternatively, it can be liquified at −253°C, with the benefit of reducing the storage volume because of the density increase by a factor of around 800. Liquefied hydrogen can be stored in pressurized and thermally insulated containers. Other options to transport hydrogen in liquid form are by combining it with CO₂ to produce methanol, and in the form of ammonia by combining it with nitrogen. In the latter case the liquefaction point is at around −30°C, a much higher temperature than the liquefication temperature of the pure hydrogen. Hydrogen can also be transported in gaseous form mixed with other gases in pressurised containers or transported and stored within the existing gas infrastructure when combined with CO₂ to produce methane gas.

The best delivery option for hydrogen depends on the distance to cover; if that is below 1,500km the cheapest transport means is a gas pipeline, whereas above 1,500km a more cost-effective solution may be the shipping of hydrogen as ammonia or by using a liquid organic hydrogen carrier (LOHC). Hydrogen transport using LOHC requires first a hydrogenation process, i.e. the hydrogen loading into the LOHC molecule to form a liquid (at ambient temperature) showing comparable properties as crude oil-based liquids (e.g. diesel, gasoline), and eventually (after the transportation) the de-hydrogenation process, which involves the unloading of hydrogen from the embedding liquid. Dehydrogenation requires elevated temperatures, which determine the consumption of a significant part of the transported energy (as much as 28% of it, corresponding to 11kWh/kg). For this reason, it is advantageous to locate LOCH preparation in places where there is availability of waste heat sources. Although more research on LOHC is necessary to obtain low-temperature de-hydrogenation combined with high storage densities and fast reaction kinetics, some promising LOHC candidates have already been identified. They are the dibenzyltoluene for energy-transport and energy-storage (good availability, non-toxic, easy to handle, energy demand is high though) and N-ethylcarbazole for mobility applications (particularly good process design and gas flow, but storage characteristics are less good). Moreover, other potentially good candidates are toluene for the transport sector (very good storage densities, moderate toxicity, and reasonable low price), and methanol for all three applications (excellent energy storage capability, low energy demand to release hydrogen from the loaded LOHC), but a compromise between de-hydrogenation temperature and gas flow must be achieved with further R&D work [57]. The costs of hydrogen transport are estimated to be between 0.11 and 0.21 €/kgH₂/1,000km when using a newly built transport infrastructure.

The blending of hydrogen into the existing gas pipelines poses several technological challenges related to measurements, energy conversion, process gas chromatographs, and gas metering. Furthermore, compressor stations used to compensate the pressure losses due to the friction of the transported gas along the pipeline are optimised only for the molar weight of a particular type of gas (natural gas). Manufactures of compressors determine the effect of hydrogen blending into existing gas pipelines. It is likely that a low hydrogen share (e.g., below 10%) only requires minor changes of existing compressors, whereas a share of more than 40% may determine the equipment replacement. In addition, some gas network operators consider 20% the upper bound to avoid the adaptation of the downstream users. Other system components such as gas turbines used to drive compressors, valves and connected underground storages might require modifications to work fine with hydrogen. The choice of a compression system for [hydrogen is still an open research problem, which is currently being studied for values of pipeline length, operating pressure, and hydrogen flow-rates](https://www.sciencedirect.com/topics/engineering/hydrogen-compression). It can be observed that for a given pipeline length and operating pressure, the number of compressor stages and/or the number of compressors required grows when the desired hydrogen flow rate increases, thereby allowing to effectively remove the heat generated in the compression process in each of the stages [53].

Regarding the blending of hydrogen in the existing infrastructure, it can be observed that the injection of 5%–15% of hydrogen by volume is not causing significant issues. Some issues must be addressed forhydrogen [fractions](https://www.sciencedirect.com/topics/engineering/high-volume-fraction) in the range of 15%–50%. More than 50% hydrogen blending are likely to generate multiple issues related to inadequate [pipeline materials](https://www.sciencedirect.com/topics/engineering/pipeline-material), safety, and required modifications of end-use equipment [54]. In the case of a pipeline conversion into a dedicated hydrogen pipeline, the estimated conversion costs are between 0.2 and 0.6 million € per km, which approximatively corresponds to 10–35% of the costs required to build a new hydrogen pipeline [52].

The conversion process of an existing gas pipeline involves the assessment of the technical conditions of the pipeline, its cleaning, the integrity inspection of the steel pipes and fittings, the installation of new compressors, turbines or motors for hydrogen compression, the achievement of proper tightness and sealing of system, the replacement of measuring equipment such as gas chromatographs [52].

If the pipeline to convert has already some fractures, the dynamical stress caused by internal pressure fluctuations may lead to an even faster crack growth when the pipeline is operated with hydrogen, because of hydrogen embrittlement phenomenon, that determines a loss of load bearing capability of the metal caused by its hydrogen absorption. Titanium and aluminium are valid alloys that can be used to prevent hydrogen embrittlement [55]. Furthermore, the cracking effects apply mostly to cases where hydrogen is injected at high concentrations into existing pipelines. Diverse types of steel react in diverse ways to hydrogen; therefore, the negative effects should be assessed on a case-by-case basis. Some carbon steel pipelines transporting pure hydrogen have been tested and kept in operation for many years. Other metallic pipes, including ductile iron, cast and wrought iron, copper pipes show no hydrogen damage under the general operating conditions in natural gas distribution systems. Similarly, it can be verified that there are no aging effects related to hydrogen on polyethylene (PE) or polyvinylchloride (PVC) pipe materials [56]. Finally, it has been observed that replacing valves may be beneficial.

## Skill development and training opportunities

The opportunities of training and skill development related to hydrogen are wide in Europe as well as in Ireland, ranging from academic degrees to more focused courses of short duration. The national association Hydrogen Ireland reports on its website multiple opportunities to develop skills related to hydrogen technology. The Dublin City University (DCU) has made available since 2020-21 undergraduate degrees and a Masters with updated modules on advanced sustainable energy systems that now include sustainable hydrogen among the topics. The company Energy CoOps Ireland and the Valentia Islands project want to support the DCU Masters offering field trips, guest speakers, shared research work and project supervision. The representative association for the Irish wind industry Wind Energy Ireland (WEI) is offering an introductive training to renewable energy developers, energy companies, transport companies and fleet owners to teach the hydrogen role in the energy transition, the technologies related to hydrogen storage and its use as an energy vector and fuel. The project HySkills is developing a modular training course on green hydrogen safety skills and a method for course accreditation to the benefit of future hydrogen workers. The project is also going to train vocational education teachers to ensure that they have the technical knowledge and the pedagogical skills to effectively teach in vocational courses about green hydrogen. The national engineering association Engineers Ireland is offering seminars on hydrogen and energy system decarbonization. The green institute in Ireland is also offering a short training covering the supply chain aspects, the production methods, the storage and the challenges in hydrogen distribution.

## The financing of hydrogen projects

In recent years, several projects in the power industry have been successfully financed especially in the sectors of the heavy transport, mining and industrial production using green bonds and loans.

Bonds and loans offer both loans to borrowers and charge an interest for that. The borrower can borrow funds from the lender either by getting a loan or purchasing a bond and pays periodic interests over the period of the bond or loan term. When the bond or loan matures, the borrower repays the total principal amount plus any other interest payments due. With loans, the bank and other financial institutions are the lenders, whereas individuals or corporations are the borrowers. With bonds, the general public is the lender, whereas corporations and governments are borrowers [90].

Bonds are issued to large corporations of governmental entities and can be traded such that the lender can obtain their funds before reaching the maturity. A loan can be issued to anybody who can repay it. There is no market where to trade loans, however recently banks have been allowed to sell off a loan to other financial institutions.

The financing of green hydrogen pilot projects will require to catalogue and allocate risks in a manner that is already familiar to project financiers, but it will also require the development of new tools, for example to classify hydrogen as a new asset as opposed to already existing assets [91].

It is foreseen that banks, financial institutions and project financers will be initially more confident in delivering bankable offtake schemes for those projects which are closer to the prevailing current use of hydrogen, related to the production of ammonia for fertilisation and the refinement of gasoline and diesel fuel from crude oil. Furthermore, the sector of fuelling special vehicles is considered promising and opportunities to finance projects demonstrating the application of fuel cells to diverse types of vehicles are envisaged.

Project financing decisions are often influenced by stable and long-term purchase agreements in place, the adoption of a reliable technology and the presence of an effective regulatory framework. Project financers usually assess the expected revenues which are needed to repay a green loan. The cost of green hydrogen should be reduced with respect to that of the conventional hydrogen produced from fossil sources, such that commercial lenders are more incentivised in financing new development projects [92].

Project financers are also aware of the emerging use cases related to electricity generation, balancing of renewables fluctuations, de-carbonisation of industrial processes, industrial, residential, and commercial heating. They will assess market and offtake risks on a case-by-case basis, prioritizing the support of those technologies which are considered more consolidated or present a lower development risk.

In some hydrogen sectors project financers have determined that probability of sufficiently high revenues is high so that a long-term offtake commitment is not necessary. Hydrogen storage is one sector that is an exception though, since hydrogen storage projects can be seen as more attractive for financiers if long term. This is related to the fact that storage is associated to generation assets that produce a predictable long term revenue stream based on applicable energy prices, which will effectively support a loan repayment. Moreover, the costs for generating renewable power are decreasing making the production of green hydrogen cheaper, and this will have a positive impact on storage costs as well [93]. In order to be successful in obtaining a loan, the project developers should prove that the expected cash-flow is enough stable to reduce the risk of not being able to return the project debt.

Bankability requirements are likely to be satisfied when a project demonstrates that either “green” or “blue” hydrogen will be used to replace an already existing supply of “grey” hydrogen for which there is a long term, stable demand, and that the required infrastructure for production and/or distribution is available. Project financiers may evaluate very positively agreements with industrial customers, where hydrogen demand has already existed for a long-time. Additional sales arrangements with other sectors such as transport may further increase their trust and willingness to consider acceptable the project offtake risks [94].

## 5.5 Organizational aspects related to the development of a hydrogen economy

## The development of the sustainable energy sector requires to synthesize multiple knowledge and data sources. Inter-organizational R&D collaborations are a valuable source of scientific and technical knowledge, whereas an integrated organizational approach based on the formation of alliances and the integration of sources is the most suitable to strengthen the connections between hydrogen knowledge-sharing networks and policymakers.

The cooperation of lower-level actors enables to undertake a multidisciplinary approach where the involvement of academic institutions and local energy companies allows to collect, organize, and process the information require to carry out the research activities on hydrogen. The connection between academic and industrial partners can be facilitated by a central entity acting as a system builder, because the actions of multiple and diverse actors involved in R&D and implementation projects often show misalignment with each other.

Successful R&D work balances exploitative and explorative actions in a way that determines technology maturation and demonstration of use cases of interest. System builders perform both exploitative and explorative work when connecting academic and industrial partners; universities and research centres usually contribute more to exploration, while energy companies contribute more to exploitation.

The actual contribution to either exploitation or exploration in the Power-to-X sector by university or industry depends on the level of knowledge and capability to develop new solution which can be readily deployed to the market. Universities have focused on new solutions which can improve process efficiency and their activities immediately relate to exploitation activities performed by commercial companies. Industrial companies have been very active in researching and implementing new solution for carbon capture, therefore they do perform exploration work, not only exploitation. Both exploitative and explorative knowledge transfer between universities and industry representatives is required to increase the pace of growth of the hydrogen economy [98].

The different actors bring their different capabilities, roles, and motivations into a dynamic and adaptive system called “innovation ecosystem”, a collaborative environment where to develop and drive the innovation process towards its success.

Hydrogen associations are prominent players, that may perform tasks of primary importance for the development of the hydrogen economy. Hydrogen Europe Research (HER) is an international non–profit association active in the sectors of hydrogen and fuel cell which groups together 91 universities as well as Research & Technology Organisations (RTO) from 26 European countries and beyond. The association participates in the European Joint Undertaking (JU) on Hydrogen, along with Hydrogen Europe (which focuses on industry applications) and the European Commission. These public-private partnerships support Research, Technological development, and Demonstration (RTD) activities in fuel cell and hydrogen technologies across Europe. The three pillars of the JU are Hydrogen production, Hydrogen storage, transport and distribution, hydrogen end-uses. More recently HER has joined the Institutionalised European Partnership (IEP) entitled Clean Hydrogen Joint Undertaking, that will run from 2021 to 2027. HER members take part in the different Technical Committees and roadmaps to discuss annual strategic priorities as well as to draft the topics for future Calls for proposals.

**5.6**  **The hydrogen markets**

Currently the primary energy commodities globally traded are oil and natural gas, which enjoy regulations, infrastructure, trading platforms, multiple suppliers and customers. Over time, the markets of hydrogen and hydrogen derivatives will be emerging with a similar structure. Nowadays the main market for hydrogen is related to grey hydrogen usage in industry as a chemical product, with refineries and ammonia production plants consuming the 80%. Such industrial uses are expected to even grow. The global hydrogen production was 61 Mt per year in 2015, with the 96% produced from fossil sources through natural or refinery gas reforming, chemical processing, or coal gasification, respectively the 48%, 30% and 18% of the total [101]. The amount of the global natural gas production used for hydrogen is 6% whereas 2% of the global coal production is used for hydrogen annually. Production of about 70 Mt of grey hydrogen per annum results in atmospheric emissions of about 830 Mt of carbon dioxide [100]. The global hydrogen production from electrolysis was only the 4% in 2015. Other emerging markets to consider are the mobility sector via FCEV for passenger light duty vehicles and the direct injection of hydrogen into natural gas networks.

The industry market shows a stable demand of hydrogen which is currently fulfilled by the grey hydrogen. Green or blue hydrogen might enter this market as soon as their selling price equals the price of grey hydrogen. The success of green hydrogen in the industrial sector produced via electrolysis with respect to the well-established SMR method is very much related to abundancy of renewable sources for electricity production in some specific regions. Hydrogen production cost using electrolysis could be achieved at a cost lower than 2$/kg of H2, if renewable cost is decreasing, and load factor is sufficiently profitable.

The development of other markets is more dependent on the energy-related policies that may foster or delay hydrogen’s large-scale deployment. Multi-regional assessment of hydrogen market penetration has shown different energy contexts and challenges arising under different circumstances. A thoroughly developed market should include multiple options for procurement, pricing and volume control means using set tariffs and auctions, as well as quotas and incentives to determine demand creation and market balancing.

The creation of a green hydrogen market should begin with the creation of hydrogen volume in the market, lowering the cost of hydrogen until hydrogen production costs will match fossil fuels plus carbon prices. This kick-start phase should be driven either by a set production tariff mechanism or auctions, or a combination of the two. The auctions are procurement schemes that use competitive tendering to determine the tariff, whereas a set production tariff is a scheme that guarantees the potential producers to receive a fixed tariff, which may be indexed to compensate for inflation. Auctions may also be used to trade the emissions that green hydrogen could avoid with respect to grey hydrogen. With this scheme, producers receive a premium as set by the auctions for each tonne of CO₂ avoided, which is added to the revenues from selling hydrogen. In the Netherlands, green hydrogen is subsidised up to USD 300/tCO₂ (about USD 3/kgH2) using the national auctions scheme for CO₂ reduction. Moreover, if taxes and levies are applied to grey hydrogen, and adequate support is provided for green hydrogen, the cost-gap between the two is reduced and the purchase of green hydrogen is incentivised. The cost of grey hydrogen can be increased of 20-40%. Taxes or levies could be tied to the GHG emissions associated with grey or blue hydrogen production. Grey hydrogen is already subject to the carbon tax in France, which was introduced in 2020 and will be further increased through 2030 [102].

The kick-start phase will likely run from 2021 to 2025 and will enable to increase the hydrogen production up to 1 million ton of clean hydrogen per annum using at least 6GW of electrolyser capacity.

The kick-start phase will be followed by a ramp-up phase, running from 2025 to 2035 and will enable to achieve commercial competitiveness of hydrogen through large scale storage and infrastructure, as well as appropriate regulatory measures to stimulate supply and demand. The regulatory support required for the ramp-up phase includes investment support, tariffs, auctions and tenders, guarantees of origin, quotas, tax relief. Also, legislation and regulatory obstacles should be removed; one example is the Renewable Energy Directive, which is imposing limitations to the use of renewable electricity for hydrogen production and should therefore be revised.

After that hydrogen has reached commercial competitiveness with the ramp-up phase, there will be a market growth phase from 2035 to 2050, characterized by price determined by demand and supply equilibrium and support mechanisms different on those of the ramp-up phase, such as those required to avoid monopoly [106]. The hydrogen infrastructure will be expanded with a large part of the natural gas pipelines converted in hydrogen pipelines and a better integration of the whole European hydrogen system [99].

Another measure that could foster the hydrogen market growth are the Guarantees of Origin (GOs) certificates. If this measure were applied to the hydrogen sector under the current regulatory framework, hydrogen producers could connect an electrolyser to the electricity grid, to purchase energy from the local electricity mix including electricity produced using non-renewable fuels; they could then purchase GOs to sell their hydrogen as “green” to their clients. There is a risk that the internal market for hydrogen would get distorted because the two types of hydrogen, respectively produced using electricity from additional renewable electricity capacity and produced using exclusively the local electricity and labelled “green” using cheap GOs, would be both traded as green hydrogen.

In the mobility sector the creation of a hydrogen market is a likely possibility, and it may present even a potential room for taxation for some countries in the medium to long term. Appropriate political decisions are needed to trigger investments such that uncertainties and the risk perception can be managed. The development of the mobility market is more favourable in countries where the competitor (such as the gasoline) is penalized by high taxes and there is a clear roadmap for hydrogen including support schemes. With regards to hydrogen-based fuels, it is likely that in some countries they will not be able to enter the market segment profitably, because of limitations in the regulatory framework in providing ground for the classification of such fuels as advanced ones. Finally, the injection of hydrogen into natural gas networks exhibits very low market entry costs, which can be as low as 2.3$/kg and are hard to achieve [101].

## 5.7 Regulatory framework and changes

Despite the long-term commitment of the governments of EU countries to the development of a hydrogen economy, there are still regulatory barriers that may prevent an effective deployment of smart power changes required by industry. In 2018 Backer McKenzie conducted a survey revealing that 77% of respondents from the industry considered inadequate the legal and regulatory frameworks related to hydrogen. These barriers may still be in place today and must be carefully considered by policymakers to improve current regulations. First, the lack of origin guarantees for hydrogen makes impossible a distinction between types of hydrogen based on greenhouse gas emissions associated to its production process. Moreover, the “power-to-hydrogen” plants or storage systems have an unclear legal status, and this can prevent their proper rewarding. Safety regulations are in many cases deemed unclear or incomplete. Funding rules are considered inconsistent or limited. There is the fear that the Government might discriminate some technologies because of superficial or incomplete information [27].

The EU Renewable Energy Directive II (REDII) is perhaps the regulation that is generating most of the uncertainties and doubts related to green hydrogen production from renewables. In order to comply with the directive, a hydrogen producer needs to prove that electricity used to supply their electrolysers is produced exclusively from renewable sources, either using on-site electricity renewable production or grid purchase. In the latter case, the utilisation of the renewable electricity can be claimed only once. In relation to green hydrogen production, the European Commission is working on a methodology to ensure the requirement of additionality. Additionality implies that renewable electricity used to supply the electrolysers to produce green hydrogen is additional to the renewable electricity used to meet the target of final electricity consumption from renewables. That means that electricity used to supply electrolysers should come entirely from renewables power plants of recent construction, which would otherwise not have been installed.

The association Hydrogen Europe has expressed some concerns regarding the practical implementation of the additionality principle. Although beyond the scope of the REDII, the lack of regulatory clarity could have a negative impact on the deployment of renewable hydrogen even hindering the targets set by the EU Hydrogen strategy and in the long run the long-term EU climate goals. One of the main concerns is that – if the additionality principle is strictly enforced – the electrolyser project developers would have a very low incentive to build until new electricity capacity is not made available yet. Moreover, the lead time for investments into some renewable electricity generation assets may be longer than the time needed to build an electrolyser (respectively up to 7 years and less than 2 years) [105].

Two important indicators can be used to assess the fulfilment of the requirement of additionality; they are the temporal and geographical correlations between renewable generation and consumption by the electrolysers used to produce hydrogen. Temporal correlation means that electricity generated using renewable power plants equals the electricity used to produce hydrogen in the considered time interval. Geographical correlation means that that electricity generated using renewable power plants, matches the electricity used to produce hydrogen within a certain geographical proximity based on the network topology. The current regulatory framework is not satisfactory regarding the definition of the time interval to be used for evaluating the temporal correlation and the way to be used to define geographical proximity. If the time interval used to evaluate time correlation is very short, then electricity production from renewables and consumption from the electrolysers happen nearly simultaneously with the advantage of guaranteeing that the consumption of the electrolysers is fully supplied at any time instant by the additional renewables. The big disadvantage of this choice is that it would either pose a limitation on the utilisation of the electrolysers, or require greater capacity of renewables-based electricity generation to allow the electrolysers to operate at their optimal utilisation rates. On the other hand, a long correlation interval would allow to operate the electrolysers close to their optimal utilisation rate, that way avoiding the need for installing a much larger capacity of renewable generation using renewables. The disadvantage of choosing a large time interval to evaluate correlation, is that electrolysers would be likely supplied in that case by a generation mix of non-renewable technologies, which may include also a significant fraction of fossil fuelled power plants. Even more challenging is to define detailed requirements for geographical correlation, and there is currently no legislation which can help with this task. Of course, the existence of a physical link between the renewable power plant and electrolysers, would immediately prove the full geographical correlation. However, this is a too demanding requirement since it is desirable that only a commercially-link would exist between electricity producer and consumer, provided that they are both connected to the same network and there is no congestion between their respective locations in the electric network, in order to allow the additional electricity produced by renewables to end up at the electrolyser [103,104].

The authorization process for hydrogen production is long and costly therefore small-scale production, localized production is significantly hindered by the existing legal and administrative barriers. A similar comment also applies to the hydrogen refuelling stations.

Overall, it can be noticed that some hydrogen technologies emerge as early as 2020, hydrogen economy emerges after 2030, even though some other technologies will emerge later, approximatively in 2050, such as cost-effective fuel cells cars and some technologies used in industry for iron smelting. The inclusion of hydrogen technologies and systems in energy system models is still considered difficult and the consequences are uncertainty and complexity associated with the hydrogen value chain [34].

The European Commission has a plan to deploy green hydrogen technologies at large scale between 2030 and 2050, reaching all the sectors where other alternatives might not be feasible or have higher costs. To reach this goal, regulatory changes and updates will be evaluated, including a revised state aid framework, new incentives in the Emission Trading Scheme, introduction of quotas for green hydrogen to drive demand, a certification scheme for hydrogen technologies, facilitation of access to energy infrastructure, such that the supply and the demand can be better connected to each other [35].

Regulatory changes will also be implemented through the EU Green Deal Recovery package which will aim at offering a stable revenue to the users of green hydrogen [38]. The recovery package will provide the adoption of a contract for difference (CFD) system for carbon for green hydrogen projects. A CFD is an agreement between two parties whereby one party agrees to pay the other party the difference between the market price of a commodity at a point in time and the strike price which was agreed when the CFD was signed [36-37]. Green hydrogen users bid the strike price at which they can reduce carbon emissions by a ton with their project, still obtaining a return. If the carbon market price goes above that strike price, they would pay back the difference to EU. If the carbon price fell below that level, the EU would pay the difference [38]. Furthermore, the draft of Green Deal Recovery package also supports efforts to reduce costs of electrolysers.

The call for evidence will provide more information about the possible developments of the Irish regulatory framework, by gathering stakeholders’ inputs for a national policy (section 1) as well as information on several technical aspects related to hydrogen production (section 2), transportation and distribution (section 3), consumption (section 4), which will further contribute to highlight the current gaps in the regulatory framework and clarify the needs for updates of it.

# Hydrogen Competing Technologies for decarbonisation of society

## Fuel cells electric vehicles vs Battery electric vehicles

The main competing technologies currently available to supply power to all-electric vehicles are the fuel cells and the batteries. Fuel cells convert the hydrogen stored in the vehicle into electrical energy, whereas batteries store electrical energy drawn by the electrical grid. Both technologies are zero carbon fuels, because hydrogen and electricity can be produced using low- or zero-carbon sources including renewables, nuclear energy and coal with carbon capture and storage (CCS).

Fuel cells electric vehicles (FCEV) are lighter than battery electric vehicles (BEV) for a given range since the compressed hydrogen powering a fuel cell can supply five times more energy per unit mass than NiMH batteries used in most gasoline HEV and two times more than advanced Lithium-ion batteries. The weight of both FCEV and BEV grow with the range covered by the vehicle. However, the weight of a FCEV grows more slowly than BEV: a 200 miles BEV is 30% heavier than a FCEV covering the same range, whereas a 300 miles BEV is more than 70% heavier than a FCEV. A comparison of different battery technologies against fuel cell technology is reported in Fig 1. For all the available battery technologies the mass of the vehicle grows more than linearly with the range. Lithium-ion batteries are the most convenient to use with respect to weight especially in long range vehicles. On the other hand, the mass of a FCEV is almost independent on its range.

Considering that BEV batteries are charged from the grid, BEV have also higher greenhouse-gases emissions than FCEV, 58% more for a 200 miles vehicle and 86% more for a 300 miles vehicle. When it comes to fuel cost for km, BEV beat FCEV. Fuel cost of a BEV is 48% of FCEV for a 200 miles vehicle and 57% of FCEV for a 300 miles vehicle [41]. In fact, several studies have determined that BEV are 1.25–3.9-times more energy efficient than FCEV [45]. The factors that impact on efficiency are the site of hydrogen production (whether transport is required or not) and the primary energy source used.

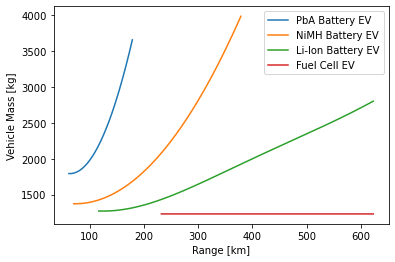


Figure 2 Mass of an electric vehicle as a function of the range and of the battery or fuel cell technology

Regarding the refuelling time, the performances of 140 FCEV were monitored by the National Renewable Energy Laboratory (NREL) for several years, and it was found that the average time was 3.3 min, which is much lower than charging batteries for an all-electric vehicle. [41]

In the long term, FCEV could become a more appealing alternative to BEV in case the production cost of hydrogen would rapidly decrease. In the future we will see the adoption of a diverse mix of battery and fuel-cell vehicles since Lithium-ion batteries also have the excellent technical features for some specific electric mobility applications and because the hydrogen refuelling infrastructure will give lower access to fuelling capability being more complex to deploy than charging stations for BEV [42].

## Hydrogen boilers vs Heat pumps for domestic heating

Electric heat pumps are the main competing technology of hydrogen for decarbonisation of the domestic heating. They are a zero-carbon emission system if their power supply is generated using renewables. UK is continuing to increase the number of installations with a target of 600000 new heat pumps in 2028. Despite the high efficiency of heat pumps, they are not necessarily a cheaper alternative to gas fired boilers, especially in those countries where the cost of electricity is high compared to the cost of natural gas. Furthermore, heat pumps installation costs are higher than those of natural gas fired boilers. Hydrogen may be a valid alternative to heat pumps because it is easier to store in massive quantities than electricity and can be used to supply the peak demand. Regarding the price, in some countries it might be cheaper to switch to hydrogen in 2030, unless the government policy will determine a cost reduction for electricity suppliers. Furthermore, the increased number of heat pumps will determine an additional load for the electric network infrastructure ranging from transmission lines to local transformers that will add to electricity bills and make the heat pumps even more expensive. On the other hand, if hydrogen boilers are fuelled using green hydrogen, they can hardly be competitive with heat pumps, because the overall efficiency of the system renewables + electrolyser + gas grid + gas boiler is about 55% (Fig.2), whereas the efficiency of system renewables + electricity grid + heat pump is 250% or higher (Fig.3). In fact, a heat pump can use electricity to transfer heat from a source to a sink, therefore has an efficiency greater than 100%, in the range 250-400%. Another green option is the electric heating using electric power from renewables (Fig. 4). It can be noticed that the running cost of a green hydrogen boiler is 4 to 6 times the running cost of heat pump. The two systems can be installed simultaneously with the heat pump being the main heat supply unit and the hydrogen boiler the auxiliary one to be used in the coldest days. Furthermore, a hydrogen transmission network could be used as energy carrier to transport energy as an alternative to the traditional electrical grid. This is depicted in Fig. 5. In this case the total efficiency of the system including a heat pump drops to 80% because of low efficiency of electrolysis, transport grid and power station compared to the case where only the electric network is present (Fig. 3). However, the possibility of using either hydrogen or electricity to transport energy adds flexibility to the entire system and the mix of different technologies enhances the security of supply. These energy systems should be carefully planned to achieve the best performances though.

A thorough comparison of heat pumps with hydrogen boilers should take into consideration life cycle costs including the environmental costs. First, it should be noticed that a heat pump using electricity from the grid produces CO₂ emissions, because the electricity from the grid is highly likely generated using a mix of fossil-fuelled power plants and renewables, whereas green hydrogen will be produced using dedicated renewable solar or wind power plants (with zero CO₂ emissions). Also, it can be noticed that heat pumps produce emissions of sulphur oxide compounds (SOx) even higher than natural gas fired boilers. Furthermore, it is well known that the manufacturing impact of a heat pump is higher than the manufacturing impact of a boiler. More energy is required with respect to a gas boiler, to transform raw materials into components (compressor, external and internal fans, batteries, damping, connections, etc), to assembly components and eventually to dismantle and recycle metals, refrigerant, and oil. This also applies to the new hydrogen fuelled boilers, because they require a manufacturing process rather similar to natural gas fired boilers.

When considering both investment and functioning costs (for a period of 10 years), heat pumps are not necessarily more convenient than gas fired boilers, despite the lower costs associated with energy consumption in the functioning stage, because of higher equipment cost and higher environmental costs in the investment stage [58]. Of course, this situation may change when the grid will use 100% renewable production, and manufacturing innovations will simplify the heat pumps manufacturing process.

In UK the policymaker foresees that the economy will determine a mix of heat pumps and decarbonised gas-fired heating replacing the current fossil fuel methane. The UK strategy has set the 2026 as the year for taking a decision about utilization of hydrogen in heating after the neighbourhood level trials in 2023 and the village level trials in 2025 [75].

A screenshot of a computer

Description automatically generated with low confidence

Figure 3 Efficiency of a hydrogen boiler system supplied by renewable energy

Graphical user interface, timeline

Description automatically generated

Figure 4 Efficiency of a heat pump system supplied by renewable energy

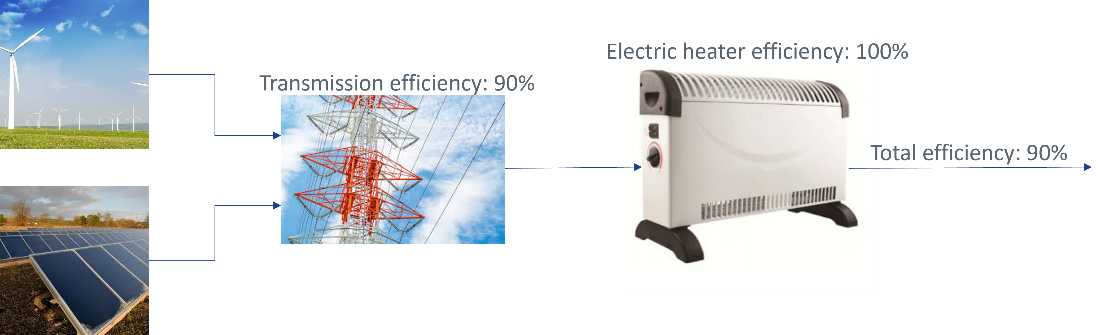


Figure 5 Efficiency of a heat pump system supplied by renewable energy

Graphical user interface, application, website

Description automatically generated

Figure 6 Efficiency of a heat pump system supplied through a hydrogen power station using green hydrogen

## Competing technologies for energy storage

Increasing diffusion of renewable power plants, which are not controllable energy sources are determining a more important weight given to energy storage in the future power system. Energy storage technologies are a way to circumvent the fact that renewable energy production does not follow the desired consumption pattern and enables to reshape the consumption pattern to harvest more renewable energy. Different technologies are emerging, being placed side by side with the already well-established ones. Among the novel energy storage means that will be competitors of hydrogen storage, there are: pumped hydro energy storage, gravity-based energy storage, liquid air energy storage, compressed air energy storage, flow batteries energy storage [61].

The Pumped Hydro Energy Storage (PHES) is based on moving water from a low to a high reservoir, from which the water descends to generate electric power, when there is demand. The main advantages of pumped hydro are the low cost of the storage and their large capacity compared to even largest batteries currently available on the market. In US, pumped hydro still provides about [95 percent of grid storage](https://www.energy.gov/eere/water/pumped-storage-hydropower). The Electric Power Research Institute (EPRI) reported that pumped hydro covers around 127 GW bulk energy storage, more than 99% of worldwide capacity [62]. The main disadvantage is the difficulty in building new pumped-hydro storage infrastructures. New projects focussing on isolated reservoirs to preserve the river ecosystems will be likely to obtain permissions; however, development time and cost will be high. Pumped hydro energy storage has an efficiency variable between 70% and 80% with capability of reaching the 87%. Most common pumped-hydro plants for energy storage have a size in the range of 1000 - 1500 MW, however largest plants may be in the range 2000 – 3000 MW with turbines sizes of 300 – 400 MW [63].

An innovative evolution of PHES is the Gravity-Based Energy Storage (GBES) which uses gravitational potential energy to store energy, similarly to PHES. The storage system includes a container filled with water, a large piston, and a return pipe [65]. The water flow from the container into and out of the return pipe is controlled by a valve. When energy is stored into the system, the water is pumped such that it flows through the return pipe causing the piston to move upward and store energy. When energy is released, the downward motion of the piston forces the water to flow through a turbine driving a generator to produce energy. The efficiency of this GBES system is more than 80% and it can be used to generate large power (several MW). A variant of GBES has been proposed by the start-up company Energy Vault. Instead of using a piston whose position changes because of the water flow, they designed a prototype that is using a six-armed robotic crane to stack monoliths into a tower to store energy and drop them down again when energy release is needed.

Compressed Air Energy Storage (CAES) is another promising means to deal with load levelling and following, power balancing and peak shaving, which is cost effective if employed at large scales. Air can be compressed and pumped into a suitable natural underground formation (such as salt domes or caverns) and released when electric power is needed. Alternatively, the compressed air can be stored in aboveground pressurised steel tanks, although with significantly higher costs. Excess electricity can be converted into compressed air. When used at large scale, CAES is much more cost effective than batteries and is particularly suitable for a long duration energy market required for global electrical grid decarbonisation, having a life of more than 50 years. A Canadian company called Hydrostor [70] has built caves or used existing ones and uses water to maintain pressure to store energy by means of compressed air using mature technologies available from industry [61].

An alternative to CAES is the [Liquid Air Energy Storage](https://www.sciencedirect.com/topics/engineering/cryogenic-energy-storage) (LAES) that is currently considered a good candidate for bulk storage of electrical energy, especially in the UK. Liquid air has a higher energy density than compressed air and can be more compactly stored. It only needs a well-insulated container to be stored, which can be installed almost anywhere. A pressurized vessel is not needed to store liquid air. Among the others, LAES is currently developed by the start-up company Highview Power, which has adopted above-ground tanks as well as other equipment form established industries for compression and power generation. Air cooled down to -196°C becomes liquid and can be stored in insulated vessels at low pressure. Re-gasification happens at ambient temperature and determines a rapid expansion in volume (700-fold), such that air can directly be used to drive a turbine and generate electricity without the need of combustion. The technology has been demonstrated in large-scale plants.

A hybrid [energy storage system](https://www.sciencedirect.com/topics/engineering/energy-storage-system) combining CAES and LAES has been proposed to benefit from the distinctive characteristics of CAES and LAES. In fact, the CAES has a higher [roundtrip](https://www.sciencedirect.com/topics/engineering/roundtrip) efficiency than LAES, whereas LAES has a lower cost per unit of [energy storage capacity](https://www.sciencedirect.com/topics/engineering/energy-storage-capacity) than CAES. This way, the low frequency power fluctuations which apply to substantial amounts of energy stored determine the conversion between compressed and liquid air and vice-versa, whereas higher frequency fluctuations determine only variations of smaller quantities of energy stored in the CAES system [64].

The Redox Flow Batteries (RFBs) are considered a promising technology for stationary long-duration and large-scale storage in terms of cost, reliability, and safety [66]. They comprise cathode and anode chambers, membranes, and flowable electrolytes. Electrochemical reactions convert energy and store it by holding the electrolytes active species in external containers. In an all-vanadium redox flow battery, the reactions taking place respectively at positive and negative electrodes when the flow battery is discharging are the reduction of ion at the cathode electrode and the oxidation of at the anode electrode [74]:

The ion diffuses through the membrane from the negative electrode chamber to the positive electrode chamber, whereas electrons flow through the external circuit connected to the battery. When the flow battery is charging the cathode/anode electrodes and the reactions are reversed, such that ion oxidates while reduces. RFBs have not been successful in conquering the market yet, a probable reason is that the performance of membranes and electrodes needs to be further improved. Furthermore, a reduction in the construction and operation costs of RFBs can be achieved by improving the cell and stack design, as well as the battery system management. The energy density of RFBs is determined by the volume of the electrolytes, concentration of active species, the cell voltage, and the number of stacks. A higher energy density can be obtained by adopting new active redox couples with higher concentration and higher cell voltage. Moreover, the power generation capability depends on the reaction kinetics behaviour of redox-active systems and can be increased enabling faster kinetics as well as increasing the size of electrodes. The ESS company has raised $30 million funds for new demonstration projects due to their interest in testing an iron flow chemistry not utilising more expensive and rare-earth minerals like vanadium and lithium. This new chemistry enables 20 years or more battery life as opposed to 7-10 of conventional chemistries before needing augmentation [67]. To overcome the issue of high material cost, Invinity Energy Systems (previously known as Avalon Battery) company has developed an agreement for [renting vanadium from mining companies](https://www.greentechmedia.com/articles/read/new-path-to-market-for-flow-batteries-rent-an-electrolyte), which are seeking a new market for their product. They have produced 160 flow batteries by factory turnkey mass-producing, which are competitive with lithium-ion batteries on life cycle for high-throughput applications. Current products have a rated power ranging from 78 kW to 10 MW and a nominal energy storage ranging from 220 kWh to 40 MWh. The battery discharge duration is from 2 to 12 hours. The lifetime is 25 years with unlimited cycle life [68]. In hydrogen production, the RFBs can be used as a buffer between renewable resources and electrolysers, such that the electrolyser can operate at a constant load. The goal is to drive the electrolysis using mainly energy harvested from renewable resources, rather than fossil fuel or nuclear resources, to produce green hydrogen [69].

A hybrid energy storage system using compressed air and hydrogen as the energy carrier was proposed in [71]. Despite its moderate efficiency (almost 40%), the hybrid CAHES system has some characteristics that may determine investment decisions. The system is highly flexible because of the load modulation capabilities of individual subsystems are combined. Especially the load of the hydrogen production sub-system can be varied within a wide range, such that it can be adapted to the surplus of electricity production. The CAHES system can also comprise a subsystem producing methane gas from the reaction between hydrogen and CO₂ and this production can be supplemented with gas from the gas network adding flexibility to the entire system operation. The hydrogen produced by means of the electrolysis process can be used for other purposes. The CAHES system does not emit any harmful substances. The required capacities of compressed air tanks may be several times smaller than large scale CAES with the same energy storage capacity. This means that suitable mine excavations such as corridors and mine shafts, or even above-ground reservoirs can be used. Therefore, the CAHES system can be installed an area without salt deposits or aquifers while keeping a high storage potential.

A hybrid battery/hydrogen storage system has been proposed in [72]. The considered hydrogen storage technology includes a hydrogen tank, electrolyser and fuel cell and has been significantly improved in recent years also achieving a tangible cost reduction. When the hydrogen storage system cost will become the 47% of the current costs assumed in [72], hydrogen storage will have the same costs of the battery system. If the hydrogen storage components cost will keep decreasing, a combined system performs better economy than each of the two alone systems. A fuel cell working in cogeneration mode contributes to the reduction of the total cost of hydrogen storage in high load conditions, considering that the average thermal efficiencies are 46% for SOFC and 57% for PEMFC (whereas average electrical efficiencies are 37% for the SOFC systems and 32% for the PEMFC systems) [73].

Demand side management is a set of programs that help customers to shift their demand of electricity to off peak periods and to reduce their energy consumption. Load shifting can reduce the peak demand for the 20-50 hours of highest demand throughout the year or the maximum demand in a 24-hour period. Flattening the load curve allows to increase utilisation of base load generation plants which are cheaper than peaking power plants. Energy efficiency is promoted by means of energy conservation programs that encourage customers to reduce energy usage and replace old appliances with more energy efficient models – to save money [80]. Demand response is a particular DSM which determines voluntary changes of end-consumers’ usual consumption patterns in response to price signals.

Several energy storage technologies have been used for industrial DSM. Most analysed are battery energy storage (BES) technologies are: Li-ion BES, Pb-acid BES, flow BES, pumped hydro ES, and compressed air ES. Although all these technologies are suitable for the purpose of DSM each of them shown a major disadvantage. Li-ion BES is one of the most expensive ES technologies, Pb-acid BES has the shortest lifetime, flow BES has the lowest power density, PHES can be installed only on a very large scale, and CAES is the least efficient [81].

Demand side management (DSM) is found to be a means to reduce the need of backup power generation. The backup power generation is a plant which is normally off (standby mode) but can quickly be restored and supply all the loads of a facility or campus for minutes, hours, or even days, when grid power supply drops for more than a few seconds [82]. Furthermore, thorough DSM adoption determines a different mix of PV and wind minimizing the amount of backup energy required to ensure reliability of power system. At European level, without DSM the optimal mix of renewables with respect to backup energy is 19% PV and 81% wind, whereas with full DSM utilisation, the optimal mix becomes 36% PV and 64% wind. PV power works better with DSM because it has a deterministic diurnal cycle and can use DSM more efficiently than wind power [83].

A realistic 2050 car sales scenario comprises 60% electric vehicles (EV) and 18% H2 Fuel Cells vehicles (FCEV) in Ireland [84]. For this reason, beside the stationary energy storage units [81], [plug-in electric vehicles](https://en.wikipedia.org/wiki/Plug-in_electric_vehicle) (PEV), such as battery electric vehicles (EVs), [plug-in hybrids](https://en.wikipedia.org/wiki/Plug-in_hybrid) (PHEV) or hydrogen [fuel cell electric vehicles](https://en.wikipedia.org/wiki/Fuel_cell_electric_vehicle) (FCEV), will significantly contribute to DSM reducing the need for dedicated stationary grid storage. PEV can participate in demand response programs in three diverse ways: charging based on a time-of-use tariff, smart charging controlled by an aggregator through virtual power plant networks, and smart control with vehicle-to-grid capability. Virtual power plants are a network of decentralized, medium-scale power generating units such as wind farms, solar plants, combined-heat-power generation units, as well as flexible loads and storage systems such as those provided by PEV. The Vehicle-to-grid (V2G) concept allows a communication between the PEVs and the [power grid](https://en.wikipedia.org/wiki/Power_grid) to enable the participation in [demand response](https://en.wikipedia.org/wiki/Demand_response) services by either selling electricity to the grid or by controlling their charging rate. V2G storage enables PEVs to charge and discharge electricity generated from renewable energy sources to contribute to smoothing out power fluctuations [[85]](https://en.wikipedia.org/wiki/Vehicle-to-grid#cite_note-4). In order to deploy successful DR programs, the operators will have to transfer cost savings to DR customers such that more DR customers are attracted to participate in DR and the whole power system can be developed to accommodate more fluctuating renewables.

The V2G business case originates from the fact that in many cases PEV are not utilised therefore their storage capability is not fully exploited. Assuming that the owner of an electric vehicle is usually using the vehicle to drive to work and back home, that it can be fully recharged during the night when electricity price is off-peak, there is still time to use the residual energy stored by the vehicle to power home lights and appliances for some hours (especially during evening peak hours) or even to export excess power to the grid [86]. The former service is called vehicle-to-home, whereas the second is the vehicle-to-grid (V2G). The energy can be sold to the grid at the regular selling price for the considered electricity market plus an additional compensation for providing an up-regulation ancillary service. Moreover, the PEV may offer a down-regulation ancillary service where it acts as an energy consumer. When the down-regulation service is provided to the grid, the PEV’s owner pays the electricity tariff discounted by the down-regulation compensation [87].

Battery capacities of current EVs range from 17.6 kWh for a small Smart EQ ForTwo with a range of 58 miles, up to 100 kWh in a Tesla Model S and Model X with a range of more than 300 miles [88]. Considering an average capacity of 60 kWh/vehicle, 1.7 million of EVs in 2050 and a utilization factor of 70%, the storage capacity available to the grid for ancillary services would be about 70 GWh [84], enough to fully integrate all the wind energy output under a 40% RES-E scenario, which applies already in 2020 [89].

# Recommendations on the development of an enabling framework for hydrogen in Ireland

The analysis of hydrogen opportunities in Ireland leads to some recommendations regarding the development of a hydrogen policy to promote the use of hydrogen and its benefits [39].

**Recommendation 1: Demonstrate the use of green hydrogen in road transportation**

Demonstration of green hydrogen in road transportation has already started with fuel-cells buses in Dublin. Existing road vehicles include cars (Toyota and Hyundai), buses (Wrightbus, a manufacturer based in Ballymena, CaetanoBus), vans (Renault and LDV), trucks (Hyundai, Nikola), Refuse Collection Vehicles (FAUN), which are all almost unknown to local communities. These demonstrations should be extended to prove the reliability of the technology and its benefits such that the technology will be considered mature for adoption when the price of green hydrogen will be close to that of gasoline.

**Recommendation 2: Build-up additional renewable energy sources for green hydrogen production and provide support for green hydrogen production using curtailed renewable power, when applicable**

Green hydrogen is the preferred type of hydrogen because does not emit any carbon. In 2030 Ireland would only use 2% of its renewable potential, therefore there is large room for building-up additional facilities to produce green hydrogen from renewables and supply part of the demand in a cost-effective manner. An example of this is the project in for the first green hydrogen plant in County Mayo, which has recently received approval. The plant will make use of 1,500 Thermal/Electric panels, a technology delivering seven times more kWhr output per sqm than solar PV. At the same time, there are cost-effective opportunities to use part of the excess electricity produced by existing renewable power plants to supply power to electrolysers which should be exploited to fulfil part of the green hydrogen demand.

**Recommendation 3: Incentivise the production of green hydrogen introducing quotas for green hydrogen to drive demand in case its market price is too high and allow auctions for hydrogen production using electricity from renewables**

In the long term, green hydrogen is the most acceptable technology. It is recommended to investigate the barriers that prevent the price of green hydrogen to be closer to the price of steam-methane reforming hydrogen. If the price of green hydrogen will not be decreased by 2030, thanks to the adoption of cheaper electrolysers and the achievement of scale economies, the production can be incentivised introducing quotas, a measure that is already under consideration by the European Commission. In addition, the policymaker should identify the opportunities for the communities to participate directly in green hydrogen production projects through auctions, to make the technology mix of renewable energy projects broader including electrolysers, and to increase system security and sustainability while ensuring that cost effective solution can be implemented, as recommended by the Renewable Electricity Support Scheme RESS2.

**Recommendation 4: Demonstrate use of hydrogen as flexibility provider to perform power system balancing**

Reduced scale experiments could show how hydrogen storage can be used as an alternative to batteries for balancing fluctuations of loads and renewables. Operation of small size electrolysers and fuel cells can be first demonstrated in relatively small power systems, such as microgrids. Electrolysers for hydrogen production can be seen as a flexible load that can help the TSOs (Transmission System Operators) to manage the variability of wind power generation and to maintain the system stability and security. If hydrogen sites are made bidirectional, they could be given the same status as energy storage and become part of the DS3 program “Delivering a Secure, Sustainable Electricity System” or of a successor of it.

**Recommendation 5: Investigate and demonstrate blending of hydrogen into the existing gas network**

Plan of blending 50% of hydrogen in the existing gas network should be actuated progressively. Currently it is not clear whether the Irish gas network, which is almost fully made of polyethylene, would allow to blend 50% hydrogen in volume into natural gas and operate the network ensuring its safety and reliability, therefore it is recommended first to set-up a feasibility investigation, performing experiments with 10% and 20% hydrogen blending as already done in other countries. In the long term, opportunities and costs to convert portions of the existing distribution network to a pure hydrogen network should also be evaluated. Low-cost green hydrogen boilers are now arriving, which are more suited to deliver energy to existing buildings with simple upgrades, requiring only minimal home improvements.

**Recommendation 6: Investigate the feasibility of low carbon hydrogen using carbon capture and storage technologies applicable to geological basins and structures in Ireland**

The cost of low carbon hydrogen (blue hydrogen) is currently lower than the cost of green hydrogen and blue hydrogen is considered a viable opportunity by the European Commission and in several European countries. The reforming natural gas into hydrogen with CCS to produce blue hydrogen is considered the most competitive process also in Ireland. Ireland has commenced research and demonstration activities on CCS at Whitegate oil refinery in the Cork harbour. It is recommended to continue with reduced scale demonstration of CCS technologies and to investigate their applicability to hydrogen production, because they could be a cost-effective alternative to the green hydrogen in the medium term. Further geological and engineering studies are needed to determine actual CO₂ storage capacities of onshore and offshore geological basins and structures. The island of Ireland has a theoretical capacity for CO₂ storage in natural structures of 93115 Mt. A thorough geological assessment based on deep geological data, is needed for each basin or structure to determine the exact amount of theoretical and effective capacities. More geological data should be obtained drilling exploration wells from the existing platforms and the data should be used to conduct reservoir simulations to investigate the effect of CO₂ injection on the structure stress and to identify possible leakage points.

**Recommendation 7: Robustly Evaluate feasibility of large-scale hydrogen storage in salt caverns**

In the North of Ireland there are a few underground salt layers which could be used to build hydrogen storage facilities. Feasibility of hydrogen storage in salt caverns is required to prove that hydrogen can be used in the future as a flexibility resource to balance the fluctuations of renewables, given the 2030 scenario where the expected installed capacity of intermittent renewable sources will be three times higher than the forecasted average load. In US salt caverns have been used for decades to store hydrogen in the Gulf Coast. Big companies such as Mitsubishi Power and Siemens are looking for partnerships to convert large natural gas reserves in giant underground salt caverns into hydrogen storage sites in both eastern and western part of the country. The policymaker should promote a similar process in Ireland to support decarbonization through large scale hydrogen production and storage.

**Recommendation 8: Establish a greenhouse gas emissions standard for low carbon hydrogen that meets multiple relevant criteria**

Low carbon hydrogen, obtained through well-understood chemical processes, is currently cheaper to obtain than green hydrogen obtained from the electrolysis process. Without any prejudice for the path towards a full utilisation of electrolysers for green hydrogen production, the policymaker should carefully consider the possible advantages of other technology pathways to produce green hydrogen. Following the UK example, it is recommended to establish a GHG emission standard meeting relevant criteria such as: neutral with respect to technology, accessible, cost-effective, user-friendly, transparent, compatible with other schemes in the energy sector and with other countries’ standards, ambitious, accurate, robust, including penalties for fraud, predictable [76].

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