International Renewable Energy Agency

GREEN HYDROGEN SUPPLY

A GUIDE TO **POLICY MAKING**

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The International Renewable Energy Agency (IRENA) serves as the principal platform for international co-operation, a centre of excellence, a repository of policy, technology, resource and financial knowledge, and a driver of action on the ground to advance the transformation of the global energy system. An intergovernmental organisation established in 2011, IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy, in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity.

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INTRODUCTION

In the 2015 Paris Agreement, nations around the world agreed that rapid decarbonisation is needed to prevent the dangerous impacts of climate change. Then in 2018, the Intergovernmental Panel on Climate Change (IPCC) report *Global Warming of 1.5°C* showed that the need to cut greenhouse gas (GHG) emissions rapidly is even more urgent than previously thought (IPCC, 2018a). The report concluded that the window of opportunity is closing fast for meaningful action to limit the planet's increase in temperature and to counter the global climate crisis. Therefore, policy makers must increase their efforts to reduce or eliminate emissions in all economic activities. Options that would deliver only partial emission reductions are not sufficient.

The full decarbonisation of some industry and transport subsectors is technically and economically challenging, and the current number of solutions is limited. These are known as "hard-to-abate" sectors. There is, however, a common solution for some of these hard-to-abate sectors: hydrogen produced with renewable energy, also known as **green hydrogen**. Green hydrogen can be used as a feedstock for the production of chemicals and fuels or directly as a fuel.

It was predictable, then, that green hydrogen should receive a new wave of attention from governments, policy makers, energy sector stakeholders and even the general public. An unprecedented number of reports, news articles, webinars and events in the last two years have touched upon the topic.

But the development of a green hydrogen sector is itself still at a very early stage.

Each year around 120 million tonnes (Mt) of hydrogen are produced globally, mostly from fossil gas and coal **(grey hydrogen)**, which together account for 95% of global production. Hydrogen used for crude oil refining and for ammonia and methanol synthesis represent almost 75% of hydrogen consumption.

The roadmap described in IRENA's *World Energy Transitions Outlook* includes a major role for green hydrogen in reducing GHG emissions and making the energy transition possible. According to the roadmap, by 2050 green hydrogen needs to have far greater dimensions than today, production reaching about 400 Mt, equivalent to 49 exajoules (EJ). Producing that much, in turn, would require a significant scale-up of electrolysers, with total installed capacity growing to 5 terawatts (TW) by 2050.

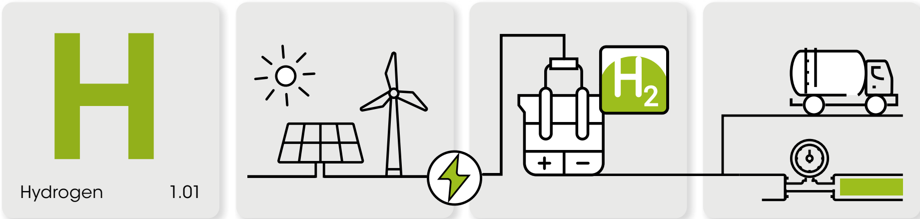
The electricity demand to produce hydrogen reaches close to 21 000 terawatt hours per year by 2050 (IRENA, 2021).[1]

Achieving these ambitious numbers will be a major challenge. But as this report describes, this challenge can be met through a wide range of policies. Policy makers then have a central role to play and already have the tools to meet the challenge.

Some countries have already introduced a hydrogen strategy and implemented initial policies to support the sector while new, targeted policies are being drafted. Still, for the sector to move from niche to mainstream, more diffused policies and measures will be needed (IRENA, 2020a).

Policy makers today can draw early lessons from the trailblazing countries in the green hydrogen sector, and from their own experiences of renewable energy policy making in the power, heat and transport sectors.

1 *An alternative, however, is that by 2050 other green hydrogen production pathways reach a useful level of maturity. This could reduce the need for dedicated renewable electricity. Still, at present the main expectation and scenarios are dedicated to electrolysis.*



ABOUT THIS REPORT

In response to the new wave of interest in green hydrogen and its potential to make a major contribution to the energy transition, IRENA has been extensively analysing the options for the production and consumption of green hydrogen, along with the policies that are needed to support and accelerate its commercialisation and wide adoption (see Box I.1).

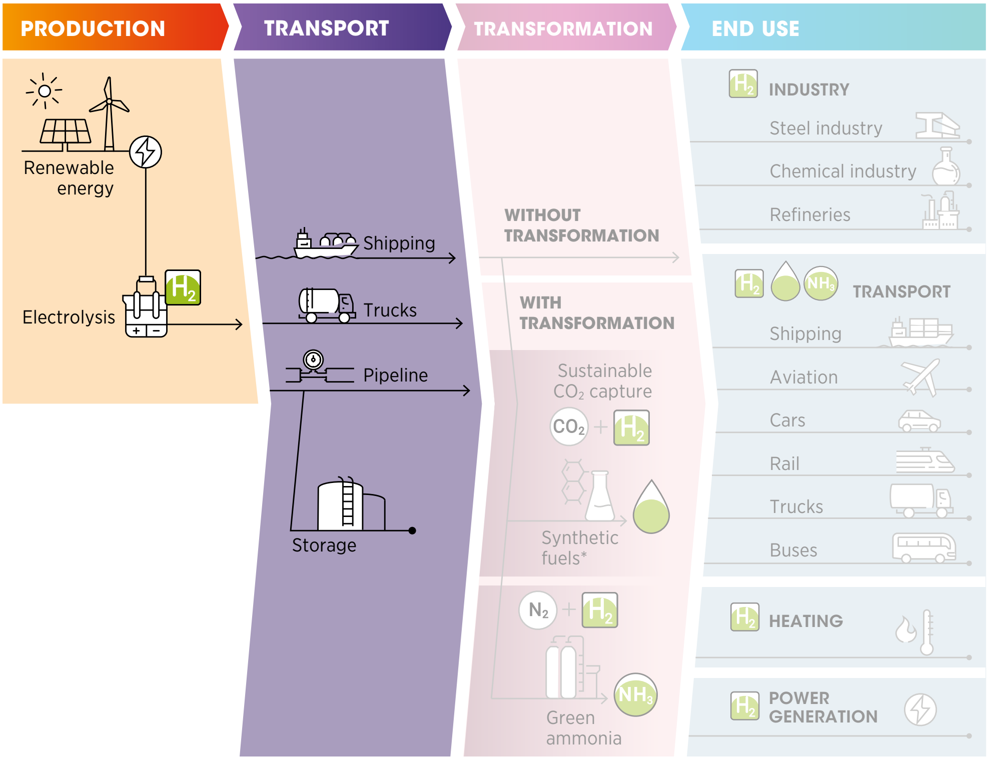
The report *Green hydrogen: A guide to policy making* (IRENA, 2020a) was the first IRENA publication focusing on green hydrogen policies. It outlines the main barriers and the key pillars of effective policy making for the uptake of green hydrogen. It provides a framework to open up a discussion about green hydrogen policy making.

The green hydrogen value chain, from production to consumption, is composed of multiple elements interlinked with the wider energy sector. Each element has its own barriers and challenges. This report focuses on the supply side of that value chain (Figure I.1). It examines the policies that are needed to support the production of green hydrogen by water electrolysis, its transport to locations where it will be consumed, and the options for storage. Future reports will focus on the use of hydrogen in various end uses (industry, aviation, shipping, etc.)

The production of hydrogen is a century-old activity. Hydrogen can be produced in multiple ways from different sources, so to differentiate them it has become customary to use colour-coding (IRENA, 2020a). Green hydrogen is, for the scope of this report, hydrogen produced through water electrolysis fuelled by renewable-based electricity.[2] Water electrolysers are devices that use electricity to separate water molecules into hydrogen and oxygen. Multiple water electrolyser technologies exist today. Four of them in particular hold promise for use in the near future: alkaline, proton exchange membrane (PEM), solid oxide electrolyser cells (SOEC) and anion exchange membrane (AEM). Alkaline and PEM technologies represent all the installed capacity today, while SOEC and AEM are at an earlier stage in the research funnel, but hold the promise of improved performance. PEM, AEM and alkaline electrolysers work at low temperatures (< 60-80°C), while SOEC work at a high temperature (> 700°C) (see Annex 1).

2 *Other pathways are available for the production of hydrogen from renewable energy, with thermochemical, photo-catalytical and biochemical processes (IRENA, 2018a). They are currently at the research stage with a low technology readiness level and are not considered in this report.*

Figure I.1 Green hydrogen value chain and the focus of this report



The transport of hydrogen is essential when electrolyser facilities are not close to locations where hydrogen is consumed. It can be transported in a variety of ways, including by truck, ship and pipeline. However, to efficiently transport hydrogen, it must either be compressed or liquefied or further synthesised into other energy carriers such as ammonia, methane, methanol, liquid organic molecules or liquid hydrocarbons, which have higher energy density and can be transported using existing infrastructure.[3] Various barriers exist to the use of each of the transport modes or treatments. In general, each method is better suited to some specific end use and distance.

The storage of hydrogen is crucial to the uptake of green hydrogen, and hydrogen's suitability for storage brings additional value to the whole energy sector. Hydrogen can provide seasonal storage for the power system, a service providable by a limited range of technologies; additionally, hydrogen storage is also essential to maintain a steady input to applications that operate continuously (e.g. the steel industry). Hydrogen can be stored in steel or composite tanks, or in underground geological formations.[4]

3 Another option is ad/absorption in solid matrices, but the high density is compromised by the relevant weight.

4 Hydrogen can also be stored in solid matrices, and in this case the relevant weight is less important, while the higher volumetric density can be a desired property.

This report explores the main barriers to the advancement of green hydrogen production and the development of the necessary infrastructure for its transport and storage (Chapter 1). It provides a map of the policies needed in the future and aims to provide insights on the policy options. This forms a basis on which to understand future challenges, providing national examples and case studies to highlight effective policies (Chapter 2).

Finally, it separates policy recommendations into various stages to help countries at varying levels of deployment address barriers and formulate suitable pathways (Chapter 3).

Box I.1 IRENA's work on green hydrogen and hard-to-abate sectors

This report is part of IRENA's ongoing body of work to provide its member countries and the broader community with analytical insights into the potential options, the enabling conditions and the policies that could deliver the deep decarbonisation of economies. IRENA provides detailed global and regional roadmaps for emission reductions, alongside assessment of the socio-economic implications. The 2021 *World Energy Transitions Outlook* includes detailed analysis of a pathway consistent with a 1.5°C goal. Building on its technical and socio-economic assessment, IRENA is analysing specific facets of that pathway, including the policy and financial frameworks needed. One particular focus is on the potential for green hydrogen. Recent IRENA publications on this topic include:

- Hydrogen from renewable power (2018)
- Hydrogen: A renewable energy perspective (2019)
- Reaching zero with renewables (2020) and its supporting briefs on industry and transport
- Green hydrogen: A guide to policy making (2020)
- Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5°C climate goal (2020)
- Renewable energy policies in a time of transition: Heating and cooling (2020)
- Decarbonising end-use sectors: Practical insights on green hydrogen (2021)[a]
- Green hydrogen supply: A guide to policy making (2021)
- Green hydrogen for industry: A guide to policy making (forthcoming)
- Green hydrogen for aviation and shipping: A guide to policy making (forthcoming)

These reports complement IRENA's work on renewables-based electrification, biofuels and synthetic fuels and all the options for specific hard-to-abate sectors.

This analytical work is supported by IRENA's initiatives to convene experts and stakeholders, including IRENA Innovation Weeks, IRENA Policy Days and Policy Talks, IRENA Coalition for Action and the IRENA Collaborative Platform on Green Hydrogen. These bring together a broad range of member countries and other stakeholders to exchange knowledge and experience.

a Authored by IRENA Coalition for Action

1 CURRENT STATUS AND CHALLENGES

At present the supply chain for green hydrogen is minimal, and the use of green hydrogen is limited to a few small projects. Rapid growth is necessary, therefore, for the industry to scale up to the size needed to make a significant contribution to the energy transition.

This section explores the current status of green hydrogen and barriers to creating a large supply of it, starting with water electrolysis and continuing to transport and storage.

1.1. CURRENT STATUS

1.1.1 Electrolyser capacity

Installed electrolyser capacity, at just around 200 megawatts (MW), is far below the size necessary for the projected future consumption of green hydrogen. However, capacity is expected to increase sharply according to the growing number of announcements of large new electrolyser projects.

Estimates of the green hydrogen pipeline are evolving very rapidly. In 2020, the pipeline for the next five years was estimated to be about 18 gigawatts (GW), but that increased sharply a few months later. Estimates vary widely according to announcements made, between 33 GW (BNEF, 2021a) and above 90 GW (Hydrogen Council, 2021).

As might be expected, most projects that have been announced are in locations that either have a developed national hydrogen strategy or a significant fleet of renewable energy power plants. Geographically, projects announced for construction up to 2035 are clustered in Europe and Australia, but these are not the only regions expecting increased electrolyser capacity (see Box 1.1).

Box 1.1 Selected announcements of electrolyser projects

The estimated electrolyser capacity by 2030 increased from 3.2 GW to 8.2 GW in Europe alone over five months (from November 2019 to March 2020). Many relatively small electrolysers have been announced; only one project, the HySynergy project in Denmark, reaches 1 GW.

In Australia about 22 GW of electrolyser capacity has been announced. In contrast to Europe, larger projects predominate. The "Asian Renewable Hub" was a 2014 proposal to create the world's largest renewable energy plant in Western Australia. Initially the concept was to connect Asia to Australia with a dedicated cable to export the electricity produced in Australia. In late 2020 the project was updated to become a hub for the production of green ammonia, with the 26 GW of wind and solar photovoltaic (PV) capacity to be coupled with 14 GW of electrolyser capacity. Other Australian projects include the H2-Hub project (3 GW) and the Pacific Solar Hydrogen project (3.6 GW).

The Arabian peninsula is also attracting investment. Air Products, ACWA Power and NEOM announced a USD 5 billion project for a 4 GW green ammonia plant to be operational by 2025 in Saudi Arabia. At the same time, the Oman Company for the Development of the Special Economic Zone at Duqm (Tatweer) signed a memorandum of understanding with the ACME group to invest USD 2.5 billion to set up a green hydrogen and green ammonia facility.

China is expected to deploy 70-80 GW of electrolysers by 2030, according to research by the China Hydrogen Alliance. In 2020, 28 green hydrogen production projects were announced across China.

Project-specific information on upcoming electrolyser projects can be found in IRENA Coalition for Action white paper *Decarbonising end-use sectors: Practical insights on green hydrogen*.

Sources: Acwa Power (2020); BNEF (2021b); European Commission (2020a); Heynes (2021).

1.1.2 Electrolyser manufacturing capacity

In 2018 the world's electrolyser manufacturing capacity was about 135 MW/year (IRENA, 2020b). Similar to the announcement of electrolyser projects, electrolyser manufacturers have been announcing expansion of their manufacturing capacity, each aiming for the hundreds of megawatts scale (Box 1.2 presents examples).

Global manufacturing capacity is expected to rise to 3.1 GW/year by the end of 2021 (BNEF, 2021b). But total manufacturing capacity will need to expand further to meet either the current targets for installed capacity on time (for example the EU targets, see Figure 2.1) or the overall energy transition targets. To achieve total installed electrolyser capacity of 5 TW by 2050, as projected by IRENA (2021), global manufacturing capacity of 130-160 GW/year will be needed, up to 50 times the expected manufacturing capacity of 2021. Delays in increasing manufacturing capacity now will make it necessary to ramp up the rate of deployment more steeply later.

Box 1.2 Selected announcements of projects to expand electrolyser manufacturing

Thyssenkrupp is a German conglomerate and one of the world's largest producers of steel. Electrolyser production is among its activities. In 2020 it announced plans to increase its annual electrolyser production capacity to 1 GW/year. Green hydrogen is expected to assist Thyssenkrupp to reduce CO_2 emissions from steel production in the future.

ITM Power is a British company that manufactures PEM electrolysers. The company is a partner in the Gigastack project, the largest planned electrolyser factory in the world at moment, which is currently in the front-end engineering and design phase and has an initial target of delivering 300 MW/year, with a view to ramping up to 1 GW/year.

NEL is a Norwegian company that provides solutions for the production, storage and distribution of hydrogen. It is expanding the electrolyser production capacity of its facility at Herøya Industrial Park (Norway) to 500 MW/year, with future expansion plans of up to 2 GW/year. The 500 MW production line at Herøya Industrial Park is scheduled to become operational in mid-2021.

Haldor Topsøe is a Danish company that specialises in carbon emission reduction technologies for chemical and refining processes. The company recently invested in a manufacturing facility that produces SOEC with a total capacity of 500 MW/year. The facility has the option to potentially expand to 5 GW/year. Construction will begin in 2022 and the facility is set to become fully operational by 2023.

Iberlyzer is a joint venture between Spanish companies Iberdrola and Ingeteam, which aims to commission the first large-scale electrolyser production plants in Spain. Operations are set to begin in 2021 and the company aims to reach 200 MW of electrolyser manufacturing capacity by 2023. To help deliver this project, as well as other projects in Spain, Iberdrola has signed a memorandum of understanding (MoU) with NEL.

Sources: BEIS (2020); Diermann (2020); Frøhlke (2021); Iberdrola (2020); Løkke (2021); NS Energy (2020).

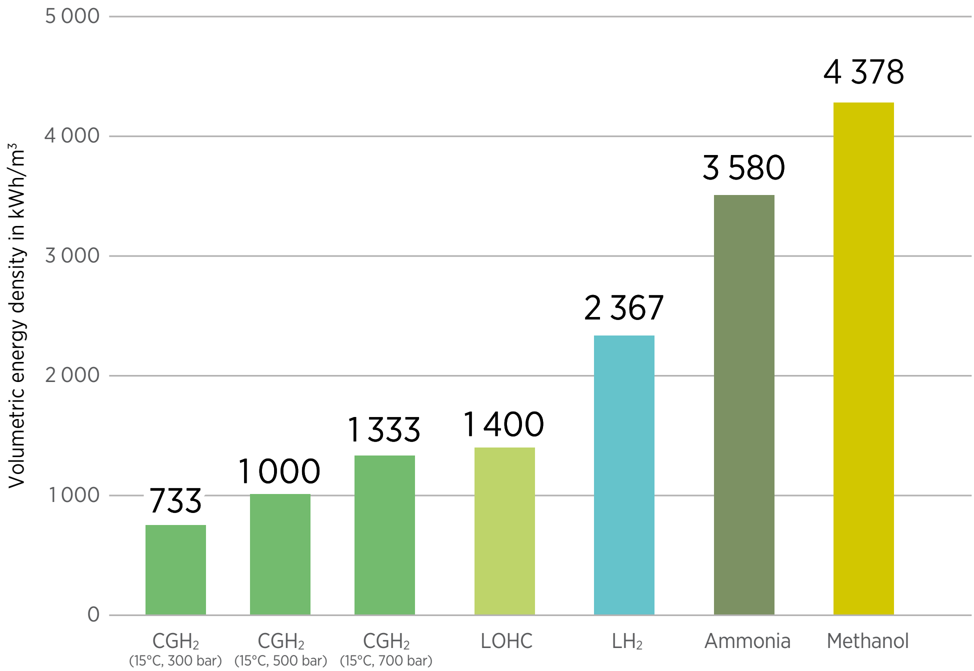
1.1.3 Modes of transporting hydrogen

The energy sector has experience of transporting gases over long distances. However, hydrogen presents additional challenges due to its physical properties. It has a high energy density by weight (33.3 kilowatt hours [kWh] per kilogram [kg] compared to 13.9 kWh/kg for methane), but has a low energy density by volume (3 kWh per cubic metre [m^3] compared to 10 kWh/m^3 for methane under normal conditions).

Essentially, to transport the same amount of energy, larger volumes of hydrogen need to be moved. For this reason, hydrogen is treated to reduce its volume when being transported. The currently available treatment options are compression, liquefaction, the use of a liquid organic hydrogen carrier (LOHC)[5] and conversion into ammonia, methanol or synthetic fuels. Each of these solutions increases its energy density by volume.

5 *LOHCs are organic compounds, like toluene, that can absorb and release hydrogen through chemical reactions.*

Figure 1.1 Volumetric energy density of various solutions to transport hydrogen



Notes: CGH_2 = compressed gaseous hydrogen; LH_2 = liquid hydrogen.

Sources: Ehteshami and Chan (2014); Nazir et al. (2020); Singh, Singh and Gautam (2020); Teichmann, Arlt and Wasserscheid (2012).

Compressed hydrogen can be transported by truck or by tube trailer in gas cylinders with pressures between 200 and 700 bar. For example, a jumbo tube trailer can carry up to 1100 kg of hydrogen compressed at 500 bar (HyLAW, 2019).

Transporting compressed hydrogen by truck is viable for short distances (up to a few hundred kilometres) and for low volumes. For longer distances, hydrogen is usually transported in liquid form. Liquefying hydrogen requires cooling it to a temperature of –253°C or below. Up to 3 500 kg of liquid hydrogen can be transported by one truck (Hydrogen Europe, 2020).

As volume and distance increase, trucks become a less feasible option. Instead, pipelines of compressed hydrogen can be used. They can potentially transport thousands of tonnes per day. But there are currently only about 5 000 kilometres (km) of hydrogen pipeline (compared to 3 million km of fossil gas pipeline), mainly in industrial clusters in Asia, Europe and North America (Hydrogen Analysis Resource Center, 2016). One option would be repurposing pipelines currently dedicated to fossil gas for the transport of green hydrogen. Repurposing pipelines may involve the replacement of valves, regulators, compressors and metering devices, but, in some cases, depending on the pipeline material, it could also require replacement of the actual pipelines.

Pipelines can also be used to transport ammonia, and some already exist for this purpose. One example is the 2 700 km Togliatti-Odessa pipeline.

Finally, hydrogen can be transported by ship. For shipping, the main pathways are liquid hydrogen, ammonia, LOHC, methanol or synthetic liquids. The government and industries of Japan have started various initiatives to assess the feasibility of these options (see Box 2.3).

Ammonia, methanol or synthetic fuels can also be the final products consumed by the chemical industry, or used in the power and transport sectors as an alternative fuel. Green ammonia, for example, is considered a very promising option to power larger ships.

1.1.4 Hydrogen storage

Two main hydrogen storage options currently exist: tanks and underground geologic formations.

Tanks of various sizes and pressures are already used in industry. They are more suited to low volumes (up to around 10 000 m^3) and frequent use (daily), and have high operating pressures (around 1 000 bar).

Storage underground is possible in different types of reservoirs, but the most feasible to date are salt caverns, which are also used for fossil gas storage. Underground storage is more suited to large volumes and long timeframes (weeks to seasons), and has a lower operating pressure (50–250 bar).

Salt caverns are spread across the globe, but some countries have limited capacity. Asia Pacific, South America, Southern Europe and the west coast of North America, for example, have few such salt caverns. For regions that do have suitable formations, however, the potential is usually vast and orders of magnitude larger than needed. Salt caverns are used for hydrogen storage in only two countries (the United States and the United Kingdom). The total capacity in use stood at about 250 gigawatt hours (GWh) in 2019 (Blanco and Faaij, 2018; BNEF, 2019; Caglayan et al., 2019; Hévin, 2019).

1.2. HYDROGEN SUPPLY **BARRIERS**

Despite the powerful factors driving the global uptake of renewable energy and green hydrogen, and the number of players supporting the transition, multiple barriers are challenging the scale-up of electrolysers and hydrogen transport infrastructure.

The most relevant barriers include the high costs, sustainability issues, unclear future and lack of demand, unfit power system structures, and lack of technical and commercial standards.

1.2.1 Cost barriers

A major challenge to the widespread production of green hydrogen is economic. To be economically attractive, green hydrogen should reach cost parity with grey hydrogen for sectors already using hydrogen, and with fossil fuels for uses not yet using decarbonised solutions.

However, current technology options are still expensive, both for the production and the transport elements of the value chain. The costs of producing and transporting hydrogen are related to the current performance of the main technologies that are available; each of them has room for improvement (see Box 1.3). The cost barrier is particularly felt by the first movers, and current investors in green hydrogen technologies are reporting it among the main barriers for their projects (IRENA Coalition for Action, 2021)

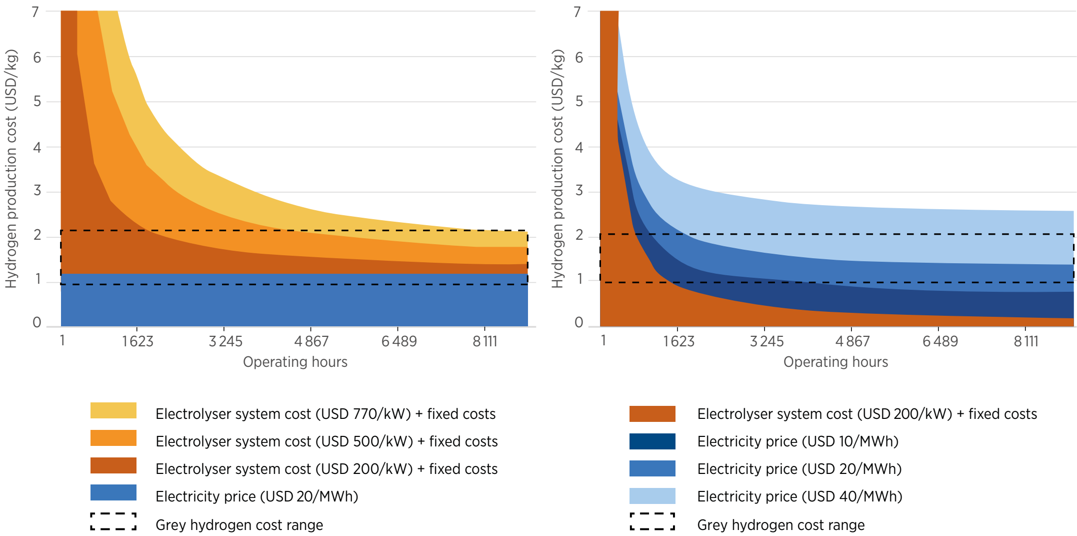
Production costs

The production cost of green hydrogen depends on the investment cost of the electrolysers, their capacity factor, which is a measure of how much the electrolyser is actually used, and the cost or price of electricity produced from renewable energy, depending on whether it is produced fully on-site or purchased from the grid or through power purchase agreements (PPAs) (see Section 2.2).

Green hydrogen projects are also capital-intensive, which makes financing an important factor. In 2020 the investment cost of an alkaline electrolyser stood at about USD 750-800 per kilowatt (kW), with a high sensitivity to capacity (below 1 MW capacity, the investment cost could double). Under optimal conditions of low-cost renewable electricity, green hydrogen can achieve cost competitiveness with fossil-based hydrogen, noting however that operational hours of just 3 000-4 000 hours per year are needed to achieve the greatest reduction in the per-unit cost of investment (IRENA, 2020b) (Figure 1.2).

The price of electricity procured from solar PV and onshore wind plants has decreased substantially in the last decade. In 2018 solar energy was contracted at a global average price of USD 56/MWh and onshore wind at USD 48/MWh (IRENA, 2019a). New record-low prices were agreed around the world in 2020, down to USD 13.5/MWh for solar PV in Abu Dhabi (United Arab Emirates). Still, given these values and the capacity factors of Variable Renewable Energy (VRE) power plants, current costs for green hydrogen have a range of around USD 4-6/kg. By comparison, the cost of grey hydrogen is currently about USD 1-2/kg (Figure 1.2)

Figure 1.2 Hydrogen production cost depending on electrolyser system cost, electricity price and operating hour



Note: GJ = gigajoule. Efficiency = 65% (lower heating value). Fixed operational cost = 3% of the capital costs. Lifetime = 20 years. Interest rate = 8.0%. Fossil fuel range: grey hydrogen, considering fuel costs of USD 1.9–5.5/GJ for coal and fossil gas.

Source: IRENA (2020b).

Conversion costs

The compression process for trucks, considering the capital costs of the compression plant and the electricity consumption, adds around USD 1-1.5/kgH_2 (Parks et al., 2014). Similarly, the liquefaction process could add around USD 2-3/kgH_2 (DOE, 2019). Estimates of the cost of conversion from hydrogen to ammonia in 2030 are in the range of USD 0.4-0.9/kg. Reconversion can double or triple these costs; however, ammonia can be used as a feedstock and as a fuel, so this process may not be needed. The cost to convert hydrogen into an LOHC and then extract it back are expected to be in the order of USD 1.3-2.3/kg by 2030 (McKinsey, 2021).

Transport costs

Transporting hydrogen generates additional costs. Too high transport and conversion costs will make not economically sustainable to transport green hydrogen, and electrolysers would only be built close to large demand centers.

Transport costs are a function of the volume transported, the distance and the energy carrier (see Figure 1.3). Moreover, the invested costs of the infrastructure itself (trucks, ships, pipelines) have to be added to the operational costs of transport.[6]

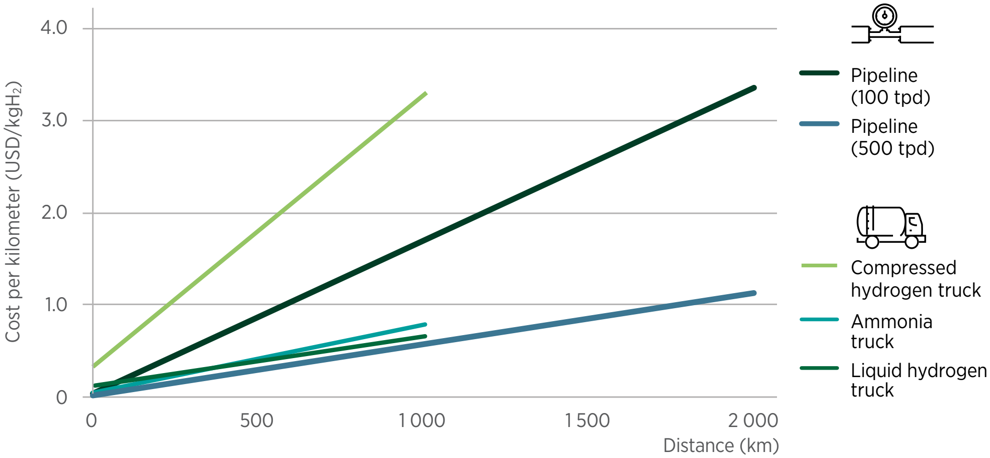
For short distances, trucks are the first option as they can be used almost everywhere. Using trucks to transport compressed hydrogen is more expensive due to the fact that these trucks can only carry a small amount of hydrogen, making the use of liquid hydrogen trucks a cheaper solution (although the conversion costs are much higher for liquid hydrogen, as discussed above).

Operational transport costs via pipeline are minimal and depend on distance and flow rate: higher flow rates allow achieving economies of scale leading to lower additional costs per unit of hydrogen transported. However, repurposing or building a new hydrogen pipeline is capital-intensive, in the order of millions of dollars per kilometre (Rödl, Wulf and Kaltschmitt, 2018). The major cost is the pipeline investment component, and hydrogen pipelines costs can be 110-150% the costs for fossil gas pipelines (Guidehouse, 2020). In contrast, fossil gas pipelines can be repurposed for hydrogen at 10-25% of the greenfield cost. Hydrogen transport by pipeline can be just one-tenth of the cost of transporting the same energy as electricity (Vermeulen, 2017).

Where possible, for long distances and large volumes the shipping option has the lowest cost (particularly with hydrogen stored in the form of LOHC or ammonia), followed by pipeline at high transported volumes. Still, the cost of transporting liquid hydrogen is quite high due to the high cost of adapting the tank for long journeys with reduced boil-off of hydrogen. For large volumes, shipping green ammonia is the lowest-cost option and adds a few USD cents per kg of hydrogen for each additional kilometre.

6 In Figure 1.3, these costs are represented as the values at 0 km.

Figure 1.3 Costs for hydrogen transport as a function of the distance by selected transport mode



Notes: Costs presented do not include conversion costs. Final costs in any transport mode depend on many variables and the values here presented are indicative. Weighted average cost of capital = 7%; useful life of infrastructure= 20 years; tpd = tonnes per day.

Source: Elaborated from IEA (2019); Nazir et al. (2020); Singh, Singh and Gautam (2020); Teichmann, Arlt and Wasserscheid (2012).

Storage costs

Storing compressed hydrogen is at least 50% more expensive than storing methane, given the lower specific energy of hydrogen, but storing hydrogen in salt caverns can be 1% of the cost of storing electricity, in particular for seasonal use (Wijk and Chatzimarkakis, 2020).

The levelised cost of storage depends on the cycling of the storage facility, i.e. how often it is used. For hydrogen storage, cycling is basically the number of times during the year that the facility is filled and emptied. The more the storage is used, the lower its additional cost will be per unit of hydrogen delivered. For this reason, technologies with high capital costs and small volumes (such as pressurised tanks or liquefied hydrogen tanks) need to cycle often to reduce their total delivered cost per unit, while solutions with low capital investment needs, such as salt caverns, are suited to a low number of cycles per year (e.g. seasonal storage).

Assuming 30 years of useful life, the use of pressurised tanks with a daily cycle currently adds USD 0.2–0.85/kg to the cost of hydrogen. These costs are expected to decrease as more tanks are deployed (BNEF, 2019). Storing hydrogen in salt caverns cycling twice a year adds between USD 0.1/kg (repurposed cavern) and USD 1/kg (greenfield investment) to hydrogen costs. These costs are also expected to decrease, to one-third of today's value (BNEF, 2019; Lord, Kobos and Borns, 2014). It should be noted that this seasonally stored hydrogen would be used in periods when other forms of energy are not immediately available and, therefore, energy prices typically increase.

Box 1.3 Energy losses of the hydrogen supply technologies

For the production of green hydrogen, different electrolyser technologies are available: alkaline, PEM, SOEC and AEM; the small market is, however, dominated by alkaline and PEM technologies.

Typical electrolysis efficiency is around 66%: this means that to produce 1 megawatt hour (MWh) of hydrogen (or 30 kg), around 1.5 MWh of electricity are needed. Some higher efficiency figures are already reachable. Alkaline electrolysers have a slightly higher efficiency and are cheaper than PEM electrolysers. Despite this, PEM electrolysers are receiving considerable interest from research institutes and developers. PEM technology can deliver pressurised hydrogen with a high purity, with lower stack degradation under conditions of dynamic operation (typical if connected to VRE power plants), satisfying a greater variety of hydrogen demands. It also has a lower footprint (less space is needed to host the plant).

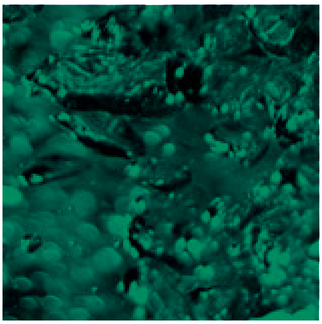
The available technologies do not share the same characteristics: a brief description is presented in Annex 1.

For its transport and storage, the low volumetric energy density of hydrogen causes the main challenges. Each mode of hydrogen production, treatment and transport requires a certain amount of energy and can result in energy losses. The higher the energy losses, the more renewable electricity capacity is needed. This would increase the annual pace of renewable capacity commissioning needed to meet targets for the decarbonisation of the energy system. The process of producing compressed hydrogen requires between 1 kWh to up to 7 kWh per kg of compressed hydrogen, depending on the compression level, while liquefaction requires up to 12 kWh/kg. However, efforts are being made to reduce this consumption down to 6 kWh/kg. Furthermore, about 1.65% of the hydrogen is lost during the liquefaction process, and around 0.3% of the liquefied hydrogen is "boiled-off" per day during transport and storage

The whole process of absorbing hydrogen and releasing it back via LOHCs such as toluene can lose the equivalent to 15-20% of the hydrogen content due to energy consumption and loss of hydrogen in the conversion. Ammonia production has a relatively low efficiency (around 55% from electricity to ammonia) and unless ammonia is the end product, its reconversion back to hydrogen will consume an additional 15-20% of the hydrogen content.

Research and development (R&D) are set to improve the efficiency of both the production and the conversion of green hydrogen, reducing in turn the overall costs of this decarbonisation solution.

Sources: DOE (2021, 2009); Ecuity et al. (2020); IRENA (2019b); Nazir et al. (2020); Niermann et al. (2019); Simbeck and Chang (2002); Soloveichik (2016); Stolzenburg and Mubbala (2013); Teichmann et al. (2012).



1.2.2 Sustainability issues

Grey hydrogen production from methane emits about 9 $kgCO_2/kgH_2$. However, this value considers only the production of hydrogen: the methane used to produce it needs to be transported and this activity implies leakages. Methane is an important GHG and methane leakages are relevant contributors to climate change. Estimates of anthropogenic methane emissions are subject to a high degree of uncertainty, but recent estimates put them at around 335 Mt per year (Saunois et al., 2016), equivalent to 28 810 Mt of CO_2 in climate impacts.[7]

Reduced CO_2 emissions are the major benefit of green hydrogen. However, if the renewable energy used for green hydrogen electrolysis, storage and transport is not sustainably produced, it could have an impact in the form of displaced CO_2 emissions.

Sustainably produced green hydrogen is made with additional renewable electricity (IRENA, 2020a), to ensure that electrolyser consumption does not increase fossil fuel consumption elsewhere or displace more efficient uses of renewable electricity. This is summarised by the **principle of additionality**: if there are other productive uses for the electricity being generated from renewable sources, that electricity should not be diverted from those uses to produce green hydrogen. Instead, green hydrogen should be produced only from additional renewable energy capacity that would not otherwise be commissioned and electricity that would not be otherwise consumed.[8] This is especially important for developing countries, which may be at risk of developing renewables projects dedicated to green hydrogen for export, with the risk of slowing the decarbonisation of their own electricity mix.

In addition, while renewable energy plants can ensure no additional emissions, grid electricity (composed of both renewable and fossil fuel power plants) cannot ensure low emissions at all times. The electricity feeding the electrolyser should have an emission factor below 190 grams of CO_2/kWh in order for electrolytic hydrogen to have lower CO_2 emissions than grey hydrogen (IRENA, 2020a).

Also, **converting and transporting** hydrogen can create additional CO_2 emissions, especially converting to LOHC (Reuß et al., 2017). The emissions during the transport stage are directly related to the energy efficiency of the transport mode and the energy density of the carrier. In the short term, trucks transporting hydrogen will most likely continue to use fossil fuels. Transport with trucks can easily erode the CO_2 emission reduction benefits. For instance, transporting compressed hydrogen for 400 km in a truck using diesel would emit about 3 $kgCO_2/kgH_2$ (Wulf et al., 2018). Liquid hydrogen reduces the CO_2 contribution per kilogram of hydrogen moved, given its higher energy density. This needs to be weighed against the additional emissions during the liquefaction step. For example, assuming current German grid electricity and EURO 5 trucks, liquid hydrogen transport is estimated to have a lower impact than compressed hydrogen in GHG emission terms for distances over 450 km (Rödl, Wulf and Kaltschmitt, 2018).

The main source of GHG emissions for pipelines is the energy consumption for compression, but the added emissions are relatively small. For instance, a pipeline transporting 40 tonnes per day for 400 km would have emissions in the order of 0.1 $kgCO_2/kgH_2$ (Wulf et al., 2018).

There are currently few national and international voluntary systems to calculate these emissions, and only a fraction of hydrogen is certified (IRENA, 2020a). In the absence of such schemes, there is the risk of unsustainable fossil fuel-based options entering the market, marketed as low-carbon without proper benchmarking or indication of the effective emission reduction.

7 Assuming a 20-year global warming potential factor for methane equal to 86 (IPCC, 2013).

8 The principle of additionality is one component of the pillars for green hydrogen policy making presented in IRENA (2020a).

1.2.3 Lack of clarity regarding future demand

Notwithstanding great promises and national plans, the green hydrogen sector is still in its infancy. The large majority of countries in the world still do not have a hydrogen strategy - even among those which already have a substantial use of hydrogen. Even those countries with a recent strategy may not have supporting policies in place yet. Project pipeline estimates vary widely and there is no real experience with electrolysers at gigawatt scale.

Moreover, many strategies include **blue hydrogen** (grey hydrogen with carbon capture and storage) among the possible solutions. While this route would provide only partial decarbonisation, the presence of competitors reduces the opportunities for green hydrogen producers.

There is still very little value recognition for green hydrogen. While interest in the idea is growing, no real demand exists yet for products made using green hydrogen, such as green steel or green ammonia.

Instead, the demand for such products is irrespective of the origin of their feedstocks. Means of placing a value on the benefits of green hydrogen (e.g. fuel mandates, blending quotas, public procurement requirements) are not widespread.

Hydrogen is still not publicly traded, in contrast to other sources of energy, as the trading of hydrogen is possible through bilateral agreements between companies.

Without a clear perspective on the consumption of hydrogen, infrastructure development may have no impetus behind it. Investing in new grids, repurposing existing infrastructure and building dedicated port terminals is capital-intensive activity that needs clear vision of the points of origin and offtake of green hydrogen.

1.2.4 Unfit power system structures

Electrolysers are flexible resources (see Annex 1) and could participate along with other technologies to provide the power grid with ancillary services. However, electrolysers are not currently allowed to provide their full range of services to the power grid, like many other demand-side resources. In some countries, compensation for ancillary services may not even be established (IRENA, 2020c). While this is not a barrier to their deployment, it hinders the opportunity to add a revenue stream and reduce the cost of hydrogen.

Short-term imbalances between load and generation can be met by many flexible resources, including batteries, but the options to fix long-term imbalances are limited. One solution is to use green hydrogen, generated and stored during a high VRE production period, and used in power production facilities (hydrogen-ready turbines, fuel cells) when VRE availability is low. However, current pricing structures, in particular in liberalised markets, do not provide enough certainty about the return on investment.

Moreover, in systems with high VRE penetration, electricity prices and seasonal electricity price differentials have fallen, making it harder for potential seasonal storage to recover costs (FTI, 2018). Even if there is a net benefit to the system and society at large, investors in the power system may not have sufficient incentives to provide seasonal storage. Current power market structures are typically unable to signal the value of secure supply and therefore fail to secure capacity to cover extreme events.

1.2.5 Lack of technical and commercial standards

Hydrogen can be as safe as the fuels in use today, with proper handling and controls. However, the need to transport and store hydrogen brings hazards that needs to be addressed.

Indeed, hydrogen has a long history of safe use in industry. For green hydrogen to become widely accepted in applications where it is not already used, it will become increasingly important to develop and implement internationally agreed codes and standards covering the safe construction, maintenance and operation of hydrogen facilities and equipment, along the entire supply chain. Such universal standards do not currently exist. Efforts are, however, being made in this direction. For example, international standardisation activities for hydrogen technologies under the ISO Technical Committee 197 (ISO/TC 197) have in particular advanced for the transport sector (ISO, 2021).

Unsuitable quality standards for hydrogen currently impose restrictive conditions or limits on its transport. While norms have been adopted in relation to biomethane in several countries, this has not been the case for hydrogen. This is in part due to the fact that standards were developed in the fossil fuel era, with a focus on fossil gases (European Commission, 2019).

Virtually all relevant hydrogen-related codes and standards rest on a voluntary process based on consensus, but governments can encourage their progression with dedicated effort. Developing and obtaining consensus for changes to these standards is a long process. Hence, urgent action is needed now to avoid them becoming a barrier to action in the medium term. Competition among standards development organisations can also complicate the process (DOE, 2020a; Morgan, 2006; Nakarado, 2011).

2 POLICY OPTIONS

The barriers presented in the previous chapter are similar to the barriers faced by renewable energy technologies during their inception phase.

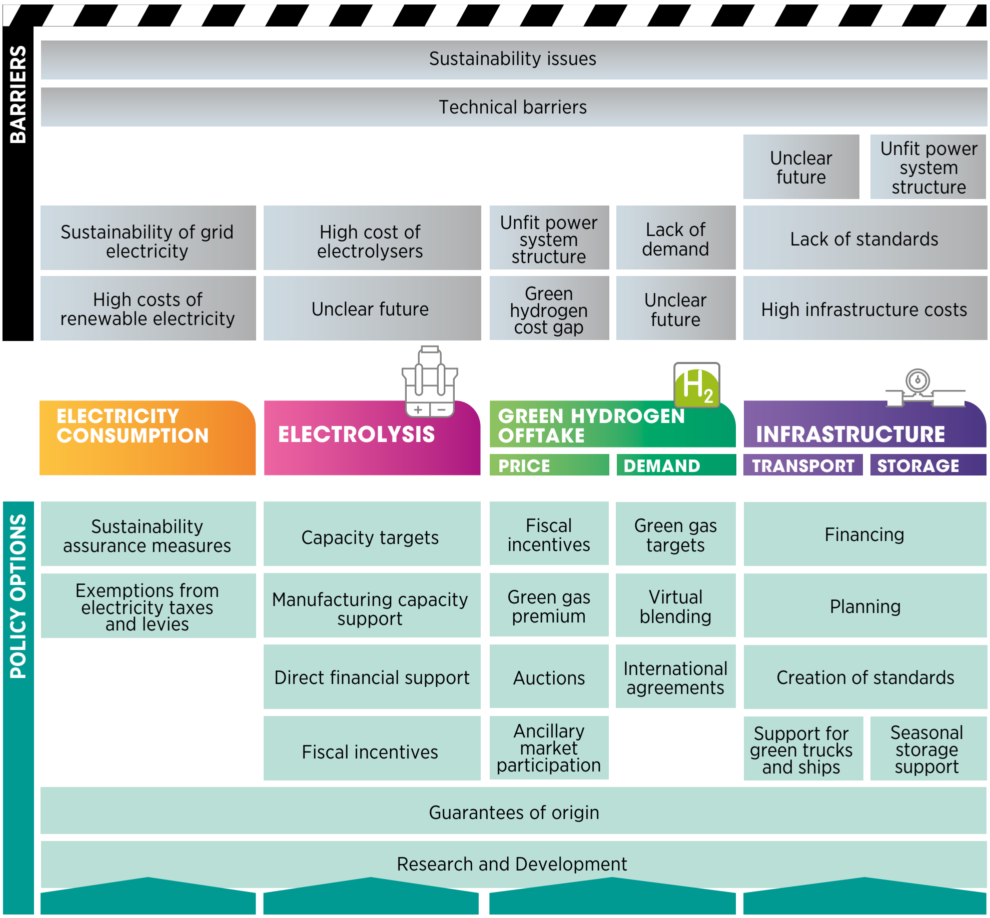
The policies presented in this chapter are possible options to address these barriers, creating a positive environment for the production, transport and trade of green hydrogen (see Figure 2.1). Multiple policy options are available for some of the barriers. The options can be attributed to specific parts of the value chain, similar to the barriers.

Current government incentives and policies targeted at electrolysers and infrastructure remain limited. But solutions can also be drawn from the experience governments have gained in supporting renewable energy in power and heating, as well as from policies in the industry sector.

As presented in Figure 2.1, a wide range of policies are available to support the development of a green hydrogen industry. Policy makers can prioritise actions depending on the maturity of the national hydrogen sector. Chapter 3 presents a series of stages, providing a roadmap of actions needed to support green hydrogen supply as it moves from niche to mainstream.

H_2

Figure 2.1 Barriers and policy options for the supply of green hydrogen



2.1. POLICIES TO SUPPORT **ELECTROLYSER DEPLOYMENT**

Reducing GHG emissions in hard-to-abate sectors through the use of green hydrogen will require large amounts of it, larger than current (mostly grey) hydrogen production. That, in turn, requires a rapid scale-up in the number and overall capacity of the electrolysers used to make hydrogen. The roadmap described in IRENA's *World Energy Transitions Outlook* foresees 400 Mt of green hydrogen consumed by 2050, produced by a total installed capacity of electrolysers of 5 TW.

This section describes policies to achieve the necessary growth in electrolysers and reduction in capital costs, including electrolyser capacity targets, measures to support the scale-up of manufacturing capacity, and direct financial and fiscal support.

2.1.1 Electrolyser capacity targets

Renewable energy targets have become a defining feature of the global energy landscape. Some 166 countries around the world had adopted at least one type of renewable energy target by 2020, up from 43 countries in 2005 (REN21, 2020). Targets serve as a principal way for public actors to demonstrate a commitment to the energy transition and can range from official government announcements to fully fledged public plans, such as a national hydrogen strategy (IRENA, forthcoming a).

Current targets for electrolyser capacity usually feature in national or regional hydrogen strategies, often with varying degrees of commitment. Target setting can ensure the appropriate parallel development of renewable energy and electrolyser capacities, while at the same time avoiding the diversion of renewable energy from end uses that may be more effective in decreasing GHG emissions (IRENA, 2020a). Electrolyser targets in national strategies tend to not differentiate between electrolyser technologies.

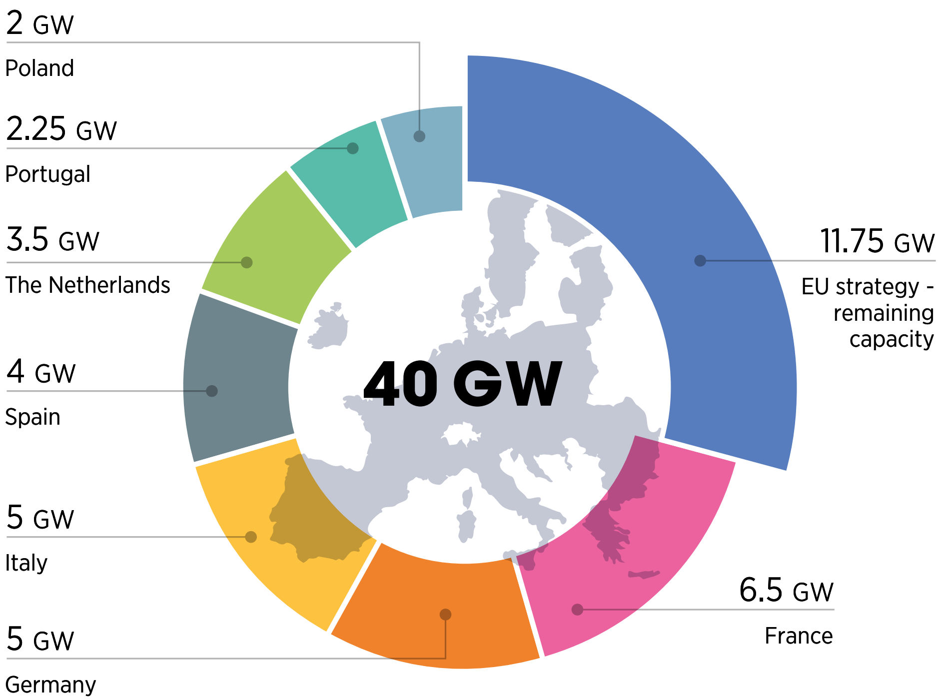
The EU hydrogen strategy sets targets of 6 GW of electrolysers by 2024 and 40 GW by 2030 (European Commission, 2020a).[9] Seven member states of the European Union have already developed national strategies, vision documents or roadmaps. By 2021 the total capacity target in those strategies added up to around 28 GW by 2030 (Figure 2.2). In addition, private developers in the European Union announced plans to install around 8 GW of electrolysers (see Box 1.1), mostly in the Netherlands, for which the pipeline is around 2.6 GW, and Denmark (1 GW).

Another country with ambitious targets is Chile, which aims to become major hydrogen producer and exporter by 2030. To achieve that goal, the government aims to see 5 GW of electrolysis capacity built or in development by 2025 and to reach 25 GW by the end of the decade (MinEnergía, 2020).

Targets should not be seen as a capacity cap (indeed, they should be seen as a floor), and they can and should be surpassed when possible and benefitting (hand in hand with a more rapid renewable energy expansion), but upscale in the manufacturing capacity will be needed. Such upscale would also decrease the investment component of hydrogen cost.

9 40 GW of electrolysers are also expected in neighbouring countries, to provide hydrogen to the European Union.

Figure 2.2 Electrolyser capacity targets in European hydrogen strategies, 2030



Note: The diagram takes the average of the target ranges adopted by the Netherlands and Portugal.

Source: IRENA analysis based on national strategies.

2.1.2 Support for the scale-up of manufacturing capacity

Given the strategic importance of green hydrogen in making a low-carbon future possible, governments are already pursuing **industrial policies** to support the scale-up and efficiency of electrolyser manufacturing capacity. In addition to defining long-term targets, such policies and measures are mainly related to setting up dedicated funds to support improved manufacturing processes and technological advancement.

Scaling up production by creating electrolyser "gigafactories" (i.e. able to produce electrolyser capacity at gigawatt scale) will provide economies of scale, especially when designs are standardised and modules are optimised. For example, increasing the manufacturing scale from 10 to 1 000 units (1 MW each) per year could decrease the cost of the stack, a main component of the electrolyser, by almost 60% (Mayyas et al., 2019). This could be complemented by increasing the module size from today's average of 1 MW to 100 MW, potentially leading to an additional 60% cost reduction (IRENA, 2020b). Some manufacturers already claim that 50-75% cost reductions are achievable in the short term, driven by the upcoming scale-up in manufacturing capacity (Collins, 2021a; 2021b) (see Box 1.2). The manufacturing process currently still requires a large amount of manual work. But it could be increasingly automated as the volume of electrolysers increases.

Policy makers can support scaling up with dedicated financial support.

In June 2020 the US Department of Energy announced a fund of USD 64 million to support 18 projects as part of the "H2@scale" vision for an affordable hydrogen value chain. In particular, around USD 17 million will be provided to projects to scale up electrolyser manufacturing to the gigawatt size (DOE, 2020b).

Policies to scale up manufacturing can also be pursued by countries aiming to export know-how and equipment. One such country is Germany, where project H2Giga is dedicated to the development of the gigawatt-scale serial production of electrolysers. It shares with other two projects (H2mare and TransportHyDE) a EUR 700 million fund from the country's research ministry (Franke, 2020). The development of German manufacturing capacity to export electrolyser technology might be attractive, exploiting the current technology leadership that Europe currently holds for PEM.

2.1.3 Direct financial support

Targets and support for the scale up and efficiency of factories could help attract investment from private-sector participants. However, invested costs would still be high and financial incentives such as grants and loans would be needed. Such financial incentives have already seen widespread use in policies to support renewable energy (IRENA, IEA and REN21, 2018).

To date, electrolysers for the production of green hydrogen have benefited from subsidies for pilot programmes and other R&D-related funding. Since the beginning of the COVID-19 pandemic, many countries have committed to support hydrogen through recovery funds. Estimates indicate a global commitment of at least USD 20 billion (Energy Policy Tracker, 2021).

France committed USD 8.3 billion by 2030 in its recent national strategy, which includes USD 2.4 billion in 2020-2022 as part of its COVID-19 recovery packages (Petrova, 2020). Germany allocated USD 8.4 billion to the creation of a demand-driven market for hydrogen as part of the USD 156 billion stimulus package for economic recovery from the COVID-19 crisis (not including the USD 2.4 billion dedicated to partnerships with countries where hydrogen can be produced) (Reuters, 2020)

In April 2020 the Australian Renewable Energy Agency announced a funding round of about USD 52 million (AUD 70 million) for green hydrogen, targeting electrolysers of at least 5 MW and preferably 10 MW or larger (ARENA, 2020a).

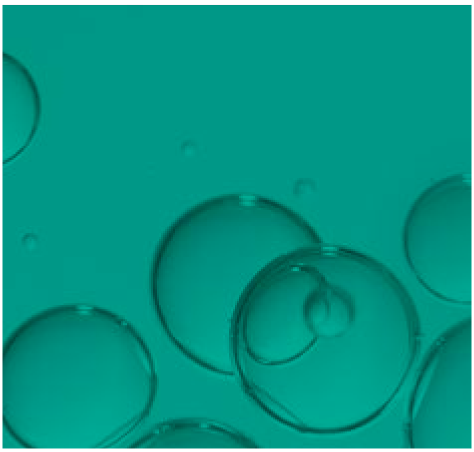
In the United Kingdom, the BEIS Hydrogen Supply Competition aimed to identify and demonstrate bulk green and blue hydrogen supply solutions, replicable at a significant scale. In the first phase, the programme used a fund of USD 6.6 million (GBP 5 million) to conduct feasibility studies. A second phase is supporting pilot projects with USD 20 million (GBP 15 million) of funding. Five different projects, some of them of relatively large in size, have been selected for the second phase (BEIS, 2020).

2.1.4 Fiscal incentives

Industrial policies commonly provide support via a dedicated fiscal regime. For green hydrogen, policies that reduce the financial burden related to electrolyser investment will reduce that cost element and strengthen the business case.

The effect of these measures on governments' fiscal budgets is expected to be very small at the beginning, given the limited electrolyser production capacity. Sliding fiscal incentives (decreasing as capacity is deployed) could keep pace with the improving economics of the industry.

There are already some examples of fiscal incentives for electrolysis. In California, projects that combine PV with electrolysis are eligible for a 3.9% state tax exemption for manufacturing and R&D, the Sales and Use Tax Exclusion Program for up to USD 20 million per project per calendar year, and the California Research Credit and the "California Competes" Tax Credit for a minimum of USD 20 000 (Eichman et al., 2020).



2.2. POLICIES TO ENSURE ELECTRICITY IS SUSTAINABLE AND TO SUPPORT ITS COST-COMPETITIVENESS

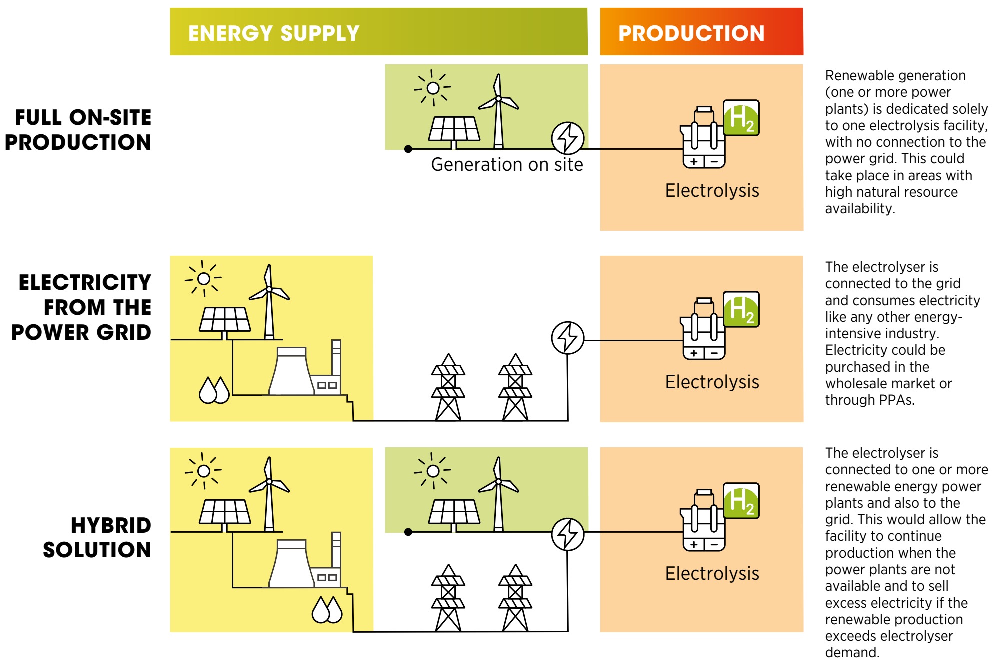
Once electrolysers are built, the electricity used must be renewable-based for the production of green hydrogen. To compete with traditional carbon-intensive hydrogen, this electricity must be affordable. This section assesses the policy options for ensuring that electrolysers have access to cost-competitive renewable-based electricity. It is possible to conceptualise three production models (Figure 2.3): full on site production, electricity from the power grid or a hybrid solution.

Connecting electrolysers to the grid may be beneficial because they would be able to produce at any moment of the year, as opposed to the full on-site electricity generation model where hydrogen production is tied to times where the power plant is generating electricity. Greater utilisation of the electrolysers in a year would consequently decrease the investment component of the hydrogen cost (Figure 2.5). Moreover, fully dispatchable hydrogen production could reduce the need for hydrogen storage infrastructure as production can be matched with the needs of the end user. However, measures would be needed to ensure the electricity use is sustainable.

In addition, the grid electricity prices paid may be high due to grid fees, taxes and levies, and exemptions may be considered.

Multiple IRENA reports have delved into the policies to accelerate renewable energy deployment and how they can be designed to minimise the price of renewable energy-based electricity (for example IRENA 2019a; 2015; IRENA, IEA and REN21, 2018). The following sections present policies and strategies to reduce the price of grid electricity for electrolysers that are connected to the grid (in either the grid-only model or the hybrid model), while also increasing the share of renewable electricity consumed.

Figure 2.3 Production models



2.2.1 Policies enabling sustainability of electricity

For grid-connected electrolysers, the sustainability of the electricity consumed must be ensured (IRENA, 2020a). Guarantees of origin can certify such features, while policy makers can also impose certain conditions or encourage them to keep true the principle of additionality (see Section 1.2.3)

Introducing a guarantees of origin scheme

A guarantee of origin (GO) system, as presented in IRENA (2020a),[10] certifies all the emissions related to the production and transport of hydrogen, and can be used to determine whether hydrogen can be more effective for decarbonisation purposes than direct electrification or the use of bioenergy.

GOs should account for the effect of grid-connected electrolysers on the overall grid mix. To prove this, the temporal and geographical correlation between production and consumption should be guaranteed (Crone, Friese and Löchle, 2020).

Measures for additionality

Grid-connected electrolysers could draw upon new renewable capacity at the expense of other electricity uses because of growing electrolysis demand and a higher willingness-to-pay (possibly due to incentives). If an electrolyser is using electricity from the grid, that demand for electricity will be covered by the so-called "marginal plant" (i.e. the running power plant with the next highest operational cost in a specific moment). In most energy systems around the world, marginal power plants are fossil power plants, as renewable power plants generally have lower short-run marginal costs (IRENA, 2020c). Using grid electricity could then lead to higher use of fossil fuel capacity, effectively locking in fossil fuel generators for more years if additional renewable energy capacity is not deployed in time. This phenomenon could actually end up increasing the average CO_2 emissions for electricity by requiring the operation of units that would otherwise have been displaced (Bracker, 2017).

Different measures can be used to ensure that the use of renewable electricity by electrolysers does not take away opportunities for direct electrification uses that have higher pathway efficiencies and that can satisfy a larger share of final energy services (Crone, Friese and Löchle, 2020; IRENA, 2021, 2020d; IRENA, IEA and REN21, 2020; Malins, 2019; Timpe et al., 2017).

In particular, to keep true the principle of additionality, at least three elements should be followed: renewable electricity production and consumption should be (1) additional, and with a (2) temporal and (3) geographical correlation.

Examples of measures to take into account are:

- **Recasting the renewable energy target and quotas.** The renewable electricity capacity targets or quotas can be either increased to account for electrolyser needs or they could exclude the electricity consumed by electrolysers. This ensures that additional renewables deployment takes place.
- **Allow (or impose) PPAs with merchant power plants.** Grid-connected electrolysers could be asked to have PPAs with additional renewable energy power plants that are not receiving any other type of support. A methodology should be in place to ensure a temporal and geographical correlation between the electricity production unit and the electrolyser production.
- **Measures to take advantage of otherwise curtailed energy.** With high shares of VRE in the power mix, VRE curtailment may increase. Policy makers can promote electrolysers' consumption of electricity that otherwise would have been curtailed. This can be done by prioritising the development of electrolysers in areas with grid congestion due to excessive VRE production (for example, northern Chile, northern Germany and southern Italy). This measure alone may not justify the electrolyser's installation, since the number of hours of curtailment are less than that needed to achieve the greatest reduction in the per-unit cost of investment (3 000-4 000 hours) (IRENA, 2020b).

10 GOs are one of the policy pillars described in IRENA (2020a). The report contains more details on their current status and requirements.

Examples of policies already ensuring additionality can be found, particularly in the transport sector. California's Low-Carbon Fuel Standard (LCFS), for example, is designed to reduce the carbon intensity of transport fuels and states that the renewable electricity used for hydrogen-based fuels does not count towards meeting California's Renewable Portfolio Standard. Similarly, the LCFS does not allow the environmental benefits of green hydrogen to be claimed under the Renewable Energy Certificates or any other programme, except for the Federal Renewable Fuel Standard and California's cap-and-trade programme (CARB, 2019). In this way, California's government ensures that the LCFS system delivers its own emission reductions without taking advantage of other policies in place (and vice versa).

In the EU Renewable Energy Directive II (REDII), the electricity used for synthetic fuels can be counted as renewable only if the electrolyser plant adopts a full on-site electricity production model or if the synthetic fuel producer can prove that grid electricity is produced exclusively from renewable sources, ensuring that the renewable properties of that electricity are claimed only once. Currently the European Commission is working on a methodology to ensure additionality. The methodology should ensure that there is a temporal correlation between the electricity production unit and fuel production. Geographical correlation will be also be ensured: a synthetic fuel would be counted as renewable if, in the case of grid congestion, both the electricity generation and the fuel production plant are located on the same side in respect of the congestion.

2.2.2 Exemption from electricity taxes and levies

Electrolysis falls under energy-intensive processes, where the cost of electricity represents a large share of the total production cost. Electrolysers connected to the grid may be subject to industrial electricity prices, with the same taxes and fees normally levied on large consumers. Industrial electricity prices can be as high as USD 200/MWh in some countries (Eurostat, 2020; IEA, 2020a). Taxes and fees can represent a significant share of the final electricity price for industrial consumers, which translate into a higher operational component in the final cost of hydrogen (Figure 2.4).

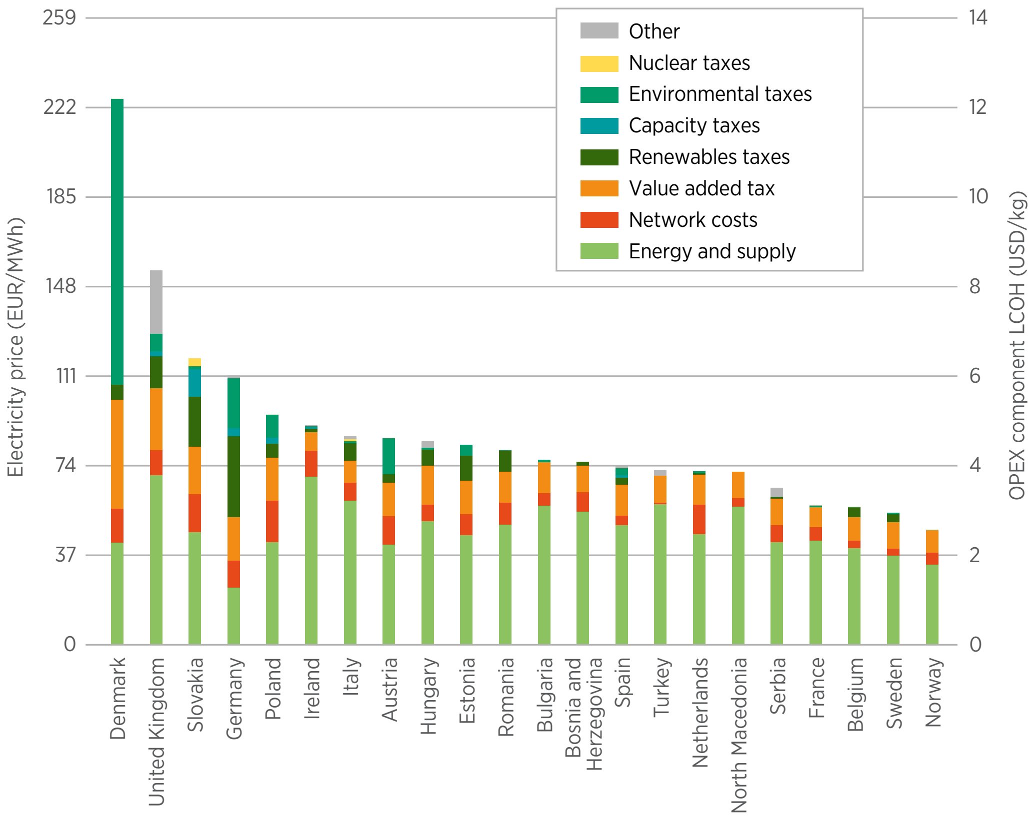
For example, an electrolyser in Germany that pays only the average electricity price component for large consumers (USD 24/MWh) could produce hydrogen at a cost of USD 2.5/kg if exempt from all taxes.[11] But when all the taxes and fees are added, the cost climbs to USD 7/kg. For this reason, Germany exempts electrolysers from the electricity tax (Stromsteuer) and the EEG renewables surcharge (Clean Energy Wire, 2020; OECD, 2019).

Electricity tax and levy exemptions for selected industries are a relatively common industrial policy. In fact, electrolysers are sometimes already indirectly supported by such industrial policies dedicated to energy-intensive industries. Electrolytic processes are exempt from electricity tax in Norway, France and the Netherlands (OECD, 2019).

Exempting electrolysers from taxes and fees can be a first move to reduce the cost of electrolytic hydrogen, strengthening its business case. As hydrogen production can be flexible, low taxes on tariffs can also be justified by the use of the power system during periods of low load and high VRE production (windy nights, for example) (see Box 2.2). Exemption should in any case be guaranteed only when the renewable share of the power mix is above a certain threshold. The tax exemption could also be introduced with a clear phase-out profile, for a certain amount of time or for a total capacity that may benefit.

11 Assuming an electrolyser cost of USD 770/kWh, 50% capacity load and an electrolyser efficiency (lower heating value) of 66%.

Figure 2.4 Industrial electricity prices by component, in selected European countries, 2019



Notes: Electricity prices for consumption above 150 GWh per year. LCOH = levelised cost of hydrogen. Right-axis values assume an electrolyser efficiency of 66%.

Source: IRENA analysis based on Eurostat (2020).

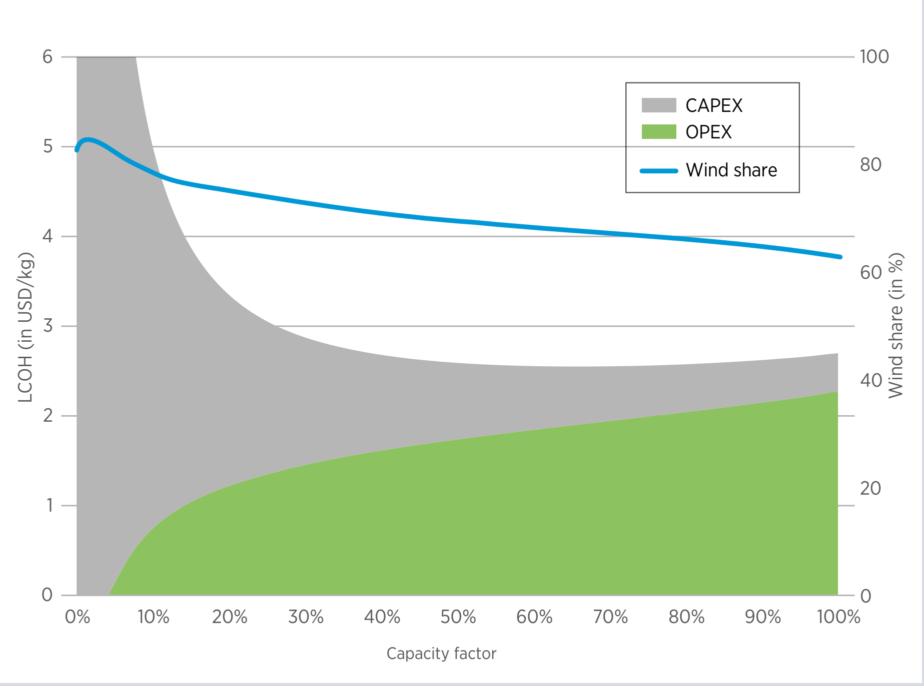
It should be noted that exempting electrolysers from taxes and fees increases the burden on the remaining customers and on other sources of system flexibility. That may change the competitive position of electrolysers relative to the other flexible resources. Attention should therefore be given to finding the best solution to levelling the playing field among flexible resources and avoiding excessive burdens on consumers. Tax exemptions can be a first step, but more strategic energy tax reform may be necessary to guarantee a fair energy taxation system.

It should be noted, however, that average electricity prices are not a good proxy to evaluate the economic attractiveness of a grid-connected electrolyser, since its flexibility allows it to operate in periods of low electricity prices (in liberalised markets) (see Box 2.2).

Box 2.1 Estimated cost of hydrogen from a grid-connected electrolyser in Denmark

In liberalised electricity systems with increasing shares of VRE, the energy component of electricity bills is expected to decrease as the VRE penetration rises (IRENA, 2020c).[12] In western Denmark, where VRE penetration is already high, wholesale electricity prices were below EUR 0/MWh for more than 1.5% of the time during 2019 and below EUR 20/MWh for about 6% of the time (Nordpool, 2020). Figure 2.5 plots the levelised cost of hydrogen using ascending 2019 western Denmark spot prices (exempt of all taxes and levies). It shows how the production cost of electrolytic hydrogen could drop below USD 3/kg with an electrolyser investment cost of USD 750/kW.

Figure 2.5 Correlation between levelised cost of hydrogen and operating hours of a grid-connected electrolyser, western Denmark, 2019



Notes: OPEX = operating expenditure; CAPEX = capital expenditure; electricity prices in ascending order, electrolyser invested costs = USD 750/kW; electrical efficiency (lower heating value) = 66%; discount rate = 7%.

Source: IRENA analysis based on western Denmark electricity spot prices in 2019 (Nordpool, 2020).

12 However, since this dynamic creates misalignments like the "missing money problem", measures to restructure the power system organizational structures will become necessary to support the power system to complete the energy transition (IRENA, 2020c).

2.3. POLICIES TO INCENTIVISE GREEN **HYDROGEN DEMAND**

Once electrolysers and renewable energy plants are built, and sustainability is ensured, green hydrogen can be produced. However, at least for the next decade, the cost of green hydrogen could still be higher than grey hydrogen and fossil fuels (IRENA, 2020b), even if policy supports electrolyser technology and brings electricity costs down.

Moreover, demand for green hydrogen and green products is, as of today, almost non-existent, so the willingness to buy higher-cost hydrogen is still missing.

Policy makers have various tools at their disposal to increase the demand for green hydrogen by closing the price gap with grey hydrogen and fossil fuels, by increasing its presence in the gas market, or by identifying off-takers outside national boundaries.

2.3.1 Policies to close the price gap between green hydrogen and fossil fuel-based alternatives

Fiscal support

Applying taxes and levies to grey hydrogen, along with dedicated support for green hydrogen, can assist in making green hydrogen cost-competitive with grey hydrogen. Hydrogen is not usually subject to taxes or levies, but they can be applied and tied to the GHG emissions associated with grey or blue hydrogen production.

In France, for example, grey hydrogen is subject to the carbon tax (Contribution Climat-Énergie) equivalent to EUR 44.6 per tonne of CO_2 (tCO_2), which was introduced in 2020 and is set to increase to EUR 100/tCO_2 in 2030. The current tax level raises the cost of grey hydrogen by USD 0.4/kg, which represents a 20-40% increase in cost (Dolci et al., 2019).

Green hydrogen tariffs or premiums

Part of the cost gap between green and grey hydrogen could be closed by offering tariffs or price premiums for the purchase of green hydrogen, to account for its environmental value.

Such support has been widely used to accelerate the deployment of renewable energy power plants, through feed-in tariff (FIT) and feed-in premium (FIP) schemes, for example. Similarly offering production subsidies for each unit of hydrogen produced can strengthen the economic case for electrolyser projects.

Green hydrogen tariffs or premiums can be compared to today's biomethane injection subsidies, present in various European countries. In France, the tariff for biomethane injected into the fossil gas grid is USD 53-166/MWh, depending on the size of the biomethane plant. A bonus can be added depending on the type of feedstocks used (REGATRACE, 2020). The upper bound of the French biomethane scheme would be equivalent to a tariff of around USD 5.5/kg of hydrogen, so it could already cover today's production costs.

Notably, a green hydrogen tariff covering green hydrogen costs equal to USD 6/kg (around USD 180/MWh) would be lower than the levels in the FIT scheme for renewable electricity in place a decade ago (when renewable electricity was at its inception like green hydrogen is today).

Previous experience with FIT and FIP schemes for renewable electricity can assist in designing a green hydrogen tariff or premium mainly focusing on some important policy design choices that must be made. They include setting the right tariff (tariffs that are too high can lead to windfall profits, but tariffs too low limit deployment), setting up a cost monitoring system to decrease the level of subsidy according to market evolution, determining a capacity cap to avoid excessive expenditure, introducing a premium floor and cap, and determining the source of the funds. Consideration should also be given to energy poverty and vulnerability, if consumers are going to pay the premium in their energy bills. For renewable power, when it became difficult to determine the right level of support, which varied from one context to another, auctions were introduced as a price discovery mechanism.

Auctions

By the end of 2020 about 116 countries had adopted auctions to support renewable energy deployment in the power sector (REN21, forthcoming). Auctions offer the potential for real price discovery, especially when there is uncertainty regarding how to price renewables-based generation. Auctions can be designed to work within a particular context or policy purpose, using many design elements including those related to auction demand, qualification requirements, winner selection, and sellers' liability and risk allocation (IRENA, 2015). Auctions offer the ability to attract private investment, domestic and foreign, through clear and transparent processes. These qualities have made auctions one of the most widely adopted tools of the energy transition, even in countries without prior experience of supporting renewables.

A competition-based mechanism like an auction may be envisaged once the green hydrogen sector has been kick-started, and rapid replacement of grey hydrogen production with green hydrogen is possible. Since auctions lock in the winning projects for the whole duration of the contracts, which can go up to 20 years, only solutions aligned with the energy transition, such as renewables-sourced electrolysers, should be able to participation in the auction.

Auctions may also be based on the emissions green hydrogen would avoid compared to grey hydrogen. For each tonne of CO_2 avoided, producers could receive a premium as set by the auctions, which they would receive on top of revenues from selling hydrogen. One example is in the Netherlands, where green hydrogen can compete with other technologies in the context of the Dutch decarbonisation scheme (Box 2.3).

If an emissions trading system is already in place, auctions may award a carbon contract for difference, whereby hydrogen producers would receive the difference between the agreed strike price per avoided CO_2 emission unit and the average carbon price on the emissions trading system. This kind of arrangement is currently being considered in the European Union (European Commission, 2020a).

A benefit of the auction scheme would be to guarantee a scheduled rollout of green hydrogen to replace grey hydrogen, which could be phased out as the energy transition progresses.

Box 2.2 The Netherlands' SDE++ scheme

The SDE++ scheme, an auction scheme that allocates EUR 30 billion to renewables projects, demonstrates the Netherlands' material support for achieving environmental targets.

Specifically, the SDE++ scheme auctions various kind of projects based on the expected CO_2 reduction, including renewable energy plants, heat pumps, electrification of industrial thermal processes and hydrogen production, carbon capture and storage for industrial processes and hydrogen production.

For hydrogen, the scheme benefits from a complex policy design to both reward hydrogen and ensure its sustainability.

The SDE++ subsidy for green hydrogen can be up to USD 300/tCO_2 (about USD 3/kgH_2). This would be enough to close the gap between green and grey hydrogen, with an electricity price of above 80 USD/MWh.

In order to encourage the use of renewable electricity in the absence of a GO scheme, hydrogen production is promoted only for 2 000 full load hours a year. The upper limit in load hours is designed to make electrolysers operate during periods of low grid electricity prices only, which coincide with higher renewable energy production (IRENA, 2020c) (see Figure 2.5). This limit also relates to the fact that the SDE++ scheme assumes that in 2030 there will be at least 2 000 hours when the marginal plant for electricity production in the Netherlands will be 100% renewable.

Sources: European Commission (2020b); Netherlands Enterprise Agency (2020).

Participation of electrolysers in ancillary services procurement mechanisms

Conventional fossil fuel generation, with a controllable generation profile, is expected to be increasingly displaced by VRE generators as part of the energy transition. System operators will need flexible resources that can provide fast ramping capabilities to address variability from wind and solar PV.

Electrolysers can offer a flexible load that can provide balancing services to the power system, as they are capable of highly flexible operation (Table 1.1) (IRENA, 2020b). Ramping production up and down according to need, electrolysers can become a valuable asset to keep the power grid stable. By providing ancillary services, electrolyser would then receive an additional revenue stream. This could, in turn, reduce the final price of green hydrogen.

However, electrolysers need to be enabled to participate in the power market to provide this flexibility to the system. This is a challenge shared with many other innovative demand-side resources (e.g. electric vehicles, heat pumps and industrial loads), which may not currently have access to the power market to offer their flexibility. Participation in the ancillary services market could lead to greater economic viability for electrolysers. Policy makers should provide solutions to reward the flexibility electrolysers offer, while also allowing revenue stacking. In order to do so, two measures can be adopted:

- **Open the system services market to new actors.** System services markets are dominated by large, centralised power plants; however, other actors on the demand side could participate if enabled. Obtaining system services from new actors may require various measures, such as specific grid codes and upgrades to the system services procurement mechanisms (IRENA, 2020c; IRENA, IEA and REN21, 2018). Moreover, opening the doors to more actors would erode the revenue of fossil fuel power plants, facilitating their phase-out and accelerating the energy transition.

- **Adopt new system services products.** In some countries with high VRE shares, new ancillary services products have been adopted; since their existence is related to the presence of high VRE shares, these services are sometimes referred to as "flexibility products". More specifically, fast reserves, overgeneration management and ramping products have been identified as potential products needed for the energy transition and are, in some cases, already adopted (RGI, 2020). New products differ as they tend to recognise the specific characteristics of new technologies and the new needs of the power system. Examples are the UK Enhanced Frequency Regulation programme and CAISO's ramping products (IRENA, 2020c; Villar, Bessa and Matos, 2018).

In Germany the participation of small electrolysers is made possible through virtual power plants – or aggregators (IRENA, 2019b). Thyssenkrupp and E.ON have recently carried out the necessary tests on an existing alkaline electrolyser in Duisburg. The Thyssenkrupp electrolyser has proved to be able to ramp production up and down at the speed required to enter the market for primary reserve, where the entire offer service has to be fully delivered within a maximum of 30 seconds and be continuously available for at least 15 minutes (Thyssenkrupp, 2020).

2.3.2 Policies to increase the market share of green hydrogen

Policies to increase the market share of green hydrogen include targets for green gases and virtual blending mechanisms.

Green gas targets

Targets for green gases can be used to support renewable energy solutions, such as biomethane and green hydrogen. They are typically introduced in the form of targets specifying a set share of overall gas consumption from renewable gases, or in the form of a renewable blending mandate for gas supply (IRENA, IEA and REN21, 2020). Targets for gas mixes are effective in providing an indicative level of future demand and, therefore, of needed production or import capacity.

Targets in the form of blending targets are not very common as they may not be the best option for the use of a versatile energy carrier like hydrogen (see Box 2.3). France has introduced a target for renewable gas in the gas supply mix, specifying that 10% of the gas consumed should be renewable by 2030. It is part of the 2019 Climate Energy Act, which introduced numerous targets in the supply and end-use sectors.

Blending targets have, however, been considered as part of many hydrogen strategies. Portugal is considering a hydrogen blending target that rises from 1-5% by volume by 2025 to 75-80% by 2050 at both the transmission and distribution levels (DGEG, 2020). Italy's 2020 "National Hydrogen Strategy Preliminary Guidelines" envisage a blend of 2% hydrogen in the gas grid by 2030 (MISE, 2020). These targets are yet not mandatory and need to be further evaluated and adopted.

A different route has been undertaken by Spain. In the Spanish hydrogen strategy, the government included a 25% minimum contribution of green hydrogen with respect to the total hydrogen consumed in 2030 by all industries both as a raw material and as an energy source, such as refineries and the chemical industry. Setting a target for the hydrogen already used would not imply blending with fossil gas and it creates clarity over the demand for green hydrogen in the next 10 years. The equivalent of 25% of current hydrogen consumption in Spain is about 125 000 tonnes per year (MITECO, 2020).

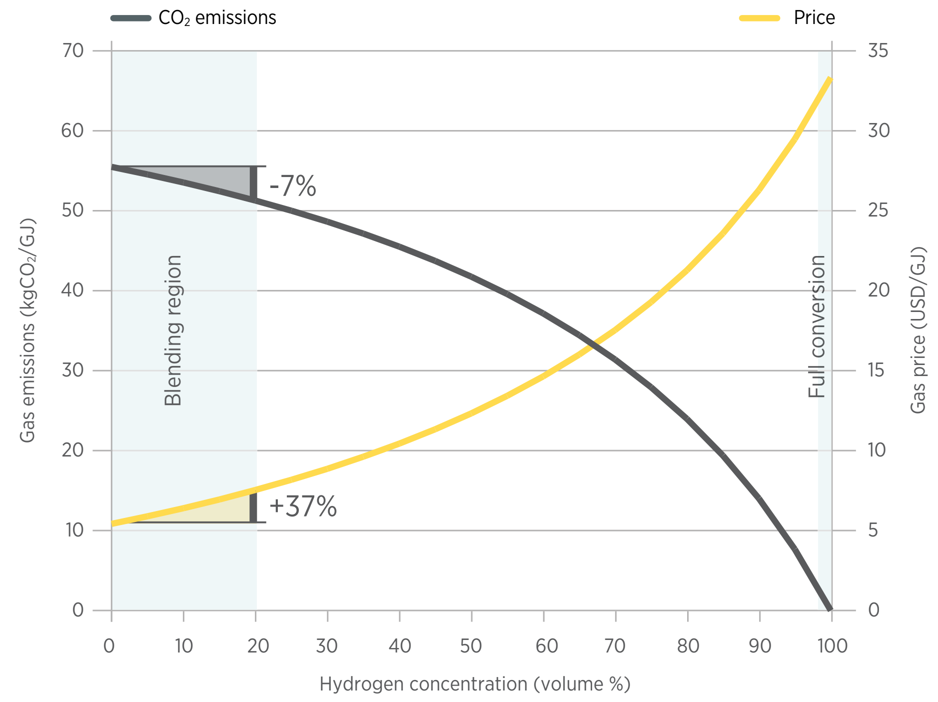
Box 2.3 Blending hydrogen in fossil gas grids

If only the production side of the green hydrogen value chain exists (i.e. electrolysers), with no dedicated infrastructure in place and no immediate use for green hydrogen, policy makers could create a secured offtake for hydrogen production by allowing the blending of hydrogen in the existing gas grid.

Deciding to blend hydrogen in the prevalent fossil gas grid has the advantage of the capillary presence, in many countries, of such infrastructure, which connects many industrial and residential loads. This solution would also allow for gradual penetration of hydrogen in the gas system, in an orderly manner that would permit policy makers and system operators to face gradual challenges with time.

Blending may appear to be a solution to (partially) decarbonising the gas grid, but it presents specific challenges. Blending is a limited solution as the maximum share of hydrogen would be limited by the capabilities of the existing gas grid to around 20% by volume, before incurring safety issues (Quarton and Samsatli, 2018). Once that is reached, the only solution is to convert the grid to be 100% hydrogen-ready. However, a 20% hydrogen blend by volume translates into only about 7% in energy terms. This also means the CO_2 emissions reduction benefit is limited to about 7% (see Figure 2.6).

Figure 2.6 CO_2 benefit and gas price increase from blending and converting the gas grid to hydrogen



Notes: Fossil gas price = USD 5/GJ; green hydrogen cost = USD 4/kg (USD 33/GJ).

Once hydrogen is mixed in, the resulting gas is a blend unsuitable for neither applications that require pure hydrogen, such as fuel cells, nor for those with low tolerance. Hydrogen could be separated from the blend, but this is very expensive and challenging at low blending ratios, bringing additional costs of USD 5-6/kg without achieving the recovery of all the hydrogen (Melaina, Antonia and Penev, 2013).

Blending limits actually vary depending on the jurisdiction. In some cases the blending limit is not even defined as part of the gas specification. When specified, the limit is dictated by the element with the lowest tolerance to hydrogen. The most sensitive applications are end uses such as industrial applications (e.g. steel furnaces). This can lead to a very low limit (as low as 0.02% by volume) being accepted under national regulations (Van der Meer, Perotti and de Jong, 2020). Moreover, varying hydrogen limits between countries hinders cross-border trade.

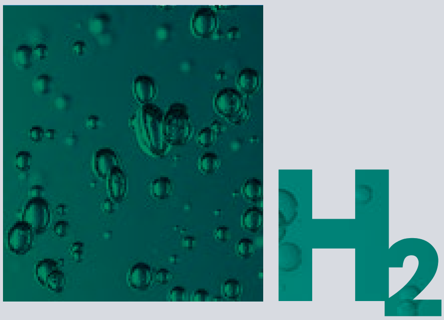
Hydrogen has a much higher cost per unit of energy than fossil gas, which means even a small share can make a large difference in cost. Even with a cost of green hydrogen at around USD 4/kg, equal to USD 33/GJ, it would be up to sixteen times more expensive than wholesale market fossil gas (USD 2-8/GJ): a 20% blend with a fossil gas price of USD 5/GJ would increase the total gas price by 37% (see Figure 2.6).

In addition, green hydrogen production might fluctuate with VRE production. This could create variable hydrogen content in the grid, which not all users can adjust to. A regulation could specify constant injection from any hydrogen production facility, but this could affect the cost (as storage would then be needed at the electrolyser site) and therefore limit production, contrary to the objectives of the policy makers. Gas composition variability in the grid is handled with models that predict the composition of the gas delivered for invoicing as realistically as possible. A similar approach could be followed to account for hydrogen variability. This would require development of specific models.

Finally, blending hydrogen in the gas grid could also be at odds with other policies for the decarbonisation of the energy sector, since blending would require adjustments towards achieving partial, rather than total, decarbonisation.

Blending hydrogen may divert a highly versatile energy carrier, precious for specific "hard-to-abate" sectors, across the whole energy sector served by fossil gas, many of which could instead benefit from more effective solutions, such as electrification and energy efficiency actions. These solutions result in those sectors that are not hard to abate becoming independent of gas, reducing the overall need for gas via the grid.

For these reasons, blending as a solution for the application of hydrogen should be carefully assessed to avoid diversion from less expensive, more efficient uses of green hydrogen.



Targets for a net-zero GHG emission energy system are relevant to the hydrogen sector too: achieving net-zero will require cutting emissions in the "hard-to-abate" sectors where green hydrogen can play an important role. In total, more than 120 countries had announced net-zero emission goals by November 2020 (World Economic Forum, 2020).

Virtual blending

One alternative to physical blending mandates are virtual blending requirements. Virtual blending would imply a quota obligation for certain hydrogen or gas consumers to use green hydrogen or, while not carrying out the physical use, buying certificates for equivalent green hydrogen consumption.

This idea is already used in green certificate systems for renewable electricity and could be explored for international trading in green hydrogen. This would require a robust certification system to avoid international double-counting, along with bilateral agreements for the trading of certificates. The approach could be useful to fund initial projects in remote locations with vast renewable resources, since it provides a price premium through the sale of certificates. Nevertheless, virtual blending is not aligned with a long-term net-zero emissions system, where each system needs to achieve real reductions in emissions rather than offsetting them through certificates.

2.3.3 International agreements for green hydrogen

In the long term, hydrogen could be globally traded just like gas, oil, coal and LPG are today. This dynamic has been recently experienced with LNG. The first international shipment of LNG departed from Algeria in 1964; 55 years later, in 2019, LNG accounted for 38.1% of all exchanges of fossil gas, with 21 countries exporting to 42 importers, and one-third of the global LNG volume was traded on a spot or short-term basis (GIIGNL, 2020; IEA, 2020b).

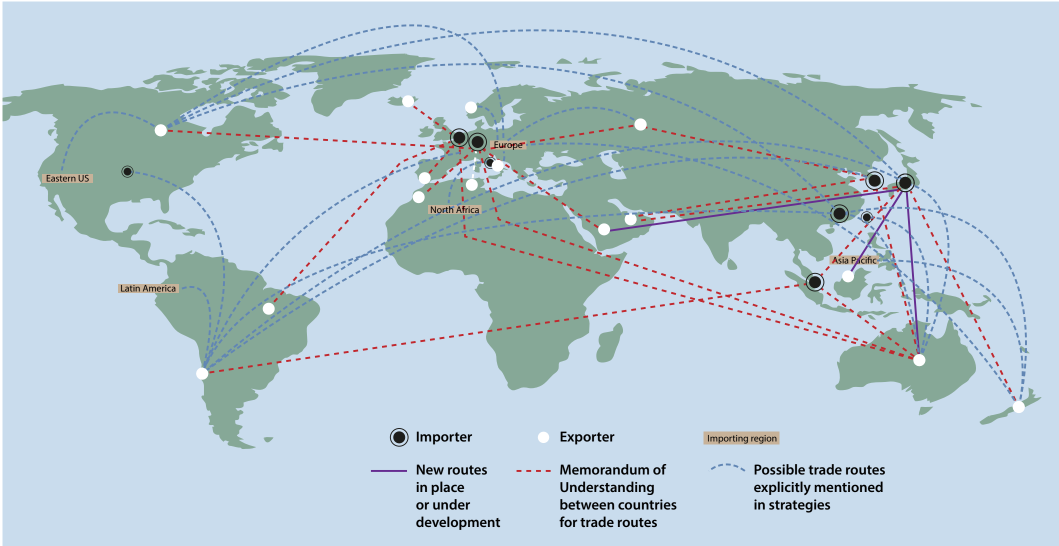
One notable difference with hydrogen is that production is less site-constrained compared to fossil fuels. It can be produced from different energy sources, with multiple transport options and different sustainability consequences. This makes it more similar to biomass markets, where the methods of production and transport play a big role in its sustainability. For this reason, when assessing the actions policy makers can take to kick-start the trading of hydrogen, a GO system is necessary to track hydrogen production technologies and transport routes to ensure sustainability (IRENA, 2020a).

Global trade in hydrogen does not exist today, and current projects for large green hydrogen facilities are planned to serve large local consumers. However, looking ahead, effective international supply chains will need to be in place to move large quantities of hydrogen. Policy makers will have a role to play in setting up such international supply chains and, in fact, the first routes are already planned. Published national hydrogen strategies show how countries foresee their role in the future hydrogen market. In some cases, national hydrogen strategies include plans to import large quantities of green hydrogen that cannot be produced locally; this is the case for Europe, Japan and The Republic of Korea. The opposite is also happening, with countries that have high hydrogen potential exploring the option of becoming exporters and identifying potential buyers. These include Australia, Chile and Norway. Finally, a small subset of countries is identifying an opportunity to become "hydrogen hubs", importing and exporting hydrogen thanks to geographical advantages (e.g. the Netherlands). Figure 2.7 illustrates the envisaged trade routes for hydrogen as of 2021.

These strategies are already slowly transforming into commitments between countries. In the last two years, various MoUs have been signed between countries to explore new trade routes, mainly by countries with an established hydrogen strategy.

Finally, in one particular case, the commitments have already been translated into practical action: Japan has one of the most comprehensive strategies for international energy trading, covering various energy sources and carriers. It is already testing various alternatives with different partners (Box 2.4).

Figure 2.7 **Envisaged trade routes for hydrogen as of 2021**



Notes: Hydrogen policies are evolving rapidly. Information on this figure has been kept as detailed and complete as possible at the time of writing, however more countries may have announced or planned new hydrogen routes.

Boundaries and names shown on this map do not imply any endorsement or acceptance by IRENA.

It should be noted that some strategies and MoUs make no differentiation between blue and green hydrogen, while in others fossil fuel-based solutions are still supported or considered for future international trade. However, as at least 120 countries have committed to a net-zero energy system (World Economic Forum, 2020), solutions such as green hydrogen will become the only viable way to reach these targets. Exporters of grey or blue hydrogen would then face the risk of stranded assets, which will be piled up to the stranded assets of the fossil fuel era.

International trading should not be at odds with scrutiny over the sustainability of hydrogen production and transport. The concept of additionality should be adhered to internationally. What that means is that the off-takers should also make sure that green hydrogen production and use are not displacing domestic use of renewable electricity. Scrutiny is also needed to ensure that hydrogen production is not adversely affecting the sustainability of the exporting country in any way, such as depriving populations of water in arid climates. In order to do this, a robust GO system for hydrogen is a crucial condition for establishing a global green hydrogen market and avoiding unfair competition from unsustainable hydrogen production modes (IRENA, 2020a).

Co-operation to create successful hydrogen routes could include the alignment of national research agendas and agreements on infrastructure development. In order to create international hydrogen value chains, countries are also making dedicated investments. In Germany, the stimulus package for the economic recovery from the COVID-19 crisis included EUR 2 billion for international partnerships for developing hydrogen value chains (Reuters, 2020).

Box 2.4 Japan's strategy for demonstrating diverse value chains

Hydrogen is a central piece of Japan's national energy strategy. The combination of limited fossil resources, high-cost renewables and large industries may lead to hydrogen becoming one of the key options to satisfy energy demand in a sustainable way. Moreover, the archipelagic nature of the country makes it a testbed for various shipping solutions.

The government has been working on international hydrogen trading since the 1990s, when it allocated USD 41.5 million (JPY 4.5 billion) to this goal (Mitsugi, Harumi and Kenzo, 1998). Japanese public and private stakeholders, backed by the government, have signed various bilateral agreements to import hydrogen produced in different countries, with different technologies and different shipping solutions. The first shipments from pilot or demonstration projects in Australia, Saudi Arabia and Brunei did not involve green hydrogen (Figure 2.7):

- The Australia-Japan pilot project is led by the HySTRA[13] and tests the viability of hydrogen from brown coal gasification, which is then liquefied and shipped to Japan. Both governments are supporting the project with almost USD 115 million (out of a total of USD 496 million). A liquid hydrogen carrier ship, "Suiso Frontier", was unveiled in 2019; it can carry 1 250 m^3 of liquefied hydrogen and should start operating between Australia and Japan in 2021. While the agreement for the commercialisation of hydrogen will depend on the presence of carbon capture and storage in Australia, this is not yet part of the pilot.

- Saudi Arabia's Aramco demonstration projects focus on the production of ammonia from crude oil, using enhanced oil recovery and carbon utilisation in methanol production. Forty tonnes of ammonia have been shipped from Saudi Arabia to Japan from the demonstration plants in one shipment.

- The collaboration with Brunei aims to prove the feasibility of using toluene (an LOHC) to ship hydrogen that is a by-product of a fossil gas liquefaction facility in Brunei. In May 2020 the hydrogen shipped in this way was used in a power plant in Japan.

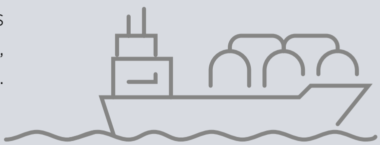
While these projects are not carbon-neutral, they can be useful to understand the most cost-competitive and sustainable ways of shipping green hydrogen. In the meantime, other routes to importing green hydrogen in Japan are being considered:

- NEL is working together with various Japanese companies on a feasibility study for a green hydrogen project in Norway. The hydrogen would be produced using hydropower and wind energy and would be delivered to Japan in the form of liquid hydrogen.

- Japan also signed a memorandum of co-operation with New Zealand in October 2018 to develop hydrogen technology. The hydrogen roadmap for Taranaki (in New Zealand) envisages 0.5-1 GW of electrolysis capacity dedicated to export by 2030, which is in line with the potential level of imports in Japan in the national strategy.

- In 2020 the Japanese company Mitsubishi Heavy Industries made a capital investment in the Australia-based H2U Group, a developer of green hydrogen and green ammonia projects.

Sources: MHI (2020); HySTRA (2021); Nagashima (2018; 2020); Venture Tanaraki (2020).



13 *A consortium of companies including Kawasaki, Iwatani, Shell, J-Power, Marubeni, ENEOS and "K"LINE*

2.4. POLICIES TO SUPPORT **HYDROGEN INFRASTRUCTURE**

Green hydrogen will need to be transported when demand centres are not co-located with the electrolysers. As presented in Chapter 1, this can be an expensive and energy-intensive activity. However, policy makers have tools at their disposal to address these issues. These include policies to support hydrogen grid construction and/or repurposing, and measures to support seasonal storage, green ships and green trucks.

2.4.1 Policies to support hydrogen grid construction and/or repurposing

Repurposing parts of existing fossil gas grid infrastructure is a cost-effective opportunity to scale hydrogen infrastructure and is not a novelty. Previous experiences that could serve as examples for hydrogen include the conversion from town gas to fossil gas in Europe with the start of North Sea production during the 1960s, and the conversion from low-calorific gas to high-calorific gas in northwest Europe with the closure of the Groningen field (IEA, ENTSOG and EZK, 2020; McDowall et al., 2014).

Transmission system operators (TSOs) in Germany are already looking to repurpose 5 900 km of pipelines (about 15% of the total national network) to hydrogen, with only 100 km of new pipelines. The network cost is expected to be USD 726 million (EUR 660 million) (DW, 2020). The Dutch TSOs Gasunie and Tennet (the main gas and electricity TSOs) are assessing the potential to use the existing gas grid for hydrogen through the HyWay 27 feasibility study (Netherlands Government, 2020).

Planning hydrogen infrastructure

A clear long-term policy for hydrogen would enable investors in green hydrogen production to assess the prospects and routes for future markets and attract investment in the needed infrastructure. Such long-term signals are already present in hydrogen roadmaps, vision documents and strategies (IRENA, 2020a). Some already provide an indication of government-selected international routes and preferred transport solutions.

These overarching strategies can be improved with actual long-term energy sector planning, such as national plans to repurpose parts of the gas grid. Dedicated planning is especially important in view of the capital-intensive and long-lived nature of gas grids, considering the lock-in effect the gas grid may have on industrial and residential users over the long term.

At the same time, not all of the gas grid will need to be converted. In a net-zero emissions world, the electrification of heating, cooling and transport, and the use of bioenergy, energy efficiency and other more cost-effective and immediate solutions, will displace the need for a gaseous energy carrier in many applications, thus reducing the need for a gas grid (IRENA, 2020e). While this is not a challenge for the development of hydrogen infrastructure, it highlights the need for careful planning in order to avoid unnecessary spending on repurposing programmes and to avoid locking end uses into inefficient uses of energy. Converting the gas network to hydrogen would require assessment to identify those applications that will need to be supplied with green hydrogen first. While a hierarchy of importance should be laid out in hydrogen strategies, economic changes could shift potential hydrogen demand, creating stranded assets in the hydrogen infrastructure.

Hard-to-abate industrial sectors do represent the "anchor demand" for hydrogen. Steel, ammonia and chemical plants will need hydrogen for their processes and, in part, for high-grade heat, although electrification can also be an option for providing heat (AFRY, 2021; IRENA and State Grid Corporation of China, 2019; IRENA, IEA and REN21, 2020).

The first step for policy makers, before aiming to convert the gas grid to hydrogen, should be to identify "no-regret" areas for hydrogen pipelines based on industrial demand. Beyond that, the anticipated additional demand from the aviation and shipping sectors will inform pipeline decisions. Future hydrogen networks will be smaller than the current fossil gas networks. Step-by-step sectoral planning for hydrogen infrastructure can reduce the risks of oversizing or creating stranded assets or abandoned projects (AFRY, 2021),[14] which would have non-trivial social and economic effects.

Indeed, as the energy transition unfolds and the traditional routes of energy markets are being challenged, key stakeholders are already abandoning gas infrastructure projects, resulting in stranded assets and costs (without benefits) that fall on the shoulders of ratepayers. It has been estimated that during the 2010s, EUR 440 billion has been spent on failed or failing fossil gas infrastructure projects in the European Union alone (Global Witness, 2021).

Regulatory framework for hydrogen infrastructure

Gas grid TSOs are subject to strict regulation of their activities. Policy makers need to provide them with an updated regulatory framework that enables the repurposing of their grids. Repurposing the grid would need the definition of a regulatory framework and hydrogen quality standards for pure hydrogen grids, since these have been limited to industrial clusters to date (ACER and CEER, 2021).

In the early days of development, hydrogen regulations could, in specific circumstances, exempt private developers so as to facilitate the development of business-to-business hydrogen networks. As hydrogen networks evolve, it will become increasingly important to put in place regulations that adapt to market conditions. Thus, it is crucial to enact flexible regulations that react to market dynamics using periodically conducted market analyses.

Regulation of the gas grid can also avoid situations of positional power abuse, such as in situations where pre-existing players do not allow competitors to access the same infrastructure.

The general principles of hydrogen regulation should be clear from the beginning to enable its cross-border transport and provide certainty and predictability to market participants, helping them make investment decisions. Areas where international agreement is needed are hydrogen quality standards, operational safety standards, pipeline integrity requirements, fuel specifications and appliance compatibility standards.

Standardisation would make the use of GOs easier because the product would always be the same. A global standard would create a more liquid market, bringing lower costs for consumers. Benefits of standards go beyond individual cross-border projects. They can spread the benefits of learning-by-doing as foreign companies that design and construct the equipment begin to operate overseas. This will enable costs to decrease more rapidly and will enhance safety as a result of applying best practices.

In the European Union, the Sector Forum Energy Management has a "Working Group on Hydrogen" that is already working towards the standardisation of the hydrogen sector among member states (JRC, CENELEC and NEN, 2019). However, the work is still at the pre-normative stage and it will take years to create actual standards.

14 AFRY (2021) presents the no-regret options for the European case.

Financing hydrogen infrastructure

TSO investment will be needed to develop hydrogen gas infrastructure, both for repurposing and for building new pipelines. The cost of repurposing programmes may be recovered through fees on gas bills. However, in the case of major expansion in a short period of time, the capital needed might be beyond the capabilities of the operator. Additional funds might then be needed.

Policies can be put in place to facilitate capital flows for this network expansion and repurposing. Investment support can accelerate the delivery of renewable gas projects during the early stages of market development when investment risks are higher. De-risking measures can help to reduce financing costs and stimulate investment by TSOs. These include capital grants, loan guarantees and soft loans from development banks.

Between 2021 and 2030 the Netherlands plans to invest EUR 7 billion in infrastructure for the energy transition, via the TSO Gasunie, to meet the increasing demand for the transport of hydrogen, green gas, CO_2 storage and renewable-based heat. EUR 1.5 billion will be dedicated to connecting the large industrial centres of the Netherlands and northern Germany to locations where blue and green hydrogen will be produced. For this network, Gasunie will use existing gas pipelines that become available due to the declining demand for natural gas. Most of Gasunie's projects are financed jointly with customers and other partners, supported by government subsidies (Gasunie, 2020).

2.4.2 Policies to support seasonal storage

Green hydrogen can provide seasonal storage for the power system, alongside other options such as pumped hydropower. Green hydrogen can in fact be produced in seasons with abundant VRE production and stored for later use in underground geological formations such as salt caverns.

As seasonal storage will become necessary to achieve a fully decarbonised power grid, policy makers should identify solutions to support it. These should be beneficial to any seasonal storage technology, and could include (FTI, 2018):

- **Seasonal storage procurement:** Policy makers could take measures to ensure that the power system has a minimum level of seasonal storage capacity. Similar to today's capacity mechanisms, this measure would aim to procure a minimum volume of energy for periods of low VRE production. This procurement could take the form of auctions for the long-term procurement of energy or capacity for a specific period of time; product-specific auctions could be tailored (IRENA, 2019a). Alternatively, suppliers of energy could be required to ensure they have a minimum amount of seasonal storage.
- **Feed-in schemes:** As seasonal storage solutions are unlikely to recover their costs within a marginal pricing system, policy makers could introduce a feed-in tariff or premium scheme to compensate them when producing during prolonged low-VRE periods. The level of support should be set at the social value of the energy produced and be designed to accompany the seasonal storage operators in replacing dispatchable fossil fuel generators.

Countries will have to regulate the injection and storage of hydrogen in geological formations within their jurisdictions (ownership, responsibilities, environment protection etc.) (see also Section 2.4.1). Such rules could take advantage of existing laws on mining, water preservation, waste disposal, resource conservation, fossil gas storage, treatment of high-pressure gases and others. They could be coupled with activities to regulate CO_2 storage, for which regulations are still similarly lacking (IPCC, 2018b).

2.4.3 Support for green ships and green trucks

When the use of pipelines is not possible, hydrogen has to be transported via dedicated vehicles or ships. If these means of transport are fuelled by fossil fuels over long distances, the environmental benefits from the use of green hydrogen can be reduced or nullified.

There are three principal options for decarbonised trucks: battery electric vehicles, fuel cell electric vehicles and alternative fuels (sustainable biofuels and synthetic fuels). None of these options is yet in widespread use, but all have been trialled and the issues preventing scale-up are mainly economic and logistical. Electrified solutions, in particular, are also emerging as an option for heavy-duty vehicles.

Electric battery systems are not suited to long-distance shipping, but they are being introduced for short-range ferries. Biofuels, green hydrogen and ammonia are being considered as fuel alternatives (IRENA, 2020e).

Policy instruments to support decarbonisation of the transport sector fall beyond the scope of this report, but are the subject of many studies that can provide guidance to policy makers (for example IRENA, forthcoming b, forthcoming c, 2019c, 2018b, 2016).

Policy makers currently looking at green hydrogen should make sure that GOs account for the emissions related to the transport of the hydrogen to make sure that the whole supply chain is sustainable (IRENA, 2020a). This would push the hydrogen sector to identify transport modes with limited to zero emissions, supporting the rapid deployment of electric trucks and ammonia-fuelled ships, for example.

2.5. RESEARCH AND DEVELOPMENT SUPPORT

Water electrolysis is a commercial technology and the policies described above can kick-start and maintain a national hydrogen sector. But continued effort is needed in research and innovation to make green hydrogen competitive with grey hydrogen and fossil fuels. This will increase the effectiveness of the supporting policies and, ultimately, make them less necessary.

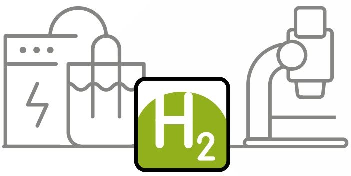
2.5.1 Public support for R&D and multilateral collaboration

R&D is a fundamental part of the energy transition and is necessary to reduce the production and transport costs of green hydrogen. Governments have a central role in setting the research agenda.

This can take the form of funding for the specific types of R&D required to accelerate development, using grants, tax incentives, concessional loans and equity in start-ups. Multilateral research initiatives can also be valuable. One example is an Italo-Australian collaboration to share knowledge among research institutions (Fuel Cells Works, 2021).

Hydrogen research infrastructure has evolved over the years and research "nodes" have emerged focusing on specific topics. Dedicated labs have been established to develop and test new solutions in co-operation with industry, creating the environment for the growth of start-ups (as, for example, in Grenoble for France). These nodes are then connected via knowledge networks to enhance the innovation results.

An important goal for future R&D is improving the efficiency of electrolysers. Since electricity is the main cost component, any improvement in efficiency will directly decrease green hydrogen costs; more details are available in IRENA (2019b).



2.5.2 Targets for technological advancement

National and international programmes supporting R&D for green hydrogen have introduced targets to measure the progress of technological advancement. These targets represent clear goals for the research programmes.

Targets for the levelised cost of hydrogen or electrolyser capital cost are common metrics:

- The **United States Department of Energy** has a target of USD 2/kg. Its "H2@Scale" research initiative is a USD 64 million programme that supports efforts to cut the cost of hydrogen production.
- The **Australian Hydrogen Strategy** has a target of USD 1.5/kg (AUD 2/kg), called the "H2 under 2" goal (ARENA, 2020b).
- In the **European Union**, the Fuel Cells and Hydrogen Joint Undertaking (FCH JU) has set targets for the capital cost of electrolysers of USD 440/kW for alkaline electrolysers and USD 550/kW for PEM electrolysers by 2030 (FCH JU, 2021).

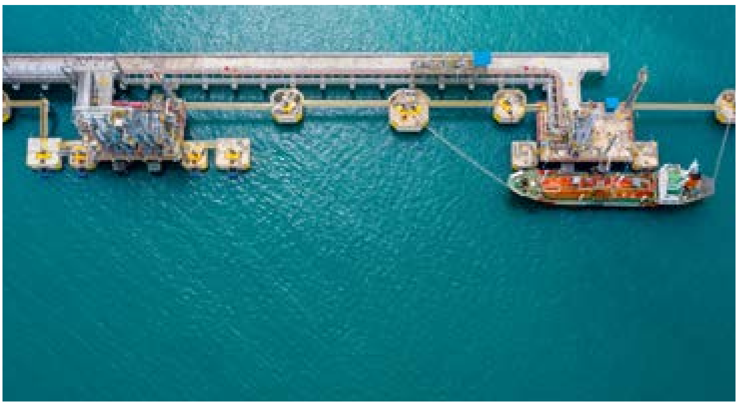
Most research programmes cover multiple objectives across segments of the hydrogen value chain. In the European Union, the FCH JU, out of an EUR 893 million research budget, has allocated a total of EUR 418 million across 135 projects for energy purposes (this includes electrolysis, hydrogen distribution, storage and fuel cells for combined heat and power, and initiatives supporting the cross-sectoral nature of hydrogen such as the "hydrogen valleys").

2.5.3 Demonstration projects

Demonstration projects have an important role in testing the feasibility of a transport solution while it is still in the early stages of development. They are pivotal in identifying issues and solutions for the later, larger deployment stage. Policy makers can support such projects, financially and with dedicated regulation, for the early discovery of weak points in the supply chain so as to be ready to address them in a timely fashion.

As discussed, Japan is testing multiple shipping options for hydrogen (see Box 2.4). There are also about 40 projects around the world focusing on the transmission and distribution of green gas in grids (IRENA, IEA and REN21, 2020).

Credit: Kawasaki Heavy Industries



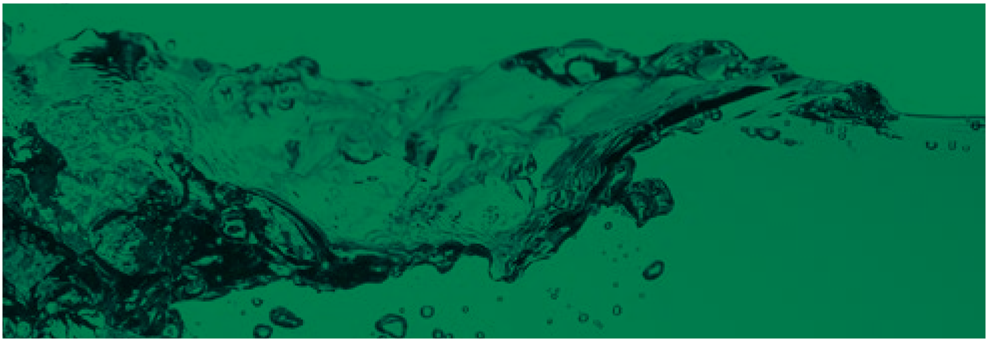
3 THE WAY FORWARD

3.1. THE **POLICY STAGES**

A wide range of policies exists to support the development of a green hydrogen industry. Policy makers may be under the impression that a wall of challenges lies ahead of them to create a green hydrogen sector in their country. However, they can prioritise their actions depending on the maturity of their national hydrogen sector.

Certain policies are suitable for kick-starting the sector, while others will be needed later as the system makes progress. The "policy stage" concept, introduced in IRENA (2020a), and elaborated here with a focus on electrolysis and infrastructure (Box 3.1), is created to assist in understanding when a policy could be introduced, based on the status of the country's hydrogen sector.

Figure 3.1 shows the range of policies explored in this report across the three stages of electrolysis and infrastructure deployment.



Box 3.1 Policy stages for electrolysis and infrastructure

STAGE 1:

→ Technology readiness

At this stage, green hydrogen is not yet economically competitive with grey hydrogen. The production capacity of electrolyser manufacturers is transitioning from the megawatt to the gigawatt scale; GOs and a commitment to use larger shares of renewable electricity for electrolysis should be put in place to make sure they are ready for the following phases. Green hydrogen is starting to be deployed for niche applications across hard-to-abate sectors, in accordance with national strategies. Volumes are still relatively small, and if electrolysis is not located close to the demand centres these small volumes can be supplied via hydrogen trucks, liquefied or compressed, as pipelines are not yet available. However, co-location of small electrolysers and demand centres can be expected as main solution. Hydrogen storage is mostly carried out with steel tanks on-site, but a few locations, especially in industrial sites and ports, could be testing underground storage.

For governments, bilateral agreements are a testbed for future large-scale trading routes, not only from a techno-economic point of view, but also to solidify the commercial and political relationships between the countries involved.

STAGE 2:

→ Market penetration

At this stage, electrolysers are at the gigawatt scale, the greatest cost decreases from economies of scale have been achieved, and hydrogen is close to grey hydrogen in markets with good renewable energy resources. The share of wind and solar in the power mix are significant, and electrolysers are increasingly important for some periods of time where other flexibility measures are not enough to cope with the variability and production surplus. Industrial applications are either progressively being replaced or adapted to handle pure hydrogen.

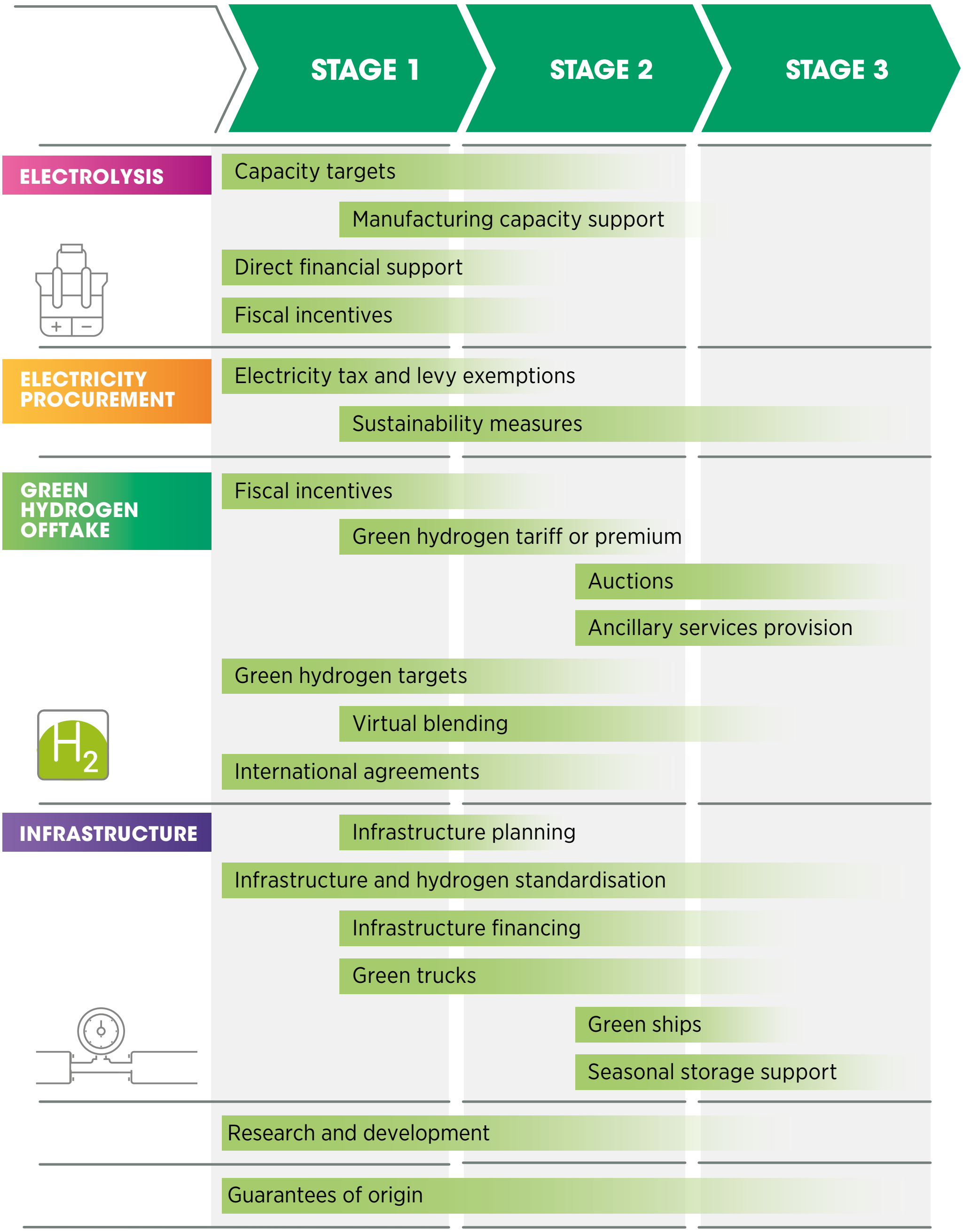
Many of these applications are located in the so-called "hydrogen valleys": large hydrogen demand centres that justify the use of more remote locations with better renewable resources for the production of either electricity or hydrogen, making pipelines and ships an attractive option, when the transport of electricity is not feasible or cost-effective. Some new hydrogen pipelines and global trading are then needed; some existing sections of the gas network are being converted. The bilateral agreements from the previous stage have created new trade routes, where economies of scale and standardised designs reduce the cost penalties of the transformation process and transport.

STAGE 3:

→ Market growth

At this stage, green hydrogen is fully competitive with grey hydrogen. Electrolysers contribute to the last few percentage points of CO_2 emissions reduction, where hydrogen and its derivatives could add the most value. At this stage, the power system is close to zero emissions, so specific actions to ensure low-carbon electricity as input become less relevant. The power system has a very high share of wind and solar, and electrolysers are a key flexibility provider. All the hard-to-abate sectors are on their way toward decarbonised solutions (sustainable bioenergy, energy efficiency or green hydrogen). The green hydrogen market has a diversified and competitive supply with multiple end users and is globally traded.

Figure 3.1 Range of policies to promote electrolysis across three stages of deployment.



Fiscal policies (such as electricity fee exemptions, VAT exemptions or grey hydrogen taxes), targets (for electrolyser capacity and green hydrogen production) and support for manufacturers can be introduced at the onset of green hydrogen policy making. International agreements, which are becoming a staple of hydrogen policy making, can also be envisaged at this stage.

Green hydrogen tariffs or premium and virtual blending mandates may immediately follow, as the real cost of hydrogen becomes clear.

As regards the transport infrastructure, the first actions are the creation of technical and commercial standards, which will potentially be applied later, the decarbonisation of delivery trucks and importantly, from the beginning, establishing a plan for future infrastructure. After that, financing instruments for that future infrastructure may be needed, making it possible to create a grid able to host hydrogen.

As the hydrogen sector progresses, more mature policies may be adopted, such as auctions and the redesign of power system structures to allow the use of seasonal storage and to procure ancillary services from electrolysers. The latter would need to be undertaken in any case, as the power system needs more flexibility to deal with higher VRE penetration.

As the market for hydrogen grows to a self-sustaining level, the attention of policy makers should turn to maintaining the speed of innovation with R&D funding, and to maintaining the sustainable nature of green hydrogen with support for green electricity and a GO system (in particular for international trade).

Some countries, like Australia, Germany, the Netherlands and Japan, are already in the middle of Stage 1, setting targets for green hydrogen and mobilising capital for investment.

Many countries are also setting the scene for future policies. One example is Portugal. The country has already published a strategy and updated the legal and legislative framework to enter hydrogen into the energy system, making the first steps for a GO scheme. The government's plans include the introduction of auctions for carbon contracts for difference, support for capital investment, subsidies to reduce the operational costs of hydrogen technologies and policies to subsidise investment in salt caverns for seasonal storage (BETD, 2021).

The early-moving countries have benefited from their governments co-funding demonstration projects for different pathways, testing what the possibilities are and developing experience of deployment and operation. These earlier demonstration projects bring the relevant stakeholders into contact through networks and working groups that serve to align and define targets. This co-operation is part of the foundation that makes the entire process possible (IRENA, 2020a).

3.2. CONCLUSION

Global GHG emissions must be rapidly reduced to prevent the potentially catastrophic impacts of climate change. Such deep decarbonisation of the world's economies is both technically feasible and economically affordable. Most of the emission reductions would come from three key actions: renewable energy, energy efficiency and direct electrification.

Still, Direct electrification is difficult, if not impossible, in some sectors, such as steelmaking and other industrial processes, long-haul aviation and maritime shipping. These hard-to-abate sectors will require another form of zero-carbon energy, the most promising of which is green hydrogen. The roadmap in IRENA's *World Energy Transitions Outlook* envisions the production of large amounts of green hydrogen to make the energy transition possible.

However, creating a large supply of green hydrogen and transporting it to where it will be used is challenging and expensive. Technological, economic, regulatory and environmental barriers are faced by the green hydrogen sector.

But as this report describes, these challenges can be met through a wide range of supportive policies. Policy makers then have a central role to play.

Policy makers can set targets for the growth of electrolyser capacity and green hydrogen production and consumption. They also can provide support for each stage of deployment – supporting electrolysers and electrolyser manufacturing capacity, ensuring a sufficient supply of renewable electricity, boosting demand for green hydrogen and its derivatives, and creating an infrastructure to store and transport hydrogen. There are many possible forms of support, including direct grants, feed in tariffs and premiums, tax incentives and R&D funding. Regulation and planning will also play an important role.

The key message from this report is that countries will be able to produce and transport a large enough supply of green hydrogen to affordably decarbonise the hard-to-abate sectors and make the energy transition possible. But proper policies must be in place, and some policies need more urgent adoption.

ANNEX
WATER ELECTROLYSIS TECHNOLOGIES

Alkaline electrolysers are already at the commercial stage, have slightly higher efficiency than PEM electrolysers and have lower investment costs (even if PEM is approaching similar values). They benefit from a simple system design (even if downstream hydrogen purification is more complex than for PEM), and they have other applications in the chemical industry that leads to the presence of an existing supply chain that can be scaled up for water electrolysis. About 20 GW of cumulative electrolyser capacity uses the chlor-alkali process. Nevertheless, they have the characteristic of operating at lower current density, and so they need a larger footprint.

PEM electrolysers are currently behind alkaline in terms of efficiency and cost, but could reach the same performance over time with further research. PEM electrolysers occupy 20-25% less space than alkaline ones, with a smaller physical footprint than alkaline. Less experience with PEM means that the lifetime and effects of operation under industrial conditions still need to be demonstrated. In terms of dynamic operation when connected to the electricity grid, they are more suitable than alkaline (fast response, lower degradation). Platinum and iridium are necessary for the PEM process and this could limit the scale-up of this technology. Current global iridium production could support annual deployment up to 7 GW/yr. maximum. Multiple strategies, including reduced material use, higher production rates and recycling, among others, could reduce material needs by at least 80%

SOEC electrolysers can offer higher efficiencies (40 kWh/kg, compared to 50 kWh/kg for alkaline and PEM electrolysers) and can be integrated with other processes that produce heat (e.g. synthesis of fuels). They could be used for the co-electrolysis of CO_2 and water to directly produce syngas, which is used as a building block for a large part of the chemical industry and which would simplify the process. The key barriers to be addressed are the stack degradation and short lifetimes due to the high-temperature of operation. SOEC electrolysers can also be reversed to become fuel cells, converting the hydrogen back to electricity to a limited extent (fuel cell operating mode is about 25% of the electrolyser capacity). This can lead to cost savings and reduced equipment requirements. SOEC electrolysers also allow for the co-electrolysis of CO_2 and water to produce syngas, which is a primary feedstock for the chemical industry. SOEC electrolyser technology is mainly at the kilowatt scale today (but some early megawatt-scale models are in production), and there are challenges in manufacturing large-scale megawatt to gigawatt modules.

AEM electrolysers are the most recent technology and have limited deployment. They are mostly in the low kilowatt range today. AEM electrolysers still have unstable and limited lifetimes, varying between 500 and 5 000 hours. AEM electrolysers' potential advantages lie in the fact that they do not use any precious metals and use a membrane that is less expensive than that used for PEM.

Table A.1 shows the main technological aspects of these water electrolyser options.

A further efficient option for the future is represented by proton-conducting ceramic cells (PCC), but they are even earlier in the research funnel than SOEC and AEM, and still need to reach prototype stage.

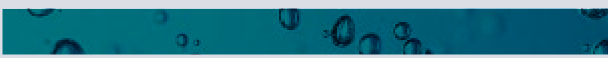
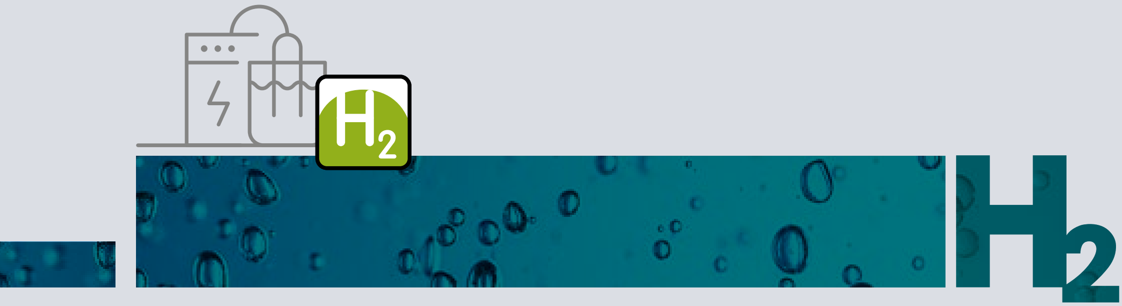


Table A.1 Water electrolysis technologies as of today

		Alkaline	PEM	SOEC	AEM
	Development status	**Commercial**	**Commercial**	**Demonstration**	**Under research**
Operating conditions	Temperature (°C)	70-90	50-80	700-850	40-60
	Pressure (bar)	~30	<70	1	<35
Cost parameters	CAPEX (system) (USD/kW)	600	1 000	> 2 000	
	Lifetime (hours)	50 000	60 000	20 000	5 000
	Efficiency (kWh/kg)	50-78	50-83	40-50	40-69
Flexibility	Load range	15-100%	0-160%	30-125%	5-100%
	Start-up	1-10 min	1 sec-5 min		
	Ramp up/down	0.2-20% per second	100% per second		
	Shutdown	1-10 minutes	Seconds		

Sources: IRENA (2018a; 2020b).



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ABBREVIATIONS

AEM	Anion exchange membrane
CAPEX	Capital expenditure
CGH2	Compressed hydrogen
FCH JU	Fuel Cells and Hydrogen Joint Undertaking
FIP	Feed-in premium
FIT	Feed-in tariff
GHG	Greenhouse gas
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
LCFS	Low-Carbon Fuel Standard
LOHC	Liquid organic hydrogen carrier
LCOH	Levelised cost of hydrogen
LH2	Liquid hydrogen
MoU	Memorandum of understanding
OPEX	Operating expenditure
PCC	Proton conducting ceramic cell
PEM	Proton exchange membrane
PPA	Power purchase agreement
PV	Photovoltaic
R&D	Research and development
SOEC	Solid oxide electrolyser cells
TSO	Transmission system operator
VRE	Variable renewable energy

UNITS OF MEASURE

EJ	Exajoule
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt hour
kg	Kilogram
km	Kilometre
kW	Kilowatt
kWh	Kilowatt hour
Mt	Million tonnes
MW	Megawatt
MWh	Megawatt hour
m^3	Cubic metre
tCO_2	Tonne of carbon dioxide
tpd	Tonnes per day
TW	Terawatt

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