IRENA
International Renewable Energy Agency

ACCELERATING **HYDROGEN DEPLOYMENT** IN THE G7

RECOMMENDATIONS FOR THE **HYDROGEN ACTION PACT**

G7

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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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FOREWORD

It has become clear that hydrogen must play a key role in the energy transition if the world is to meet the 1.5 °C target of the Paris Agreement.

In particular, low carbon and green hydrogen offer vital opportunities for the development of hard-to-decarbonise sectors that cannot be electrified, or which have no viable alternatives to fossil fuels – such as industry and heavy transport including aviation, shipping and road haulage.

The potential of hydrogen is well understood, and has been a subject of IRENA analyses and studies since 2018. What is more important now is to implement policies and regulatory frameworks, and to provide incentives to establish and ramp-up a new hydrogen industry. Given that individual nations are unable to do this alone, the focus must be on fostering closer collaboration between countries to develop the mechanism to enable new hydrogen markets.

The announcement by the German G7 Presidency of the G7 Hydrogen Action Pact in May 2022 signalled the Group's intent to strengthen joint development of hydrogen and power-to-X value chains, and to streamline the implementation of existing multilateral initiatives that are committed to deploying hydrogen.

The analysis undertaken by IRENA to assist the development of the Hydrogen Action Pact resulted in the recommendations presented in this report. These aim to support the efforts by G7 leaders to align policy making and prioritise actions to harmonise standards and certification; share lessons from early implementation; balance the focus on supply with demand creation; promote hydrogen uptake in industrial applications; and establish more targeted collaboration with industry stakeholders and civil society.

This work was made possible by the engagement of delegates of the G7 countries, under the leadership of the German Federal Ministry for Economic Affairs and Action (BMWK).

The G7 group of countries has the opportunity to play a leading role in accelerating the development of a global hydrogen market. The recommendations presented in this report mark the start of this journey for the policy makers and stakeholders who will facilitate a new hydrogen trade.

It is time for action and IRENA remains committed to working with G7 leaders to ensure a fair, sustainable and secure energy transition.

Francesco La Camera

Director-General

International Renewable Energy Agency

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ABBREVIATIONS

ACES	advanced clean energy storage
BCA	border carbon adjustment
BEIS	Department for Business, Energy and Industrial Strategy (UK)
BIL	Bipartisan Infrastructure Law (US)
CAD	Canadian dollar
CAPEX	capital expenditure
CBAM	carbon border adjustments mechanism
CCfD	carbon contracts for difference
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CEN	European Committee for Standardisation
CFP	calls for proposal
CO_2	carbon dioxide
DRI	direct-iron-reducing
DoE	Department of Energy (US)
DPA	Defense Production Act (US)
ECMWF	European Centre for Medium-Range Weather Forecasts
ERA5	fifth-generation ECMWF reanalysis
ETS	emissions trading scheme
EU	European Union
EUR	euro
FCEV	fuel cell electric vehicle
GATT	General Agreement on Tariffs and Trade
GBP	United Kingdom pound
GDP	gross domestic product
GHG	greenhouse gas
GWP	global warming potential
H_2	hydrogen
HAP	Hydrogen Action Pact
HINT.CO	Hydrogen Intermediary Network Company
HRS	hydrogen refuelling stations
ICAO	International Civil Aviation Organization
IDA	Industrial Decarbonisation Agenda
IEC	International Electrotechnical Commission
IMO	International Maritime Organization
IPCEI	Important Projects of Common European Interest
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
ISO	International Standard Organisation
IUCN	International Union for Conservation of Nature
JPY	Japanese yen
LCOH	levelised cost of hydrogen
LNG	liquefied fossil gas
MCH	methylcyclohexane
NDC	nationally determined contribution
NECP	National Energy and Climate Plan (France)
NH_3	ammonia
PEM	polymer electrolyte membrane
PTX	Power to X
PV	photovoltaic
R&D	research and development
SoT	State of the Transition
SPP	sustainable public procurement
TES	total energy supply
TFEC	total final energy consumption
USD	United States dollar
VRE	variable renewable energy
WACC	weighted average cost of capital
WTO	World Trade Organization
ZEV	zero emission vehicle

UNITS OF MEASURE

bcm	billion cubic metres
CO_2eq	carbon dioxide equivalent
EJ	exajoule
gCO_2	gramme of carbon dioxide
GJ	gigajoule
Gt	gigatonne
GW	gigawatt
kg	kilogramme
$kgCO_2$	kilogramme of carbon dioxide
kgH_2	kilogramme of hydrogen
km	kilometre
km^2	square kilometre
$ktCO_2eq$	kilotonne of carbon dioxide equivalent
ktH_2	kilotonne of hydrogen
kW	kilowatt
kW_{el}	electric kilowatt
kWh	kilowatt hour
L	litre
m^3	cubic metre
MMBtu	metric million British thermal unit
Mt	million tonne
$MtCO_2$	million tonne of carbon dioxide
MtH_2	million tonne of hydrogen
MW	megawatt
Nm^3/h	normal cubic metre per hour
t/d	tonne per day
tCO_2	tonne of carbon dioxide
TW	terawatt
TWh	terawatt hour

EXECUTIVE SUMMARY

G7 members are committed to net-zero emissions by 2050 at the latest. To achieve this, they will need to rely on renewable energy, energy efficiency and electrification. This will also provide opportunities for developing hydrogen and power-to-X products, which have become prominent in energy policy discourse since 2019, and now all G7 members have issued strategic documents that include an expected role for low-carbon hydrogen in their societies.

In May 2022, G7 members officially launched the Hydrogen Action Pact (HAP). Its objectives include strengthening joint action on power-to-X, hydrogen and derivatives (especially ammonia), and streamlining the implementation of existing multilateral initiatives (G7, 2022).

The actions agreed are to:

"

1. ***Accelerate the development of low-carbon and renewable hydrogen domestically and at global scale, with emphasis on hard-to-abate sectors.***
2. ***Shape regulatory frameworks and standards to facilitate production, trade, transport and use of low-carbon and renewable hydrogen.***
3. ***Secure financial commitments for the market ramp-up of low-carbon and renewable hydrogen.***
4. ***Identify and close gaps for the ramp-up of low-carbon and renewable hydrogen.***
5. ***Exchange best practices on sustainability criteria and facilitate dialogue on the geopolitical implications of a global hydrogen market.***
6. ***Support the role of low-carbon and renewable hydrogen in decarbonising the natural gas and power systems.***

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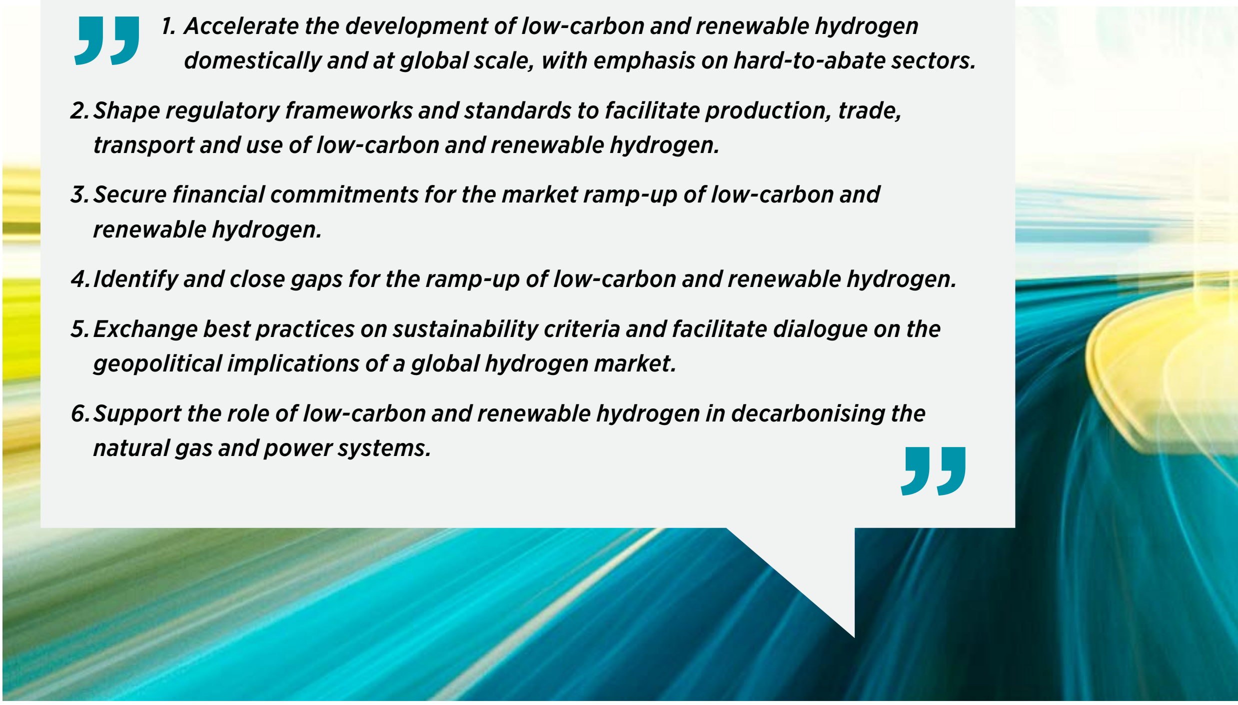

G7 members also recognise the importance of exploring the means to decarbonise their industrial sectors; in June 2021, the Industrial Decarbonisation Agenda (IDA) was launched to enhance collaboration among G7 members in the areas of market regulation, decarbonisation standards development, investment, procurement strategies and joint research related to industrial decarbonisation.

The G7 group is also committed to the implementation of policies and strategies that align financial flows with the goals of the Paris Agreement. These will indirectly affect financial flows towards hydrogen R&D and projects. Regarding industrial activity, the G7 group also recognises the need to collaborate on developing measurement standards to set the emission intensity threshold of production and other social and governance metrics.

These efforts are also closely aligned with international initiatives such as the Breakthrough Agenda, launched at COP26.

This report summarises the status and outlook for hydrogen in terms of technology, costs, strategy and policy support in the G7 member jurisdictions. The main reference used for policies in each country are hydrogen strategies, together with other complementary government announcements and policies.

The aim of the report is twofold: to present a cross-strategy analysis that examines trends, common priorities, differences and misalignments within the G7 membership; and to identify the main areas in which collaboration among G7 members can make the greatest difference in advancing hydrogen deployment. The report also provides five sets of specific recommendations that G7 members can follow to enact the HAP.

The recommendations focus on the hydrogen value chain only; the availability of low-cost, carbon-free, renewable-based electricity is not included but is a critical enabling factor for the provision of low-carbon and renewable hydrogen (Figure S.1).

FIGURE S.1 Recommendations for G7 members

Pillar 01: Align efforts on standards and certification

01

The G7 is working closely with the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE), which is developing a methodology for certifying emissions from hydrogen production and transport that will be used as input to develop an international standard from the ISO. The G7 can lead the progress in certification of hydrogen by driving the effort to agree on a common methodology to measure greenhouse gas (GHG) emissions across the value chain for consolidation under an international standard.

- Recommendation 1.1: **Establish common sustainability criteria for traded and supported hydrogen.**
- Recommendation 1.2: **Align methodologies for hydrogen certification.**
- Recommendation 1.3: **Spearhead efforts to set harmonised technical standards.**

Pillar 02: Collaborate internationally and share lessons from early implementation

02

G7 members are among the first movers in the new hydrogen sector, with specific policies and incentives in place. This presents an opportunity to share their experiences to enable a faster uptake of best practices, including sustainability and social aspects. At the same time, the G7 represents almost 90% of the public R&D budget for hydrogen and fuel cells, and about 73% of international inventions across hydrogen technologies. This provides the G7 with valuable knowledge of hydrogen technologies from which other countries will benefit and which could lead to the acceleration of global decarbonisation.

- Recommendation 2.1: **Support the sustainable development of hydrogen in Global South countries.**
- Recommendation 2.2: **Share lessons learnt as first movers.**
- Recommendation 2.3: **Implement innovative schemes such as regulatory sandboxes for hydrogen valleys.**
- Recommendation 2.4: **Address technology gaps and transfer technology knowledge.**

Pillar 03: Balance focus on supply with demand creation

03

The current focus of policy makers is on the supply side of hydrogen generation; but without offtake, projects remain risky and development limited.

In addressing this, G7 members have an opportunity to adopt new policies to support both the supply and the demand for green hydrogen. Within the G7 framework, members should signal their common intent through clear support with prioritisation for specific end uses and create a bulk demand for hydrogen in the most critical hard-to-decarbonise (commonly known as 'hard-to-abate') applications.

- Recommendation 3.1: **Prioritise hard-to-abate industrial applications for hydrogen demand.**
- Recommendation 3.2: **Agree on common actions to decarbonise shipping and aviation.**
- Recommendation 3.3: **Co-ordinate supply and demand.**
- Recommendation 3.4: **Plan the scale-up of financing.**

Pillar 04: Promote hydrogen uptake in industrial applications

04

The green hydrogen industrial sector is still in its infancy – not yet cost-competitive with grey hydrogen. As such, it is a good candidate for new, adaptive industrial policy making. Industrial policies can be defined as a range of policy interventions aimed at guiding and controlling the structural transformation process of an economy. The G7 members, which account for some of the most industrialised countries in the world, thus have the opportunity to act as a pivot for the hydrogen momentum needed to adopt a new set of industrial policies to support the transformation of industry at large.

- Recommendation 4.1: **Test and implement new policies for the uptake of green products.**
- Recommendation 4.2: **Address carbon leakage and create a level playing field.**
- Recommendation 4.3: **Support disruptive and step-changing technologies.**

Pillar 05: Conduct outreach among civil society and industry stakeholders

05

Awareness is a stepping stone toward creating public acceptance. This is essential in securing the legitimacy of the policies and public investment choices related to a new product such as hydrogen, and in avoiding opposition and resistance to its uptake. Acceptance hinges on policy fairness, meaning that the policy costs and benefits are distributed equitably. Citizen participation is essential for public acceptance and can be enabled by a unified message on the future of hydrogen, via direct engagement and by providing clear information on green products.

- Recommendation 5.1: **Adopt a unified message around hydrogen and increase awareness.**
- Recommendation 5.2: **Involve civil society in the governance of the hydrogen sector.**
- Recommendation 5.3: **Introduce and sponsor an international eco-label for hydrogen-based products.**

The application of such recommendations may require the adaptation of local policies and plans. This is not unusual in policy making. A good practice is indeed to maintain flexibility in policy design and to have strategies that are able to react to changes in market situations and new technological disruptions. As the green hydrogen sector is bound to evolve rapidly, the policies regulating it are certain to change. Promptly sharing lessons learnt can be key in making such changes successful and accelerating hydrogen deployment.

For all recommendations, G7 members may need to find the most suitable initiatives and platforms to take some of the actions forward. The IRENA Collaborative Framework on Green Hydrogen – the intergovernmental platform with the widest global membership coverage – can serve as the platform for information sharing and collaboration on all issues related to green hydrogen.

Finally, these recommendations are intended as long-term commitments between G7 members and potential hydrogen trading partners. Their adoption and application will require an implementation process that includes monitoring and evaluation in order to ensure their effectiveness.

CHAPTER **01**

G7 AND THE HYDROGEN SECTOR

1.1 INTRODUCTION

Hydrogen activities within the G7 context

In May 2022, the G7 members officially launched the Hydrogen Action Pact (HAP). Its objectives included strengthening joint action on power-to-X, hydrogen and derivatives (especially ammonia), and streamlining the implementation of existing multilateral initiatives (G7, 2022).

The actions agreed were:

> "1. *Accelerate the development of low-carbon and renewable hydrogen domestically and at global scale, with emphasis on hard-to-abate sectors.*
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>
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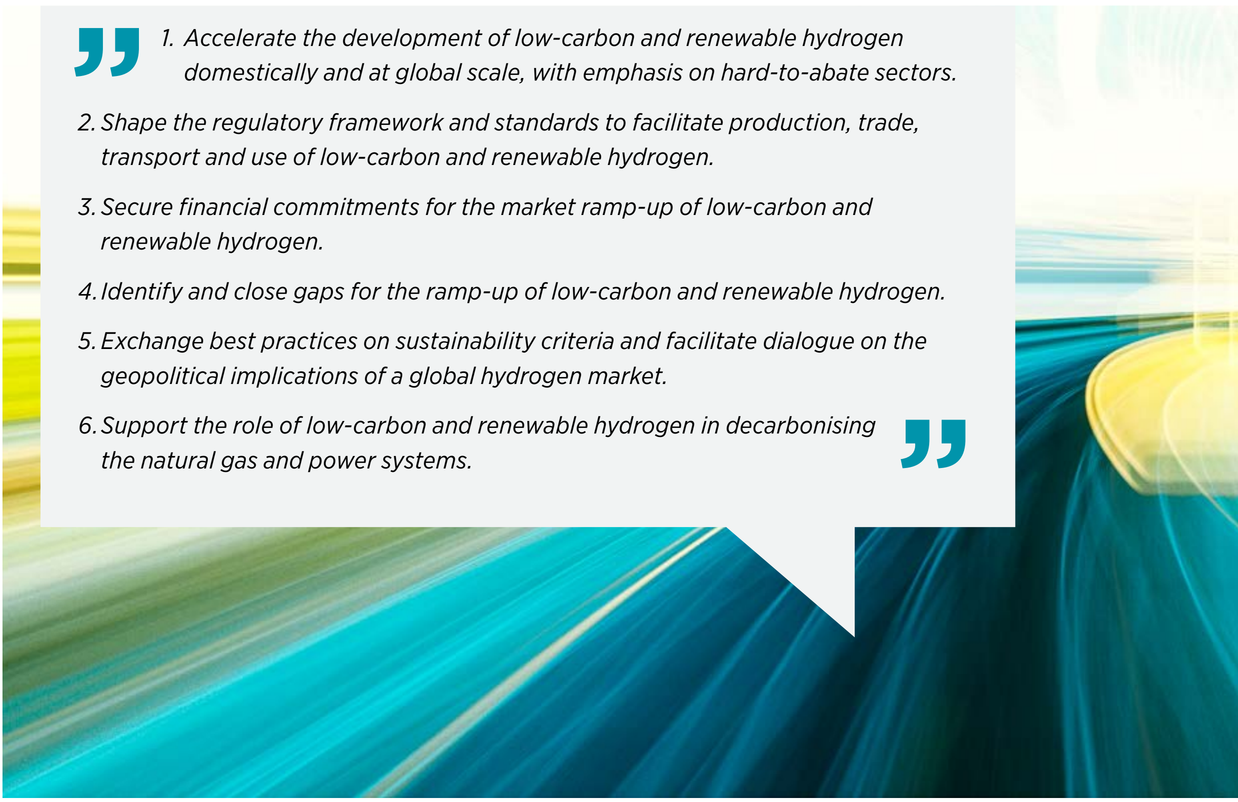
>
> 5. *Exchange best practices on sustainability criteria and facilitate dialogue on the geopolitical implications of a global hydrogen market.*
>
> 6. *Support the role of low-carbon and renewable hydrogen in decarbonising the natural gas and power systems.*"



HYDROGEN IN THE G7

The G7 members are already looking at the decarbonisation of industrial sectors. In June 2021, the Industrial Decarbonisation Agenda (IDA) was launched to enhance collaboration among G7 members in the areas of market regulation, decarbonisation standards development, investment, procurement strategies and joint research related to industrial decarbonisation (G7, 2021a). This is part of a broader decarbonisation portfolio for industry that includes energy efficiency, circular economy, electrification, heat use, waste reduction and carbon capture utilisation and storage.

The G7 members are also committed to global efforts by supporting low- and middle-income countries through financial and technical co-operation (G7, 2021b). The IDA has also recognised initial emissions thresholds for low-carbon and zero-emission steel, with these being 50 kilogrammes (kg) to 400 kg of carbon dioxide (CO_2) equivalent per tonne and 40 kg to 125 $kgCO_2$ equivalent per tonne for cement production (G7, 2022). The precise threshold value depends on the amount of scrap use and the clinker-to-cement ratio, respectively. These thresholds can serve as a starting point for further discussion (G7, 2022; IEA, 2022a)

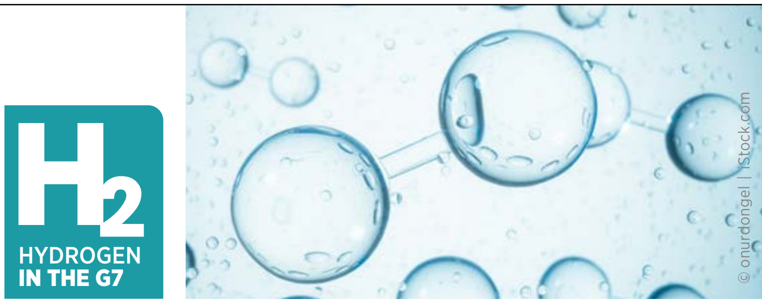
The IDA initiative also includes market-oriented approaches to set the conditions for a level playing field that fosters free and fair trade that prevents carbon leakage (G7, 2021a).

The G7 group is also committed to the implementation of policies and strategies that align financial flows with the goals of the Paris Agreement (G7, 2021b). These will indirectly affect financial flows for hydrogen. Regarding industrial activity, the G7 members also recognised the need to collaborate in developing measurement standards for the emission intensity (G7, 2021b) of production and other social and governance metrics.

Efforts by the G7 members are also closely aligned with international initiatives. The Breakthrough Agenda, launched at COP26, is one of the most recent and overarching of these and aims to bring multiple stakeholders together. The initiative is endorsed by 45 governments and is initially focused on five sectors (called 'Glasgow Breakthroughs'): power, road transport, steel, hydrogen and agriculture (COP26, 2021a). The Hydrogen Breakthrough is endorsed by 35 countries and the European Commission and has as its main statement, "Affordable renewable and low carbon hydrogen is globally available by 2030". Progress in these sectors will be accelerated through four key priorities, the first of which is a report on the State of the Transition (SoT), which provides an overview of the status, progress, gaps, opportunities and benefits of enhanced collaboration. Recommendations from the SoT report are focussed in four areas:

demand creation, international standards and certification, innovation, and financing. Follow-up of the SoT report includes bringing together governments, non-state actors and international organisations from leading initiatives; co-convening ministerial discussions on the state of the transition; and encouraging new leader-level commitments (COP26, 2021b).

There are several synergies between the Hydrogen Breakthrough and the G7 HAP. First, the Breakthrough performed a landscape mapping of all the active initiatives against the enabling conditions that they focus on as part of the SoT report. The HAP could use this mapping to identify the most suitable initiatives to take forward the HAP recommendations. Second, all the G7 members are part of the Hydrogen Breakthrough, and this can provide a platform for the G7 to have a broader influence. In terms of hydrogen flow, for example, the Breakthrough covers around 66% of global demand while the G7 accounts for around 28%. Third, a fundamental driver for the inception of the Breakthrough is collaboration, which is a common goal for the G7.



Scope of this report

All G7 members are committed to net-zero emissions by 2050 at the latest. To achieve this, they will have to rely on renewable energy, energy efficiency, electrification and carbon capture, storage and utilisation, and low-carbon hydrogen. The latter became prominent in energy policy discourse from 2019, and now all G7 members have strategic documents presenting the expected role of low-carbon hydrogen in their societies (hydrogen strategies).

This report summarises the status and outlook for hydrogen in terms of technology, costs, strategy and policy support in the G7 member jurisdictions (Chapter 1, Section 1.2). The main reference used for policies in each country is their respective hydrogen strategy (Section 1.3). However, some strategies were published before developments in the energy sector and in its geopolitical stance – as well as in the hydrogen sector itself – have taken place. Therefore, other government announcements and policies complementing these strategies have also been considered, when applicable.

A cross-strategy analysis looks at establishing trends, common priorities, differences, and misalignments within the G7 membership (Chapter 2). It also identifies the main areas where collaboration among G7 members can make the greatest difference in advancing hydrogen deployment, while providing specific recommendations that G7 members can take up in each area (Chapter 3).

1.2 ENERGY AND HYDROGEN OVERVIEW IN THE G7

The G7 represents about 30% of global energy demand and 25% of global energy-related CO_2 emissions, while accounting for only 13% of the global population. The average gross domestic product (GDP) per capita in the G7 is 60% higher than the global average. In combination with a skilled workforce and developed industry, this gives the G7 an opportunity to demonstrate leadership in energy system transition. G7 members represent about 16% of global steel demand (World Steel Association, 2022), about 21% of global ammonia production and 11% of global methanol production (USGS, 2022). Displacing fossil fuels in heavy industry can also improve energy security. Heavy industry in G7 represents more than 15% of global coal use and about 10% of global oil and fossil gas use (IEA, 2022a).

The energy starting point for each G7 member is different (see Figure 1.1.1). While a commonality is that oil represents a relatively large share of the primary energy supply (between 28% and 37%), given its use in the transport sector, other energy carriers show significant variation between countries. For instance, coal represents 28% of the energy supply in Japan with 40% of this used for steel production (IEA, 2021a). In contrast, coal represents 3.4% of the supply mix of the United Kingdom (BEIS, 2021a), having dropped by more than 85% in the last decade (BEIS, 2021a). Nuclear represents almost 42% of the energy supply in France. In 2020, Canada exported 44% of its domestic energy production (IEA, 2022b), while Japan satisfies 88% of its energy demand with imports (IEA, 2021a).

Focusing on the electricity sector, the differences are starker. In 2019, Japan produced over 70% of its electricity (IEA, 2021a) from fossil fuels, having seen the share of these increase after the 2011 Fukushima nuclear accident. Over the last decade, nuclear has represented between 80% and 85% of the electricity mix in France (IEA, 2021b). In 2019, hydropower was about 60% of the electricity supply in Canada (Government of Canada, 2022). The largest share of wind and solar photovoltaic (PV) among G7 members is in Germany, where almost a third of total electricity generation came from this in 2021 (Burger, 2022). The weighted average electricity CO_2 emissions intensity for G7 members was 45% below the global average in 2020 (273 grammes of CO_2 per kilowatt hour [gCO_2/kWh] vs 506 gCO_2/kWh). France and Canada were already below 70 gCO_2/kWh in 2020, when Japan had the highest emission intensity, with 466 gCO_2/kWh. In May 2022, the G7 committed to achieve predominantly decarbonised electricity sectors by 2035 (G7, 2022).

FIGURE 1.1 Primary energy supply mix (right) and electricity mix (left) by G7 member, 2020

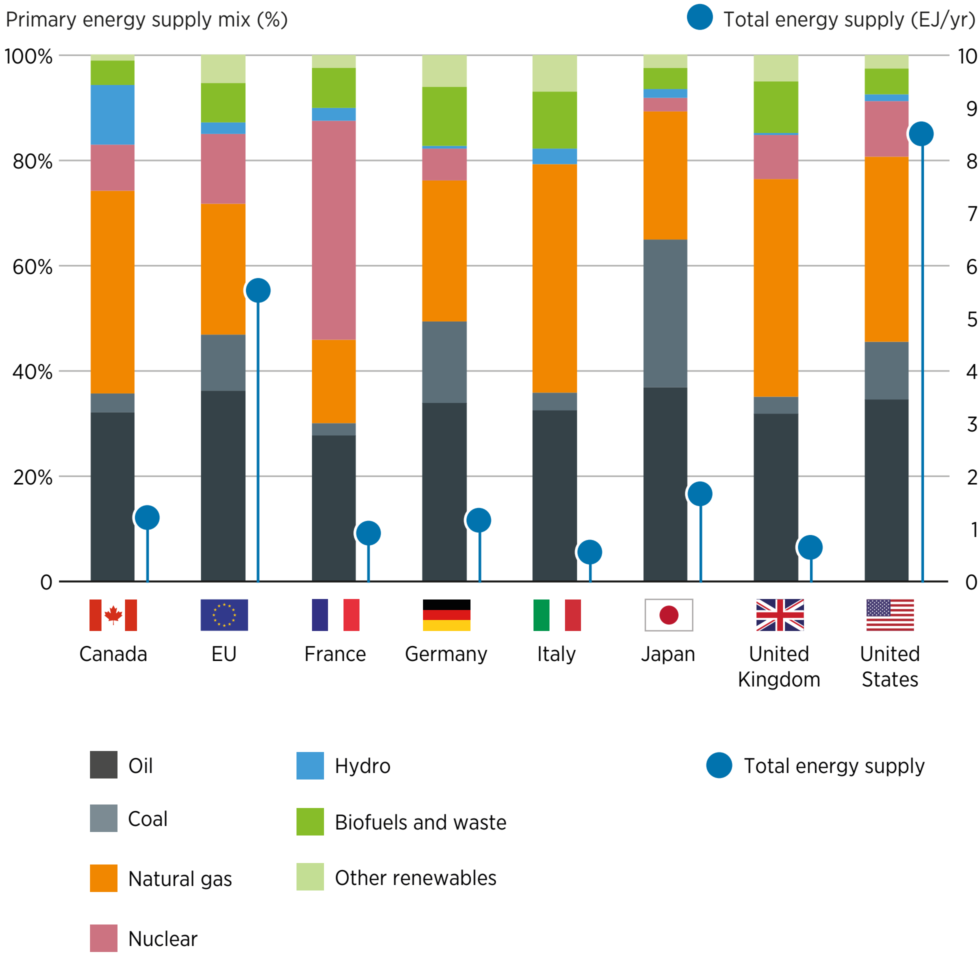
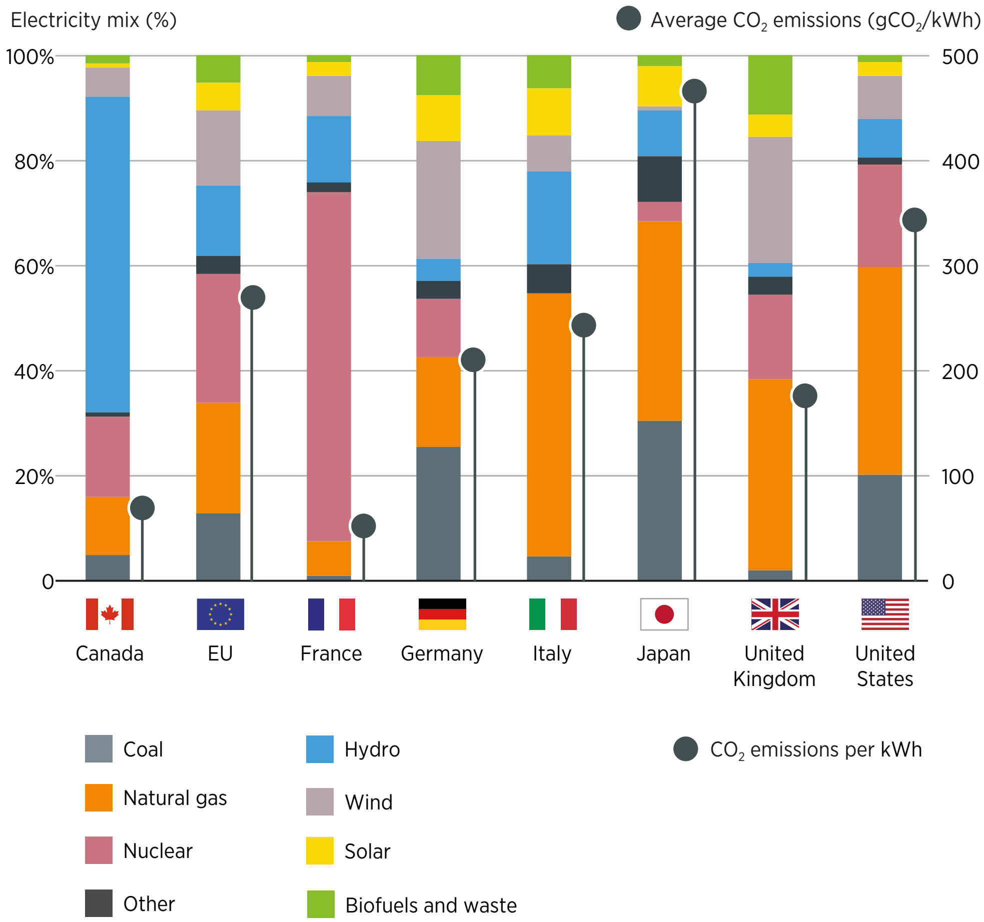


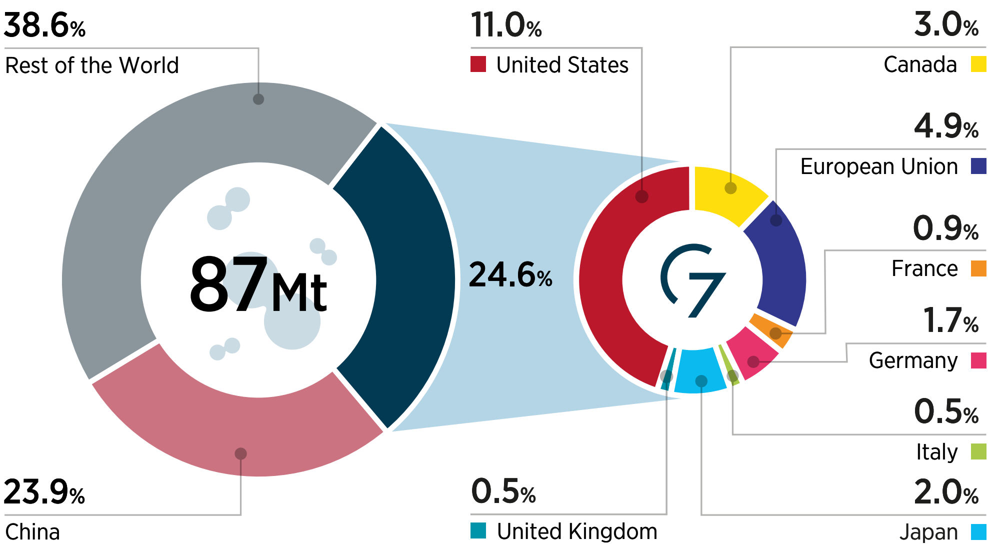
FIGURE 1.1 Primary energy supply mix (right) and electricity mix (left) by G7 member, 2020 (continued)



Hydrogen demand in 2020

The aggregated hydrogen demand for G7 members was about 24.2 million tonnes (Mt) of hydrogen (H_2) in 2020, representing almost 28% of the global demand (see Figure 1.2), just above China's total consumption. The United States (US) is the largest consumer from the G7 group, with 11 MtH_2. The European Union follows closely behind with almost 7.7 MtH_2. Almost two-thirds of this demand is for oil refining, while the majority of the remaining third is for the production of chemicals: ammonia and methanol. While this is the average, specific countries have some more dominant sectors. For instance, 90% of the hydrogen demand in Japan is for refining, while the split is closer to 50/50 in Germany.

FIGURE 1.2 Global hydrogen demand in 2020 and share from G7 members and China (MtH_2)



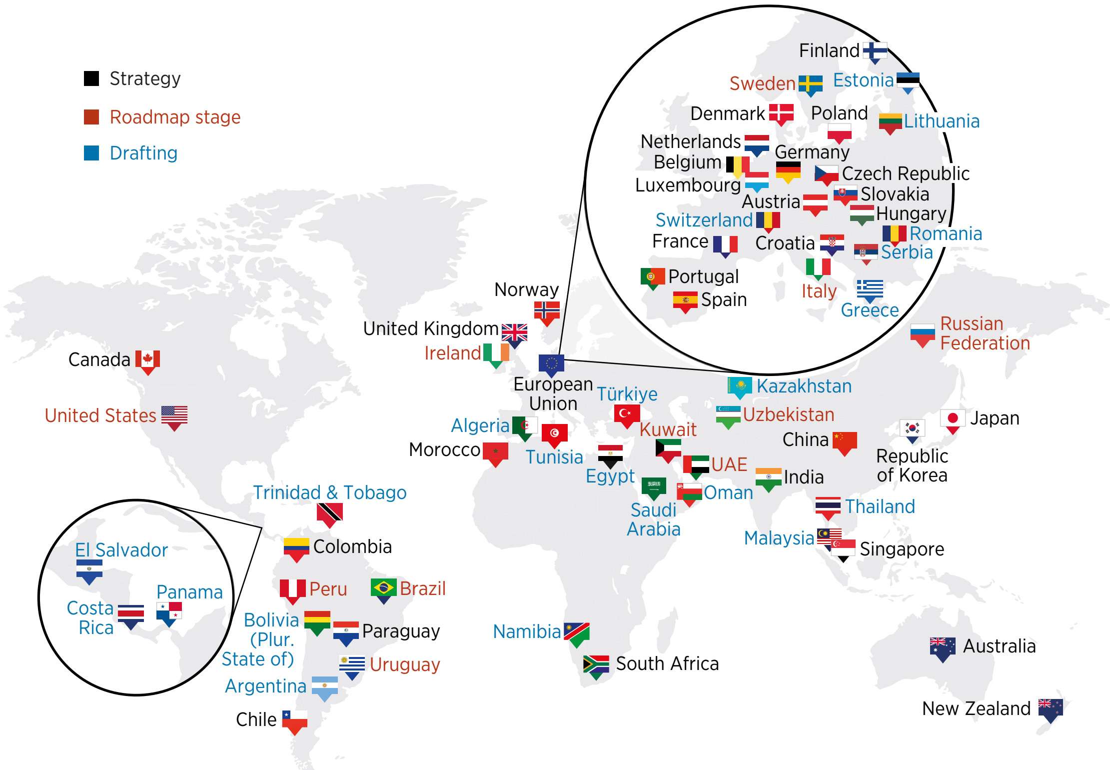
Source: IRENA (2022a).
Note: 'European Union' in this graph excludes demand from France, Germany and Italy.

Hydrogen drivers and 2050 demand

A hydrogen policy or strategy is influenced by the priorities and drivers of the time it was adopted, changing its framing, objectives and political weight. The initial interest in hydrogen solutions before the 2020s was mostly driven by oil price shocks and concerns about peak oil demand or air pollution. As a result, most policies focused on fuel cell electric vehicles (FCEVs) and fuel cell applications with grey hydrogen. More recently, there have been two fundamental trends driving the interest in hydrogen: first, an increased focus on net-zero emissions – by mid-2019, only about 16% of global CO_2 equivalent (CO_2eq) emissions were covered by a net-zero target, but this had increased to almost 83% by mid-2022 (Net Zero Tracker, 2022). Second, the costs of renewable electricity drastically decreased from 2010 to 2021: by 88% for solar PV, 68% for onshore wind and 60% for offshore wind (IRENA, 2022b).

The focus on net-zero has created the need to look at all the energy end uses, including those where there is no clear single technological solution and that are difficult to electrify (including aviation, shipping, steel and chemicals), while renewable electricity cost reduction has led to renewable hydrogen becoming more attractive. This has led to a rapid growth in the number of countries with hydrogen strategies, with more than 60 being developed or under development at the time of writing (see Figure 1.3). The private sector has not remained idle, either, with more than 1 500 hydrogen-related projects being announced, globally, by mid-2022.

FIGURE 1.3 Hydrogen strategies published or under development, July 2022



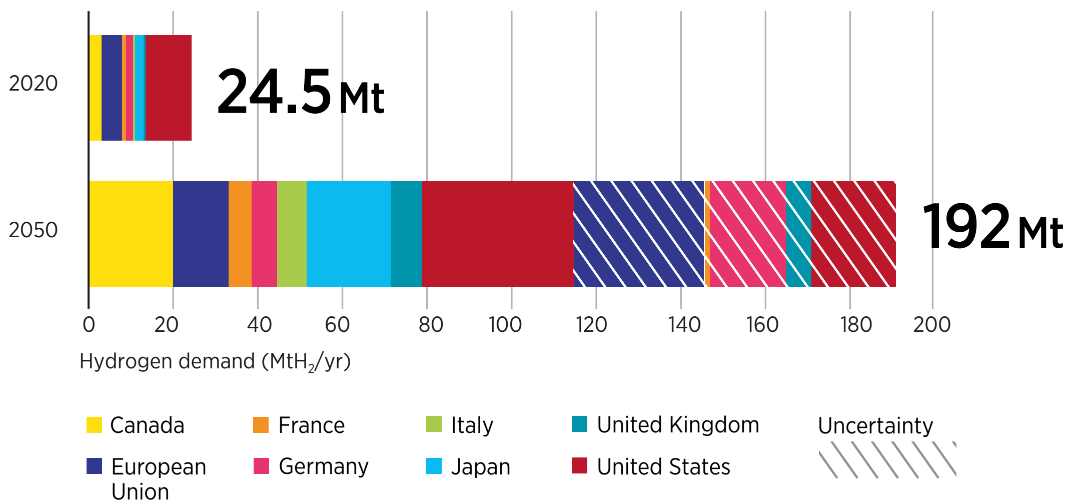
Note: "Strategy" indicates an official final document approved by the government. "Roadmap" indicates the publication of a preliminary document. "Drafting" is for countries for which there is an official announcement that a strategy is being developed.

Hydrogen policies are evolving rapidly. Information on this figure has been kept as detailed and complete as possible at the time of writing, however more countries may have announced, drafted and published hydrogen strategies.

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

In a net-zero emissions system scenario, the role of hydrogen is defined by the assumptions for the competing decarbonisation alternatives (namely renewable energy, electrification, energy efficiency, bioenergy and carbon capture storage and utilisation), the extent to which hydrogen pathways are considered (if all the hydrogen derivatives are included with all the relevant end uses), and hydrogen technology cost evolution. Considering these factors, hydrogen demand in the G7 may increase by four to seven times compared to 2020 to satisfy the needs of a net-zero emissions system by 2050 (see Figure 1.4). Currently, hydrogen use is split mostly across two applications: refining and chemicals. By 2050, the picture is much more diverse thanks to innovation and the need for decarbonisation.

FIGURE 1.4 Hydrogen demand growth to 2050 by G7 member



Based on: Natural Resources Canada, (2020); Guidehouse, (2021); Scheller et al., (2022); ADEME, (2021); European Commission Joint Research Centre, (2019); METI, (2020); Satyapal, (2022); Ruth et al., (2020); BEIS, (2021b).

Note: Hashed pattern denotes uncertainty in hydrogen demand. Hydrogen demand includes production of derivatives, where possible.

Hydrogen production potential and cost in the G7

Countries and regions with high renewable potential or fossil gas reserves can use their resources to become major producers of hydrogen. The ability of G7 members to produce green[1] or blue[2] hydrogen varies widely. Among G7 members, Canada and the United States have the largest fossil gas reserves, together representing 8% of the global total (with 84% of those reserves in the United States). This is enough to produce a cumulative amount of 3 100 MtH_2. With gas prices at pre-2021 levels, blue hydrogen prices could have reached USD 1.00/kgH_2 to USD 1.30/kgH_2.[3]

A main constraint for renewable hydrogen is the renewable electricity production potential, which is limited by the land available to install renewable capacity, the quality of the resource and how densely the facilities can be installed (megawatt [MW]/square kilometre [km^2]). The largest uncertainty is the land availability. The technical potential, as used in this report (see Annex for more details on the methodology), considers the total land of a region and applies several exclusion zones, including protected areas, forests, permanent wetlands, croplands, urban areas, a slope of 5% (for solar PV) and 20% (for onshore wind), population density (excluding areas with a density higher than 130 people per km^2), and water stress. Further technical constraints could be included (*e.g.* distance to existing electricity and gas infrastructure, ports, roads, demand centres). Similarly, socio-political criteria (*e.g.* social acceptance of renewable technologies) could reduce the potential further. These additional criteria were not used since it could lead to a conservative number that might not be representative for some countries. As such, the potential values represent an upper bound with downside potential.

Another constraint for renewable hydrogen is water availability. The water requirement for electrolysis is 18 litres (L) to 24 L per kilogramme of hydrogen (kgH_2) when considering the water treatment losses (Lampert *et al.*, 2016). Furthermore, electricity generation consumes 0.2 L/kgH_2 to 2.1 L/kgH_2 for onshore wind and 2.4 L/kgH_2 to 19 L/kgH_2 for solar PV (Jin *et al.,* 2019). Even when considering the worst case for water supply, desalination, the cost and energy consumption of water treatment is relatively small. The cost would be, at most, around USD 0.05/kg (less than 2% the typical hydrogen cost) and the energy consumption would be on the order of 1% of the electricity used by the electrolyser (Blanco, 2021). Lack of access to water can reduce the amount of land available for renewable hydrogen by more than 50% for Saudi Arabia, the Middle East, North Africa and East Asia (IRENA, 2022b).

For renewable hydrogen, Canada and the United States are the G7 members with the largest potential – 70 and 100 times, respectively, of their expected 2030 demand. This is due to the large land area these countries possess. At the other extreme is Japan, which would be able to produce less than 3% of the hydrogen it needs at a cost lower than USD 2/kgH_2. The rest of the G7 members would be able to produce three to five times what they need by 2030 at

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1 Produced through electrolysis using renewable electricity.

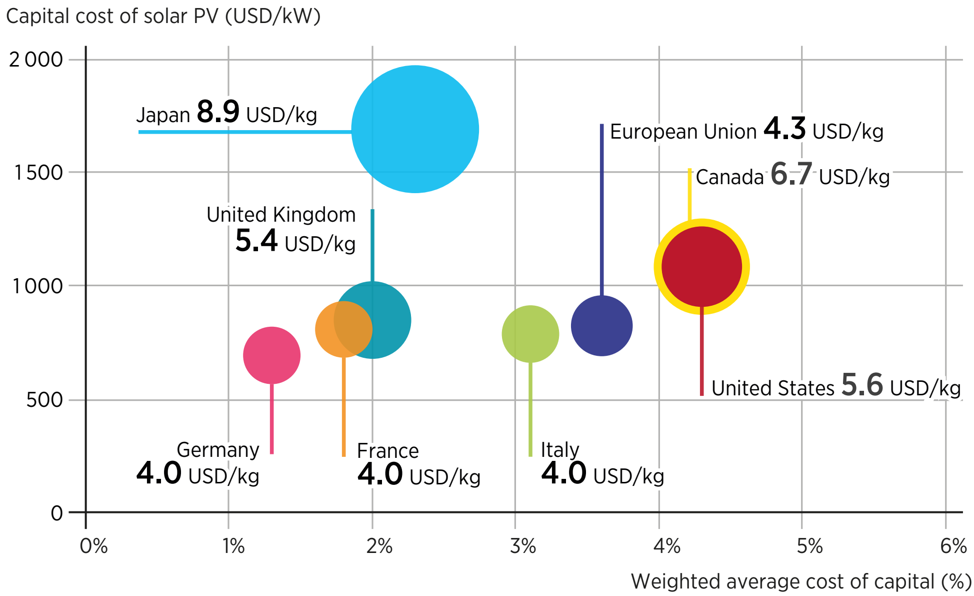
2 Produced through reforming of natural gas combined with carbon capture utilisation and storage.

3 Not all this hydrogen would be available at the same cost because the gas production cost will increase as the resource is exploited.

a cost lower than USD 2/kgH_2, but this would quickly decrease as demand rises towards its 2050 value. An advantage for renewable hydrogen is that the amount of hydrogen that can be produced below a certain threshold will increase over time as technologies become cheaper and the production cost decreases.

Renewable hydrogen does not use any fuel, and all the costs come from physical assets. The cost of electricity is the dominant driver, and it is defined by the capital expenditure (CAPEX) and operating hours of the upstream renewable generation. This makes weighted average cost of capital (WACC) a key parameter defining the hydrogen production cost. In 2020, WACC across G7 members ranged from 1.95% in Germany to more than 8% in parts of the European Union (Croatia) for solar photovoltaic (PV). At the same time, the CAPEX for solar PV differed by a factor of more than two across G7 members, from USD 694/kilowatt (kW) in Germany to more than USD 1 693/kW in Japan (IRENA, 2022b). Based on these factors, the cheapest hydrogen production from solar PV among G7 members is Germany, with USD 4.1/kgH_2 (see Figure 1.5), despite having a relatively low resource quality (full load hours over a year are less than 15% in the best locations) than other members. The combination of low CAPEX and WACC have a larger influence on the cost.

FIGURE 1.5 Estimated hydrogen production cost from solar PV for G7 members in 2021 as a function of CAPEX and WACC



Note: Bubble size represents the levelised cost of hydrogen production in USD/kgH_2. Spain is used for the European Union to show the best case in terms of solar irradiation. Solar PV facility is oversized to optimise hydrogen production cost. Global CAPEX for the electrolyser is assumed to be USD 1 000/ electric kilowatt (kW$_{el}$) and with the same cost ratios between countries as solar PV.

HYDROGEN IN THE G7

The electrolyser needs to operate at least 2 500 to 3 000 hours a year to be able to achieve the largest reduction in the cost contribution from the CAPEX component (IRENA, 2020). When coupled with solar PV, the generation plant needs to be oversized to reach such a number of operating hours, and some electricity will be curtailed. For G7 members, the optimal configurations at their best locations have a PV capacity that is double the one from the electrolyser, curtailing 11% to 18% of the electricity. An alternative to improve the operating hours of the electrolyser is to combine solar PV with onshore wind. The optimal configuration and dominant renewable technology will depend on the quality of the renewable resources and the CAPEX ratio between technologies. Solar PV needs to be at least two to three times cheaper than onshore wind to compensate for the lower operating hours. In 2021, the global average CAPEX for onshore wind was about 1.5 times higher than for solar PV (USD 1 325/kW as opposed to USD 857/kW) (IRENA, 2022b).

Another alternative to improve the operating hours of the electrolyser is to use batteries coupled with solar PV. In 2020, the cost of a 4-hour Li-ion utility-scale battery was about USD 340/kWh (Cole *et al.*, 2021). This is not a cost-effective configuration, but costs could decrease to as low as USD 100/kWh by 2050. Even USD 150/kWh would be enough to halve curtailment and more than double the operating hours of the electrolyser, resulting in up to a 20% reduction in the hydrogen production cost.

There are three levers to reduce the hydrogen production costs, in addition to reducing the cost of renewable electricity. First, economies of scale. For the stack (core of the electrolyser where the electrochemical conversion takes place), costs will decrease as the manufacturing plants are scaled up. This can decrease the cost contribution of fixed costs (*e.g.* labour, utilities, building) and provide opportunities to transition to automated assembly. The largest benefits of increasing manufacturing capacity are already achieved at a capacity of 1 gigawatt (GW)/year. As projects scale up, equipment can be larger, and the design can be standardised. This will mainly have a positive impact on the rest of the equipment not included in the stack (such as vessels, compressors and inverters).

The second lever is learning effects from deployment that are incorporated into the design. This will mainly be for the stack, and estimates range from 11% to 18% cost reduction for every doubling of global deployment. The third lever is that innovations can improve the performance of the electrolyser by increasing efficiency, reducing the cost contribution of the electricity, and increasing the output per electrolyser along with a reduced use of materials.

Industrial leadership and patents

The strategies account for the potential benefit that hydrogen deployment can provide to domestic industry in terms of economic growth and job creation, while placing an emphasis on areas where a country can develop technological leadership.

Of the G7 members, the European Union as a whole and Germany in particular aim to become technology (electrolysers) exporters, building on their industrial development. By the end of 2021, roughly half of all electrolyser manufacturers were located in Europe[4] and their component suppliers were mostly European (IRENA and European Patent Office, 2022; Suurs *et al.*, 2020). By 2024, Europe, the Middle East and Africa are projected to account for about 20% of electrolyser manufacturing capacity, based on announced investment plans (BNEF, 2022). Fuel cell manufacturing, for both stationary and transport applications, is led by Asian countries, which account for more than half of the global market, followed by North America. China, Germany, Japan, the Republic of Korea and the United States account for 89% of all patents for fuel cells for vehicles.

About 65 000 inventions[5] for hydrogen were filed globally between 2010 and 2020.[6] G7 members accounted for around 50% of these inventions, with about two-thirds coming from Japan (Figure 1.6). China has been accelerating patent activity, and while it represented less than 12% of patents in 2010, it reached almost 30% of the cumulative inventions by 2020.

The outlook is different when considering high-value inventions[7] (top of Figure 1.6). Of the total inventions regarding hydrogen, 24% are of high value, and G7 members account for about 80% of the total. As much as 38% of high-value inventions related to hydrogen storage have been developed by European Union countries, with Germany alone accounting for 20% of the total. Concerning the other hydrogen-related technologies, the United States covers 31% of the total inventions in hydrogen distribution, while Japan ranks first on fuel cells, with 39% of the total (bottom of Figure 1.6).

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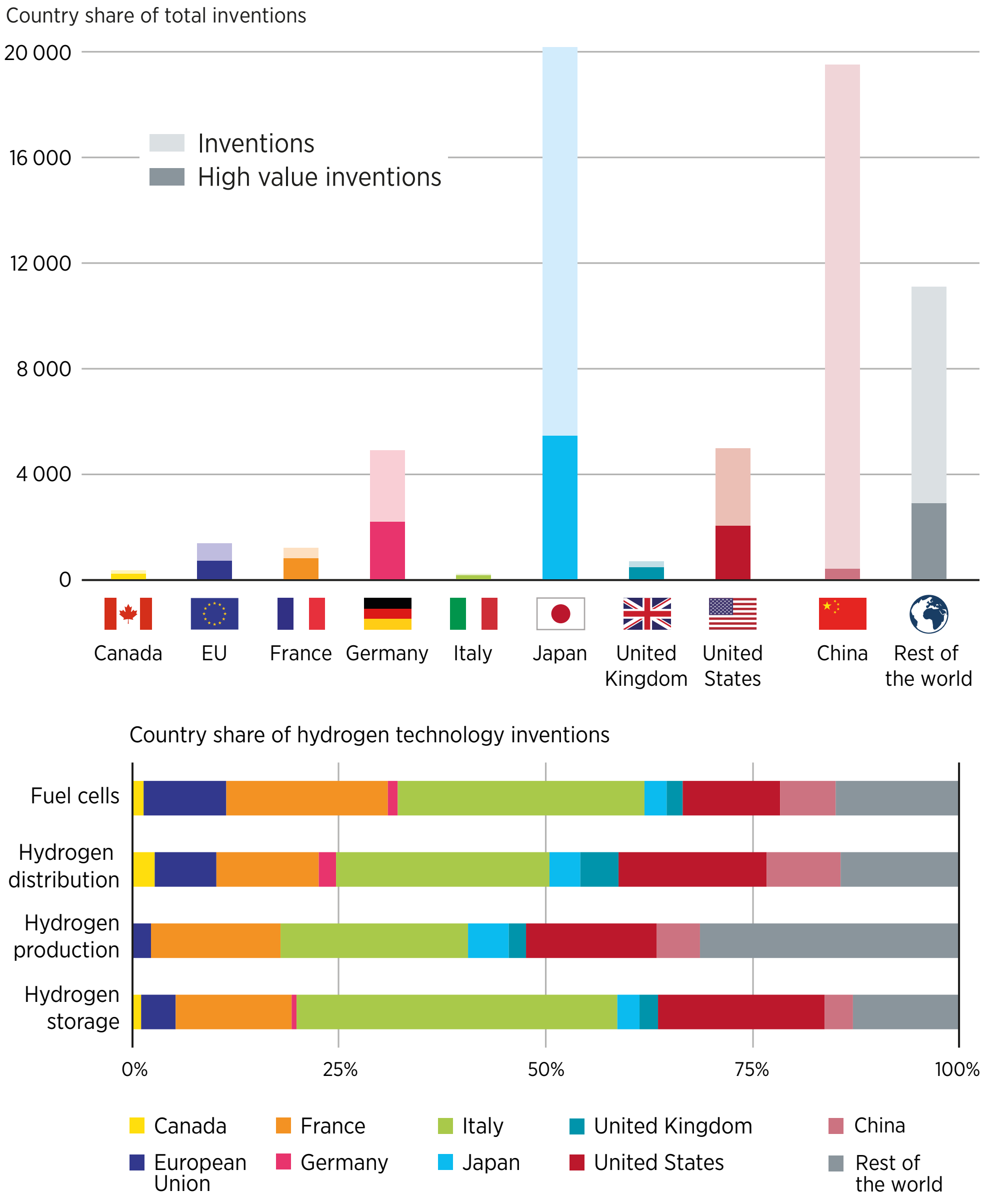
[4] *Including Norway, which is neither a G7 member nor part of the European Union.*

[5] *Patent family is used to proxy an invention. A patent family groups together patent applications that protect the same invention. A dashboard with interactive graphs can be accessed online (IRENA INSPIRE webtool, n.d.).*

[6] *Patent data for 2020 are not complete because of confidentiality in the early stage of the patenting process.*

[7] *A high-value invention is an invention protected in more than one patent office. An equal share is assigned to applicants and patent offices in the patent family.*

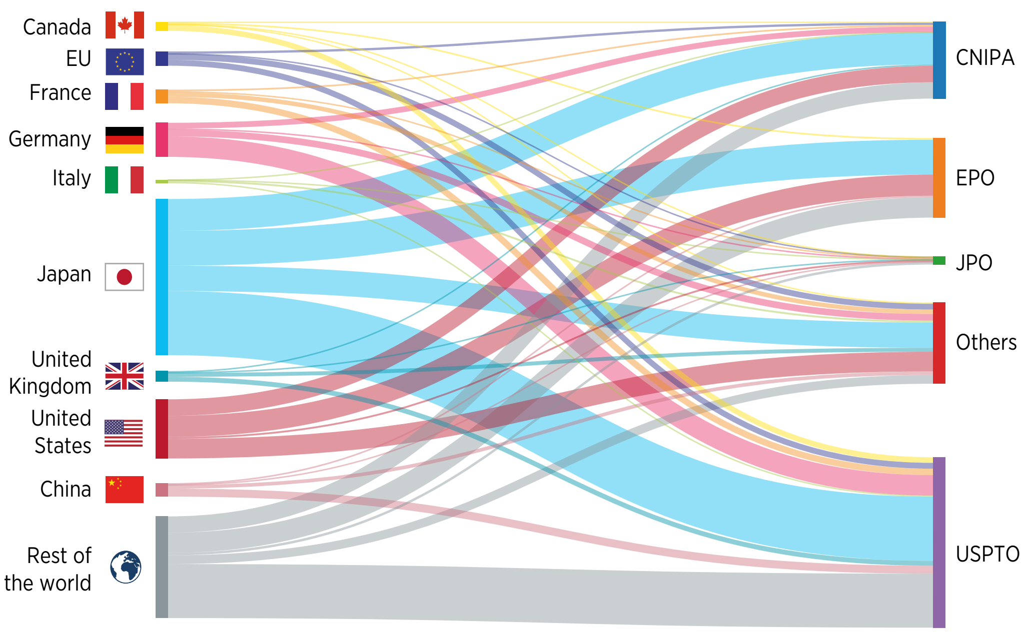
FIGURE 1.6 Share of G7 members' high-value inventions over the total inventions (top) and countries' high-value invention share in hydrogen technologies (bottom)



Note: Hydrogen technology is defined by means of the Cooperative Patent Classification (CPC): Y02E60/34 Distribution, Y02E60/50 Fuel cells, Y02E60/36 Production and Y02E60/32 Storage.

Looking at international inventions,[8] from 2010 to 2020, about 73% of these were filed by G7 members (left side of Figure 1.7). The drastic difference in the total number of inventions is due to only 2% of the Chinese inventions being protected internationally, representing just 3% of the global total. Looking at where these inventions are protected (right side of Figure 1.7), almost two-thirds are protected in three G7 members' patent offices: the United States Patent and Trademark Office (USPTO), the European Patent Office (EPO) and the Japan Patent Office (JPO). The China National Intellectual Property Administration (CNIPA) is the main non-G7 national patent office, with 18% of international inventions.

FIGURE 1.7 Estimated hydrogen production cost from solar PV for G7 members in 2021 as a function of CAPEX and WACC

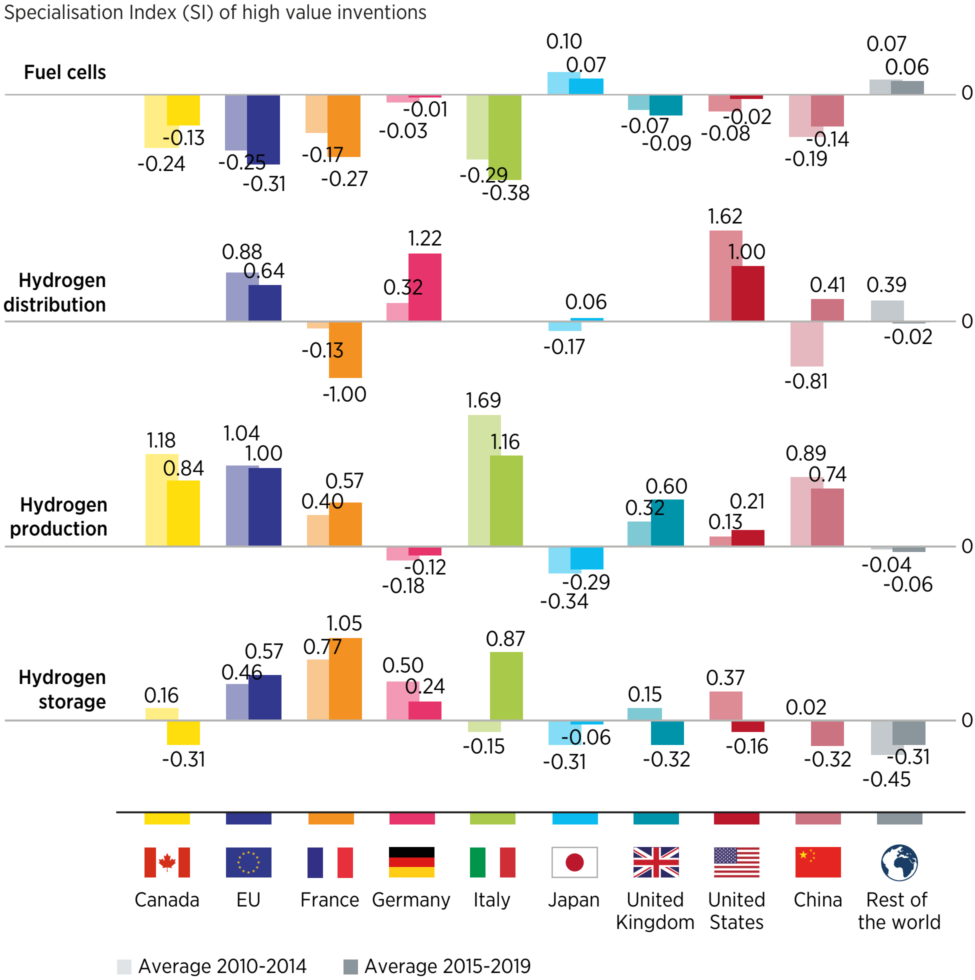


Note: The countries on the left are where inventions are developed. The national/regional patent offices where inventions are protected are on the right: the United States Patent and Trademark Office (USPTO), the European Patent Office (EPO), the Japan Patent Office (JPO) and the China National Intellectual Property Administration (CNIPA).

[8] *International inventions are inventions protected in a country different from the country where the inventions are developed.*

Looking at the specialisation index[9] for hydrogen technologies (see Figure 1.8), Japan had a positive index in fuel cells, while the countries of the European Union had positive indices in hydrogen distribution, production and storage, meaning that the focus on these areas was higher in these countries than the global average. The United States had the highest index in hydrogen distribution, while China shows a positive index on hydrogen production only.

FIGURE 1.8 Specialisation index for hydrogen technology areas, comparing average values in the periods 2010-2014 and 2015-2019



[9] *The Specialisation Index represents patenting intensity in technology for a given country compared to the global activity. It is calculated as (i) the county's share of inventions related to a hydrogen technology over the total hydrogen inventions over (ii) the global share of inventions related to the same hydrogen technology over the total hydrogen inventions.*

Carbon pricing

Hydrogen is currently used in industrial applications, and this sector will represent major demand going forward (including new applications such as steel). Carbon pricing can be a fundamental incentive for the transition of these industrial assets to low-carbon production. At the same time, industry (together with power) is one of the sectors with the widest coverage across emissions trading schemes (ETS). In 2021, there were 68 carbon pricing instruments (36 carbon taxes and 32 ETS) covering 23% of global greenhouse gas (GHG) emissions, generating about USD 84 billion of revenue (World Bank, 2022a).

All G7 members have some form of carbon pricing implemented (see Figure 1.9). Canada has a federal backstop that serves as the standard for provinces and territories that do not have a carbon price in place. It has two components, a charge on fuels (based on carbon content) and an output-based pricing system for emissions-intensive and trade-exposed industrial facilities larger than 50 kilotonnes (kt) of CO_2eq per year. The price for 2022 is CAD 50/tonne (t) of CO_2 (USD 36/tCO_2) , increasing CAD 15 (USD 10.85) per year until it reaches CAD 170.00/tCO_2 (USD 123/tCO_2) in 2030. Japan implemented a carbon tax in 2012 covering the emissions from combustion of all fuels. Considering exemptions, it still provides the widest GHG coverage among G7 members, covering 75% of national emissions. At the same time, the price level is the lowest among G7 members at around USD 2/tCO_2 in 2022. Germany introduced a national ETS for heating and transport (except for aviation) in 2021 covering the bulk of emissions not covered under the EU ETS (Wettengel, 2019). The price rises from EUR 25.00/tCO_2 (USD 24.35/tCO_2) in 2021 to EUR 55.00/tCO_2 (USD 53.75/tCO_2) in 2025, a period after which there will be auctions with a price corridor (Wettengel, 2019). In France, carbon tax is part of domestic tariffs for energy consumption of all fossil fuels. The tax was introduced in 2014 with a set annual increase of EUR 10.00/tCO_2 (USD 3.74/tCO_2), but the increases were suspended in 2019, leading to a level of EUR 45.00/tCO_2 (USD 43.8/tCO_2) by mid-2022. Italy has the EU ETS without an additional domestic carbon price. The United States has several regional and state-level carbon pricing state initiatives, but there is no such regulation at the federal level.

The EU ETS was introduced in 2005 and is the largest carbon market in the world, representing 41% (USD 34 billion) of the global carbon pricing revenues of USD 84 billion in 2021 (World Bank, 2022a). It covers power and heat generation, energy-intensive industries, and aviation,[10] which represent about 40% of regional GHG emissions (World Bank, 2022b). The EU ETS is not limited to the EU, as it also includes Iceland, Liechtenstein and Norway. From its introduction until 2020, emissions fell by 43%. In July 2021, as part of the Fit for 55 package, proposals were made to expand the EU ETS to cover road transport and buildings.

The United Kingdom has had some form of carbon pricing for 20 years. The current ETS was introduced in 2021 to replace the United Kingdom's participation in the EU ETS. The initial UK ETS cap was set 5% lower than its national share of the EU ETS cap (giving a cap of 156 MtCO_2 in 2021).

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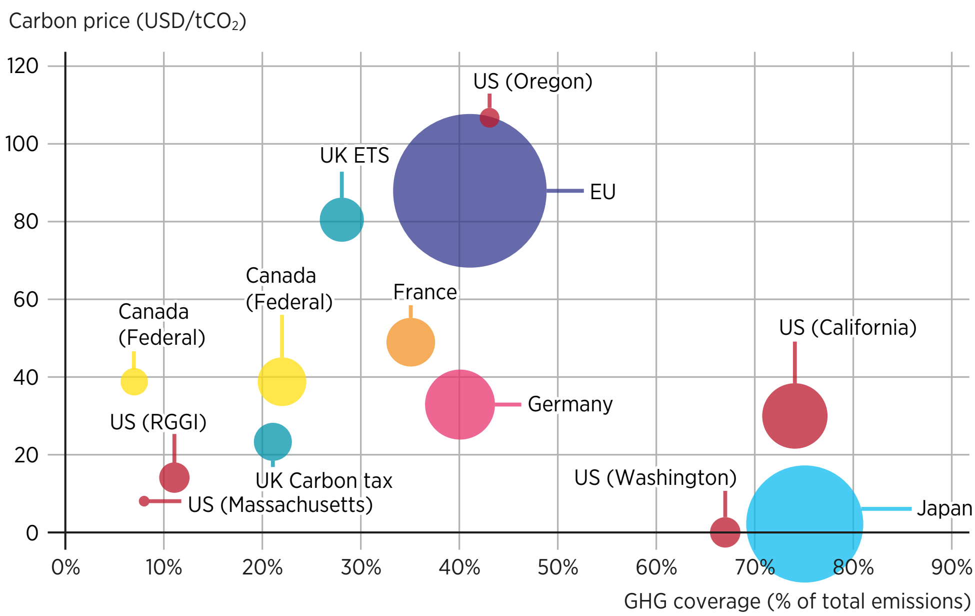
[10] Flights within the European Union, Iceland, Liechtenstein, Norway, Switzerland, and the United Kingdom.

However, the intention has always been to reset this cap to be consistent with a net-zero trajectory as soon as possible, and the UK government proposed in its 2022 consultation that this would be done in 2024. The ETS has a floor price of GBP (United Kingdom pounds) 22/tCO_2 (USD 25/tCO_2) known as the auction reserve price and a cost containment mechanism[11] aimed at improving price stability. In addition to the ETS, the United Kingdom also has a carbon price support which taxes fossil fuels used specifically for power generation and is aimed at reducing the emissions from the United Kingdom's electricity supply by improving the financial viability of renewable generation compared to coal-fired power.

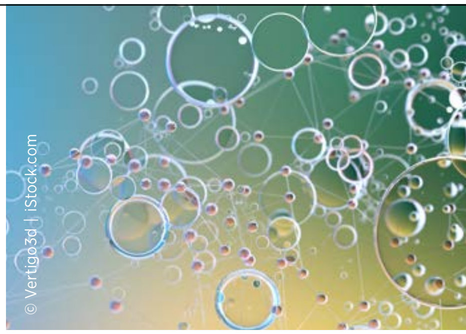
FIGURE 1.9 Carbon pricing level, coverage, and total emissions across G7 members



Source: World Bank (2022b).

Note: Bubble size represents the total GHG emissions covered by each scheme. Canada has two schemes at a federal level: a backstop carbon tax and an output-based pricing system.

[11] *It is triggered when the average allowance price is double the average price of the preceding two-year period for more than three consecutive months. Some potential actions in response include releasing additional allowances (e.g. from the market reserve) or changing the distribution of allowances to be auctioned.*



The total carbon revenues estimated for G7 members for 2022 are in the order of USD 64 billion (World Bank, 2022b). Over half of this amount comes from the EU ETS, followed by France (13%), Germany (12%) and the United Kingdom (10%). For the EU countries, at least half of the revenues must be used for climate and energy-related purposes. From 2013 to 2019, 78% of the revenues were used for that purpose (European Commission, 2020). Some of the mechanisms introduced for Phase 4 of the ETS (2021-2030) are the Innovation Fund and the Modernisation Fund. In Germany, all the income from carbon pricing goes to the Energy and Climate Fund, which promotes climate protection measures. From 2016 to 2020, about half of the budget was used for building retrofits, followed by compensation for electricity-intensive companies for electricity price increases due to emissions trading (10% to 15%) and electromobility (6% to 12%) (Haase *et al.*, Velten, Branner and Reyneri, 2022: 25). Part of the funds were used to reduce the EEG surcharge used to finance the expansion of renewables in 2021 (Umweltbundesamt, 2022). France spent about 100% of its ETS revenues from 2013 to 2017 on climate action, mainly through a building retrofitting programme. After 2018, the established cap of EUR 550 (USD 536) million[12] was reached, and the surplus was allocated to the national budget. For Italy, 36% of the ETS revenues were used for climate action over the 2013 to 2020 period (fluctuating between 0% in 2013 to a 70% peak in 2017) (Haase *et al.*, 2022).

[12] *For 2019 and 2020, the cap was reduced to EUR 420 million, increasing the share of revenues allocated to the state budget to 42%.*

Technical standards and certification schemes landscape

There are two types of standards: technical standards that refer to the design, manufacturing, operation, safety and testing of equipment; and standards related to the environmental impact and emissions from hydrogen production, transport and use. Most of the historical focus has been on technical standards, while emissions standards have been a more recent trend over the past few years, apart from in the European Union.

Technical standards

Over 120 technical standards had been developed up to 2021: 64% of them focused on hydrogen use and 40% were associated with the transport sector. Over 95% of standardisation work is conducted through three organisations: the International Standard Organisation (ISO), the International Electrotechnical Commission (IEC) and the European Committee for Standardisation (CEN) (IRENA, 2022c). Gaps have been identified and pre-normative research has to be conducted to inform the further development of these standards (IPHE, 2021a).

As hydrogen and its derivatives are used in new applications and on a larger scale, new standards will need to be developed. These will have to cover design, operation and safety in the use of hydrogen and its derivatives across new applications in the maritime and aviation sectors, as well as in steel production. Close collaboration is needed between bodies with hydrogen knowledge and standard-setting bodies in these sectors, such as the International Maritime Organisation (IMO) and the International Civil Aviation Organisation (ICAO).

There is currently a lack of widely accepted direct measurement at low detection thresholds for hydrogen leakage at each step along the value chain; initial estimates are based on fossil gas leakage rates extrapolated to hydrogen, based on compound properties. This leads to a high level of uncertainty, which requires further research. Hydrogen has a short-lived warming effect (10 to 20 years) that is not fully captured in the standard 100-year time horizon used for global warming potential (GWP100) (Ocko and Hamburg, 2022). Recent estimates indicate that hydrogen could have a GWP100 of 11 +/- 5 and GWP20 of 33 (Warwick *et al.*, 2022).

Certification schemes and standards

Certification is essential to enable differentiation of product characteristics, such as hydrogen or ammonia or other fuels made from renewable energy. There are two distinct categories of certification: objective (related to methodologies to quantify emissions) and subjective (related to specific criteria that define if a product or activity is sustainable).

For an objective scheme to be effective, certification schemes must have the same meaning across jurisdictions. Commonly agreed methodologies between the certification schemes need to be identified to measure the emissions of hydrogen production, transport and end use. This includes specifying where the boundaries lie for emissions quantification, allocation methods for co-products, spatial and temporal resolution of the measurements, product specifications, conversion factors, emission factors from energy supply, fugitive emissions, and other conditions and values. Achieving consistency ensures that there are no unaccounted-for emissions and that there is a common understanding of the emissions inherent in the certification during transfer of custody of the certificate. Efforts in this direction are ongoing by the international level (IRENA, forthcoming). A leading example is the methodology from the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) that focuses on production pathways (IPHE, 2021b). This is being followed up in 2022 by a similar methodology for the transportation step.

Alternative, subjective certification schemes are related to the specific criteria needed to define if a product or activity is sustainable. These could also be used to discover if certain hydrogen activities will be supported. These schemes can include thresholds for GHG emissions (varying over time), additionality of renewable energy used for electrolysis, and spatial and temporal correlation between electricity and hydrogen production.

Hydrogen itself cannot convey information on how it was produced or its carbon footprint. Therefore, certification is crucial for transparency and to promote the consumption of low-carbon hydrogen and products. Transparency of information is also crucial for cross-border trading: standardisation of the certification schemes can therefore support the development of hydrogen trading and accelerate the emergence and establishment of an international market.

Figure 1.10 below shows the different initiatives (voluntary and mandatory) that have been introduced, or are under development, for hydrogen certification.

FIGURE 1.10 Hydrogen certification market initiatives

VOLUNTARY MARKET

- **Aichi Prefecture**
  Low Carbon Hydrogen Certification
- **Australian Government***
  Hydrogen Guarantee or Origin
- **CertifHy**
  Green and Low-Carbon Hydrogen Certification
- **CEN-CENELEC***
  Joint Technical Committee 6
- **China Hydrogen Alliance**
  Standard and Assessment for Low Carbon Hydrogen, Clean Hydrogen, and Renewable Hydrogen Energy
- **Green Hydrogen Organisation**
  GH2 Standard
- **Smart Energy Council**
  Zero Carbon Certification
- **TÜV SÜD**
  CMS 70

MANDATORY MARKET

- **California Air Resources Board**
  Low Carbon Fuel Standard
- **European Commission***
  Renewable Energy Directive (RED II)
- **UK Department for Business, Energy, and Industrial Strategy**
  Low Carbon Hydrogen Standard
- **UK Department of Transport**
  Renewable Transport Fuel Obligation
- **US Department of Energy***
  Clean Hydrogen Production Standard

*in development

Source: IRENA (forthcoming).

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By August 2022, three standards had been drafted by countries to define what type of hydrogen could receive state support. The UK Department for Business, Energy and Industrial Strategy (BEIS) Low Carbon Hydrogen Standard, for example, defines 'low-carbon' hydrogen as that where GHG emissions up to the point of production were less than 2.4 kg of CO_2/kg of H_2. If hydrogen is used for transport, in order to receive support, it must comply with the UK Renewable Transport Fuel Obligation, which differentiates fuels based on the feedstock and, in the case of non-biological fuels, based on the origin of the electricity used. Both the European Union and the United States are developing their own standards. In addition, California has in place a Low Carbon Fuel Standard which also promotes the use of hydrogen to reduce the emissions in the transport sector.

Voluntary schemes are certification schemes adopted by industry to prove the sustainability of their products. By August 2022, four voluntary schemes had been developed for hydrogen, with a fifth in pilot phase (see Table 1.1). These schemes are being developed within the G7 jurisdictions (European Union and Japan) and beyond (Australia and China).

Although some voluntary schemes and their standards have been developed using the same or similar methodologies, there are several significant differences. Several of the schemes have not set an emissions threshold, but limit their scope in assessing the hydrogen footprint. For those voluntary schemes with a threshold, the same ranges vary widely (between 1 $kgCO_2/kgH_2$ and 4.9 $kgCO_2/kgH_2$ for green hydrogen pathways). Another difference among voluntary schemes is the boundary setting (meaning the end point where total emissions are accounted for). Only two schemes include emissions up to the point of consumption. Differences also exist in the validation process for renewable energy use, requirement for renewable energy additionality and chain of custody models.

A voluntary scheme, by its nature, is not bound to comply with national standards or used to determine if the hydrogen commodity can receive state support. Instead, collaboration between governments and private stakeholders can make hydrogen certification (currently voluntary) align with national standards and become suitable for cross-border trading.

TABLE 1.1 Comparison of voluntary mechanisms for hydrogen certification

Title	Label	Emissions threshold (kg CO_2eq/ kg H_2)	Boundary	Power supply requirement for electrolysis	Hydrogen production pathway	Chain of custody (CoC) model
Australia **Smart Energy Council** Zero Carbon, Certification Scheme	**Renewable H_2**	No threshold				Unclear
China **China Hydrogen Alliance** Standard and Assessment for Low-carbon Hydrogen, Clean Hydrogen, and Renewable Hydrogen Energy	**Renewable H_2**	4.9				Not specified
	Clean H_2	4.9				Not specified
	Low-carbon H_2	14.5		not applicable		Not specified
European Union **CertifHy** Green and Low-Carbon Hydrogen Certification	**Green H_2**	4.4				B&C
	Low-carbon H_2	4.4				B&C
Germany **TÜV SÜD** CMS 70	**Green H_2** (non-transport)	2.7				B&C
	Green H_2 (transport)	2.8				Mass
Japan **Aichi Prefecture** Low-carbon Hydrogen Certification	**Low-carbon H_2**	No threshold				B&C
International **Green Hydrogen Organisation** Green Hydrogen Standard	**Green H_2**	1.0				Not specified

Boundary

Includes upstream methane | To point of production | To point of use

Power supply requirements

GO + additionality | GO required | No GO/ additionality specified

Solar, wind or hydro | Nuclear | Grid (or unspecified)

Hydrogen production pathway specified

Electrolysis | Fossil SMR/ ATR with carbon capture | Biogas SMR

Source: IRENA (forthcoming).

Classified in the mandatory markets are schemes which provide a regulatory basis for classifying hydrogen. These schemes set a benchmark which hydrogen production must follow in order to get government support through credits or subsidies. The challenge with classifying these schemes is that while some are industry operated, others may have explicit government support. It can also be the case that while some schemes are government operated, the standards they produce are not mandatory.

TABLE 1.2 Comparison of mandatory mechanisms for hydrogen certification

Country/ region	Title	Boundary and scope (sector)	Emissions threshold (kg CO_2eq/ kg H_2)	Power supply requirement for electrolysis	Hydrogen production pathway	Regulatory mechanism	Status of regulatory mechanism
	Government of the United Kingdom UK Hydrogen Strategy	Energy	2.4			**BEIS** UK Low Carbon Hydrogen Standard	To be implemented in 2022 Certification scheme **to be developed by 2025**
		Transport	3.9			**UK Dept. for Transport** Renewable Transport Fuel Obligation (RTFO)	**Active**
proposed	**European Commission** A hydrogen strategy for a climate-neutral Europe	Transport	3.4			**European Commission** RED II	**Active** New Delegated Act of RED II proposed in May 2022
		Boundary not specified	3.0			**European Commission** EU Taxonomy	**Active**
proposed	Framework only (Hydrogen Strategy: Enabling A Low-Carbon Economy). **US Department of Energy** National Clean Hydrogen Strategy and Roadmap in development	Transport, Energy	2.0			**US Department of Energy** H_2Hub draft (may be adopted by standard for clean H_2 production)	Draft guidance released; **Still in development**
		Transport	No threshold (Certificate issued based on reduction from annual target)			**California Air Resources Board** Low Carbon Fuel Standard (LCFS) - California only	**Active**

Boundary

Includes upstream methane — To point of production — To point of use

Power supply requirements

GO + additionality — GO required — No GO/ additionality specified

Solar, wind or hydro — Nuclear — Grid (or unspecified)

Hydrogen production pathway specified

Electrolysis — Fossil SMR/ ATR with carbon capture — Biogas SMR

Source: IRENA (forthcoming).

The existing schemes, their commonalities, differences and actions for the short term are explored in more detail in a parallel report to this one (IRENA, forthcoming).

1.3 COUNTRY-SPECIFIC FACTSHEETS

HYDROGEN SECTOR STATUS

Status of hydrogen sector and renewables

In 2020, Canada produced around 3 MtH_2. About 80% of this was produced from fossil gas reforming, with the balance coming from refineries (as a by-product). Hydrogen use was almost equally split between refining and chemicals (IEA, 2022b). The specific CO_2 emissions from electricity production were already low (69 gCO_2/kWh) (Climate Transparency, 2021a) with 60% of the electricity produced from hydropower and 14% from nuclear (IRENASTAT, n.d). Variable renewables were relatively limited, with 14.3 GW of onshore wind and 3.6 GW of solar PV by the end of 2021 (IRENA, 2022d) contributing about 6% of the generation mix.

Outlook for hydrogen in 2050

Canada is committed to achieving by 2030 40% to 45% less GHG emissions than in 2005 and reaching net-zero by 2050. According to the Canada Energy Regulator, by 2050, domestic hydrogen demand is expected to have grown by at least an additional 4.7 MtH_2, including 65% consumed in the industrial sector (steel, oil sands, chemicals, fertilisers), 25% in transport (long distance freight trucking and maritime), and 10% in the residential and commercial sectors (through blending for space and water heating). On the production side, fossil gas with carbon capture and storage (CCS) makes up 57% of the supply, complemented by 33% of off-grid electrolysis and 9% on-grid. Net capacity additions of wind and solar PV are between 100 GW and 150 GW, across the different scenarios (Canada Energy Regulator, 2021).

Low-carbon hydrogen production projects

In terms of low-carbon routes, a 20 MW polymer electrolyte membrane (PEM) electrolyser started operation in 2021 in Quebec using hydropower to produce hydrogen for existing industrial applications. There are also four operating projects with fossil gas reforming with CCS. These have a cumulative capacity of about 220 ktH_2/year capturing about 3 MtCO_2/year. Among the planned projects, an 88 MW electrolyser in Quebec will produce 11.1 ktH_2/year for a biofuel plant with expected commissioning by the end of 2023. A 20 MW electrolyser in Ontario has been proposed. The hydrogen will be used for industrial applications and power generation. A final investment decision will be taken in late 2022, subject to federal funding, with a starting date in 2024. Regarding low-carbon hydrogen, Air Products, together with the government, have announced a CAD 1.3 billion (USD 1 billion) project in Alberta that will capture 95% of the CO_2 from a fossil gas reforming facility. Hydrogen will be used for existing refineries and petrochemical plants and as liquid hydrogen for road transport. The plant is planned to come onstream by 2024 (Air Products, 2021).

Other projects and companies include:

- **TEAL**, a Quebec-based company aiming to produce green ammonia via electrolysis, which has signed an exclusive off-take agreement for green ammonia with Trammo, an international merchandising and trading company and market leader in ammonia.
- **EverWind Fuels**, which plans to develop a regional hydrogen hub in Point Tupper, Nova Scotia. The infrastructure will be expanded to include renewable hydrogen and ammonia production, with ample space available for onshore and offshore wind.
- A 0.5 GW renewable hydrogen (from wind) project in Newfoundland to export 0.7 Mt/year to 0.9 Mt/year of ammonia. The project would initially comprise 164 turbines with a long-term potential of triple this size. It is awaiting environmental assessment approval (as of September 2022) and would start operation by 2024.

Existing and planned infrastructure

Canada has almost 150 kilometres (km) of hydrogen pipelines (80% in Alberta) (Adelphi, 2022). It does not have any large ammonia ports today, but there are federal commitments to develop five hydrogen hubs in the next five years. Provincial hydrogen valleys will provide a new focus on zero-carbon energy exports (including ammonia) in British Columbia (West Coast). Canada has two small methanol terminals in Quebec and Vancouver. Canada has had hydrogen liquefaction plants since the 1980s, and it has a cumulative liquefaction capacity of almost 80 tonnes per day (t/d) across five plants. There is a 30 t/d liquid hydrogen plant scheduled to start operation in 2024 in Alberta which will use the hydrogen for road transport.

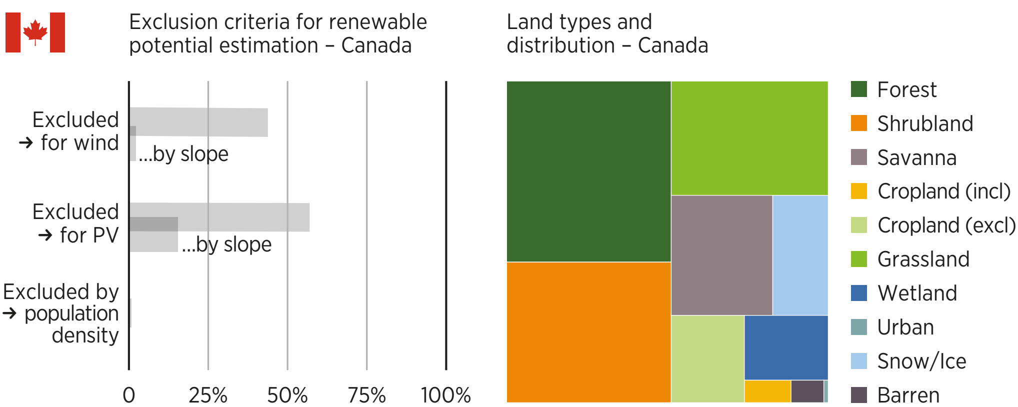
Estimated renewable hydrogen cost in 2021

The capital costs for solar PV and onshore wind were USD 1137/kW and USD 1042/kW, respectively, in 2021 (Canada Energy Regulator, 2021). The WACCs (real after tax) for utility-scale solar PV and onshore were 4.3% and 3%, respectively (IRENA, 2022d). Assuming the same capital cost ratio (as opposed to the global average) for the electrolyser, the estimated levelised cost of hydrogen was USD 6.40 kgH_2 to USD 12.70/kgH_2 for solar PV and USD 3.50 kgH_2 to USD 4.80/kgH_2 for onshore wind. Up to the end of 2021, there had been no deployment of offshore wind in Canada. The lowest total delivered export hydrogen costs in Canada are from onshore wind via electrolysis and fossil gas-derived hydrogen via gas reforming with CCS.

Renewable hydrogen supply in 2030

In terms of potential, 29% of Canada's land is covered by forests and considered to be excluded for solar PV and wind installation. About 15% of the land has a slope unsuitable for solar PV and 2% has a slope unsuitable for wind, while the population density criterion (130 people per km^2) leads to the exclusion of 0.5% of the land. This still leaves roughly 43.5% and 56.5% of the land available for solar PV and onshore wind (see Figure 1.11). This would be enough to produce almost 1 860 MtH_2/year (technical potential).

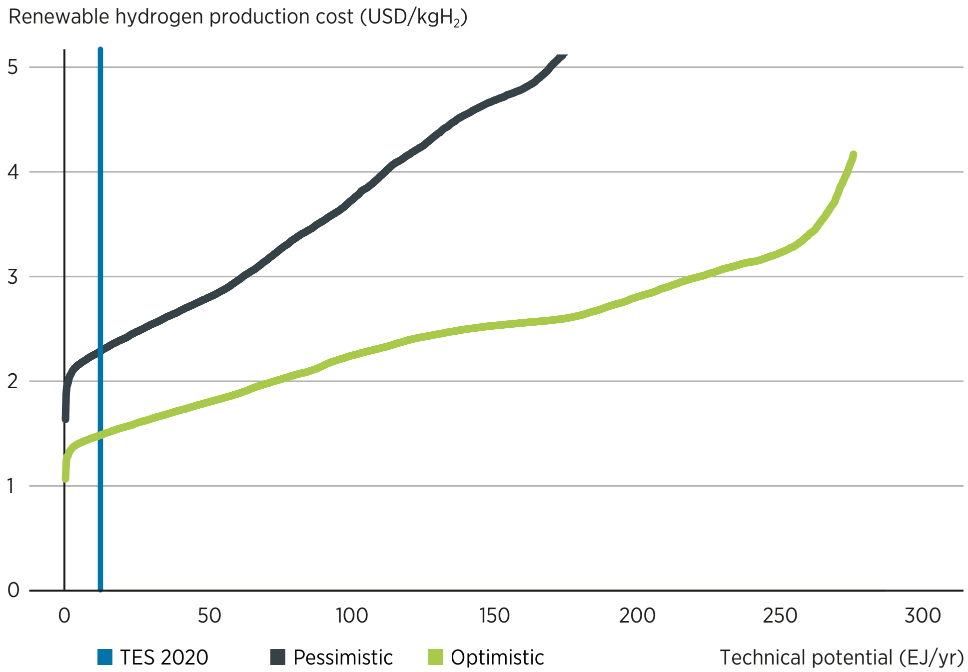
FIGURE 1.11 Land types and exclusion criteria for renewable potential estimation in Canada



Source: IRENA (2022e).

By 2030, capital costs could come down by 60% for solar PV and by 30% for both onshore wind and electrolysis in a scenario aligned with a 1.5°C trajectory (IRENA, 2022f). Considering these costs, the economic potential below USD 2.00/kgH_2 would be 7.5-608 MtH_2/year in 2030[13] (see Figure 1.12). See Annex for more details on the assumptions and methodology for the technical potential.

FIGURE 1.12 Supply cost curve for Canada in a low-cost scenario in 2030



Source: IRENA (2022e).

Note: TES = total energy supply in 2020 to put the hydrogen potential values into perspective. See Annex for more details on methodology and assumption for technical potential.

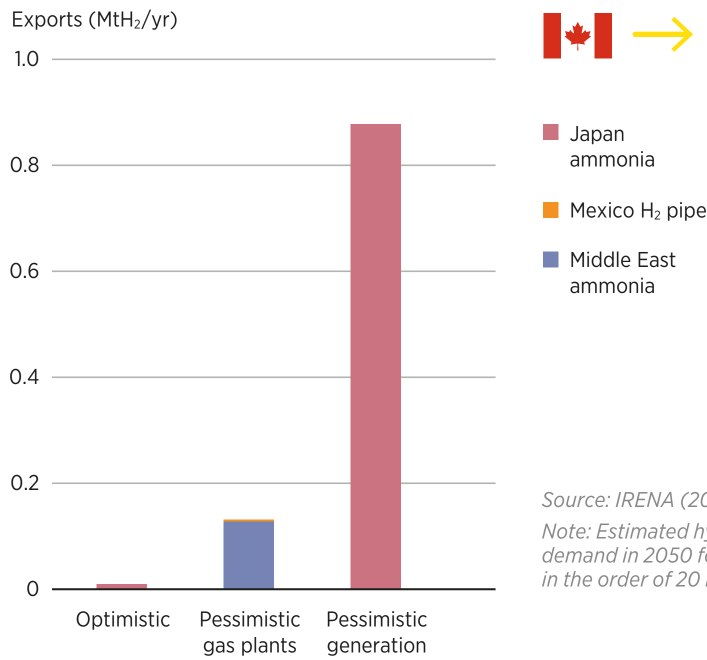
CANADA

[13] *Range captures the uncertainty in CAPEX and WACC trends up to 2030 by using two scenarios with optimistic (the lowest cost estimates) and pessimistic (high cost) values.*

Hydrogen and ammonia trade outlook for 2050

This analysis is based on solar PV and onshore wind. Of the solar resource, 95% has an annual capacity factor of less than 14%, with the best resources (above 17%) in the south areas of Alberta and Saskatchewan. Even though onshore wind in Canada is about 23% cheaper than the global average, the additional operating hours are not sufficient to compensate for the higher electricity price of other countries. This results in relatively expensive hydrogen. Hydropower could also be considered to produce hydrogen, but it has lower opportunities for learning from deployment and its average long-term costs are expected to be higher than solar PV and onshore wind. Hydropower in Canada therefore would not be able to compete with solar PV or onshore wind from other potential exporting regions. Furthermore, Canada is not close to any potential large importer. The largest close demand is in the United States, but it has enough domestic resources to avoid imports. The combination of these factors results in a limited hydrogen and ammonia trade based on economics across the scenarios evaluated (IRENA, 2022f). However, geopolitical factors such as bilateral and trade relationships, preference for pathways, and the current status of the hydrogen industry might have a larger influence than economics in shaping the future trade flows (IRENA, 2022a).

FIGURE 1.13 Hydrogen exports from Canada across scenarios for 2050



Source: IRENA (2022e).

Note: Estimated hydrogen demand in 2050 for Canada is in the order of 20 MtH_2/year.

POLICY ANALYSIS

TABLE 1.3 Analysis of Canadian hydrogen strategic documents

	Category	Priority level	Targets		Policies
SUPPLY	Green hydrogen	●●	→ USD 4-9.5/kg by 2025 → USD 1.16-2.71/kg by 2050	Production: → 20 Mt by 2050	Grants Taxation
	Blue hydrogen	●●			
	Other hydrogen	●○			
DISTRIBUTION	Ships	○○			Grants Strategies/ planning External consultation Research and development Trade policies
	Trucks	●●			
	Pipelines	●●			
	Storage	●○			
	Blending	●●			
END-USE	Steelmaking	●○	Consumption: → 4 Mt by 2030 → 20 Mt by 2050		
	Petrochemical	●●			
	Other industry	●○			
	Shipping	●●			
	Aviation	●●			
	Trains	●●			
	Trucks	●●			
	Buses	●●			
	Cars	●●	→ 5 million by 2050		
	Power generation	●●			
	Residential heating	●●			
	Other		→ 30% of H_2 in TFEC by 2050 → 350 000 jobs by 2050		

●● High priority
●○ Priority/mentioned
○○ Low/no priority

■ Adopted (blue)
■ Announced (grey)

The federal "Hydrogen Strategy for Canada" (hereafter: Canadian strategy) was published in late 2020, under the premise that Canada possesses many comparative advantages in the production of hydrogen. These include: established energy and clean-technology sectors; proximity to key global trade markets; a large and highly skilled energy sector workforce; growing domestic demand for hydrogen; strong supply chains; and critical infrastructure.

The strategy provides the perspective of numerous Canadian stakeholders from across governments and industry, as well as indigenous organisations, non-governmental organisations, and academia.

The strategy includes 32 recommendations, four for each of eight pillars: 1) strategic partnerships; 2) de-risking investments; 3) innovation; 4) codes and standards; 5) enabling policies and regulations; 6) awareness; 7) regional blueprints; and 8) international markets.

The Hydrogen Strategy Steering Committee has been created to establish priorities, guide actions, share knowledge and track results to deliver on the recommendations outlined in the Canadian strategy. It has also been tasked with ensuring actions evolve to meet the changing market conditions, over the short, medium and long term.

In addition, the provincial governments of Alberta, British Columbia, Ontario and Quebec adopted their hydrogen strategies to support local industry. While different in some forms, these provincial strategies align with the federal one by being export oriented.

Indeed, the Canadian strategy is bullish in positioning the country as a major hydrogen exporter. It targets G7 members (the European Union, Japan and the United States) and other major economies (China and the Republic of Korea) as potential trade partners. The rationale for this export-oriented strategy relies on:

1. existing fossil gas, energy and grey hydrogen industries
2. existing energy trade relationships (Canada is the sixth largest fossil gas exporter in the world)
3. richness in feedstocks to produce hydrogen (both from fossil fuels and from renewable electricity).

Similar to other fossil fuel-rich countries (Norway, the United Arab Emirates, the United Kingdom), the Canadian strategy sees in the hydrogen market an opportunity for the fossil fuel sector by providing carbon-reduced products from fossil gas. Indeed, the major hydrogen projects in Canada are blue hydrogen projects in the fossil-rich province of Alberta that envisage national and international demand large enough to create a need for both green and blue hydrogen is essential to Canada's plans.

The Canadian strategy proposes targeting first traditional end uses (the petrochemical sector), but it then expands its scope to include not only hard-to-abate sectors like steelmaking and maritime shipping, but also more electrifiable sectors such as residential heating. If successful, this catch-all approach could be proposed elsewhere to increase the total demand for hydrogen and make the use of fossil-based hydrogen necessary.

CANADA

Although Canada is open to promoting blue hydrogen, its strategy mentions the need to transition to an increasing percentage of green hydrogen and to bring carbon intensity down over time. Canada provides details of expected or necessary carbon capture rates, set at or over 90%.

With the strategy being a collection of different points of view, the recommendations contained in the strategy are high-level objectives for the government. As a result, the strategy lacks specific indications for funding or specific policies. However, Canada already provides some funding to industry and zero emission vehicles (ZEVs) that can be tapped by hydrogen technologies:

- The CAD 8 billion (USD 6.15 billion) Net Zero Accelerator supports projects that enable the decarbonisation of large emitters. The fund is also used to support hydrogen projects: for example, CAD 400 million (USD 307 million) has been used to support the ArcelorMittal Dofasco plan to switch from coke blast furnaces to a hydrogen direct reduced iron project.
- The 2021 CAD 1.5 billion (USD 1.17 billion) Clean Fuels Fund can be used to de-risk capital investment required to build new or expand existing clean fuel production facilities, including facility conversions.
- The Clean Technology investment tax credit scheme provides a 30% tax credit on a firm's capital investment in net-zero technologies, such as battery storage solutions or clean hydrogen.
- CAD 1100 million (USD 847 million) was allocated in the 2022 federal budget for ZEV purchase in three different funds.
- The Canada Infrastructure Bank is set to provide funding to the next generation of infrastructure. Hydrogen can then tap into the CAD 36 billion (USD 27.5 billion) funds of the bank.

HYDROGEN SECTOR STATUS

Status of hydrogen sector and renewables

In 2020, the European Union (including the G7 member states France, Germany and Italy) produced 7.7 MtH_2. About 87% of this was produced from fossil gas reforming, with the balance coming as a by-product from steel, steam cracking and chlor-alkali. Refineries are the dominant hydrogen application, with 51% of the demand, followed by chemicals, with 40% (Fuel Cells and Hydrogen Observatory, 2022). Specific CO_2 emissions from electricity production were already relatively low in 2020 (230.7 gCO_2/kWh [EEA, 2021]) with 45% of the electricity produced from fossil fuels, 19% from nuclear and 36% from renewables (Eurostat, 2022). Variable renewables had an installed capacity of 86.4 GW of onshore wind, 7.4 GW of offshore wind and 62.2 GW of solar PV by the end of 2021 (IRENA, 2022d) contributing to about 20% of the generation mix. Out of the 24 EU members (that are not G7 members), two[14] already have over 80% of the generation mix from renewables or nuclear which opens the opportunity of connecting the electrolysers directly to the grid, instead of to off-grid plants.

Outlook for hydrogen in 2050

A survey of 11 scenarios found a mean hydrogen (derivatives) estimated demand of 35 MtH_2/year by 2050 (most scenarios lie in the 7 MtH_2/year to 45 MtH_2/year range) resulting in a hydrogen (derivatives) share of final energy demand between 11% and 19% (European Commission Joint Research Centre, 2019). The European Commission Mix scenarios[15] reach hydrogen flows of 60 MtH_2/year to 65.6 MtH_2/year by 2050 (European Commission, 2021). Electrolyser capacity reaches 528 GW to 581 GW for hydrogen production with another 80 GW to 95 GW of synthetic methane and 40 GW to 50 GW of synthetic fuels. Hydrogen accounts for 46% to 49% of the gas supply by 2050, which stays at a level similar to the 2015 level (11.7 exajoules [EJ]/year to 13.4 EJ/year in 2050 as opposed to 14.2 EJ/year in 2015). About 15% of the passenger vehicles, 22% of the vans and 23% to 26% of the heavy goods vehicles use fuel cell vehicles. Hydrogen uptake in industry is relatively small with about 8% of the energy demand in the form of hydrogen and another 8% as synthetic methane (EC, 2020).

[14] *Luxembourg and Sweden.*

[15] *These scenarios rely on both carbon price signal extension to road transport and buildings and intensification of energy and transport policies.*

The 2050 outlook will be largely affected by the ongoing negotiations between the European Council and the Parliament for the REPower EU legislative package that will revise the targets in the Renewable Energy Directive. Final agreement on these targets is expected before the end of 2022.

Existing and planned infrastructure

The European Union has almost 1600 km of hydrogen pipelines (95% in Northwest Europe) (HyArc, 2016). The Netherlands is planning to have a national hydrogen network by 2027, consisting of 85% repurposed fossil gas pipelines, with a capacity of 10 GW and requiring an investment of EUR 1.5 billion (USD 1.48 billion). There are two main projects to expand the hydrogen network in the Netherlands: 1) HyWay27 targets a domestic network by 2026 and an international network with neighbours by 2028-2030; and 2) the Delta Corridor, connecting Rotterdam to North-Rhine Westphalia (Germany). The European Union has 24 ammonia terminals and 17 methanol terminals (DNV, 2022). The Port of Rotterdam aims to import 4.6 MtH_2/year by 2030 (Port of Rotterdam, 2022). For ammonia, new dedicated green ammonia terminals will be available by 2025. For liquid organic hydrogen carriers, a pilot is planned for 2023 and small-scale import by 2025 (IRENA, 2022f). The ACE terminal in Maasvlaakte (Netherlands) is expected to be ready by 2026 to import renewable ammonia. For liquid hydrogen, the only plant in the European Union (outside other G7 members) is in the Netherlands, a 5 t/d plant operating since 1987 (Krasae-in, Stang and Neksa, 2010).

Estimated renewable hydrogen cost in 2021

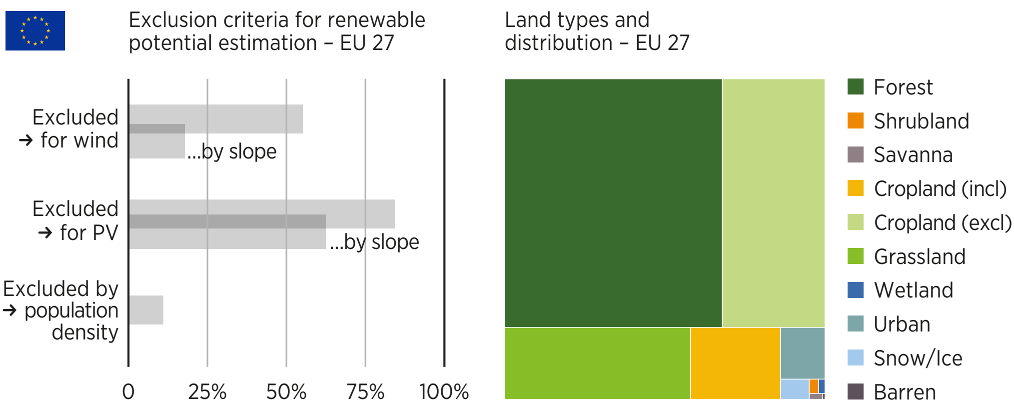
The capital costs for solar PV and onshore wind were from USD 679/kW to USD 1155/kW and USD 1110/kW to USD 2300/kW, respectively, in 2021 (IRENA, 2022f). The WACCs (real after tax) for utility-scale solar PV and onshore wind ranged from 1.3% (Germany) to 5.7% (Lithuania/Romania) (IRENA, 2022b). Assuming the same capital cost ratio (as opposed to the global average) for the electrolyser, the estimated levelised cost of hydrogen is USD 4.60/kgH_2 to USD 9.10/kgH_2 for solar PV and USD 6.90/kgH_2 to USD 9.70/kgH_2 for onshore wind.

EUROPEAN UNION

Renewable hydrogen supply in 2030

In terms of potential, about 16% of the land is suitable for solar PV and 45% for onshore wind (see Figure 1.14). This would be enough to produce almost 420 MtH_2/year (technical potential). By 2030, capital costs could come down by 60% for solar PV and by 30% for both onshore wind and electrolysis in a scenario aligned with a 1.5°C trajectory (IRENA, 2022f). Considering these costs, the economic potential below USD 2.00/kgH_2 would be 30.8 MtH_2/year in 2030[16] (see Figure 1.15). See Annex for more details on the assumptions and methodology for the technical potential.

FIGURE 1.14 Land types and exclusion criteria for renewable potential estimation in the European Union

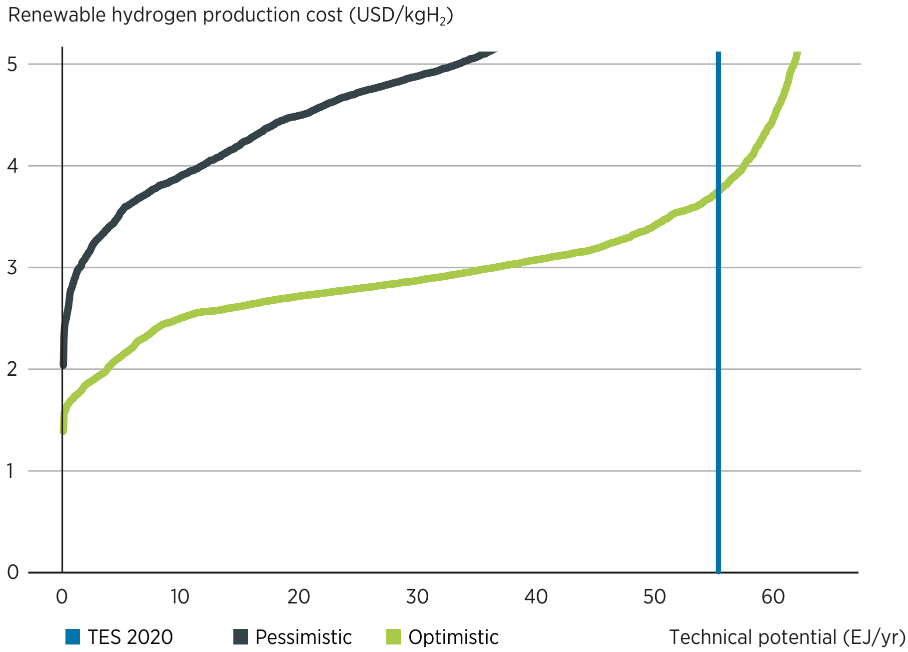


Source: IRENA (2022e).

H2 EUROPEAN UNION

[16] *There is no economic potential below USD 2/kgH_2 for a scenario with higher costs (pessimistic). The potential does not consider competition of resources for electricity, which means this low potential will be reduced further.*

FIGURE 1.15 Supply cost curve for the European Union in a low-cost scenario in 2030



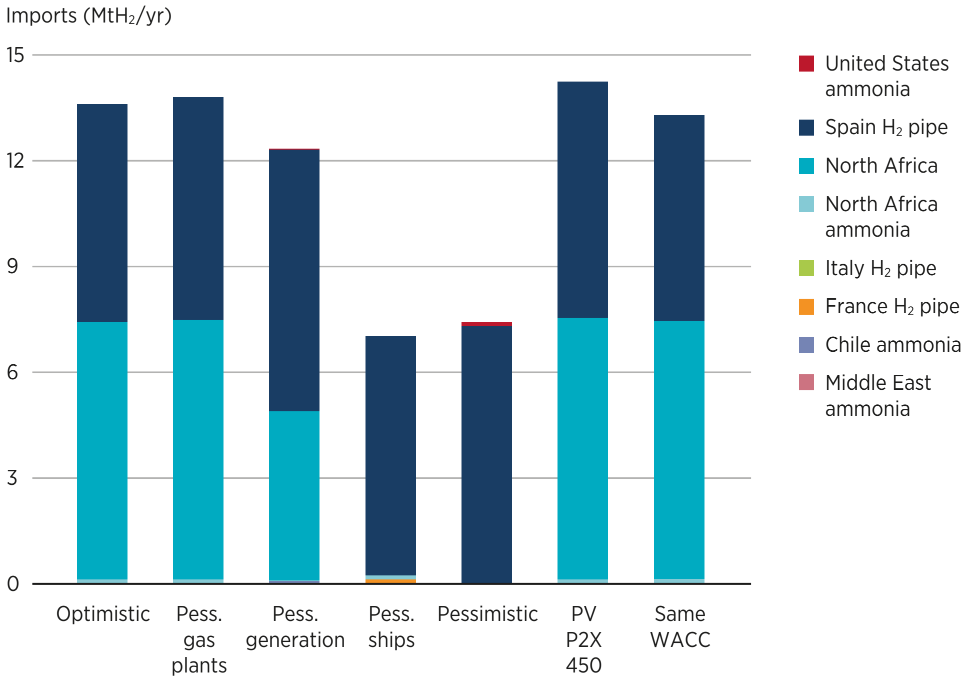
Source: IRENA (2022e).

Notes: TES in 2020 puts the hydrogen potential values into perspective. See Annex for more details on methodology and assumption for technical potential.

Hydrogen and ammonia trade outlook for 2050

The European Union has already set explicit hydrogen import targets in the REPowerEU initiative: 10 MtH_2/year by 2030 out of which 4 MtH_2/year is from ammonia and derivatives. While a large share of this is expected to be for Germany, the Netherlands is already aiming to fulfil 46% of the EU target. By 2050, the European Union (excluding other G7 members) could import 7 MtH_2/year to 14 MtH_2/year (see Figure 1.16) representing 17% to 50% of the hydrogen demand by 2050 (European Commission Joint Research Centre, 2019). Most of these imports would be through pipelines with pure hydrogen instead of importing hydrogen derivatives. The European Union already has an extensive fossil gas network of almost 200 000 km of transmission pipelines that could be repurposed to hydrogen, at least halving the cost of transporting hydrogen. Across scenarios, the European Union ends up importing by pipeline from southern countries that have better solar resources and that can achieve a low production cost when the massive solar PV deployment and low capital costs are considered (IRENA, 2022f). For all practical distances within Europe and neighbouring countries (less than 3 000 km), repurposed pipelines remain more attractive than shipping, which only becomes attractive for 7 000 km to 9 000 km (IRENA, 2022g).

FIGURE 1.16 Total hydrogen imports to the European Union across scenarios for 2050



Source: IRENA (2022f).

Note: Estimated hydrogen demand in 2050 for the EU is 7 MtH_2/year to 45 MtH_2/year (JRC, 2020). Optimistic CAPEX assumptions for 2050 (global range): PV: USD 225/kW to USD 455/kW; onshore wind: USD 700/kW to USD 1 070/kW; offshore wind: USD 1 275/kW to USD 1 745/kW; electrolyser: USD 130/kW. WACC: Per 2020 values without technology risks across regions. CAPEX assumptions for the pessimistic (Pess.) scenario: PV: USD 271/kW to USD 551/kW; onshore wind: USD 775/kW to USD 1 191/kW; offshore wind: USD 1 317/kW to USD 1 799/kW; electrolyser: USD 307/kW. Same WACC refers to a scenario where all the countries have the same risk profile, resulting in the same WACC (5%) across all countries. Pess. ships and Pess. gas plants use roughly double the costs for these steps and consider the rest of the values with an optimistic outlook (single change). Pess. generation only considers higher CAPEX for solar PV and onshore wind. PV P2X 450 uses a capital cost of USD 450/kW for solar PV and the electrolyser.

POLICY ANALYSIS

TABLE 1.4 **Analysis of European hydrogen strategic documents**

	Category	Priority level	Targets	Policies
SUPPLY	Green hydrogen	●●	→ 10 Mt produced, 6 Mt imported by 2030	Grants
	Blue hydrogen	●○		
	Other hydrogen	○○		
DISTRIBUTION	Ships	○○		Grants; Strategies/ planning
	Trucks	○○		
	Pipelines	●●		
	Storage	●●		
	Blending	●○	→ 1.3 Mt by 2030	
END-USE	Steelmaking	●○	→ 1.5 Mt by 2030	Grants
	Petrochemical	●●	→ 5.5 Mt by 2030	
	Other industry	●○	→ 3.6 Mt by 2030	
	Shipping	●●	→ 1.8 Mt by 2030 (synthetic fuels)	
	Aviation	●●		
	Trains	●●		
	Trucks	●●	→ 2.3 Mt by 2030	
	Buses	●●		
	Cars	●●		
	Power generation	●●	→ 0.1 Mt by 2030	
	Residential heating	●●		
	Other		→ 4 Mt of H_2 in imported ammonia and other derivatives (2030)	Trade policies

●● High priority
●○ Priority/mentioned
○○ Low/no priority

■ Adopted
■ Announced

Two European documents dedicated to hydrogen, the 2020 "A hydrogen strategy for a climate-neutral Europe" (hereafter EU strategy) and the 2022 "REPowerEU", provide an example of how strategic documents are influenced by policy framing.

The ambition while writing the EU strategy was to make European industry a global leader in green hydrogen equipment and zero-carbon heavy industry. As such, it was an industrial policy that included energy transition considerations.

The strategy aimed to create at least 6 GW of electrolyser capacity by 2024, enough to produce up to 1 Mt/year of green hydrogen. That would increase to 40 GW in EU countries by 2030, with an additional 40 GW of electrolyser capacity in southern and eastern neighbours (*e.g.* Ukraine or Morocco), from which the European Union could import green hydrogen.

The RepowerEU package is instead driven by energy security concerns. It is explicitly described as "a plan to rapidly reduce dependence on Russian fossil fuels and fast forward the green transition". As the concern is more immediate and politically strategic, REPowerEU has more ambitious targets. It aims to produce 10 Mt of green hydrogen by 2030 and import another 10 Mt from neighbouring countries. This is expected to replace 25 billion cubic metres (bcm) to 50 bcm of fossil gas (BNEF, 2022).

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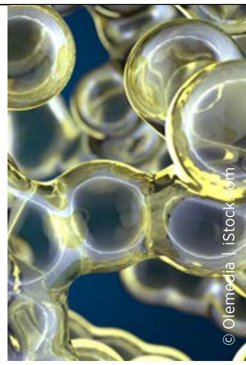


It is estimated that around 120 GW of electrolyser is needed to meet the objective of producing 10 Mt of green hydrogen. To achieve such capacity, electrolyser manufacturers agreed a target with the Commission to increase the manufacturing capacity tenfold to 17.5 GW/year.

To unlock investment in green hydrogen use, the Commission will increase the funding available in the Innovation Fund for industry and electrolysers. The Innovation Fund may cover 100% of the relevant costs in the case of competitive bidding. Moreover, the Innovation Fund may also be able to support hydrogen uptake by industry through an EU-wide scheme for carbon contracts for difference (CCfD).

Apart from funding, the important role of the European Union is to co-ordinate the regulation between its Member States. For example, to speed up permitting procedures for green hydrogen, the Commission put forward a legislative proposal on permitting and a related recommendation.

Another important element of the REPowerEU package is the carbon border adjustments mechanism (CBAM), which can be described as a carbon-content import tariff. An important challenge for a CBAM is the fact that, as a border tax, it should be compliant with the World Trade Organization (WTO) General Agreement on Tariffs and Trade (GATT). Generally speaking, the GATT mandates that taxation on imported goods cannot result in treatment that is less favourable than the treatment of comparable goods produced domestically. However, the GATT exempts certain cases from obligations where they are based on environmental protection; moreover, WTO case law suggests that a BCA would be allowed if it were based on the carbon content of a product rather than on the goods' country of origin.

However, this raises an additional challenge: to truly account for the carbon content of a product, a certification scheme (of hydrogen, material and/or finished products) must be in place. The European Union will then have to be able to set up a transparent and accountable certification system. Exporters will have to demonstrate the trustworthiness of their own carbon measurements. At the same time, the importing country applying the CBAM will need to trust the certificate while making sure not to unduly favour any country or producer.

HYDROGEN SECTOR STATUS

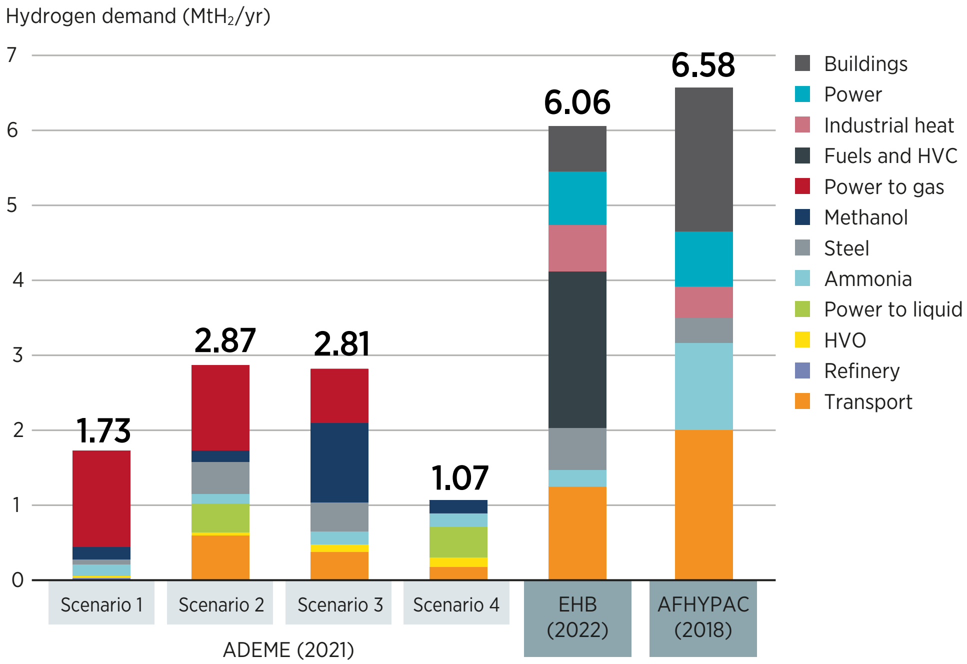
Status for hydrogen and renewables

In 2020, France produced around 0.9 MtH_2 (French Government, 2020). About 79% of this was produced from fossil gas reforming, with the balance coming as a by-product from steel, steam cracking and chlor-alkali. Refineries are the dominant hydrogen application, with 49% of the demand, followed by chemicals (35%) (Fuel Cells and Hydrogen Observatory, 2022). In 2021, the specific CO_2 emissions from electricity production were the lowest among G7 (36 gCO_2/kWh [RTE, 2022]) with 69% of the electricity produced from nuclear and 12% from hydropower (RTE, 2022). Variable renewables are relatively limited, with 18.7 GW of onshore wind and 14.7 GW of solar PV by the end of 2021 (IRENA, 2022d) contributing to about 10% of the generation mix.

Outlook for hydrogen in 2050

There is a wide range of potential outcomes for hydrogen demand in France 2050 (see Figure 1.17). Demand could stay at levels similar to current levels to reach 1.1 MtH_2/year by 2050 in a scenario that is more reliant on CCS, which makes it a more attractive option for industry. CCS use also requires the development of a CO_2 transport infrastructure which makes direct air capture coupled with CCS more attractive, relying more on negative emissions and less on mitigation pathways, such as hydrogen. The largest single use is for synthetic fuels for aviation (representing 0.4 MtH_2/year) followed by ammonia (0.2 MtH_2/year) and mobility (0.2 MtH_2/year). The preference for CCS also translates into a third of the hydrogen being produced through this route and only requiring about 5 GW of electrolysis to satisfy the demand. At the other extreme, hydrogen could reach almost 3 MtH_2/year driven by Power-to-Gas (methanation), steel and methanol. This scenario would rely mostly (89%) on electrolysis (requiring 29 GW of electrolysis), and it would take advantage of France's storage potential in salt caverns, developing a storage capacity of 1.65 Mt (ADEME, 2021). A group of gas transmission system operators in Europe also assessed potential supply and demand for 2050. For France, the estimated demand is almost 6 MtH_2/year by 2050, with a third of that coming from fuels and high value chemicals, followed by transport, with 1.2 MtH_2/year (Guidehouse, 2021).

FIGURE 1.17 Survey of hydrogen demand estimates for 2050 in France



Note: Agence de la transition écologique (ADEME [Ecological Transition Agency]), European Hydrogen Backbone (EHB), Association Francaise pour l'Hydrogene et les Piles a Combustible (AFHYPAC [French Association of Hydrogen and Fuel Cells])

Low-carbon hydrogen production projects

By July 2022, France only had single-digit MW projects for electrolysis. Looking ahead, the project pipeline adds up to over 1.3 GW by 2028 (BNEF, 2022). The largest project is the HyGreen Provence project that will use 1.5 terawatt hours (TWh) of solar PV to produce 30 ktH_2/year of hydrogen for mobility and for injection in the gas grid by 2028. Air Liquide is also planning a 200 MW electrolyser in Normandy to be commissioned by 2025 to produce hydrogen for refining and heavy-duty transport. H2V is planning to build four electrolysers of 100 MW each between 2026 and 2030.

Existing and planned infrastructure

France has almost 300 km of hydrogen pipelines (HyArc, 2016), four ammonia terminals and three methanol terminals in the west of the country (DNV, 2022). For liquid hydrogen, France only has one liquefaction plant, of 10 t/d, operating since 1987 (Krasae-in, Stang and Neksa, 2010). The country is developing the Lacq hydrogen project that will import hydrogen from solar PV in Spain (4.5 GW of electrolysis) using a repurposed pipeline. The hydrogen will be then used for reconversion to power in a combined cycle plant from 2026. France is also involved in the MosaHYC project, which involves a 100 km pipeline between France, Luxembourg and Germany and uses 70 km of repurposed fossil gas pipeline. The final investment decision for this project is expected later in 2022, with commissioning in 2026 and a capacity of 60 000 tH_2 by 2030.

Estimated renewable hydrogen cost in 2021

The capital costs for solar PV and onshore wind were USD 808/kW and USD 1 850/kW, respectively, in 2021 (IRENA, 2022b). The WACC (real after tax) for both utility-scale solar PV and onshore wind was 1.8%. Assuming the same capital cost ratio (vs. the global average) for the electrolyser, the estimated levelised cost of hydrogen is between USD 3.10/kgH_2 and USD 6.20/kgH_2 for solar PV and USD 5.6/kgH_2 and USD 7.8/kgH_2 for onshore wind.

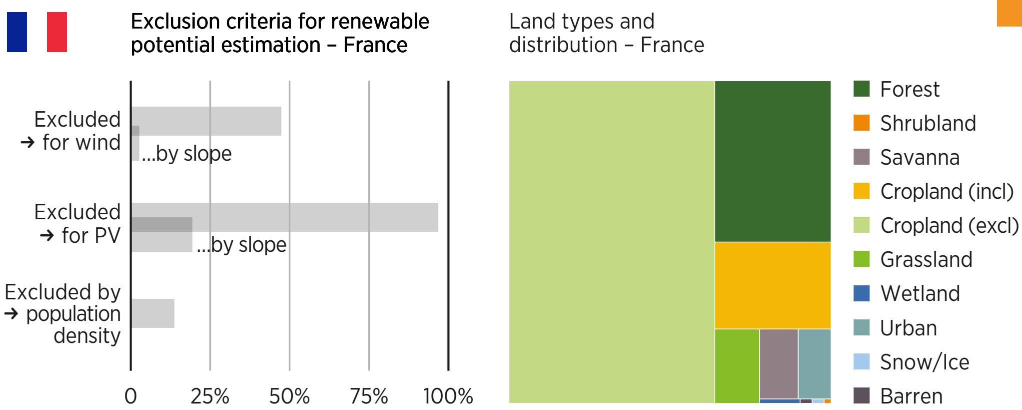
Renewable hydrogen supply in 2030

In terms of potential, almost 74% of the land is cropland and only a fraction of this[17] (10% of the land) is assumed to be available for solar PV (although onshore wind is also still possible). A further 18% of the land is covered by forests and considered to be excluded for solar PV and wind installation. Due to its slope, about 19% of the land is unsuitable for solar PV and 3% is unsuitable for wind. The population density criterion (130 people per km^2) leads to the exclusion of almost 14% of the land. This still leaves roughly 3% and 53% of the land available for solar PV and onshore wind (see Figure 1.18). This would be enough to produce almost 45 MtH_2/year (technical potential).

H_2 FRANCE

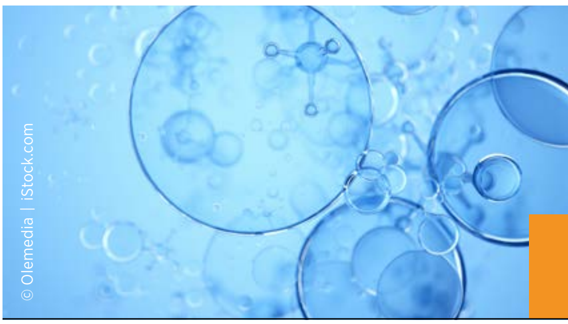
[17] *The land type dataset distinguishes between cropland and cropland/natural. The former is completely excluded for the installation of PV, while the latter, being a mosaic of 40% to 60% cultivated land and the remainder natural trees, shrubs or herbaceous vegetation, is excluded by only a 60% fraction.*

FIGURE 1.18 Land types and exclusion criteria for renewable potential estimation in France



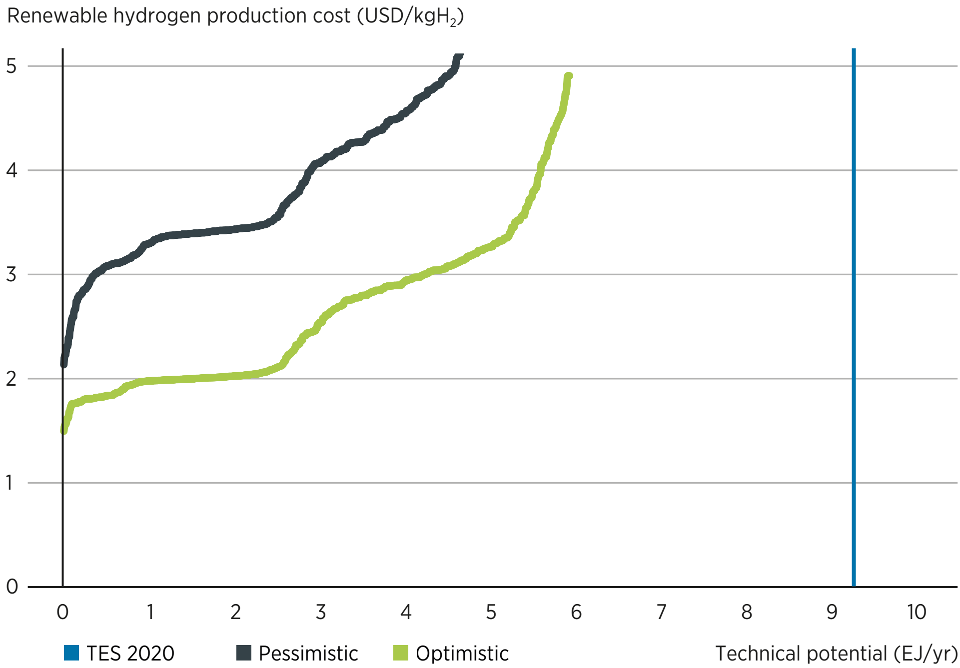
Source: IRENA (2022e).

By 2030, capital costs could come down by 60% for solar PV and by 30% for both onshore wind and electrolysis in a scenario aligned with a 1.5°C trajectory (IRENA, 2022f). Considering these costs, the economic potential below USD 2.00/kgH_2 would be 12.7 MtH_2/year in 2030[18] (see Figure 1.19). See Annex for more details on the assumptions and methodology for the technical potential.



[18] *There is no economic potential below USD 2.00/kgH_2 for a scenario with higher costs (pessimistic). The potential does not consider competition of resources for electricity, which means this low potential will most likely be used for electricity.*

FIGURE 1.19 Supply cost curve for France in a low-cost scenario in 2030



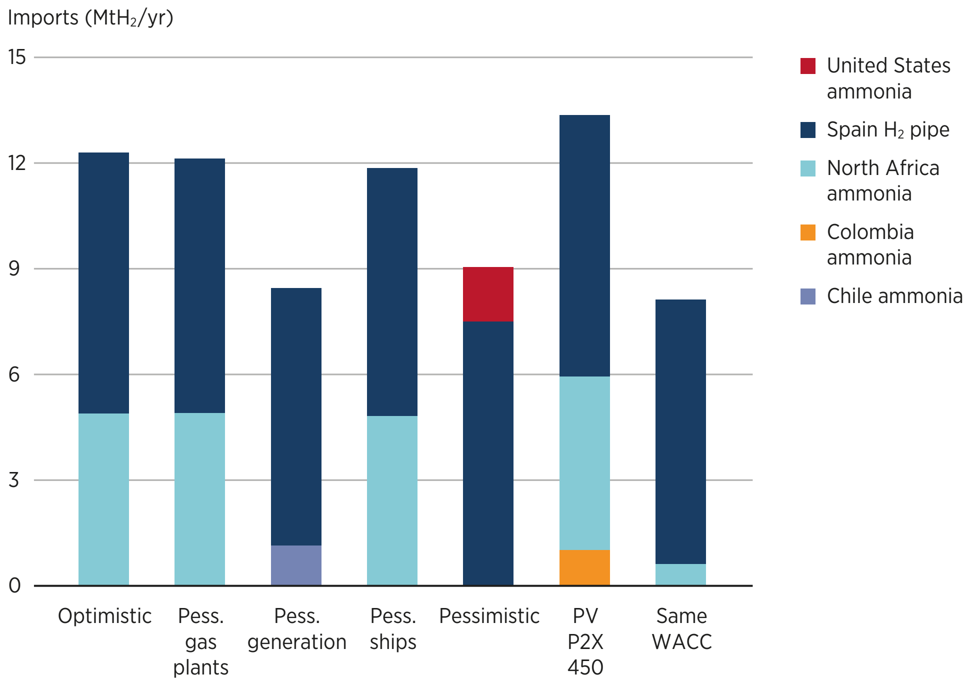
Source: IRENA (2022e).

Notes: TES in 2020 puts the hydrogen potential values into perspective. See Annex for more details on methodology and assumption for technical potential.

Hydrogen and ammonia trade outlook for 2050

France is well interconnected by fossil gas pipelines that could potentially be repurposed to hydrogen. This means it faces a low transport cost penalty for importing and the hydrogen production differential is larger when compared to neighbouring countries. This means, from a pure cost perspective, France could end up importing nearly all its hydrogen and ammonia demand. At the same time, France also acts as a transit country between the solar-rich resources in the southern countries and the large hydrogen and ammonia demand centres in northwest Europe, and thereby imports 2.5 to 3.5 times its domestic demand (see Figure 1.20), only to export 1.5 to 2.5 times by pipeline. About 60% of the imports are by pipeline, while the rest is in the form of ammonia that is directly used as a chemical feedstock and fuel. Ammonia transport is favoured by the short distance to North Africa, although there are also some imports from Chile, Colombia and the United States across scenarios (IRENA, 2022f).

FIGURE 1.20 Total hydrogen imports to France across scenarios for 2050



Source: IRENA (2022f).

Note: Estimated hydrogen demand in 2050 for France is 5.5 MtH_2/year to 6.6 MtH_2/year. Optimistic CAPEX assumptions for 2050 (global range): PV: USD 225/kW to USD 455/kW; onshore wind: USD 700/kW to USD 1070/kW; offshore wind: USD 1275.kW to USD 1745/kW; electrolyser: USD 130/kW. WACC: Per 2020 values without technology risks across regions. CAPEX assumptions for the pessimistic (Pess.) scenario: PV: USD 271/kW to USD 551/kW; onshore wind: USD 775/kW to USD 1191/kW; offshore wind: USD 1317/kW to USD 1799/kW; electrolyser: USD 307/kW. Same WACC refers to a scenario where all the countries have the same risk profile, resulting in the same WACC (5%) across all countries. Pess. ships and Pess. gas plants use roughly double the costs for these steps and consider the rest of the values with an optimistic outlook (single change). Pess. generation only considers higher CAPEX for solar PV and onshore wind. PV P2X 450 uses a capital cost of USD 450/kW for solar PV and the electrolyser.

FRANCE

POLICY ANALYSIS

TABLE 1.5 Analysis of French hydrogen strategic documents

	Category	Priority level	Targets	Policies	
SUPPLY	Green hydrogen	●●	→ 1-10 MW by 2023 → 10-100 MW by 2028 → 6.5 GW by 2030	Grants, Taxation	Jobs and Training Research and development
SUPPLY	Blue hydrogen	○○			
SUPPLY	Other hydrogen	●●		Grants, Taxation	
DISTRIBUTION	Ships	○○			
DISTRIBUTION	Trucks	○○			
DISTRIBUTION	Pipelines	●○			
DISTRIBUTION	Storage	○○			
DISTRIBUTION	Blending	○○			
END-USE	Steelmaking	○○	Share of decarbonised and renewable hydrogen in H_2 consumption: → 10% by 2023 → USD 20-40 by 2028	Grants	
END-USE	Petrochemical	●●			
END-USE	Other industry	●○			
END-USE	Shipping	●○			
END-USE	Aviation	●○			
END-USE	Trains	●●		Grants	
END-USE	Trucks	●●	→ 500 FCEVs by 2023 → 800-2 000 by 2028*		
END-USE	Buses	●●			
END-USE	Cars	○○	→ 5 000 FCEVs by 2023 → 20 000-50 000 by 2028 HRS: → 100 by 2023 → 400-1 000 by 2028*		
END-USE	Power generation	○○			
END-USE	Residential heating	○○			
END-USE	Other		→ 50 000-150 000 jobs → 6 Mt of avoided CO_2		

** National Energy and Climate Plan (NECP); HRS = hydrogen refuelling stations.*

●● High priority
●○ Priority/mentioned
○○ Low/no priority

■ Adopted
■ Announced

France is among the few countries to have updated their initial hydrogen strategy. The current "National strategy for the development of decarbonised and renewable hydrogen in France" (hereafter "French strategy") is the second strategy after the 2018 hydrogen roadmap. The first strategy kickstarted financing for the first projects in France with an investment of USD 102 million (EUR 100 million) through public calls for tenders.

Hydrogen played a role in the 2019 National Energy and Climate Plan (NECP). The NECP was very ambitious in the short-term targets for hydrogen, with up to 10% of hydrogen used for industry to be decarbonised by 2023. Moreover, the 2019 Climate Energy Act, which introduced numerous targets in the supply and end-use sectors, introduced a target for renewable gas in the gas supply mix, specifying that 10% of the gas consumed should be renewable by 2030.

The French strategy is part of the National Recovery Plan following the COVID-19 crisis. It strengthens the previous roadmap and aims to make France a leading nation in decarbonised and renewable hydrogen production by 2030. It sets very ambitious goals:

1. to install enough electrolysers to make a significant contribution to the decarbonisation of the economy
2. to develop clean mobility, in particular for heavy-duty vehicles
3. to build a French industrial sector that creates jobs and guarantees France's technological prowess.

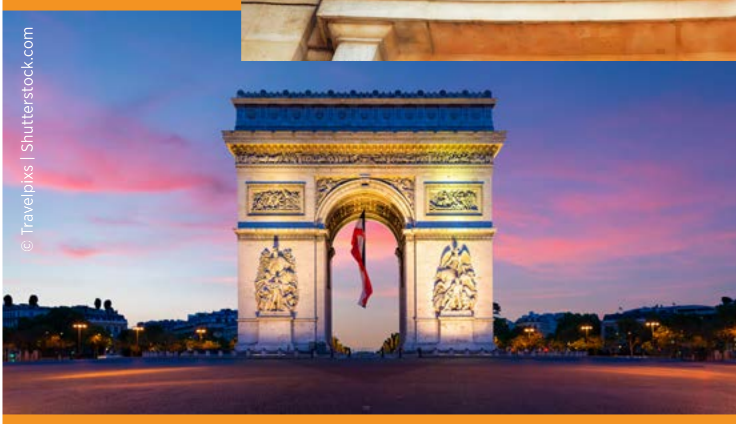
The French strategy accompanies such objectives with a commitment for EUR 7.2 billion (USD 7 billion) of investments for the next decade, of which 47.2% is to be allocated before 2023. A difference from the 2019 NECP is the refocus, in the mobility sector, from light-duty to heavy-duty vehicles.

A notable feat of the hydrogen sector policy making in France is the use of calls for proposal (CFP) to allocate the funding. CFP are managed by ADEME, the French government agency for ecological transition, and have regularly been carried out since 2016. The current French Strategy announced new CFP that will be carried out over multiple years. These new CFP allocate funds which are significantly higher than in the past. The CFP for "Regional hydrogen hubs" (Hydrogen valley) will be allocated EUR 275 million (USD 268 million) until 2023, while the CFP for "Technological building blocks and demonstrators" (production and transport of hydrogen) has been allocated EUR 350 million (USD 341 million).

Other supporting measures are the grey hydrogen carbon tax (Contribution Climat-Énergie), equivalent to EUR 86.2/tCO_2 (USD 84/tCO_2) (which is set to increase to EUR 100/tCO_2 [USD 7.5/tCO_2] in 2030) and the electricity tax exemption for electrolytic processes.

Another characteristic of the French strategy is the planned use of nuclear energy for hydrogen production. The French strategy is ambitious about the use of electrolysis to produce hydrogen (with 6.5 GW of electrolysers by 2030, the highest target among G7 members). Indeed, the country already has a pipeline of 1.3 GW of electrolyser projects. However, the country faces the challenge of producing enough nuclear and renewable electricity to fuel hydrogen production while decarbonising the rest of its power consumption and electrifying other sectors. From 2009 to 2019, French electricity consumption increased by 6.5%, from 535 TWh to 570 TWh. However, additional non-fossil energy accounted for only 32 TWh in 2019, while renewable electricity production increased by 42 TWh and nuclear energy decreased by 10 TWh. The recent disruption of nuclear energy production due to maintenance and EDF's recent cuts of French nuclear output will likely lead to a call for an increased effort to deploy renewable energy capacity. This will be necessary both to maintain the high level of decarbonised electricity and to achieve electrification of the heating, transport and hydrogen sectors.

FRANCE



HYDROGEN SECTOR STATUS

Status for hydrogen and renewables

In 2020, Germany produced around 1.7 MtH_2. About 79% of this was produced from fossil gas reforming, with the balance coming as a by-product from steel, steam cracking and chlor-alkali. Refineries are the dominant hydrogen application, with 42% of the demand, followed by chemicals (40%) (Fuel Cells and Hydrogen Observatory, 2022). In 2021, the specific CO_2 emissions from electricity production were 355 gCO_2/kWh with 41% of the electricity produced from renewables and 12% from nuclear (BDEW, 2022). Variable renewables have an installed capacity of 56 GW of onshore wind, 7.7 GW of offshore wind and 58.5 GW of solar PV by the end of 2021 (IRENA, 2022d) contributing about 29% of the generation mix.

Outlook for hydrogen in 2050

In May 2021, Germany raised its climate ambition, establishing a net-zero emissions target by 2045. Most of the studies providing insights into the hydrogen outlook either consider the net-zero target by 2050 or even the previous 80% to 95% GHG reduction by 2050. An analysis of 37 scenarios across 12 studies led to a hydrogen demand range from 0-24 MtH_2/year by 2050 with a mean demand of 7.2 MtH_2/year (Scheller, 2022). Most of the studies also find that this growth happens only after 2030.

When looking at the hydrogen (derivatives) share by 2050, the share of synthetic fuels is, on average, higher than hydrogen itself. The share also increases significantly by using a more ambitious climate target. The change from 80% to 95% GHG reduction by 2050 leads to a 1.5 to 3 times increase in the share of hydrogen (derivatives), giving hydrogen a 10% to 20% share of in final energy demand for most scenarios with an 80% GHG reduction, and a 20% to 30% share for scenarios with a 95% GHG reduction. For net-zero emission scenarios, the hydrogen demand is 18 MtH_2/year to 36 MtH_2/year with an additional 0 MtH_2/year to 22.5 MtH_2/year for synthetic fuels (Fraunhofer, 2021). On the supply side, since early 2022, Germany has been looking to drastically decrease its reliance on gas imports, a position that dispenses with the option of domestic production based on fossil gas reforming. The only domestic route considered is from renewables.

Low-carbon hydrogen production projects

The total project pipeline for electrolysis is 16.7 GW. The largest project (10 GW) is AquaVentus, which aims to produce 1 MtH_2/year using offshore wind by 2035 deploying at least 5 GW by 2030. The project is currently at the concept stage, evaluating the potential for production from offshore wind and the integration of various components (platforms, pipelines, ships, ports).

Existing and planned infrastructure

Germany has almost 390 km of hydrogen pipelines (HyArc, 2016), two ammonia terminals in the north of the country, and three methanol terminals in Kehl, Hamburg and Oberhausen (DNV, 2022). For liquid hydrogen, Germany has two liquefaction plants reaching almost 10 t/d of design capacity (Krasae-in, Stang and Neksa, 2010). There are 15 IPCEI[19] projects dedicated to infrastructure adding up to 1 700 km of hydrogen pipelines. The H2ercules project envisions a 1 500 km hydrogen network starting construction in 2026 and continuing until 2030. Modelling undertaken by the gas transmission operators estimates that a 13 300 km hydrogen network will be needed by 2050 using 11 000 km of repurposed fossil gas pipelines (FNB Gas, 2021). In terms of terminals for import by shipping, one of the German energy companies (RWE) plans to build a terminal in the north of the country to import 0.3 Mt of ammonia by 2026, and another one (Uniper) plans to construct an import terminal for renewable ammonia (potential for liquid hydrogen) for 0.3 MtH_2 by 2030. Multiple import projects and feasibility studies with partner countries have been announced (see policy section of this factsheet).

Estimated renewable hydrogen cost in 2021

The capital costs for solar PV and onshore wind were USD 694/kW and USD 1800/kW, respectively, in 2021. The WACC (real after tax) for both utility-scale solar PV and onshore wind was 1.3% (IRENA, 2022b). Assuming the same capital cost ratio (as opposed to the global average) for the electrolyser, the estimated levelised cost of hydrogen for solar PV is between USD 3.30/kgH_2 and USD 6.70/kgH_2 and for onshore wind, between USD 6.30/kgH_2 and USD 8.80/kgH_2.

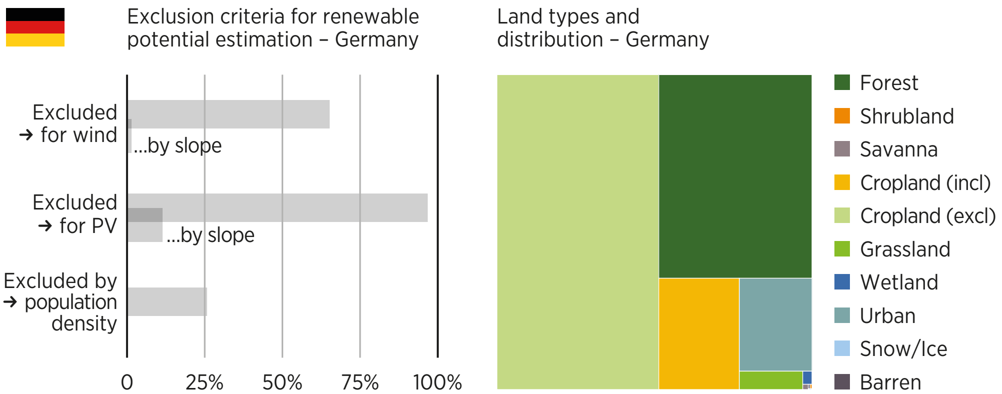
Renewable hydrogen supply in 2030

In terms of potential, 38% of the land is a protected area, and is considered unavailable for either solar or wind technology. Almost 60% of the land is cropland, and only a fraction of this[20] (9% of the land) is assumed to be available for solar PV (but onshore wind is still possible); 32% of the land is covered by forests (largely overlapping with the protected areas) and considered to be excluded for solar PV and wind installation. About 11.5% of the land has a slope unsuitable for solar PV and 0.3% a slope unsuitable for wind. The population density criterion (130 people per km^2) leads to the exclusion of 26% of the land. This still leaves roughly 3% and 34% of the land available for solar PV and onshore wind, respectively (see Figure 1.21). This would be enough to produce almost 32 MtH_2/year (technical potential). See Annex for more details on the assumptions and methodology for the technical potential.

[19] The Important Projects of Common European Interest (IPCEI) initiative was launched for hydrogen in December 2020; the projects are part of the EU Industrial Strategy and are meant to bridge the gap between research and development (R&D) and commercialization.

[20] The land type dataset distinguishes between cropland and cropland/natural. While the former is completely excluded for the installation of PV, the latter, being a mosaic of 40% to 60% cultivated land and the remainder natural trees, shrubs or herbaceous vegetation, is excluded by only a 60% fraction.

FIGURE 1.21 Land types and exclusion criteria for renewable potential estimation in Germany

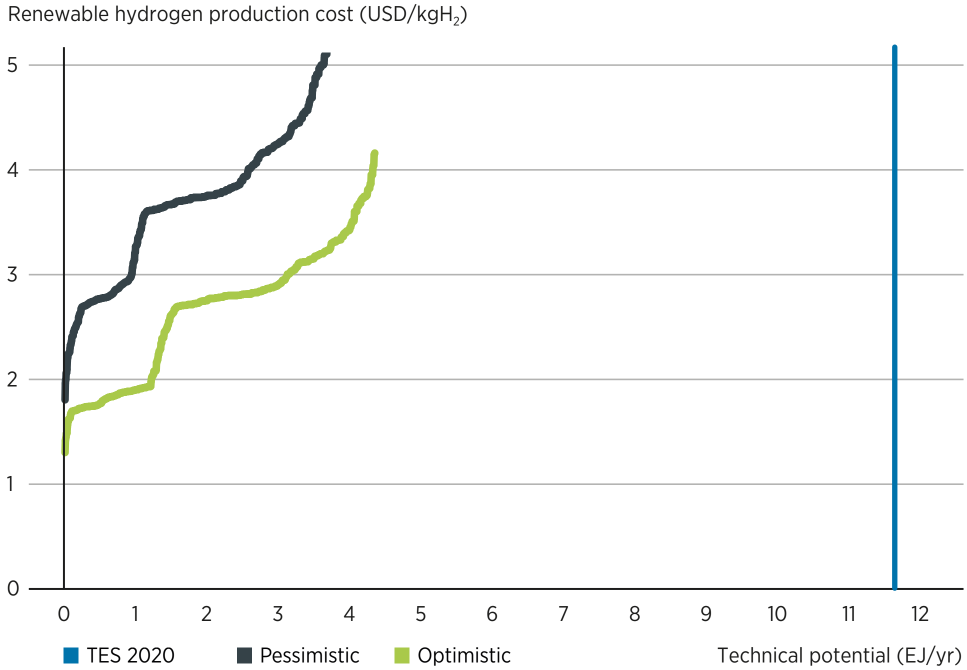


Source: IRENA (2022e).

By 2030, capital costs could come down by 60% for solar PV and by 30% for both onshore wind and electrolysis in a scenario aligned with a 1.5°C trajectory (IRENA, 2022f). Considering these costs, the economic potential below USD 2.00/kgH_2 would be 10 MtH_2/year in 2030[21] (see Figure 1.22).

[21] *There is no economic potential below USD 2/kgH_2 for a scenario with higher costs (pessimistic). The potential does not consider competition of resources for electricity, which means this low potential will most likely be used for electricity.*

FIGURE 1.22 Supply cost curve for Germany in a low-cost scenario in 2030



Source: IRENA (2022e).

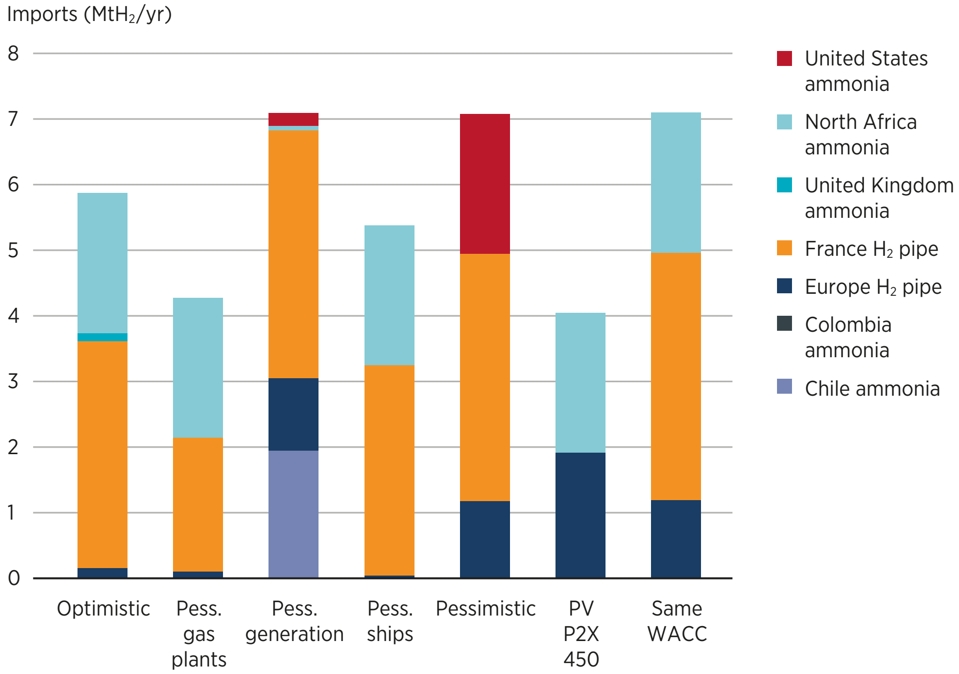
Notes: TES in 2020 puts the hydrogen potential values into perspective. See Annex for more details on methodology and assumption for technical potential. Cost and potential by pixel can be found at https://irena.lcoh.kartoza.com/.

Hydrogen and ammonia trade outlook for 2050

Multiple drivers favour hydrogen imports for Germany. First, the country has a limited technical renewable potential that would be enough to produce 32 MtH_2/year, if all the potential were used for hydrogen production. Second, an expanding hydrogen demand could grow by more than a factor of 12 by 2050 for some scenarios, driven by industrial use, steel, aviation and shipping (Scheller, 2022; Fraunhofer, 2021). Third, good interconnections with neighbouring countries through fossil gas pipelines could potentially be repurposed to hydrogen and lead to low transport costs.

The combination of all these factors could lead to Germany importing 60% to 100% of its hydrogen and ammonia demand (see Figure 1.23). The potential trading partners are France (acting as a trading hub for production from the Iberian Peninsula) and North Africa for imports by pipeline. Chile, North Africa and the United States are potential trading partners for ammonia, depending on the scenario (with similar landed costs). A commonality across scenarios is that all the ammonia demand is satisfied with imports because the production cost differential due to the renewable quality is larger in magnitude than the transport costs (IRENA, 2022f). Similarly, ammonia cracking is absent across most scenarios, given that Germany has the potential to import low-cost hydrogen by pipeline. This is more cost-effective than importing ammonia and taking the cost and energy penalty of cracking. An analysis of 37 scenarios across 12 studies reaching 80% to 100% GHG reduction by 2050 (on 1990 levels) found an average import rate of 67% for hydrogen (with a range of 0% to 100%) and an average import rate of 90% for synthetic fuels (Scheller, 2022).

FIGURE 1.23 Total hydrogen imports to Germany across scenarios for 2050



Source: IRENA (2022f).

Note: Estimated hydrogen demand from several studies for Germany in 2050 is 6 MtH_2/year to 24 MtH_2/year (Scheller, 2022; Fraunhofer, 2021). This analysis considers 7.1 MtH_2/year. Optimistic CAPEX assumptions for 2050 (global range): PV: USD 225/kW to USD 455/kW; onshore wind: USD 700/kW to USD 1070/kW; offshore wind: USD 1275/kW to USD 1745/kW; electrolyser: USD 130/kW. WACC: Per 2020 values without technology risks across regions. CAPEX assumptions for the pessimistic (Pess.) scenario: PV: USD 271/kW to USD 551/kW; onshore wind: USD 775/kW to USD 1 191/kW; offshore wind: USD 1 317/kW to USD 1 799/kW; electrolyser: USD 307/kW. Same WACC refers to a scenario where all the countries have the same risk profile, resulting in the same WACC (5%) across all countries. Pess. ships and Pess. gas plants use roughly double the costs for these steps and consider the rest of the values with an optimistic outlook (single change). Pess. generation only considers higher CAPEX for solar PV and onshore wind. PV P2X 450 uses a capital cost of USD 450/kW for solar PV and the electrolyser.

POLICY ANALYSIS

TABLE 1.6 Analysis of German hydrogen strategic documents

	Category	Priority level	Targets	Policies
SUPPLY	Green hydrogen	●●	→ 10 GW capacity by 2030	Grants; Taxation
SUPPLY	Blue hydrogen	○○		
SUPPLY	Other hydrogen	○○		
DISTRIBUTION	Ships	○○		
DISTRIBUTION	Trucks	○○		
DISTRIBUTION	Pipelines	●●		Strategies/ planning
DISTRIBUTION	Storage	○○		
DISTRIBUTION	Blending	○○		
END-USE	Steelmaking	●●		Grants; Quotas; Strategies/ planning; Research and develop- ment
END-USE	Petrochemical	●●		
END-USE	Other industry	●●		
END-USE	Shipping	●○		Research and development
END-USE	Aviation	●●	→ 0.5% synthetic fuels by 2026 and → 2% in 2030	Quotas; Research and develop- ment
END-USE	Trains	●●		Grants
END-USE	Trucks	●●		
END-USE	Buses	●●		
END-USE	Cars	●○		
END-USE	Power generation	○○		
END-USE	Residential heating	●○		Grants; Taxation
END-USE	Other			Trade policies; Research and develop- ment; External consul- tation

●● High priority
●○ Priority/mentioned
○○ Low/no priority

■ Adopted
■ Announced

The German "National hydrogen strategy" (hereafter: the German Strategy) was drafted in 2020 as part of the German recovery plan after the COVID-19 crisis. The strategy is being implemented through a committee of state secretaries supported by a national hydrogen council (with 25 representatives from business, science and civil society). There will be annual reports with performance indicators and a main report every three years to re-evaluate the overall strategy and adjust targets depending on market developments. Moreover, the revision of the German Strategy is taking place at the moment and should be finished at the end of 2022. The new version will define new priorities for the use of hydrogen in the light of Germany's aim of climate neutrality in 2045 and sets a focus on international action fields.

A key element of the German strategy is the consideration that demand and supply of green hydrogen must grow and therefore be supported together. Actions will also be taken to match demand and supply. On the demand side, the strategy focuses on applications where green hydrogen is the least in need of economic support or where there are limited choices for decarbonisation (the hard-to-abate sectors), and strive to avoid path dependency. These include refineries, steel, the chemical industry, aviation and shipping. In the industrial sector, the strategy is based on replacing grey hydrogen with green hydrogen in the chemical industry and substituting blast furnaces for direct iron reduction in the steel industry. To promote hydrogen in industrial processes, the government will provide investment grants and launch a CCfD programme, which is mainly aimed at the steel and chemical industries. The other prioritised sector is transport. Shipping, aviation, trains, and heavy-duty and light-duty vehicles will be recipients of future analysis, R&D and funding. In particular, a 0.5% quota for 2026 and a 2% quota for 2030 for power-to-liquid fuels in the aviation sector is in place.

The German government is considering establishing a demand quota for materials such as green steel to increase the demand for industrial products manufactured using green hydrogen and other low-emission processes.

To pursue its strategy, Germany allocated EUR 9 billion (USD 9.1 billion) to create a demand-driven market for hydrogen (as part of the stimulus package for economic recovery from the COVID-19 crisis), plus EUR 2 billion (USD 2 billion) dedicated to partnerships with countries where hydrogen can be produced. Indeed, an interesting aspect of the German strategy is its international outreach. The strategy recognises that the domestic generation of green hydrogen will not be sufficient to cover all new demand.

At the same time, the German strategy states that one of its goals is to position Germany as a leading exporter of green hydrogen technologies worldwide in the future. Germany supports domestic companies in developing internationally competitive innovations through a variety of R&D programmes (*e.g.* the Hydrogen Flagship Projects).

Moreover, EUR 350 million (USD 356 million) has been earmarked to promote the use of German technology abroad to contribute to timely and targeted efforts to set up a global market for green hydrogen and to prepare structures for the import of hydrogen.

To pave the way to an international market, the German strategy commits to the promotion of co-ordinated actions in the European Union and international co-operation beyond the European Union. Moreover, in recent years, Germany has been noted for its proactive "hydrogen diplomacy", seeking partnerships with potential future hydrogen exporters (*e.g.* Australia, Canada, Morocco, Gulf States, Latin America, Namibia) and intensifying the dialogue with key fossil exporters on the opportunities and challenges of a global hydrogen market. To this end, Germany set up "hydrogen diplomacy offices" in Angola, Nigeria and Saudi Arabia. In addition, Germany has established the H2Global programme (see Box 1.1).

Box 1.1 The H2Global programme

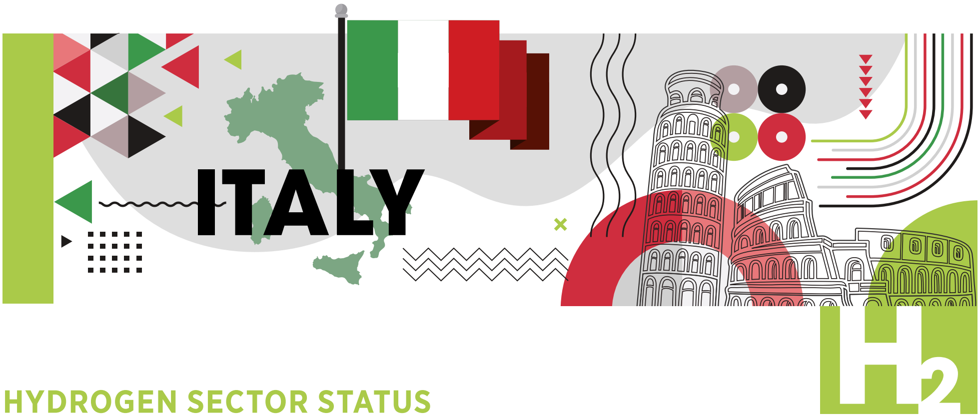
Without sufficient demand for green hydrogen, producers lack the incentive to deploy it at a large enough scale to reduce costs. This positions green hydrogen at a cost that cannot generate demand and creates a chicken-and-egg problem. This situation is hastened by the foreseen international trading of hydrogen: communication and agreements between importing and exporting countries add additional layers of complexity.

Germany has already signed memorandums of understanding with other countries to plan future imports of hydrogen. At the same time, the German H2Global funding programme, conceptualised in 2020, was established by 16 major players in German industry together with the German government to tackle these barriers.

The H2Global programme aims to procure green hydrogen and derivatives from across the globe for German industry. It will use a double auction-based mechanism for both hydrogen supply and demand, aiming to match the suppliers that are able to provide the lowest cost with the users that are willing to pay the most.

The H2Global programme established an intermediary body called the Hydrogen Intermediary Network Company (HINT.CO) to sign purchase and service agreements. HINT.CO is supported with EUR 900 million (USD 915 million) of funding to temporarily compensate the difference between the hydrogen purchase agreements and sale agreements. The minimum project size for application is 100 MW of electrolysis capacity.

The first auction will be targeted at ammonia, methanol and synthetic fuels. The programme expects that future adjustments to the regulatory framework will increase industrial off-takers' willingness to pay for green hydrogen and the sale agreement price will rise over time. As technologies develop, it is expected that the gap between auctions will close, reducing the overall subsidy required. This will gradually reduce the need for HINT.CO to compensate for the price differential until a point is reached where the demand and supply prices are in line with each other. At that point, the role of the intermediary would end.



HYDROGEN SECTOR STATUS

Status for hydrogen and renewables

In 2020, Italy produced around 0.5 MtH_2 (Fuel Cells and Hydrogen Observatory, 2022). About 89% of this came from fossil gas reforming, with the balance coming as a by-product from steel, steam cracking and chlor-alkali. Refineries are the dominant hydrogen application, with 75% of the demand, followed by chemicals (20%) (Fuel Cells and Hydrogen Observatory, 2022). In 2021, the specific CO_2 emissions from electricity production were 261 gCO_2/kWh with 65% of the electricity produced from fossil fuels and 35% from renewables (ISPRA, 2022). Variable renewables had an installed capacity of 11.3 GW of onshore wind and 22.7 GW of solar PV by the end of 2021 (IRENA, 2022d), contributing to about 16% of the generation mix.

Outlook for hydrogen in 2050

By 2050, the Italian government expects that hydrogen could satisfy up to 20% of final energy demand with applications across transport, industry, power generation and some use for the residential and commercial sector (where heat pumps are not technically possible). The penetration of fuel cells for long-haul heavy-duty trucks could reach up to 80% (MISE, 2020). A study by SNAM, one of the three fossil gas transmission system operators in Italy, estimates a 2050 demand of 9.5 MtH_2/year driven by power generation (3 MtH_2/year) followed by the transport sector (2.6 MtH_2/year) and the buildings sector (2.1 MtH_2/year) (SNAM, 2020). A group of gas transmission system operators in Europe also assessed potential supply and demand for 2050. For Italy, the estimated demand is almost 7.4 MtH_2/year by 2050, with almost half of that coming from industrial use, followed by power generation (2.8 MtH_2/year) and transport (0.7 MtH_2/year) (Guidehouse, 2021). Thus, a commonality across scenarios constitutes the use of hydrogen as seasonal storage for power generation, while a drastic difference exists for industry and the residential sector.

Low-carbon hydrogen production projects

Italy has a project pipeline of almost 300 MW of electrolysers. The largest is the Puglia Green Hydrogen Valley project with a total capacity of 220 MW of electrolysis across three locations powered by 380 MW of solar PV. One of the locations has already started the authorisation process. The hydrogen will be used for local industries, mobility and blending. There is also a 20 MW electrolysis project in the Saras refinery, and Enel Power (a renewables company) is partnering with Eni (oil and gas) to build two 10 MW projects in refineries between 2022 and 2023.

Existing and planned infrastructure

Italy only has one, 8 km hydrogen pipeline (HyArc, 2016). It has two ammonia terminals and two methanol terminals in the north of the country (DNV, 2022). Italy does not have any hydrogen liquefaction plants. SNAM has tested hydrogen blending of up to 10% (volume) and claims that 70% of its network (a total of 32 600 km in 2021) is compatible with hydrogen (SNAM, n.d.).

Estimated renewable hydrogen cost in 2021

The capital costs for solar PV and onshore wind were USD 785/kW and USD 1 375/kW, respectively, in 2021. The WACCs (real after tax) for utility-scale solar PV and onshore wind were 3.1% and 3.3%, respectively (IRENA, 2022b). Assuming the same capital cost ratio (compared to the global average) for the electrolyser, the estimated levelised cost of hydrogen is between USD 4.30/kgH_2 and USD 8.50/kgH_2 for solar PV and USD 7.40/kgH_2 and USD 10.30/kgH_2 for onshore wind.

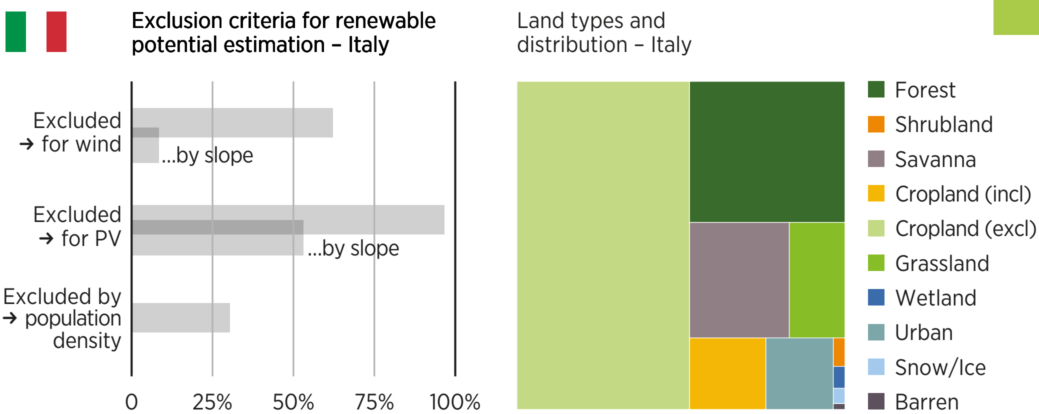
Renewable hydrogen supply in 2030

In terms of potential, about 53% of the land has a slope unsuitable for variable solar PV and 9% has a slope unsuitable for wind energy. The population density criterion (130 people per km^2) leads to the exclusion of 30.5% of the land; forests cover 20% of the land and croplands, 58%. This leaves roughly 3% and 36% of the land available for solar PV and onshore wind, respectively (see Figure 1.24). This would be enough to produce almost 19.4 MtH_2/year (technical potential).

H_2

ITALY

FIGURE 1.24 Land types and exclusion criteria for renewable potential estimation in Italy

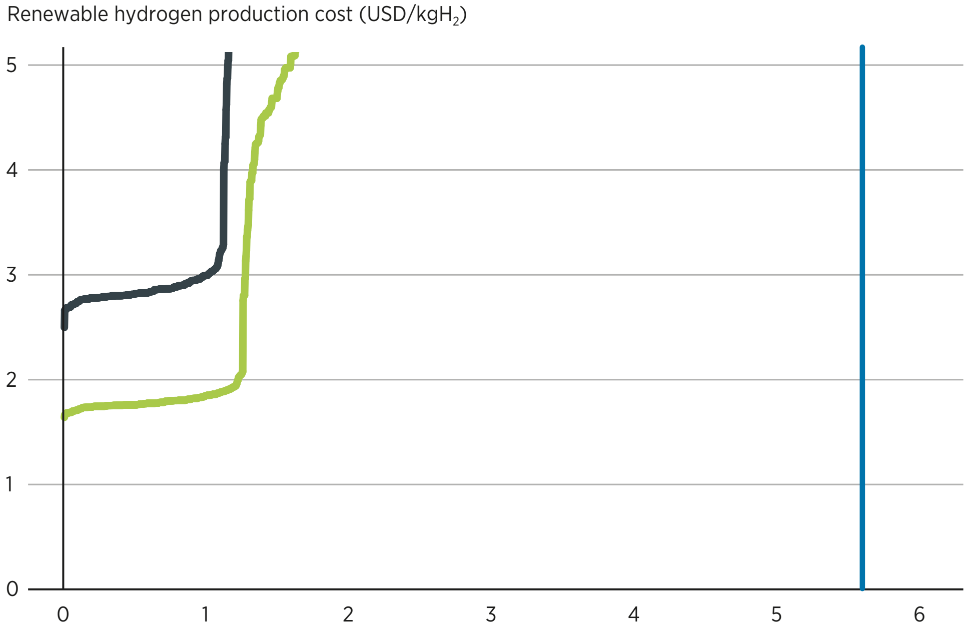


Source: IRENA (2022e).

By 2030, capital costs could come down by 60% for solar PV and by 30% for both onshore wind and electrolysis in a scenario aligned with a 1.5°C trajectory (IRENA, 2022f). Considering these costs, the economic potential below USD 2.00/kgH_2 would be 10.1 MtH_2/year in 2030[22] (see Figure 1.25). See Annex for more details on the assumptions and methodology for the technical potential.

[22] *There is no economic potential below USD 2/kgH_2 for a scenario with higher costs (pessimistic). The potential does not consider competition of resources for electricity, which means this low potential will most likely be used for electricity.*

FIGURE 1.25 Supply cost curve for Italy in a low-cost scenario in 2030



Source: IRENA (2022e).

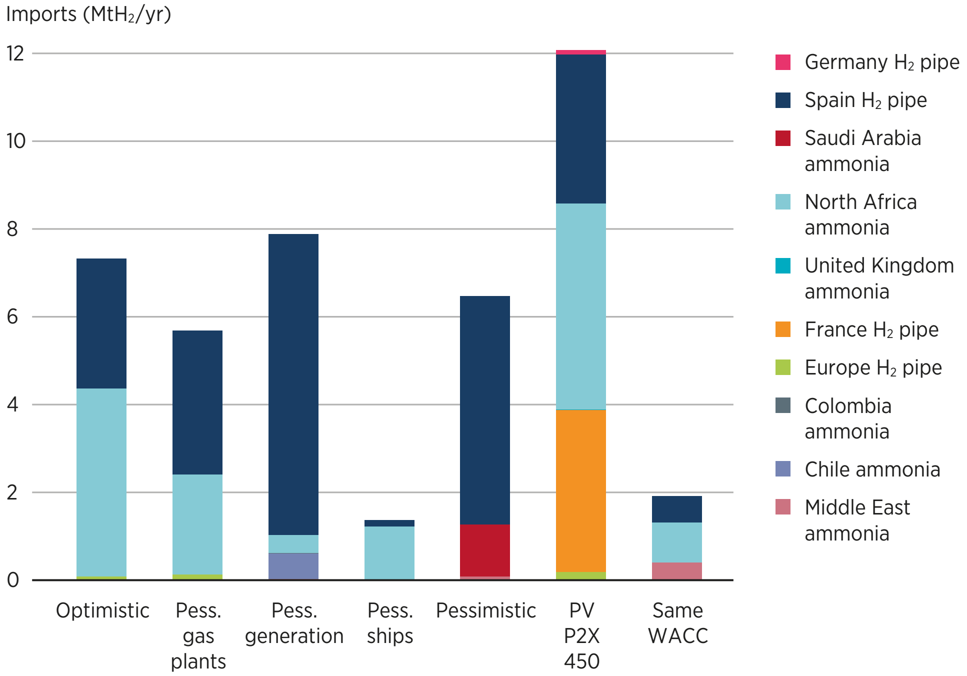
Notes: TES in 2020 puts the hydrogen potential values into perspective. See Annex for more details on methodology and assumption for technical potential.

Hydrogen and ammonia trade outlook for 2050

Italy could act as a transit country (like Spain) between North Africa and demand centres in northwest Europe, and between the Iberian Peninsula (with rich renewable resources and vast potential) and the eastern European countries. Thus, across scenarios, Italy mostly imports between 1.5 MtH_2/year and 7 MtH_2/year by pipeline from Spain and 1 MtH_2/year and 4.5 MtH_2/year in the form of ammonia by ships from North Africa (see Figure 1.26). Most of these flows are re-exported to the rest of Europe, complemented by some additional domestic production that is also exported (IRENA, 2022f).

ITALY

FIGURE 1.26 Total hydrogen imports to Italy across scenarios for 2050



Source: IRENA (2022e).

Note: Estimated hydrogen demand in 2050 for Italy is in the order of 7 MtH_2/year. Optimistic CAPEX assumptions for 2050 (global range): PV: USD 225/kW to USD 455/kW; onshore wind: USD 700/kW to USD 1 070/kW; offshore wind: USD 1 275/kW to USD 1 745/kW; electrolyser: USD 130/kW. WACC: Per 2020 values without technology risks across regions. CAPEX assumptions for the pessimistic (Pess.) scenario: PV: USD 271/kW to USD 551/kW; onshore wind: USD 775/kW to USD 1 191/kW; offshore wind: USD 1 317/kW to USD 1 799/kW; electrolyser: USD 307/kW. Same WACC refers to a scenario where all the countries have the same risk profile, resulting in the same WACC (5%) across all countries. Pess. ships and Pess. gas plants use roughly double the costs for these steps and consider the rest of the values with an optimistic outlook (single change). Pess. generation only considers higher CAPEX for solar PV and onshore wind. PV P2X 450 uses a capital cost of USD 450/kW for solar PV and the electrolyser.

POLICY ANALYSIS

TABLE 1.7 Analysis of Italian hydrogen strategic documents

	Category	Priority level	Targets	Policies
SUPPLY	Green hydrogen	●●	→ 1 GW capacity by 2026 → 5 GW capacity by 2030	Grants, Taxation, R&D
SUPPLY	Blue hydrogen	●○		
SUPPLY	Other hydrogen	○○		
DISTRIBUTION	Ships	○○		
DISTRIBUTION	Trucks	●○		
DISTRIBUTION	Pipelines	●○		
DISTRIBUTION	Storage	●○		Research and development
DISTRIBUTION	Blending	●●		R&D, Standards
END-USE	Steelmaking	●○	→ 2% of hydrogen in TFEC by 2030 → 20% of hydrogen in TFEC by 2050	Grants, Research and development, Standards
END-USE	Petrochemical	●●		
END-USE	Other industry	●○		
END-USE	Shipping	●○		
END-USE	Aviation	●○		
END-USE	Trains	●●		
END-USE	Trucks	●●		
END-USE	Buses	●○		
END-USE	Cars	○○		
END-USE	Power generation	●○		
END-USE	Residential heating	●○		
END-USE	Other		→ 200 000 jobs → EUR 27 billion in GDP → EUR 10 billion of investments → 8 Mt of avoided CO_2 by 2030	

●● High priority
●○ Priority/mentioned
○○ Low/no priority

■ Adopted
■ Announced

In November 2020, the Ministry of Economic Development published the "Italian Hydrogen Strategy preliminary guidelines" (hereafter: the Italian strategy).

The document is, as the name states, a preliminary document to present the high-level vision of the government on the evolution of the hydrogen sector. It sets medium and long-term objectives, according to which the hydrogen is expected to cover of 2% of TFEC by 2030 and 20% by 2050. The sectors identified for the use and development of hydrogen include public transportation, chemicals, and refining. A 2% blending in the fossil gas grid is also considered. While blue hydrogen is mentioned in the strategy, green hydrogen has a clear prominence.

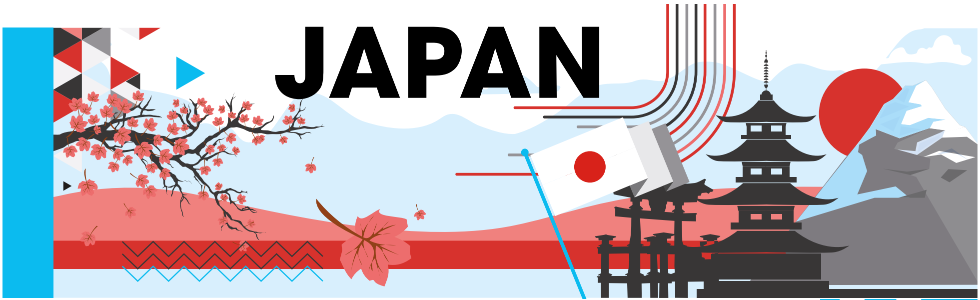
Being a high-level document, it does not contain details on the specific policy measures to be adopted to support hydrogen, with the exception of funding. As with many hydrogen strategies published in 2020, the Italian strategy aims to use the recovery from the COVID-19 crisis to support hydrogen. The National Recovery and Resilience Plan, approved in 2021 to revive the economy after the COVID-19 pandemic, allocated around EUR 3.5 billion (USD 3.4 billion) to kickstart the hydrogen sector.

By mid-2022, total announced investments in green hydrogen in Italy totalled EUR 3.6 billion (USD 3.5 billion) (from 2021 to 2026). This includes investments in R&D, development of the supply chain for electrolysers, and development of hydrogen valleys in current industrial areas, railways, hydrogen refuelling stations (HRS) and hard-to-abate industries. Hard-to-abate industries, in particular, are meant to receive up to EUR 500 million (USD 508 million) a year from 2021 to 2026 for their decarbonisation. One of the first research hubs is the ENEA Hydrogen Demonstration Valley project, which acts as a testing hub for hydrogen technologies covering production, storage, and distribution of hydrogen and hydrogen blends.

In the meantime, other policies have been adopted to support green hydrogen. For example, electrolytic processes are exempt from the payment of electricity fees, since new rules recognise hydrogen as an energy vector and electrolysis as a transformation process, and not as an end-use. Additionally, the authorisation process for electrolysers with a capacity up to 10 MW has been simplified. In June 2022, hydrogen blending up to 2% in volume was allowed in transmission and distribution gas networks.

More enabling policies for green hydrogen are to be expected in Italy if the sector is to grow as intended in the Italian strategy. Measures to promote the consumption of green hydrogen are under governmental analysis and should be made public by the end of 2023.

Given the relevance that the green hydrogen sector can have in Italy, pursuing these announced developments is key. It provides stakeholders with clarity about government priorities and objectives, and presents the expected actions by the Italian government in this realm and the funding that will be available. More detailed targets or even hydrogen quotas could inform stakeholders about expected hydrogen production needs, reducing the volume risk for potential hydrogen producers.



HYDROGEN SECTOR STATUS

Status for hydrogen and renewables

In 2020, Japan produced around 2 MtH_2. About 50% of this came from fossil gas reforming, complemented by 45% coming as a by-product from steel, steam cracking and chlor-alkali and 5% from coal. Refineries are the dominant hydrogen application, with 90% of the demand, and with ammonia production representing the balance (IEA, 2021a). In 2021, the specific CO_2 emissions from electricity production were 461 gCO_2/kWh with 22% of the electricity produced from renewables and 6% from nuclear (Climate Transparency, 2021b). Variable renewables had an installed capacity of 4.4 GW of onshore wind and 74.2 GW of solar PV by the end of 2021 (IRENA, 2022d) contributing to about 6% of the generation mix.

Outlook for hydrogen in 2050

Japan targets a 20 MtH_2/year demand by 2050. This is a relatively fast ramp-up from the 3 MtH_2/year target by 2030. One of the main uses for the imported hydrogen is for power generation, where it needs a supply cost level of about USD 1.50/kgH_2. An alternative for power generation is to use a hydrogen derivative – ammonia (NH_3) – and co-fire it with coal. There are ongoing tests to demonstrate co-firing at 20% at large scale by 2024, with commercial operations beginning in the second half of the 2020s. Technical demonstrations of 50% or more co-firing will be finished by 2028. Additionally, tests of single fuel-firing will be finished by 2030. This will drive the domestic hydrogen demand to reach 3 $MtNH_3$/year by 2030 and 20 $MtNH_3$/year by 2050 (The Government of Japan, 2021).

Low-carbon hydrogen production projects

Japan has multiple electrolysis projects in the kW-scale for research purposes. Most of them have come online since 2016 and focus on PEM electrolysis. The largest electrolysis project is the Fukushima Hydrogen Energy Research Field, a 10 MW alkaline electrolyser coupled with 20 MW of solar PV and the grid, which started operating in 2020. The hydrogen is used for stationary power (fuel cells), mobility and as industrial feedstock. Japan is also aiming to develop synthetic methane which can use the existing infrastructure. The technology development is planned for the 2020s, reaching a scale of 400 normal cubic meters per hour (Nm^3/hour) by 2025, with demonstration of the technology at a larger scale (10 000 Nm^3/hour) by 2030 and full commercialisation (60 000 Nm^3/hour) after 2030. Synthetic methane is expected to represent 90% of the gaseous fuel mix (city gas) by 2050, reaching 1% of the gas supply by 2030. Japan has projects underway for both large and small turbines for co-firing of hydrogen and liquefied fossil gas (LNG) and for hydrogen single-fuel firing power generation. In the 500 MW class of power generation, a hydrogen co-firing rate of 30% was achieved in 2018, and development of single-fuel power generation is underway.

Estimated renewable hydrogen cost in 2021

The capital costs for solar PV and onshore wind were USD 1693/kW and USD 3050/kW, respectively, in 2021. The WACCs (real after tax) for utility-scale solar PV and onshore wind were 2.3% and 4.7%, respectively (IRENA, 2022b). Assuming the same capital cost ratio (versus the global average) for the electrolyser, the estimated levelised cost of hydrogen is between USD 10.7/kgH_2 and USD 16.4/kgH_2 for solar PV and USD 13/kgH_2 and USD 18.2/kgH_2 for onshore wind.

Existing and planned infrastructure

Japan does not have any hydrogen pipelines today. Japan has 13 ammonia terminals and two methanol terminals (DNV, 2022). For liquid hydrogen, Japan is the third largest producer in the world (after Canada and the United States), with almost 40 t/d of capacity (Linde, 2019). Japan is on the importing side of the HySTRA[23] project, which uses brown coal from Australia to produce liquid hydrogen and ships it to Japan. The project achieved its first voyage at the pilot scale (1250 m^3) in February 2022. HySTRA aims to scale up to full commercial scale (160 000 m^3 ships) by 2030. Japan has also demonstrated the use of liquid organic hydrogen carriers[24] from Brunei Darussalam at a demo scale (210 t/year) in the AHEAD project in 2020 and the shipment of 40 t of ammonia from fossil gas with carbon capture from Saudi Arabia in 2020. Japanese companies purchased ammonia from fossil gas with carbon capture from the United Arab Emirates in 2021 and 2022.

Renewable hydrogen supply in 2030

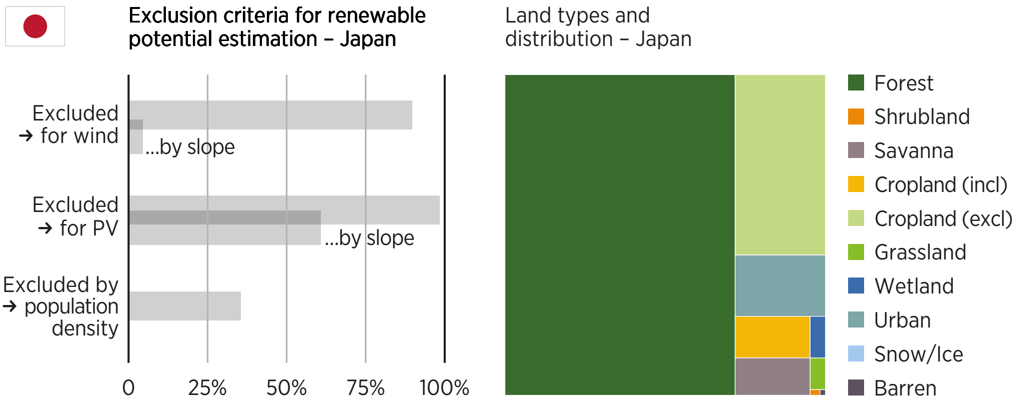
In terms of potential, 72% of the land is covered by forests and considered to be excluded for solar PV and wind installation. Almost 19% of the land is cropland, and only a fraction of this[25] (3% of the land) is assumed to be available for solar PV (but onshore wind is still possible); 61% of the land has a slope unsuitable for solar PV and 4.5% has a slope unsuitable for wind. The population density criterion (130 people per km^2) leads to the exclusion of 35% of the land. This leaves roughly 1.4% and 10% of the land available for solar PV and onshore wind, respectively (see Figure 1.27). This would be enough to produce almost 83 MtH_2/year (technical potential).

[23] The project is also called Hydrogen Energy Supply Chain (HESC).

[24] Hydrogen is produced from natural gas steam reforming as a by-product of a natural gas liquefaction plant.

[25] The land type dataset distinguishes between cropland and cropland/natural. While the former is completely excluded for the installation of PV, the latter, being a mosaic of 40% to 60% cultivated land and the remainder natural trees, shrubs or herbaceous vegetation, is excluded by only a 60% fraction.

FIGURE 1.27 Land types and exclusion criteria for renewable potential estimation in Japan



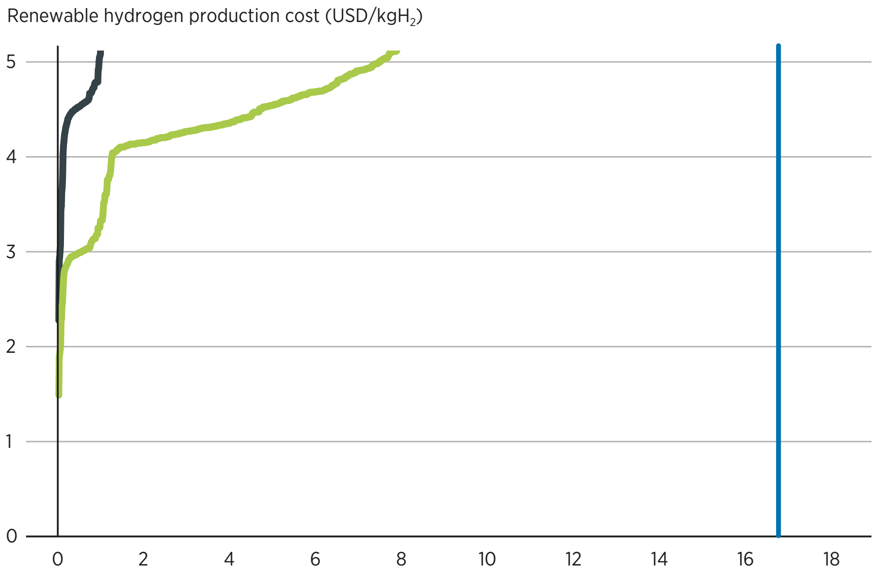
Source: IRENA (2022e).

By 2030, capital costs could come down by 60% for solar PV and by 30% for both onshore wind and electrolysis in a scenario aligned with a 1.5°C trajectory (IRENA, 2022f). Considering these costs, the economic potential below USD 2/kgH_2 would only be 0.3 MtH_2/year for a scenario with low costs in 2030.[26] See Annex for more details on the assumptions and methodology for the technical potential.

[26] There is no economic potential below USD 2.00/kgH_2 for a scenario with higher costs (pessimistic). The potential does not consider competition of resources for electricity, which means this low potential will most likely be used for electricity.

JAPAN

FIGURE 1.28 Supply cost curve for Japan in a low-cost scenario in 2030



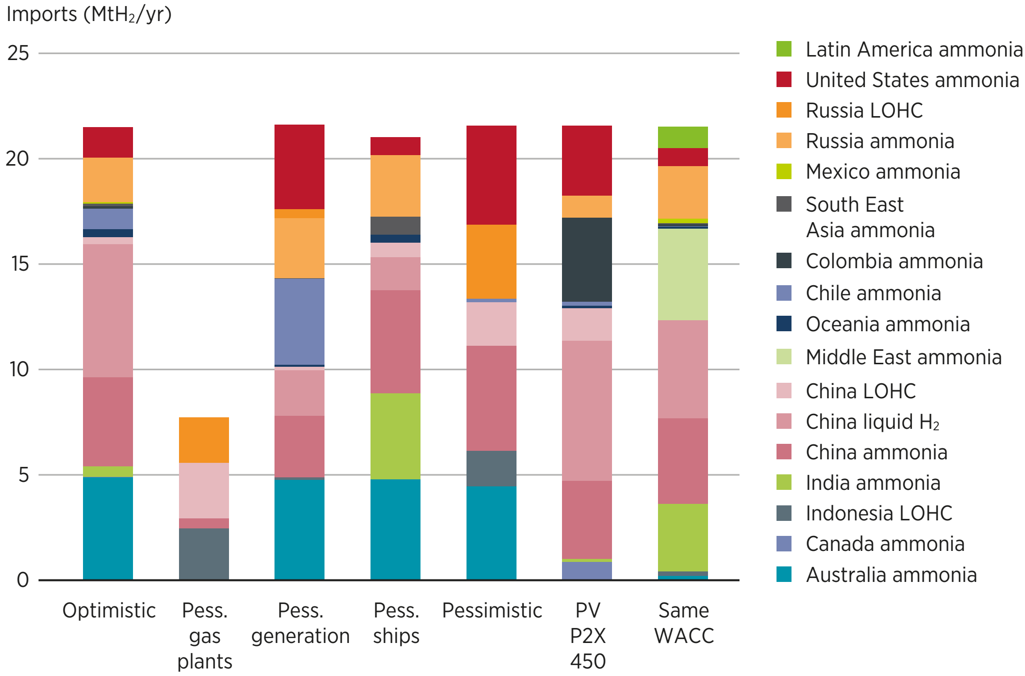
Source: IRENA (2022e).

Notes: TES in 2020 puts the hydrogen potential values into perspective. See Annex for more details on methodology and assumption for technical potential.

Hydrogen and ammonia trade outlook for 2050

Japan is one of the few countries with an explicit import or export target. It targets 300 ktH$_2$/year by 2030 (out of 3 MtH$_2$/year of demand). Japan faces the dual challenge of limited land area available for renewable energy (see section above and Obane, Nagai and Asano [2020]; Renewable Energy Institute [2020]) and high capital costs for renewables. This means the scarce renewable resource is better used directly as electricity rather than for conversion (and associated energy losses) to hydrogen. As a result, Japan ends up importing all of its hydrogen and ammonia demand for most scenarios (see Figure 1.29). The only scenario where this is not the case is one where the conversion costs (from hydrogen to the carrier and back to hydrogen), which can represent 15% to 20% of the landed cost in Japan, are double those of the reference values. This would make imports more expensive, and the worst domestic renewable resources would be more attractive. Hydrogen imports for Japan are expected to be transported via ships. Ammonia is the dominant carrier due to its low transport cost and the potential to use it directly as a fuel – especially relevant for Japan, which targets ammonia for power generation. Given that the transport cost of ammonia is relatively low, the supply mix for Japan can be relatively varied with multiple countries in a narrow cost range (IRENA, 2022f).

FIGURE 1.29 Total hydrogen imports to Japan across scenarios for 2050



Source: IRENA (2022f).

Note: Estimated hydrogen demand in 2050 for Japan is on the order of 22 MtH_2/year. Optimistic CAPEX assumptions for 2050 (global range): PV: USD 225/kW to USD 455/kW; onshore wind: USD 700/kW to USD 1 070/kW; offshore wind: USD 1 275.kW to USD 1 745/kW; electrolyser: USD 130/kW. WACC: Per 2020 values without technology risks across regions. CAPEX assumptions for the pessimistic (Pess.) scenario: PV: USD 271/kW to USD 551/kW; onshore wind: USD 775/kW to USD 1 191/kW; offshore wind: USD 1 317.kW to USD 1 799/kW; electrolyser: USD 307/kW. Same WACC refers to a scenario where all the countries have the same risk profile, resulting in the same WACC (5%) across all countries. Pess. ships and Pess. gas plants use roughly double the costs for these steps and consider the rest of the values with an optimistic outlook (single change). Pess. generation only considers higher CAPEX for solar PV and onshore wind. PV P2X 450 uses a capital cost of USD 450/kW for solar PV and the electrolyser.

POLICY ANALYSIS

TABLE 1.8 Analysis of Japanese hydrogen strategic documents

	Category	Priority level	Targets		Policies	
SUPPLY	Green hydrogen	●●	→ CAPEX: USD 473/kW	→ USD 3.15/kg (2030) → USD 2.15/kg (future)		Grants Standards Strategies/ planning External consultation Research and development
	Blue hydrogen	●●				
	Other hydrogen	●●				
DISTRIBUTION	Ships	●●			R&D	
	Trucks	○○				
	Pipelines	○○				
	Storage	○○				
	Blending	○○				
END-USE	Steelmaking	●○		→ 300 000 tH_2 consumed by 2030		
	Petrochemical	●●				
	Other industry	●○				
	Shipping	●●			Grants	
	Aviation	○○				
	Trains	●○				
	Trucks	●●			Grants R&D	
	Buses	●●	→ 1200 buses by 2030			
	Cars	●●	→ 800 000 cars by 2030 → 900 HRS* by 2030			
	Power generation	●●	→ Fuel cells USD 160/MWh by 2030		R&D	
	Residential heating	●●	→ 3 million fuel cells by 2030		R&D	
	Other					

*HRS - Hydrogen Refueling Stations

●● High priority
●○ Priority/mentioned
○○ Low/no priority

Adopted
Announced

The 2014 "Japanese Hydrogen Society Roadmap" is one of the world's first hydrogen strategic documents. The roadmap has been updated several times, most recently in 2019 with the publication of the "Strategic Road Map for Hydrogen and Fuel Cells" (hereafter: Japanese strategy).

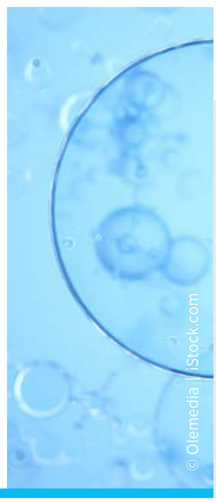
In October 2020, Japan declared that it aims to achieve carbon neutrality by 2050, with the goal of reducing overall GHG emissions to zero by that date. The Ministry of Economy, Trade and Industry developed a Green Innovation Fund at the level of JPY 2 trillion (Japanese yen; USD 14.2 billion) to support, for the coming ten years, projects that can assist such objectives, including hydrogen projects. The Japanese government announced in 2021 the allocation of up JPY 370 billion (USD 2.8 billion) from this fund to promote hydrogen. JPY 70 billion (USD 500 million) was allocated in particular to promote green hydrogen electrolysis. However, the pipeline of new electrolyser projects is a mere 102 MW.

The Japanese strategy primarily aims to achieve cost parity with competing fuels, such as gasoline in the transportation sector or LNG in power generation. Given limited natural resources and limited land availability, hydrogen import plays a key role in the Japanese strategy. The approach has been to pursue parallel demonstration projects with multiple sources, hydrogen carriers and end-use sectors to de-risk future imports and increase the flexibility of supply. Moreover, the archipelagic nature of the country makes it an ideal testbed for various shipping solutions.

Japanese public and private stakeholders, backed by the government, have signed various bilateral agreements to import hydrogen produced in different countries and regions (including ASEAN countries, Australia, GCC countries and the United States), with different technologies and different shipping solutions. Through the Green Innovation Fund, the Japanese government has funded demonstration projects with liquefied hydrogen and methylcyclohexane (MCH) to develop a global hydrogen supply chain.

The first shipments from pilot or demonstration projects in Australia, Brunei and Saudi Arabia did not involve low-carbon hydrogen.

JAPAN



While these projects are not carbon-neutral, they can be useful to understand the most cost-competitive and sustainable ways of shipping green hydrogen. The economic and geographical circumstances of each country are different, and Japan seeks to co-operate with various countries to address climate change and realise the transition to carbon-neutral via various paths. Japan's approach differs from other G7 countries for two main reasons: first, it focuses on consumer applications (FCEVs and fuel cells) and, second, it uses a carbon-neutral approach for the hydrogen production, allowing the import of grey hydrogen and enabling new grey and blue hydrogen production planning in the ASEAN region (ACE, 2022).

In Japan, there were over 6 700 FCEVs and over 430 000 stationary fuel cells for residential use by 2021. The Japanese government has been continuing efforts, such as providing subsidies for FCEVs, to achieve its targets. However, battery vehicles and heat pumps are set to become the cheapest solutions for transport and residential heating, while for the hard-to-abate sectors, hydrogen is among the few solutions able to achieve decarbonisation. Indeed, achievement of the FCEV and fuel cell targets can be challenging (BNEF, 2020): a recalibration hydrogen's intended uses, favouring industrial applications, may keep the hydrogen consumption target afloat.

The Japanese government is conducting demonstration projects, such as for hydrogen burners and boilers for the hard-to-abate sectors, to achieve decarbonisation. The Japanese government established a new subcommittee for hydrogen policy in March 2022. The subcommittee examines ways to expand the introduction and commercialisation of hydrogen and ammonia, focusing on the price difference with existing fuels and the state of infrastructure development.

Refocusing on green hydrogen production and import would yield many advantages. By imposing a maximum carbon footprint threshold for imported hydrogen, Japan would spur green hydrogen projects – and therefore renewable electricity development – in the ASEAN region, taking leadership of regional environmental stewardship.

HYDROGEN SECTOR STATUS

Status for hydrogen and renewables

In 2020, the United Kingdom produced around 0.5 MtH_2. About 89% of this was produced from fossil gas reforming with the balance coming as a by-product from steel, steam cracking and chlor-alkali. Refineries are the dominant hydrogen application, with 52% of the demand, followed by chemicals (40%) (Fuel Cells and Hydrogen Observatory, 2022). In 2021, the specific CO_2 emissions from electricity production were 268 gCO_2/kWh with 27% of the electricity produced from renewables and 15% from nuclear (Ember Climate, 2022). Variable renewables had an installed capacity of 14.4 GW of onshore wind, 12.7 GW of offshore wind and 13.7 GW of solar PV by the end of 2021 (IRENA, 2022d), contributing to about 25% of the generation mix.

Outlook for hydrogen in 2050

The United Kingdom was a pioneer in 2019 when it set a net-zero emissions target by 2050. The country sees a crucial role for hydrogen to achieve its net-zero ambitions. By 2050, hydrogen demand is estimated to be 7.5 MtH_2/year to 13.8 MtH_2/year for a net-zero scenario, representing 20% to 35% of the final energy demand (BEIS, 2021b). Hydrogen derivatives are a leading solution for industry and transport (including shipping), where demand could reach 3 MtH_2/year to 7.4 MtH_2/year. Demand for power is relatively small (0.75 MtH_2/year to 1.2 MtH_2/year), but is essential in providing flexibility to the grid and for integrating variable renewables.

The largest uncertainty is in the building sector, where hydrogen demand ranges from nothing to 6.3 MtH_2/year (BEIS, 2021c). The reason for this uncertainty is that the government is still collecting evidence from R&D projects and trials to inform decisions to be made in 2026 on the role of 100% hydrogen in heat decarbonisation.

On the supply side, there is a mix of three pathways: methane reforming with carbon capture, use and storage (CCUS), which could supply 0.3 MtH_2/year to 10 MtH_2/year; electrolysis, which could supply 0.6 MtH_2/year to 4 MtH_2/year; and biomass gasification with CCUS, which could supply 1.5 MtH_2/year to 3 MtH_2/year. The wide range is driven by the uncertainty in cost and performance of each technology over time (including CO_2 capture rate), the cost and availability of low-carbon electricity, sustainable biomass availability, and the scale of the demand (if demand is too large, then multiple production routes may be needed at scale). To supply this hydrogen, a capacity of 15 GW to 60 GW (running at 95% capacity factor) would be needed (BEIS, 2021c). This could be significantly higher if production runs at lower load factors.

Estimated renewable hydrogen cost in 2021

The capital costs for solar PV and onshore wind were USD 848/kW and USD 1 980/kW, respectively, in 2021. The WACCs (real after tax) for utility-scale solar PV and onshore wind were 2% and 2.6%, respectively (IRENA, 2022b). Assuming the same capital cost ratio (versus the global average) for the electrolyser, the estimated levelised cost of hydrogen is USD 4.3/kgH_2 to USD 8.6/kgH_2 for solar PV and USD 6.6/kgH_2 to USD 9.3/kgH_2 for onshore wind. Alongside the 2021 UK Hydrogen strategy, a report was published which presents levelised cost estimates for different hydrogen production technologies (BEIS, 2021d).

Existing and planned infrastructure

The United Kingdom has almost 40 km of hydrogen pipelines (HyArc, 2016), four ammonia terminals and five methanol terminals (DNV, 2022). It does not have any hydrogen liquefaction capacity today. UK hydrogen storage currently mainly consists of on-site aboveground storage, with one operational underground salt cavern storage facility in Teesside with a capacity of 0.025 TWh. Current infrastructure can only facilitate the use of hydrogen in industrial processes rather than for use in the energy system.

The UK strategy envisages an eventual regional (or even national) pipeline network with multiple entry and exit points, supported by a number of large-scale geological storage facilities. The UK government is reviewing the requirements for a hydrogen network in the 2020s and beyond, including economic regulation and funding, and it is reviewing the feasibility, costs and benefits of different infrastructure options to enable strategic decisions in 2026 on the role of 100% hydrogen for heat. There are several feasibility studies and pilots to inform this decision, including: Project Union, a concept for a 2 000 km (about 25% of the gas network) hydrogen backbone to be completed in the early 2030s (Gas Transmission and Metering, 2022); H21, a series of industry-led projects to convert the fossil gas network to hydrogen by developing understanding of the technical changes and safety considerations needed (H21, n.d.); HyNet, that focuses on blue hydrogen for industrial applications (HyNet, 2020); the FutureGrid programme, demonstrating hydrogen transport in an offline facility and helping to develop the safety standard (Gas Transmission and Metering, 2022: 12-3); and H100, demonstrating hydrogen use for residential heating in a small (300 houses) network starting in 2023. There are also several projects at the pilot/trial phase aiming to de-risk blending (decision to be taken by 2023), such as HyDeploy.

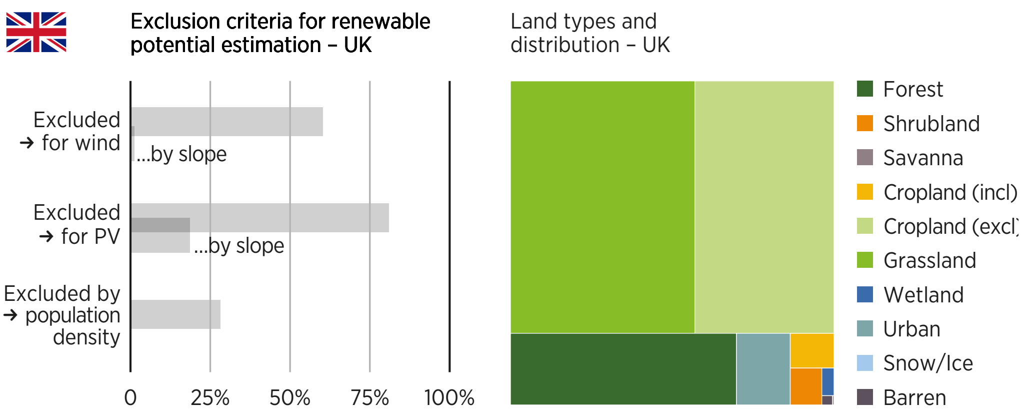
Between 11 TWh and 56 TWh of hydrogen storage may be required in the United Kingdom by 2050 (National Grid ESO, 2022), providing system flexibility and balancing misalignment in supply and demand. There are several planned large-scale underground hydrogen storage projects in the public domain which are in planning stages.[27]

[27] This includes two salt cavern storage facilities: Aldbrough storage facility, providing up to 320 GWh of capacity, and HyNet salt cavern, with a planned capacity of 1.3 TWh. There is also a proposal to store hydrogen in Rough, a depleted gas field, which could provide up to 9 TWh of capacity.

Renewable hydrogen supply in 2030

In terms of potential, almost 35% of the land is cropland, and only a fraction of this[28] (1.4% of the land) is assumed to be available for solar PV (but onshore wind is still possible); 15% of the land is covered by forests and considered to be excluded for solar PV and wind installation. About 18% of the land has a slope unsuitable for variable Solar PV and 0.5% has a slope unsuitable for wind. The population density criterion (130 people per km^2) leads to the exclusion of 28% of the land. This still leaves roughly 19% and 40% of the land available for solar PV and onshore wind, respectively (see Figure 1.30). This would be enough to produce almost 48 MtH_2/year (technical potential).

FIGURE 1.30 Land types and exclusion criteria for renewable potential estimation in the United Kingdom

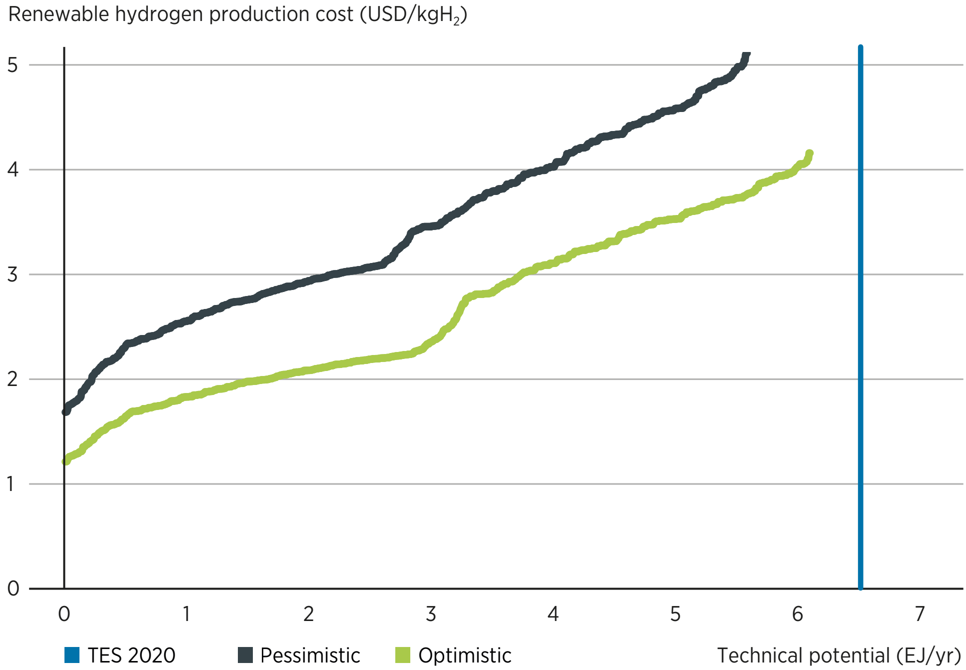


Source: IRENA (2022e).

[28] *The land type dataset distinguishes between cropland and cropland/natural. While the former is completely excluded for the installation of PV, the latter, being a mosaic of 40% to 60% cultivated land and the remainder natural trees, shrubs or herbaceous vegetation, is excluded by only a 60% fraction.*

The cost for renewable power generation is expected to continue to fall due to economies of scale. By 2030, capital costs could come down by 60% for solar PV and by 30% for offshore wind, onshore wind and the electrolyser, in a scenario aligned with a 1.5°C trajectory (IRENA, 2022f). Considering these costs, the economic potential below USD 2.00/kgH_2 would be 1.8 MtH_2/year to 13.8 MtH_2/year in 2030[29] (see Figure 1.31) (IRENA, 2022e). See Annex for more details on the assumptions and methodology for the technical potential.

FIGURE 1.31 Supply cost curve for the United Kingdom in a low-cost scenario in 2030



Source: IRENA (2022e).

Notes: TES in 2020 puts the hydrogen potential values into perspective. See Annex for more details on methodology and assumption for technical potential.

[29] *Range captures the uncertainty in CAPEX and WACC trends to 2030 by using two scenarios with optimistic (the lowest cost estimates) and pessimistic (high cost) values. Potentials do not consider competition of resources for electricity, which means low potentials will most likely be used for electricity, leaving a limited amount for hydrogen production.*

Hydrogen and ammonia trade outlook for 2050

The United Kingdom has enough domestic resources and multiple pathways to satisfy its hydrogen (derivatives) demand. The extent to which the UK can become a hydrogen exporter will depend on technology evolution towards 2050 (including electrolyser cost and CO_2 capture rate), whether importers are technology neutral, and the development of international standards and certification schemes. The United Kingdom will develop its Low Carbon Hydrogen Standard into a certification scheme by 2025 to support international trade and market development.

Part of the electrolytic hydrogen production in the United Kingdom is expected to rely on offshore wind (the United Kingdom has committed to deliver 50 GW of offshore wind by 2030). In July 2022, there was a record bid of USD 44/MWh for fixed-bottom turbines, which is even lower than the record for onshore wind (USD 50/MWh). The electricity price is the main cost driver for hydrogen production; even USD 44/MWh would represent a hydrogen production cost of USD 2/kg (assuming 30% losses in electrolysis). This would be higher than other regions that could have solar PV or onshore wind in the USD 10/MWh to USD 20/MWh range by 2050 (IRENA, 2022f) and also access to low-cost transport (*e.g.* southern Europe or North Africa).

Regarding export by pipelines, new or re-purposed pipelines may be in operation by 2050. The National Grid is working with European counterparts on the European Hydrogen Backbone through its "Project Union" work. The use of existing gas interconnectors between the United Kingdom and Belgium, Netherlands and Ireland may enable the United Kingdom to trade low-carbon hydrogen with its neighbours in the future.[30] For example, there is work ongoing to evaluate the suitability of the Belgian interconnector for hydrogen transport, which is a 40-inch pipeline that has a capacity of 25.5 bcm (equivalent to about 21 GW[31]) (Fluxys, n.d.). The United Kingdom could use ships to export its hydrogen. For this route, the advantage of proximity to continental Europe that United Kingdom has could have limited benefit since most of the energy losses and costs are in the (re)conversion steps rather than in the shipping step (IRENA, 2022g).

The export opportunity for the United Kingdom might lie in exporting technology and equipment, building upon its developed hydrogen industry, rather than exporting hydrogen as a commodity.

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[30] *IUK Belgium and BBL Netherlands connect the United Kingdom to the mainland EU gas market.*

[31] *Assuming a lower heating value of 40 megajoules/m³ and considering the difference in properties between natural gas and hydrogen.*

POLICY ANALYSIS

TABLE 1.9 Analysis of UK hydrogen strategic documents

	Category	Priority level	Targets	Policies	
SUPPLY	Green hydrogen	●●	→ Up to 1 GW by 2025 of electrolytic H_2 in construction or operational → Up to 2 GW by 2025 of H_2 production capacity (including blue hydrogen) in construction or operational → 10 GW by 2030, at least half of which will come from electrolytic hydrogen*	Grants, External consultation, Standards, Strategies/planning	External consultation, Research and development, Jobs and Training, Trade policies
	Blue hydrogen	●●			
	Other hydrogen	●○			
DISTRIBUTION	Ships	●●			
	Trucks	●●			
	Pipelines	●●			
	Storage	●●			
	Blending	●○			
END-USE	Steelmaking	●○			
	Petrochemical	●●			
	Other industry	●○			
	Shipping	●●			
	Aviation	○○			
	Trains	●○			
	Trucks	●●			
	Buses	●●			
	Cars	●●			
	Power generation	●●			
	Residential heating	●●			
	Other		→ 12 000 jobs by 2030 → 100 000 jobs by 2050 → Unlock more than USD 10.9 billion in private investment by 2030		

* from the British Energy Security Strategy

●● High priority
●○ Priority/mentioned
○○ Low/no priority

Adopted
Announced

In August 2021, the United Kingdom published its first Hydrogen Strategy, which sets out a comprehensive roadmap to support the development of a hydrogen economy over the 2020s and beyond. More than 50 government commitments were outlined, including policy detail on support mechanisms for low-carbon hydrogen production across the country.

Like other fossil gas rich countries (*e.g.* Canada), the United Kingdom eyes export opportunities, but the UK strategy focuses mostly on securing domestic deployment of any shade of low-carbon hydrogen while serving all possible end uses with hydrogen. The strategy pursues a 'twin track' approach, inclusive of both blue and green hydrogen in reaching the target of 5 GW of production capacity by 2030. However, the 2022 British Energy Security Strategy increased the target to 10 GW of production capacity, including hydrogen produced from nuclear energy. At least 5 GW should be from electrolytic hydrogen, taking advantage of otherwise curtailed VRE production. Similar to Canada, the UK strategy supports all end uses, with the notable exception of light-duty FCEVs. Notably, large space is dedicated to the use of hydrogen for residential heating.

The strategy acknowledges that the hydrogen sector is an evolving one and commits to the creation of many national and international working groups, awareness programmes, and makes a call for evidence to better operate in the field in the future.

Industrial fuel switching in the United Kingdom will be supported by a variety of funds, for a total up to GBP 460 million (USD 540 million), including the Industrial Energy Transformation Fund, the Industrial Hydrogen Accelerator programme, the Industrial Fuel Switching 2 competition, the Red Diesel Replacement Scheme and the Green Distilleries programme.

Innovation and trials for the use of hydrogen in transport are supported by GBP 680 million (USD 790 million) from the Hydrogen for Transport Programme, the Clean Maritime Demonstration Competition, the UK Shipping Office for Reducing Emissions (UK SHORE), the Tees Valley Hydrogen Hub, the Zero Emission Buses Regional Area (ZEBRA) scheme and the Zero Emission Road Freight Demonstrator (ZERFD). Most of these funds provide subsidies for innovative decarbonisation solutions and are not dedicated solely to hydrogen.

The UK government is also working with industry, regulators and other stakeholders to deliver a range of research, development and testing projects on the use of hydrogen for residential heating. This includes a neighbourhood trial of hydrogen for heating due to commence in 2023 to assess the feasibility, costs and benefits of using 100% hydrogen for heating.

The country has committed to designing new business models to support the development of hydrogen transportation and storage by 2025, which will be essential to grow the hydrogen economy and provide security for producers and consumers of hydrogen.

In July 2022, alongside wider funding and policy announcements, the United Kingdom published a Hydrogen Strategy update, which summarised the UK hydrogen policy development and delivery since the publication of the UK Hydrogen Strategy, and also included further detail on the United Kingdom's hydrogen production strategy.

Key policy developments since the publication of the UK Hydrogen Strategy include:

- The launch of the GBP 240 million (USD 280 million) Net Zero Hydrogen Fund and policy detail on the Hydrogen Business Model.
- The conclusion of Phase 1 of the "CCUS Cluster Sequencing process", making public the clusters to be prioritised for deployment in the mid-2020s. The United Kingdom is in the process of shortlisting CO_2 emitter projects – including CCUS-enabled hydrogen producers – to connect to these clusters.
- The Low Carbon Hydrogen Standard set a maximum threshold of 2.4 $kgCO_2/kgH_2$ in the production process for hydrogen. Hydrogen producers seeking government funding must not exceed this threshold.

Overall, the focus on all hydrogen production pathways could make the United Kingdom a large producer of low-carbon hydrogen in the short term, but this approach could put those same targets in jeopardy. Blue hydrogen may become quickly inconsistent with net-zero emissions targets worldwide, and current gas prices make it uncompetitive with green hydrogen in the short term. An earlier focus on green hydrogen could accelerate the cost decrease of this pathway, avoiding the risk of stranded assets. Also, the full value chain approach risks diluting efforts and funding. In particular, developing domestic heating hydrogen solutions may prove tough due to the existence of cheaper and already existing alternatives.

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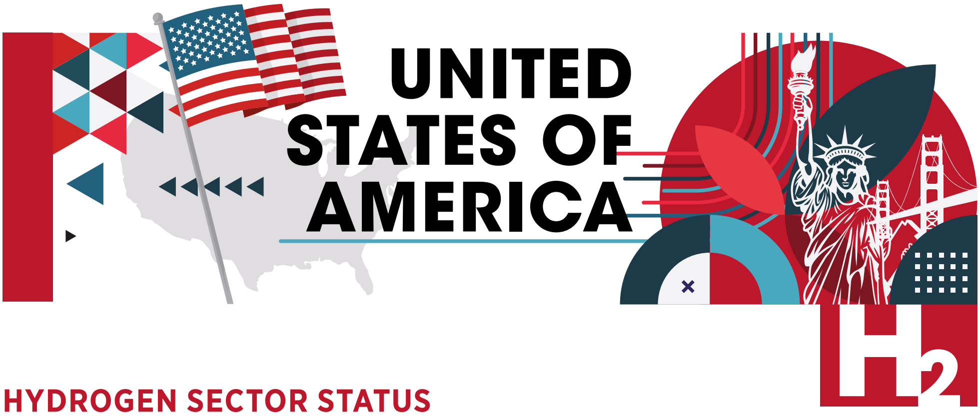

HYDROGEN SECTOR STATUS

Status for hydrogen and renewables

In 2020, the United States consumed around 11 MtH_2. About 80% of this was produced from fossil gas reforming, with the balance coming as a by-product from refineries, steam cracking and chlor-alkali. Refineries are the dominant hydrogen application, with almost two-thirds of the demand, followed by ammonia production (IEA, 2021). In 2021, the specific CO_2 emissions from electricity production were 377 gCO_2/kWh, with 61% of the electricity produced from fossil fuels, 19% from nuclear and 20% from renewables (EIA, 2022). Variable renewables are relatively limited with 132.7 GW of onshore wind and 93.7 GW of solar PV by the end of 2021 (IRENA, 2022d) contributing to about 12% of the generation mix. Out of 50 US states, 6[32] already have over 70% of the generation mix from renewables or nuclear, which opens the opportunity of connecting the electrolysers directly to the grid instead of off-grid plants.

Outlook for hydrogen in 2050

The United States is committed to achieving 50% to 52% GHG reduction by 2030 (vs. 2005) and reaching net-zero by 2050 (UNFCCC, 2021). By 2050, scenario analyses estimate that domestic hydrogen demand could grow to 36 MtH_2/year to 56 MtH_2/year. Although there is a range of estimates by sector, scenarios show transportation (trucks, biofuels, power-to-liquid) is expected to become the dominant application, with 45% (19 MtH_2/year) of the total demand, industry (steel, ammonia, methanol) followed by 25% of the demand, complemented by energy storage (21%) and blending in the fossil gas network for heating (9%) (Satyapal, 2022). A fundamental requirement to reach these demand levels is to achieve a low hydrogen production cost at the point of end use. Hydrogen production would need to reach a levelised cost of USD 1.00/kgH_2 to USD 2.00/kgH_2 to become competitive in the applications that are the most technically challenging. The hydrogen supply mix depends on the assumptions for gas price and electrolyser cost. For low gas prices in 2050 (average of USD 6.60/metric million British thermal units [MMbtu] across the United States) and high electrolyser costs (USD 400/kW_{el}), the mix is dominated by fossil-based hydrogen with CCS (85% to 100%). If gas

[32] *Vermont, South Dakota, Washington, Maine, Idaho and New Hampshire.*

prices are high (an average of USD 11.30/MMBtu across the United States) and the electrolyser costs are low (USD 100 kW_{el} to USD 200/kW_{el}), then the electrolysis share increases to between 40% and 90% (Ruth *et al.*, 2020).

Low-carbon hydrogen production projects

As of May 2022, there were 621 MW of PEM electrolysers under construction or already deployed. This is a threefold increase from the value reported on the same date of the previous year (DoE, 2022). The bulk of the future electrolyser installations comes from four projects, each at 120 MW of electrolysis, from Plug Power (California, Georgia, New York, Texas), which will produce 135 t/d of liquid hydrogen for road transport. Regarding projects using alkaline electrolysis, the Advanced Clean Energy Storage (ACES) project is the most prominent. ACES includes a 220 MW electrolyser and received a conditional loan commitment of USD 504 million from the Department of Energy (DoE) in April 2022 (DoE, 2022). For this project, the hydrogen will be used for power generation with a 30/70 hydrogen/fossil gas mix by 2025, increasing to 100% H_2 by 2045 and coupled with underground storage. Larger projects are planned, but are in earlier stages of planning. For instance, there is a sustainable aviation fuel plant expected to start operations by 2025 which aims to combine agricultural and timber waste feedstock with hydrogen from an 839 MW electrolyser (DG Fuels, 2021). Multiple initiatives and consortia have also received DoE funding aiming to improve the performance of the electrolyser, such as H2NEW, HydroGEN, ElectroCAT and the Hydrogen Shot Incubator Prize. The targets driving these initiatives are a hydrogen production cost of USD 1.00/kg in one decade (also known as the DoE Hydrogen Earthshot or Hydrogen Shot), a capital cost of USD 150/kW for the electrolyser (including balance of plant), 73% efficiency (lower heating value) and 80 000 hours of lifetime by 2030 (Satyapal, 2022).

Estimated renewable hydrogen cost in 2021

The capital costs for solar PV and onshore wind were USD 1166/kW and USD 1400/kW, respectively, in 2021. The WACCs (real after tax) for utility-scale solar PV and onshore wind were 4.3% and 3%, respectively (IRENA, 2022b). Assuming the same capital cost ratio (compared with the global average) for the electrolyser, the estimated levelised cost of hydrogen is USD 7.60/kgH_2 to USD 11.7/kgH_2 for solar PV and USD 5.20/kgH_2 to USD 7.30/kgH_2 for onshore wind. The DoE has reported a range of roughly USD 4.00/kgH_2 to USD 6.00/kgH_2 as the levelised cost using representative solar and wind costs and capacity factors (Vickers *et al.*, 2020).

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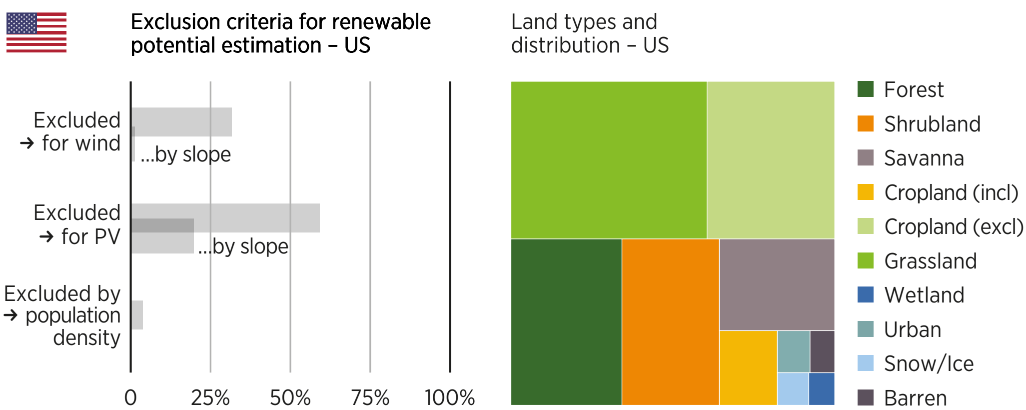
Existing and planned infrastructure

The United States has the world's most extensive hydrogen pipeline infrastructure at almost 2 700 km (HyArc, 2016). Only 250 km is located outside Texas, where the concentrated operation of refineries and industrial facilities creates the economies of scale required to justify hydrogen pipelines and to have merchant suppliers. The United States has 15 ammonia terminals and 14 methanol terminals (10 for both commodities in the Gulf Coast) (DNV, 2022). The United States has the largest hydrogen liquefaction capacity in the world with almost 310 t/d (Linde, 2019). Additionally, the United States has the largest salt cavern in the world used for hydrogen storage, based in the Gulf Coast (Linde Hydrogen, n.d.). There are multiple liquefaction plants planned – including a 90 t/d plant from the H2OK project in Oklahoma that is planning to start operation by 2025 – and additional targets of 500 t/d by 2025 and 1 000 t/d by 2028 by Plug Power.

Renewable hydrogen supply in 2030

In terms of potential, 18% of the land is covered by forests and not considered in analyses for solar PV or wind installation. About 20% of the land has a slope unsuitable for solar PV and 1.6% has a slope unsuitable for wind. The population density criterion (130 people per km^2) leads to the exclusion of 4% of the land. This still leaves roughly 41% and 68% of the land available for solar PV and onshore wind, respectively (see Figure 1.32). This would be enough to produce almost 2 625 MtH_2/year (technical potential).

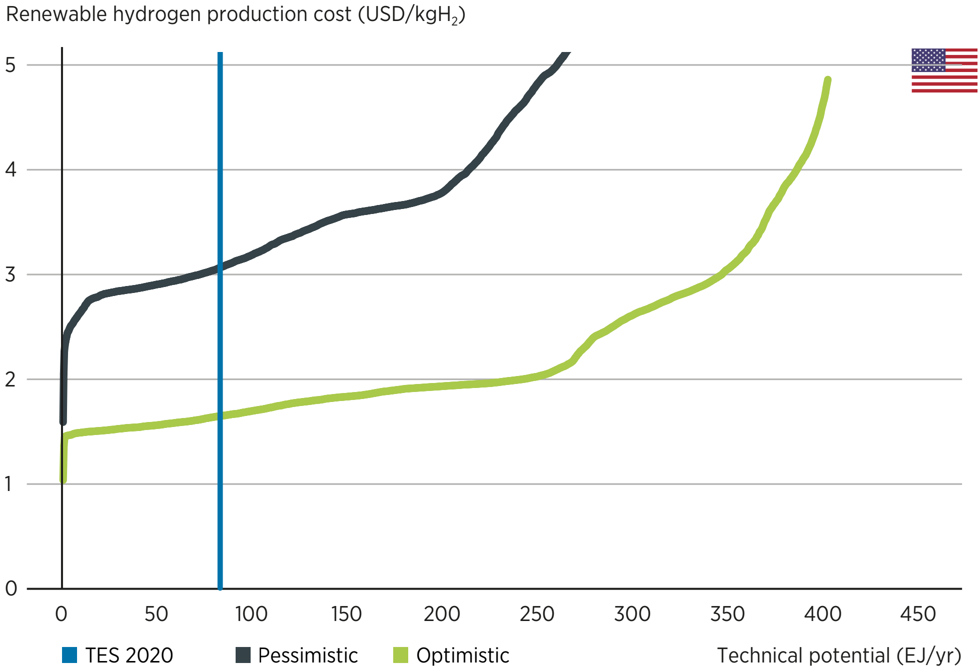
FIGURE 1.32 Land types and exclusion criteria for renewable potential estimation in the United States



Source: IRENA (2022e).

By 2030, some studies estimate that capital costs could come down by 60% for solar PV and by 30% for both onshore wind and electrolysis in a scenario aligned with a 1.5°C trajectory (IRENA, 2022f). Considering these costs, the economic potential below USD 2.00/kgH_2 could result in almost 2 000 MtH_2/year in the most optimistic case for 2030 (see Figure 1.33).[33] See Annex for more details on the assumptions and methodology for the technical potential.

FIGURE 1.33 Supply cost curve for the United States in a low-cost scenario in 2030



Source: IRENA (2022e).

Notes: TES in 2020 puts the hydrogen potential values into perspective. See Annex for more details on methodology and assumption for technical potential.

[33] *Due to the higher CAPEX in the United States, there is no economic potential below USD 2.00/kgH_2 for a scenario with pessimistic (higher) costs.*

Hydrogen and ammonia trade outlook for 2050

Previous analyses have shown that demand in the United States may increase to between 36 MtH_2/year and 56 MtH_2/year by 2050 (Satyapal, 2022). Its vast renewable potential is more than enough to satisfy such demand. Thus, it is unlikely it will become an importer. Instead, its role as an exporter will depend on the extent to which capital costs come down to a level below other regions with rich resources. Soft costs (*e.g.* labour, transmission line, overhead, sales tax) can represent 20% to 25% of the total capital cost for solar PV (NREL, 2022), which increases the average hydrogen production cost compared to other regions.

In a scenario with optimistically low production and transport costs, some estimates project that the United States could export close to 5 MtH_2/year. This amount would be reduced by about 20% in a future where transport costs are higher and by 80% in a future where cost of capital differentials across countries have eroded. This would mean there are other regions closer to large importers (Asia and Europe) with a similar hydrogen production cost that can substitute for the United States. The import can almost triple to 15 MtH_2/year in a scenario where all the costs are higher (IRENA, 2022f). While this increases the production cost in the United States and the transport to importers, it also makes domestic production much more expensive for importers that rely to a larger extent on imports.

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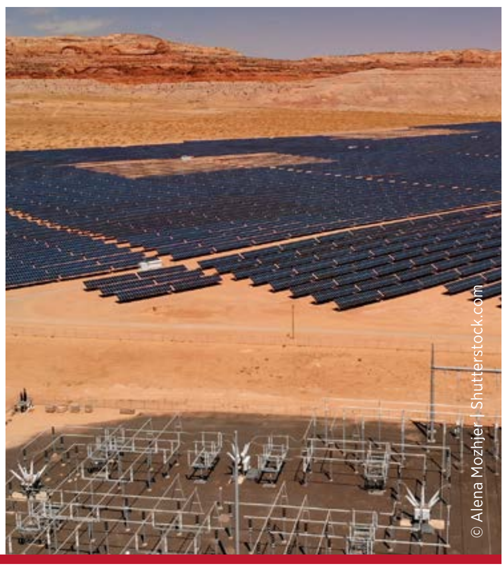
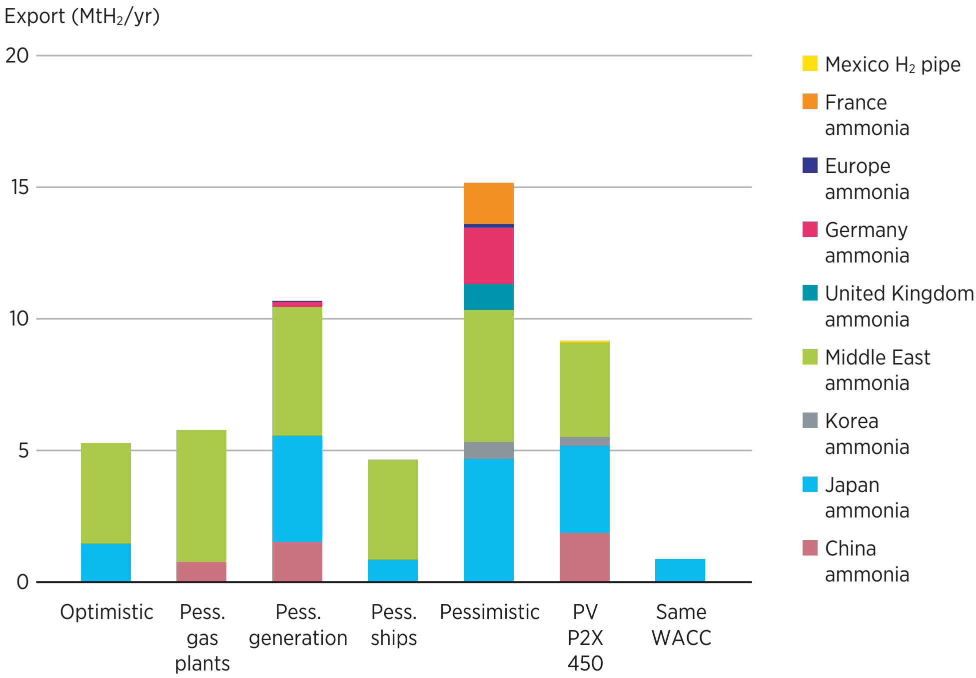


FIGURE 1.34 Total hydrogen export flows from the United States across scenarios for 2050



Source: IRENA (2022f).

Note: Estimated hydrogen demand in 2050 for United States is on the order of 36 MtH_2/year to 56 MtH_2/year. The Middle East appears as an importer because it excludes Saudi Arabia – that is considered separately, being a G20 member – which only leaves countries with high WACC, resulting in a high ammonia production cost and imports becoming more attractive. Optimistic CAPEX assumptions for 2050 (global range): PV: USD 225/kW to USD 455/kW; onshore wind: USD 700/kW to USD 1070/kW; offshore wind: USD 1275/kW to USD 1745/kW; electrolyser: USD 130/kW. WACC: Per 2020 values without technology risks across regions. CAPEX assumptions for the pessimistic scenario: PV: USD 271/kW to USD 551/kW; onshore wind: USD 775/kW to USD 1191/kW; offshore wind: USD 1317/kW to USD 1799/kW; electrolyser: USD 307/kW. Same WACC refers to a scenario where all the countries have the same risk profile, resulting in the same WACC (5%) across all countries. Pess. ships and Pess. gas plants use roughly double the costs for these steps and consider the rest of the values with an optimistic outlook (single change). Pess. generation only considers higher CAPEX for solar PV and onshore wind. PV P2X 450 uses a capital cost of USD 450/kW for solar PV and the electrolyser.

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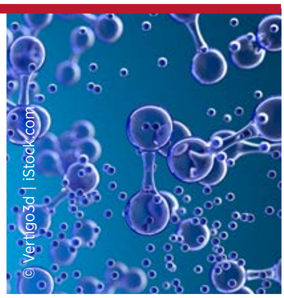
POLICY ANALYSIS

TABLE 1.10 Analysis of US hydrogen strategic documents

	Category	Priority level	Targets	Policies
SUPPLY	Green hydrogen	●●	→ 10 Mt (2010) → 20 Mt (2040) → 50 Mt (2050) → USD 2/kg (2026) → USD 1/kg (2031)	Grants, Taxation
	Blue hydrogen	●●		
	Other hydrogen	●●		
DISTRIBUTION	Ships	○○		
	Trucks	●○		
	Pipelines	●○		
	Storage	●○		
	Blending	●○		
END-USE	Steelmaking	●○		Grants
	Petrochemical	●●		Grants
	Other industry	●○		Grants
	Shipping	●○		Grants
	Aviation	●○		Grants
	Trains	○○		Grants
	Trucks	●●		Grants, Tax-ation
	Buses	●●		Grants, Tax-ation
	Cars	○○		Grants
	Power generation	●○		
	Residential heating	○○		Grants, Tax-ation
	Other			

●● High priority
●○ Priority/mentioned
○○ Low/no priority

Adopted
Announced



Similar to other countries supporting hydrogen solutions, the gas was initially promoted in the United States with a focus on stationary fuel cells and FCEVs. Policies that supported hydrogen did so by including it in a group of alternative fuels for transportation within ZEV policies. This gave FCEVs the opportunity to benefit from incentives given to ZEV in general, without the need for policies that specifically promote hydrogen use.

The past two years, however, represented a game-changing moment for hydrogen policies.

The Hydrogen Shot, launched in June 2021, is a DoE programme seeking to reduce the cost of low-carbon hydrogen to USD 1.00/kg in one decade (by 3031), versus a baseline hydrogen cost of USD 5.00/kg to USD 7.00/kg. The Hydrogen Shot includes support for research, development and demonstration projects. DoE activities in hydrogen include a total of approximately USD 400 million in the 2022 budget request. Under the Hydrogen Shot programme, the DoE announced a fund of USD 64 million to support 18 projects as part of the H2@scale vision for an affordable hydrogen value chain. In particular, around USD 17 million will be provided to projects to scale up electrolyser manufacturing to the gigawatt size. The rest was allocated to demonstration projects, including steelmaking, shipping and heavy-duty applications. Additionally, in August 2022, the DoE announced an additional USD 40 million specifically to support research, development and demonstration activities to advance progress towards the Hydrogen Shot (DoE, 2022).

Another step forward for the hydrogen sector in the United States occurred in June 2022, through determinations providing the DoE with the authority to utilise the Defense Production Act (DPA) to accelerate domestic production of key energy technologies. Similar to the European REPowerEU package, this amendment was signed with the explicit goal of reducing oil and fossil gas dependency. The DPA Executive Order aims to accelerate domestic production of five key energy technologies: (1) solar; (2) transformers and electric grid components; (3) heat pumps; (4) insulation; and (5) electrolysers, fuel cells and platinum group metals. This would be achieved through various mechanisms, including granting the DoE access to the USD 545 million emergency fund to build US manufacturing capacity.

The first stage of an industrial decarbonisation strategy has been undertaken, by setting targets and funding a select number of pilot projects across key industries, with the 2021 Infrastructure Investment and Jobs Act (also known as the Bipartisan Infrastructure Law, or BIL). The BIL allocates USD 9.5 billion for hydrogen, including for hydrogen hub deployments and electrolysis and clean hydrogen manufacturing and recycling projects. The passage of the Inflation Reduction Act in August 2022 will also bring significant support and tax incentives for the production and use of hydrogen (The White House, 2022). In particular, the production tax credit, which will vary based on lifecycle emissions and will total up to USD 3.00/kg for hydrogen production with emissions below 0.45 kg CO_2/kgH_2, is a key support scheme to decrease the cost of low-carbon hydrogen and decrease its offtake risk.

Finally, in September 2022 the draft of the “DoE National Clean Hydrogen Strategy and Roadmap” (hereafter: US strategy) was published. The DoE will elicit stakeholder feedback to publish the final document. While still a draft, the document presents the three main pillars of the US strategy:

- Target strategic, high-impact uses for clean hydrogen. The strategy focuses on sectors where limited decarbonisation alternatives exist. As a result, there is not a particular focus on private cars or residential heating.
- Reduce the cost of clean hydrogen. The Hydrogen Shot will remain a key element of the US strategy.
- Focus on regional networks. The US strategy aims to co-develop large-scale hydrogen production and end-use in proximity.

A specific feature of the US hydrogen policy is the “Justice 40 initiative”, which directs 40% of the overall benefits of certain federal investments – including those on low-carbon hydrogen – to flow to disadvantaged communities (Office of Economic Impact and Diversity, 2022).

The United States may also be one of the signatories of the first carbon content trade agreement. This was announced in November 2021, when the United States agreed with the European Union to modulate its tariffs on steel and aluminium based on the carbon content of the commodities. This new arrangement (which will be negotiated over a three-year period) will give preference to trade in low-carbon commodities. While this will require a strong certification system, it is the basis for a global market for green hydrogen-based products that could be enlarged to other countries.

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CHAPTER **02**

CROSS-STRATEGY ANALYSIS

Chapter 1 focused on the status of the hydrogen sector in the G7 members. This chapter explores the main differences and similarities between G7 hydrogen strategies and policy making. This cross-country analysis is performed with the aim to identify opportunities for collaboration within the G7 framework. Chapter 3 presents recommendations built upon this analysis.

Currently, G7 members consume around 28% of global hydrogen (24 Mt) (see Figure 1.2) and they are set to consume 115 - 192 MtH_2/year by 2050 (see Figure 1.4). Today, hydrogen production is mostly local, while in the future the G7 could have a mix of importers and exporters. The G7 could import 37 MtH_2/year to 62 MtH_2/year by 2050 and export 18 MtH_2/year to 41 MtH_2/year. This amount would represent 29% - 43% of the global trade in hydrogen.

The G7 is also likely to be among the first areas where green hydrogen will see rapid growth. Some of the favourable conditions that will enable this to take place are access to capital, presence of heavy industry, VRE availability, a local green hydrogen industry and technical know-how.

The G7 is therefore in a position to take leadership and responsibility for the development of green hydrogen. If the member governments partly align their strategies, priorities and definitions of supported hydrogen, they could create a core “hydrogen blueprint”. This blueprint could then facilitate investment inside and outside the region, accelerating hydrogen worldwide by creating a solid demand-side that will create investor trust.

Hydrogen strategies differ across G7 members due to different hydrogen sector statuses, hydrogen potential, when hydrogen strategies were written, and industrial leadership, among other elements. However, some differences may be smoothed over to improve collaboration between countries or acknowledged to understand how they can kickstart synergies. The similarities include the use of stages of deployment, the decarbonisation driver and the use of hydrogen valleys as facilitators of deployment. These similarities can work as a basis to foster collaboration among the G7 members and serve as a guideline for countries that have yet to develop their own hydrogen strategies.

2.1 POLICY FRAMING

Hydrogen is currently high on the policy agenda, and the reasons for this vary by country Indeed, G7 hydrogen strategies and policies are framed in different ways. Policy framing is the activity to select the issues that need to be solved. Hydrogen is intended to solve different issues in the strategies, which is in line with the expected outcomes of the energy transition – and that will not influence only the energy sector, but also national economies, society and the Earth as a whole (IRENA, 2022h). Table 2.1 presents the different framing in hydrogen strategic documents published at the time of writing.

TABLE 2.1 Stated policy framing in the hydrogen strategic documents and policies

	Energy diversification	COVID-19 recovery and industrial leadership	Energy security	Decarbonisation
Canada		●		●
European Union		●	● *	●
France		●		●
Germany		●		●
Italy				●
Japan	●			●
United Kingdom		●	● **	●
United States			● ***	●

* In the REPowerEU Plan.

** In the "British Energy Security Strategy".

*** In the DPA amendment and related documents.

The Japanese strategy considers hydrogen as an energy carrier with the potential to diversify Japan's primary energy supply structure away from a heavy reliance on imported fossil fuels from overseas.

Policy makers adopted various measures to support economic growth after the economic effects of the COVID-19 pandemic lockdowns and similar measures were tallied. Green hydrogen measures were adopted and announced within a larger industrial policy for economic recovery, in particular in European countries.

Owing to the increased costs of fossil fuels due to the Russia-Ukraine conflict, energy security ranks high on the policy agenda. The European Union and the United Kingdom re-framed their hydrogen policies under the lens of energy security, increasing their hydrogen targets. It is highly probable that hydrogen documents published in the future will add the energy security frame. This will strengthen the business case and the political will to invest in green hydrogen to reduce dependence on imported fossil fuels.

Finally, the decarbonisation frame ranks high in visibility and position – being one of first topics mentioned, if not in the title itself – highlighting the importance, for the countries, of adopting hydrogen as a decarbonisation tool.

While hydrogen is the common solution for such issues, a different framing can lead to different policies and measures. Identifying a common frame in the G7 framework could align policy making, accelerating the adoption of measures to support hydrogen and therefore hydrogen deployment.

2.2 HYDROGEN PRIORITIES

Countries focus on different ways of both producing and consuming hydrogen (see Table 2.2). On the production side, Canada and the United Kingdom foresee a large role for blue hydrogen in their future, while other countries have a more cautious approach to the use of fossil gas as a feedstock. France, for example, does not mention blue hydrogen in its strategy. Japan is notable for its colour-blind approach. On end uses, hard-to-abate industries are supported by all the G7 governments, while hard-to-abate transport sectors are in some cases left for later stages.

Light-duty FCEVs, power generation and residential heating are sectors currently supported by few countries: in general, countries with fossil gas availability have a more flexible approach, aiming to use hydrogen in any end use where fossil gas is used today, whereas countries that are likely to import hydrogen in the future have a more focused approach.

TABLE 2.2 **Stated policy priority across G7 strategic documents**

	Category	Canada	European Union	France	Germany	Italy	Japan	United Kingdom	United States
SUPPLY	Green hydrogen	●●	●●	●●	●●	●●	●●	●●	●●
SUPPLY	Blue hydrogen	●●	●○	○○	○○	●○	●●	●●	●●
SUPPLY	Other hydrogen	●○	○○	●●	○○	○○	●●	●○	●●
DISTRIBUTION	Ships	○○	○○	●●	○○	○○	●●	●●	○○
DISTRIBUTION	Trucks	●●	○○	●○	○○	●○	○○	●●	●○
DISTRIBUTION	Pipelines	●●	●●	●○	●●	●○	○○	●●	●○
DISTRIBUTION	Storage	●○	●●	●○	○○	●○	●○	●●	●○
DISTRIBUTION	Blending	●●	●○	●○	○○	●●	○○	●○	●○
END-USE	Steelmaking	●●	●●	○○	●●	●○	●○	●●	●○
END-USE	Petrochemical	●●	●●	●●	●●	●●	●●	●●	●●
END-USE	Other industry	●●	●●	●○	●●	●○	●○	●●	●○
END-USE	Shipping	●●	●●	●○	●○	●○	●●	●●	●○
END-USE	Aviation	●●	●●	●○	●●	●○	○○	●●	●○
END-USE	Trains	●●	●○	●●	●●	●●	●○	●●	○○
END-USE	Trucks	●●	●●	●●	●●	●●	●●	●●	●●
END-USE	Buses	●●	●○	●●	●●	●○	●●	●●	●●
END-USE	Cars	●●	○○	○○	●○	○○	●●	●●	○○
END-USE	Power generation	●●	●○	○○	○○	●○	●●	●●	●○
END-USE	Residential heating	●●	○○	○○	●○	●○	●●	●●	○○

●● High priority ●○ Priority/mentioned ○○ Low/no priority

However, despite hydrogen's great potential, it must be kept in mind that its production, transport and conversion require energy, as well as significant investment. Indiscriminate use of hydrogen could therefore slow down the energy transition. This calls for priority setting in policy making.

The first priority should be to decarbonise existing hydrogen applications. About three-quarters of pure hydrogen today is produced from fossil gas, with the remainder produced from coal (mainly in China). This results in annual CO_2 emissions of almost 900 $MtCO_2$, which is about 2.5% of global energy-related CO_2 emissions. The second priority is to use hydrogen in large demand centres that cannot be easily electrified. These are called 'hard-to-abate applications' because the decarbonisation alternatives either have a higher mitigation cost or low technology maturity. Hard-to-abate applications include chemicals, steel, shipping and aviation.[34]

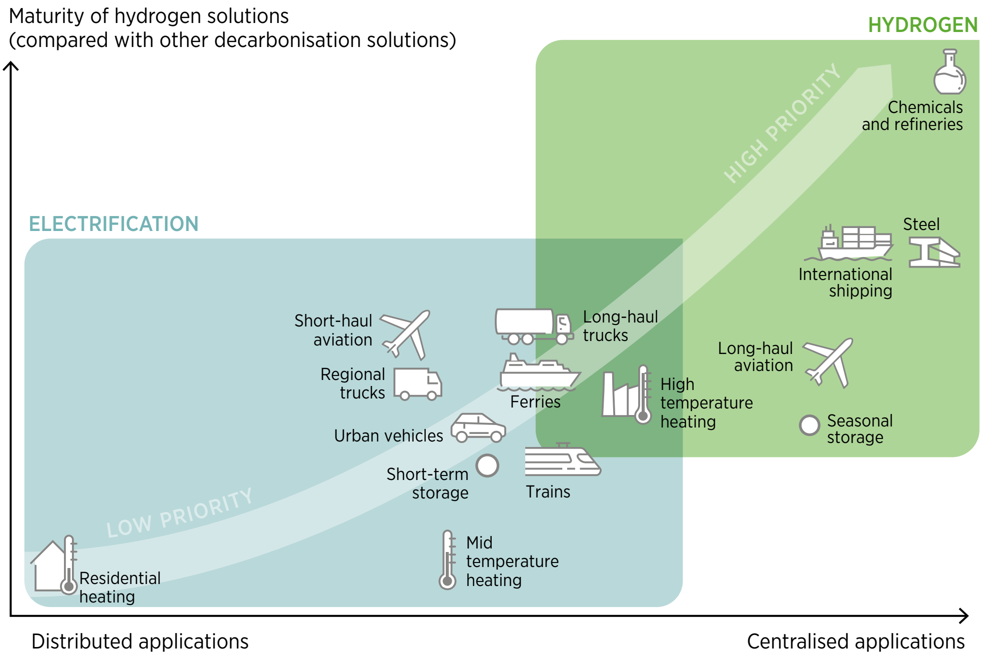
Basic chemicals and primary steel production can consume large quantities of hydrogen in centralised locations and can provide opportunities for economies of scale, making the shift towards hydrogen more cost-effective compared to distributed applications (IRENA, 2022c).

Emissions from the shipping and aviation sectors have increased in the past decades and accounted for approximately 2 gigatonnes (Gt) of CO_2 in 2019. About 66% of these emissions are international, meaning they are not covered under the nationally determined contributions (NDCs) of signatories to the Paris Agreement. At present, the International Civil Aviation Organisation (ICAO) and the International Maritime Organisation (IMO) are the specialised United Nations agencies tasked with addressing international GHG emissions. Hydrogen derivatives are a main solution considered to solve the emissions of such sectors, but countries will have to agree on the next steps within the ICAO and IMO frameworks to transform the decarbonisation commitments into an international reality.

The rest of the applications should be last in priority. Hydrogen use for these applications will depend on technology evolution, and hydrogen could be attractive for a niche set of conditions.

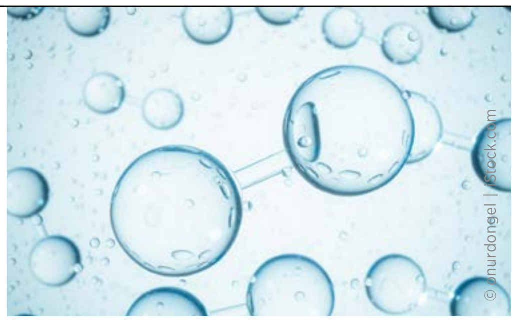
[34] Long-term seasonal storage is also an application where hydrogen (derivatives) is better placed to satisfy, but this is not a final energy use.

FIGURE 2.1 Complementarity between electrification and hydrogen across end-use applications policies



Source: IRENA (2022i).

Note: On the x-axis the end uses are placed according to the estimated average daily hydrogen demand for industry, refuelling stations and combustion devices, with a power relationship. On the y-axis the end uses are placed according to the differences between the technological readiness levels of hydrogen-based vs electricity-based solutions.



2.3 HYDROGEN POLICIES

All the strategies serve to present some policy measure that is going to be undertaken by the government. It should be noted, however, that hydrogen strategies differ substantially in terms of commitments made, in at least two aspects. The first aspect is the quantity of commitments: some countries present in their strategic documents many measures that will be undertaken in the near future (for example, Germany and the United Kingdom); other documents present only a few focused examples of committed policies. The second aspect is the level of detail of the commitment. In some cases, the measures presented have timelines, budgets allocated, and details on the procedures that will be adopted (for example, France). In other cases, the commitments maintain a more high-level description.

One aspect common to all the strategies is the commitment (and in some cases allotment) of funds for the development of the first hydrogen production facility. On the demand side, countries differ in priority applications (see previous section), but also on the instrument proposed to support the consumption of hydrogen or the operational costs of hydrogen production. However, policies for the adoption of green hydrogen in the industrial sector (that should be prioritised; see previous section) are needed in a short time frame (IRENA, 2022c).

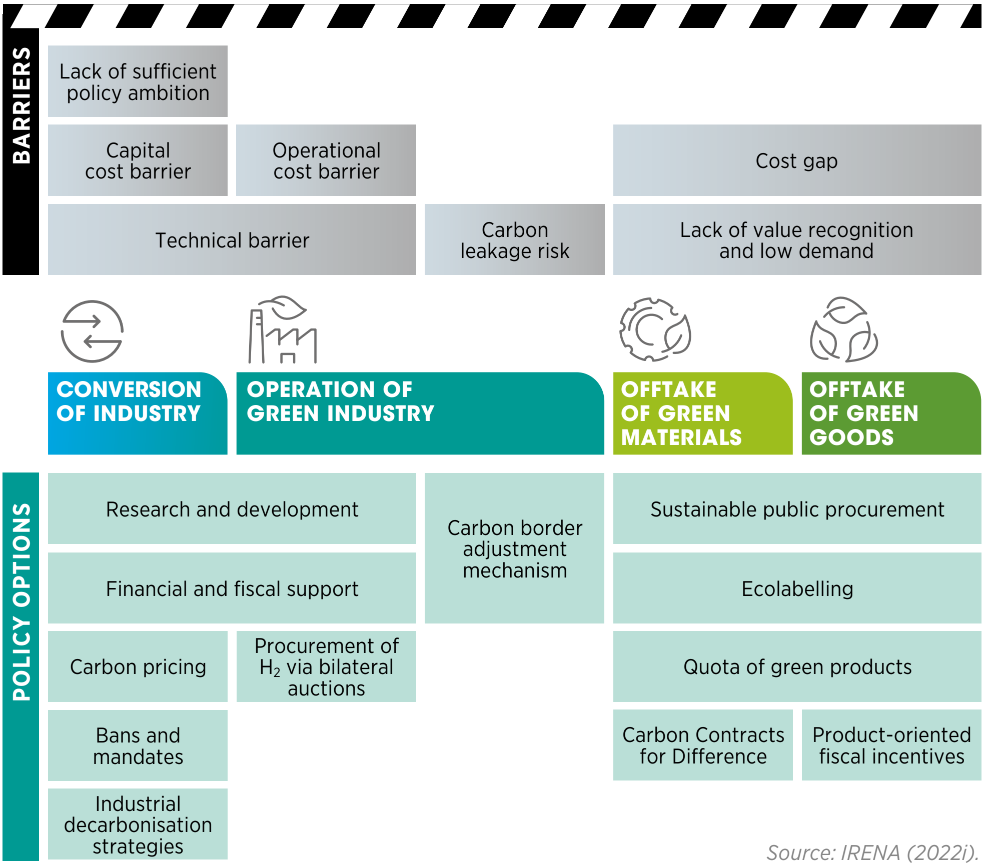
The green hydrogen industrial sector is still in the early stages – still not competitive with grey hydrogen – and therefore is a good candidate for industrial policy making. Industrial policy making implies a variety of policy interventions aimed at guiding and controlling the structural transformation process of an industrial sector, protecting it until it becomes competitive.

Industrial policies can take many forms and likely a combination of these will be needed to support green hydrogen: regulatory actions that mandates a change, financial and fiscal support to help first movers, and policies to create demand for green materials and goods.

There are two fundamental barriers that hinder green hydrogen deployment in hard-to-abate applications: high costs and very limited current use of green hydrogen and its derivatives. This calls for putting policies in place to close the cost gap, creating demand for an initial uptake and providing long-term visibility into how the volume uptake can increase over time to provide a sense of market opportunities and attract investment. At the same time, actions to phase out carbon-intensive practices are needed.

Policy makers have multiple alternatives to deal with the current barriers (see Figure 2.2) (IRENA, 2022i).

FIGURE 2.2 Policy options to deal with the cost gap for hydrogen derivatives and offtake



Source: IRENA (2022i).

Supporting policies

The cost gap can be addressed by tackling the capital cost through financial and fiscal support in the form of grants and loans (especially for smaller projects) and tax rebates, among others. These supportive mechanisms are likely to be accompanied by more measures to drive a change that will otherwise not happen spontaneously.

Auctions, which have been successful for renewable electricity, also provide multiple tailoring opportunities in the auction design to adapt the incentives and achieve targeted results. There can be supply-side auctions (driving competition among suppliers to reduce costs), demand-side auctions (to ramp up hydrogen demand) or double-side auctions. A pioneer example of a double-side auction for hydrogen is H2Global from Germany (see Box 1.1).

Three main options are available to deal with the lower volume uptake by creating a differentiated market for sustainable products:

• Sustainable public procurement (SPP). G7 members represent about 16% of global steel demand (World Steel Association, 2022), about 21% of global ammonia production and 11% of methanol (USGS, 2022). This gives them a lever large enough to make a difference in driving uptake volumes. Thus, they should set common targets for procuring sustainable products through SPP when available, creating an anchor market for these products. The G7 has already highlighted the importance of sustainable and green procurement as a mechanism (G7, 2022).

• Quotas for green materials. These can create the foundation of a green materials market which is currently very small. Large consumers of basic materials (*e.g.* carmakers) would have requirements for purchasing a predetermined minimum amount of green materials. This instrument would need to be used in tandem with eco-labelling as a mechanism to convey information to consumers on products that meet environmental standards and to nudge them towards buying low-impact products.

• Product-oriented fiscal incentives. These can aim to make specific products more economically attractive compared to their carbon-intensive counterparts. Examples of such measures are already common in G7 countries and could be expanded for hydrogen-based products as well.

Mandates, quotas and carbon pricing

Technological bans and mandates can direct the industrial sector to reduce or eliminate the use of carbon-intensive practices, introducing punitive measures such as fines or confiscation of property in case of non-compliance. Binding quotas move the implementation of targets a step ahead, imposing an obligation on selected industries to reach a share of green hydrogen in their total amount of hydrogen or total gas demand.

Another option is the internalisation of climate change externalities to make the use of carbon-intensive technologies less financially sustainable in the long term. This can be achieved, for example, by creating a carbon pricing instrument that will enable green hydrogen technologies to become more financially attractive. Carbon pricing is already common in G7, although not harmonised (see Chapter 1). There is no strict obligation in this second case, but the cost of the carbon-intensive technologies may become unbearable.

The idea behind mandates and carbon pricing is that operators comply following a cost-benefit assessment where green hydrogen becomes more attractive. Stricter penalties lead to faster compliance and a diminishing role for fossil fuels as the expected costs of consuming the latter rises. However, these policies may increase the risk of carbon leakage[35] or loss of competitiveness leading to lower economic activity. Therefore, specific carbon leakage policies may be needed to avoid such a situation.

[35] *Carbon leakage describes the situation where, due to higher costs incurred to comply with climate policies, an industry relocates facilities to jurisdictions with laxer emission constraints. This leads to lower emissions in the region with climate policies in place but to limited benefit on a global basis because the emissions have just relocated.*

Measures to prevent carbon leakage

There are at least four ways to prevent carbon leakage while fulfilling climate commitments. First, G7 members could align the trajectory of carbon pricing or define sectoral agreements for decarbonisation. The former might prove too difficult to implement in practice since this will largely depend on the domestic context and the same carbon price might not be suitable for all countries. For the latter, there are already some signs of progress, with the United States making joint statements on carbon-content trade tariffs in steel and aluminium with the European Union, Japan and the United Kingdom (The White House, 2021; US Department of Commerce, 2022a, 2022b).

Second, adopt CBAM that use import taxes based on the carbon content the products. The objective is to make carbon emitters, even outside the importing jurisdiction, pay the same (or a similar) carbon price paid by local industry, discouraging carbon leakage and levelling the playing field between industry regardless of the local carbon policy (IRENA, 2022i). The European Union is at the forefront in this area with a CBAM proposed as part of the Fit for 55 package to reduce emissions by 55% by 2030 (on their 1990 levels) proposed in July 2021. This CBAM would initially apply to iron and steel, hydrogen and ammonia (EY Global, 2022), among others, and free allowances for these sections will be phased out from 2027 to 2032. Negotiations between the European Parliament and the European Council are still to take place before becoming law, which should take place by the end of 2022. Canada, the United Kingdom, and the United States are also considering the introduction of a CBAM (Department of Finance, 2020; UK Parliament, 2021; US Trade Representative, 2021).

Third, consumption-based regulations introduce a tax or penalty on emissions at the point of consumption rather than production. That way, all the commodities, regardless of whether they are domestic or imported in nature, face the same cost penalty. Fourth, the carbon content import tariffs could cover all lifecycle emissions of products rather than only direct emissions from combustion. These last two options would require either assigning default values or tracing all the supply chain emissions.

2.4 HYDROGEN VALLEYS

A recurring aspect of hydrogen strategies is a focus on hydrogen valleys or hubs. These are hydrogen demand centres constituting various end users that can enable economies of scale while also testing various technologies. Hydrogen valleys are mentioned in the strategies of Canada, the European Union, France, Italy, the United Kingdom and the United States. These valleys are going to receive specific support, in the form of special regulations that will allow experiments on various configurations (regulatory 'sandboxes') and that can be used for international best practice sharing.

Hydrogen valleys have multiple benefits. First, they present an opportunity to create a large, stable and long-term source of demand that can be used as an anchor for future hydrogen producers. Second, they benefit from the participation of multiple users, which widens the offtake possibilities and decreases the risks. Third, they allow for the simultaneous testing of different business models encompassing various industries, users and economics.

2.5 HYDROGEN DEFINITION AND SUPPORT

There is no standard terminology when referring to hydrogen's different pathways of production. This is evident in the hydrogen strategies, where each country uses a different terminology (see Table 2.3). It is possible to note how countries with a clear aim toward green hydrogen tend to use explicit terminology ('green', 'renewable'), while countries that combine CCS and electrolysis as technologies on the same level prefer to use umbrella terms ('low-carbon', 'CO_2-free', 'clean'). The French strategy uses the term 'decarbonised' for hydrogen produced using electrolysis powered by nuclear electricity.

TABLE 2.3 Terminology used for hydrogen across strategies

Country	Canada	European Union	France	Germany	Italy	Japan	United Kingdom	United States
Terminology	Low carbon	Clean; sustainable;* renewable	Decarbonised; renewable	Colour coding	Colour coding	CO_2-free	Low carbon	Clean

* EU taxonomy.

The terminology utilisation conceals a more complex issue: how to determine if a certain batch of hydrogen will be accepted and supported in the future. The European Union and the United States are currently determining the requirements for hydrogen to be considered for state support, while the United Kingdom set up the national threshold and standard; however, these are not aligned in emission thresholds, boundary definitions or additionality requirements.

Setting up an agreed methodology to measure GHG emissions (including system boundaries, allocation factors and gaseous compounds) and the definition of what hydrogen should be traded and supported is another opportunity for collaboration within the G7 framework to support the uptake of hydrogen.

2.6 UNEVEN HYDROGEN DIPLOMACY

In contrast to the oil and gas sector, the hydrogen market will most likely be characterised by many potential sellers and few buyers. Moreover, hydrogen trade flows are unlikely to become cartelised. This is because hydrogen can be produced in a wide variety of places worldwide. Therefore, green energy trade flows are unlikely to lend themselves as easily to geopolitical influence as oil and gas (IRENA, 2022a). On the other hand, the presence of few buyers will allow them to set up the basic rules, and hydrogen characteristic and production pathways.

The potential buyers are now split into two large markets: European and East Asian. These two markets are quite distinct. Europe aims to support the import of green ammonia and green hydrogen by 2030 to decarbonise mainly the industrial sector and grow independent from fossil gas imports while achieving the Paris Agreement targets. East Asia (particularly Japan) looks at hydrogen as an option for energy diversification, focusing on consumer applications and allowing any type of hydrogen, currently, to be imported (see Table 2.1 and Table 2.2).

Hydrogen diplomacy is becoming a recurring theme in the hydrogen sector. It can promote political dialogue and support countries in exchanging ideas on hydrogen. It can raise awareness of the rising demand for green hydrogen among decision makers in potential exporting countries and kickstart international support for new projects.

However, it has so far been driven by potential import-export relationships, and there has been limited collaboration among groups of importers and exporters (IRENA, 2022d). In fact, bilateral deals forged to date are aimed at facilitating cross-border hydrogen trade. These deals range from feasibility studies to letters of intent, memorandums of understanding, energy partnerships and even trial shipments.

Hydrogen trade deals often involve countries that have an established energy trade relationship. Whether the hydrogen trade routes will materialise remains to be seen, but the potential is there for a completely new cartography of energy trade. Among European countries, Germany has conducted hydrogen diplomacy activities with a wide range of (mostly developing) countries potentially supplying hydrogen in the future. Through these activities, Germany intends to support international dialogue on the geopolitical implications of a global hydrogen market.

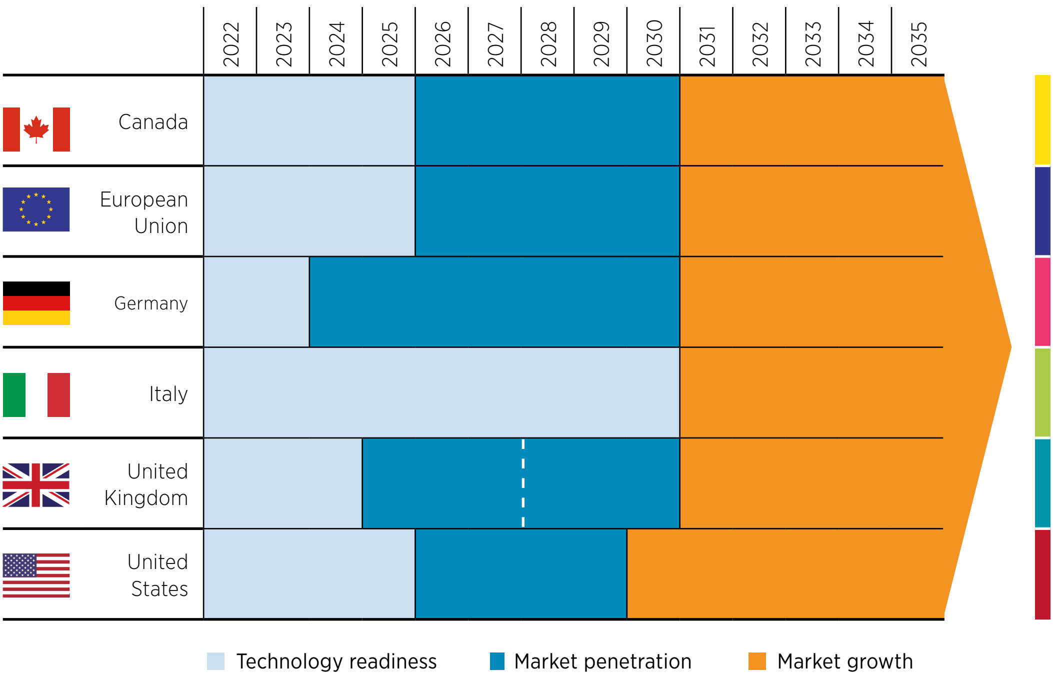
Japan is engaging with Australia, Brunei, Norway, Saudi Arabia and others on setting up value chains for the hydrogen trade. Japan's international hydrogen strategy aims to secure new import flows of green fuels to compete with LNG in power generation and gasoline in transport. In both cases, a complementary aim is to sell local low-carbon technologies and know-how overseas.

2.7 DIFFERENTIATED PHASES OF DEPLOYMENT

As the penetration of green hydrogen technologies increases and costs come down, five of the G7 members explicitly recognise that policies will have to evolve accordingly. A phased approach is used to reflect the expected evolution of the hydrogen sector and its policy needs along with the increased deployment of green hydrogen.

Canada, the European Union, Germany, Italy, the United Kingdom and the United States explicitly mention in their strategies such a phased approach, with explicit mid-term targets and forecasts for the market growth of hydrogen (see Figure 2.3).

FIGURE 2.4 Timelines of phases in five of the G7 members' strategies



Note: the UK strategy is split in four phases, the middle ones focusing on early and late market penetration of hydrogen.

All these strategies mark around 2030 as the beginning of the last phase, when a rapid hydrogen market expansion is expected. Japan and France do not use a phased approach explicitly, but have a similar target date of 2030 to kickstart the hydrogen sector.

The advantage of the phased approach is that, as the penetration of green hydrogen technologies increases and costs come down, policies will evolve, while knowing that the sector will evolve in stages can assist in planning policies that make sense for the challenges still to come.

The risk of the use of the phased approach is the adoption of gradual policies. Regardless of the policy mechanism, stable and long-term frameworks are necessary to realise the potential of green hydrogen. The short timeframes of the energy transition imply that a technological change must happen as soon as possible. However, decarbonisation policies often promote a gradual pathway for each sector (for example, the gradual use of renewable-based solutions or energy efficiency measures).

The goal of reaching zero emissions requires a very different mindset compared to an objective of gradually reducing emissions. In some cases, progressing with a mindset of gradual reduction risks locking in emissions. The gradual reduction mindset, in fact, enables a market for less carbon-intensive, but still fossil fuel-based solutions. These solutions can create additional transitional barriers, as adopters of the more efficient (but still fossil fuel-based) solutions aim to complete their investments' lifetimes instead of changing technology as new, more restrictive policies are adopted (for example, when Phase 3 is reached). This situation will require additional actions to eliminate the remaining emissions when more ambitious climate change objectives are later adopted, creating additional government expenditure and stranded assets that pile up – as with the infrastructure of the fossil fuel era.

Investment decisions in industry have a long-term impact due to the high capital costs and long useful life of industrial assets. These investment decisions are also urgent: 71% of blast furnaces will need major refurbishment before 2030, and the remainder will need it before 2040. The average lifetime of chemical plants is around 30 years; the average ammonia plant is 15 years old, and the oldest are located in Europe and Asia (IRENA, 2022i). Therefore, only one investment cycle exists before 2050, and new low-carbon technologies must be the next recipient of investment to avoid carbon lock-in within the limited timeframe we have to avoid climate catastrophe.

CHAPTER **03**

RECOMMENDATIONS FOR THE G7

Through their sizeable economic footprint (representing 45% of global GDP) and joint action, G7 members can establish themselves as leaders and determine the conditions of a future hydrogen market. While each country will have to adopt national policies to support hydrogen uptake adapted to its local context, there are opportunities for cross-border collaboration among G7 members in line with the Hydrogen Action Pact. These opportunities are focused around five pillars (see Figure 3.1).

These recommendations focus only on the hydrogen value chain: the availability of low-cost, carbon-free, notably renewables-based electricity is a critical enabling factor for the provision of low-carbon and renewable hydrogen.

The recommendations presented here are selected from among the actions G7 members (and other countries around the world willing to embark on these efforts) can enact in a collaborative manner. It is possible to divide them into two categories:

- **Collaboration-first recommendations**: To translate these recommendations into reality, G7 members would have to agree on concerted actions at a high level and then translate these agreements into local legislation or concrete actions on the ground.

- **Action-first recommendations**: These recommendations call, generally speaking, for transparent channels of communication to spread information about specific local experiences. Policy makers would first enact new policies in their jurisdictions and then share their successes and setbacks with the international community in order to replicate best practices.

FIGURE 3.1 Recommendations for G7 members

Note: HAP numbers refer to the HAP goals (see page 16)

The application of such recommendations may require the adaptation of local policies and plans. This is not unusual in policy making. A good practice is to maintain flexibility in policy design and to have strategies that are able to react to changes in market situations and new technological disruptions. As the green hydrogen sector is bound to evolve rapidly (see Section 2.7), the policies regulating it are bound to change. Promptly sharing lessons learnt can be key in making such changes successful and accelerating hydrogen deployment.

For all recommendations, the G7 members may need to find the most suitable initiatives and platforms to take some of the actions forward. The IRENA Collaborative Framework on Green Hydrogen – the intergovernmental platform with the widest global membership coverage – can serve as the platform for information sharing and collaboration on all issues related to green hydrogen.

Finally, the recommendations are intended as long-term commitments between G7 members. Their adoption and application will require an implementation process that includes monitoring and evaluation in order to achieve effectiveness.

PILLAR 01: Align efforts on standards and certification

01

As of August 2022, there were 15 different initiatives aiming to certify hydrogen or regulate its emissions. These initiatives differed in boundaries of the system covered, emissions thresholds, labels, production pathways, chain of custody model and conditions (see Section 1.2). At the same time, hydrogen unlocks the use of new energy carriers (*e.g.* ammonia) enabling the global trade of low-carbon energy. Since all the GHG emissions associated with hydrogen are from its production, transport and end use, certification is crucial to ensure it contributes to climate mitigation and compatibility among countries and with international trade rules, as hydrogen is traded across borders. Certification also allows the differentiating hydrogen flows by the GHG emissions associated to the end of relating emissions to prices, economic incentives, and emissions allocation among users. Hydrogen can also be converted to other materials and commodities, hence hydrogen certification should be modular and certify each conversion step separately. It should also be compatible with existing efforts for some of these commodities (*e.g.* steel). The focus of existing schemes has been on GHG emissions, while broader sustainability aspects should also be considered (German Energy Agency and World Energy Council, 2022; PtX Hub, 2022).

The G7 can lead in this area by driving the effort to agree on a common methodology to measure GHG emissions across the value chain and consolidating those into an international standard. It can also work to define a common terminology and minimum sustainability criteria (which individual countries could still choose to exceed) for hydrogen production, transport and end use. An advantage for the G7 is that most of the existing efforts are from G7 members, complemented by three international ones (where the G7 could have a large influence) and two Australian ones. The G7 is also working closely with the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE), which is developing a methodology for certifying emissions from hydrogen production and transport that will be used as input to develop an international standard from ISO.

The UK Breakthrough Agenda, launched at COP26, identifies standards and certification as one the key areas where international collaboration could make the largest difference. It finds that agreement is needed on “a comprehensive portfolio of international standards and associated certification schemes for renewable and low-carbon hydrogen, addressing emissions accounting, safety, and operational issues, including leakage… This will be vital for supporting a series of other actions, most notably high-quality demand commitments and trade agreements" (IEA, IRENA and UN Climate Change High-Level Champions, 2022). The Breakthrough Agenda aims to take this action forward by working together with existing initiatives that are already active in this area in consultation with other key hydrogen initiatives, such as the G7 HAP. The G7 HAP already contributed to this goal by commissioning a review of global hydrogen certification schemes (conducted by IRENA) (IRENA, forthcoming).

RECOMMENDATION 1.1: **Establish common sustainability criteria for traded and supported hydrogen.** G7 members can take the lead to set up a minimum set of sustainability criteria for hydrogen and create minimum standards for international trade and local policy support, avoiding a plethora of rules and approaches. The set of sustainability criteria should include carbon footprint; technological, temporal and geographical additionality elements; assessment of environmental impact (*e.g.* direct and indirect land use change and water stress); and socioeconomic impacts for the producing country (*e.g.* job creation and energy poverty issues). The consensus could determine which concrete sustainability criteria should be set in the short term and how they may have to be strengthened in the medium term and the long term. The G7 could also be pioneers in expanding beyond hydrogen itself to cover derivatives like ammonia, methanol, synthetic fuels and steel, while maintaining consistency in the ongoing certification efforts for those commodities.

Collaboration

RECOMMENDATION 1.2: **Align methodologies for hydrogen certification.** International collaboration is needed to avoid fragmentation of the hydrogen market due to incompatible conditions inherent in different hydrogen certification schemes. The G7 has the opportunity to lead the process of harmonising hydrogen certification, driving the effort to agree on a common methodology to measure GHG emissions and environmental impact across the value chain and consolidating the ongoing efforts for international standards. The development of an international harmonised certification scheme is essential to enable the swift ramp-up of hydrogen and should be completed by the end of 2023.

Collaboration

RECOMMENDATION 1.3: **Spearhead efforts to set harmonised technical standards.** The G7 can mobilise the resources required to close the gaps in standardisation, assess the revisions needed to the wide set of existing technical and safety standards – both international and national – that cover the handling and use of hydrogen and hydrogen derivatives, and develop the standards for the new parts of the value chain (*e.g.* direct reduction of steel) (see Section 1.2). This will ensure the compatibility of standards across borders and enable trade under uniform conditions. Pre-normative research is also required to inform those standards, with hydrogen leakage being an area of attention. This includes research to better understand the leakage from operations and infrastructure, as well as its effect on global warming potential.

Collaboration

PILLAR 02: Collaborate internationally and share lessons from early implementation

02

Hydrogen diplomacy is a recurrent theme across strategies (see Section 2.6). Exporting countries have been focusing mostly on their domestic renewable or fossil fuel resources to allocate support to specific production pathways based on the expected demand of importing countries (see Section 2.5). This could lead to a fragmented market where some producers export hydrogen from a specific production pathway that is not compatible with the preference of all importers. This is exacerbated by the different typologies of hydrogen that are going to be supported by countries. However, other factors such as future technology, carbon content preferences and cost competitiveness over time need to be considered.

Potential exporting countries, in particular in the Global South, are looking at hydrogen as an opportunity for economic growth and industrial development. In doing so, there is the risk that new hydrogen industry is developed at the expense of domestic decarbonisation and wider economic needs. This has a risk of diverting investment from renewable electricity production for domestic use, resulting in slower emissions reduction for the power sector. In countries where energy access is still an issue, investment in hydrogen infrastructure can also divert investments from infrastructure that is needed to achieve basic access. This would undermine the decarbonisation objectives all G7 members have agreed on (see Section 2.1). At the same time, green industrialisation can also provide an opportunity for the Global South to harness the potential of low-carbon hydrogen for creating jobs in local value chains, facilitating access to clean water (by building upon synergies with water supply for electrolysers) and improving the business case for developing a domestic renewables industry.

G7 members are among the first movers in the new hydrogen sector, with specific policies and incentives in place (see Section 2.3). This presents the opportunity to share their experiences with followers and observers to enable a faster uptake of best practices, including sustainability and social aspects. At the same time, the G7 represents almost 90% of the public R&D budget for hydrogen and fuel cells (IEA, 2022) and about 73% of the international inventions across hydrogen technologies (Section 1.2). This provides the G7 with valuable knowledge of hydrogen technologies, from which other countries will benefit and which could lead to the acceleration of global decarbonisation.

A leading initiative for hydrogen research is Mission Innovation, which targets joint research and development activities, demonstration projects, the creation of an enabling environment and the dissemination of knowledge. Seven of the eight G7 members (including three of the five co-leads) are part of this initiative, which puts the G7 in a good position to achieve the research-related goals outlined above. The UK Breakthrough Agenda has also identified R&D as a key area for co-ordinated action targeting the increase in the "number and geographical distribution of hydrogen demonstration projects and to ensure that these appropriately cover each of hydrogen's high-value end use sectors, including maritime shipping, heavy industry, and long-duration energy storage... doing so will help overcome technology availability barriers and accelerate the pace of deployment in multiple regions in parallel" (IEA/IRENA/HLC, 2022).

RECOMMENDATION 2.1: **Support the sustainable development of hydrogen in Global South countries.** G7 members can assist the Global South by supporting renewable energy and green industrialisation based on hydrogen through national and international development finance institutions. This should be supported by a common process in which donor countries (G7 and other Global North countries), lending institutions and recipient countries work together to identify viable projects that are being delayed by, for example, high costs of capital, and to assess obstacles to investment. To ensure investments have positive effects on local job creation and stimulate domestic value chains, donors and countries need to address local demand creation for green hydrogen and not focus only on export opportunities.

Action

RECOMMENDATION 2.2: **Share lessons learnt as first movers.** G7 members are at the global forefront in terms of hydrogen policy design, implementation, impact, demonstration projects, ecosystem of stakeholders and business models. Continuously sharing lessons learnt from implementation in these areas, in particular with the Global South, can lead to accelerated hydrogen deployment.

Action

RECOMMENDATION 2.3: **Implement innovative schemes such as regulatory sandboxes for hydrogen valleys.** Five of the G7 members have plans to develop hydrogen valleys to trigger new hydrogen deployment (see Section 2.4). G7 members can commit to using the model of hydrogen valleys to implement regulatory sandboxes and share the results among the G7 and beyond.

Action

RECOMMENDATION 2.4: **Address technology gaps and transfer technology knowledge.** G7 members are at the forefront of the hydrogen revolution. Further innovations are needed to reduce cost, enhance energy systems integration, allow upscaling and open up new application areas, among others. A systemic innovation approach is needed that combines new technologies with enabling markets and regulations, new operational practices, and new business models. G7 members should not lose the momentum of hydrogen innovation (see Section 1.2) and should fast-track essential technological development opportunities. On the supply side, this includes improving the design of the electrolyser and considering trade-offs between cost, efficiency and lifetime, reducing the use of critical minerals, and understanding the recycling possibilities. For infrastructure, understanding hydrogen leakage and limitations to convert fossil gas infrastructure to hydrogen (including porous storage) are the most critical. Technology gaps in end uses are wide because hydrogen is necessary for new applications, which requires large demonstration projects and an understanding of the flexibility needs of conversion units for steel production, as well as ammonia and methanol synthesis.

Action

PILLAR 03: Balance focus on supply with demand creation

03

By mid-2022, renewable and low-carbon hydrogen production was less than 1 MtH_2/year. Infrastructure for pure hydrogen is limited to 4 600 km of pipelines (nearly all in G7 members). There are limited incentives and specific policies in place for the consumption of renewable hydrogen and most of the focus has been on the supply side (see Section 2.3). While supply commitments from governments add up to between 140 GW and 150 GW (which could produce roughly 15 MtH_2/year – depending on the capacity factor) and the European Union alone has a 2030 target of 20 MtH_2/year, commitments on the demand side only add up to less than 3 MtH_2/year.

The combination of these factors creates a 'hydrogen deadlock'. A deadlock happens when two or more actors block each other because they are waiting for one actor to provide information or resources to the other, or vice versa. In the hydrogen sector, potential off-takers need to know the price, physical properties and quantity of the low-carbon hydrogen from the potential suppliers, who in turn cannot start the deployment of electrolysers without an offtake agreement. Both players need to know the support policies in place and the standard and regulation of hydrogen in the jurisdictions where they operate. However, where the policy makers have no experience with hydrogen technologies, this will make the creation of policy more arduous. Potential infrastructure development, in turn, can happen only after supply and demand points are determined. Finally, finance institutions need clear information from these projects to evaluate the risks and make informed decisions.

To address this, G7 members have the opportunity to adopt new policies to support both the supply and the demand for green hydrogen. Within the G7 framework, members should signal their common intent through clear support with prioritisation for specific end uses and create a bulk demand for hydrogen in the most critical hard-to-abate applications (see Section 2.2).

RECOMMENDATION 3.1: **Prioritise hard-to-abate industrial applications for hydrogen demand.** Hydrogen is already used today as a chemical feedstock, which provides an opportunity to scale up renewable hydrogen while contributing to the reduction of current GHG emissions. Furthermore, hydrogen can play a fundamental role in steel decarbonisation. These two applications represent almost 5% and 7% of global GHG emissions. Most G7 members have already stated their intention to focus on such sectors (see Table 2.2). G7 members should jointly signal such priorities to inform determinations of the size, use and location of initial hydrogen demand. This activity would then lead to agreed policy making for harmonised public procurement and common action to support decarbonisation of the identified priority areas.

Collaboration

RECOMMENDATION 3.2: **Agree on common actions to decarbonise shipping and aviation.** International aviation and shipping accounted for around 4% of the total GHG emissions pre-pandemic (Crippa *et al.*, 2020) and have limited alternatives for decarbonisation. G7 members already have a common understanding of the importance of decarbonising international aviation and shipping (see Chapter 2, Section 2.2), but due to the international nature of such sectors most of the actions to decarbonise them can be effective only if agreed on a global scale. The G7 should work within existing fora, like the corresponding United Nations agencies, to highlight the importance of alternative fuels to decarbonise these applications and lead the process of setting clear timelines and incentives for their uptake in the short term. For example, the G7's input would be very relevant in working towards harmonised rules for blending requirements and certification of sustainable aviation fuels.

Collaboration

RECOMMENDATION 3.3: **Co-ordinate supply and demand.** Most of the policies enacted so far focus on the supply side, while fewer and different policies have been announced on the demand side (see Section 2.6). In particular, to date, few policy makers have focused on the actual creation of an anchor hydrogen demand. G7 members should work to identify solutions to grow supply and demand at the same time, creating an enabling environment for supply and demand co-ordination. Efforts should then evolve in a way that both supports the supply deployment and the demand creation. Assistance for offtake agreements should accompany such efforts to kickstart a hydrogen market.

Action

RECOMMENDATION 3.4: **Plan the scale-up of financing.** G7 members should focus on making hydrogen projects more bankable. To date, grants have been the most common support schemes considered for the hydrogen sector (see country-specific factsheets), as they are effective in supporting innovation or early-stage demonstration projects. G7 members should plan the incentives to large-scale investments from mainstream debt and equity markets and share best practices regarding appropriate policy, regulatory and fiscal frameworks to de-risk investments in hydrogen. Novel financing mechanisms, such as H2Global in Germany (see Box 1.1) should be explored. The support of the closure of credit-worthy offtake agreements, in particular, would signal the commercial viability of projects. The G7 can also support risk reduction and capital mobilisation towards developing economies by working with multilateral development banks to provide financial support on top of technical support and capacity building.

Action

PILLAR 04: Promote hydrogen uptake in industrial applications

04

The green hydrogen industrial sector is still in its infancy – not yet cost-competitive with grey hydrogen. As such, it is a good candidate for new, adaptive industrial policy making. Industrial policies can be defined as a range of policy interventions aimed at guiding and controlling the structural transformation process of an economy. The G7 members, which account for some of the most industrialised countries in the world, thus have the opportunity to act as a pivot for the hydrogen momentum needed to adopt a new set of industrial policies to support the transformation of industry at large. This adoption of industrial policy is already happening (IRENA, 2022c), and G7 countries have also announced new policies (see factsheets and Section 2.3) but more is needed to accelerate this and meet the Paris targets.

The G7 is already tackling the industrial sector through the Industrial Decarbonisation Agenda (IDA) (see Introduction). This includes hydrogen as part of a broader decarbonisation portfolio and tackles several areas covering market regulation, decarbonisation standards development, investment, procurement strategies and joint research (G7, 2021a). The HAP would be an alternative to operationalise the IDA on one particular pathway for alternative fuels.

Carbon leakage (see Section and 2.3) raises both environmental and socio-economic concerns, putting global decarbonisation efforts at risk. Hydrogen policies, therefore, should be accompanied by carbon leakage policies.

RECOMMENDATION 4.1: **Test and implement new policies for the uptake of green products.** G7 members should, as first movers and as developed countries, develop and test new policies that support the demand for green hydrogen and green products. These include bans and mandates, CCfD, SPP, product-based fiscal incentives and bilateral auctions. Initial experience from these should be shared across members and outside the G7 framework to facilitate a global hydrogen uptake. Once the impact has been assessed, the lessons from such policies should be shared swiftly to inform other policy makers of the best design elements and to encourage other countries to adopt the same policies.

Action

RECOMMENDATION 4.2: **Address carbon leakage and create a level playing field.** Carbon leakage risk is high for hard-to-abate applications – particularly for heavy industry, where measures to contain emissions can substantially increase production costs, making the case for relocation more appealing to producers. The G7 should enact an exchange on measures to address the problem of carbon leakage (CBAM, carbon-based import tariffs, etc.) and co-ordinate them in order to create a common front against carbon leakage.

Collaboration

RECOMMENDATION 4.3: **Support disruptive and step-changing technologies.** Five of the G7 members have already stated their vision of a phased evolution of the hydrogen sector, but this comes with the risk of a 'gradual approach' mindset (see Section 2.7). A planned step-change[38] will help introduce the processes needed for deep decarbonisation and align the actions of investors and businesses with public interests. G7 members should commit to the introduction of such a step-change, harmonising the efforts for the decarbonisation of industry.

Action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[38] *Step-change refers to a technological shift that aims to achieve a discontinuous improvement in GHG emissions rather than progressive and continuous change (e.g. energy efficiency).*

PILLAR 05: Conduct outreach to civil society and industry stakeholders

05

To date, the messaging and media coverage of the role of hydrogen has been broad in its coverage and not focused on the specific priorities that should be applied to those sectors that are hard to abate; there is a sense that hydrogen can be used for all end uses regardless of alternative renewable energy applications (The Energy Mix, 2022).

In addition, hydrogen is currently produced and consumed mainly in industrial areas, and therefore civil society may have a limited understanding of the potential of low-carbon hydrogen to decarbonise end uses outside of industrial applications. The non-engaged population may still remember the past waves of interest in hydrogen, which have mostly not been realised. Efforts are also needed to raise awareness of the safe use of hydrogen (Kolodziejczyk and Ong, 2019). Some G7 members do include awareness programmes in their strategies, with recommendations to engage with civil society and industrial stakeholders (see country factsheets).

Without clear signals and information, consumers may not be aware of the potential low-carbon nature of hydrogen compared to other forms of hydrogen made using processes that result in higher GHG footprints: eco-labelling can unlock demand for products that can prove the origin of their feedstock, among other low-carbon production processes. Eco-labelling is instrumental in creating a market that values sustainability, with this value translating into justifiable higher prices and improved economics for sustainable producers. However, voluntary eco-labels may have a limited impact on the market and struggle to be recognised and accepted (Song *et al.*, 2019). On the other hand, mandatory eco-labelling is more expensive for governments, as the regulator endorses the cost of setting up the eco-labelling system and of monitoring all firms.

Most importantly, awareness is a stepping stone towards creating public acceptance. This is essential in generating the legitimacy of the policies and public investment choices of a new product, such as hydrogen, and in avoiding opposition and resistance to hydrogen's uptake. Acceptance hinges on policy fairness and its perception, meaning that the policy costs and benefits are distributed equitably. Citizen participation is essential for public acceptance, to allow for interest groups to be represented and to maintain a balance between power relationships and marginalised groups.

Within the IDA framework, G7 members have already committed to "prioritising a people-centred energy transition that creates opportunity and is inclusive of all communities". G7 members have the opportunity to deliver this by involving civil society in the governance of the hydrogen sector and aligning communication on the future of hydrogen. This could create acceptance and accelerate the deployment of hydrogen, which is at the core of the HAP.

RECOMMENDATION 5.1: **Adopt a unified message around hydrogen and increase awareness.** Hydrogen strategies already mark a historic step for the hydrogen sector, presenting a hydrogen future that is aligned with national policy priorities (see Section 2.1). G7 members, which are already planning to increase public awareness, should provide a stronger unified message on the future of the hydrogen sector. This message should go beyond the benefits hydrogen will bring and its overall safety, and clearly present how hydrogen will impact society – as well as where new skillsets are needed. Unified messaging offers the opportunity to use the same framing across major economies and highlight the same long-term goal: decarbonisation in parallel with energy security (see Table 2.1). A unified message will provide much-needed clarity and increase public acceptance.

Action

RECOMMENDATION 5.2: **Involve civil society in the governance of the hydrogen sector.** Civil society and industry can have strong voices and provide advice to policy makers on future policies and amendments to strategies. An advisory council is an efficient way to provide high-quality input to government and could include a diverse range of actors from academia, business and civil society to ensure that all interests are considered.

Within G7 frameworks, members should build a network of civil society actors interested in the development of low-carbon hydrogen to facilitate dialogue around the role of hydrogen, its feasibility and prospects, and to assist the G7 governments in developing policy.

Action

RECOMMENDATION 5.3: **Introduce and sponsor an international eco-label for hydrogen-based products.** Eco-labelling is a necessary feature to distinguish product characteristics and differentiate goods produced with low-carbon processes (IRENA, 2022i). However, mandatory eco-labelling can be burdensome for governments. Under the IDA framework – set up to mitigate first-mover issues by diffusing the burdens – G7 members should set up and sponsor an international eco-label for hydrogen-based products (or larger in scope) that will both inform consumers and allow policy makers to recognise where support is needed for selected products. An international eco-label could also be instrumental in setting up CBAMs or carbon-content based trade agreements.

Collaboration

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ANNEX: METHODOLOGY FOR ESTIMATING RENEWABLE POTENTIAL

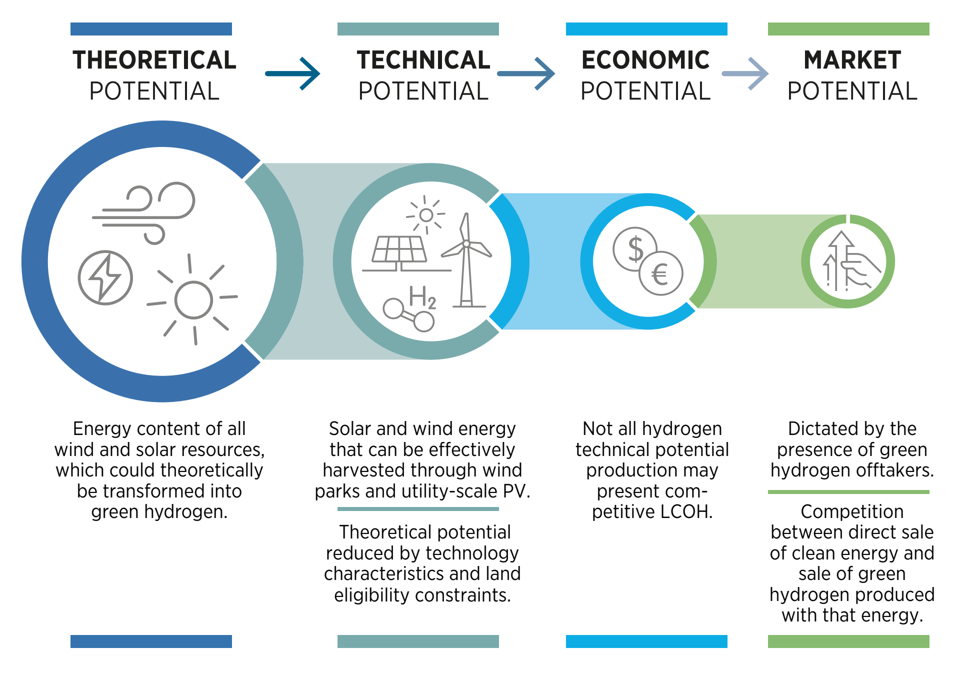
This annex contains a brief explanation of the main assumptions and methodology used in estimating potential. For more details, refer to (IRENA, 2022e).

The approach is composed of three parts:

- Land eligibility criteria to determine which sites were suitable for solar PV, onshore and offshore wind (see Table A.1).
- Meteorological data (ERA5) to determine the hourly profiles for each remaining area.
- Cost optimisation to estimate the renewable and electrolyser capacities necessary to minimise the levelised cost of hydrogen (LCOH).

The potentials used for this report are technical. This means that they represent upper boundaries and could be constrained further by additional criteria, such as: distance to existing infrastructure (electricity grid, gas network, water access); cost thresholds (excluding very expensive resources that would not be attractive to use); market conditions (suitable offtakers in the vicinity of the project); and social (acceptance from local community) (see Figure A.1). Thus, in reality, potentials are expected to be much lower than the ones used for this report, given such constraints. The reason to take the technical potential is that some of these additional constraints will be different for each country, will vary over time, are subjective (*e.g.* social criteria) and can be overcome with additional measures (different than the base criteria used for the technical potential). Given the global nature of this analysis, it was not possible to assess these additional constraints for every country over time in order to be able to assess the realistic potential.

FIGURE A.1 Types of renewable potentials and applicable constraints



The potentials focus on solar PV and onshore wind because these are the technologies with the highest potential and with the most drastic cost reductions. Offshore wind had an average levelised cost of electricity of USD 75/MWh in 2021 and the additional operating hours[39] do not justify the additional electricity price, which has a higher penalty on the hydrogen production cost. Offshore wind is expected to play a role for countries that have limited low-cost renewable potential as an option to diversify their energy mix while maintaining domestic production (*e.g.* countries around the North Sea).

The supply cost curves shown in each factsheet do not account for the competition with electricity (lowest cost resources would be used for electricity first over hydrogen), but this was considered for the trade analysis, decreasing the potential.

[39] *Global weighted average capacity factor for onshore and offshore wind was 39% for both in 2021 (IRENA, 2022d).*

Land eligibility criteria

TABLE A.1 Sources and datasets used for land eligibility criteria

Exclusion criterion	Reference	Dataset
Forests & shrublands	(Mattsson *et al*., (2021))	(Friedl *et al.*, (2010)
Woody savannahs		(Friedl *et al.*, (2010)
Croplands		(Friedl *et al.*, (2010)
Urban		(Friedl *et al.*, (2010)
Nature reserves		(IUCN-UNEP-WCMC, (2019)
Wilderness areas		(IUCN-UNEP-WCMC, (2019)
National parks		(IUCN-UNEP-WCMC, (2019)
Natural monuments		(IUCN-UNEP-WCMC, (2019)
Natural protected habitats		(IUCN-UNEP-WCMC, (2019)
Population density		(Gao, 2017)
Slope	(Maclaurin *et al*., (2019)	(Amatulli *et al.*, (2018)
Water	(Hofste *et al.*, (2019)	(Hofste *et al.*, (2019)

Note: These datasets have a spatial resolution of 0.01 degrees, which corresponds to 1 x 1 km land areas at the equator.

More specifically, the excluded protected area categories are the following International Union for Conservation of Nature (IUCN) codes from the World Database of Protected Areas: "Strict Nature Reserve", "Wilderness Area", "National Park", "Natural Monument", "Habitat/Species Management", "Not Reported" (IUCN-UNEP-WCMC, 2019). The land type dataset is the MCD12C1 Version 6 from 2016 based on the work of Friedl *et al.* (2010). The population density dataset is for the Shared Socio-economic Pathway 2nd Scenario based on the work done by Gao (2017) and areas with a density higher than 130 people per km^2 are excluded. Terrains with slopes higher than 20% are excluded for onshore wind and higher than 5% for solar PV (Maclaurin *et al.*, 2019).

For solar PV, only utility-scale is considered (rooftop potential was excluded) and a fraction of the croplands were included. The land type dataset distinguishes between cropland and cropland/natural. While the former is completely excluded for the installation of PV, the latter – being a mosaic of 40% to 60% cultivated land and the remainder natural trees, shrubs or herbaceous vegetation – is excluded by only 60%. Croplands are generally excluded for the installation of utility-scale PV systems since they generally impede agricultural use of land, while onshore wind parks have little impact on the usability of croplands.[40] Thus, eligibility criteria is the same for solar PV and onshore wind except for the slope criterion (5% against 20%) and the cropland eligibility.

A land exclusion criterion for water availability for electrolysis was also added, and geographical areas in which water availability is problematic were excluded. Water availability is assessed through water stress. This indicator is defined as the ratio between the total water withdrawals and the surface/ground water supplies (Hofste *et al.,* 2019). All areas where withdrawals are greater than the supply were excluded (Fraunhofer, 2021).

Land eligibility for the installation of offshore wind parks depends on marine protected areas as well as the maximum water depth, determined through a topographical analysis (NOAA National Geophysical Data Centre, 2009) and minimum distance from shore, which were set to 40 metres and 5 km, respectively.

Meteorological data

The meteorological dataset acquired for the assessment is the fifth-generation European Centre for Medium-Range Weather Forecasts (ECMWF) Reanalysis, or ERA5, produced by the Copernicus Climate Change Service at ECMWF (Hersbach *et al.,* 2018). ECMWF makes the data available for the years 1979 to the present with hourly temporal resolution and a spatial resolution of 0.28125 degrees, which translates to about 31 x 31 km at the equator. In particular, the ERA5 datasets used for the assessment are "surface solar radiation downwards" and "the direct solar insolation on a horizontal surface" for solar radiation and the "u and v components of wind at 100 m" for wind speed data.

The reference year for the meteorological data used in this analysis is 2018. This year was considered as representative of the period 2010-20 considering weather anomalies, which were of relatively low intensity for the period 2015-20 (NOAA, 2022), which includes the most critical years concerning climate change effects. More specifically, 2018 was a La Niña year, meaning a globally cold year. La Niña years present better wind and solar irradiation for renewable production (Li and Xie, 2018) (on average globally). However, it was also the warmest La Niña recorded (Yale Climate Connections, 2018), thus presenting anomalies in wind and solar irradiation that are not too extreme.

The ERA5 data were subsequently translated into hourly capacity factors for the renewable generation technologies of solar PV and wind power. Onshore and offshore hourly wind power generation capacity factors were obtained through onshore and offshore turbine power curves. In the first case, the power curve implemented to obtain hourly capacity factor was that of the 3 MW Vestas V112 (Vestas, n.d.), while in the second case the larger 12 MW General Electric Haliade-X 220 12 was implemented (Saint-Drenan *et al.,* 2020). In both cases 15% losses were assumed. These account for availability and electrical losses, as well as wind farm-induced wake losses.

[40] *In a more conservative approach, agro-photovoltaics was not considered in the analysis. This variant of the ground mounted utility-scale PV is not applicable to all crop typologies, the local distinction of which would increase the complexity of the global model.*

Solar PV hourly capacity factors were obtained through the processing of the ERA5 radiation datasets into global tilted irradiation. The orientation (azimuth) of the PV panels is assumed to always be facing the equator, meaning south-oriented in the northern hemisphere and north-oriented in the southern. The optimal tilt of the PV panels is a function of latitude (Jacobson and Jadhav, 2018). The wind dataset is rescaled linearly to 1 x 1 km based on high resolution annual average wind speeds from the Global Wind Atlas (DTU, 2019).

The eligible land from the exclusion criteria can be translated into renewable generation potential through the power densities (per unit area) of solar PV, onshore wind and offshore wind power. The global values used in this assessment are 45 megawatts of alternating current power (MWAC) per km^2 for PV (Bolinger and Bolinger, 2022; Ong *et al.,* 2013), 5 MW/km^2 for onshore wind and 7.43 MW/km^2 for offshore wind (Enevoldsen and Jacobson, 2021; IRENA, 2015). The power densities for wind include wake effects but do not consider the reduction of the capacity factor because a higher share of the potential is used.

Cost optimisation

LCOH is optimised by changing the capacities of solar PV, onshore wind and the electrolyser. The key input parameters are the CAPEX for the three technologies, the WACC, and the capacity factors for each technology. The CAPEX assumptions for renewables in G7 countries are shown in Tables A.2 and A.3

TABLE A.2 CAPEX assumptions for renewable energy in 2030 and 2050 in G7 members for an **optimistic scenario**

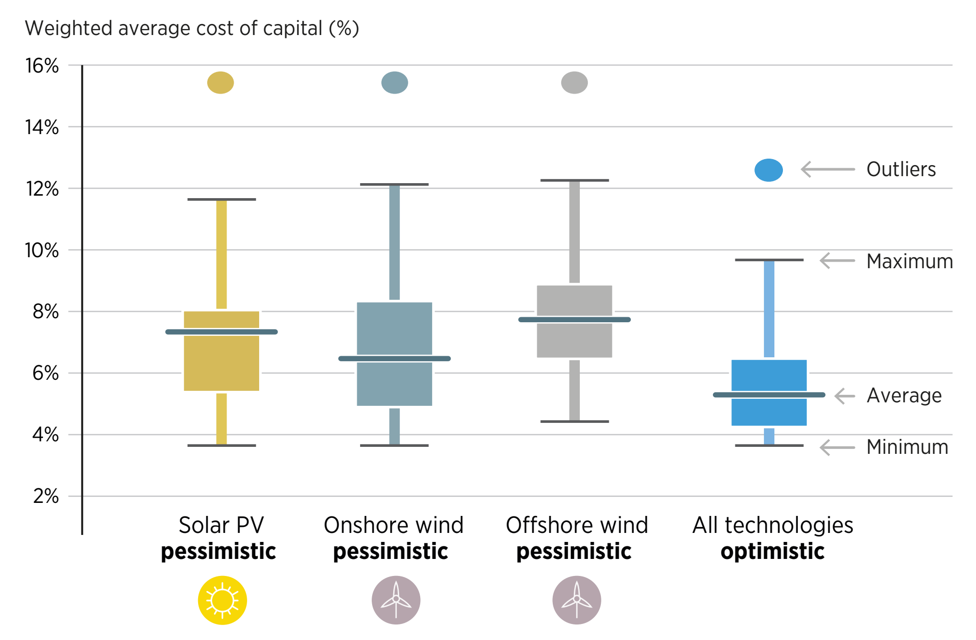
	2030			2050		
	Utility-scale solar PV	Onshore wind	Offshore wind	Utility-scale solar PV	Onshore wind	Offshore wind
Canada	490	920	2 080	350	795	1 445
European Union	365	1 060	2 090	285	870	1 450
France	380	930	2 070	295	800	1 440
Germany	300	930	2 425	255	800	1 610
Italy	330	930	2 070	270	800	1 440
Japan	675	1 095	2 700	445	890	1 745
United Kingdom	350	930	2 470	280	800	1 635
United States	435	920	1 985	320	795	1 400

TABLE A.3 CAPEX assumptions for renewable energy in 2030 and 2050 in G7 members for a **pessimistic scenario**

	2030			2050		
	Utility-scale solar PV	Onshore wind	Offshore wind	Utility-scale solar PV	Onshore wind	Offshore wind
Canada	615	1 025	2 245	425	880	1 490
European Union	455	1 035	2 250	345	965	1 495
France	475	1 035	2 230	355	890	1 485
Germany	375	1 035	2 610	305	890	1 660
Italy	410	1 035	2 230	325	890	1 485
Japan	840	1 220	2 910	540	985	1 800
United Kingdom	435	1 035	2 665	335	890	1 685
United States	540	1 025	2 140	390	880	1 445

The WACC is used as the discount rate for the investments in hydrogen generation systems. This parameter is used to express the risk of investment in a particular region. The range of WACC values across countries for various scenarios and technologies is shown in Figure A.2

FIGURE A.2 Range of WACC by technology and scenario



Note: Box and whisker charts show variation within a set of data, similar to a histogram. The line and the x within the box represent the median and the mean, respectively. The upper and lower boundaries of the box represent the first (Q1) and third (Q3) quartiles of the dataset. A value is considered an outlier if greater than Q3+1.5(Q3-Q1) or smaller than Q1-1.5(Q3-Q1). The upper and lower whiskers represent the maximum and minimum values which are not outliers.

The electrolyser capital costs per kilowatt used for this assessment are in line with the potential cost decrease for electrolysers as a function of deployed capacity, considering the cost corresponding to 5 terawatts (TW) of deployed capacity by the year 2050 (IRENA, 2020). These are expected to fall from USD 384/kW$_{el}$ in 2030 to USD 134/kW$_{el}$ in 2050 under optimistic assumptions and USD 688/kW$_{el}$ to USD 326/kW$_{el}$ in a pessimistic scenario. These values include installation costs. The remaining inputs for the optimisation problem are technology-specific characteristics such as lifetimes and operating expenditures. Lower performance due to degradation for solar PV was not considered. All system components' lifetimes were set to 25 years, while the yearly operating expenditures were set to 1% of CAPEX for solar PV, 3% for onshore wind and 2.5% for offshore wind.

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