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HYDROGEN FROM RENEWABLE POWER

TECHNOLOGY OUTLOOK FOR THE ENERGY TRANSITION

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About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation that supports countries in their transition to a sustainable energy future and serves as the principal platform for international co-operation, a centre of excellence and a repository of policy, technology, resource and financial knowledge on renewable energy. 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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UNITS OF MEASUREMENT

°C	degree Celsius
EJ	exajoule
Gt/yr	gigatonnes per year
GW	gigawatt
h	hour
kg	kilogram
kW	kilowatt
kWh	kilowatt hour
MJ	megajoule
MPa	megapascal
MW	megawatt
Nm^3	normal cubic metre
TWh	terawatt hour

ABBREVIATIONS

ALK	alkaline
BEV	battery electric vehicle
CAPEX	capital expenditure
CCS	carbon capture and storage
CCU	carbon capture and utilisation
COP21	21st Conference of the Parties to UN Framework Convention on Climate Change
CO_2	carbon dioxide
CSP	concentrated solar power
DRI-H	direct reduction via hydrogen
e-fuel	electrofuel
FCEV	fuel cell electric vehicle
FCH JU	Fuel Cell Hydrogen Joint Undertaking
FCR	frequency containment reserve
HHV	high heating value
HRS	hydrogen refuelling station
H_2	hydrogen
LDV	light-duty vehicle
LCOH	levelised cost of hydrogen
LHV	lower heating value
LOHC	liquid organic hydrogen carrier
OPEX	operating expenditure
PEM	proton exchange membrane
PV	photovoltaic
P2G	power-to-gas
R&D	research and development
SMR	steam-methane reforming
SOEC	solid oxide electrolyser cell
TFEC	total final energy consumption
VRE	variable renewable energy
w/RE	with renewable energy

INSIGHTS FOR POLICY MAKERS

The global energy system has to undergo a profound transformation to achieve the targets in the Paris Agreement. In this context, low-carbon electricity from renewables may become the preferred energy carrier. The share of electricity in all of the energy consumed by end users worldwide would need to increase to 40% in 2050 (from about half that amount in 2015) to achieve the decarbonised energy world envisaged by the agreement.

However, the total decarbonisation of certain sectors, such as transport, industry and uses that require high-grade heat, may be difficult purely by means of electrification. This challenge could be addressed by hydrogen from renewables, which allows large amounts of renewable energy to be channelled from the power sector into the end-use sectors.

Hydrogen could therefore be the **missing link in the energy transition**: renewable electricity can be used to produce hydrogen, which can in turn provide energy to sectors otherwise difficult to decarbonise through electrification.

These include the following:

- **Industry:** Hydrogen is widely used in several industry sectors (refineries, ammonia production, bulk chemicals, etc.), with the vast majority of it being produced from natural gas (see Figure 4). Hydrogen from renewables could replace fossil fuel-based feedstocks in high-emission applications.

- **Buildings and power:** Hydrogen from renewable sources can be injected into existing natural gas grids up to a certain share, thereby reducing natural gas consumption and emissions in end-use sectors (e.g. heat demand in buildings, gas turbines in the power sector). Hydrogen can be combined with carbon dioxide (CO_2) from high-emission industrial processes to feed up to 100% syngas into the gas grid.

- **Transport:** Fuel cell electric vehicles (FCEVs) provide a low-carbon mobility option when the hydrogen is produced from renewable energy sources and offer driving performance comparable to conventional vehicles. FCEVs are complementary to battery electric vehicles (BEVs) and can overcome some of the current limitations of batteries (weight, driving range and refuelling time) in the medium to high duty cycle segments.

Hydrogen produced from renewable electricity – achieved through an **electrolyser** – could facilitate the integration of **high levels of variable renewable energy (VRE)** into the energy system.

- An electrolyser is a device that **splits water into hydrogen and oxygen** using electricity. When electricity produced from renewable energy sources is used, the hydrogen becomes a carrier of renewable energy, complementary to electricity. **Electrolysers can help integrate VRE into power systems**, as their electricity consumption can be adjusted to follow wind and solar power generation, where hydrogen becomes a source of storage for renewable electricity. Thus, they offer **a flexible load** and can also provide **grid balancing services** (upwards and downwards frequency regulation) whilst operating at optimal capacity to meet demand for hydrogen from industry and the transport sector or for gas grid injection.

- The built-in **storage capacity** of downstream sectors (e.g. gas infrastructure, hydrogen supply chain) can serve as a buffer to absorb VRE over long periods and allow for seasonal storage.

- **Hydrogen from renewable electricity** could create **a new downstream market for renewable power**. It has the potential to reduce renewable electricity generators' exposure to power price volatility risk, in instances where part or all generation is sold to electrolyser operators through long-term contracts. This may or not may be possible depending on market configuration and regulations.

Key hydrogen technologies are maturing. Scale-up can yield the necessary technology cost reductions.

- The hydrogen sector is building upon **decades of experience** with an array of established global players and mature technologies and processes.

- **Proton exchange membrane (PEM) electrolysers and fuel cells** are approaching technical maturity and economies of scale. Commercial deployment has started in several regions of the world (e.g. Japan, California, Europe). Energy companies, industrial gas companies, original equipment manufacturers for vehicles, and other industry stakeholders have positioned themselves and established advocacy groups (e.g. the Hydrogen Council) to take advantage of this potentially large and rapidly growing market. They aim to make the best use of existing infrastructure (e.g. the gas grid) and to prepare for hydrogen from renewables potentially to partly replace the energy supply and revenues that are now based on oil and gas.

- Initial efforts could focus on **large-scale applications**, so as to rapidly generate economies of scale with minimal infrastructure requirements, and on sectors where hydrogen from renewables stands out as the **best-performing option to meet climate targets** and comply with local emissions regulations. Such applications include large-scale industry (e.g. petrochemicals, steel) and medium- to heavy-duty transport (medium to large passenger vehicles and commercial vehicles, large fleets of buses, trucks, trains, maritime, aviation, etc.).

- **Electrofuels** (e-fuels, liquid fuels produced from renewable power)[1] can **replace fossil fuels without the need to change end-use technologies.** This might be complementary to biofuels and potentially important for specific sectors (e.g. aviation).

1 Synthetic fuels based on hydrogen produced from renewable electricity (through water electrolysis) that is fed together with CO_2 into a reactor forming a synthesis gas (CO and H_2), which is then liquefied and further refined to become, for example, e-diesel or e-kerosene. Such fuels can be blended with existing fuels in internal combustion engine vehicles (and therefore also referred to as drop-in fuels).

A **policy and regulatory framework** to encourage the appropriate **private investment** is critical. Such a framework could consider the following:

- The adoption of technology-neutral instruments aimed at final consumers (e.g. emission restrictions, mandates for renewable energy content in industry) to trigger hydrogen demand in a structural way and justify investment in infrastructure, while addressing concerns related to carbon leakage. In addition, **financial support instruments (e.g. capital expenditure subsidies, tax rebates and waivers)** are necessary to cover the **initial cost premium** relative to incumbent technologies.

- The introduction of long-term gas grid injection tariffs, take-or-pay contracts, participation of electrolyser operators in the ancillary services markets, schemes allowing exemption from electricity grid charges and levies, and de-risking instruments to encourage market uptake to support infrastructure and hydrogen deployment.

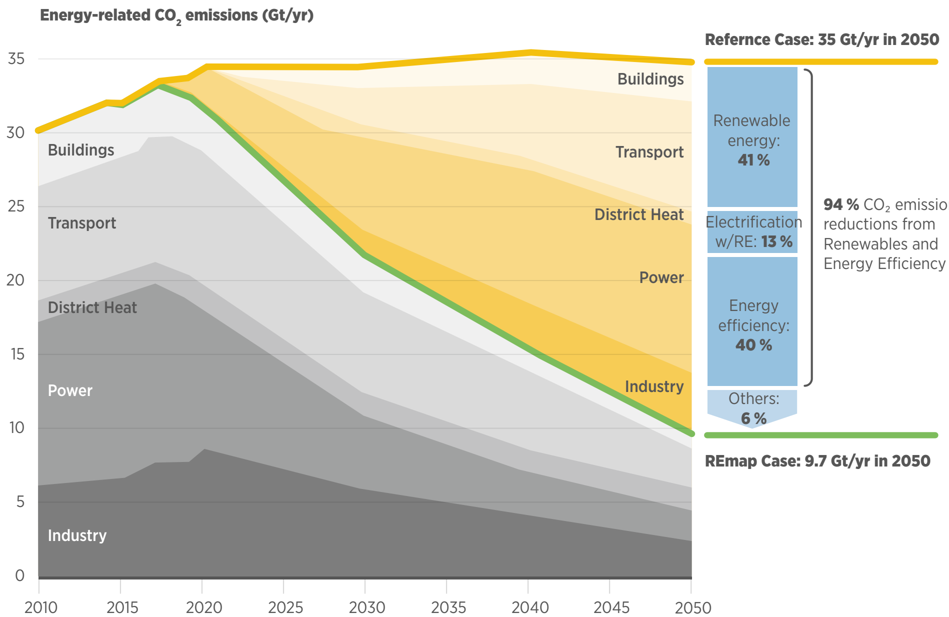
Hydrogen offers added possibilities to tap high-quality renewable energy resources, including those located far from end-user demand. Once produced, hydrogen (like liquefied natural gas) can be transported as a global commodity unconstrained by grid connections.

Broadly, hydrogen from renewable electricity is most likely to achieve cost-effectiveness through high electrolyser utilisation rates combined with low-cost renewable electricity. Yet outcomes should be assessed carefully for each possible production site. Large scale, off-grid hydrogen projects directly connected to solar and wind farms in high-resource locations may provide low-cost, 100 % renewable hydrogen. However they will have lower electrolyser utilisation rate due to the nature of solar and wind resources, which would increase hydrogen cost (see Fig. 12). Meanwhile, close-to-demand, grid-connected production facilities can maximise the utilisation rate of the electrolyser and minimise logistic costs, but might not have access to such low electricity prices, and from 100 % renewable electricity supply (see Fig. 9).

1 SETTING THE SCENE

The Paris Agreement aims to limit the rise in average global temperature to "well below 2 °C" in this century as compared to pre-industrial levels. Achieving this will require substantial emissions reductions across all sectors.

Figure 1: Energy-related carbon dioxide emissions with current policies (Reference Case) compared to accelerated uptake of renewables (REmap), 2010–2050



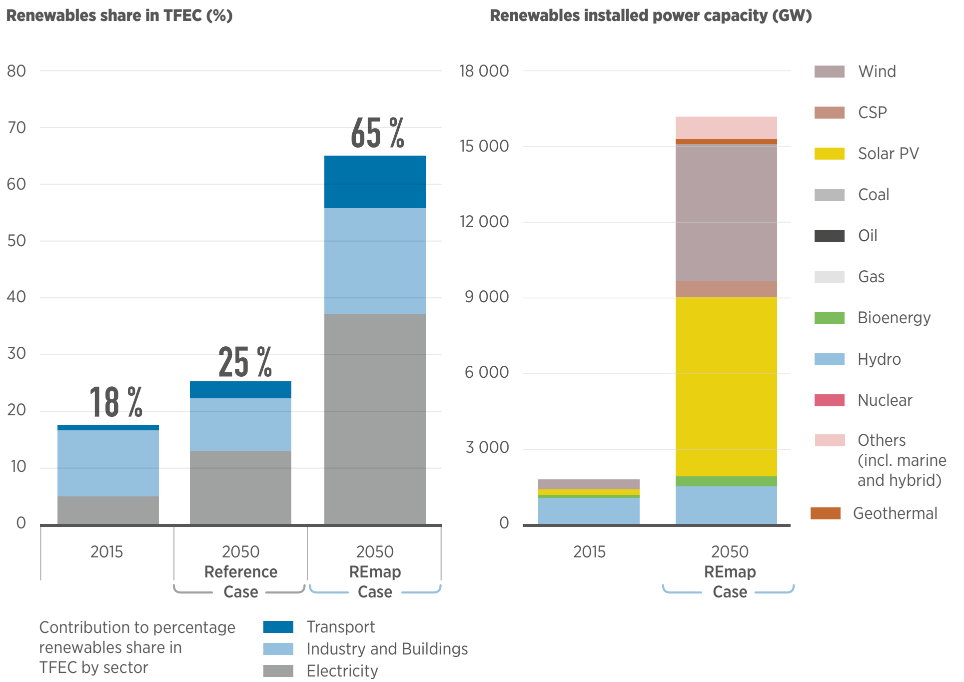
Notes: REmap refers to IRENA's roadmap to rapidly scale up renewables within the coming decades; the Reference Case refers to the path set by current plans and policies; CO_2 = carbon dioxide; Gt/yr = gigatonnes per year; w/RE = with renewable energy.
Source: IRENA (2018).

Substantial greenhouse gas emission reductions are required across all sectors; renewable energy and energy efficiency can provide over 90 % of the reduction in energy-related CO_2 emissions.

1.1 THE ENERGY TRANSITION: THE BIGGER PICTURE

To achieve the targets in the Paris Agreement, the global energy system must undergo a profound transformation from one largely based on fossil fuels to an efficient and renewable low-carbon energy system. According to analysis by the International Renewable Energy Agency (IRENA, 2018), over 90% of the necessary global CO_2 emission reductions could come from these measures; renewable energy is expected to contribute 41% of the required emission reductions directly and an additional 13% through electrification (see Figure 1). To meet this objective, renewable energy's share of global final energy consumption needs to increase from 18% today to 65% in 2050. Variable renewable energy in the power system, in

Figure 2: Share of renewables in total final energy consumption under the Reference Case and REmap (left), and projected renewable power capacity installed in 2050 under REmap (right)



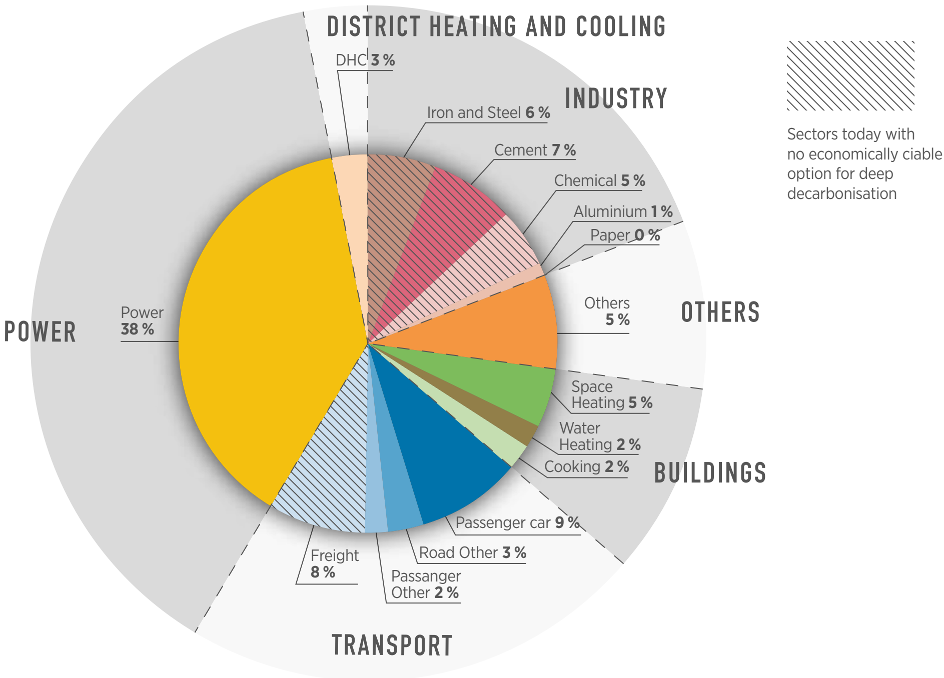
Notes: CSP = concentrated solar power; GW = gigawatt; PV = photovoltaic; TFEC = total final energy consumption.
Source: IRENA (2018).

Renewables could provide a large share of the world's energy, with greater reliance on electricity and significant growth in installed power capacity by 2050.

particular wind and solar, will make up the vast majority of generation capacity (see Figure 2) and ca. 60 % of all electricity generation. The power system needs to become more flexible to economically integrate such large shares of variable generation.

Today, one-third of global energy-related emissions come from economic sectors for which there is presently no economic alternative to fossil fuels (IRENA, 2017a). These emissions originate mostly from the energy-intensive industry sectors and freight transport (Figure 3).

Figure 3: Breakdown of global energy-related CO_2 emissions by sector in 2015.



Source: IRENA (2017a).

Around one-third of energy-related emissions currently have no economically viable options for deep decarbonisation.

Hydrogen could be the "missing link" in the energy transition from a technical perspective: hydrogen from renewable electricity allows large amounts of renewable energy to be channelled from the power sector into sectors for which electrification (and hence decarbonisation) is otherwise difficult, such as transport, buildings and industry.

Hydrogen could thus play a key role in facilitating three positive outcomes: the decarbonisation of these sectors; the integration of large amounts of variable renewable energy (VRE); and the decoupling of VRE generation and consumption through the production of transportable hydrogen. However, hydrogen is not economically competitive at present, and therefore significant reductions in the cost of production and distribution need to take place for the decarbonisation of such sectors to take place.

This notion is becoming well recognised around the globe as a result of various developments, which include the need for deep decarbonisation (COP21), the increasing share and decreasing cost of renewable energy sources, wind and solar in particular, and the associated need for additional flexibility in power systems. In parallel, technological advancements and cost reductions in hydrogen-related technologies are increasing the competitiveness of hydrogen from renewable electricity.

1.2 HYDROGEN TODAY

The hydrogen industry is well established and has decades of experience in industry sectors using hydrogen as a feedstock. The hydrogen feedstock market has a total estimated value of USD 115 billion and is expected to grow significantly in the coming years, reaching USD 155 billion by 2022.[2] In 2015 total global hydrogen demand was estimated to be 8 exajoules (EJ) (Hydrogen Council, 2017).

The largest share of hydrogen demand is from the chemicals sector for the production of ammonia and in refining for hydrocracking and desulphurisation of fuels. Other industry sectors also use hydrogen, such as producers of iron and steel, glass, electronics, specialty chemicals and bulk chemicals, but their combined share of total global demand is small (Figure 4).

Over 95 % of current hydrogen production is fossil-fuel based. Steam-methane reforming (SMR) is the most common way of producing hydrogen. Oil and coal gasification are also widely used, particularly in China and Australia, albeit to a lesser extent than SMR. Only around 4 % of global hydrogen supply is produced via electrolysis, mainly with chlor-alkali processes (Figure 4).

2 www.marketsandmarkets.com/PressReleases/hydrogen.asp.

Figure 4: Global hydrogen demand and production sources

INDUSTRY SECTOR	KEY APPLICATIONS	PERCENTAGE OF GLOBAL H_2 DEMAND
CHEMICAL	• Ammonia • Polymers • Resins	65 %
REFINING	• Hydrocracking • Hydrotreating	25 %
IRON & STEEL	• Annealing • Blanketing gas • Forming gas	
GENERAL INDUSTRY	• Semiconductor • Propellant fuel • Glass production • Hydrogenation of fats • Cooling of generators	10 %

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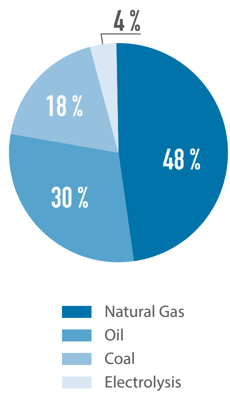
HYDROGEN SOURCES



Source: IRENA based on FCH JU (2016).[3]

Petrochemical feedstocks account for most of the present hydrogen demand, and almost exclusively based on fossil fuels.

3 Figures based on the Global CCS Institute 2008. The figures do not include hydrogen that is currently obtained as a by-product and vented or burned. Around 80 % of the total amount of ammonia produced globally is used to produce inorganic nitrogen-based fertilisers.

1.3 HYDROGEN IN THE ENERGY TRANSITION

Hydrogen is an energy carrier and not a source of energy. It can be produced from a wide variety of energy sources. Historically, hydrogen has been predominantly produced from fossil sources. In a low-carbon energy future, hydrogen offers new pathways to valorise renewable energy sources (see Section 2.1 for a discussion of possible pathways for the production of hydrogen from renewable power). This outlook report focuses on hydrogen produced from renewable electricity via electrolysis – referred to, more simply, as "hydrogen from renewable power", or in industry parlance as "power-to-hydrogen".[4]

Hydrogen and electricity, as energy carriers, are complementary in the energy transition. Hydrogen from renewables has the technical potential to channel large amounts of renewable electricity to sectors for which decarbonisation is otherwise difficult:

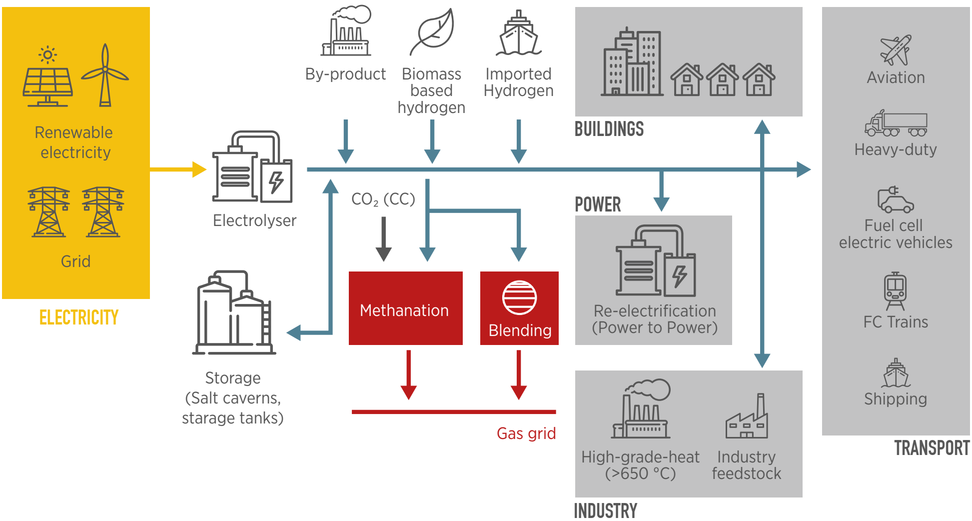
- **Industry:** Hydrogen produced from fossil fuels, currently widely used in several industry sectors (refineries, ammonia, bulk chemicals, etc.), technically can be substituted by hydrogen from renewables. In the longer term, hydrogen from renewables may replace fossil fuel-based feedstocks in these CO_2 emissions-intensive applications provided it can achieve economic competitiveness, which may require modification of existing processes.
- **Buildings and power:** Hydrogen injected into the gas grid reduces natural gas consumption. Injection could be an additional revenue source for electrolyser operators beyond their hydrogen sales to mobility or industrial markets. In the short term, this could be of significant help to reach the volumes necessary to trigger cost reductions through economies of scale and improve the competitiveness of hydrogen from renewable power in the long term. A key advantage of this so-called "power-to-hydrogen" over electricity is the fact that hydrogen can be stored on a large scale, which enables the system to cope with large swings in demand as well as allowing for inter-seasonal storage to meet seasonal demand peaks (e.g. heat in winter).
- **Transport:** When fuelled by hydrogen produced from renewables, fuel cell electric vehicles (FCEVs) are a low-carbon mobility option with the driving performance of conventional vehicles (driving range, refuelling time). FCEVs are complementary to battery electric vehicles (BEVs). They expand the market for electric mobility to high duty cycle segments (long-range or high utilisation rate vehicles, e.g. trucks, trains, buses, taxis, ferry boats, cruise ships, aviation, forklifts) where batteries are currently limited.

4 There is no globally agreed or standardised definition of "green" hydrogen yet. However, in Europe there is an advanced, widely endorsed consensus on the definition achieved under the CertifHy project financed by the Fuel Cell Hydrogen Joint Undertaking (FCH JU) (www.certifhy.eu). In the near term, significant volumes of hydrogen could potentially be produced from fossil fuels with carbon capture and utilisation/storage (CCU/CCS), but this is beyond the scope of this outlook report.

Power-to-hydrogen can provide flexibility to accommodate increasing shares of VRE into the power system.

An electrolyser is a device that splits water into hydrogen and oxygen using electricity. Electrolysers offer a flexible load that can provide low-cost balancing services (up and down) to the power system while producing hydrogen for mobility applications, industrial uses, or injection into the gas grid. The built-in storage capacity of downstream sectors (gas infrastructure, hydrogen supply chain etc.) can be used as a buffer to adjust hydrogen production (and hence electricity consumption) in real time depending on the

Figure 5: Integration of VRE into end uses by means of hydrogen



Hydrogen can facilitate coupling between electricity and buildings, transport and industry.

needs of the power system, and to absorb VRE possibly over long periods thus allowing for seasonal storage.

In other words, hydrogen contributes to "sector coupling" between the electricity system and industry, buildings and transport, increasing the level of flexibility while facilitating the integration of VRE into the power system (Figure 5).

In the medium to long term, hydrogen could become a way to transport and distribute renewable energy over long distances, especially in those cases where the electricity grid has insufficient capacity or when it is too impractical or expensive to build. This might be the case with offshore wind, where hydrogen could be produced offshore and then be transported to the shore via natural gas pipelines, either converted existing offshore pipelines or newly installed, where the costs are lower than those for laying submarine cables.

Regions with abundant and cheap renewable energy sources could produce hydrogen for transport to regions with either limited potential or higher costs of renewable power generation. Transport of renewable energy via hydrogen could be developed at different scales, from local to international. This latter option is being investigated in several countries either with abundant renewable energy potential (e.g. Australia) or with limited indigenous renewable energy potential, such as Japan.

Hydrogen carriers, such as liquid organic hydrogen carriers (LOHCs) or ammonia, could be more suitable for long-distance transport than gaseous or liquid hydrogen. To date, however, pipelines remain the most economic route to transporting hydrogen in large volumes, hence "greening the gas grid" allows volumes to ramp up rapidly and provide the economies of scale necessary to reduce the cost of hydrogen.

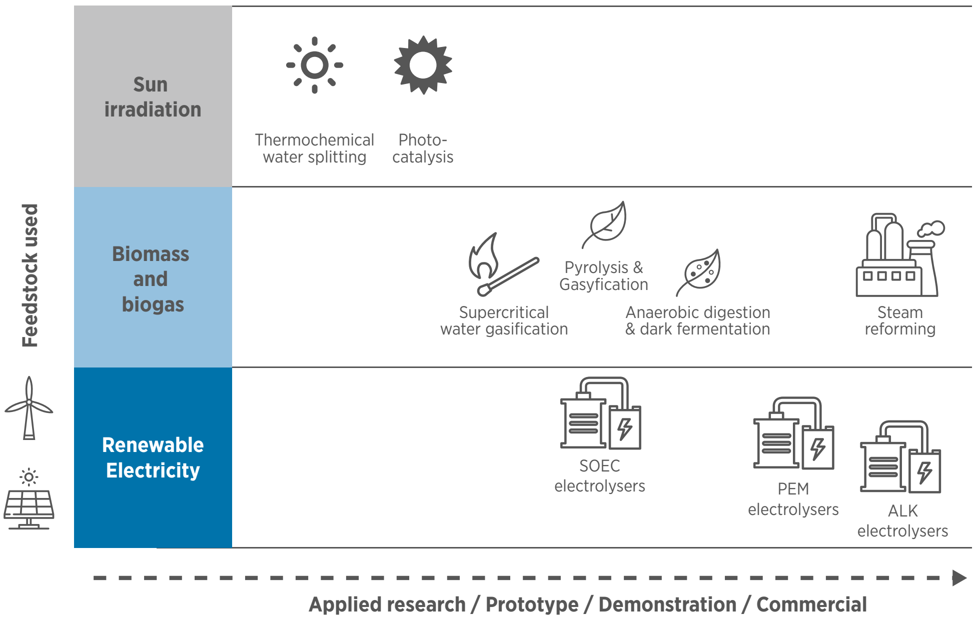
Hydrogen could eventually become a way to transport renewable energy over long distances.

2 CURRENT TECHNOLOGY STATUS AND DEVELOPMENTS

2.1 RENEWABLE HYDROGEN PRODUCTION PATHWAYS AND THEIR CURRENT LEVEL OF MATURITY

The most established technology options for producing hydrogen from renewable energy sources are water electrolysis and steam reforming of biomethane/biogas with or without carbon capture and utilisation/storage (CCU/CCS), as shown in Figure 6. Less mature pathways are biomass gasification and pyrolysis, thermochemical water splitting, photocatalysis, supercritical water gasification of biomass, and combined dark fermentation and anaerobic digestion.

Figure 6: Renewable hydrogen production pathways and current levels of maturity



Notes: ALK = alkaline; PEM = proton exchange membrane; SOEC = solid oxide electrolyser cell.
Source: Based on FCH JU (2015), Study on Hydrogen from Renewable Resources in the EU.

2.2 HYDROGEN PRODUCTION VIA ELECTROLYSIS

Three main electrolyser technologies are used or being developed today. This section provides a brief overview of the technology outlook for electrolysers, or detailed modelling of their performance and related impact on the cost of hydrogen production.

Alkaline (ALK) electrolysers have been used by industry for nearly a century. Proton exchange membrane (PEM) electrolysers are commercially available today and are rapidly gaining market traction as, among other factors, they are more flexible and tend to have a smaller footprint. Solid oxide electrolysers hold the potential of improved energy efficiency but are still in the development phase and, unlike ALK and PEM, work at high temperatures (FCH JU, 2017a; FCH JU, 2014).

ALK and PEM electrolysers compared

ALK electrolyser technology is fully mature. It has been used by industry since the 1920s for non-energy purposes, particularly in the chemicals industry (e.g. chlorine manufacture). By contrast, PEM electrolyser technology is rapidly emerging and entering commercial deployment. Past development and established production volumes have resulted in average capital expenditure (CAPEX) being lower for ALK electrolysers than for PEM electrolysers on a per kilowatt basis The CAPEX for PEM, however, has been dropping significantly in recent years (FCH JU, 2014; FCH-JU, 2017a). The lifetime of an ALK electrolyser is currently twice as long, and is expected to remain significantly longer for the next decade. Table 1 below provides a general overview of the techno-economic characteristics of ALK and PEM electrolysers today and their expected future improvements.[5]

State-of-the-art PEM electrolysers can operate more flexibly and reactively than current ALK technology. This offers a significant advantage in allowing flexible operation to capture revenues from multiple electricity markets, as PEM technology offers a wider operating range and has a shorter response time (NREL, 2016a; NREL, 2016b).

Systems can be maintained in stand-by mode with minimal power consumption and are able to operate for a short time period (10–30 minutes) at higher capacity than nominal load (beyond 100 %, up to 200 %). With both upward and downward regulation capability, a PEM electrolyser can provide capacity for high-value frequency containment reserve (FCR) without sacrificing available production capacity. In other words, operators of PEM electrolysers can supply hydrogen to their clients (for industry, mobility or injection into the gas grid), while still being able to provide ancillary services to the grid with low additional CAPEX and OPEX, provided that sufficient hydrogen storage is available (NREL, 2016a; NREL, 2016b).

5 Electrolyser manufacturers' product roadmaps have focused on different aspects: whereas some have been focusing on efficiency (going up to 75 % plant efficiency,), others have focused on flexibility (both for ALK as well as PEM). Improvement of one parameter (e.g. efficiency) will in general result in deteriorating other parameters (e.g. price/kW); therefore Table 1 represents the average state-of-play of electrolyser technology.

Table 1: Techno-economic characteristics of ALK and PEM electrolysers (2017, 2025)

Technology		ALK		PEM	
	Unit	2017	2025	2017	2025
Efficiency	kWh of electricity/ kg of H_2	51	49	58	52
Efficiency (LHV)	%	65	68	57	64
Lifetime stack	Operating hours	80 000 h	90 000 h	40 000 h	50 000 h
CAPEX – total system cost (incl. power supply and installation costs)	EUR/kW	750	480	1 200	700
OPEX	% of initial CAPEX/year	2 %	2 %	2 %	2 %
CAPEX – stack replacement	EUR/kW	340	215	420	210
Typical output pressure*	Bar	Atmospheric	15	30	60
System lifetime	Years	20		20	

* Higher output pressure leads to lower downstream cost to pressurise the hydrogen for end use.

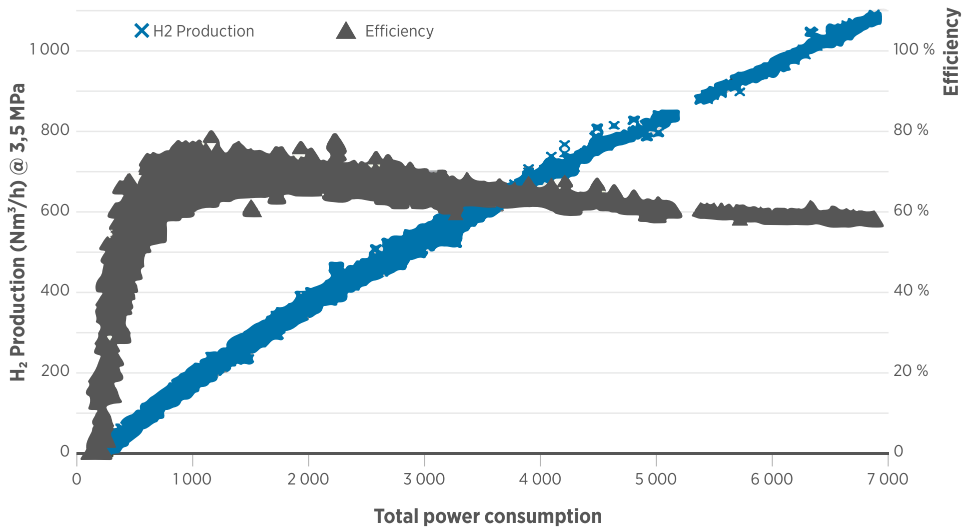
Notes: H_2 = hydrogen; h = hour; kg = kilogram; kW = kilowatt; kWh = kilowatt hour; LHV = lower heating value; OPEX = operating expenditure; CAPEX and OPEX are based on a 20 MW system.
Sources: FCH JU (2017a), Program Review Days Report; FCH JU (2014), Development of Water Electrolysis in the European Union.

This enhanced flexibility might improve the overall economics of power-to-hydrogen, potentially providing a new revenue stream from multiple electricity markets to compensate for the higher capital cost of PEM compared to ALK electrolysers (NREL, 2016a; NREL, 2016b). However, the ancillary services market is currently experiencing strong competition, reflected in significant reductions in prices, which might affect the business case for electrolysers in the medium term.

PEM electrolysers produce hydrogen at a higher pressure (typically around 30 bar) than ALK electrolysers, which produce hydrogen at atmospheric pressure (up to 15 bar).

As a result, the need for downstream compression to reach the desired end-use pressure is lower; this is particularly relevant in applications where high pressure matters, such as for mobility.

Figure 7: Hydrogen production and efficiency as a function of the total power consumption of a PEM production plant



Notes: MPa = megapascal; Nm^3 = normal cubic metre.
Source: Kopp et al. (2017).

Electrolysers operate more efficiently at lower load, with a counter-intuitive impact on hydrogen cost: contrary to most assets in the power sector, PEM electrolysers have a higher efficiency when operated below nominal load. This is illustrated for a PEM production plant in Figure 7.

The alkaline technology was not originally designed to be flexible and has traditionally been operated at constant load to serve industrial needs. Recent progress should nevertheless be noted, making ALK technology compatible with the provision of grid services on a short timescale. At present, however, ALK technology remains less flexible than PEM technology,[6] which ultimately limits the amount of extra revenue that the operator could potentially capture from flexibility. Table 2 presents a comparison on the key parameters determining the dynamic operation of PEM and ALK electrolysers.

Achieving technology scale-up and cost reductions from wider adoption are currently the most critical challenges, mainly for PEM but also for ALK electrolyser manufacturers. Continued R&D efforts are also needed to keep improving power density, lifetime and balance of plant efficiencies.[7]

6 ALK cannot go below a certain load (typically ~20–30 %) for safety reasons, a constraint that does not apply to PEM.

7 For a recent and detailed assessment of the upcoming and necessary innovation, see Schmidt et al. (2017).

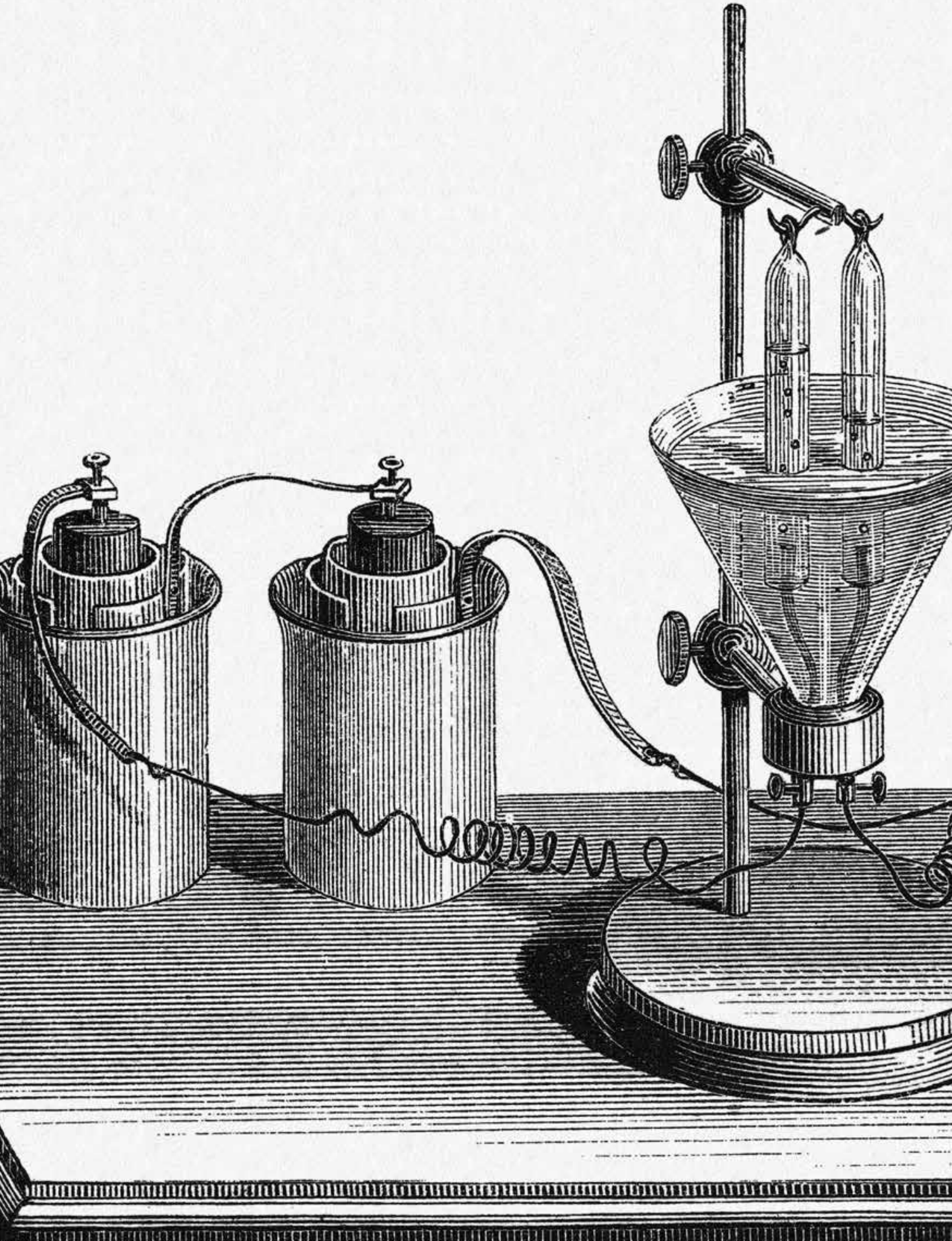


Table 2: Dynamic operation of ALK and PEM electrolysis

	ALKALINE	PEM
Load range	15–100 % nominal load	0–160 % nominal load
Start-up (warm – cold)	1–10 minutes	1 second–5 minutes
Ramp-up / ramp-down	0.2–20 %/second	100 %/second
Shutdown	1–10 minutes	Seconds

Note: Values for 2017.

Source: FCH JU (2017b).

SOEC electrolysers compared to ALK and PEM

SOEC technology holds the promise of greater efficiencies compared to ALK and PEM. However, SOEC is a less mature technology, only demonstrated at laboratory and small demonstration scale.[8] Its investment costs (CAPEX) are currently higher; however, SOEC production mainly requires ceramics and a few rare materials for their catalyst layers, while PEM electrolysers need significant amounts of platinum for their catalyst layers. The need for high-temperature sources of heat close by might also limit the long-term economic viability of SOEC – for which the only renewable sources are likely to be concentrated solar power (CSP) and high-temperature geothermal.

SOEC can potentially be a game-changing technology in the medium term. Its advantages are expected to include increased conversion efficiency and the possibility of producing a synthesis gas directly from steam and CO_2, for use in various applications such as synthetic liquid fuels.[9]

Harnessing synergies with CSP plants, which co-produce steam and electricity on site from solar irradiation and have a high capacity factor, is one pathway to ensuring all energy inputs are completely renewable.

The full flexibility benefits and systemic added value of PEM electrolysers can only be captured if they are grid-connected. This configuration is also the most competitive because it enables the operator to capture ancillary service revenues, and optimise the utilisation rate and electricity purchases. Figure 9 showcases different LCOH at current technology cost levels and in 2025 for a PEM electrolyser of 20 megawatts (MW)[10] connected to different electricity sources: the grid in Denmark (in 2017), an offshore windfarm in the North Sea, a large-scale solar PV plant in the United Arab Emirates, and a combined solar and wind farm in Chile.

8 For example, see FCH JU project GrInHy, www.green-industrial-hydrogen.com/.
9 https://hydrogeneurope.eu/index.php/electrolysers.
10 CAPEX, OPEX and technical characteristics of the 20 MW electrolyser are taken from FCH JU (2017b).

BOX 1: Levelised cost of hydrogen production through PEM electrolysis

The levelised cost of hydrogen (LCOH) production can be showcased by comparing two extreme cases: a) an electrolyser connected to a highly interconnected grid with a high share of wind generation (in Denmark), and b) off-grid dedicated facilities. In the first case, the generated hydrogen might not be 100 % renewable and the plant would have to bear the cost of taxes, grid fees, etc. It could operate at a higher capacity factor and close to demand, therefore avoiding long supply chains. In the second case, the electrolyser load factor will be determined by the load factor of the renewable power plant, leading to a lower capacity factor. The plant will, in general, need a longer supply chain.

More detailed studies provide potentially interesting business cases between these two extremes (Hou et al., 2017).

With respect to grid connection, the PEM electrolyser is assumed to be able to participate directly in the electricity market, which is only likely to be the case if the electrolyser is installed within an existing industrial plant and its power portfolio; as a stand-alone plant, the unit is likely to be too small to operate directly in the market.

As ALK technology is not as flexible as PEM and might not follow fluctuating generation from VRE, the only scenario considered is where ALK electrolysers are run as grid-connected (without accounting for any revenues from grid services).

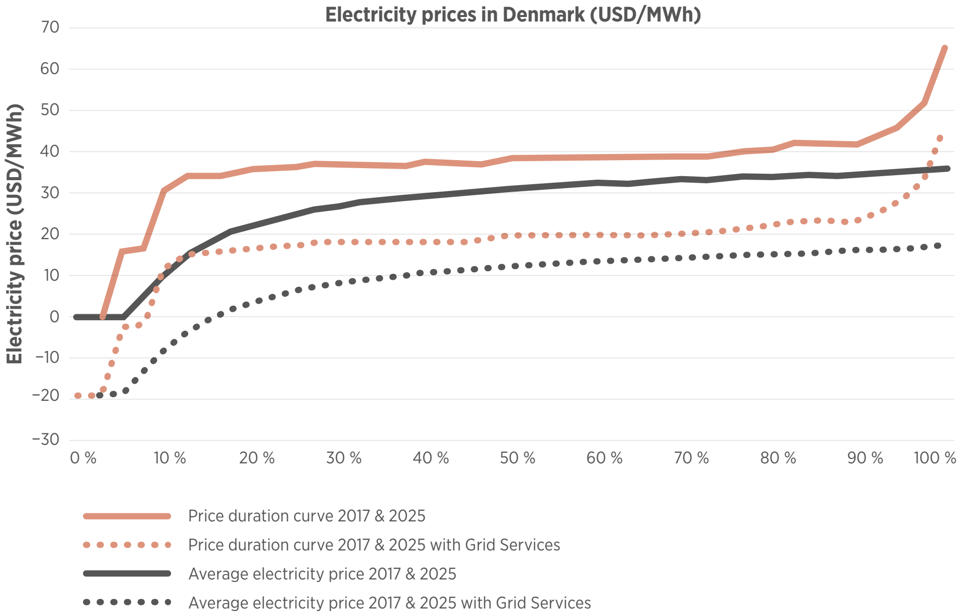
Providing flexibility services to different electricity markets could significantly improve the business case of PEM electrolysers. The revenues from this service can be considered as a reduction in the cost of electricity. As a result, the price duration curve of the Danish grid moves downwards with grid service valorisation of USD 18/MWh[11] for the calculation of LCOH from PEM electrolysers (Figure 8). This has a significant impact on the LCOH.

The following conclusions can be drawn from the case where the PEM electrolyser is connected to the grid:

- Low load factors yield a high LCOH: the CAPEX of the electrolyser is a key component of the hydrogen cost as the amortisation needs to be allocated to low production volumes; at low load factors, the typical electricity mix within Denmark is characterised as close to 100 % renewable.

11 The model assumes that electrolyser operator receives the FCR bid cleared for every hour it is in operation: 18 USD/MWh remuneration for commitment is an assumption taken from the study for FCH JU (2017b). The hypothesis is only likely to hold during early deployment stage of electrolysers: the (shallow) flexibility market will be saturated after a while. Moreover, electrolysers would have to compete with other assets in this competitive market.

Figure 8: Electricity price factors in Denmark, 2017–2025



Note: To avoid the uncertainty of predicting future electricity prices, 2017 prices are also assumed to apply in 2025. Source: Price duration curves, grid fees and grid service revenues (applied as a discount on electricity prices) are taken from FCH JU (2017b).

- At mid-range load factors (40–80 %), the LCOH remains almost constant: the decrease in amortisation per kilogram of hydrogen when the load factor increases is compensated by the electrolyser consuming the "expensive" part of the electricity price duration curve; at mid-range load factors, the typical electricity mix within Denmark is still characterised by a high renewables percentage, but not close to 100 %.

- At higher load factors, combined also with high electricity prices, any further reduction in the CAPEX component has a small impact on LCOH values; at such prices, the share of VRE is also likely to be very low.

The Power-to-Gas Roadmap for Flanders study[12] shows similar results: based on the electricity price duration curves foreseen in Belgium, the study calculates the LCOH for dispensing H_2 at a hydrogen refuelling station (HRS) for buses (25 buses refuelling daily, a 0.2 MW electrolyser producing 900 kg/day). The LCOH calculations integrate the CAPEX and OPEX of the HRS.

12 www.power-to-gas.be/roadmap-study.

Figure 9: Levelised cost of hydrogen (LCOH) produced via ALK and PEM in 2017 and as expected in 2025

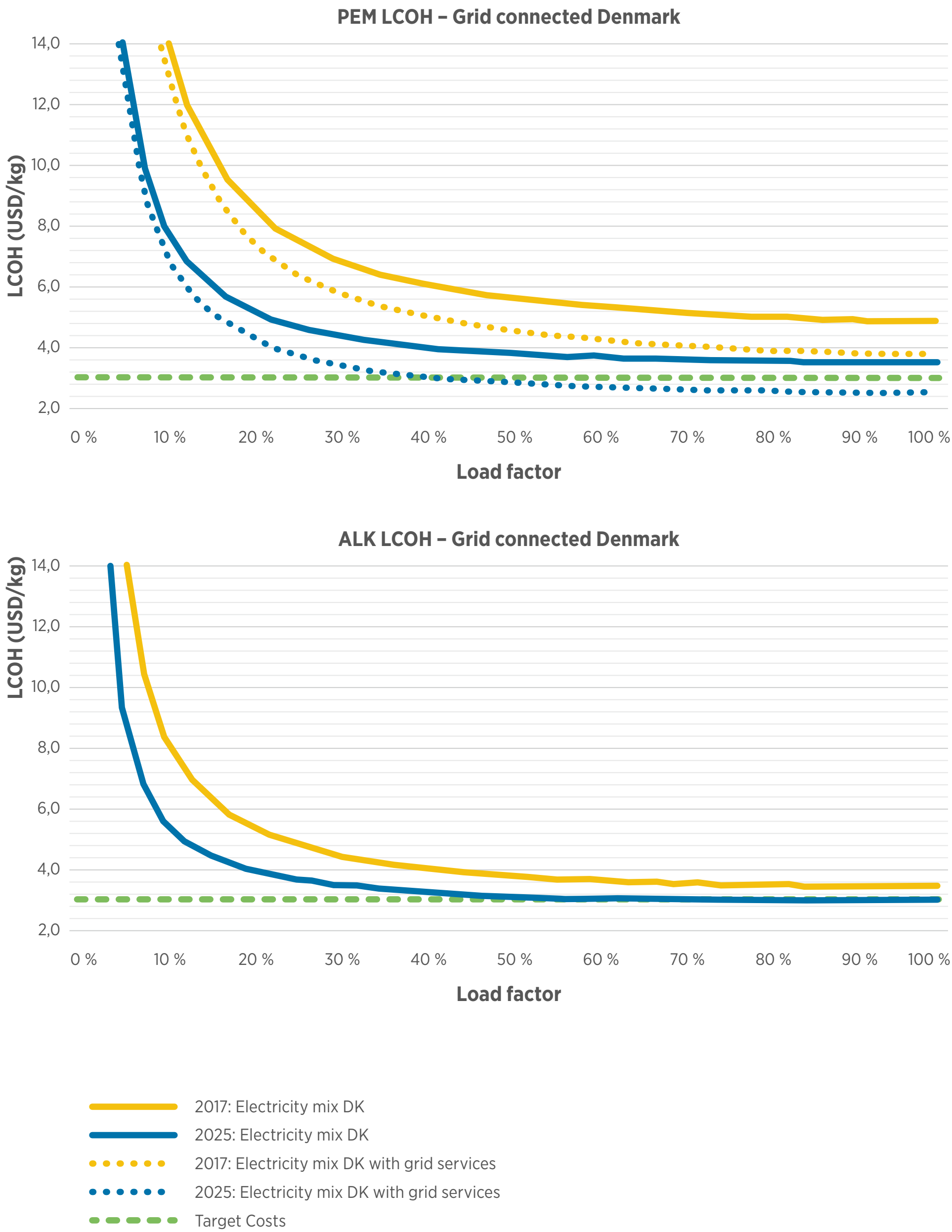
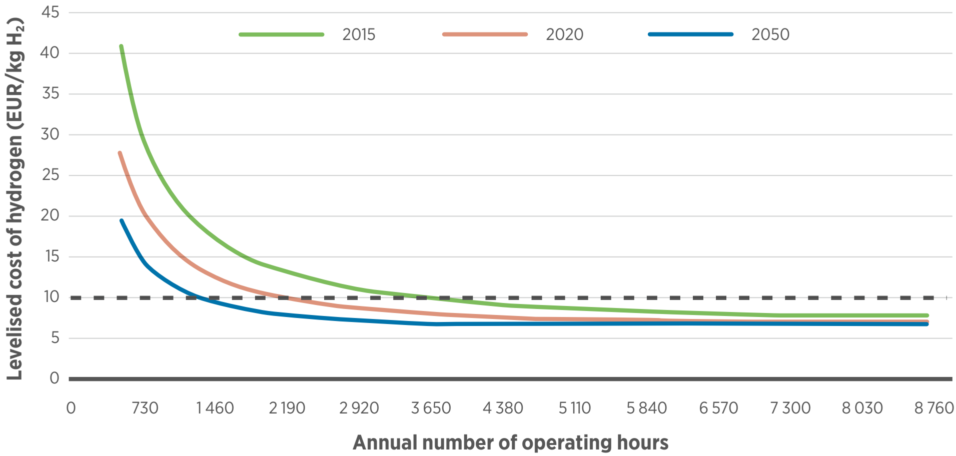


Figure 10: LCOH vs. operating time (HRS for buses)



Source: Thomas, D. et al. (2016)

The study concludes: "Considering the same methodology for the business case, it is expected that the LCOH for the HRS can fall below the EUR 10/kg landmark if the utilisation of the HRS (and electrolyser) is generally above 25 % [see Figure 10]. If the utilisation is lower, then the LCOH is increasing drastically to high numbers."

Moreover, it concludes from the Waterfall diagram (Figure 12) that "the overall high impact of the electricity grid fees on the LCOH, representing EUR 2.60/kg in this specific example, is high. If these fees could be removed, the LCOH would be in the range of EUR 5.2/kg".

When directly connected to a VRE plant and off grid, the electrolyser will have to follow the VRE generation pattern, which requires the flexibility of a PEM electrolyser. Hence the CAPEX component of the LCOH will be determined by the load factor of the VRE plant.

Figure 13 shows the LCOH for electrolysers that are directly connected to a VRE plant. Lower load factors (smaller bubble size in Figure 13) increase the LCOH: the amortisation costs of the electrolyser need to be allocated to a lesser amount of hydrogen produced. Only when the cost of VRE and electrolyser CAPEX drop further in the future can hydrogen be produced at competitive cost.

At the same time, the LCOE of electricity for an off-grid system produces a flat price duration curve: no increase in electricity cost with increased consumption.

Based on the logic of such analysis, Chile is developing a strategy aimed at exporting hydrogen. Japan, meanwhile, is looking at Chile as a long-term source of renewable hydrogen, beyond the shift to new coal and gas sources in the nearer term.

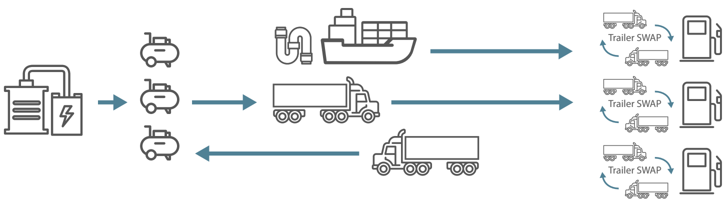
The ideal case for Chilean hydrogen production combines a low LCOE with a high capacity factor, making the best use of cheap renewable electricity and minimising the impact of electrolyser depreciation on the LCOH. Notably, countries such as Argentina (due to the high load factor of wind generation in Patagonia) and Australia and Chile (due to abundant sun) are developing roadmaps to convert their surplus VRE into compressed gaseous or liquid hydrogen (or another carrier similar to LCOH, see above) for transport to regions with a net demand, such as Japan[13] and the Republic of Korea.

The first international supply of hydrogen is already set to begin operations by 2020, when Brunei will produce liquefied hydrogen and ship it to Kawasaki in Japan.

To put the LCOH in perspective, the target selling prices for different hydrogen applications have been represented on the graph. For future cost projections, the US Department of Energy has a target for the cost of hydrogen dispensed at the pump of USD 5/kg (US DOE, 2018), whereas Japan has a target to reduce cost at fuel stations from the current USD 10/kg to USD 3/kg by 2030[14] and FCH JU is targeting EUR 6/kg.

This is depicted in Figure 11.[15]

Figure 11: Cumulative supply chain target costs for hydrogen in transport



	H_2 production	H_2 compression	H_2 logistics	H_2 distribution
Cumulated supply chain cost – current estimate	5–6 $/kg	$$	$$	13–16 $/kg
Cumulated supply chain costs – targets (Europe)	1–3 $/kg	$	$	3–7 $/kg

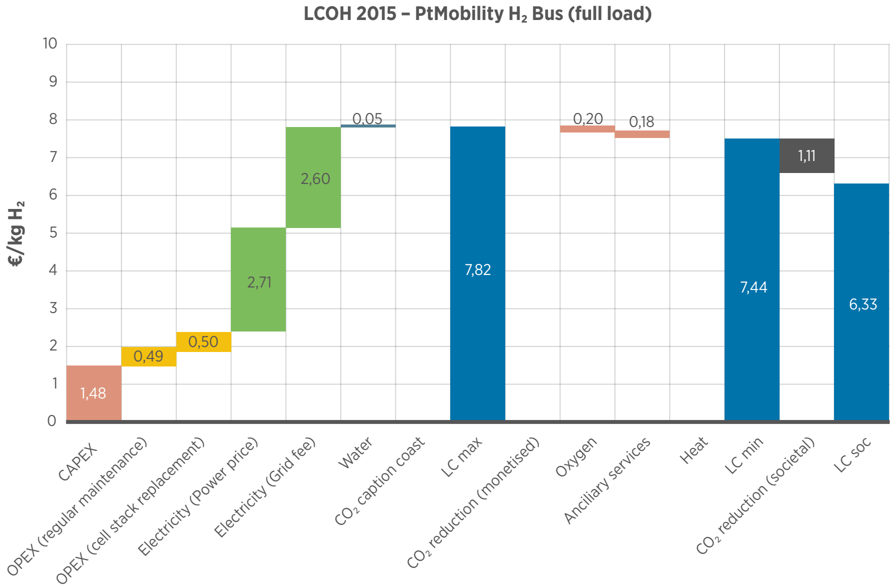
Based on HINICIO (2016), present costs estimate at the pump from US DOE (2018). However Japan current estimate is 10 USD/kg. Target prices for production: IRENA analysis. Target prices at the pump of 3 USD/kg for Japan, 5 for US and 6–7 for Europe. See text for references.)

13 www.ammoniaenergy.org/kawasaki-moving-ahead-with-lh2-tanker-project/ and https://www.bizbrunei.com/ahead-to-begin-worlds-first-international-supply-of-hydrogen-from-brunei-in-2020/.

14 www.bizbrunei.com/ahead-to-begin-worlds-first-international-supply-of-hydrogen-from-brunei-in-2020/.

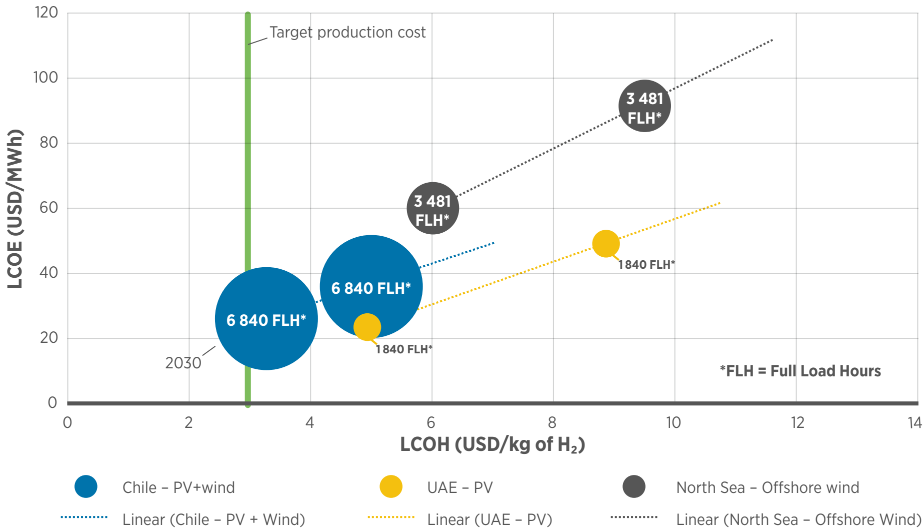
15 It is impossible to come to a unified conclusion on an industrial hydrogen price, as the variation in targeted sales prices across countries and applications is too diverse.

Figure 12: Waterfall graph of 2015 LCOH at HRS for buses (full load operation)



Source: Thomas, D. et al. (2016)

Figure 13: Cost of hydrogen as a function of cost of electricity and utilisation rate of PEM electrolyser



A target cost of USD 5–6/kg can already be achieved today by connecting an electrolyser to the electricity grid (with 2017 Danish electricity prices that include all grid fees, levies and taxes) (FCH-JU, 2017b). Moreover, the target LCOH can be achieved by operating the electrolyser only 40 % of the time, meaning that the electrolyser does not need to operate at full load (consuming fossil-based electricity). Additionally, a grid-connected electrolyser can operate close to hydrogen demand, or even on-site, reducing logistic costs significantly.

The business case for hydrogen from off-grid VRE remains challenging, mainly due to the comparatively low load factor of renewable power plants compared to electricity from the grid, the case in Chile (with high load factors combining PV and wind plants) being the exception.

However, this approach does allow for avoidance of any grid costs and the use of marginal land with high solar or wind resource to develop large-scale, low-cost VRE facilities dedicated to hydrogen production.

Options for increasing the load factor of an electrolyser in an off-grid context include: a combination of solar and wind plants (as showcased in Figure 13), the use of CSP with thermal storage, and the use of batteries to optimise electrolyser efficiency. By 2030, using more mature PEM electrolyser technology, the case for a direct connection with VRE plants could yield a positive business case. Policies to encourage decarbonisation of the energy system could change this picture rapidly, triggering large-scale deployment and, in turn, further cost reductions.

The business case for hydrogen from variable renewable energy in off-grid settings remains challenging.

3 HYDROGEN APPLICATIONS IN END-USE SECTORS

Hydrogen can help further deployment of renewable energy in hard-to-electrify sectors: transport, industry and those relying on existing gas grids, such as buildings and power.

A recent study for the Hydrogen Council[16] (2017) provides a comprehensive assessment of hydrogen's long-term potential and a roadmap for its deployment. **The study envisages that by 2050, 18 % of global final energy demand could be met by hydrogen, equal to about 78 EJ.**[17] The corresponding abatement potential represents 6 gigatonnes of CO_2 annually. As of 2015, hydrogen demand was 8 EJ, dedicated mostly to feedstock uses in industry. This hydrogen, as presented in Figure 14, is currently produced from fossil fuels.

For this potential to materialise, policy and financial support and significant cost reductions are required. The latest economic assessment by IRENA (2018) estimates hydrogen's **economic potential at about 8 EJ at the global level by 2050** in addition to feedstock uses.[18] Most of this would be in transport, with significant use also in industry, mainly the steel and chemicals sectors. While the Hydrogen Council roadmap is industry's consensus vision of hydrogen's potential in the economy under the right circumstances (e.g. alignment of policies, regulations, codes and standards), it is just one vision of numerous potential outcomes; IRENA's assessment looks at the mix of renewable options to achieve the targets set out in the Paris Agreement, ranking options by their substitution cost.[19] Figure 14 compares these studies.

The sections that follow provide an overview of the potential applications of hydrogen as a feedstock and as an energy carrier.

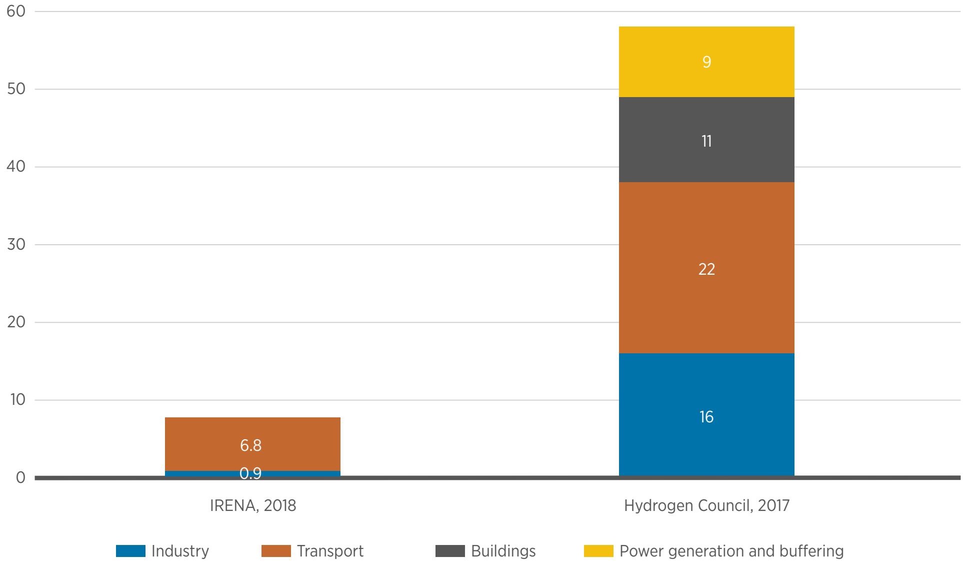
16 The Hydrogen Council is a global initiative of leading energy, transport and industrial companies that have an interest in different technologies related to hydrogen (e.g. passenger vehicles, batteries, natural gas, carbon capture and storage or usage), which has developed a united vision and long-term ambition for hydrogen to foster the energy transition. Launched at the World Economic Forum 2017, in Davos, the growing coalition of CEOs has the ambition of accelerating their significant investment in the development and commercialisation of the hydrogen and fuel cell sectors and encourages key stakeholders to increase their backing of hydrogen as part of the future energy mix with appropriate policies and supporting schemes.

17 Of which 19 EJ are feedstock uses.

18 Excluding feedstocks, e.g. gas for ammonia.

19 For more information about REmap methodology, see: http://irena.org/remap/Methodology.

Figure 14: 2050 potential for hydrogen in total final energy supply (all values in EJ)



Sources: IRENA (2018), Hydrogen Council (2017).

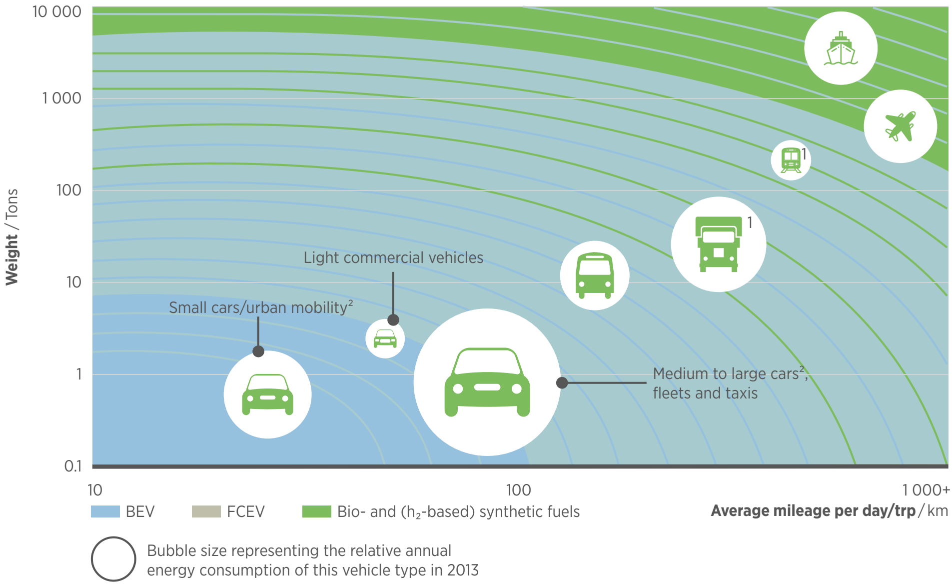
3.1 DECARBONISING TRANSPORT

FCEVs are electric vehicles with a driving range and refuelling time similar to conventional vehicles. In this perspective, they expand the scope of electric mobility to high duty cycle segments, such as long-range and high-utilisation road vehicles (trucks, buses), trains, ferry boats and utilitarian vehicles such as forklifts,[20] where today's batteries face limitations. Hydrogen should therefore be considered as complementary to BEVs in the broader context of the energy transition; while they may compete in some market segments, for each segment there is a clear competitive advantage for either FCEVs or BEVs.

Figure 15 below is an illustration of this complementarity and provides a segmentation of the transport sector based on vehicle weight and required driving range. For each market segment, it presents the suitability of three families of alternative drivetrains: BEV, FCEV, and bio- and H_2-based synthetic fuels.

20 In the forklift market, FCEVs are already a commercial solution, with a value proposition based on productivity gains. The forklift truck segment is the most advanced, with thousands of units already deployed in warehouses across the United States (Coca Cola, BMW, Amazon, etc.). The switch from batteries to fuel cells allows the operator to increase the fleet's utilisation rate, reduce labour cost (no battery swapping operation) and reduce required space (no need to dedicate space to store batteries). (IEA Hydrogen, 2017).

Figure 15: Segmentation of the transport market



1 Battery-hydrogen hybrid to ensure sufficient power
2 Split in A- and B-segment LDVs (small cars) and C+segment LDVs (medium to large cars) based on a 30 % market share of A/B-segment cars and a 50 % less energy demand

Source: Hydrogen Council (2017).

It shows that while BEVs are highly suited to smaller and lighter vehicles travelling short distances, FCEVs provide advantages for heavier vehicles travelling over longer distances (trucks, regional/intercity buses, etc.) and high utilisation rate vehicles (e.g. taxis). Furthermore, FCEVs would combine the flexibility of hydrogen with the efficiency of BEVs, and might therefore be the most economical long-term option.

FCEVs have near-term potential in heavy-duty vehicle markets (trucks and buses). This is a segment where hydrogen and fuel cells are expected to play an important role and have clear advantages over BEVs for users (refuelling time and driving distance). Fuel cell buses have been demonstrated and validated in real-life environments. Production costs have dropped significantly over recent years and will continue to do so as volumes increase. Fuel cell trucks are under development and large-scale deployment is expected to start in the coming years, in particular in the United States (e.g. Toyota, Nikola). In the short to medium term, in this segment, hydrogen may experience competition from vehicles running on natural gas and bio-natural gas, which are currently also being deployed around the world.

FCEVs hold longer-term potential in the medium to large passenger vehicle segment, provided several factors materialise, including refuelling supply chains and infrastructure. FCEVs will particularly have a competitive advantage for users over BEVs in market segments with high utilisation rates and where refuelling times need to be limited (such as taxis, last-mile delivery). Currently, such vehicles are largely in their commercial infancy, with only about 8 000 on the road worldwide in 2017. Several global automakers, such as Toyota, Hyundai, Honda and the Chinese car manufacturer SAIC, have begun commercialisation in certain regions of the world, including Japan, California, Europe and China.

In addition to road transport**,** hydrogen also holds the potential to contribute to **decarbonising rail transport, shipping and aviation** in the longer term.

In the rail sector, the first fleet of hydrogen trains, manufactured by Alstom, are being deployed for commercial service in Northern Germany to replace diesel trains on non-electrified lines, which allows system providers to avoid the high capital expense of building new overhead wires. Several other countries are planning similar moves in the next few years (including the United Kingdom, the Netherlands and Austria).

In the maritime sector, fuel cell ships are at the demonstration stage in various segments (ferries, shuttles, etc.) and regulatory push is creating the opportunity for more rapid development. Hydrogen fuel cells can also be used to replace on-board and onshore power supply, currently often based on diesel or fuel oil, to eliminate pollutants emissions (NO_X, SO_X and particulate matter) in harbours, while avoiding expensive installation costs for electrical connections at the harbour. For long-distance ship runs, liquefied hydrogen is now being considered as a potential option to meet the International Maritime Organization's greenhouse gas (GHG) emission reduction target of 50 % by 2050 (UNFCCC, 2018).

In aviation, fuel cell-based electric propulsion is being considered and demonstrated for smaller propeller-driven regional aircrafts (e.g. German HY4 demonstration project). Also, hydrogen fuel cells have several potential applications relating to on-board power supply that could potentially be deployed between 2020 and 2050. For jet aircraft, decarbonisation may be achieved through the use of electrofuels (e-fuels) that could be used as a drop-in fuel, to complement aviation biofuels. This is dependent on improvement in the economics (currently the cost of producing e-fuels is significantly higher than the fossil fuels they aim to replace) and further technological advancement, demonstration and rigorous testing as required in the aviation industry.

As with BEVs, the deployment of fuel cell-based vehicles requires a coordinated roll-out of dedicated refuelling infrastructure. The types and numbers of vehicles directly influence the required typology of HRSs, which is structured according to capacity and hydrogen output pressure level (350 or 700 bar).

Overcoming the chicken-and-egg dilemma is the primary challenge facing the hydrogen industry in the mobility sector. This is particularly problematic for the passenger vehicle segment. On the one hand, vehicle manufacturers are reluctant to invest in manufacturing fuel cell vehicles without hydrogen refuelling infrastructure in place, as no consumer would purchase a vehicle without the ability to refuel it. On the other hand, energy and industrial gas companies are not prepared to roll out the necessary hydrogen infrastructure before hydrogen vehicles become commercial, as they would face several years before seeing any return on their investment. In a number of countries, governments are therefore stepping in to provide investment support.


Hydrogen
Fuel

On the infrastructure side, hydrogen production and distribution infrastructure is capital intensive, and such investment is risky and difficult to justify without long-term visibility on hydrogen demand and the **political commitment needed** to ensure the market is there for the long term. For the technology to be viable, large-scale installations will be necessary to achieve economies of scale and thereby reduce the cost of hydrogen to the end user. Securing a critical volume of hydrogen demand is a major roadblock to infrastructure investment, hence the increasing interest in heavy-duty and high duty cycle applications. The lack of available commercial vehicles represents an additional bottleneck to the provision of infrastructure in most countries. Nonetheless, in the short to medium term hydrogen could initially be produced on site at smaller refuelling stations, beginning with fleets that return to their base to be refuelled (for example, local authority fleets or bus depots). These stations could also be open to the public.

3.2 DECARBONISING INDUSTRY

In the short term, large industrial sectors where hydrogen has been used for decades (refineries, ammonia production, etc.) are expected to be key early markets for power-to-hydrogen, as they would be able to generate immediate scale effects and hence rapid cost reductions. In the long term, hydrogen produced from renewable energy via electrolysis has the potential to contribute to the deep decarbonisation of industry.

Decarbonise current hydrogen supply

Power-to-hydrogen using electricity from renewables can contribute to reducing emissions in the following sectors, where hydrogen has been used for decades as a (fossil-based) feedstock. For each industry, specific pathways with associated conversion costs have to be carefully assessed, as in some cases it would only require moving production of hydrogen away from fossil fuels to renewables, while in other sectors it might require process changes with associated need for investment.

- **Heavy industry:**
  - **Chemicals:** ammonia, polymer and resin production are the primary industrial markets for hydrogen (see Figure 4).
  - **Refining:** globally, refineries are the second-largest consumer of hydrogen in industry (see Figure 4). Hydrogen is used for hydrocracking and for desulphurisation of fuels (hydro treating).
  - **Iron and steel:** hydrogen is used for annealing (heat treatment of processed metal to restore ductility after deformation). The total global demand for hydrogen in the sector is relatively small.

- **Other industries:**

  Several other industrial processes use hydrogen, but altogether account for just 1% of the global hydrogen demand. These include: the manufacture of glass, food (hydrogenation of fats), bulk chemicals, property chemicals and semiconductors, the cooling of electrical generators, and as a propellant fuel for rockets in aerospace. The current production options are mostly based on fossil fuels. For instance, in Europe and the United States, SMR is the primary option. In China, the valorisation of by-product hydrogen dominates the scene, although coal gasification is also used for metal and petrochemical production. In Australia, most hydrogen is generated via the gasification of coal.

Industry could constitute a strategic enabling market for power-to-hydrogen where large potential volumes would generate economies of scale, thereby unlocking further cost reductions even with a limited number of installations. This could further accelerate deployment and improve the economics of power-to-hydrogen in other segments, notably mobility. However, the uptake of hydrogen from renewable power in industry is hampered by its high costs.

The industry tends to be very sensitive to feedstock prices and there is a risk of carbon leakage where plants might relocate to other countries. Policy and regulatory frameworks should therefore be considered the main drivers for the development of hydrogen from renewable power in heavy industry (emission reduction regulations, renewable energy mandates, carbon markets, etc.).

In contrast to large industry, the deployment of power-to-hydrogen in light industry is mostly supported by pure economics as these sectors are generally not subject to emissions restrictions nor carbon market obligations. Historically, electrolysers have not been the least-cost option, with the exception of hydrogen used for the cooling of large turbines for power generation, where hydrogen-cooled power generators produce hydrogen on site for their own use via electrolysis. A reduction in electrolyser cost, combined with the possibility of capturing additional revenues from flexibility, might change the picture in the medium term.

The chemicals and refining sectors could be key enabling markets for hydrogen from renewable power. These industries require large quantities of hydrogen over long periods at a given price. Industry is a captive customer that commonly works with long-term contracts, which provide certainty of price and quantity. Large volumes can lead to economies of scale and to revenue stacking from sources such as gas grid injection and provision of grid services, bringing hydrogen from renewables closer to competitiveness with hydrogen from SMR.

Hydrogen from renewable power to displace fossil fuels in end-use sectors

New hydrogen applications can be found in a variety of industrial sectors where hydrogen from renewable power could therefore constitute an option for deep decarbonisation:

- **Replacing natural gas and other fossil fuels with hydrogen to produce high-grade heat** (>650°C) via hydrogen combustion in hydrogen-specific burners. Cement and iron production, for instance, require significant amounts of high-temperature process heat. Hydrogen can also be used in cogeneration plants to generate both heat and power.

- **Reducing emissions from iron ore reduction.** Currently, steelmaking largely uses coking coal as a carbon source. Coking coal acts as a reduction agent for iron ore (reacting the oxygen [O] with carbon [C] in iron ore, generating CO_2). An alternative and innovative process called direct reduction via hydrogen (DRI-H), avoiding coke usage, is currently at demonstration phase and could be a stepping stone for energy-efficient and low-carbon steelmaking (reacting oxygen [O] with hydrogen [H_2], generating water [H_2O]) (FCH JU, 2017b).

- **Producing synthetic fuels,** such as gasoline, diesel, kerosene, methanol (so-called "power-to-liquids") or natural gas (methanation) by combining hydrogen produced via electrolysis and CO_2 captured from emitting processes (or possibly extracted from the air). Despite the limited energy efficiency of the overall production process, these pathways can channel renewables towards sectors with limited emission reduction alternatives, such as aviation.

3.3 DECARBONISING THE GAS GRID

In the short term, the injection of hydrogen from renewable power into the gas grid represents a potential upside revenue to improve power-to-hydrogen's economics. In the long term, it holds the promise of storing large amounts of renewable power, while decarbonising demand for natural gas.

Hydrogen produced from renewables via electrolysis can be blended with natural gas and injected into the gas grid, up to certain levels depending on several factors and components. It can thereby contribute to reducing emissions related to natural gas usage in buildings, industry and power plants.

In the short term, gas grid injection is a low-value, low-investment stepping stone to support the early-stage scaling-up of hydrogen production. As highlighted by HINICIO and Tractebel in their recent FCH JU study (2017b):

Hydrogen injection should be considered as a de-risking instrument for Power-to-Hydrogen through the 'valley of death' of mobility…

Gas grid injection can boost cash flows at low marginal cost towards breakeven during the ramp-up phase of mobility applications, when the risk of expected demand not materialising remains high ('valley of death'). Injection also allows for nearly continuous electrolyser operation that helps to secure revenues from providing grid services, which generally require that the electrolyser is running.

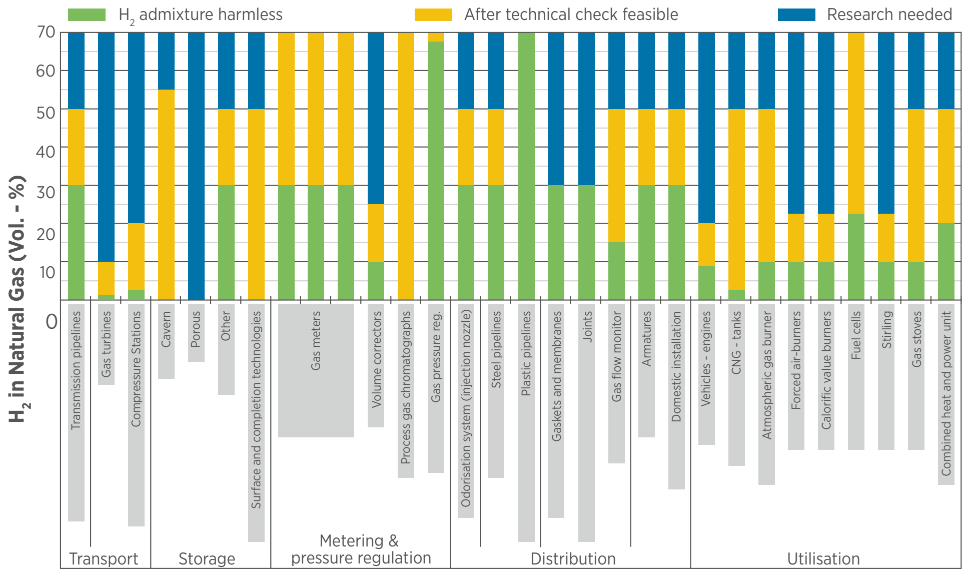
Instruments such as injection tariffs could support hydrogen injection into the gas grid. Their level could be set to cover the difference in cost between hydrogen and natural gas. Hydrogen would be injected whenever surplus capacity is available (when mobility or industry demand does not require full load production) and the marginal cost of hydrogen is lower than the injection tariff. Injection would therefore occur when spot electricity prices are low. Given the current state of the art of electrolysers, the tariff level could be roughly equivalent to existing biomethane injection tariffs in certain European countries (+/- EUR 90/MWh) (FCH JU, 2017b).

In the long run, injecting hydrogen into the gas grid is considered a way to store massive amounts of renewable energy. Because hydrogen will use existing gas infrastructure, expensive electricity grid upgrades and expansion can be avoided.

A key advantage of power-to-hydrogen over electricity is the fact that hydrogen can be stored on a large scale. This will enable the system to cope with large swings in demand, as well as being an option for interseasonal storage to meet seasonal demand peaks (e.g. heat in winter). Given the large capacity of gas networks, even low blending shares could enable the absorption of significant quantities of variable renewable energy. In the European Union alone the amount of energy stored in the form of methane in the gas grid is around 1 200 terawatt hours (TWh) (ENERGINET, 2017). This is equal to roughly one-fifth of the total European natural gas demand.[21]

21 In 2015, Europe's total natural gas demand totalled 548 billion cubic metres, equal to roughly 5 375 TWh. "Europe" comprises 31 countries: OECD Europe + Bulgaria + Croatia + Lithuania + Malta + Romania + the Former Yugoslav Republic of Macedonia. Note: Serbia is not taken into account, as data on the country has only been available from Eurostat since 2017. OIES (2018). "OECD Europe" consists of members of the Organisation for Economic Co-operation and Development (OECD), roughly equating with the most advanced economies.

Figure 16: Hydrogen tolerance of gas infrastructure components



Source: Adapted from DVGW (2012).

Optimal blending concentrations strongly depend on the characteristics of the existing network, natural gas composition and end-use applications. Existing studies show that, generally, at relatively low hydrogen concentrations (up to 10–20 % in volume), blending may not require major investment or modification to the infrastructure and can be done in a safe manner (IEA, 2015; DNV-GL, 2017; NREL, 2013; National Research Council Canada, 2017). The most critical applications with respect to blending shares are gas turbines, pore storage, compressor stations and compressed natural gas tanks (see Figure 16). Gas flow detectors, quantity transformers and end-use meters, as well as most gas appliances installed in the residential sector, may need adjustment or modification.

Blending concentrations greater than 20 % hydrogen by volume would require significant changes to existing infrastructure and end-use applications. In particular cases, it may therefore be more economic to transform the entire infrastructure and applications to work with pure hydrogen on a local or regional basis (e.g. in a particular neighbourhood).

The Iron Mains Project in the city of Leeds in the United Kingdom is specifically investigating this option and a feasibility study has been completed (Northern Gas Networks, 2017). Leeds is a unique case of favourable conditions, with access to an industrial cluster (Teesside), a large coal power station and an offshore former gas field for carbon capture and storage (CCS). Also, the main gas grid in the UK is ageing and in need of replacement. Old pipelines will be replaced in a 40-year programme to reduce the risk of accidents, with modern polyethylene pipes and state-of-the-art equipment that are likely to be more suitable for hydrogen distribution. These factors form the rationale for considering a transition to hydrogen in Leeds. There are also other test cases, including one in the German district of Kreis Nordfriesland (towns of Klanxbüll und Neukirchen).[22]

More research is required to better understand the technical impact of different levels of hydrogen blending and injection into existing gas infrastructure and the required modifications and investment. This has to be done on a case-by-case basis as gas grids have local technical characteristics. After relevant research and tests have been performed, hydrogen blending will require adaptation of regulations as most countries have set limits on the hydrogen content of natural gas.

In the long term, in cases where the blending concentration reaches the acceptable upper limit due to the presence of low-cost variable renewables, it is also technically possible to produce synthetic methane from hydrogen through methanation, whereby hydrogen (H_2) is combined with carbon (C) from biomass or carbon dioxide (CO_2) captured from a concentrated source (or from the air) to produce synthetic methane (CH_4).[23] Even though this route does not involve any added cost or technical barrier at the gas infrastructure or end-use level, the main difficulties remain the low efficiency and the cost of the process itself due to the additional CO_2 capture and methanation steps required on top of hydrogen production.

22 www.hansewerk.com/de/ueber-uns/innovationen/forschungsprojekte/wasserstoff-einspeisung.html.

23 The Port of Rotterdam is looking to use H_2 from offshore wind and combine it with biomass waste to continue to be a hub for chemicals production; www.portofrotterdam.com/en/news-and-press-releases/study-outlines-how-rotterdams-industrial-sector-can-comply-with-paris.

3.4 HYDROGEN-TO-POWER BASED ON FUEL CELLS

The re-electrification pathway (electricity storage and regeneration) is a promising option in the long term for when high shares of variable renewables make seasonal storage a necessity to match the seasonality of demand with that of generation. However, in most cases, such business cases will be very challenging in the short to medium term due to the low roundtrip efficiency and high CAPEX compared to alternatives such as pumped hydro or battery storage.

Isolated power systems with high (fossil-based) electricity costs represent a potential niche market, as the development of variable renewables and electricity storage usually take place based on a purely economic rationale. In such an environment, longer-term storage via hydrogen in combination with intra-day battery storage may become an economic reality much faster than in settings with lower prices for energy.

A few other niche applications exist where hydrogen and fuel cells can already play a role, such as stationary power for uninterruptible supply or power backup systems for network equipment (telecom towers) and datacentres, and the supply of off-grid power in isolated regions or islands. Stationary hydrogen fuel cells often compete with batteries that are generally less expensive and show better roundtrip efficiencies. However, hydrogen storage and fuel cells do not self-discharge, in contrast to batteries, have a longer lifetime and a higher temperature tolerance, which is useful in more extreme climates.

Where there is a need for larger amounts of energy compared to power (storing many hours of electricity supply), there might be a case for using hydrogen for stationary power generation. Stationary fuel cells can also replace diesel generators that require more maintenance, which makes them attractive for deployment in remote locations. For premium tourist island locations, the reduced noise, odour and improved air quality could make the case for stationary fuel cell application more attractive.

4 CREATING THE HYDROGEN SUPPLY CHAIN

The progressive deployment of hydrogen end-use applications will require the joint ramping-up of a hydrogen supply chain, including additional capacity for production, purification and pressurising for transport, and transport and distribution capacity. From a theoretical standpoint, a wide spectrum of options is possible, ranging from on-site production (producing hydrogen where it is consumed) all the way up to centralised production and long-distance delivery, for instance via tanker trucks, or through gas or dedicated hydrogen pipelines.

In reality, the structure of the supply chain will be influenced by the geographic distribution and nature of the demand, as well as the following factors:

- First, the availability of **existing hydrogen sources or feedstock to produce hydrogen** in the vicinity, compared to the **cost of on-site production,** because the production of hydrogen is the most capital-intensive part of the supply chain.

- Second, beyond a certain **consumption threshold,**[24] **on-site production** or delivery via **dedicated hydrogen pipeline** could be the only viable **mainstream mode of supply**. These are likely to remain so in the near future.

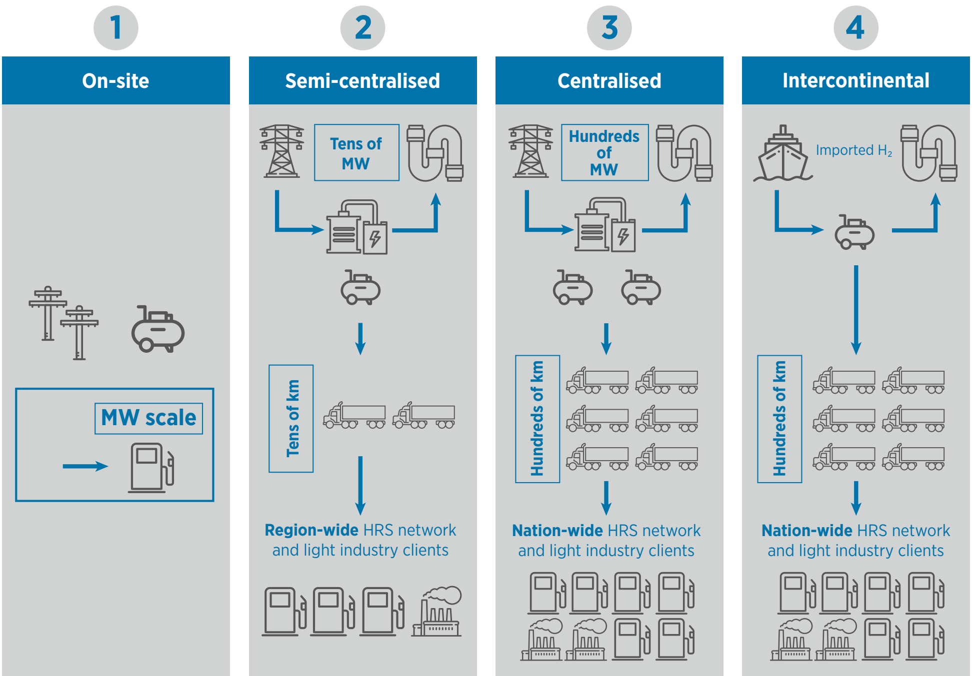
- Third, from a risk management perspective, **investment in new large-scale production capacity** has traditionally only been made if a large proportion of the production is sold to a **single client** (or a limited number of clients) with **long-term contracts signed upfront** (NREL, 2016a), or if it could be justified by having **sufficient equity buffer** to cover initial losses or by **financial de-risking instruments** offered by policy makers (FCH JU, 2013).

These forces have already played out and shaped the hydrogen supply chain as it is today. Historically, industrial gas companies used to recover by-product hydrogen and deliver it to their merchant clients. At the same time, large industrial consumers, such as refineries, used to own and operate large on-site SMR facilities for their own purposes.

24 This threshold is defined by the capacity of trailer trucks, currently 400 kg of hydrogen, considering that delivering more than two trailers per day per site is not feasible from a practical perspective in most cases. Technological progress could theoretically lead to increase the capacity of trailers up to 1.3 tonnes of hydrogen (physical limit). Therefore, it can be reasonably stated that beyond 0.5–1.5 tonnes of consumption per day, on-site production or delivery via dedicated hydrogen pipeline is the only technically feasible option.

Only during the 1960s did industrial gas companies expand their footprint in heavy industry and start to invest in large-scale "over-the-fence" production capacity to supply large consumers under long-term contracts. From there, they further invested in conditioning and filling centres, thus leveraging the economies of scale from their large production assets to supply hydrogen in smaller quantities and over long distances to the merchant market via truck delivery. Depending on the quantities and distances involved, hydrogen is either delivered in gas cylinders (small quantities), gas trailers (large quantities, shorter distances) or in liquid form (large quantities, longer distances, typically in the United States).

Figure 17: Potential future ramp up pattern of the hydrogen supply chain



Note: The numbers 1, 2, 3 and 4 refer to the different potential future development stages in chronological order.
Based on: HINICIO (2016) .

The **historic deployment pattern** could serve as a **blueprint for future investment** in the hydrogen supply chain**,** to achieve economic viability and ensure the supply of competitively priced hydrogen to end consumers. Four stages can be envisaged (Figure 17):

- Investment in **new hydrogen production facilities** could be focused on **multi-megawatt capacities for large consumers** (regions converting the natural gas grid to a hydrogen grid, medium-sized to large industry, hydrogen trains, boats, bus fleets, etc.), thus securing a long-term off-taker for the investor (via long-term supply contracts).

- In the second and third stages, these new production facilities could be leveraged to become **"semi-centralised" or "centralised"** hydrogen sources supplying **smaller local consumers** through investment in conditioning and filling centres, as well as logistics (trailer trucks).

- As end applications reach the mass market and the supply of hydrogen from renewable power keeps expanding, regional disparities in the availability of hydrogen from renewable power could start to emerge. Regions with **surplus hydrogen** would start **exporting** to regions in deficit. This leads to the creation of a continent-wide or even intercontinental hydrogen market between countries with large renewables potential and hence export capacities (e.g. Chile, Australia, Middle East, North Sea region), and countries with large hydrogen demand and costlier or limited renewables potential. As in the case of the global natural gas market, long distances will require the transport of hydrogen via dedicated pipeline or in forms other than gas (which has a low volumetric density). Options range from liquefied hydrogen to other carriers, such as LOHCs, methanol or ammonia (which is produced from hydrogen and from which hydrogen can be extracted again).

5 RECOMMENDATIONS FOR POLICY MAKERS

Hydrogen has been in use as a feedstock in several key industry segments for decades. In the energy transition, hydrogen could be the **"missing link"** to help supply large amounts of renewable power to sectors that are otherwise difficult to decarbonise through direct electrification, such as transport, industry and current natural gas uses. In this regard, power-to-hydrogen can provide part of the added flexibility needed to accommodate the large shares of VRE expected to come online in the decades ahead.

The technologies are ready. A rapid scaling-up is now needed to achieve the necessary cost reductions and ensure the economic viability of hydrogen as a long-term enabler of the energy transition.

Initial efforts could focus on large-scale applications that are able to rapidly generate economies of scale, with minimal infrastructure requirements, and in sectors where hydrogen from renewables stands out as the best-performing option for meeting climate targets: large industry (refineries, chemicals facilities, methanol production) and heavy-duty transport (large fleets of hydrogen buses, trucks, trains on non-electrified lines, maritime, etc.).

To achieve rapid scale-up, a stable and supportive policy framework would be needed to encourage the appropriate private investments. This is the case across the entire supply chain (equipment manufacturers, infrastructure operators, vehicle manufacturers, etc.).

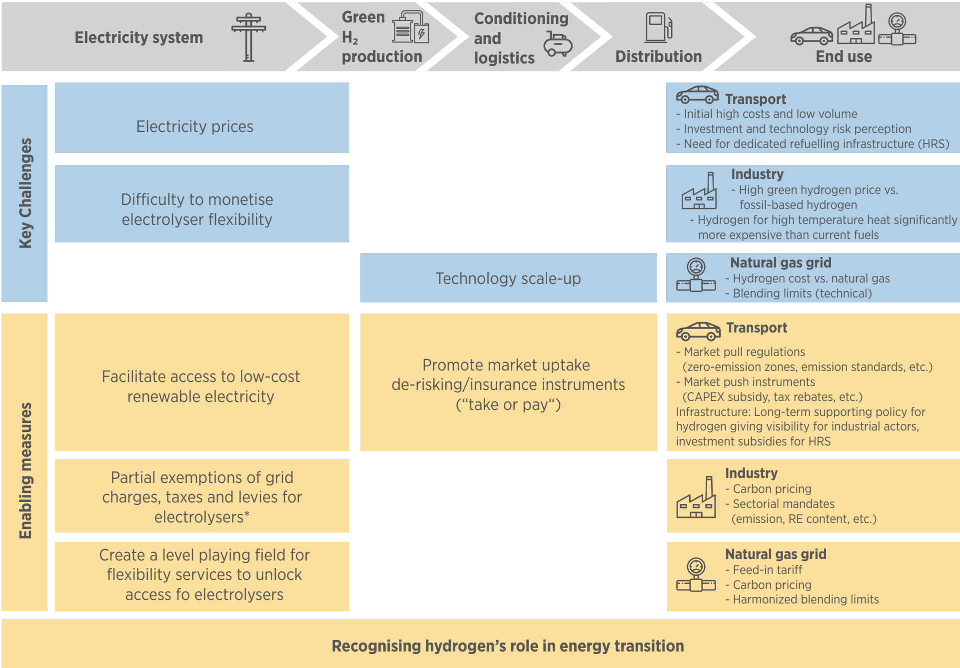
The chart in Figure 18 summarises the key challenges facing the industry at every step of the value chain and proposes a set of policy measures to overcome them.

Technology-neutral instruments aimed at final consumers can trigger hydrogen demand and justify investment in infrastructure. Such instruments may include carbon pricing, emissions restrictions (low-emission zones, emissions standards or targets), specific mandates for renewable energy content or carbon pricing in the targeted sectors.

In the short term, measures that can (partially) cover the initial cost difference with incumbent technologies are needed. This is especially the case for vehicle applications (FCEVs) and infrastructure investments. Those measures (CAPEX subsidies, tax rebates) could be directed to priority technologies and segments, with a clear phasing-out trajectory.

Specific instruments would be needed to de-risk infrastructure investment and improve the economics of the supply chain. For example, access to stacked revenues from energy, energy service and carbon markets could be regarded as an important element toward achieving infrastructure investment bankability in the short term, while being entirely in line with the long-term vision of the role of hydrogen in the energy transition. Significant infrastructure investment will have to take place to supply end applications with hydrogen produced from renewables.

Figure 18: Key challenges and overview of possible enabling measures for power-to-hydrogen



*Provided that they run in system beneficial mode
Source: Adapted from HINICIO (2016).

In addition, the creation of tariffs for the injection of hydrogen into the gas grid may prove critical to creating sufficient demand in a short time scale to trigger cost reductions through economies of scale and de-risk initial investments in large-scale electrolysers to supply mobility or industry as a primary application. Gas grid injection can be an additional layer of revenue next to such primary applications.

Upstream, the full exploitation of renewable generation capacity for hydrogen production could be facilitated by promoting the **certification of hydrogen from renewable power**. Certification schemes could help to register such power use (when grid-connected) and further highlight the systemic added-value of electrolysers.

Access to cheap electricity will remain critical to ensure a competitive hydrogen price for end-users. Guarantee of origin schemes[25] will be instrumental to ensure both simultaneously ensuring economic efficiency and environmental soundness. Installation of hydrogen production facilities where nodal electricity prices are lower – for instance, close to abundant solar and wind generation and upstream of congested transmission lines – could be a strategy to ease grid constraints and provide the required flexibility to the system. This is complementary with decentralised production from dedicated renewable energy facilities.

The steep decrease in the cost of electricity from renewables that has taken place recently makes the case for remote production and intercontinental logistics infrastructure viable under certain circumstances (for example, see today's global liquefied natural gas market), although not the only option to be considered.

First, this model requires **extremely low renewable prices**, as found in the Middle East, North Africa, Mexico, Chile, Australia, the North Sea, etc.

Second, **scale is needed** (e.g. hundreds of megawatts to gigawatts) to reduce the cost of hydrogen production.

Third, **local downstream customers** (large industry or large-scale mobility deployment) need to be secured early on, with long-term contractual arrangements to de-risk investment.

In the medium to long term, in an expansion phase, overseas exports to hydrogen-consuming countries with limited potential for low-cost renewable energy can be considered; the first projects are being set up to transport hydrogen from Brunei and Australia via ship (see above).

In addition, continued investment in research, development and deployment is needed to keep reducing costs and improve overall system efficiencies that, in turn, will help to reduce the cost of hydrogen for end users. Pilot and demonstration projects with a vision to full deployment are needed to gain further experience in real-life situations with technological, economic and regulatory variables. Further research and demonstration in the area of high-efficiency, flexible electrolysers may lead to breakthroughs that would allow further reductions in the LCOH.

Finally, the role of hydrogen from renewables has to be viewed as part of the broader global energy transition. The means integrating hydrogen into decarbonisation scenarios and giving it due consideration as an option in energy system models.

25 The guarantee of origin (GO or GoO) of electricity is an instrument defined in Article 15 of the European Directive 2009/28/EC and is to provide information to electricity customers on the source of their energy.

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CONVERSION FACTORS

Hydrogen				
Volume equivalent				
1	kg H_2	=	11.1	Nm^3 H_2
Electrical power equivalent				
1	kg H_2	=	39.4	kWh HHV
1	kg H_2	=	33.3	kWh LHV
Energy equivalent				
1	kg H_2	=	120	MJ LHV
1	kg H_2	=	142	MJ HHV
Energy				
1	TWh/yr	=	31.5	EJ

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