IRENA
International Renewable Energy Agency

HYDROGEN:

A RENEWABLE ENERGY PERSPECTIVE

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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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CONTENTS

ABBREVIATIONS

°C	degrees Celsius
ALK	alkaline
ATR	auto-thermal reforming
AUD	Australian dollar
Btu	British thermal unit
CAD	Canadian dollar
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CO	carbon monoxide
CO_2	carbon dioxide
CSP	concentrating solar power
DAC	direct air capture
DRI	direct-reduced iron
e-fuel	electrofuel
EJ	exajoule
EOR	enhanced oil recovery
EUR	Euro
EV	electric vehicle
FCEV	fuel cell electric vehicle
GJ	gigajoule
GW	gigawatt
H_2	hydrogen
HRS	hydrogen refuelling station
ICE	internal combustion engine
IRENA	International Renewable Energy Agency
km	kilometre
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelised cost of electricity
LCOH	levelised cost of hydrogen
LNG	liquefied natural gas
MCH	methyl cyclohexane
MM Btu	million British thermal units
MOST	China Ministry of Science and Technology
MRV	monitoring, reporting and verification
Mt	megatonne
MW	megawatt
MWh	megawatt-hour
NDC	Nationally Determined Contribution
PEM	proton exchange membrane
PPA	power purchase agreement
PV	photovoltaics
R&D	research and development
SOEC	solid oxide electrolysis cells
SMR	steam methane reforming
t	tonne
THE	Tianjin Mainland Hydrogen Equipment Co., Ltd
TW	terawatt
UK	United Kingdom
US	United States
USD	United States dollar

1. OVERVIEW OF FINDINGS

- Clean hydrogen is enjoying unprecedented political and business momentum, with the number of policies and projects around the world expanding rapidly. Further acceleration of efforts is critical to ensuring a significant share of hydrogen in the energy system in the coming decades.

- Two key developments have contributed to the growth of hydrogen in recent years: the cost of hydrogen supply from renewables has come down and continues to fall, while the urgency of greenhouse gas emission mitigation has increased, and many countries have begun to take action to decarbonise their economies, notably energy supply and demand. The hydrogen debate has evolved over the past two decades, with a shift in attention from applications for the auto industry to hard-to-decarbonise sectors such as energy-intensive industries, trucks, aviation, shipping and heating applications.

- Ensuring a low-carbon, clean hydrogen supply is essential. Current and future sourcing options include: fossil fuel-based hydrogen production (grey hydrogen); fossil fuel-based hydrogen production combined with carbon capture, utilisation and storage (CCUS; blue hydrogen); and hydrogen from renewables (green hydrogen).

- Green hydrogen, produced with renewable electricity, is projected to grow rapidly in the coming years. Many ongoing and planned projects point in this direction. Hydrogen from renewable power is technically viable today and is quickly approaching economic competitiveness. The rising interest in this supply option is driven by the falling costs of renewable power and by systems integration challenges due to rising shares of variable renewable power supply. The focus is on deployment and learning-by-doing to reduce electrolyser costs and supply chain logistics. This will require funding. Policy makers should also consider how to create legislative frameworks that facilitate hydrogen-based sector coupling.

- Important synergies exist between hydrogen and renewable energy. Hydrogen can increase renewable electricity market growth potentials substantially and broaden the reach of renewable solutions, for example in industry. Electrolysers can add demand-side flexibility. For example, European countries such as the Netherlands and Germany are facing future electrification limits in end-use sectors that can be overcome with hydrogen. Hydrogen can also be used for seasonal energy storage. Low-cost hydrogen is the precondition for putting these synergies into practice.

- Electrolysers are scaling up quickly, from megawatt (MW)- to gigawatt (GW)-scale, as technology continues to evolve. Progress is gradual, with no radical breakthroughs expected. Electrolyser costs are projected to halve by 2040 to 2050, from USD 840 per kilowatt (kW) today, while renewable electricity costs will continue to fall as well. Renewable hydrogen will soon become the cheapest clean hydrogen supply option for many greenfield applications.

- Blue hydrogen has some attractive features, but it is not inherently carbon free. Fossil fuels with CCUS require carbon dioxide (CO_2) monitoring and verification and certification to account for non-captured emissions and retention of stored CO_2. Such transparency is essential for global hydrogen commodity trade.

- Development of blue hydrogen as a transition solution also faces challenges in terms of production upscaling and supply logistics. Development and deployment of CCUS has lagged compared to the objectives set in the last decade. Additional costs pose a challenge, as well as the economies of scale that favour large projects. Public acceptance can be an issue as well. Synergies may exist between green and blue hydrogen deployment, for example economies of scale in hydrogen use or hydrogen logistics.

- A hydrogen-based energy transition will not happen overnight. Hydrogen will likely trail other strategies such as electrification of end-use sectors, and its use will target specific applications. The need for a dedicated new supply infrastructure may limit hydrogen use to certain countries that decide to follow this strategy. Therefore, hydrogen efforts should not be considered a panacea. Instead, hydrogen represents a complementary solution that is especially relevant for countries with ambitious climate objectives.

- Per unit of energy, hydrogen supply costs are 1.5 to 5 times those of natural gas. Low-cost and highly efficient hydrogen applications warrant such a price difference. Also, decarbonisation of a significant share of global emissions will require clean hydrogen or hydrogen-derived fuels. Currently, significant energy losses occur in hydrogen production, transport and conversion. Reducing these losses is critical for the reduction of the hydrogen supply cost.

- Dedicated hydrogen pipelines have been in operation for decades. Transport of hydrogen via existing and refurbished gas pipelines is being explored. This may reduce new infrastructure investment needs and help to accelerate a transition. However, equipment standards need to be adjusted, which may take time. Whether the way ahead involves radical natural gas replacement or gradually changing mixtures of natural gas and hydrogen mixtures is still unclear. A better understanding is needed.

- While international hydrogen commodity shipping is being developed, another opportunity that deserves more attention is trade of energy-intensive commodities produced with hydrogen. Ammonia production, iron and steel making, and liquids for aviation, marine bunkers or feedstock for synthetic organic materials production (so-called electrofuels or e-fuels that are part of a power-to-X strategy) seem to be prime markets, but cost and efficiency barriers need to be overcome. This may offer an opportunity to accelerate global renewables deployment with economic benefits.

2. HYDROGEN AND RENEWABLES

The G20 Karuizawa Innovation Action Plan on Energy Transitions and Global Environment for Sustainable Growth, released on 16 June 2019, calls on the International Renewable Energy Agency (IRENA) to develop the analysis of potential pathways to a hydrogen-enabled clean energy future, noting that hydrogen as well as other synthetic fuels can play a major role in in the clean energy future, with a view to long-term strategies. This report has been prepared in response. It is launched on the occasion of the Hydrogen Energy Ministerial Meeting on 25 September 2019 in Tokyo, Japan.

The current policy debate suggests that now is the time to scale up technologies and to bring down costs to allow hydrogen to become widely used:

- **Hydrogen can help tackle various critical energy challenges**. It offers ways to decarbonise a range of sectors – including intensive and long-haul transport, chemicals, and iron and steel – where it is proving difficult to meaningfully reduce emissions. It can also help improve air quality and strengthen energy security. In addition, it increases flexibility in power systems.

- **Hydrogen is versatile in terms of supply and use.** It is a free energy carrier that can be produced by many energy sources.

- **Hydrogen can enable renewables to provide an even greater contribution.** It has the potential to help with variable output from renewables, such as solar photovoltaics (PV). Hydrogen is one of the options for storing energy from renewables and looks poised to become a lowest-cost option for storing large quantities of electricity over days, weeks or even months. Hydrogen and hydrogen-based fuels can transport energy from renewable sources over long distances.

At the same time, the widespread use of clean hydrogen in global energy transitions faces several challenges:

- **Today, hydrogen is almost entirely supplied from natural gas and coal.** Hydrogen is already deployed at the industrial scale across the globe, but its production is responsible for annual CO_2 emissions equivalent to those of Indonesia and the United Kingdom (UK) combined.

- **Producing hydrogen from low-carbon energy is currently costly.** However, the costs of producing hydrogen from renewable electricity are falling rapidly.

- **Hydrogen must be used much more widely.** Today, hydrogen is used mostly in oil refining and for the production of ammonia. For it to make a significant contribution to the clean energy transition, it must also be adopted in sectors where it is currently almost completely absent, such as transport, buildings and power generation.

- **The development of hydrogen infrastructure is a challenge and is holding back widespread adoption.** New and upgraded pipelines and efficient and economic shipping solutions require further development and deployment.

- **Regulations currently limit the development of a clean hydrogen industry.** Government and industry must work together to ensure that existing regulations are not an unnecessary barrier to investment.

This IRENA report provides a more in-depth perspective on the nexus between hydrogen and renewable energy, on hydrogen supply economics in light of the rapidly falling cost of renewables and the role of hydrogen in the energy transition, as well as on existing challenges that have hampered hydrogen development to date. This report addresses the following questions:

- What are the specific economic characteristics of green hydrogen (from renewables) and blue hydrogen (from fossil fuels with CCUS) today and in the future?
- How can hydrogen accelerate the deployment of renewable energy, and how can renewable energy accelerate the deployment of hydrogen?
- What aspects of the "green" hydrogen supply chain should be the main focus of research and development (R&D) and innovation?
- How can hydrogen contribute to the decarbonisation of end-uses in various sectors?
- What will be the characteristics of future hydrogen trade?

This report builds on the unique IRENA datasets for renewable power generation cost, electrolysers, and future power and energy system configurations. These aspects are critical to understanding the various opportunities associated with hydrogen.

The paper has four components:

- Strategic considerations
- The hydrogen-renewable energy nexus
- Hydrogen economics
- Future hydrogen commodity trade in light of emerging applications.

3. STRATEGIC CONSIDERATIONS

Hydrogen is a clean energy carrier that can play an important role in the global energy transition. Its sourcing is critical. Green hydrogen from renewable sources is a near-zero carbon production route. Important synergies exist between accelerated deployment of renewable energy and hydrogen production and use.

Hydrogen roadmaps and respective opportunities have been elaborated for different countries including: Australia (ARENA, 2018; Bruce *et al.,* 2018), Brazil (CGEE, 2010), Europe (FCH, 2019), France (MTES, 2018), Germany (Robinius *et al.,* 2018; Smolinka *et al.,* 2018), Japan (ANRE, 2017; METI, 2016), the Netherlands (Gigler and Weeda, 2018; NIB, 2017), the UK (E4tech and Element Energy, 2016) the United States (US) (US Drive, 2017). Country's strategies differ in terms of hydrogen production pathways and key hydrogen-end uses according to each country particularity (Kosturjak et al., 2019).

3.1 The need for climate action now

Climate is a main driver for hydrogen in the energy transition. Limiting global warming to below 2 degrees Celsius (°C) requires that CO_2 emissions decline by around 25% by 2030, from 2010 levels, and reach net zero by around 2070 (IPCC, 2018). For a reasonable likelihood to stay below 1.5 °C of warming, global net anthropogenic CO_2 emissions should decline by around 45% by 2030, from 2010 levels, reaching net zero by around 2050 (IPCC, 2018). In contrast with these ambitions, emissions have recently risen (UNEP, 2018). Energy-related CO_2 emissions account for two-thirds of global greenhouse gas emissions. An energy transition is needed now to break the link between economic growth and increased CO_2 emissions.

3.2 Current hydrogen use and future projections

Hydrogen will be part of emissions mitigation efforts in the coming decades. IRENA's Renewable Energy Roadmap (REmap) analysis indicates an 6% hydrogen share of total final energy consumption by 2050 (IRENA, 2019a), while the Hydrogen Council in its roadmap suggests that an 18% share can be achieved by 2050 (Hydrogen Council, 2017).

Today, around 120 million tonnes of hydrogen are produced each year, of which two-thirds is pure hydrogen and one-third is in mixture with other gases. This equals 14.4 exajoules (EJ), about 4% of global final energy and non-energy use, according to International Energy Agency (IEA) statistics. Around 95% of all hydrogen is generated from natural gas and coal. Around 5% is generated as a by-product from chlorine production through electrolysis. In the iron and steel industry, coke oven gas also contains a high hydrogen share, some of which is recovered. Currently there is no significant hydrogen production from renewable sources. However, this may change soon.

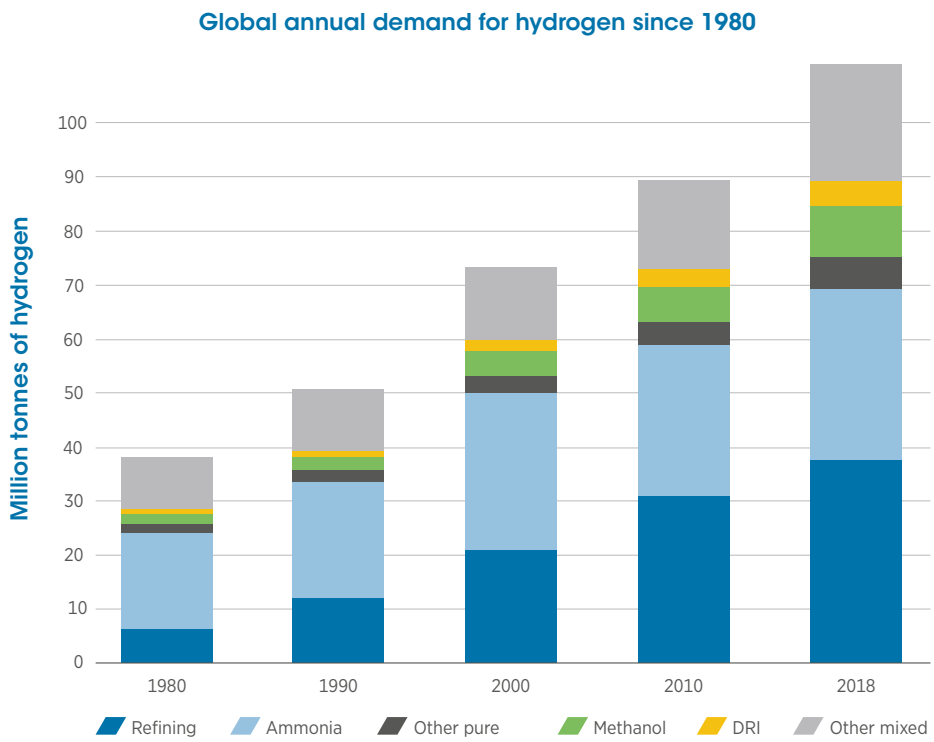
The vast majority of hydrogen today is produced and used on-site in industry. The production of ammonia and oil refining are the prime purposes, accounting for two-thirds of hydrogen use (Figure 1). Ammonia is used as nitrogen fertiliser and for the production of other chemicals. At petroleum refineries, hydrogen is added to heavier oil for transport fuel production. Methanol production from coal has grown rapidly in China in recent years.

While today's hydrogen use has limited direct relevance for the energy transition, it has resulted in ample experience with hydrogen handling. Hydrogen pipeline systems spanning hundreds of kilometres are in place in various countries and regions and have operated without incident for decades. Similarly, there is a long track record of transporting hydrogen in dedicated trucks.

Beyond these conventional applications, which have been around for decades, hydrogen use is very modest. The importance of hydrogen for energy transition has to come from new applications, and its supply needs to be decarbonised.

Ammonia production and oil refining dominate hydrogen use

Figure 1: Hydrogen use trends, 1980 to 2018



Source: IEA, 2019

Residential fuel cell applications in the residential sector have constantly increased and comprised 225 000 units installed globally as of the end of 2018. Japan is the global leader with 98% of these applications (Staffell *et al.,* 2019).

According to the IEA (2019a), 380-plus hydrogen refuelling stations are open to the public or fleets, and the global fuel cell electric vehicle (FCEV) stock reached 11 200 units at the end of 2018, with sales of around 4 000 that year. To put these numbers in perspective, 2.5 million electric vehicles (EVs) were sold in 2018. The Hydrogen Council envisions 3 000 refilling stations by 2025, which would be sufficient to fuel around 2 million FCEVs (Staffell *et al.*, 2019).

The experience with hydrogen refuelling stations is mixed. At least three stations have had significant incidents (in Norway, the Republic of Korea and the US state of California). In the most recent case, in Norway in early 2019, the cause of an explosion in a hydrogen fuelling station was a faulty installation, and in the Republic of Korea a storage tank became contaminated with oxygen.

3.3 A shift towards production of green hydrogen

Water can be converted into hydrogen and oxygen using an electrolyser and electricity. Electrolysis plays a central role in the deployment of renewable hydrogen.

In **Germany,** transmission system operator Amprion and gas net operator OGE have presented an investment-ready plan for a 100 MW electrolyser and a dedicated hydrogen pipeline in the north-west of Germany that could come online in 2023, a EUR 150 million (USD 168 million[1]) proposal (Amprion and Open Grid Europe, 2019). A 40 MW wind park coupled with electrolysers is planned near a chemical industry in Germany by VNG, Uniper, Terrawatt and DBI, including 50 billion cubic metres of storage and a dedicated hydrogen pipeline, with potential expansion to 200 MW by 2030. A 10 MW polymer electrolyte membrane (PEM) electrolyser is planned to come online at Shell's Wesseling refinery near Cologne in 2020, under a consortium with ITM Power from the UK (Energate, 2018).

In Mainz, a 6 MW electrolyser has been operational since 2017 (BINE, 2018). **Germany** is especially active in this context. In July 2019, the government approved 11 demonstration projects that will result in significant upscaling (FCB, 2019):

- CCU P2C Salzbergen – synthetic methane production
- DOW Green MeOH – methanol production
- Element eins – 100 MW electrolyser
- EnergieparkBL – 35 MW electrolyser
- GreenHydroChem – 50 MW electrolyser
- H_2 Stahl – hydrogen injection in a blast furnace
- H_2 Whylen – 10 MW electrolyser
- HydroHub Fenne – 17.5 MW electrolyser
- Norddeutsches reallabor – 77 MW electrolyser
- RefLau – 10 MW electrolyser
- REWest – 10 MW electrolyser

Similar upscaling efforts are occurring in other European countries as well as in Australia, China, Japan and elsewhere. These announcements all point to a strong global momentum and a focus on upscaling, notably of electrolyser unit capacities.

In the Rotterdam harbour in **the Netherlands**, a 2 GW electrolyser system is being studied (DI, 2019). Also, large-scale hydrogen deployment is planned in the province of Groningen (Delfzijl), the Netherlands; the decision for a 20 MW electrolyser is due in early 2020 with a possible expansion decision for 60 MW at the end of 2020. The plant would supply hydrogen for methanol and synthetic aviation fuel production (Burridge, 2019).

In Linz, **Austria**, Siemens is supplying a 6 MW PEM electrolyser funded by the Fuel Cells and Hydrogen Joint Undertaking (FCH JU) (IWR, 2018).

With regard to high-temperature electrolysers, a pilot project in **Norway** produces synthetic fuel from hydrogen and CO_2. The plant is to be scaled up to produce 8 kilotonnes of synthetic crude oil from 20 MW of input power.

1 EUR = 1.12 USD (13/09/2019)

In Fukushima, **Japan**, a 10 MW electrolyser has been ordered by Toshiba to provide 900 tonnes per year of hydrogen from renewables, to be used for transport applications. Hydrogen is produced from a 20 MW solar PV project. The Japanese strategy also comprises the Yamanashi Fuel Cell Valley which includes a power-to-gas facility utilising a 1.5 MW PEM electrolysis coupled with a 21 MW solar PV system (Ohira, 2019).

In the Pilbara region in **Australia**, 15 GW of solar and wind capacity is being developed with an eye to supply the local mining industry and to provide electricity for hydrogen commodity production through electrolysis (RN, 2019). A 50 MW wind and solar-fuelled electrolyser is planned as part of a new Hydrogen Hub to be built by Neoen near Crystal Brook, Australia. A 30 MW electrolyser coupled with an ammonia facility with a capacity of 50 tonnes per day is also planned in Port Lincoln, South Australia (Brown, 2018).

In **France**, the Les Hauts de France project, an ambitious power-to-gas project, aims to build five hydrogen electrolyser production units of 100 MW each over a five-year period. For the first operational unit by the end of 2021, HydrogenPro will supply turnkey electrolysers under the authority of H2V INDUSTRY, an integrator specialising in the engineering and development of large hydrogen production plants (GasWorld, 2018; Nel, 2017). The Port-Jérôme plant, to be built next to the Exxon refinery, aims to supply hydrogen to the petrochemical industry (Exxon, Total, Yara, etc.) to desulphurise fuels or to manufacture fertilisers. In Dunkirk, the project consists of introducing hydrogen into the natural gas distribution network, in order to decarbonise the natural gas used for heating and cooking as well as for mobility (Energy Storage & P2G, 2018; Engie, 2019; Les Echos, 2019).

In the **UK**, ITM Power received funding through the UK Department for Business, Energy and Industrial Strategy's Hydrogen Supply Competition for the Gigastack feasibility study with Ørsted and Element Energy. Gigastack will demonstrate the delivery of bulk, low-cost and zero-carbon hydrogen through gigawatt-scale PEM electrolysis, manufactured in the UK. The project aims to dramatically reduce the cost of electrolytic hydrogen through the development of a new 5 MW stack module design to reduce material costs. A new semi-automated manufacturing facility with an electrolyser capacity of up to around 1 GW per year will be developed, aimed at delivering large-scale (100 MW-plus) projects using multiple 5 MW units. The use of PEM electrolysers can be leveraged to exploit synergies with large, gigawatt-scale renewable energy deployments (ITM Power, 2019).

In **Canada**, Air Liquide will build the largest PEM electrolyser in the world with 20 MW capacity to produce low-carbon hydrogen using hydropower (Green Car Congress, 2019). Renewable Hydrogen Canada (RH2C), based in Victoria, British Columbia, is planning to produce renewable hydrogen through water electrolysis powered by renewables (primarily wind, augmented by hydropower). One potential application is to reduce the carbon intensity of the gas grid in Vancouver by injecting 120 MW worth of hydrogen into the main natural gas line, equivalent to reducing the volume of natural gas consumed in Metro Vancouver by 10%. The utility has determined that, using existing infrastructure, hydrogen-enriched natural gas with up to 10% renewable hydrogen could be supplied without the need for infrastructure or equipment modification or safety compromises. (RH2C, n.d.).

In the **US**, the Department of Energy has multiple workstreams on hydrogen. The Office of Energy Efficiency and Renewable Energy has a dedicated workstream on hydrogen from renewables, with a focus on electrolysis that includes clear targets for cost and efficiency (US DOE, 2019) .

In **China**, manufacturing capacity for electrolysers, in particular alkaline, is well established and very cost competitive. The most important domestic producers are Tianjin Mainland Hydrogen Equipment Co., Ltd. (THE) and Beijing CEI Technology Co., Ltd. THE is a world leading supplier of alkaline electrolysers and has delivered more than 400 production plants since 1994, with units of up to 1 000 normal cubic metres per hour (THE Co., Ltd., 2019). THE has a partnership with HydrogenPro from Norway for all projects involving THE equipment in Europe and the US. This includes the large-scale power-to-gas project (five 100 MW hydrogen production units) over a five-year period in Dunkirk, France (discussed earlier).

Another domestic manufacturer, Suzhou JingLi Hydrogen Production Equipment Co., Ltd., signed co-operation agreements in August 2018 with Dalian Institute of Chemical Physics for new hydrogen generation via water electrolysis technology research and is also part of the "973" National Research Program "Large Scale Hydrogen Production of Wind Power". The Ministry of Science and Technology (MOST) promotes the R&D of new industries in China. The " 863" and "973" national plans receive funding from MOST and include several projects related to fuel cell technology development, which seems to be the main focus for hydrogen development in China (Holland Innovation Network China, 2019).

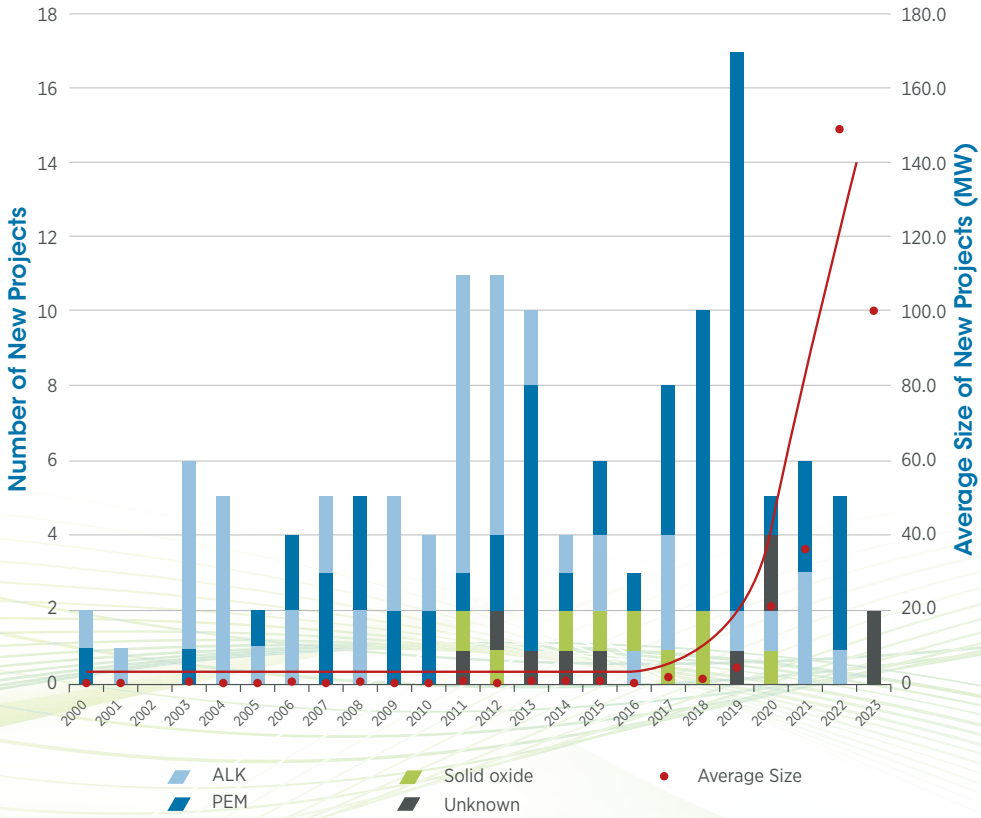
This sample is indicative of the strong interest worldwide. Many more pilot and early-commercial projects exist that show a clear trend towards larger electrolysers and technological improvements.

In terms of hydrogen usage, the emphasis has shifted. Whereas 15 years ago transport was at the centre of all developments, the field of applications has recently broadened with much more emphasis on stationary applications in industry and the buildings sector, as well as feedstocks for chemical products. On one hand, the falling costs of renewable power have increased the appeal of these stationary applications; on the other hand, the urgency of climate action has increased and now constitutes a key driver.

Efforts to ramp up green hydrogen and hydrogen use for the energy transition are increasing in many countries, with an emphasis on larger-scale, more power system-friendly electrolysis.[2] Projects have moved into the megawatt-scale; however, further R&D, mass production and learning-by-doing is needed to achieve significant cost reductions. The trend in recent years indicates exponential growth in project scale, albeit from a low starting point, as illustrated in Figure 2 (Quarton and Samsatli, 2018).

Rapid upscaling of electrolysers for hydrogen production

Figure 2: Timeline of power-to-hydrogen projects by electrolyser technology and project scale



Source: Quarton and Samsatli, 2018 and IRENA Database

2 *Whereas electrolysis does not per se imply the use of renewable or carbon-free electricity, the fact that hydrogen incurs additional cost makes it so there is no incentive for such a transition without enabling policy frameworks that result in clean electricity supply.*

3.4 A broadening field of applications

In the transport sector, in addition to the first mass-produced hydrogen passenger cars from Toyota, Honda and Hyundai (among others), hydrogen trucks are being developed to decarbonise road transport of goods (Forbes, 2019). At present, mid-size hydrogen FCEVs are offered at a premium cost, around 50% more than similar internal combustion engine (ICE) vehicles, although a significant scaling effect could decrease costs if production grows substantially, according to manufacturers. Battery-electric vehicles are growing much more quickly in the passenger car sector, especially for urban and short-range applications.

Long-distance, heavy-duty transport is potentially a more attractive market for FCEVs (IRENA, 2018a). Hydrogen buses are already widely deployed, and several hundred are on the roads in certain Chinese cities. A new H2Bus consortium in Europe was also recently announced, aiming for 1000 commercially competitive buses fuelled with hydrogen from renewable power, the first 600 of which are due by 2023. Furthermore, Japan will utilise hydrogen buses for the 2020 Olympics.

In the UK, the role of hydrogen in combination with existing natural gas distribution infrastructure has been thoroughly explored in a region of 5 million inhabitants as a key option for decarbonisation of heating, and a large-scale pilot project is scheduled in the north of England (CCC, 2018; Sadler *et al.,* 2018). See also Box 2 for more information.

Electrofuels, or e-fuels, constitute a new concept where hydrogen from electrolysis and CO_2 are converted into liquid fuels (also referred to as power-to-X). Costs remain high (DENA, 2017), although they are projected to fall to around USD 1 per litre in the coming decades (IRENA, 2019b). Notably, while EVs and FCEVs result in large efficiency gains compared to ICE vehicles, due to the use of electric motors instead of ICEs, this is not the case with e-fuels in combustion engines. This limits the market potential of e-fuels to applications where fuel cells are not a viable alternative, competing with biofuels for the same applications. The same concept can be used to produce feedstock for petrochemicals, but again, the economics remain challenging.

Ammonia (fertiliser) and iron can be produced using hydrogen. This offers the prospect of growth in the renewables share of the energy use. While ammonia production technology is commercially available today, direct-reduced iron (DRI) production requires further development. DRI, however, is promising and technically feasible: commercial-scale plants have been in operation for decades and are steadily growing in number, with global DRI production reaching 100 million tonnes in 2018 (Midrex, 2018).

Beyond renewable fuels of the future, current demand for hydrogen has grown to a large extent due to changes in the oil products market. This has led to an increase in hydrogen demand in refineries, in particular for hydrocracking (Figure 3) (Speight, 2011a), to increase the refining yield of middle distillates (notably diesel and jet kerosene) (US EIA, 2019). This is because of a shift towards diesel in passenger cars as well as the continuous growth in trade, which relies on (diesel) trucks and airplanes (burning jet kerosene) in addition to ships and trains, which require a lower yield of naphtha (for gasoline), compared to middle distillates (in particular diesel and jet kerosene).

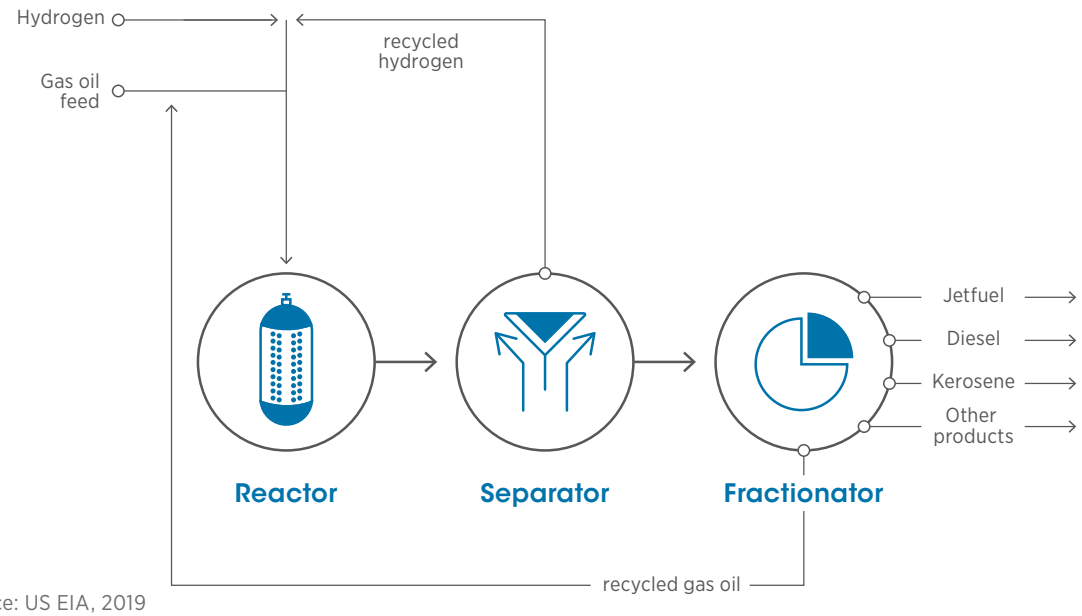
More stringent requirements on sulphur oxide emissions led to rapidly increasing demand for low-sulphur diesel, with the associated growth of demand for hydrogen for desulphurisation in refineries through hydrotreating (Speight, 2011b).

Because of the rising hydrogen needs, numerous refineries and chemical plants have installed, or are installing, electrolysers to supply additional hydrogen. However, the long-term market outlook is clouded, as oil demand may decline as the energy transition moves forward.

Refineries use hydrogen for oil product upgrading

Figure 3: Hydrogen for oil refining – hydrocracking

Overview of hydrocracking process



Source: US EIA, 2019

3.5 Fossil fuel-based hydrogen as a transition option

Today, the vast majority of hydrogen is produced from fossil fuels without CO_2 capture. This is the least-cost solution for hydrogen production today, but it is not sustainable. Hydrogen from steam methane reforming (SMR) has an emission factor of around 285 grams of CO_2 per kilowatt-hour (kWh) (9.5 kilograms of CO_2 per kilogram of hydrogen), and coal gasification has an emission factor of around 675 grams of CO_2 per kilowatt of hydrogen, accounting only for energy use and process emissions (CCC, 2018). A different clean hydrogen source is needed for energy transition applications.

One option is the production of hydrogen from fossil fuels with CO_2 capture and storage (CCS), so called blue hydrogen. Blue hydrogen has been proposed as a bridging solution as the cost of producing hydrogen from renewable power decreases. It offers a prospect of continuity to fossil fuel producers, and it can help to meet climate objectives at acceptable cost.

While producing large volumes of blue hydrogen could be important to support increasing hydrogen demand as well as kick-start global and regional supply chains for hydrogen and hydrogen-derived fuels, some aspects must be considered:

- Blue hydrogen is deployed in limited niche applications today; for instance, a minimum amount of clean hydrogen is required for FCEVs in California (Carbs, 2014). At large scale, it is critical to ensure that all projects producing hydrogen from fossil fuels include CCS from the start. Hydrogen production and use without CCUS can increase CO_2 emissions compared to direct use of fossil fuels, due to chain energy efficiency losses.

- Deployment of blue hydrogen is not necessarily CO_2-free. CO_2-capture efficiencies are expected to reach 85-95% at best, which means that 5-15% of all CO_2 is leaked. However, the current flagship CCS projects achieve far lower capture rates. The Petra Nova project in the US captures just over a third of the flue gas from one of four coal-fired units, while the Boundary Dam project in Canada has an overall CO_2 capture rate of 31% (FT, 2019). As the ultimate goal is greenhouse gas reduction, other gases also deserve attention: for example, shale gas production has recently been identified as a major source of emissions of methane, another greenhouse gas much more potent than CO_2.

- CO_2 can be stored underground, as proven by several megatonne (Mt)-scale projects. However, there is increased focus on CO_2 use. The vast majority of CO_2 that is captured today is used for enhanced oil recovery (EOR). Underground CO_2 retention varies by EOR project and over time. A significant share of CO_2 can be released again in the EOR operation, with no monitoring currently in place. Because the majority of the around 20 CCS projects currently in operation are dedicated to EOR, it is crucial to ensure that CO_2 is retained after injection. While data for dedicated geological storage facilities show no leakage (Rock et al., 2017), this is not the case for EOR projects, with retention rates during EOR production ranging from as high as 96% to as low as 28%, largely depending on the formation type (Olea, 2015). Therefore, EOR project design must consider maximised storage at a cost, or the effectiveness can be low (Rock *et al.,* 2017; Olea, 2015).

- If captured CO_2 is used for sparkling drinks or for petrochemical products or synfuels, no CO_2 is emitted from the original source, but the CO_2 is released after use. So instead of two units of CO_2 that are emitted without CCUS, one unit is released in total. The net effect is therefore a halving of emissions. This represents a significant improvement, but it is not consistent with the need to decarbonise the global energy system by 2050.

- With any CCS system it is key to have monitoring, reporting and verification (MRV) systems in place to ensure that the capture and storage rate is maximised, and that remaining emissions are correctly accounted for. It is also crucial to account for the storage efficiency, where only geological formations currently offer a viable prospect for carbon neutrality.

- Finally, fossil CCS investments may divert limited capital away from renewable energy deployment back to fossil fuels. Given the significant increase in renewable energy deployment pace required to meet the 2030 emissions reduction targets, this might not be the most effective use of limited financial resources.

Rapid scale-up of CCS demonstration and deployment was identified early on as a necessary condition for its uptake (IEA, 2004). However, as of today, CCS remains off track in both power generation (IEA, 2019b) and industry (IEA, 2019c), with only 2 and 17 projects, respectively, in operation as of September 2019. The IEA set targets for CCUS capture levels to reach 350 Mt CO_2/year in power and 400 Mt CO_2/year in industry by 2030. As of September 2019, CCUS reached 2.4 Mt CO_2/year in the power sector and a "potential of" 32 Mt CO_2/year in industry.

Many projects have been abandoned or suffered significant delays. For instance, the Gorgon CCS facility was due to start operations in 2009 (IEA, 2004), while in reality it started a decade later (Global CCS Institute, 2019). Some of the recommendations from the 2004 IEA report remain unaddressed today, and pipeline projects identified suffer significant delays. Thus, as of today, CCS has not scaled up in line with the earlier objectives.

Currently, two of the operating CCS projects are dedicated to hydrogen production. Both projects are related to refineries, where hydrogen is produced from steam methane reforming and used in refinery processes. One of them, Air Products' SMR in Port Arthur, Texas, injects CO_2 into oil fields for EOR. The second facility, Quest in Alberta, Canada, injects around 1 Mt CO_2/year for long-term geological storage, with successful MRV in place and performed by a third party, DNV GL. The capture rate of 80% was reached most days during the first year of operations, although some days this dropped significantly for various reasons (Rock *et al.,* 2017). The costs of the initial projects are high: the project in Canada has received public funding on the order of CAD 865 million (USD 968 million) from the national government and from the government of Alberta (Finanzen.net, 2019).

Box 1: Hydrogen Energy Supply Chain (HESC)

The Hydrogen Energy Supply Chain (HESC) is a new project being developed in Victoria State (Australia) with the support of Japan. Lignite is gasified and converted to hydrogen, and the hydrogen is shipped to Japan. The pilot phase involves a gasification plant in the Latrobe Valley and a liquefaction facility at the Port of Hastings. CCS will not be a feature of the pilot phase but has been described as an "essential component" of the commercial phase, and offshore geological storage sites are being explored.

The AUD 500 million (USD 344 million) project is supported by the Japanese government and Japanese industry, and the Australian and Victorian governments each have contributed AUD 50 million in funding. The plant will produce 5000 tonnes per year of hydrogen and 18 000 tonnes per year of ammonia. The liquefaction facility is due to be completed by June 2020. The pilot phase will demonstrate the integrated supply chain by 2021, and the decision to progress to a commercial phase is due to be made in the 2020s.

Taking stock of the renewed interest in CCS has to be balanced with the lack of progress to date. This raises concerns about the development of hydrogen production facilities based on fossil fuels, which are justified by the assumption that CCS will be scaled up, will see greatly increased capture rates and efficiency improvements, and will ensure long-term storage with adequate MRV in place.

Box 2: Blue hydrogen from natural gas in the Netherlands and the UK

H-vision initiative

H-vision is the first potential blue hydrogen project in the Rotterdam harbour, the Netherlands. The goal is to realise the complete project by 2030. The consortium contains 14 parties from within the harbour as well as parties in the entire process chain. In 2018, a feasibility study was started to explore the business case, technological challenges, hydrogen markets and CCS.

The H-vision project is set out to realise four steam-reforming plants, at a total capacity of 15-20 tonnes of hydrogen per hour, to store the CO_2 under the North Sea and then deliver the hydrogen to industrial parties in the harbour. The first plant is planned to open in 2025, and the hydrogen produced will be transported to parties within the harbour or elsewhere in the Netherlands. The final goal is to capture and store 8 Mt of CO_2 per year, for which the co-operation of power plant owners in the harbour is needed (Cappellen *et al.,* 2018).

Hydrogen to Magnum (H2M)

H2M is a collaboration between Nuon, Equinor and Gasunie. Nuon has set the goal of converting a 440 MW unit of its Magnum power plant, located in Eemshaven in the province of Groningen, to hydrogen. Equinor will develop an auto-thermal reforming (ATR) plant where hydrogen will be produced from natural gas that is imported from Norway and the CO_2 is captured. This hydrogen will be transported to consumers via infrastructure developed by Gasunie. The goal is to integrate a salt cavern to enable system flexibility. The CO_2 will be shipped back to Norway and stored offshore (Cappellen *et al.,* 2018).

H21 NoE

The H21 North of England (H21 NoE) project has been developed in partnership between Cadent, Equinor and Northern Gas Networks. The objective is to convert the gas networks in the north of England to hydrogen between 2028 and 2034. This would involve a 12.5 GW natural gas conversion facility at the Humber estuary, an 8 terawatt-hour hydrogen gas storage facility, a new hydrogen transmission pipeline system to the major centres of demand (Hull, Leeds, Liverpool, Teesside) and 20 million tonnes of CO_2 storage per year by 2035. An estimated 17% of UK gas connections would need to be converted to hydrogen. A government policy decision is due in 2023 (h21 NoE, 2018; Sadler *et al.,* 2018).

3.6 The role of gas infrastructure for renewable hydrogen

Pipelines carrying pure hydrogen gas are technically feasible and have operated for decades in various locations including the US, Germany, the Netherlands, France and Belgium. However, the extent of such pipeline systems is limited, and they do not provide an extensive basis for rapid upscaling of hydrogen deployment.

In certain parts of the world, significant infrastructure is in place for natural gas transmission and distribution. Such infrastructure can be leveraged to facilitate the delivery of hydrogen, as well as acting as a large and low-cost source of storage capacity (Panfilov, 2016).

- At low shares, hydrogen can be blended into natural gas without significant technical challenges. The infrastructure should be assessed, but for most components a share in volume[3] of 10-20% seems to be achievable without major investments (IRENA, 2018a; Judd and Pinchbeck, 2016; Müller-Syring *et al.,* 2013).

- Studies suggest that pipeline systems can be converted from natural gas to hydrogen gas with limited investment required, but this is case specific. A recent study for the Netherlands concludes that its transmission pipelines can be converted to hydrogen gas with the replacement of compressors and gaskets (DNV GL, 2017a). The extent to which distribution systems need adjustment also varies. While plastic pipelines are generally suited for hydrogen gas, old cast-iron pipelines (in cities) are not. The main challenge is in the applications where equipment would need to be adjusted or replaced to deal with hydrogen gas. Today, standards limit the amount of hydrogen that can be deployed in natural gas pipeline systems.

- Detailed studies have been developed for the UK, where some of the concerns identified relate to embrittlement for current high-pressure natural gas transmission pipelines if converted to pure hydrogen, as well as reduced energy density and line pack buffer storage, together with a series of regulatory and safety requirements that would have to be adjusted (Dodds and Demoullin, 2013; Sadler *et al.,* 2018) Further hydrogen embrittlement research has shown that this is not of large influence. Hydrogen will lead to more fatigue of the pipelines; however, the process can be performed safely and reliably. The fatigue is strongly related to pressure changes in the tubes, which can be an important parameter regarding line packing (the energy storage in the pipeline) (van Cappellen *et al.,* 2018). Finally, hydrogen can be used to produce synthetic methane, a gas that is fully compatible with existing natural gas infrastructure. However, this adds significant cost, in particular for the CO_2 supply and methanisation unit, making this an expensive option, although potential for cost reductions exists (Fasihi *et al.,* 2019; Gutknecht *et al.,* 2018; Sutherland, 2019).

Joint use of the natural gas infrastructure for hydrogen and natural gas might be a win-win transition strategy. For hydrogen, this would allow for a scale-up of production from renewables and from the electrolyser industry by tapping into large, existing demand and its supply chain, in particular gas pipeline infrastructure. This, in turn, can help leverage the role of natural gas as a low-carbon transition fuel.

Economies of scale to drive cost reductions in hydrogen production from renewables are a priority (IRENA, 2018a). Gradually increasing the share of hydrogen that can be accommodated by the gas infrastructure can provide reliable long-term signals for large-scale deployment of electrolysis from renewable electricity. However, a careful assessment is needed to see if end-use equipment such as boilers, gas turbines and cook stoves could sustain such a gradual transition.

3 To obtain the share in energy terms, divide the hydrogen share by a factor of 3, which is the ratio of energy content per unit of volume between natural gas and hydrogen.

Box 3: Gas grid conversion experience

Experience with gas grid conversions exists. Originally many natural gas systems were operated with hydrogen-rich town gas (from coal). Also, natural gas composition can vary. In Germany, the gas grid is undergoing a 10-year, EUR 7 billion (USD 7.8 billion) renovation to switch 30% of its customers from natural gas with lower methane content (L-gas) to gas with higher methane and higher calorific content (H-gas). This is due to the decline in supplies of L-gas. Although this seems like a minor shift compared to adding hydrogen into natural gas, this comes at a significant cost (Newman, 2018).

At this stage, the required level of hydrogen blending for such a transition remains unclear, and it will likely depend on local infrastructure as well as regulation. What is certain is that to move to 100% hydrogen, most appliances – as well as most of the transmission and part of the distribution system for natural gas – will need major upgrades. A clear roadmap, most likely national in nature, would be helpful to understand what would be needed for a shift from natural gas to 100% hydrogen in existing infrastructure, which milestones in blending levels trigger the need for major investments, and what the whole transition would look like in terms of investments, volumes of hydrogen required, timelines and regulatory changes.

Early adoption of the assets installed in the "natural" renewing cycles towards hydrogen-tolerant products will reduce the costs greatly. Postponing the starting point for installing tolerant products by five years will lead to additional transition costs of around EUR 12 billion (USD 13.4 billion) for the German gas infrastructure, including gas grids and underground storage (Müller-Syring *et al.,* 2018).

What must also be clear is how such a transition would play out: whether it would involve switching one gas distribution system at a time from natural gas to 100% hydrogen, switching 0-20% of systems or switching potentially 100% of systems simultaneously. In such a transition process, how can the hydrogen share be kept below the technical limits in the transmission system? Perhaps this means first moving all transmission to 100% hydrogen tolerance, then starting to convert one distribution system at a time while increasing the hydrogen share in transmission. Also, how can the hydrogen share be kept constant throughout the network and at different times of the year? For example, if production comes from solar and wind power, would levels of hydrogen injected into the gas grid also be variable?

Such questions must be answered before the natural gas grid can become a key off-taker for renewable hydrogen in the coming decades. However, work is ongoing to answer as many of these questions as possible, particularly in Germany (E.ON, 2019; Michalski *et al.,* 2019), the Netherlands (DNV GL, 2017a; H-vision, 2019), the UK (DNV GL, 2017b; Sadler *et al.,* 2018) and elsewhere in Europe (Florisson, 2016).

A strategic use of natural gas infrastructure in the energy transition can benefit large, established energy companies and a nascent hydrogen industry (which is related to the power sector more than the hydrocarbon sector), allowing for a broader constituency to push for the energy transition. The disrupting elements of rapid change can be mitigated by common goals and a clear roadmap where incumbents join new players in implementing a low-carbon global energy transformation roadmap (IRENA, 2019a).

3.7 The potential of clean hydrogen as a new commodity

Hydrogen offers the prospect of a new commodity that can be traded. The fact that green hydrogen can be converted into synthetic natural gas (using CO_2 from bioenergy combustion processes or from direct air capture) and shipped to markets using existing infrastructure, and that natural gas can be converted into low-carbon hydrogen using SMR and CCS, offers a prospect for natural gas-producing countries such as Canada, Iran, Norway, Qatar, the Russian Federation and the US. Because hydrogen can be produced at low cost in remote desert locations and shipped to markets, regions such as the Middle East and North Africa and countries such as Argentina, Australia, Chile and China, among others, see new opportunities. A conversion to a hydrogen economy therefore offers new economic prospects to countries and regions that rely today on fossil fuel exports for a significant part of their national revenues. It also may help to create new export opportunities for countries with rich renewable energy resources.

Where pipelines are in place, the prospects are evident. However, shipping of hydrogen requires either liquefaction – implying significant energy losses – or the conversion of hydrogen into other carriers, for example ammonia, methanol and liquid organic hydrogen carriers. This comes with significant losses. If hydrogen can be used at its production site to manufacture clean products such as ammonia, methanol, DRI or e-fuels, such losses can be reduced.

For more in-depth discussion of the hydrogen trade opportunities see section *Future hydrogen and hydrogen commodity trade projections.*

4. THE ROLE OF HYDROGEN FOR DECARBONISATION – THE HYDROGEN / RENEWABLE ENERGY NEXUS

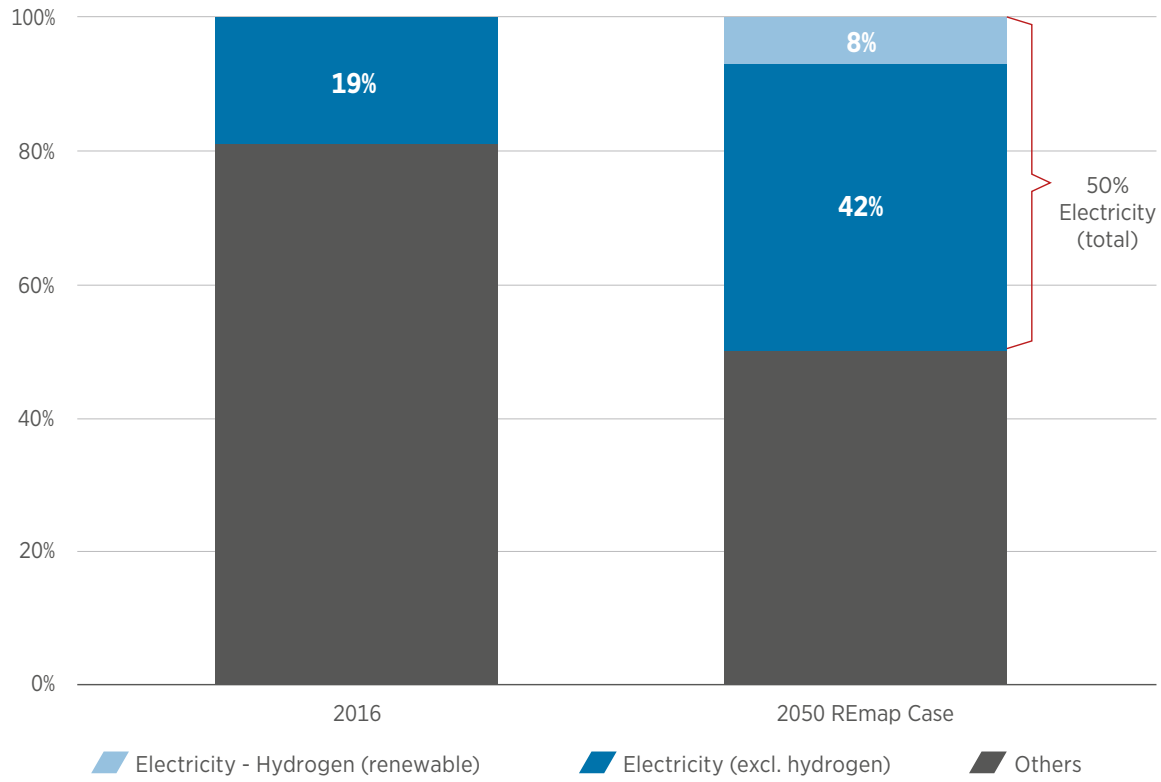
4.1 Hydrogen production as a driver for accelerated renewable energy deployment

Large-scale adoption of hydrogen (or hydrogen-derived fuels and commodities) can fuel a significant increase in demand for renewable power generation. In total, IRENA sees a global economic potential for 19 EJ of hydrogen from renewable electricity in total final energy consumption by 2050 (Figure 4) (IRENA, 2019a), whereas others (for example, the Hydrogen Council) see this number increasing to around 80 EJ (not necessarily all from renewables).

This demand gives a range of 30-120 EJ of renewable electricity needed for electrolysis, or 8-30 petawatt-hours. This translates into around 4-16 terawatts (TW) of solar and wind generation capacity to be deployed to produce renewable hydrogen and hydrogen-based products in 2050, considering losses along the supply chain. In comparison, today's global power generation capacity is 7 TW, with 1 TW of solar and wind power capacity in place.

In IRENA's REmap scenario for 2050, 19 EJ of hydrogen from renewable power translates into 5% of total final energy consumption and 16% of all electricity generation being dedicated to hydrogen production in 2050

Figure 4: Electricity in total energy consumption (EJ/yr)



Source: IRENA, 2019a

Furthermore, direct electrification (for example through EVs and heat pumps) has a higher end-use efficiency than the respective alternative with hydrogen. EVs and heat pumps provide 75% and 270% more energy services, respectively, when compared to fuel cell vehicles and hydrogen boilers, respectively, in equivalent applications (CCC, 2018).

In the case of shipping, significant losses occur in the logistics chain (for example, for pressurisation and liquefaction), which can multiply the power demand for hydrogen supply. Consider the following main forms of hydrogen transport:

- Ammonia: From primary solar and wind resources to final hydrogen delivery by trucks, Obara (2019) quantified energy losses of 45% from having ammonia as the energy carrier, with the main losses in hydrogen compression (19%), in electrolysers (16%) and in the power converter efficiency (10%).

- MCH (methyl cyclohexane): The same analysis found losses of around 43% from having MCH as the hydrogen carrier, with most of the losses being from the hydrogenation unit waste heat (15%), the electrolyser (16%) and losses from the toluene produced in the dehydrogenation unit (12%).

- Liquefaction: A significant amount of electricity is required to liquefy hydrogen via the liquefaction process, which currently leads to losses of 20% to 45% of the hydrogen energy content only (Berstad *et al.,* 2013; Cardella *et al.,* 2017; H21 NoE, 2018, p. 21).

In conclusion, if hydrogen is deployed at scale this can have significant implications for the power sector, and it opens up additional opportunities for renewable power deployment.

4.2 Increased power system flexibility through hydrogen production

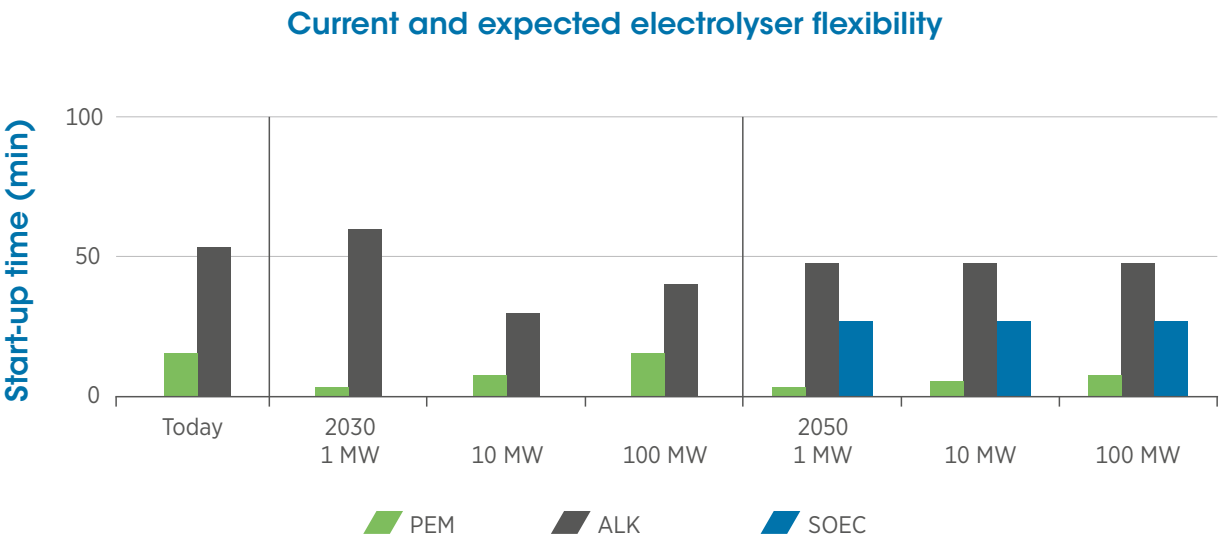
Hydrogen production could help reduce curtailment in grids with a high share of variable renewable electricity. However, it likely is not possible to produce significant amounts of hydrogen using exclusively cheap or free "otherwise curtailed" electricity if electrolysers operate only around 10% of the time or less. Given this utilisation rate, the hydrogen produced might not be competitive even considering zero-cost electricity. This may change if the electrolyser cost drops further. For the hydrogen production cost to be lowered, electrolysers should have a higher utilisation rate, which is not compatible with the occasional availability of curtailed electricity. A balance needs to be struck between buying electricity at times of low prices and increasing the utilisation of electrolysers (IRENA, 2018a). With regard to improving system flexibility, many other options exist that should be more profitable (IRENA, 2019c, 2018b).

Hydrogen electrolysers, however, can provide additional flexibility to a constrained power system. Modern electrolysers can ramp their production up and down on a time scale of minutes or even seconds, and further improvements are foreseen (Figure 5). PEM electrolysers are able to respond faster than alkaline electrolysers, which is one reason why they feature prominently in future studies despite their emerging status.

Electrolysers can be strategically located to ease power grid congestion and to transport hydrogen instead of electricity, which helps to avoid VRE curtailment. Such a strategy can be considered, for example, in the context of offshore wind development in the North Sea region. Therefore, countries have the option to move renewable power via copper wire or embedded in hydrogen.

Electrolysers add demand-side flexibility to power systems

Figure 5: Start-up times for electrolysers



Source: InWEDe, 2018

4.3 Hydrogen for seasonal storage of variable renewable electricity

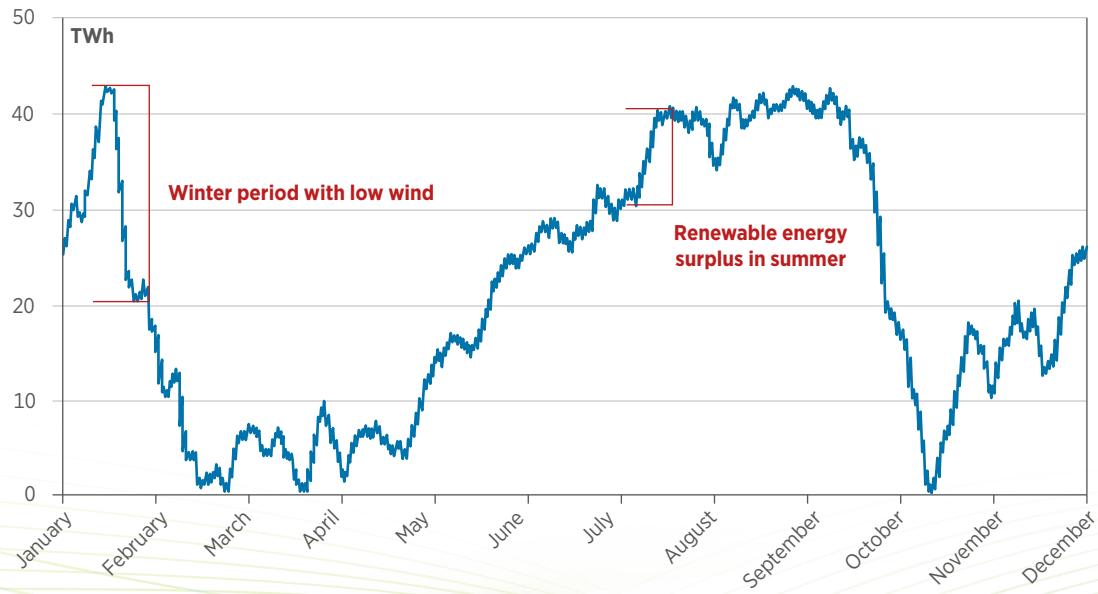
According to IRENA's analysis (2019b), storage needs for integrating large shares of solar and wind power will grow significantly in 2050, compared to today. The production of a very large volume of hydrogen from renewable power in combination with hydrogen storage can help provide long-term seasonal flexibility to the system (Figure 6). Hydrogen storage can take place in a multiplicity of modes, from storage of pure hydrogen in compressed or liquefied form, for instance compressed in underground geological structures, or liquefied in dedicated artificial structures, as well as mixed with other elements to produce liquid fuels or solids, or blended with natural gas in the natural gas infrastructure (Judd and Pinchbeck, 2016; Stetson *et al.,* 2016)

IRENA sees the seasonal storage of renewable electricity as a growth market after 2030, and hydrogen can play an important role in this. Although IRENA does not envisage significant seasonal storage requirements within the next decade based on current projections where other flexibility options might be more relevant, infrastructure and regulations should start being planned today.

A 440 MW hydrogen power generation retrofit of a gas power plant is being implemented in the Netherlands and is due for commissioning in 2023. The hydrogen production from natural gas will be located in the Netherlands, and the CO_2 will be captured and shipped to Norway for storage (NS Energy, 2019). Similar concepts are being studied in Japan.

Hydrogen can play a key role for seasonal storage in power systems with a high share of variable renewable energy

Figure 6: Hydrogen storage profile in 2050



Source: LBST, 2019

Also, a recent study for Northern Europe concluded that despite the relatively low 45% cycle efficiency, power-to-gas electricity storage would be beneficial and economically viable in a high-renewables scenario for 2050. It helps to avoid curtailment, and it increases overall renewables deployment. The study concludes that hydrogen storage and use for power generation is more beneficial than its use for industry. The potential to transport hydrogen gas instead of electricity and its subsequent use for electricity production is beneficial as the electricity system in the region is capacity constrained (DNV GL, 2017b).

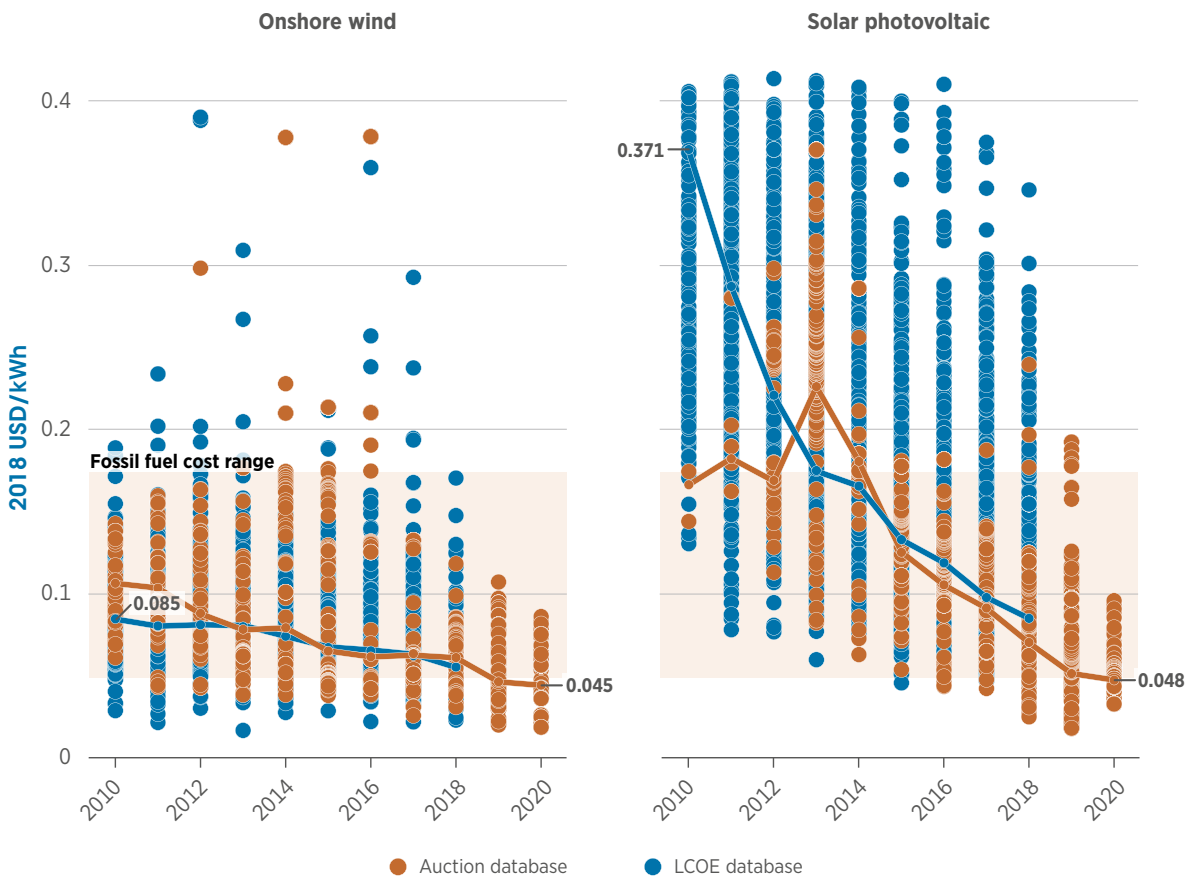
5. COMPETITIVENESS OF RENEWABLE HYDROGEN

This section compares the costs of producing green and blue hydrogen. Three main parameters are critical for the economic viability of hydrogen production from renewables: the electrolyser capital expenditure, the cost of the renewable electricity to be used in the process (levelised cost of electricity, LCOE) and the number of operating hours (load factor) on a yearly basis.

Utility-scale solar PV and onshore wind have reached cost levels of 2-3 US cents per kWh in an increasing number of locations; in 2018 the average cost of a solar PV or onshore wind commissioned project dropped 14% (Figure 7) (IRENA, 2019d).

The cost of renewable power generation has fallen dramatically in recent years

Figure 7: Global cost trends for onshore wind and solar PV

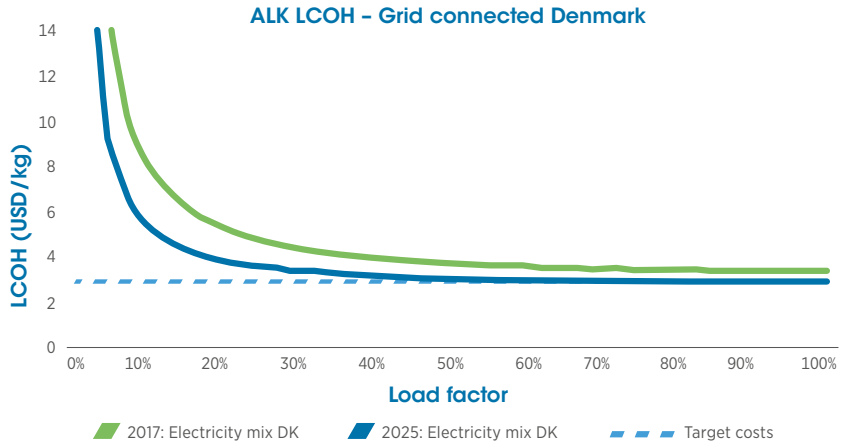


Note: Blue dots indicate commissioned projects, orange dots indicate data from auctions and power purchase agreements.
Source: IRENA, 2019d

The higher the electrolyser load factor, the cheaper the cost of one unit of hydrogen, once fixed investments are diluted by a higher quantity of product output. Electrolyser load factors should in general exceed 50% at today's investment cost levels, but nearly optimal hydrogen costs start being achieved at over 35% (Figure 8). This percentage will drop as electrolysers get cheaper. Solar-wind hybrid systems appear as a promising solution and could achieve capacity factors well above 50% in places such as the Atacama Desert in Chile where they complement each other in terms of availability.

Electrolysers require sufficiently high load factors for affordable hydrogen supply

Figure 8: Hydrogen supply cost as a function of electrolyser load



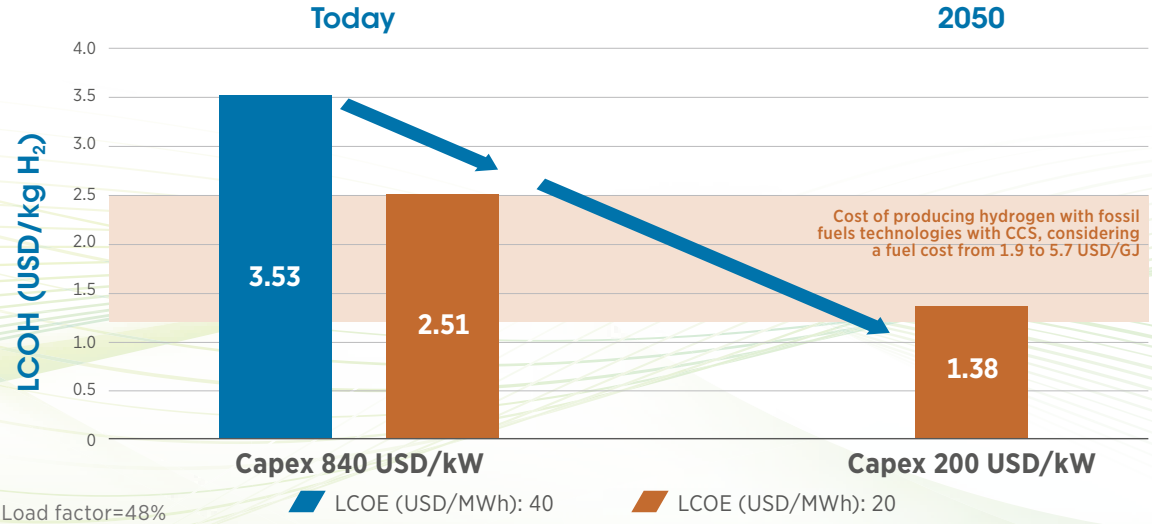
Source: IRENA, 2018a

A more expensive alternative is producing hydrogen from concentrating solar power (CSP) projects. For instance, a recently installed CSP project in Morocco is planned to produce electricity with a capacity factor as high as 65%, based on eight-hour thermal storage, which enables power generation also at night. Similar projects are still expensive, however, and generate electricity at a price of more than USD 80 per megawatt-hour (MWh) (IRENA, 2019c). Other storage devices can similarly support hydrogen production from renewables.

For competitiveness reasons, renewable hydrogen must be generally produced at less than USD 2.5 per kilogram (kg), but this value also depends on whether production is centralised or decentralised, as well as on the market segment and other factors. IRENA (2019a) quantified hydrogen costs from relatively low (USD 40/MWh) and very low (USD 20/MWh) power tariffs from wind energy. Current and future electrolyser investments (alkaline) of around USD 840/kW and USD 200/kW[4], respectively, were also considered (Figure 9). Under such assumptions, renewables are generally not competitive with low-cost natural gas available in industry (USD 5 per gigajoule, GJ) but could be competitive with average (USD 10/GJ) to high (USD 16/GJ) natural gas prices for non-household sectors in Europe.

Falling renewable electricity and electrolyser prices make green hydrogen the economic supply option

Figure 9: Hydrogen costs at different electricity prices and electrolyser Capex*



*Load factor=48%
Source: IRENA, 2018a

4 Electrolyser costs of USD 200/kW have been seen in some projects today, but such costs are expected to be achieved at large scale further in the future.

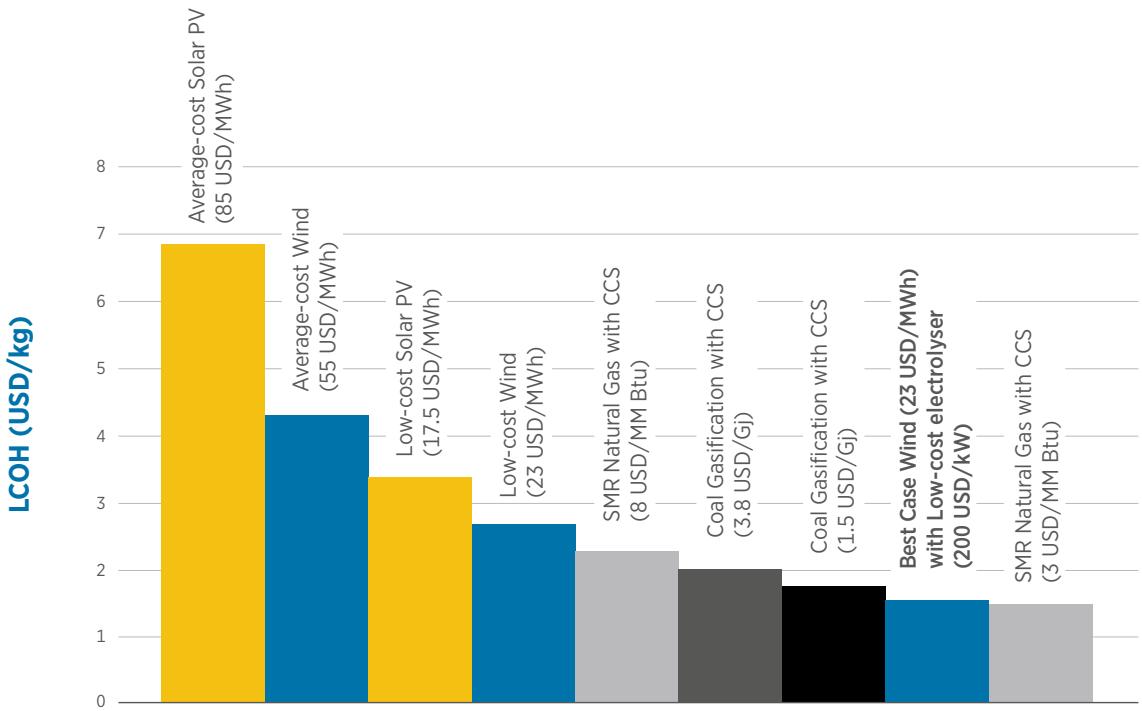
5.1 Current hydrogen production cost

Total costs of delivering hydrogen can be divided into production and logistics costs. Local regulation and financial aspects such as cost of capital are also relevant for final delivery cost. Along the production stage, the price of both renewable power and fossil fuels (natural gas and coal) is relevant to variable costs and thus to the final competitiveness of each technology.

Figure 10 shows the average and best-case supply costs of renewable electricity today, compared to the supply from fossil fuels with CCS. The data suggest that CO_2-free renewables could be among the cheapest hydrogen sources even today, although only in very particular situations. The best case considers a low-cost electrolyser of USD 200/kW, which at a broader scale is expected to be achieved only from 2040, although Chinese manufacturers claim that it is a reality already today. The low-cost renewable power of USD 23/MWh is seen today in wind projects in countries such as Brazil and Saudi Arabia (IRENA, 2019d).

The best-case renewable hydrogen supply can be economic today, but typical conditions need further cost reductions. The lowest-cost wind and solar projects can provide hydrogen at a cost comparable to that of hydrogen produced from fossil fuels

Figure 10: Costs of producing hydrogen from renewables and fossil fuels today



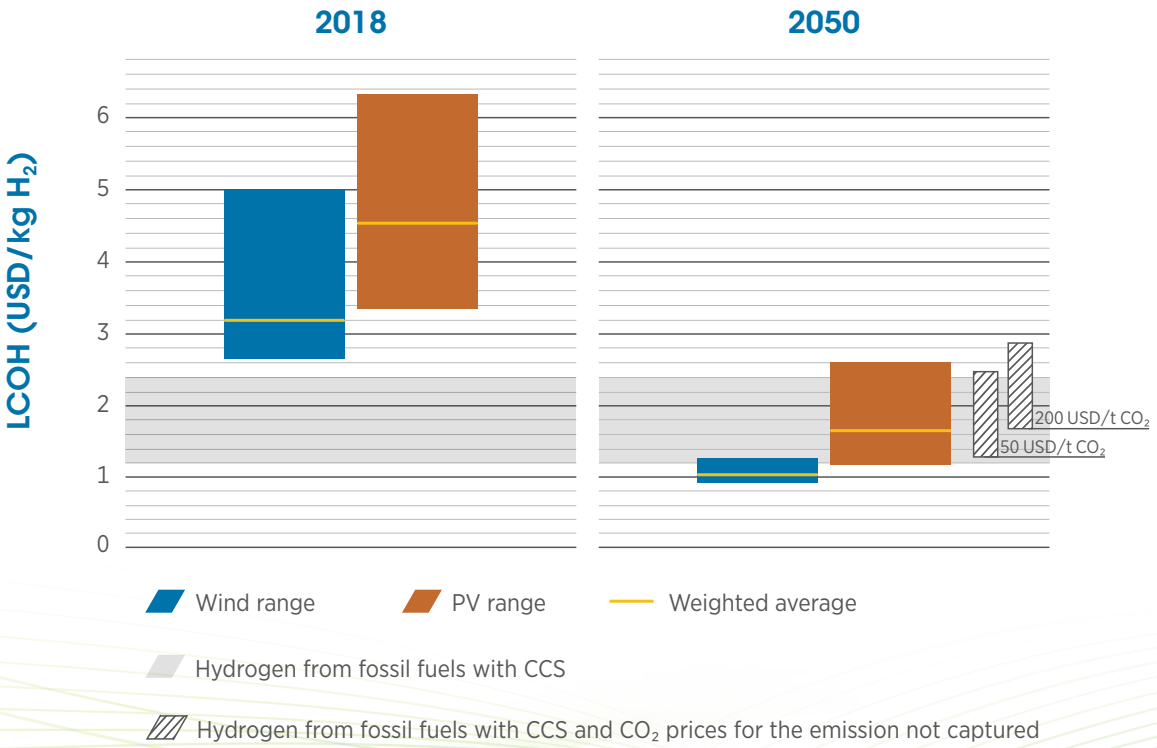
Notes: Electrolyser capex: USD 840/kW; Efficiency: 65%; Electrolyser load factor equals to either solar or wind reference capacity factors. For sake of simplicity, all reference capacity factors are set at 48% for wind farms and 26% for solar PV systems.
Source: IRENA analysis

Provided that low-cost electricity is available, the challenge is then in ensuring a high load factor to the electrolyser. The ideal case for 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 amortisation on the levelised cost of hydrogen (LCOH). High-quality wind and solar PV resources with availabilities of 4 161 and 2 356 hours, respectively, inherently attached to low LCOEs, result in better economics but still not enough to achieve competitiveness today (Figure 11, left). To further improve load factors, additional measures include the use of PV tracking and hybrid wind and solar plants.

With the expected decrease of both electrolyser costs (see section 4.3) and renewable electricity costs in the long run, the electrolyser load factor will play a smaller role, and hydrogen from renewable power will become competitive with or cheaper than all forms of producing hydrogen from fossil fuels (Figure 11, right). Higher capacity factors at wind farms (higher turbines and technology improvements) are also an important factor to decrease total costs. Thus, the question is how early competitiveness is to be achieved given expected developments in the different parameters, and to what extent complementary technologies can or will help this movement.

The competitiveness of hydrogen from renewables will continue to improve between now and 2050. CO_2 pricing makes for a more compelling case for green hydrogen

Figure 11: Cost of producing hydrogen from renewables and fossil fuels, 2018 and 2050



Source: IRENA analysis

5.2 Hydrogen logistics cost

Hydrogen can be produced in dedicated, large-scale renewable energy generation facilities and transported to the centres of demand. This model would allow for the development of large-scale wind and solar farms, as well as other renewables such as hydro and geothermal where applicable, where the resource potential and the investment conditions allow for lower costs of electricity from renewables. In addition, it could take advantage of existing transmission lines when they are not operating at full capacity, which is most of the time. A recent analysis suggests that competitiveness is currently close and is expected to improve continuously as the costs of renewable electricity and electrolysers continue to fall (Glenk and Reichelstein, 2019).

In some cases, it is also possible to transport electricity and produce the hydrogen near the centres of demand, saving on logistics costs. However, this means more power transmission costs. Given the high expected demand for hydrogen in the medium and long terms, this business case may also lead to significant grid investments.

In case renewable electricity is also produced locally, logistics costs are minimised. However, renewable power availability and cost will limit the locations where this option is possible.

If connected to the grid, hydrogen can be produced subject to short-timescale variations in the power market or under flat rates through power purchase agreement (PPA) contracts. In the first case, production will happen especially at moments of low and medium power prices. There will be a certain number of operating hours at higher prices, causing hydrogen costs to increase. Electrolysers may be operated as demand response assets to support energy balance over the grid (IRENA, 2019f), making profits from balancing or ancillary services (IRENA, 2018c). In the second case, hydrogen is produced at flat power rates under PPA contracts. In this case, operation can be continuous, which can improve the overall efficiency of the process – the higher the number of operating hours, the lower the hydrogen production costs. However, such baseload operation reduces the flexibility of the power system.

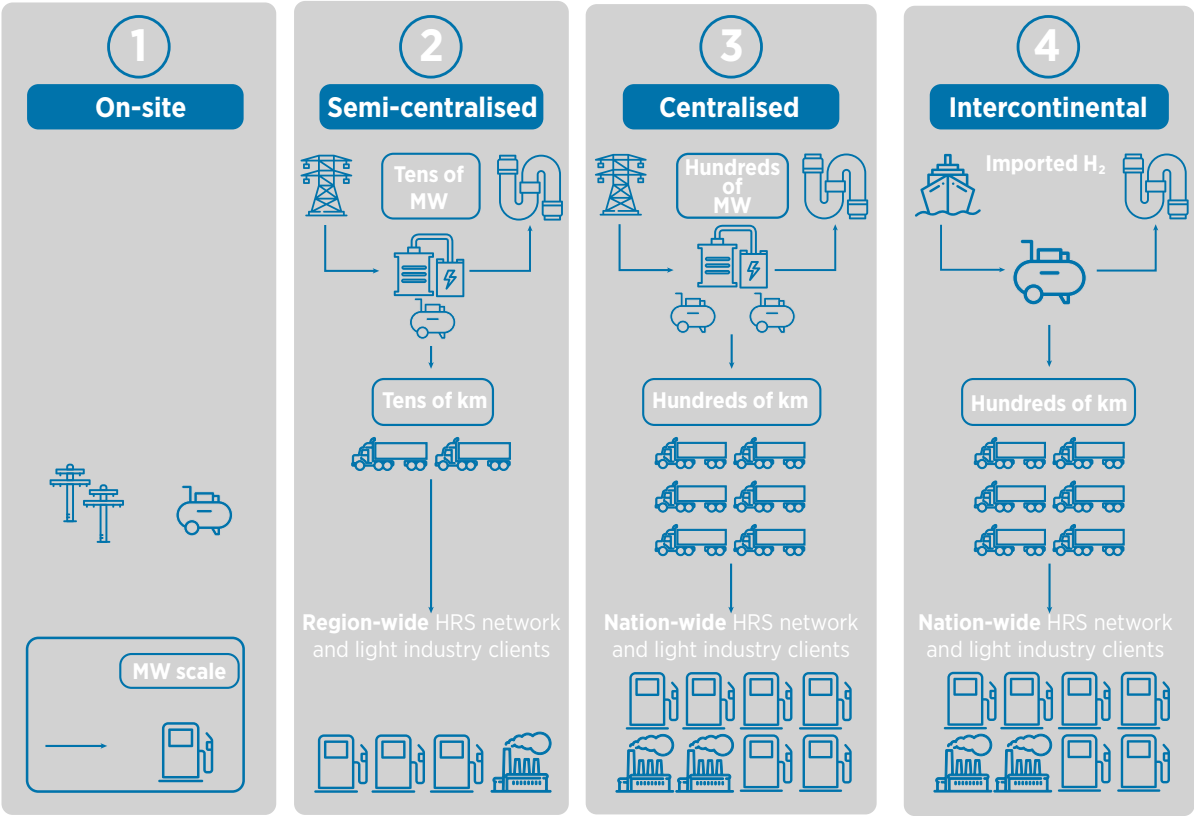
From a logistics perspective, four development stages can be envisaged (Figure 12):

- The first stage involves multi-megawatt-capacity hydrogen facilities to directly feed large consumers, such as medium- to large-scale industries and specific transport fleets leveraging on the use of existent gas grids, and eventually their conversion to hydrogen grids. This approach would ensure long-term off-take for hydrogen system developers.

- In the second and third stages, these and other new facilities can supply smaller, local consumers through trailer trucks. For this, investments in conditioning and filling centres would be needed.

- Once hydrogen from renewables applications achieves mass markets, regional hydrogen imbalances may result in regions with surplus hydrogen exporting to regions with deficits. This may lead to the creation of a continent-wide or even intercontinental hydrogen markets between countries with large renewables potential and hence export capacities (for example, Australia, Chile, Africa, the Middle East and the North Sea region), and countries with large hydrogen demand and costlier or limited renewables potential.

Figure 12: Potential future ramp-up pattern of the hydrogen supply chain



Note: HRS = hydrogen refuelling station
Source: IRENA, 2018c

Hydrogen production may also be envisioned to supply international markets without necessarily meeting internal demand. Similar projects have been developed in Australia and Norway to supply the Asian market and Japan, respectively.

The international hydrogen market and related shipping can be considered similar to natural gas, and the hydrogen will likely need to be transported over long distances. Its low volumetric density, in addition to a relatively high energy content, means that it is lighter to transport, but it requires more space than fossil fuel alternatives. To overcome this characteristic, hydrogen can be either compressed or liquefied or embedded in energy carriers such as ammonia, methanol and other liquid organic hydrogen carriers at the expense of energy losses.

The hydrogen form to be chosen depends on the quantities and distance involved, typically gas cylinders (small quantities), gas trailers (large quantities, shorter distances) or in liquid rather than gaseous form (large quantities, longer distances). Whereas hydrogen transport by gas grids generally occurs by compressing it, the most promising and studied pathways for international shipping are liquid forms either through hydrogen liquefaction or its transformation into ammonia, converted back to hydrogen at the local of destination if required. MCH has been studied as a possible pathway, but costs currently seem to be higher than the alternatives (Table 1).

Table 1: Challenges and characteristics faced by each storage/transport pathway

CHARACTERISTICS	LIQUID	TOLUENE-MCH	AMMONIA (NH_3)
Challenges	• Requires very low temperature (about –250 °C) • High energy requirement for cooling/liquefaction • Demands cost reduction for liquefaction • Liquefaction currently consumes about 45% of the energy brought by H_2 • Difficult for long-term storage • Requires boil-off control (0.2%–0.3% d^{-1} in truck) • Risk of leakage	• Requires high-temperature heat source for dehydrogenation (higher than 300 °C, up to 300 kilopascal) • The heat required for dehydrogenation is about 30% of the total H_2 brought by MCH • As MCH with molecular weight of 98.19 gram per mol^{-1} only carries three molecules of H_2 from toluene hydrogenation, the handling infrastructure tends to be large • Durability (number of cycles)	• Lower reactivity compared to hydrocarbons • Requires treatment due to toxicity and pungent smell • Treatment and management by certified engineers • Consumes very high energy input in case of dehydrogenation (about 13% of H_2 energy) and purification
Advantages	• High purity • Requires no dehydrogenation and purification	• Can be stored in liquid condition without cooling (minimum loss during transport) • Existing storing infrastructure • Existing regulations • No loss	• Possible for direct use • Potentially be the cheapest energy carrier • Existing NH_3 infrastructure and regulation
Development stage	• Small scale: application stage • Large scale: infrastructure development is being carried out	• Demonstration stage	• Research and development stage • Partly has entered demonstration stage
Required development/ actions	• Regulation for transport loading/ unloading system • Development in H_2 engines • Improvement of energy efficiency in liquefaction	• Catalysts for both hydrogenation and dehydrogenation • Energy-efficient dehydrogenation	• High energy efficiency in synthesis • Fuel cell with direct NH_3

Source: Wijayanta *et al.* (2019)

Like liquefied natural gas, hydrogen in liquid form can be shipped as a global commodity. Liquefaction has as the main drawback its high consumption of power, accounting for roughly 20-40% of the hydrogen energy content in the liquefaction process[5], in addition to eventual hydrogen loss due to boil-off. Trade in the form of ammonia also consumes a large amount of energy in both synthesis and cracking, but it is expected to have a higher overall energy efficiency and thus lower costs, especially in the case where final cracking back to hydrogen is not needed, for instance for direct combustion for power generation[6]. However, if pure hydrogen is required (for example, for fuel cells) and thus ammonia cracking is needed, liquefaction may be the most efficient route (Kojima, 2019; Wijayanta *et al.,* 2019).

Ammonia has been synthesised, handled and transported for decades and has an existent international supply chain in its favour. The cracking step is still a technical challenge currently under development (Andersson and Grönkvist, 2019; CSIRO, 2018; Lamb *et al.,* 2019; Miyaoka *et al.,* 2018; Mukherjee *et al.,* 2018); Miyaoka (2018), Mukherjee (2018), Lamb (2019)) but can be a game changer if technical and economic challenges are successfully solved.

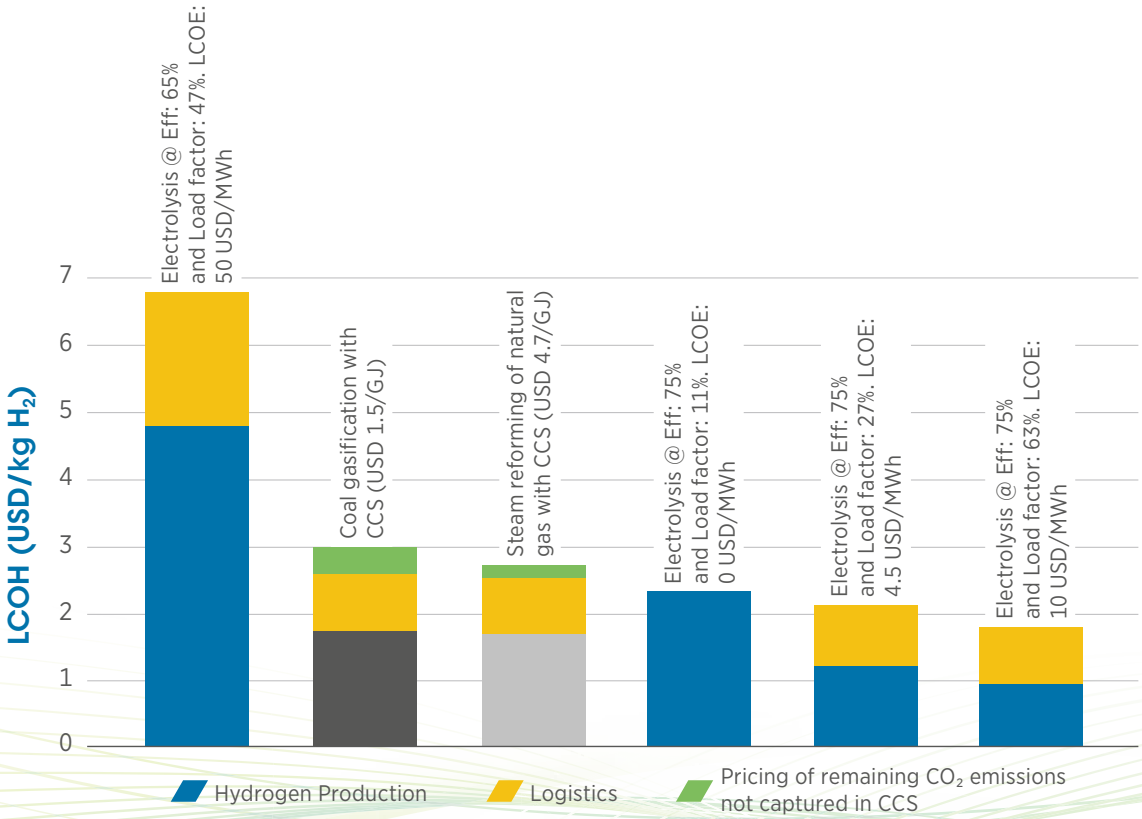
5 Alkaline and PEM electrolysers produce hydrogen at different output pressures, higher for the latter. This aspect may give some advantage to PEM whether hydrogen is to be liquefied.
6 Efficiency for the repowering pathway is particularly low.

Hydrogen can also be stored and transported embedded in other liquid organic hydrogen carriers that are potentially cheap, safe and easy to manage. Like other pathways, hydrogen is typically saturated with other compounds in an exothermic process at high temperature and pressure. It is then released in pure form by an endothermic dehydrogenation process at high temperature and atmospheric pressure. Examples of potential liquid organic hydrogen carriers are methanol, toluene and phenazine (Aakko-Saksa *et al.,* 2018; Niermann *et al.,* 2019). Other emerging solutions include a non-organic liquid based on silane, which is non-toxic and stable. In this solution, most of the energy needed in the process occurs in the hydrogenation step, where decarbonised power is likely to be available (export country), while the de-hydrogenation process in the import country is very low-energy intensive.

Figure 13 shows different cases for hydrogen delivery through the ammonia pathway. The graph shows that logistics costs matter in the total supply cost; typically, they account for 30-40% of the total supply cost.

Hydrogen trade and the use of surplus renewable electricity for local production close to centres of demand can co-exist. Logistics of imported hydrogen account for 30-40% of supply cost

Figure 13: Production and logistics costs for ammonia to transport hydrogen from Australia to Japan



Note: CO_2 price applies only on the remaining CO_2 emission not captured in the CCS facility for both coal and natural gas.

5.3 Future hydrogen supply cost

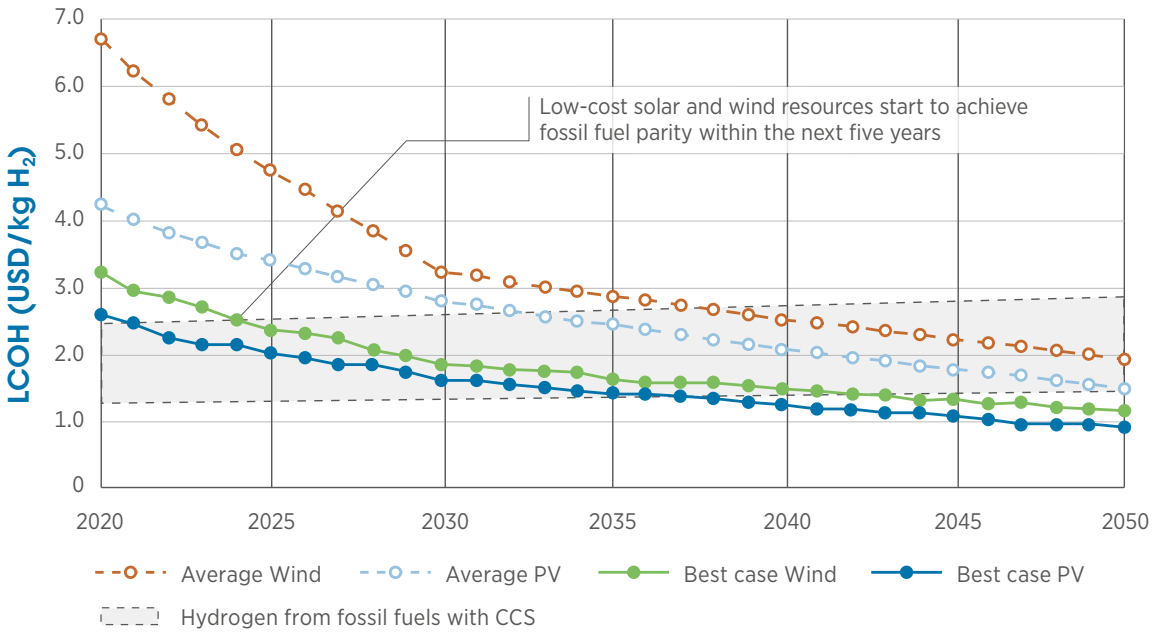
According to (IRENA, 2019a), a total of 19 EJ of renewable hydrogen will be consumed in the energy sector by 2050. This translates to around 700 GW of installed electrolysis by 2030 and 1700 GW by 2050 (considering retirements). With such development, and considering past technological learning rates responsible for costs decreasing (Junginger, 2018; Louwen *et al.,* 2018), electrolyser costs should halve from USD 840/kW to USD 375/kW between now and 2050. With respect to fossil fuels with CCS, costs are expected to remain generally unchanged. According to CCC (2018), costs of hydrogen from SMR with CCS are expected to increase by 2% on average from 2025 to 2040. For advanced natural gas reforming, costs would increase by 13%, while for hydrogen from coal gasification, costs would decrease by 11%. For the sake of simplicity, costs of CCS technologies for hydrogen production were considered constant during the period.

In addition to investment costs, the LCOE for solar and wind projects from different regions, together with respective solar and wind capacity factors, were taken from IRENA (2019b). A forecast of hydrogen from renewables production costs can be then inferred and compared to fossil fuel options with CCS. A small part of CO_2 is not captured in the CCS facility for which carbon prices were considered (Figure 14).

The forecast for hydrogen from low-cost wind and solar PV projects is expected to achieve competitiveness with fossil fuels within the next five years, specifically against SMR from natural gas with CCS at a natural gas price of USD 8 per million Btus. In the case of low-cost PV projects, this would be achieved in eight years. From 2030 to 2040, renewable hydrogen costs dip below fossil fuel with CCS in all cases.

Future costs of green hydrogen will be below those for blue hydrogen fossil fuels. By 2035, average-cost renewables also start to become competitive. Pricing of CO_2 emissions from fossil fuels further improves the competitiveness of green hydrogen. In the best locations, renewable hydrogen is competitive in the next 3-5 years compared to fossil fuels

Figure 14: Hydrogen production costs from solar and wind vs. fossil fuels



Note: Remaining CO_2 emissions are from fossil fuel hydrogen production with CCS.

6. FUTURE HYDROGEN AND HYDROGEN COMMODITY TRADE PROJECTIONS

One of the key drivers of the development of hydrogen is the unlocking of new trade opportunities. Hydrogen can be produced at lowest cost in locations with the best renewable energy resources and low project development costs. This hydrogen can be traded with consuming countries that lack the domestic potential for sufficiently affordable hydrogen production.

At the same time, hydrogen can be an important input for specific energy-intensive processes in industry. Processes that require significant amounts of hydrogen include ammonia production, direct reduction of iron ore and methanol production. Hydrogen is also used in oil and biofuel refineries for hydrocracking, with a focus towards diesel and biodiesel production. Finally, hydrogen and CO_2 can be used as feedstocks for so-called electrofuels or e-fuels, synthetic fuels with the same as or superior qualities than refined oil products.

New renewable hydrogen production activities can become a major contributor to a country's economy, creating jobs and potentially having a multiplier effect when the hydrogen can be used in conjunction with other resources (*e.g.,* iron ore) to export higher value-added commodities (*e.g.,* iron instead of separately iron ore and hydrogen).

6.1 Leveraging remote renewable energy resources to develop a new global commodity

Many oil-exporting countries have excellent renewable energy resources, which when combined can provide very low-cost electricity together with high capacity factors (Wouters, 2019). For oil-exporting countries, renewable hydrogen could provide the opportunity to transition to lower-carbon fuels and diversify the economy. A first step could be to use renewable hydrogen for hydrocracking and desulphurisation in refinery operations, as a stepping stone on the way to e-fuels.

Hydrogen production from renewable electricity is gaining momentum worldwide. Australia exported for the first time a small amount of green hydrogen produced from renewable energy to a large energy company in Japan in 2019 (Nagashima, 2018). Japan is one of the main hydrogen destinations, and countries have included the country in their own roadmaps. Japan has engaged with Australia, Chile, Norway and Saudi Arabia, among others, to import hydrogen.

- **Australia:** South Australia has significant renewable generation capacity and limited interconnection with the rest of the country. It is an ideal site for hydrogen production from solar and wind power and can help with integration of these renewable energy sources. At the same time, significant potential for renewable power generation at low cost exists in areas with very limited electricity demand. Therefore, large-scale facilities can be deployed as fully dedicated to hydrogen production. In the north-west Pilbara region, 15 GW of solar PV and wind is planned. This capacity is aimed primarily at the local iron mining industry but also with an eye to hydrogen exports.
    - » Utility-scale solar PV costs decreased from USD 90/MWh in 2015 and are expected to reach USD 29.8-41.2/MWh in 2020 (Acil Allen Consulting and ARENA, 2018). This would result in a levelised cost of hydrogen in the range of USD 4.34-3.77/kg in 2020 from solar PV systems (2 600 full load hours).

» From the expected cost reduction of electrolysers and efficiency improvements, hydrogen production from solar panels (2 600 full load hours) can go as low as USD 2.46/kg, for an LCOE of USD 21/MWh by 2030.

» Australia envisions meeting 3.5% of global hydrogen demand, most of it by exporting to Japan, the Republic of Korea, China and Singapore, according to ARENA (2018). Hydrogen exports could bring significant economic gains and job creation.

- **Chile:** Chile is also developing a strategy aimed at exporting hydrogen to countries including Japan and the Republic of Korea. The Chilean hydrogen case leverages one of the best solar resources in the world in regions such as the Atacama Desert, with more than 3 000 sun hours and less than 2 millimetres of rainfall per year, which results in the low-cost, high-capacity renewables essential for low-cost hydrogen production (Ministry of Energy, Chile, 2018).

  » Bidding processes in 2017 (no subsidies) were cleared at USD 30/MWh for utility-scale solar PV units and at USD 63/MWh for CSP facilities.

  » By combining both technologies, CORFO expects combined PV/CSP LCOEs at USD 50/MWh in 2025 and USD 40/MWh in 2035 (Baeza Jeria, 2017), which in turn would give a combined capacity factor of at least above 50%. This would lead to a levelised cost of hydrogen of around USD 2.7/kg, according to IRENA assumptions. On-grid, CORFO found as low as USD 1.6/kg for 2025 in its energy modelling.

  » Utilising a small amount of the solar PV potential in the Atacama Desert could lead to hydrogen production of more than 450 000 tonnes per year.

- **Norway:** *T*he Norwegian proposal is hydropower (or wind) paired with high-temperature electrolysis. Hydrogen would then be liquefied for shipment to Japan. The proposal expects to achieve a levelised cost of hydrogen of USD 2.2/kg (Nagashima, 2018).

- **Saudi Arabia:** In the future, hydrogen from Saudi Arabia could be produced from a combination of wind and solar PV with the objective of increasing the capacity factor while marginally raising electricity costs (WEC, 2018). CSP can also greatly contribute to increasing the capacity factor and potentially use high-efficiency electrolysis (*e.g.,* the use of heat plus electricity for solid oxide electrolysis cells, SOEC).

  » Saudi Arabia has signalled ammonia as the chosen pathway to transport hydrogen given the existing international experience, and its use may facilitate the country's envisioned transition from fossil fuels. According to Nagashima (2018), parity with fossil fuels would be achieved in the country at USD 3.5/kg of ammonia.

  » Based on the latest bids of USD 23.4/MWh for a utility-scale solar PV project and USD 21.3/MWh for a wind farm (IRENA, 2019g), hydrogen could be produced today at USD 3.95/kg by PV panels (2 100 full load hours) and at USD 3.31/kg in wind farms (2 620 full load hours). This results in ammonia being produced at a cost range of USD 4.4-5.2/kg. Given the country's high DNI (direct normal irradiance), comparable to the best resources in Spain and Morocco, which would guarantee high load factors, CSP is likely to play an important role.

» Hydrogen from renewables achieves parity in the country by 2030 with the LCOE of PV decreasing to USD 18/MWh. Wind farms at current power levels and CSP plants drop to USD 35-40/MWh.

» The country's power generation relies heavily on fossil fuels, consuming around 1 million barrels a day.

» Hydrogen from renewables could support a better management of fossil fuels. If achieved, renewable power targets could reduce oil consumption to 141 million barrels of oil equivalent (Mboe) or 19% of the power sector's fossil-fuel consumption.

Countries have varying incentives and strategies to become e-fuel suppliers, as listed by the World Energy Council (WEC, 2018) in Table 2.

Table 2: Reasons leading countries to become e-fuel suppliers and hydrogen suppliers

TYPE	CHARACTERISTICS	EXAMPLE
Frontrunners	• Powerfuels already on countries' (energy) political radar • Export potential and powerfuels readiness evident • Uncomplicated international trade partner → Especially favourable in early stages of market penetration	Norway
Hidden champions	• Fundamentally unexplored renewable energy potential • Largely mature, but often underestimated, (energy) political framework with sufficiently strong institutions → Powerfuels could readily become a serious topic if facilitated appropriately	Chile
Giants	• Abundant resource availability: massive land areas paired with often extensive renewable energy power • Powerfuels readiness not necessarily precondition, may require facilitation → Provide order of powerfuels magnitudes demanded in mature market	Australia
Hyped potentials	• At centre of powerfuels debate in Europe with strong powerfuels potential • Energy partnerships with Europe foster political support → Potential to lead technology development; may depend strongly on solid political facilitation	Morocco
Converters	• Global long-term conversion from fossil to green energy sources • Powerfuels to diversify portfolio as alternative long-term growth strategy → Strong motivation for powerfuels export technology development; may require political facilitation and partnerships with the demand countries	Saudi Arabia
Uncertain candidates	• Partially unexplored renewable energy potentials, possibly paired with ambitious national climate change countries • Powerfuels export in competition with growing national energy demand → Powerfuels export motivation and potential unclear – may drive powerfuels technology development, however export uncertain	China

Source: WEC, 2018

6.2 Electrofuels

Electrofuels (e-fuels) are produced by the reaction of hydrogen with CO_2 (see Box 4) into liquid products with gasoline, diesel, jet fuel or naphtha-like characteristics.

Hydrogen-based e-fuels are considered attractive for multiple reasons:

- Easier storage than for hydrogen
- Easier integration with existing logistic infrastructure (*e.g.,* use in gas pipelines, tankers, refuelling infrastructure)
- Ability to enter new markets (*e.g.,* aviation, shipping, freight, building heating, petrochemical feedstocks)

However, there are also clear disadvantages: further costly processing is needed, a climate-neutral CO_2 source is needed, and further efficiency losses occur. There is also a strategic risk that a focus on a costly solution with straightforward integration stifles efforts to introduce enabling changes for radical solutions. For example, if e-fuels can replace gasoline, there is no need to develop a hydrogen supply infrastructure and introduce EVs. However, if e-fuels do not materialise, valuable time is lost. This poses a significant risk. Therefore e-fuel deployment should be focused on sectors where no viable alternatives exist.

Box 4: Direct air capture of CO_2

Because a primary driver for the energy transition is abatement of greenhouse gas emissions, the source of the CO_2 used for producing e-fuel is important. If the CO_2 is captured from a fossil fuel combustion process (*e.g.,* a power plant) and is reacted with renewable hydrogen to yield an e-fuel, and this e-fuel is used to replace fossil fuel (*e.g.,* jet fuel), then the total CO_2 emissions of both processes are halved. However, this is not in line with the Paris climate objectives, which require significant decarbonisation of the global economy in the second half of this century.

This leaves as options only CO_2 from biomass combustion and from direct air capture (DAC). The first option is less costly yet limited in potential (*e.g.,* biomass combustion is only possible in large power plants, biofuel refineries, bagasse boilers and pulp plants). The second (DAC) is costlier but has unlimited potential, provided that significant cost reductions take place and that the price for CO_2 is sufficient to support investments in such technologies.

Recent pilot-scale cost estimates for DAC are lower than earlier expected, at levels of USD 94 to USD 232 per tonne of CO_2 (Keith *et al.,* 2018), with some cost projections reaching below USD 60 per tonne of CO_2 by 2040 (Fasihi *et al.,* 2019). Sutherland (2019) found that minimum costs considering sorbents under various conditions ranged from USD 29 to USD 91 per tonne of CO_2. At such price levels, DAC could become a promising source of carbon-neutral carbon for the production of e-fuels by synthesis with renewable hydrogen. It could also be a potentially game-changing technology for negative emissions if combined with secure long-term geological storage or storage in solids, as demonstrated by the first pilot plants of this kind (Gutknecht *et al.,* 2018) .

Hydrogen can unleash the opportunity of new exports of energy-intensive commodities. The main feedstock produced from hydrogen today is ammonia. Ammonia is a global commodity with production volumes of around 175 Mt/year. However, the hydrogen used for ammonia production today is produced from natural gas or coal. This hydrogen is reacted with nitrogen from the air to produce ammonia through the Haber-Bosch process, a particularly energy-intensive process. Ammonia as a feedstock is usually further processed into solid or gaseous nitrogen fertilisers (urea, ammonium nitrate, etc).

Because ammonia has an energy content of 18.6 GJ per tonne, roughly half that of oil products and comparable to biomass, it can also be used as an energy carrier. It is also the only e-fuel that does not contain carbon, making it carbon-free like pure hydrogen, unlike most of the other e-fuels. On the downside, ammonia is highly toxic for humans as well as for aquatic life if leakages occur in water sources. It is also a potential source of nitrogen oxide emissions, if combustion is not perfectly optimised.

As an advantage, ammonia is already largely consumed today as a feedstock. Therefore renewable hydrogen can be supplied to an existing demand, using existing supply chain and logistics.

Another increasingly important chemical product is methanol. Methanol is currently produced from a mixture of hydrogen and carbon monoxide, which themselves are produced from natural gas or coal. However, methanol can also be produced from hydrogen and from CO / CO_2 gas (Agarwal *et al.,* 2019).

Methanol also has the potential to be used as a drop-in fuel. For instance, it is used in China as a gasoline additive as well as in the maritime industry. It is relatively simple to extract hydrogen back from methanol, for instance through on-board reformers in transport, to allow the use of hydrogen in fuel cells rather than methanol in ICEs, greatly increasing the end-use efficiency. Methanol from renewables also has a limited cost-gap with its fossil-based counterpart and is experiencing a growth in demand. On the downside, it is toxic and water soluble and has been banned in several countries including the US.

Hydrogen gas can also be processed with CO_2 to yield synthetic methane or liquids. Synthetic liquid production from syngas (hydrogen / CO / CO_2 mixture) is a proven technology and is applied on a commercial scale in South Africa, where coal is used as feedstock.

Synthetic natural gas can benefit from natural gas infrastructure as well as from a strong and growing LNG industry. It can be used directly in existing infrastructure as well as in appliances, including for power generation and heating. Today the cost gap between synthetic methane and natural gas is the largest among the e-fuels (see Table 3). However, there is potential for improvement if the cost of the CO_2 DAC drops significantly.

Table 3: Power-to-X production cost

	Formula	Hydrogen feedstock [t H2/t]	CO_2 feedstock [t CO2/t]	Feedstock cost [USD/t]	Total production cost [USD/t]	Fossil-based product price [USD/t]
Ammonia	NH_3	0.14	0	429	500-600	200-350
Methanol	CH_4O	0.13	1.38	513	675	300-350
Synthetic methane	CH_4	0.25	2.75	1025	1380	100-500
Synthetic oil products	C H_2	0.14	3.14	743	1000	500-800

Assumptions: USD 3 per kilogram of hydrogen, USD 100 per tonne of CO_2, 75-80% conversion efficiency.
Product price source: FAO, Methanex

6.3 Beyond fuels: Trade of energy-intensive commodities produced with hydrogen

Some of the fuels described in the previous section can also be considered feedstocks. In particular, ammonia is used mostly a feedstock for fertiliser production, although it can be used as a carbon-free fuel. Losses in the process are significant, but they can be reduced if ammonia is used as a fuel instead of being cracked to extract hydrogen (Obara, 2019).

The same is true for methanol, which is a key feedstock for petrochemical products as well as a fuel additive. It can be used as a fuel in the future, either directly combusted or reformed on board fuel cell vehicles (Agarwal *et al.,* 2019).

A key process where hydrogen can make a significant contribution to emissions reductions is the production of iron through direct reduction of iron ore using renewable hydrogen. Renewable hydrogen-based iron production can become a viable alternative to traditional blast furnaces at a CO_2 price of around USD 67 per tonne, making this the least-cost low-carbon production route where low-cost renewable electricity is available (IRENA calculations). China, Australia and Brazil together produce more than half of the world's iron ore. China is also by far the largest producer of iron, at around two-thirds of the world total.

Instead of exporting iron ore, Australia and Brazil could export direct-reduced iron (DRI) to be further processed into steel, ideally in a renewable-powered electric-arc furnace. Such a strategy could reduce global CO_2 emissions substantially. At the same time, it could increase the value-added in countries with both raw materials and high-quality renewable energy resources, while maintaining steel production in countries that are currently processing ore into iron and steel, such as China, Japan and the Republic of Korea. Meanwhile, China could make use of its abundant and low-cost renewable energy resources to process the growing production of domestic iron ore (Li, 2018) into DRI on-site, producing hydrogen through electrolysis at mining sites and avoiding the transport of iron ore. Transporting iron instead of iron ore reduces the transported weight by about one-third, which brings economic benefits.

Hydrogen-based iron and steel production has already been applied on a commercial scale in the past. There is considerable ongoing R&D to explore new production routes. The global potential is significant: compared to the iron and steel industry's current CO_2 emissions of around 2.5 gigatonnes (Gt), an estimated 0.8 Gt of emissions can be reduced by investing USD 0.9 trillion in this production and commodity trade route. This represents 0.7% of total energy sector investment needs and would save 2.3% of global energy-related CO_2 emissions.

To do this, global hydrogen-based iron production capacity coupled with DRI would have to increase seven-fold from today's level. In terms of hydrogen use, around 5 EJ (or 460 billion cubic metres) per year would be required, equivalent to 1% of global primary energy supply. Such an industry could develop from 2025 onward at scale, if the right industrial and climate policies are put in place. Finally, the local health benefits of relocating coal use and coke making from today's centres of iron production in China and elsewhere should also be considered in any cost-benefit analysis (IRENA analysis).

7 POLICY RECOMMENDATIONS

IRENA's key recommendations to scale up hydrogen are as follows:

Acknowledge the strategic role of hydrogen in the energy transition

- **Consider hydrogen as part of a larger energy transition effort.** Whereas its role will be modest in the coming decade, and further cost reductions are required, hydrogen can grow thereafter to make a substantial contribution by 2050. Governments and the private sector must strengthen their efforts to make this prospect a reality. Climate and energy objectives must be aligned for a hydrogen future.

- **Focus on green hydrogen as the long-term supply option.** Hydrogen production from renewable power is today the only sustainable hydrogen supply option for the long term. Green hydrogen supply is competitive under optimal conditions, and its competitiveness will spread gradually in the coming decades. Low-cost renewable power, cost reductions and efficiency increase in electrolysers, and the power system integration aspects all deserve special attention. **Blue hydrogen from fossil fuels with CCS** can also play a role as a transition solution, notably in situations where low-cost fossil fuel reserves exist, where storage sites are available and where a natural gas pipeline system exists that can be converted to hydrogen.

- **Include the hydrogen economy in the revision of Nationally Determined Contributions (NDCs) for the Paris Agreement, due in 2020.** As climate is a prime driver for a transition to a hydrogen economy, it is critical for energy systems that this potential is reflected in the climate commitments. The first revision of NDCs is due in 2020, and the next opportunity is 2025. Within the climate process, understanding of green hydrogen as an important greenhouse gas mitigation option needs to be improved.

- There are several ways in which the energy market can be stimulated to increase the use of clean hydrogen. Some examples include: setting a mandatory target for sustainable hydrogen production (for example, as adopted in the French energy strategy), mandatory blending shares with natural gas, or implementing a renewable energy directive to promote the use of hydrogen in the transport sector (for example, as proposed by the European Commission's RED II).

Enable and mandate clean and efficient hydrogen use

- **Develop certification systems and regulations for carbon-free hydrogen supply.** It is critical to ensure that any future hydrogen supply is climate compatible. Especially if hydrogen is transported from far-flung places, there will be a need to ascertain its origin.

- **Information sharing: Document and exchange international best practices.** The hydrogen field is still evolving rapidly. Technology, regulatory frameworks and standards all need further development.

- **Ensure high-efficiency hydrogen supply and use.** Hydrogen gas volatility means that energy use for conversion, transport and storage can pose significant efficiency losses. At the same time hydrogen use can create efficiency gains compared to conventional fossil fuel use. Technology improvements are needed to ensure a high overall efficiency.

Focus more on hydrogen supply infrastructure and viable transition pathways

- **Better understand the potential to re-use natural gas pipeline systems for hydrogen transport – assess materials as well as end-use issues.** A number of demonstration projects will come onstream in the coming years where transmission pipelines, gas distribution systems and districts are converted to hydrogen. Various studies (DNV GL, 2017a; Dodds and Demoullin, 2013; E.ON, 2019; Judd and Pinchbeck, 2016; Quarton and Samsatli, 2018) suggest that a transition of the gas pipeline system is viable, but that only practice will show the technical and economic viability. It is critical that these cases are well-documented and that learnings are widely known. As gas systems expand in places such as China, it is worth considering designs that ease a transition to hydrogen early-on, during the initial investment phase.

- **Collaboration on technologies and co-ordination on harmonisation of regulations, codes and standards.** Standards for natural gas pipeline systems, underground storage and use of gas mixtures in burners have generally been designed from the viewpoint of a few percent hydrogen in natural gas. If hydrogen gas becomes the norm, these standards need to be revised. Initial technical assessments suggest that there is room to revise standards in favour of hydrogen. National standardisation institutions and international bodies such as the International Organization for Standardization (ISO) have a key role to play in such a process. Regulatory bodies need to be on board to actually implement standards. Developing and obtaining consensus on changes to standards is a long process. Hence, urgent action is needed now to avoid them becoming a barrier to action in the medium term.

- **Encourage development of hydrogen infrastructure while reducing green hydrogen supply cost through R&D, upscaling and learning-by-doing.** Whereas green hydrogen is technically viable and, in many instances, available today, a huge scaling-up will be needed in the coming decades to ensure that hydrogen lives up to its promise as a significant part of the energy transition.

Develop new hydrogen markets

- **Consider emerging hydrogen applications for decarbonisation of challenging sectors** such as trucking and industry. For trucking, the availability of low-cost hydrogen is a critical factor. In industry, ammonia production based on green hydrogen is technically viable today. More process development is needed for iron production, but the global climate benefits could be very substantial. Rail, shipping and aviation are also promising applications. New hydrogen commodity trade can change the narrative around energy transition as it can create an economic prospect for today's major oil and gas-producing countries.

- **Consider power-to-X and e-fuel applications for the aviation, shipping, chemical and petrochemical sectors.** Whereas the cost is high today, significant cost reduction potential exists that can help to create technically viable and affordable solutions to decarbonise sectors that have limited or lacking alternative options. It is critical that a sustainable source of CO_2 is used in the long term, such as biomass combustion processes or direct air capture of CO_2.

- **Consider hydrogen as an enabler to deploy more variable renewable power in the transition to tomorrow's energy systems.** The flexibility benefits, electricity demand growth benefits and growing renewables shares that can be achieved create new compelling reasons to consider hydrogen as an energy transition solution.

- **Launch demonstration projects at sites where hydrogen production and hydrogen commodity production can be combined.** This includes, for example, projects for iron and ammonia production and synfuel production, thereby eliminating the cost for hydrogen transport.

Next steps for further work

- Enhance understanding of the energy system benefits of hydrogen production from electrolysis and of integration of high shares of renewable power. Notably, the **economics of seasonal storage** and **electrolyser** demand-side **flexibility** need to be understood better.

- Improve understanding of the **cost-reduction potential for electrolysers** and their potential to operate part-load based on the availability of variable power. This includes the ability to enhance ramp rates, future characteristics of different electrolyser designs and degradation under different operating conditions, which impacts the cost of hydrogen.

- Improve understanding of the **potential and rate to reduce electrolyser investment costs** to USD 200 kW or below.

- Enhance understanding of the **transition issues for pipeline systems** from natural gas to hydrogen.

- Improve understanding of **hydrogen fuel chain efficiency losses** and options to reduce these.

- Enhance understanding of the **potential to reduce greenhouse gas emissions** in the **production of blue hydrogen**.

- **Exchange best practices** and engage in international joint research and evaluation of hydrogen's potential, for example for power-to-X, as well as outreach and addressing regulatory barriers, codes and standards.

- Assess the potential for **low-cost, large-scale production of green hydrogen** in different regions and countries to make use of best-available renewable resources.

- Further develop the analysis of **potential pathways to a hydrogen-enabled clean energy future,** including the use of methanol and ethanol as hydrogen carriers in fuel cells.

- Explore the potential to enhance energy security and reduce environmental impacts through **relocation of manufacturing activities for energy-intensive commodities** based on hydrogen and renewable power.

- Improve understanding of the **socio-economic impacts of the hydrogen economy**, building on the work of IRENA.

- Improve understanding of the geopolitics of hydrogen, building on the work of the **IRENA commission on the geopolitics of energy transition.**

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