IRENA
International Renewable Energy Agency

GLOBAL HYDROGEN TRADE TO MEET THE 1.5°C CLIMATE GOAL

PART III

GREEN HYDROGEN COST AND POTENTIAL

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ABBREVIATIONS

CAPEX	capital expenditure
CF	capacity factor
ECMWF	European Centre for Medium-Range Weather Forecasts
EJ	exajoule
FLOH	full-load operating hours
G20	Group of 20
GW	gigawatt
HHV	higher heating value
IRENA	International Renewable Energy Agency
kgH_2	kilograms of hydrogen
km^2	square kilometre
kW	kilowatt
kW_e	kilowatt electric
kWh	kilowatt hour
LCOE	levelised cost of electricity
LCOH	levelised cost of hydrogen
m^3	cubic metre
MENA	Middle East and North Africa
MtH_2	million tonnes of hydrogen
MW	megawatt
MWh	megawatt hour
OPEX	operational expenditure
PV	photovoltaic
TW	terawatt
USD	United States dollars
WACC	weighted average cost of capital

EXECUTIVE SUMMARY

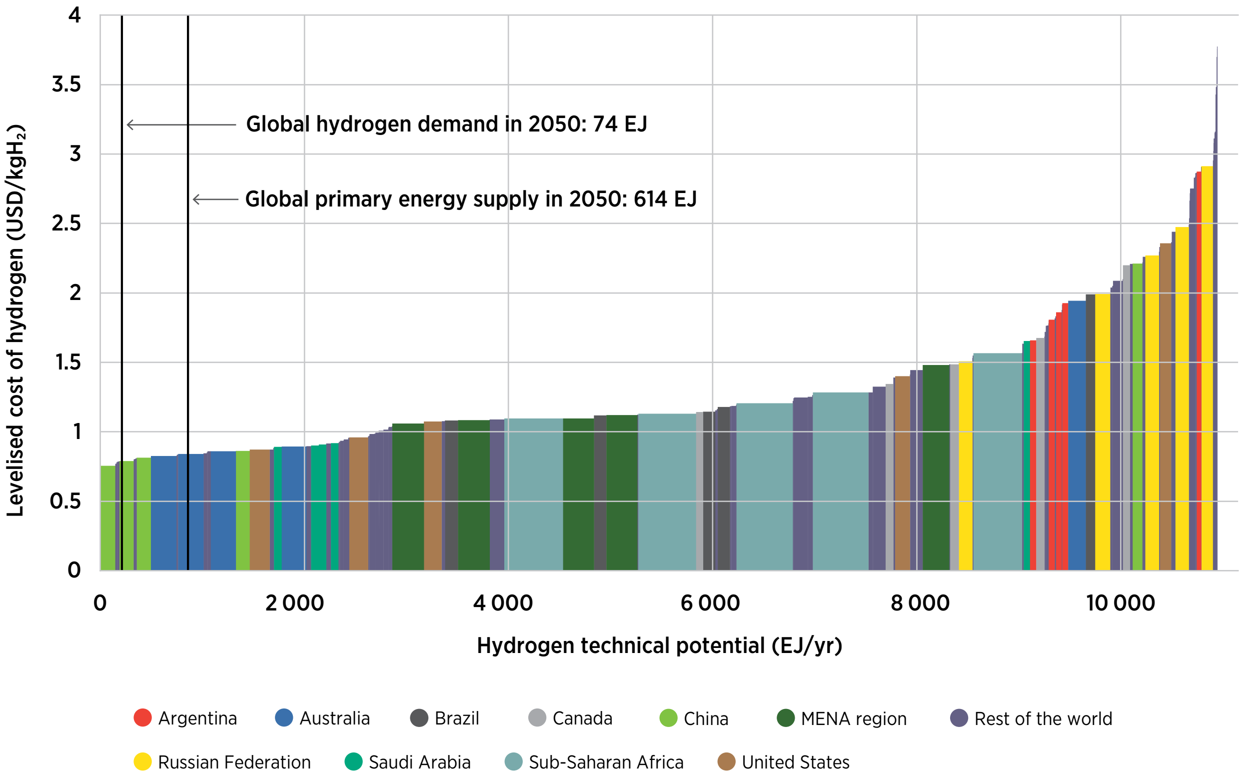
Hydrogen is an essential component of a net zero energy system. It provides an alternative to decarbonise sectors that are difficult to electrify such as heavy industry and long-haul transport. Electrolytic hydrogen produced through renewables (green hydrogen) is the most sustainable hydrogen production technology. It allows sector coupling with the power sector providing additional flexibility to integrate variable renewable energy, and it provides an alternative for seasonal storage of energy and provision of capacity adequacy. One of the main challenges that green hydrogen faces today is its higher cost compared with fossil fuels and other alternative low-carbon technologies. With technology innovation to improve performance, deployment to increase global scale, larger electrolyser plants and continuous decrease in renewable power cost, which is the main cost driver, green hydrogen is expected to reach cost parity with fossil-derived hydrogen within the next decade.

This report explores the global cost evolution of green hydrogen towards 2030 and 2050. For this, a geospatial approach is used since the renewable resources are highly dependent on the location. The world is divided in pixels of roughly 1 square kilometre (km^2), and the optimal configuration among renewable generation technologies (solar PV, onshore wind and offshore wind) and the electrolyser is determined to achieve the lowest production cost. The cost is based on the assumption of dedicated (off-grid) plants and refers only to production without hydrogen transport to the coastline or potential consumption site. The potential for a specific country or region is based on the land available, for which various exclusion zones are applied including protected areas, forests, wetlands, urban centres, slope and water scarcity, among others. This allows estimating both the production cost and the potential for green hydrogen for every region.

The green hydrogen technical potential considering these land availability constraints is still almost 20 times the estimated global primary energy demand in 2050. Green hydrogen potential, however, is not a single value; it is a continuous relationship between cost and renewable capacity (Figure 0.1). In terms of production cost, this is directly dependent on the cost of the renewable input (major cost driver), the electrolyser and the WACC. In 2050, almost 14 terawatts (TW) of solar PV, 6 TW of onshore wind and 4-5 TW of electrolysis will be needed to achieve a net zero emissions energy system. Thanks to these deployments, technology costs are expected to decrease dramatically because of innovation, economies of scale and optimisation of the supply chain. In this future, green hydrogen production could reach levels of almost USD 0.65/kg of hydrogen (kgH_2) for the best locations in the most *optimistic* scenario. In a more *pessimistic* scenario with higher technology costs, still for 2050, the lowest production cost is USD 1.15/kgH_2 increasing to USD 1.25/kgH_2 to meet a demand of 74 exajoules (EJ) per year.

While global green hydrogen potential is more than enough, there are specific countries where potential is restricted and where domestic production might not be enough to satisfy domestic demand. Due to the nature of their territory, Japan and the Republic of Korea are the most restricted: 91% of Japan's total country land and 87% of the Republic of Korea's total country land is excluded for hydrogen production. The Republic of Korea would need to use about one-third of its renewable potential to satisfy its domestic energy demand in 2050. However, once the electricity consumption is considered, there is hardly any left for hydrogen production. The technical potential for Japan is about 380 gigawatts (GW) of PV and 180 GW of onshore wind, which would be enough to produce about 20 million tonnes of hydrogen (MtH_2) per year of hydrogen below USD 2.4/kgH_2. The quality of the resources is relatively poor (less than 14% for the majority of PV and less than 30% for wind) and most of this potential is used to satisfy electricity demand rather than hydrogen. Other countries that would require a relatively high share of their renewable potential to satisfy their domestic hydrogen demand are India (89% of the land is excluded mainly due to population density, cropland, savannahs and forests); Germany (66% excluded mainly by forests and cropland); Italy (62% excluded mainly due to slope, population density and croplands); and Saudi Arabia (94% excluded mainly due to water stress).

FIGURE 0.1. Global supply-cost curve of green hydrogen for the year 2050 under *optimistic* assumptions



Notes: MENA = Middle East and North Africa. Optimistic assumptions for 2050 CAPEX are as follows: PV, USD 225/kilowatt (kW) to USD 455/kW; onshore wind, USD 700/kW to USD 1070/kW; offshore wind, USD 1275/kW to USD 1745/kW. WACC per 2020 values without technology risks across regions. Electrolyser CAPEX and efficiency set to USD 134/kW_e and 87.5% (higher heating value [HHV]). Technical potential has been calculated based on land availability considering several exclusion zones (protected areas, forests, permanent wetlands, croplands, urban areas, slope of 5% [PV] and 20% [onshore wind], population density and water stress).

Water is used as input to electrolysis, and it is perceived as one of the critical parameters for green hydrogen production. In water-scarce regions, desalination could be used. Even in regions far from the coastline, water transport could be considered, which will increase the cost of water supply, but it will still represent a relatively small share of the total hydrogen production cost, reaching levels of USD 0.05/kgH_2 and representing 1-2% of the energy consumption of the electrolyser. The regions where this constraint restricts the hydrogen potential the most are Saudi Arabia (92% reduction); the Middle East (83% reduction); Morocco (63% reduction); and the rest of Asia (61% reduction). Even then, the potential remains relatively vast. The reduced PV potential in Saudi Arabia would still be enough to produce about 190 MtH_2/year and Morocco would represent the smallest one from these regions and still be able to produce about 90 MtH_2/year.

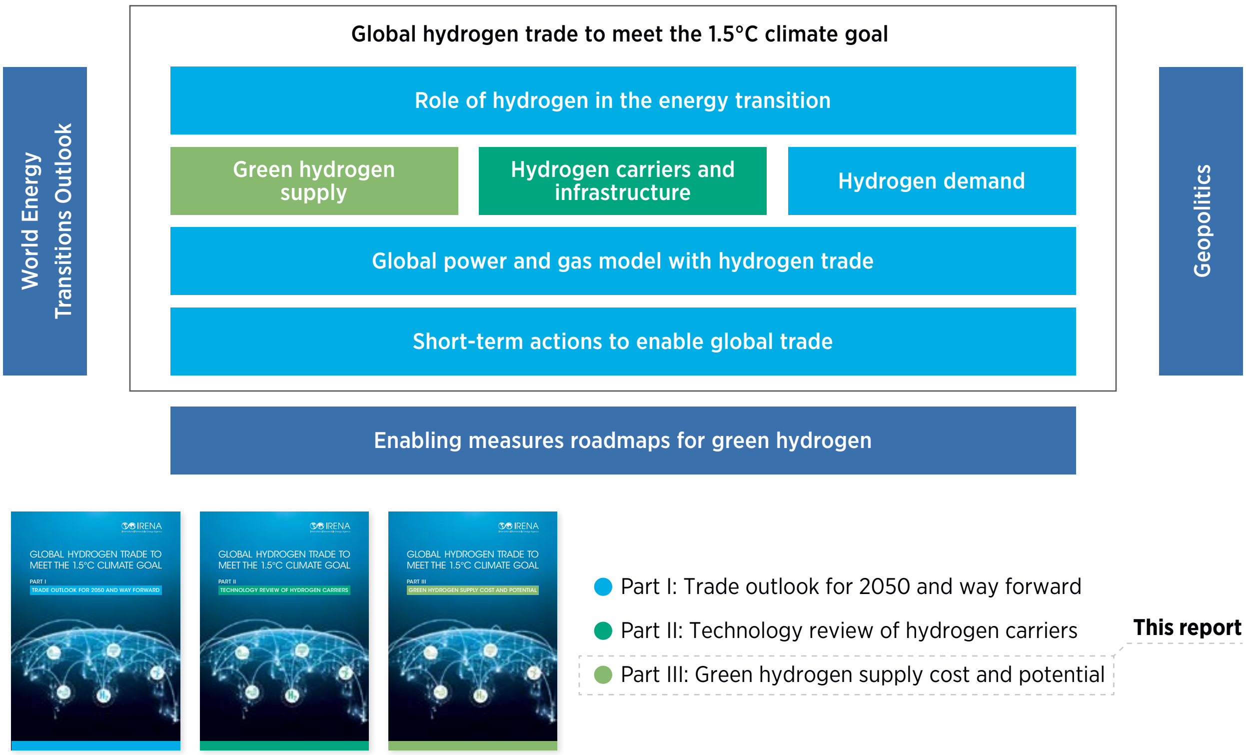
The main uncertainties for the analysis lie in the cost levels and, in particular, the evolution of CAPEX for renewables, and electrolysis and the WACC towards 2050. On the one hand, technology will continue to progress, and deployment will lead to optimisation of global supply chains, standardisation and faster execution. On the other hand, as the system transitions to fixed capital assets rather than fuels, cycles in commodity prices such as the one experienced in 2021 can lead to periods of higher capital costs although with a smaller impact on energy prices since it would be affecting only new assets. The floor costs for the various technologies are not yet known with certainty. If solar PV cost continues its recent trend and electrolyser costs also achieve low levels, PV-dominated can become more cost-effective. Multiple countries in sub-Saharan Africa, the Middle East and Latin America have vast renewable potential and the main uncertainty in their cost levels is how much they will be able to decrease their high WACCs towards 2050. This proved to be more critical in defining the cost differential among countries than the quality of the renewable resource.

CONTEXT OF THIS REPORT AND WHAT TO EXPECT

The *Global Hydrogen Trade to Meet the 1.5°C Climate Goal* series of reports is divided into three parts (Figure 0.2). The first report integrates these components with the demand, analysing various scenarios for technology development towards 2050 to assess the outlook of global hydrogen trade. It also presents short-term actions to achieve that long-term vision (IRENA, 2022a). The second part covers the state-of-the-art literature for four different transport technology pathways (IRENA, 2022b). The third (this report) covers the cost and potential of green hydrogen for various regions and time horizons under different scenarios and assumptions.

The *Global Hydrogen Trade to Meet the 1.5°C Climate Goal* report series complements other IRENA publications. The *World Energy Transitions Outlook* (IRENA, 2022c) provides a perspective on the role of hydrogen within the wider energy transition in a scenario in line with a 1.5°C pathway. This outlook covers all energy sectors and includes the trade-off between hydrogen and other technology pathways (*e.g.* electrification, carbon capture and storage, bioenergy). The short-term actions to enable global trade that are identified in the *Global Hydrogen Trade to Meet the 1.5 °C Climate Goal* report are only the beginning.

FIGURE 0.2. Scope of this report series in the broader context of IRENA publications



Enabling measures are needed to accelerate hydrogen deployment. While there are measures that are applicable at the global level (*e.g.* certification), some of the measures will be country-specific depending on local conditions including energy mix, natural resources and level of mitigation ambition, among others. Thus, the global toolbox of enabling measures needs to be adapted to the local context. The International Renewable Energy Agency (IRENA) has already addressed this for Europe and Japan (IRENA and WEF, 2021), with more regions to be analysed in the coming months.

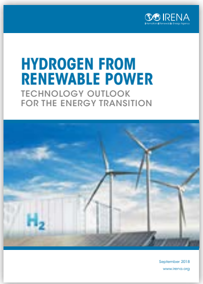
Hydrogen trade will be defined by not only production and transport cost or comparison of domestic and import cost but also by other factors such as energy security, existence of well-established trade and diplomatic relationships, existing infrastructure, greenhouse gas emissions and air pollution. Stability of the political system will also have a large impact on the trade partners each country chooses to have. Therefore, the actual trade partners will probably look different from the ones presented in this report since these "soft factors" are not considered in the model, which is based on pure cost optimisation. These geopolitical factors are covered in a separate report (IRENA, 2022d) as part of IRENA's Collaborative Framework on Geopolitics.

The present report assesses the global green hydrogen production outlook for 2030 and 2050, based on a geospatial analysis. The assessment regards 34 global regions, comprised of Group of 20 (G20) countries (as well as Chile, Colombia, Morocco, Portugal, Spain and Ukraine) and macro-regions representing country aggregates (for example sub-Saharan Africa and the Middle East/North Africa). The methodology section introduces the model implemented followed by the quantification of a land suitability analysis for the installation of stand-alone systems, *i.e.* off-grid, green hydrogen generation systems, with a focus on the impact of land typology on terrain eligibility for the installation of utility-scale photovoltaic (PV) and onshore wind parks. Subsequently, techno-economic assumptions of the model are presented as technical characteristics of the generation technologies (utility-scale PV, onshore and offshore wind) alongside those of the electrolyser. Economic assumptions, which define the scenario trends, are reported in terms of capital expenditure (CAPEX) and weighted average cost of capital (WACC). The CAPEX of the generation technologies shows its decreasing trend between 2030 and 2050 and varies among the assessed regions, while that of the electrolyser is assumed to be equal globally. The values of WACC, which express the risk of investment in the single regions, are reported with a brief analysis of its impact on the cost of hydrogen.

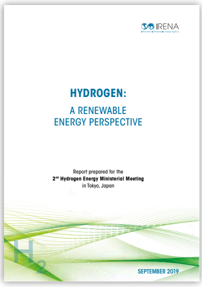
The impact of the above-mentioned assumptions is then quantified in the second section, starting with an analysis of the levelised cost of hydrogen (LCOH) and optimal system configuration. In particular, the individual effects of the generation technology capacity factors and technology CAPEX are reported. Following is a consideration of the hybrid systems' configuration (systems in which an electrolyser is potentially coupled with both solar PV and onshore) with a focus on the effect of generation technology CAPEX on optimal hybrid configurations.

Lastly, the global outlook of green hydrogen generation is presented. Global supply-cost curves are shown accompanied by maps illustrating the global distribution of LCOH. The supply-cost curves serve the purpose of showing how in the 2030 and 2050 time horizons, the global supply of green hydrogen is fully satisfied with costs below USD 2 (United States dollars) per kilogram of hydrogen (kgH_2) in 2050. The maps then allow visualisation of the geospatial allocation of the different regions' LCOH. All values are put in perspective with forecast hydrogen demand.

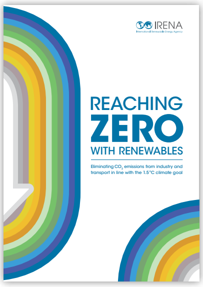
This report is part of IRENA's ongoing programme of work to provide its member countries and the broader community with expert analytical insights into the potential options, the enabling conditions and the policies that could deliver the deep decarbonisation of economies. Green hydrogen, being an indispensable element of the energy transition, is one focus of IRENA analysis. Recent IRENA publications include:



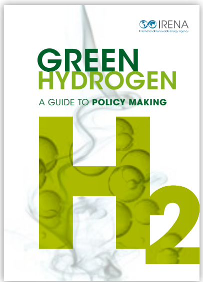
Hydrogen from renewable power (2018)



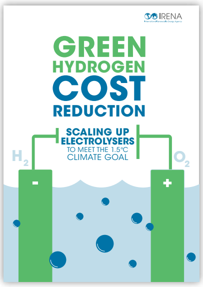
Hydrogen: A renewable energy perspective (2019)



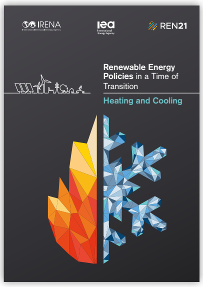
Reaching zero with renewables (2020) and its supporting briefs on industry and transport



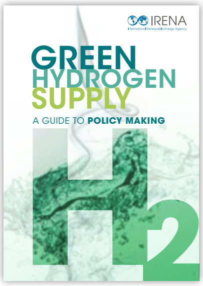
Green hydrogen: A guide to policy making (2020)



Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5°C climate goal (2020)

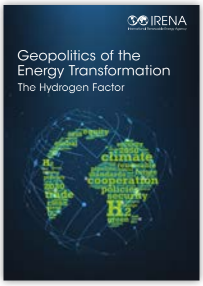


Renewable energy policies in a time of transition: Heating and cooling (2020)

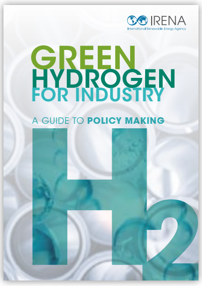


Green hydrogen supply: A guide to policy making (2021)

Enabling measures roadmap for green hydrogen (2021), in collaboration with the World Economic Forum



Geopolitics of the energy transformation: The hydrogen factor (2022)



Green hydrogen for industry: A guide to policy making (2022).

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

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

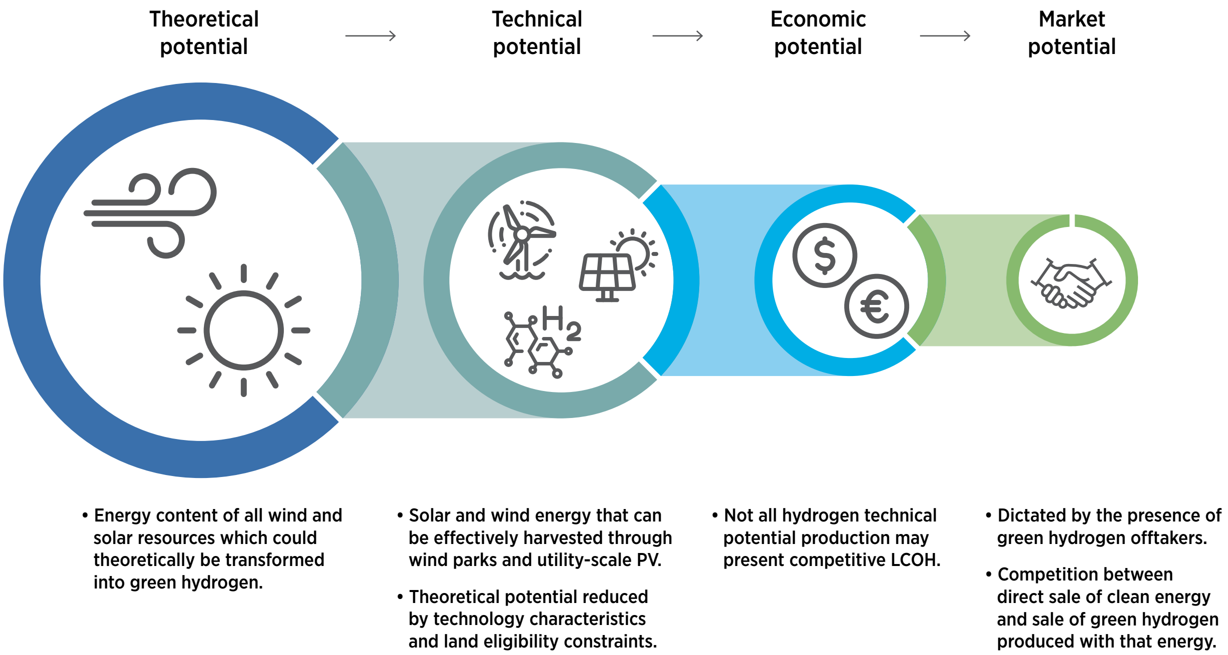
1 INTRODUCTION

INTRODUCTION

Hydrogen is recognised as an essential element for the deep decarbonisation of our energy system that is required to meet the current climate targets and limiting the temperature increase below 2°C (IEA, 2021; DNV AS, 2021; IRENA, 2021). However, to establish itself in such a role the production of hydrogen must be guaranteed to be emission-free (hydrogen produced by steam methane reforming emits nine metric tonnes per single metric tonne of hydrogen produced without considering methane emissions [Howarth and Jacobson, 2021]). Hydrogen from steam methane reforming coupled with carbon capture (blue hydrogen), electrolytic hydrogen produced through low-carbon electricity (yellow hydrogen) and electrolytic hydrogen produced through renewables (green hydrogen) are the main potential candidates to satisfy the requirement. Hydrogen has a wide range of industrial applications, from refining to petrochemicals to steel manufacturing. Furthermore, similarly to natural gas, H_2 can be stored for a long time and transported over considerable distances through pipelines or shipped after being converted into liquid organic hydrogen carriers or ammonia, or as liquefied hydrogen.

The hydrogen transport methods at present have varying costs that are foreseen to settle to a similar value by 2050, resulting in an increment of around USD 1/kgH_2 on the transported hydrogen (IRENA, 2022b). Moreover, transport induces losses and may require energy-intensive processes for the conversion (hydrogen liquefaction) and reconversion (ammonia cracking). Green hydrogen production is currently limited to a few applications due to its high cost and its production capacity. While green hydrogen use in transport is currently the most robust business case, there is an increasing interest in using hydrogen in hard-to-abate sectors such as production of steel and cement and in oil refineries. However, advances in electrolysis technology, decreasing costs of renewables and increased economies of scale should significantly reduce its production cost and make it an economically viable solution.

FIGURE 1.1. Types of renewable energy potentials and applicable constraints



Different types of potentials can be identified when discussing sustainably produced hydrogen (see Figure 1.1): theoretical, technical, economic and market potentials. These represent upper potential limits based on increasingly stringent criteria. A region's theoretical solar and wind potential is defined as the overall energy content of wind and solar radiation in that region (McKenna *et al.*, 2022), setting a true upper boundary to how much energy can be ideally harvested from renewable resources. Next, the green hydrogen technical potential is defined as the energy content of the hydrogen that can actually be produced by electrolysis powered by renewables. This accounts for the technological characteristics and requirements of the system. First, efficiencies of the power generation technologies allow that only a portion of the exploitable energy is transformed into power. Second, the electrolyser efficiency ensures that only part of the harvested energy is converted into hydrogen.

Technical and/or regulatory unsuitability of land to host such systems further contributes to the decrease of the technical potential from the theoretical one. The economic potential is defined if the focus is also posed on the cost of the produced hydrogen.

The LCOH is given by the ratio between the total system cost (CAPEX and operational expenditure [OPEX]) and the total hydrogen production. This last quantity is directly dependent on the quality of renewable energy resources and the electrolyser's cost and performance. To be economically attractive, green hydrogen must have costs compatible with those that potential offtakers are willing to pay. This is the reasoning behind the definition of the economic potential, which represents the portion of the technical hydrogen production potential which has an LCOH below a certain threshold (excluding the additional cost of storage and transportation to the consumption gate).

The economic potential may not correspond to market demand, which leads to curtailing production, hence potential. The reasons for this may be for the lack of offtakers in certain locations or, in some cases, it may be more economically sound to sell the generated renewable power directly to the national grid, instead of dedicating it completely to hydrogen production. This last decrease in production potential defines the market potential, the analysis of which will be excluded from this report, which focuses on the definition of the economic potential of 34 global regions. Of these, G20 countries are analysed individually while the remaining countries are aggregated in macro-regions such as the Middle East/North Africa and Latin America. An exception was made for Chile, Colombia, Morocco, Portugal, Spain and Ukraine, which were also assessed individually because of their good prospects in green hydrogen production. In summary, the results of this analysis give a clear view of the economic hydrogen potential, the local hydrogen production cost, and the areas available for renewable energy plants and hydrogen production as well as those with lowest LCOH.

2 METHODOLOGY

METHODOLOGY

This section describes the data and tools used in this analysis. In general, meteorological data is combined with land eligibility criteria to determine where green hydrogen production is possible and at what cost. The model considers stand-alone hydrogen generation systems powered by solar PV, onshore wind and offshore wind. Based on land exclusion criteria and resource quality, it may occur that some systems are hybrids, that is, the electrolyser may be powered by both solar PV and onshore wind. An optimisation provides the optimal ratios between the capacities of the generation technologies and the capacity of the electrolyser depending on the local resource quality and regional costs. The aim is to maximise hydrogen production while minimising the cost of the system, thus providing the lowest LCOH, allocated geospatially. This allows the production of global LCOH maps which enable users to visually grasp the suitability of certain regions to produce green hydrogen. Moreover, this analysis also generates regional green hydrogen supply cost curves which accompany the LCOH maps to provide the production potential corresponding to a given LCOH.

The solar and wind resource data used as input to the model has an hourly temporal resolution and a 31x31 km spatial resolution.[1] Therefore, solar PV and onshore/offshore wind plants will be characterised by hourly capacity factor profiles for 961 km^2 areas. 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.

Additional datasets regarding land cover type, protected areas, population density and terrain slope were added to the model to characterise land under different aspects. With a higher spatial resolution of 1x1 km,[2] such datasets allowed identification of what areas of a region are suitable for the installation of the green hydrogen generation systems. Different exclusion criteria were applied for solar PV, onshore wind and offshore wind power. In a second step of analysis a land exclusion criterion for water availability for electrolysis was also added, and geographical areas in which water availability is problematic were excluded.[3] However, desalination was considered as a viable option for electrolysis water supply in areas within 50 km from the coast (Fraunhofer, 2021). The additional cost for desalination was not computed given the marginal contribution of water supply to the overall LCOH, despite the potential additional costs of desalination (Yates *et al.*, 2020). Reverse osmosis desalination and multistage flash distillation desalination produce water with costs below USD 3 per cubic metre (m^3) (Reddy and Ghaffour, 2007; Kyriakarakos and Papadakis, 2021; Huehmer *et al.*, 2011). It was determined that at a site with an annual production

[1] *Meteorological data taken from ERA5 dataset produced by the European Centre for Medium-Range Weather Forecasts (ECMWF) (Copernicus Climate Change Service, 2017) presents a spatial resolution of 0.28125 degrees. This translates into 31x31 km land area at the equator.*

[2] *Additional datasets present spatial resolution of 0.01 degrees, which correspond to 1x1 km land areas at the equator.*

[3] *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).*

of almost 2500 tonnes/year, the total water consumption would be around 60 m^3/day[4] (or 21900 m^3/year). The site presents LCOH of USD 0.7/kgH_2,[5] and considering a desalination cost of USD 3/m^3 the increment of LCOH would be 3.8%.

As this analysis aims to assess the intrinsic green hydrogen production potential and its cost in a certain location, the following assumptions have been made. First, all green hydrogen is produced in off-grid stand-alone systems placed in a plot of land of about 1x1 km. The systems are characterised at component level by techno-economic parameters. The generation technologies and the electrolyser are described through investment costs, operating expenses, lifetimes and efficiencies. The capacities of the system components are optimised to yield the lowest LCOH, and therefore curtailment is present when the hourly average power production exceeds the electrolyser capacity. This is a conservative approach as the potential synergy with the grid is not being considered. Because the systems are assumed to be stand-alone, there is no underlying hypothesis of the presence of power offtakers which might make the system more profitable by selling the curtailed electricity. Similarly, hydrogen demand is not considered, resulting in a free production of hydrogen whenever the resources allow it.

Geographical constraints and exclusion criteria

The additional datasets mentioned in the previous section allowed applying land eligibility masks for the three types of generation technologies, according to different land exclusion criteria. Regarding land type, all protected areas,[6] forests and wetlands[7] were excluded from the analysis, for both solar PV and onshore wind. On the other hand, special regard was taken when excluding croplands, which were excluded only for solar PV. 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 40-60% cultivated land and 60-40% natural trees, shrubs or herbaceous vegetation, is excluded by only a 60% fraction. Southeast Asia, France and Germany are the most affected by this land eligibility criterion, excluding 16% of Southeast Asia's total land area, 15% of France's and 14% of Germany's. 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.[8] Different exclusion criteria are also applied for terrain slope: as suggested by Maclaurin *et al.* (2021), the terrain slope threshold for the installation of onshore wind turbines is higher (20%) than that of utility-scale PV (5%).[9]

The differences in exclusion criteria for onshore wind and solar PV, which appear to be more stringent for the latter, will yield larger portions of land suitable for the installation of wind parks. In addition, since this assessment concerns wind parks and utility-scale PV systems, urban areas and settlements were also excluded from the eligible areas. This is achieved with the aid of two

4 *Electrolyser capacity factor is 31%, with generation systems capacities of 50 megawatts [MW] utility-scale PV and 41 MW electrolyser, water consumption of 9 litres/kgH_2*

5 *Techno-economic assumptions for Chile 2050. CAPEX solar PV: USD 312/kW. CAPEX alkaline electrolyser: USD 134/kW_e. Alkaline electrolyser efficiency: 45 kilowatt hours (kWh) per kgH_2*

6 *Strict Nature Reserve, Wilderness Area, National Park, Natural Monument, Habitat/Species Management, Protected Landscape/Seascape, Managed Resource Protected Area (IUCN-UNEP-WCMC, 2019).*

7 *Evergreen Needleleaf Forests, Evergreen Broadleaf Forests, Deciduous Needleleaf Forests, Deciduous Broadleaf Forests, Mixed Forests, Permanent Wetlands (Friedl et al., 2010).*

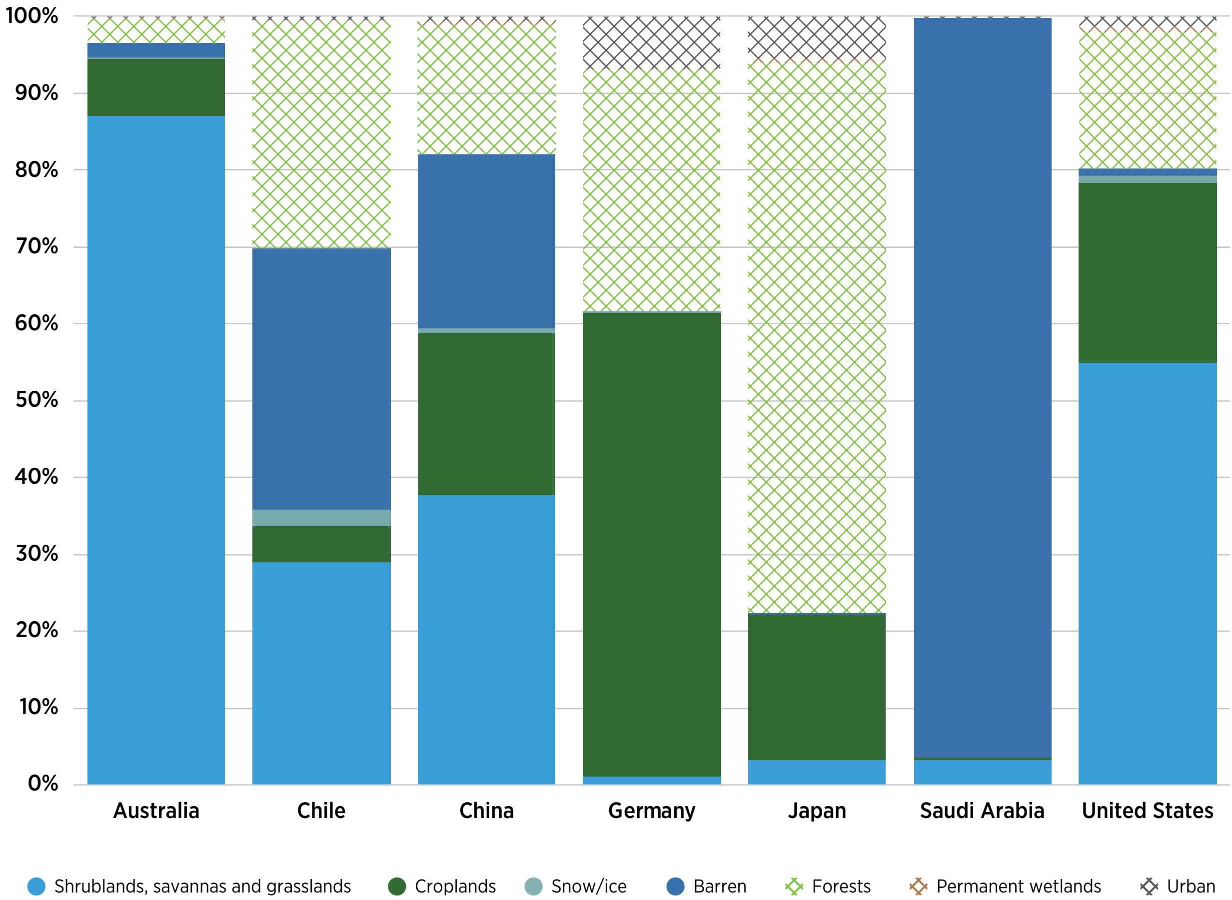
8 *In a more conservative approach, agrophotovoltaics was not considered in the analysis. This variant of the ground-mounted utility-scale PV is not applicable to all crop typologies (Fraunhofer ISE, 2020), the local distinction of which would increase the complexity of the global model.*

9 *Global slope dataset provides mean slope values for 1x1 km land areas (Amatulli et al., 2018).*

distinct datasets. Urban land type (Friedl *et al.*, 2010) as well as population density (Gao, 2017) were implemented together[10] in excluding areas which are built up or present a population density greater than a threshold of 130 people per square kilometre. A more in-depth analysis and further tool developments are required to also assess global rooftop PV potential, and is therefore excluded from this work. 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 Center, 2009), and minimum distance from shore, which were set to 40 metres and 5 km, respectively. Existing wind and solar parks are not accounted for in land exclusion criteria, leading to an overestimation of the potential. However, the difference between the technical renewable potential and the currently installed potential is large; therefore the impact of the overestimation is negligible in this assessment.

Figure 2.1 shows the land type composition for relevant countries and the percentage of land excluded based on land type suitability assumptions. Countries with large areas of unused space with little vegetation, namely shrublands and desert, show a large installable renewable generation potential. Australia, Saudi Arabia and the United States have large unused desert-like areas that can be used for renewable power. On the other hand, Japan is more constrained due to the presence of forests.

FIGURE 2.1. Land type distribution and suitability for variable renewable energy for a selection of countries

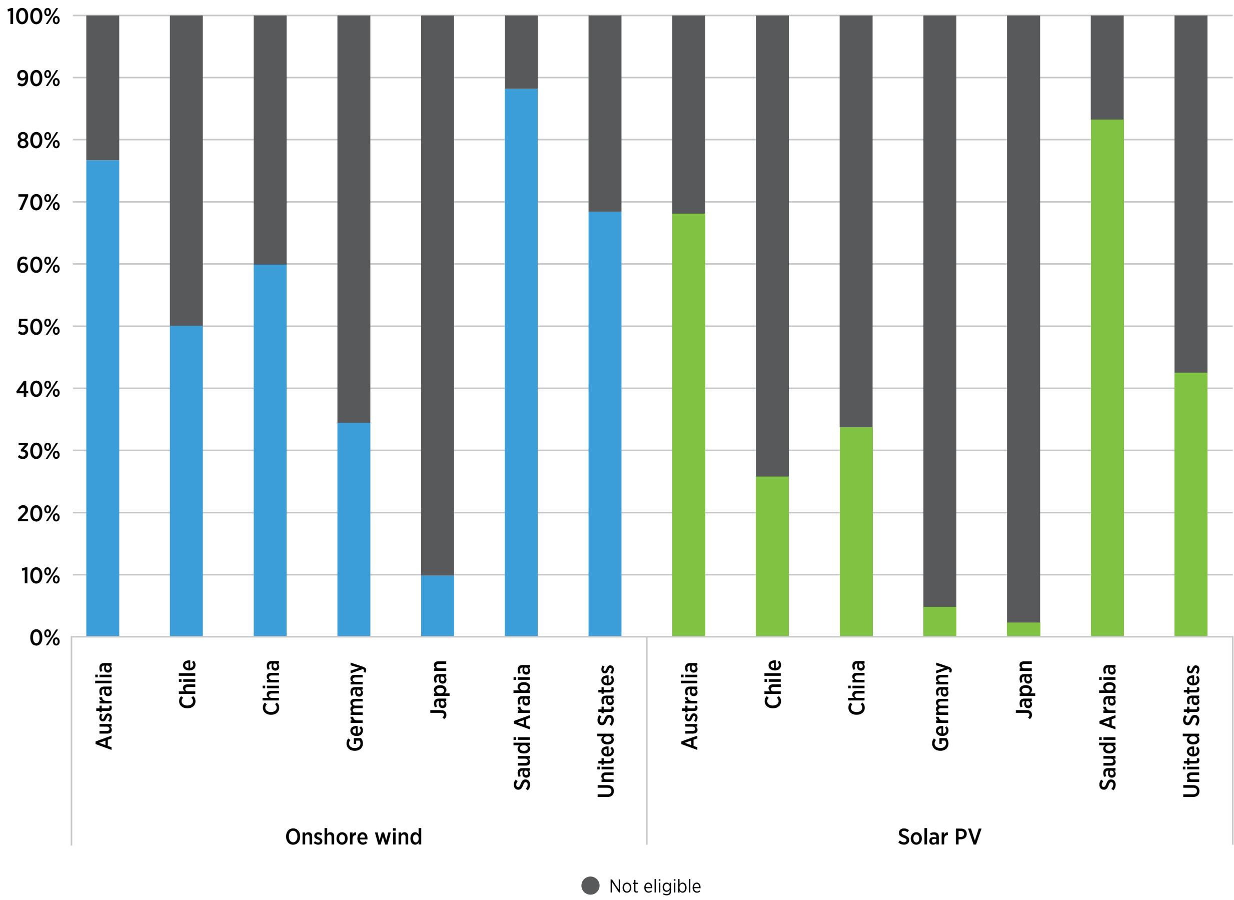


Note: Solid colours represent suitable land types for both onshore wind and solar PV. Hatch-patterned colours represent land types excluded for both solar PV and onshore wind. The intent of this representation to provide representative cases for different combinations of land typologies and their impact in different regions.

[10] *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 Socioeconomic Pathway 2nd Scenario based on the work done by (Gao, 2017).*

The effect of additional constraints on land eligibility can be observed in Figure 2.2. By adding constraints on protected areas, terrain slope and maximum population density, eligible land for wind parks changes. The limitation of the maximum terrain slope to 20% (Maclaurin *et al.*, 2021) will affect countries known for having mountainous regions. A greater effect of additional constraints can be noticed in the case of utility-scale solar PV. Besides the exclusion of protected areas and the limitation on population density, a more stringent constraint was imposed on terrain slope compared with onshore wind, and croplands were excluded. This magnifies its effect on countries with mountainous regions and countries with high portions of land intended for agriculture, such as Germany, the People's Republic of China (hereafter China), Japan and the United States. In conclusion, the land eligibility criteria provide the framework to determine the technical potential of hydrogen production. Only a fraction of this potential will have attractive costs, defining the economic potential. This last step defined the market potential, and as discussed in the introduction, is not considered in the assessment.

FIGURE 2.2. Percentage of land excluded for onshore wind (left) and utility-scale PV (right) due to land exclusion criteria



Note: Dark shading indicates the percentage of land not eligible for the installation of each generation technology. The eligible portion, reported in colour, is the percentage of eligible land described in Figure 2.1 further decreased by additional constraints on protected areas, terrain slope and population density.

Techno-economic assumptions

To estimate the potential green hydrogen production, renewable energy generation is assumed to be locally coupled with an alkaline electrolyser. This type of electrolyser was selected due to its lower cost and high technological maturity, also considering future improvements in efficiency and dynamic operation (Hydrogen Europe, 2020). The possible configurations of the stand-alone systems are dictated by the land eligibility analysis. Due to the differences in land exclusion criteria, it may occur that some stand-alone systems are composed of both onshore wind and solar PV in a hybrid configuration. The local meteorological data of wind speed and solar irradiation are translated into local hourly capacity factor distributions. Obtained through technology characteristics,[11] these profiles represent the technical inputs to the problem of determining the potential production of green hydrogen. The eligible land 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 (MW_{AC}) per km^2 for PV (Bolinger and Bolinger, 2022; NREL, 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 as a higher share of the potential is used (Box 2.1).

Box 2.1. Impact of offshore wind capacity expansion on capacity factor

The deployment of offshore wind has been much more limited to date than onshore wind. By the end of 2021, the total installed offshore wind capacity was 56 GW roughly split equally across China and Europe and representing about 5% of total global wind capacity. This would need to grow to almost 2 000 GW by 2050 in a 1.5°C scenario (IRENA, 2022c).

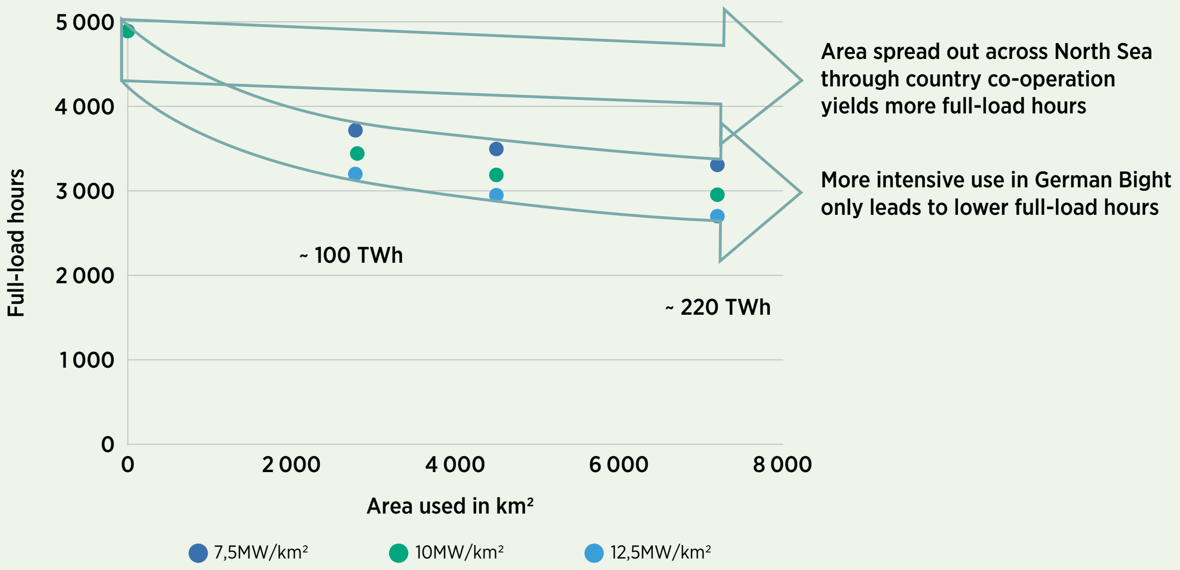
Turbines create downstream wakes, in which the wind flow is reduced due to the extraction of kinetic energy by the turbine itself. Sufficiently downstream from the turbine, the wake recovers due to mixing with the surrounding undisturbed wind flow. Turbine spacing allows avoidance or at least reduction of the impact of wakes on neighbouring turbines. However, the overall kinetic energy present in the undisturbed wind flow over a given geographical area is finite. Therefore, if a region is densely populated by wind parks, the replenishing of the depleted wake regions is not as effective, thus inducing unforeseen losses which deviate capacity factors from the expected ones. For example, a study for offshore wind farms in the German Bight found that by installing 28 GW of offshore wind over an area of 2 800 km^2, the cumulative full-load operating hours (FLOH) would decrease from an average of 4 500 to 3 400, which translates into a capacity factor of 39%. The effect is further enhanced if the installed capacity increases to 72 GW using a surface area of 7 200 km^2, decreasing the FLOH to 3 000, resulting in a cumulative capacity factor of 34% (Figure 2.3).

The unexpected capacity factor reduction may undermine the effectiveness of offshore in playing a role in the 2050 climate goals since it significantly increases the electricity cost and erodes the main advantage that offshore wind has, its higher capacity factor. Therefore, such a phenomenon must be accounted for by dedicated spatial planning of the eligible maritime regions for the installation of offshore wind parks. Countries with densely packed exclusive economic zones (*e.g.* North Sea, Baltic Sea) must co-operate to ensure sufficient spacing between farms to ensure effective wake recovery. A complementary solution to this issue is that of accessing regions of sea ineligible for fixed-bottom offshore, with the emerging floating offshore technology.

[11] *Wind speed transformed into hourly capacity factor through turbine power curve. Onshore: 3 MW V112, Vestas (Vestas, 2021). Offshore: 10 MW Siemens Gamesa SG 10.0-193 DD (Saint-Drenan et al., 2019). Solar irradiation transformed into global tilted irradiation (Jacobson and Jadhav, 2018) then divided by 1 000 watts per square metre to obtain capacity factors with respect to standard test conditions. Additional system losses of 15% were added for onshore/offshore wind and 23% for solar PV.*

Box 2.1. (Continued)

FIGURE 2.3. Full-load hours achievable depending on area for offshore wind deployment in the North Sea (and expected yield in terawatt hours)



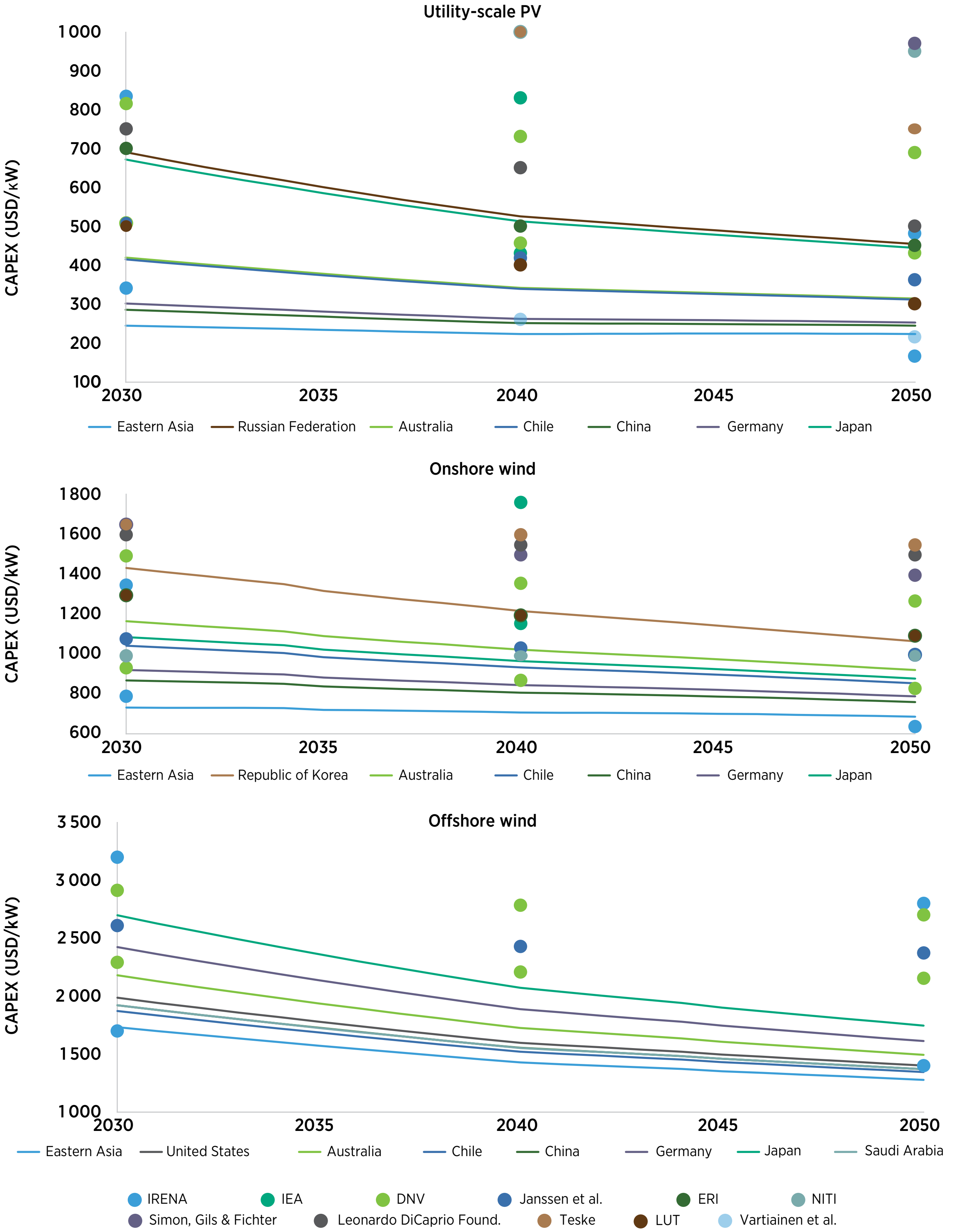
Notes: TWh = terawatt hours. Wind speed reductions are estimated with the kinetic energy budget of the atmosphere method.
Source: Agora Energiewende *et al.* (2020).

A challenge for hydrogen production from offshore wind is the high cost of electricity compared with solar PV. Auctions and power purchase agreement data suggest that the European market could reach electricity costs of USD 50 per megawatt hour (MWh) to USD 100/MWh for offshore wind by 2023, with some of the most competitive projects reaching USD 30/MWh (IRENA, 2022c). Even the lower bound would be triple the current lowest bids for solar PV (USD 10/MWh) and would translate into a hydrogen cost of USD 1.5/kgH2 without adding any costs for the electrolyser. The trade-off for countries with a large offshore potential is the higher cost of supply versus a higher energy independence. Thus, a higher cost of production might be preferred by some countries. The high gas and commodity prices during late 2021 and early 2022 in European and Asian markets have re-emphasised the need for energy security, making domestic production more attractive.

On the other hand, it is also necessary to consider the costs associated with the hydrogen generation systems. Taking these into consideration allows one to define the economic potential of production. In order to envision a transition pathway, two time horizons were considered: 2030 and 2050. For each of the time horizons, an *optimistic* and a *pessimistic* scenario were analysed. These will serve as an upper and lower boundary for the cost and potential production of green hydrogen in the global regions. An additional scenario was run with the inclusion of the water availability constraint. The definition of the different scenarios depends on the assumptions regarding the CAPEX of the components of the standalone systems, the efficiency of the electrolyser[12] and the WACC. Moreover, the CAPEX of the generation technologies (utility-scale PV, onshore and offshore wind) are considered variable by region (Figure 2.4). The WACCs are considered to be variable by both technology and region. However, unlike the CAPEX, the WACCs are assumed to be fixed through to 2050, for both the *optimistic* ad *pessimistic* scenarios.

[12] *Alkaline electrolyser efficiency varies based on the time horizon (2030, 2050) and scenario (optimistic, pessimistic). The specific electrical energy consumptions in 2030 are 48.5 kWh/kgH_2 and 52.2 kWh/kgH_2 while in 2050 they are 45.0 and 48.0 kWh/kgH_2 for the optimistic and pessimistic scenarios, respectively.*

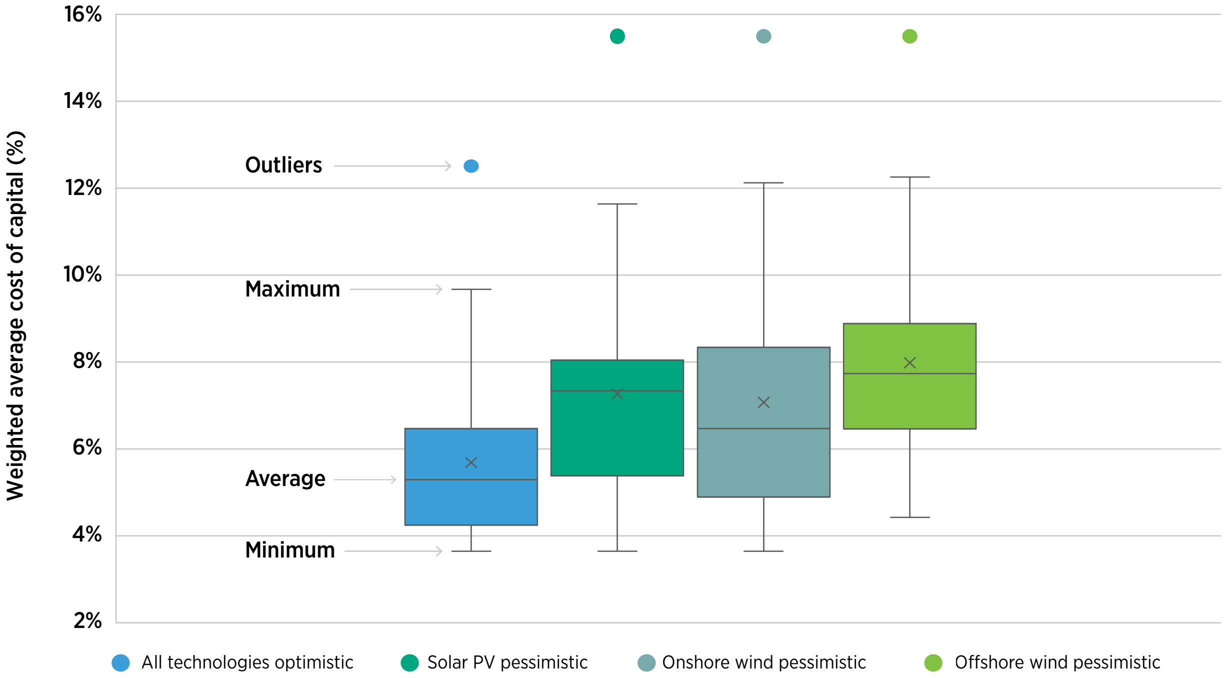
FIGURE 2.4. Capital cost trends for renewable technologies towards 2050 under *optimistic* assumptions and benchmark with other studies



Notes: *Optimistic* assumptions used. Solid lines are the assumptions for this report and dots are previous studies. The upper and lower boundaries are represented by the regions presenting the highest and lowest CAPEX for each category. The relevant countries are reported and lie within this range. Reference values found in literature are superimposed.
Sources: IRENA (2019); IEA (2019); DNV GL (2019); Janssen *et al.* (2022); ERI & China National Renewable Energy Centre (2017); NITI Aayog (2015); Simon, Gils and Fichter (2016); Leonardo DiCaprio Foundation (2019); Teske *et al.* (2015); LUT University and EnergyWatchGroup (2019); Vartiainen *et al.* (2021).

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 2.5. Besides the highlight on the relevant countries, a significant outlier is represented by Argentina.[13] This particularly above-average risk of investment will have a significant impact on the cost of the produced hydrogen. The respective impact of WACC and CAPEX can be assessed through their effect on the levelised cost of electricity (LCOE). Assuming an annual capacity factor of 21% for solar PV and fixing the CAPEX to USD 245/kW,[14] effects of the WACC increase can be quantified. A WACC increase from 4% to 6% would cause the LCOE to increase from USD 18.7/MWh to USD 25.5/MWh (37% increase). On the other hand, fixing the WACC to 4% and increasing the CAPEX by 50% to USD 381/kW yields USD 26.3/MWh of electricity produced (41% increase).

FIGURE 2.5. Range of WACC by technology and scenario



Notes: 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). Finally, 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 TW of deployed capacity by the year 2050 (IRENA, 2020). These are expected to fall from USD 384/kW$_e$ in 2030 to USD 134/kW$_e$ in 2050 under optimistic assumptions and USD 688/kW$_e$ to USD 326/kW$_e$ 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.[15]

[13] *There are other outliers at the country level, but these are part of one of the 34 regions (see Methodology section) averaging out these extreme values when all the countries in the region are considered.*

[14] *Values correspond to China in 2050 in an optimistic scenario.*

[15] *IRENA own assumptions.*

3 LEVELISED COST OF HYDROGEN AROUND THE WORLD

LEVELISED COST OF HYDROGEN AROUND THE WORLD

Optimal combination of renewable energy sources and electrolysers

The LCOH depends on the yearly production and cost of the hydrogen generation system, which in return are a function of the size of the single components of said system. Single technology configurations couple one generation technology with an electrolyser, while hybrid systems combine an electrolyser with two generation technologies (solar PV and onshore wind). In all cases there is an optimal combination between the capacities of the components which yield the maximum hydrogen production at the minimal cost. This optimal system configuration is dictated by the local meteorological conditions and the regional costs and risks of investments (represented by WACCs). In general, for a given generation technology capacity, increasing the capacity of the electrolyser increments the marginal hydrogen yield at a higher rate than the marginal system cost. The optimal electrolyser capacity is that at which any further capacity increment causes a lower increase in hydrogen production compared with that of the system cost. In practice, an oversized electrolyser for a given local resource will find itself idling for most of the year, remaining unproductive.

An additional resource quality characterisation was implemented by determining capacity factor distributions characteristic to each region. After applying the land exclusion criteria, such profiles are determined by assigning the spatially distributed resource distributions to a quality class, based on the yearly capacity factor produced by that resource. The best-performing resource is allocated to Class 1 and the worst to Class 5. The profiles in each class are then averaged to produce a characteristic hourly profile for that region's class. Table 3.1 shows the resource quality class boundaries for PV and wind.

TABLE 3.1. Classification of resource quality for each renewable technology

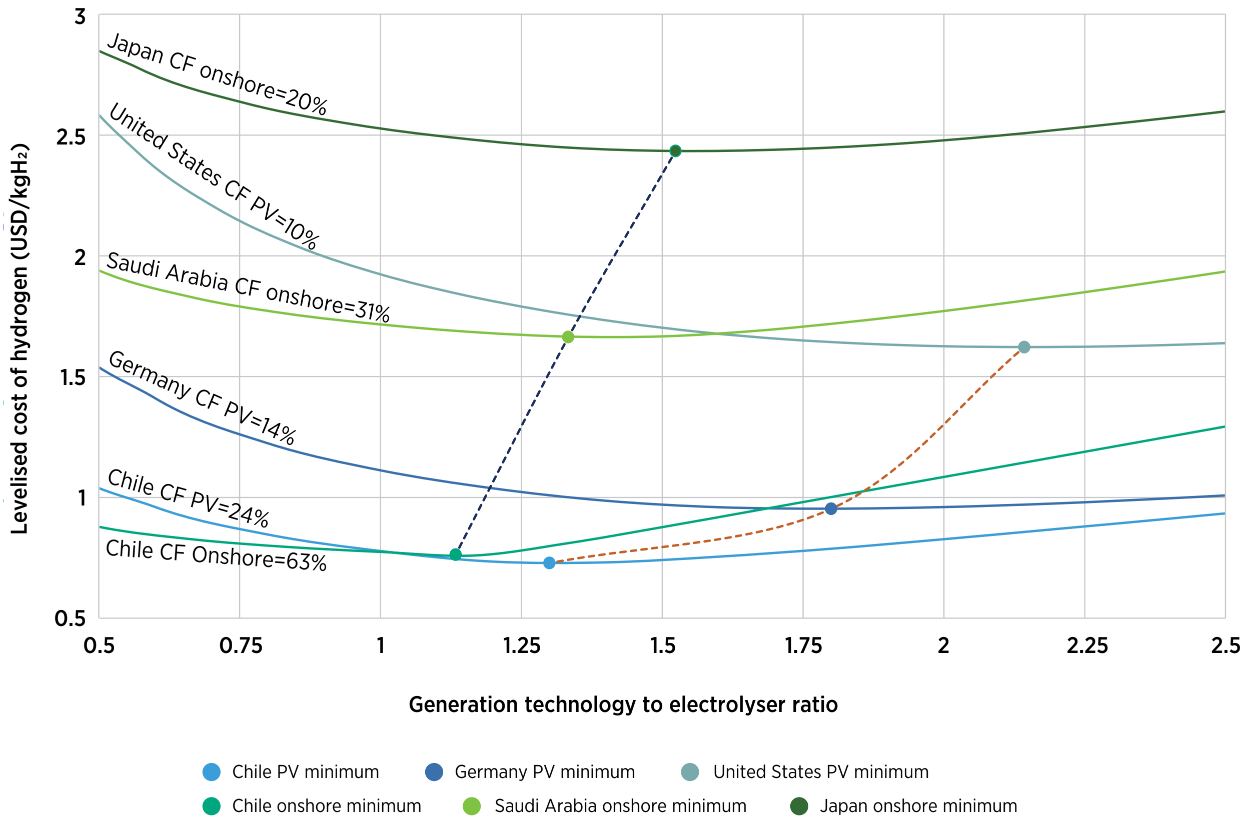
	SOLAR PV	ONSHORE/OFFSHORE WIND
CLASS	ANNUAL CF INTERVAL IN %	
1	CF>20	CF>60
2	17<CF≤20	45<CF≤60
3	14<CF≤17	30<CF≤45
4	11<CF≤14	15<CF≤30
5	0<CF≤11	0<CF≤15

Notes: CF = capacity factor. The values represent the annual capacity factor (ratio between the full-load operating hours and the total hours in a year).

Each resource quality class and its characteristic profile are associated with a potentially installable generation technology capacity. The characteristic capacity factor profiles are representative for the single regions and allow the introduction of a region-level generalisation on the optimal green hydrogen generation systems configurations.

Regarding single-technology systems, the ratio between the capacity of power generation and the capacity of the electrolyser that ensures minimum LCOHs will tend towards unity if the resource allows for reaching high yearly capacity factors. This can be seen in the direct comparison between two single-technology systems using different quality resources. First, the different optimal solar PV-to-electrolyser ratios for systems benefiting from highest quality solar resource in Chile (PV Class 1) and the highest-quality solar resource present in Germany (PV Class 3) are shown in Figure 3.1. Considering the annual capacity factor obtained from the resource is 24% for Chile and 14% for Germany (also shown in Figure 3.1), the optimal PV-to-electrolyser ratios are 1.3 for Chile and 1.8 for Germany. Under the assumption of an *optimistic* 2050 scenario, the minimum LCOHs obtained are USD 0.73/kgH_2 (Chile) and USD 0.95/kgH_2 (Germany) for PV-fed electrolyser systems. With even less performing resource, the optimal PV capacity may also end up being twice as much as the electrolyser's. For example, using the cost assumptions for the United States for the 2050 *optimistic* scenario and a 10% annual capacity factor solar PV resource, the ratio between the generation technology and the electrolyser increases to 2.14, yielding an LCOH of USD 1.62/kgH_2, as can be seen in Figure 3.1.

FIGURE 3.1. Comparison between levelised cost of solar- and wind-produced hydrogen as function of annual capacity factor and optimal ratio

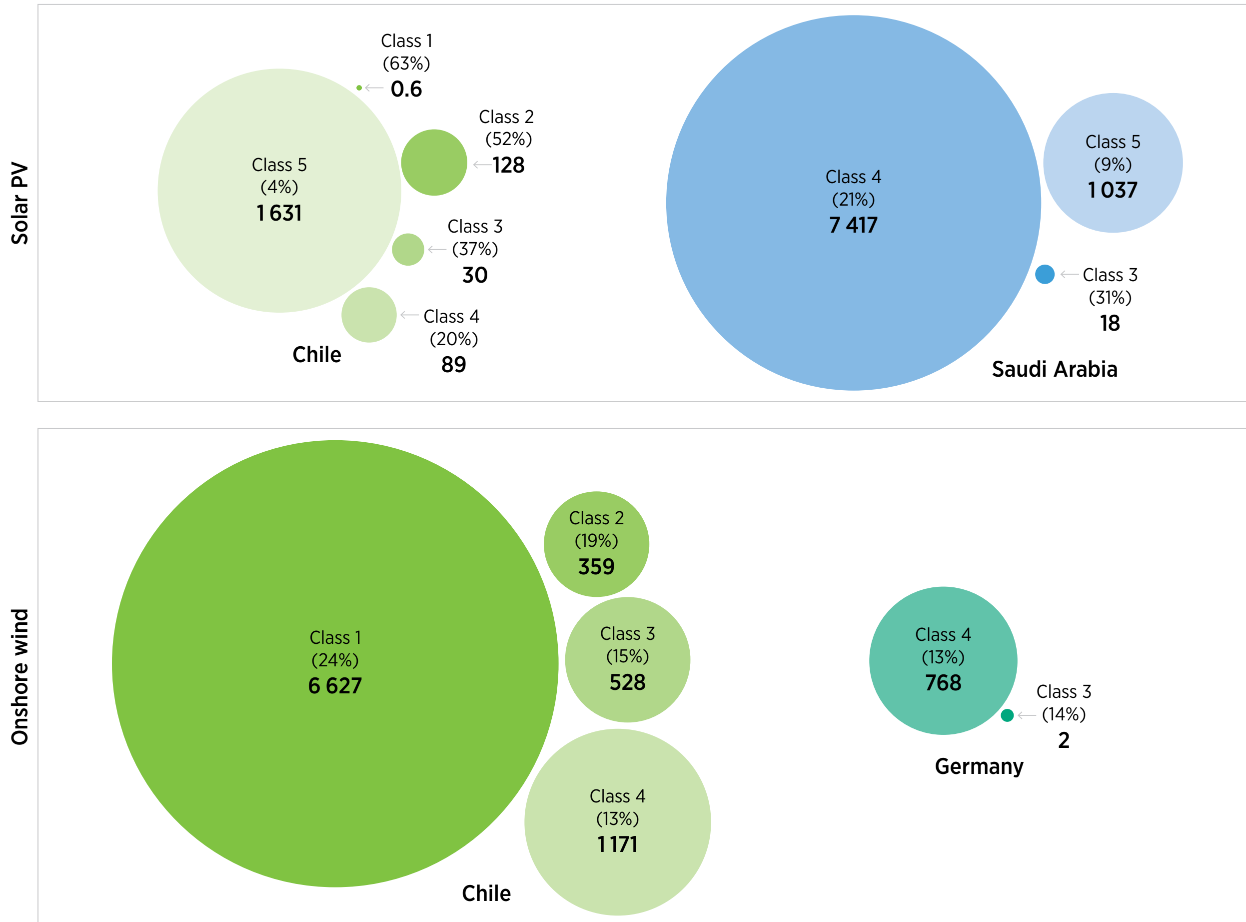


Notes: Highlighted is the impact of the resource quality on the optimal generation technology to electrolyser capacity ratio and LCOH, which are reported as discrete points. In general, the optimal ratios are a function of the capacity factor, with higher-quality resources ensuring lower ratios. The curves for Chile, Germany and Saudi Arabia were generated through their best-performing characteristic resource. The curves for the United States and Japan on the other hand are representative of the effect of poor-quality resources on the LCOH and optimal ratio.

A similar comparison is shown between wind-generated hydrogen in Chile and in Saudi Arabia. In both cases their best available resource was used, presenting annual capacity factors of 63% (onshore Class 1) for Chile and 31% (onshore Class 3) for Saudi Arabia respectively (see Figure 3.1). The optimal ratios between the capacities of wind and electrolyser are 1.13 for Chile and 1.3 for Saudi Arabia. Assuming again an *optimistic* 2050 scenario, LCOHs are USD 0.76/kgH_2 for Chile and USD 1.66/kgH_2 for Saudi Arabia. A further increase of the optimal ratio occurs if the annual capacity factor decreases. Under 2050 *optimistic* scenario cost assumptions for Japan and an annual capacity factor of 20%, the result is an LCOH of USD 2.43/kgH_2, at a ratio of 1.52.

By comparing the unfavourable cases of PV and wind (Germany and Saudi Arabia), it can be noticed how the optimal ratio is higher for PV and this is due to the lower capacity factor of PV in Germany. However, given the much lower CAPEX of the PV technology, the LCOH produced in Germany by solar PV is much more competitive. Figure 3.2 shows how the majority of Chile's onshore wind potential belongs to the worst performing technology class, which only has an annual capacity factor of 4%, and it is not economically feasible. On the other hand, Saudi Arabia's large onshore potential is allocated mainly to the better-performing tier (Class 4). With reference to Figure 3.2, Chile can largely benefit from its high-quality solar PV resource (PV Class 1) while the best-quality resource in Germany (Class 3) has little capacity potential. The majority of solar PV capacity is allocated to Class 4.

FIGURE 3.2. Difference in onshore wind potential by resource quality in Chile, Germany and Saudi Arabia (in GW)



Notes: Represented in these figures are the potentials in gigawatts of the installable utility-scale PV and onshore wind found in their respective resource quality classes, defined by the annual capacity factor (reported as a percentage in brackets). The potentials are determined by applying the power density of the technologies to the eligible area. Each class is characterised by an average annual capacity factor. The class upper and lower boundaries are those specified in Table 1.

It can be seen how, in Chile, the best resources of solar PV and onshore wind yield comparable LCOHs though the annual capacity factors differ widely (24% of PV against 63% of onshore). This is due to the difference in CAPEX of the two generation technologies: USD 312/kW for PV and USD 864/kW for onshore. The ratios between the generation technology and electrolyser are lower in the case of onshore wind, therefore the minimum LCOHs are ensured by a smaller capacity electrolyser, compared with the case of solar PV.

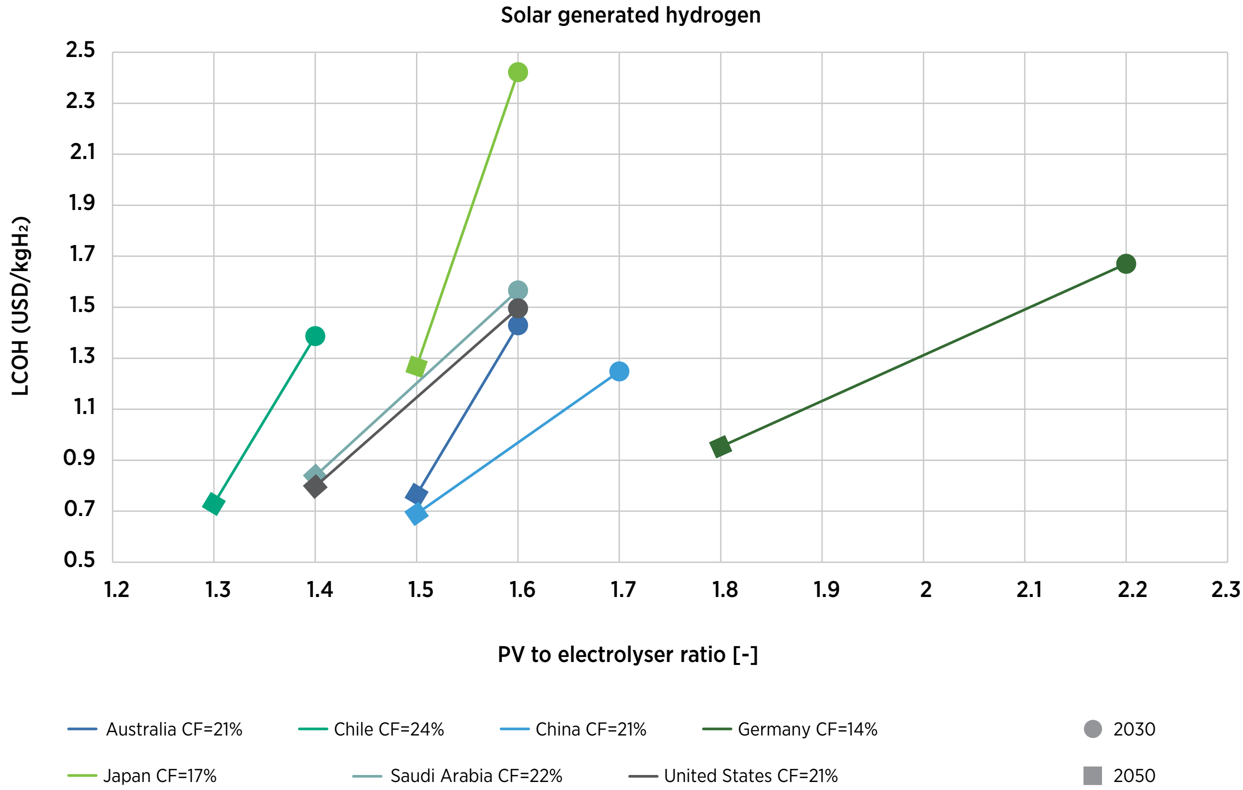
The optimal ratios between the generation technologies and the electrolyser capacities also depend on the economic assumptions of the model. By considering single-technology systems operating with the same annual capacity factors, a decrease in the system cost will cause the optimal ratio to also decrease. In Figure 3.3, the process is highlighted for solar PV and onshore wind hydrogen generation systems. The resource quality used to assess the optimal ratios is the best performing of each country and is used for both time horizons.

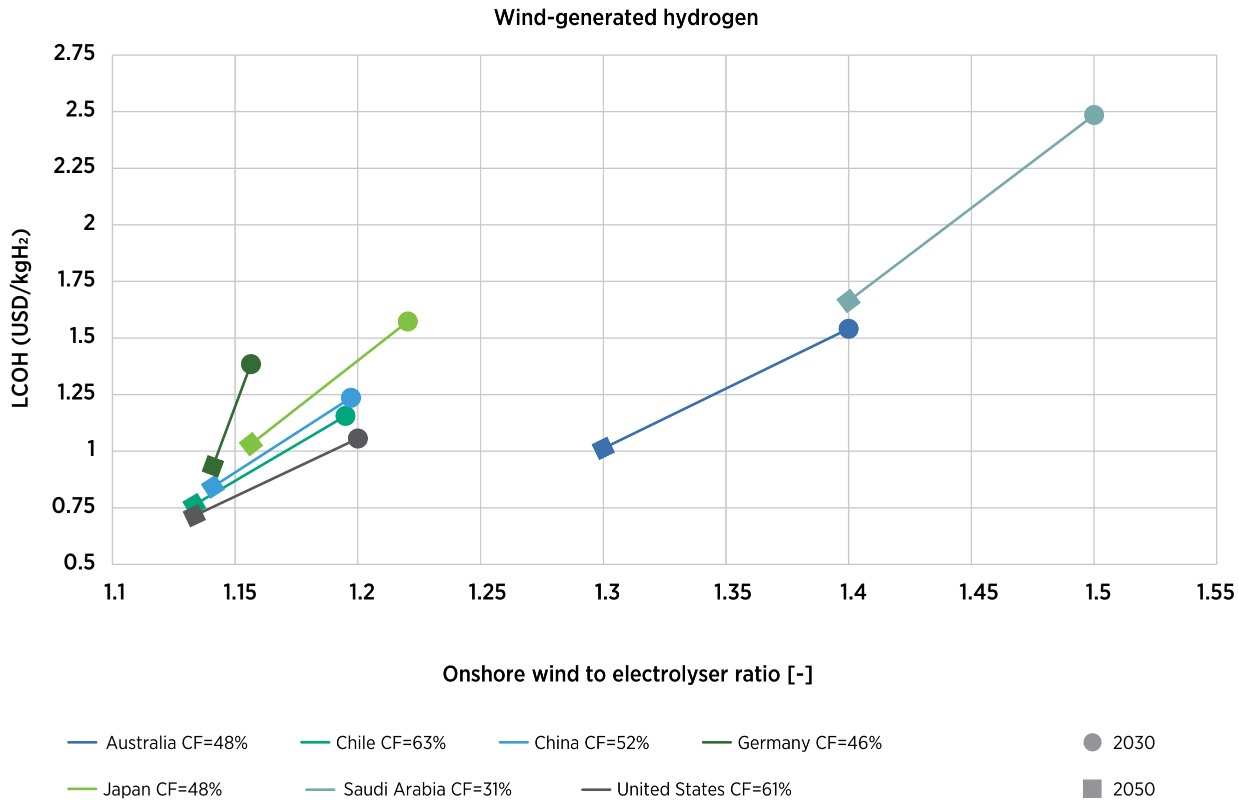
The land suitability assessment might in some cases coincide for both solar PV and onshore wind, potentially giving way to hybrid hydrogen generation systems. The optimal ratios among the capacities of the three system components are those that ensure the lowest LCOH and will depend on the local solar and wind resource but also on the regional cost assumptions. In Figure 3.4, the comparison between Australia and Germany in terms of the ratio between the optimal PV capacity and the overall hybrid system generation capacity is shown as a function of increasing CAPEX of solar PV (x-axis) and onshore wind (y-axis). Note that the renewable resources are fixed and yield annual capacity factors of 21% and 48% for Australia, and 14% and 46% for Germany, for solar PV and onshore wind respectively. The electrolyser CAPEX and efficiency are also fixed to the values corresponding to the 2050 *Optimistic* scenario (USD 134/kW_e and 87.5% [HHV]).

The potentially hybrid hydrogen generation systems' optimal configuration may be one in which one power generation system is strongly dominant over the other. More competitive CAPEX of one of the generation technologies might cause the optimal ratio to favour that technology. Therefore, potentially hybrid system configurations may be led back to single-technology type systems previously discussed. Under 2050 optimistic assumptions, and without considering water availability as a land exclusion criterion, it was determined that, on global average, 93.2% of the land surface that could potentially host hybrid generation systems (over 56 million km^2) at a global level yields minimum LCOH when operating as a solar PV-only system. This result is mainly due to the penalising CAPEX values of onshore wind which, on global average, are nearly three times those of solar PV. Most regions present the totality or near totality of potentially hybrid systems yielding minimum LCOH when operating as a PV-only system, with the exception of the United Kingdom (34%), Canada (43%) and the Russian Federation (hereafter Russia) (57%).

On the other side of the scale, potentially hybrid systems that find their optimal configuration when operating as onshore-only systems represent, on global average, only a share of 2.93%. Canada (34%), Russia (32%) and the United Kingdom (16%) are the only three countries presenting much higher than average shares, followed by Chile (9%), the United States (2.6%) and Japan (2%). This optimal configuration is strongly dictated by the local meteorological conditions, which ensure high onshore wind capacity factors against poor-quality solar PV ones.

FIGURE 3.3. Relationship between LCOH and renewable to electrolyser capacity as a function of capacity factor for 2030 and 2050

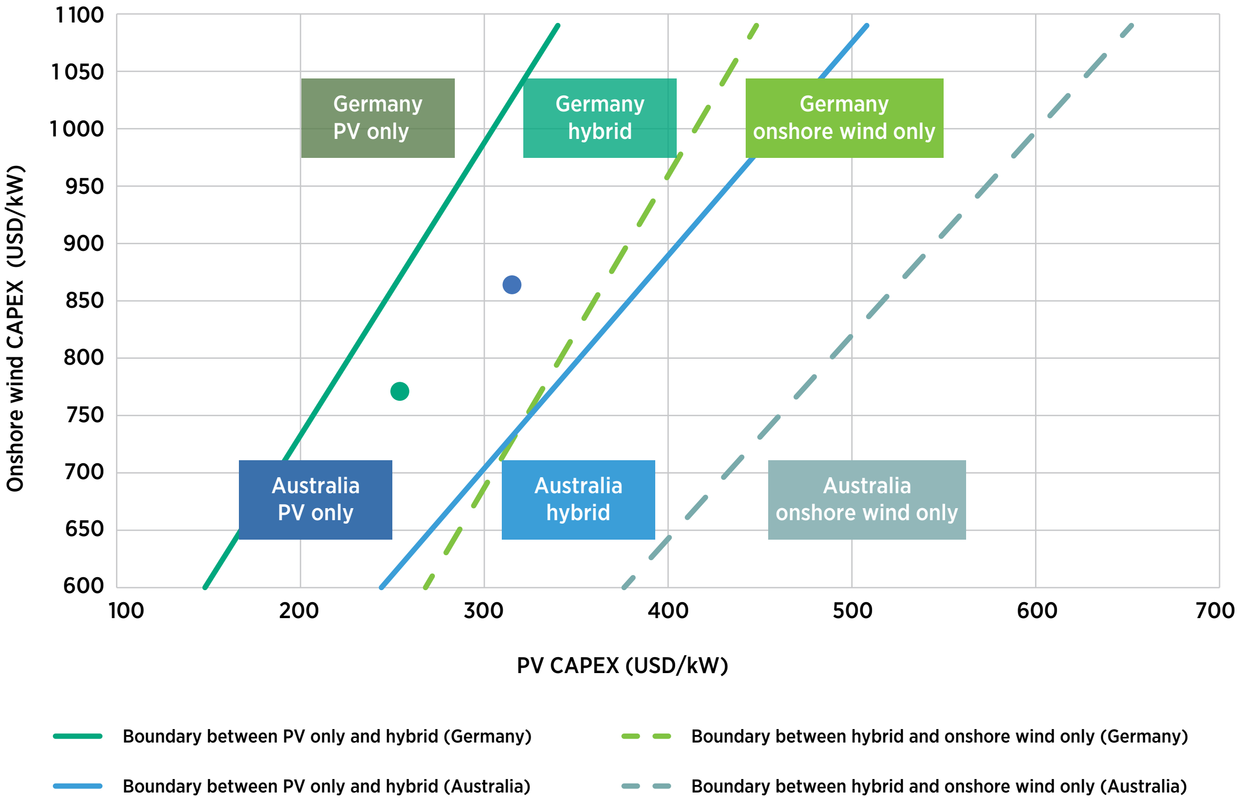




Notes: Capacity factors used for PV and onshore wind are the same for 2030 and 2050. Changing CAPEX assumptions (in the *optimistic* scenario) for both generation technologies and the electrolyser (as well as efficiency) causes the shift of the optimal ratios.

Lastly, truly hybrid systems represent only, on global average, 2.48% for onshore prevalent, and 1.38% for solar PV prevalent, of all potentially hybrid systems. Solar PV prevalent hybrid systems are mostly encountered in the United Kingdom (25%), followed by Russia (4.6%) and Canada (3%). Onshore prevalent hybrid configurations are mostly found in the United Kingdom (25%), Canada (19%), Japan (9%) Argentina (6.6%). These configurations are also strongly dependent on local meteorological conditions. The renewable resources used in Figure 3.4 are the best-performing resource class in Australia and Germany.

FIGURE 3.4. Optimal hybrid system configurations (dots) in 2050 as a function of CAPEX of the generation technologies for Germany (green lines) and Australia (blue lines)

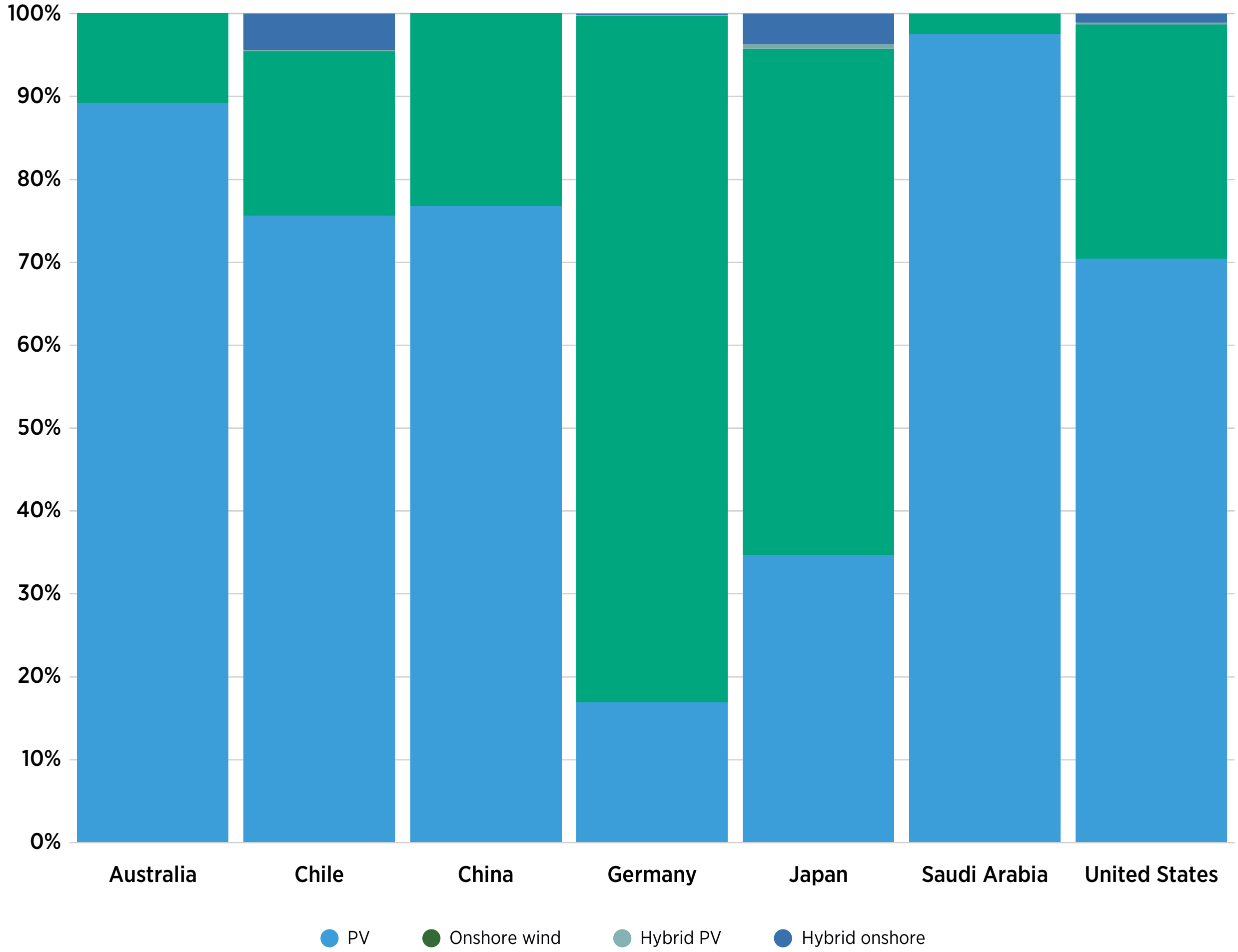


Notes: The renewable resources used in this representation are the best-performing resource class in Australia and Germany. The points represent the following CAPEX values: Germany, solar PV: USD 254/kW, onshore wind: USD 771/kW; Australia, solar PV: USD 315/kW, onshore wind USD 864/kW.

The majority of solar PV and onshore wind potentials in Germany are allocated to areas where the capacity factors are lower (13% for solar PV and 21% for onshore wind). Based on the 2050 CAPEX of solar PV and onshore wind, the hybrid hydrogen generation systems with the lowest costs use a single generation technology, specifically, solar PV.

The underlying CAPEX assumptions are those of the 2050 *optimistic* time horizon (see Figure 2.4), ranging between USD 245/kW and USD 690/kW for solar PV and between USD 743/kW and USD 1434/kW for onshore wind. The outcome of the cost difference of the two generation technologies is that the vast majority of the potentially hybrid systems yield minimum LCOH when installing only solar PV as a generation technology. In the case of Australia, most of the land is deemed as eligible for both PV and onshore (as shown in Figure 3.5) and based on the above-mentioned analysis, most of these potentially hybrid systems will ensure minimal LCOHs when operating as PV-only systems.

FIGURE 3.5. Breakdown of hydrogen production by renewable technology for selected countries



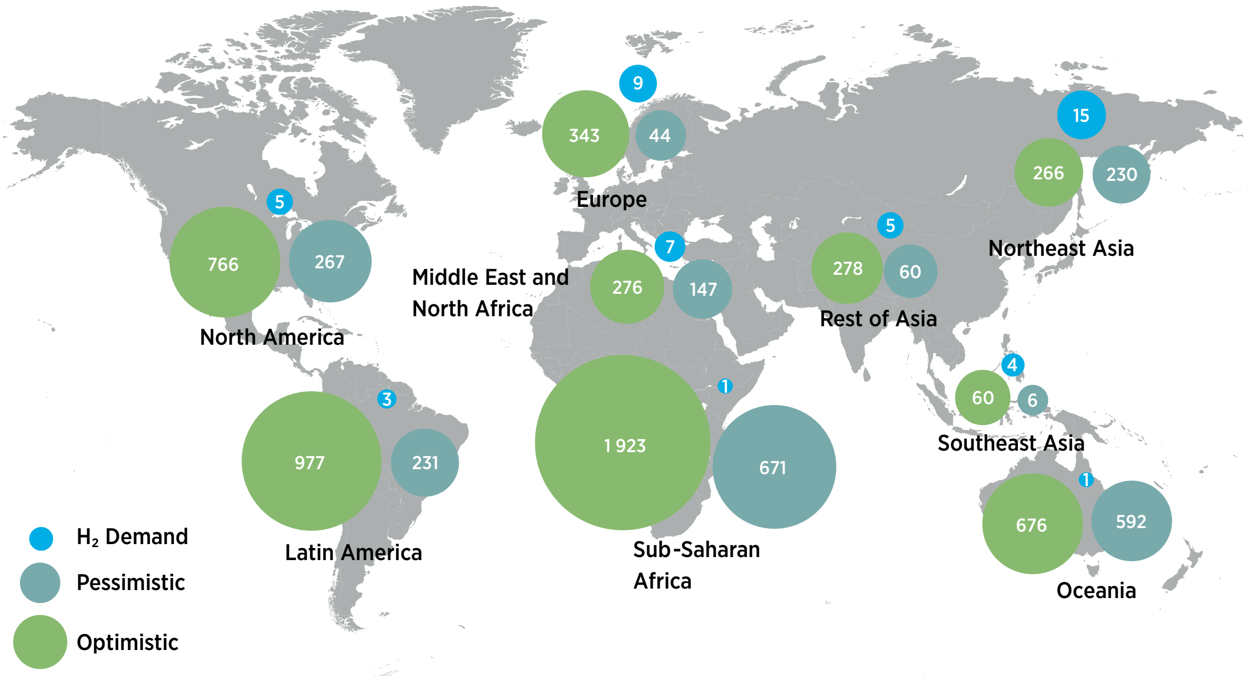
Notes: The composition of each country depends on the land exclusion criteria applied and the quality of the resource present at the eligible sites. Hybrid systems with optimal capacities strongly in favour (ratio lower than 1%) of one technology are reported as single-technology systems. The proper hybrid systems are divided into PV or onshore prevalent. This representation accounts only for systems yielding LCOH lower than USD 5/kgH_2. The intent of this representation is that of providing representative cases for different combinations of land use, cost assumptions and resource quality.

On the other hand, in Germany the land eligibility analysis (as shown in Figure 2.2) highlights that most of the available land is elected as suitable for the installation of onshore wind. However, in those areas where a hybrid system could be installed, cost assumptions and resource quality still favour solar PV-exclusive systems. In Figure 3.5, the system composition is reported for relevant countries for the year 2050 under optimistic assumptions. It can be seen how hybrid systems represent the minority of the overall generation systems simply because of the low CAPEX assumed for solar PV. In regions where the CAPEX for solar PV is higher (or CAPEX for onshore wind is lower), then hybrid configurations can be attractive.

Global LCOH maps and potential

For this study, the world is divided into 34 regions. G20 countries are modelled individually, while the rest of the world is clustered in eight regions. Furthermore, some selected countries that could play an important role as exporters and importers are also analysed individually (Chile, Colombia, Morocco, Portugal, Spain and Ukraine). The results of the analysis show that for stand-alone green hydrogen production systems in 2050, the LCOH is on average quite low, with values below USD 1.5/kgH_2 in most countries when the best renewable resources are used. Concerning the hydrogen production potential, it is evident that the economic potential below USD 2/kgH_2 is huge and largely satisfies the forecast demand for the year 2050 (Figure 3.6). The total demand for hydrogen in 2050 represents 12% of the total final energy demand and amounts to 74 EJ (IRENA, 2022c). Of this, 24 EJ will be dedicated to the power sector while the remaining 50 EJ will be mostly between the chemical (mostly ammonia) and transportation sectors (IRENA, 2022c). However, if the economic potential of the single countries is addressed, it may fall below the forecast hydrogen demand for the year 2050. Under optimistic assumptions and including water availability constraints, the hydrogen production potential under USD 2/kgH_2 of Japan and the Republic of Korea is already half and one-third of the forecast demand, deeming them as potential future importers.

FIGURE 3.6. Comparison between economic potential of green hydrogen supply below USD 2/kgH_2 and forecasted hydrogen demand, in EJ/year, in 2050

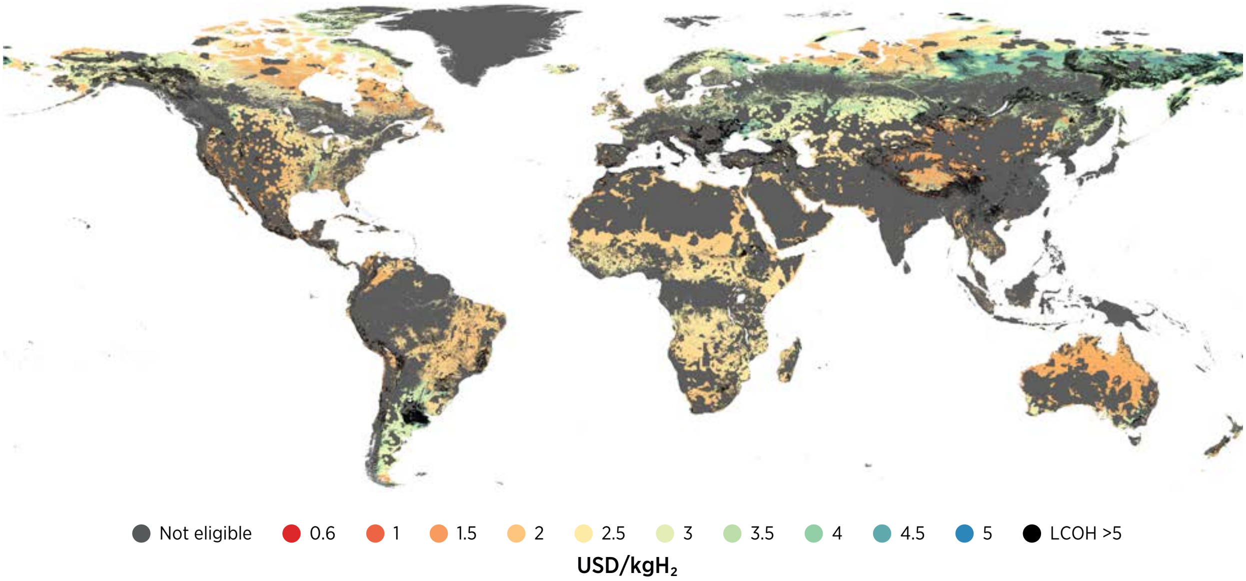


Notes: Assumptions for CAPEX 2050 are as follows: optimistic, PV: USD 225/kW to USD 455/kW; onshore wind: USD 700/kW to USD 1070/kW; offshore wind: USD 1275/kW to USD 1745/kW. Pessimistic, PV: USD 271/kW to USD 551/kW; onshore wind: USD 775/kW to USD 1191/kW; offshore wind: USD 1317/kW to USD 1799/kW. WACC: optimistic, per 2020 values without technology risks across regions. Pessimistic, per 2020 values with technology risks across regions. Technical potential has been calculated based on land availability considering several exclusion zones (protected areas, forests, permanent wetlands, croplands, urban areas, slope of 5% [PV] and 20% [onshore wind], population density and water stress). Total hydrogen demand, not including power sector (24 EJ/year), is equal to 50 EJ/year.

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply any endorsement or acceptance by IRENA.

Concerning the economic potential of green hydrogen below USD 4/kgH_2 in the 2030 time horizon, sub-Saharan Africa holds the greatest production potential, with values ranging between 1650 EJ and 1242 EJ/year (where the upper and lower values represent the pessimistic and optimistic techno-economic assumptions). Following the lead are Australia (520 EJ to 598 EJ/year), Brazil (376 EJ to 461 EJ/year), the United States (213 EJ to 385 EJ/year), Russia (198 EJ to 276 EJ/year), Canada (185 EJ to 274 EJ/year) and the Middle East/North Africa (112 EJ to 214 EJ/year). On the other end of the scale, countries that are geographically constrained by their high water stress, land use, orography and/or and protected areas (reported as not eligible areas in Figure 3.7), present significantly lower hydrogen production potentials. The most penalised is the Republic of Korea, with a potential ranging between 0.2 EJ and 0.1 EJ, followed by Japan (0.1 EJ to 1.2 EJ/year), Italy (1.1 EJ to 1.3 EJ/year), Portugal (1.8 EJ to 2.1 EJ/year), Germany (2.6 EJ to 4.3 EJ/year) and France (2.9 EJ to 5.6 EJ/year). The economic potential decreases significantly if the threshold is lowered to USD 2/kgH_2, and most countries and regions do not present any hydrogen production potential under pessimistic assumptions in 2030.

FIGURE 3.7. Global map of levelised cost of green hydrogen in 2030 considering water scarcity



Notes: Geospatial distribution of LCOH below USD 5/kgH_2 for 2030 under optimistic assumptions. In this representation, land exclusion criteria also account for water availability.

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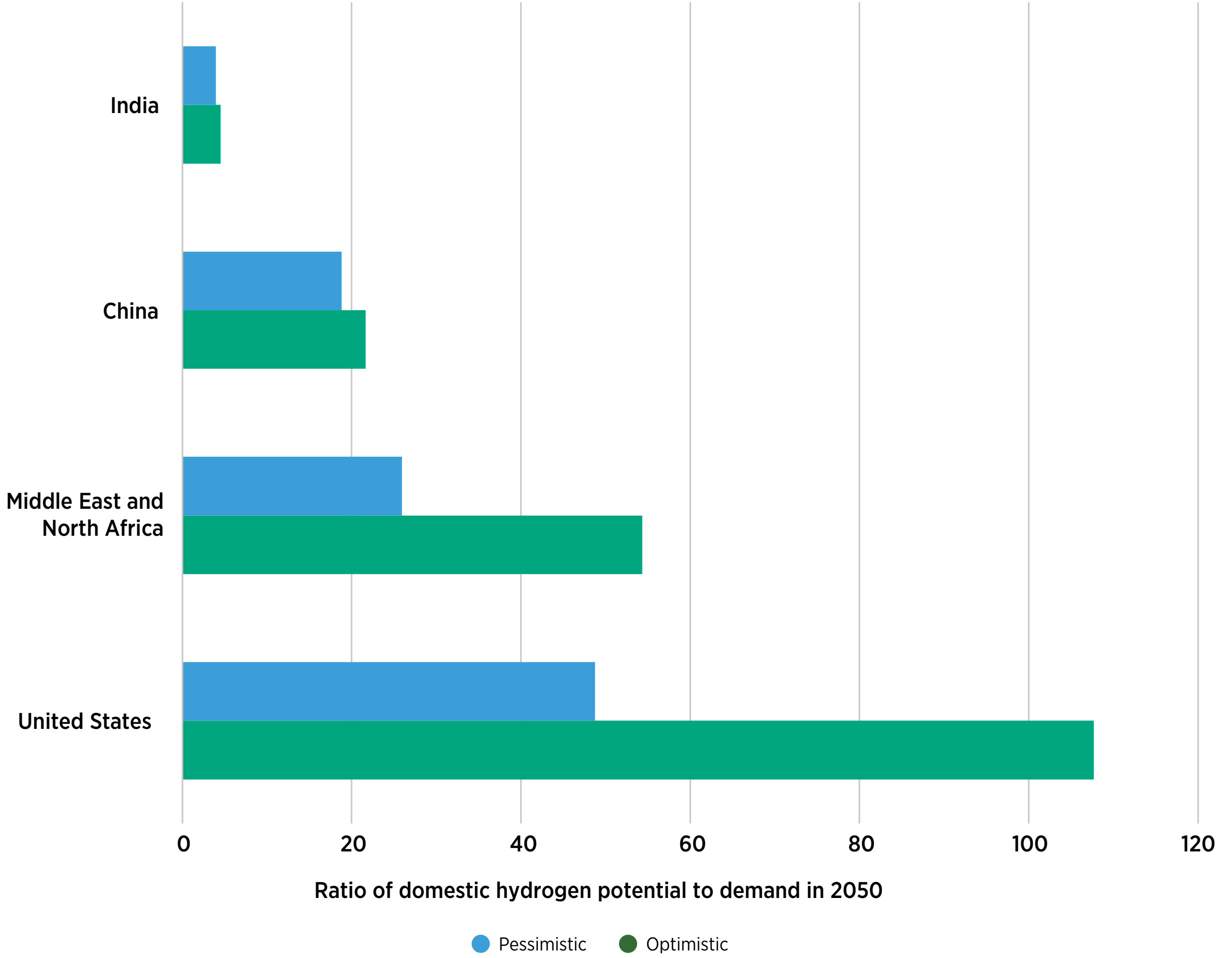
Focusing on the 2050 time horizon and considering the general decrease of the CAPEX of the technologies, even lowering the economic potential threshold to an LCOH of USD 2/kgH_2, the 2050 time horizon hydrogen production potential is still large. Sub-Saharan Africa still holds the greatest potential (Box 3.1), varying between 1845 EJ and 602 EJ/year, under the pessimistic and optimistic assumptions respectively. Following are Australia (584 EJ to 659 EJ/year), Brazil (86 EJ to 511 EJ/year), the United States (193 EJ to 426 EJ/year) and China (230 EJ to 265 EJ/year). The countries presenting the lowest economic potentials in 2050 are the Republic of Korea (0.15 EJ to 0.2 EJ/year), Japan (0.04 EJ to 1.3 EJ/year), Italy (1.3 EJ to 1.4 EJ/year) and Portugal (1.9 EJ to 2.4 EJ/year). These values can be put in perspective by comparison with the forecast total hydrogen demand (excluding that of the power sector) in 2050 of 50 EJ. Many regions will have more than sufficient domestic supply of green hydrogen below USD 2/kgH_2, considering that the highest demand regions are China (12.2 EJ/year), the Middle East/North Africa (4.5 EJ/year), India (4.2 EJ/year) and the United States (4 EJ/year) (Figure 3.8).

FIGURE 3.8. Ratio between the potential domestic production of green hydrogen and the estimated 2050 hydrogen demand for selected countries



Notes: Hydrogen supply determined with cost with techno-economic assumptions for the year 2050 under *optimistic* and *pessimistic* scenarios. Water availability for electrolysis is considered in this analysis.

Box 3.1. Africa's green hydrogen potential

Africa combines good-quality resources for PV (across the entire continent) with onshore wind (particularly in the Western Sahara and the Somali Peninsula), large areas of land, and a burgeoning energy sector. Green hydrogen provides an additional opportunity to satisfy the growing energy needs of the continent while at the same time providing prospects for economic growth and industrial development through export of hydrogen and its derivatives.

The African Hydrogen Partnership has identified regions within the African continent with sufficiently favourable conditions to establish future green hydrogen hubs: Democratic Republic of Congo, Egypt, Ethiopia, Kenya, Mauritania and Namibia (AHP, 2019). These six regions are placed strategically around the continent at major interconnections between trans-African highways, and will serve as both supply and demand centres for green hydrogen.

Box 3.1. (Continued)

There are multiple activities that have been announced aiming to take advantage of this vast potential. Morocco has published a green hydrogen roadmap (MEM, 2021) and announced a bilateral trade agreement with Germany and the Netherlands. Egypt has today the largest hydrogen demand in Africa (1.4 MtH_2 in 2020) (IRENA, 2022d) and revealed a USD 5 billion project for producing green ammonia (Reuters, 2022). The Ethiopia-Djibouti region combines benefits of Ethiopian renewable energy policy, need for fertiliser ammonia and good-quality resources with Djibouti's access to the Red Sea and Indian Ocean. Kenya and Tanzania could create supply and demand for green hydrogen given the demand for fertilisers in Kenya and the strategic position of Tanzania on the Chinese Silk Route with the Bagamoyo harbour project (AHP, 2019). The Democratic Republic of the Congo is already being backed by Germany for the development and construction of the world's largest hydroelectric dam. In Mauritania, two major green hydrogen projects are under way: Aman (30 GW of wind and solar PV) and Nour (10 GW of renewables and potentially the first African offshore wind farm. Namibia has announced bilateral trade agreements with Belgium, Germany and the Netherlands (IRENA, 2022d) and has also announced a USD 9.4 billion investment to develop a 300 ktH_2/year green hydrogen project.

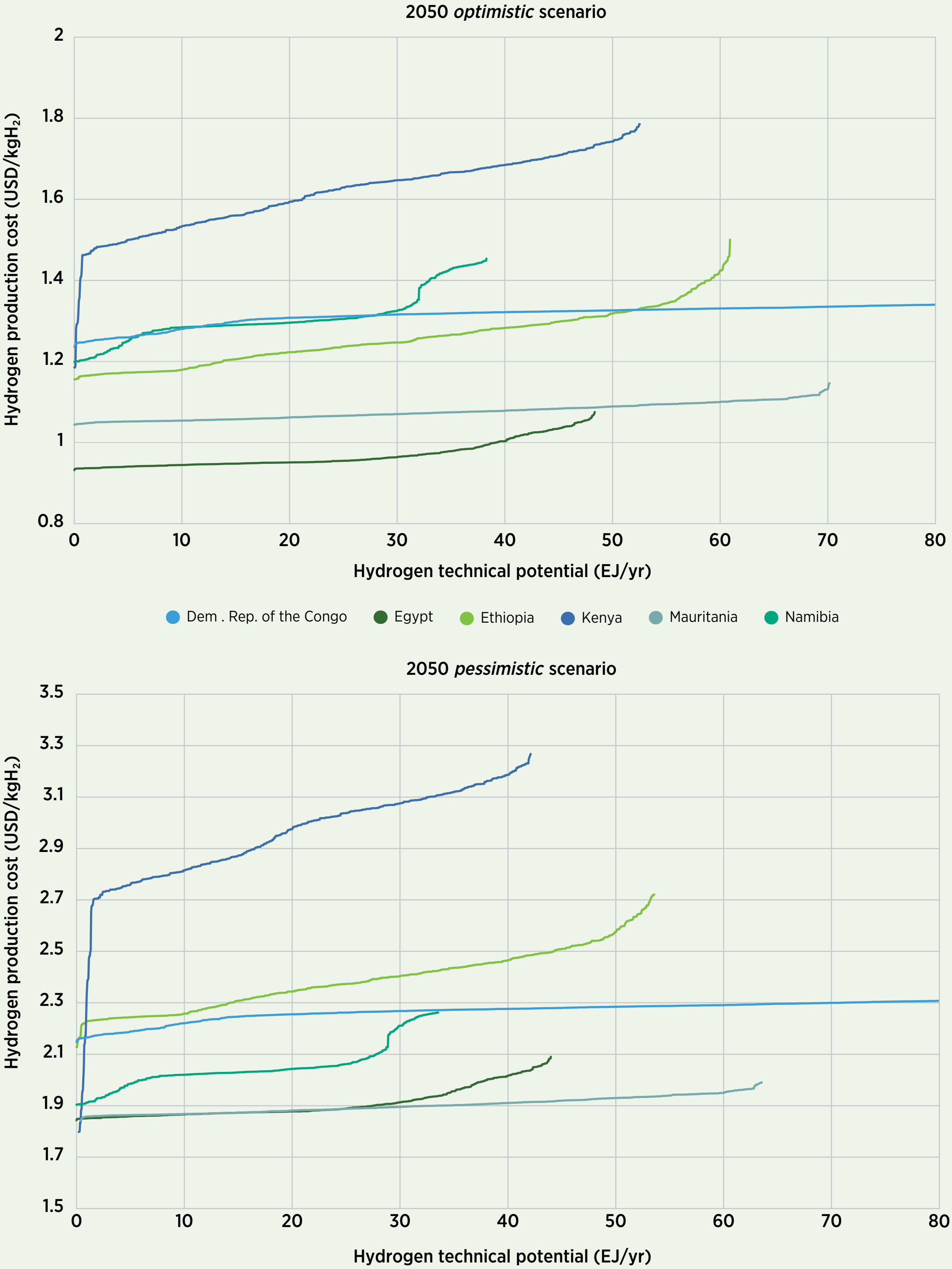
A challenge for Africa is water scarcity, but green hydrogen could provide an opportunity to tackle this challenge instead of aggravating it. Even for low LCOH scenarios, water supply, in the most conservative case, through desalination, represents only less than 4% of the total LCOH (see Methodology), which means it is relatively cheap when compared with the hydrogen supply. The water supply system could be expanded to cater for other water uses (*e.g.* sanitary) at a relatively small cost penalty for the hydrogen but providing the economies of scale needed to achieve low water costs.

Other challenges are the lack of energy access, low electrification rate and low deployment of renewables. This means hydrogen production for export needs to consider these competing needs for renewable capacity. If planned together, hydrogen could have socio-economic benefits across these dimensions and accelerate progress rather than hinder it. For instance, projects could include provisions for a minimum share of energy for local users or by larger economies of scale, lower financing costs and supply chain development for renewables leading to lower costs of energy. Measures to foster innovation and create new jobs in Africa, could be embodied in policies to support the production, use and export of green hydrogen from countries with abundant resources. Green hydrogen can absorb excess renewable electricity, leading to higher system efficiencies and energy security (IRENA and AfDB, 2022).

Figure 3.9 shows the hydrogen supply cost curves for key African countries. The curve shows the cost of green hydrogen as a function of the technical potential from utility-scale PV, onshore wind or offshore wind. For an *optimistic* cost scenario, Egypt and Mauritania reach cost levels below USD 1.1/kgH_2 with potentials of 40 EJ/year (Egypt) and 60 EJ/year (Mauritania), which would already be enough to satisfy the entire primary supply of the African continent in 2019. All six countries have relatively flat supply curves and most costs are under USD 1.4/kgH_2. To unlock this future, capital costs for solar PV would need to reach values as low as USD 340/kW combined with a low cost (USD 130/kW_e) of the electrolyser and a high efficiency. Increasing the capital costs of solar PV by 20% and the electrolyser by almost 2.5 times would increase the costs to the USD 1.8/kgH_2 to USD 2.3/kgH_2 range.

Box 3.1. (Continued)

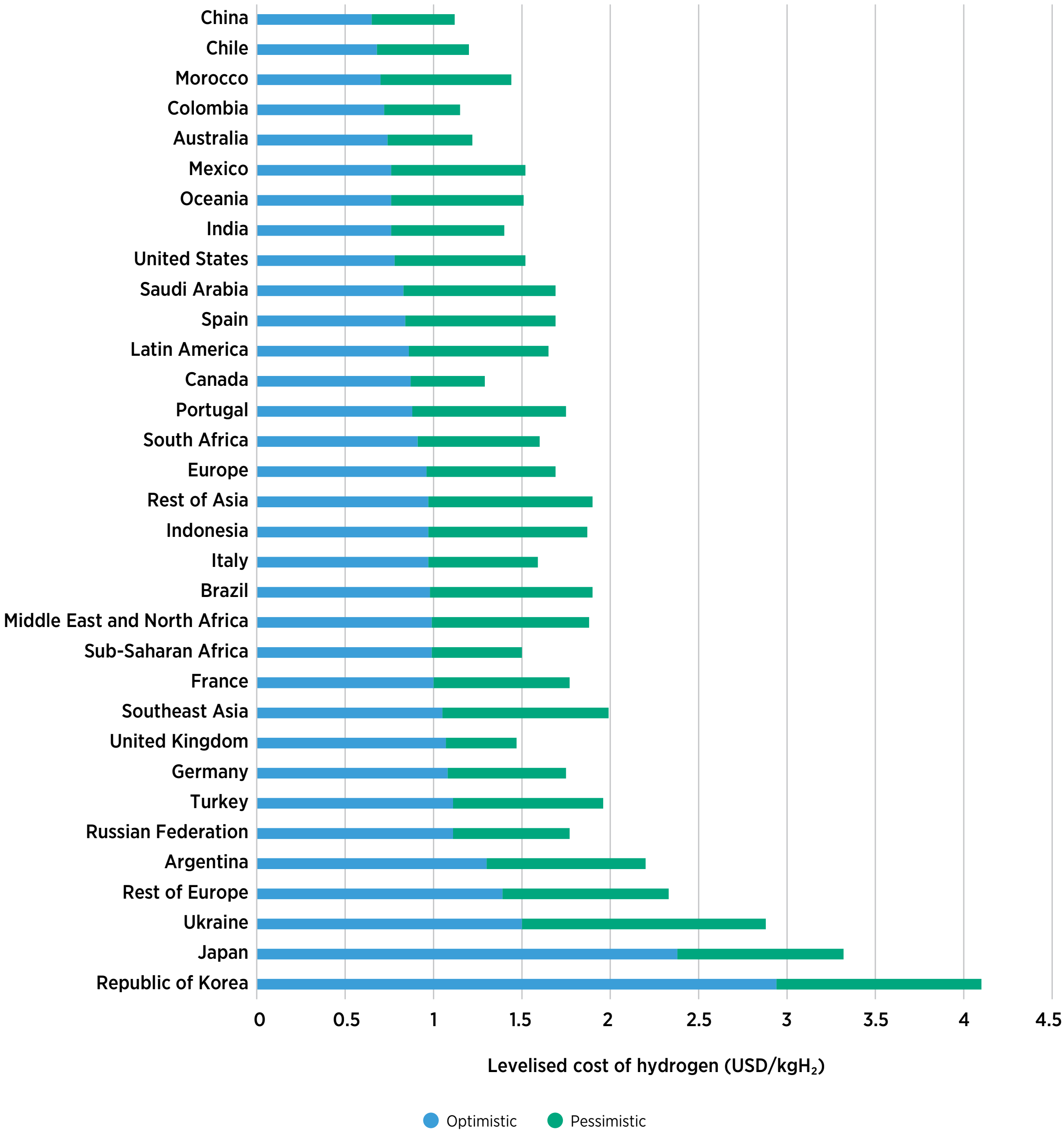
FIGURE 3.9. Green hydrogen supply-cost curves for selected African countries in 2050



Notes: (Top chart) CAPEX: PV: USD 278-573/kW, onshore wind: USD 829-1 088/kW, offshore wind: USD 1 494-1 540/kW, electrolyser: USD 134/kW_e. Electrolyser efficiency: 87% (HHV). WACC range: 6-11%. (Bottom chart) CAPEX: PV: USD 253-416/kW, onshore wind: USD 888-1 006/kW, offshore wind: USD 1 369-1 540/kW, electrolyser: USD 326/kW_e. Electrolyser efficiency: 82% (HHV). WACC range: 7-12%. Common assumptions for both charts: Electrolyser CAPEX and efficiency set equal for all countries. Technical potential has been calculated based on land availability considering several exclusion zones (protected areas, forests, permanent wetland, croplands, urban areas, slope of 5% [PV] and 20% [onshore wind], population density), water availability.

By comparing the demand for the year 2050, the LCOH of each region can be determined through the supply-cost curves of the single countries and regions (Figure 3.10). The countries best suited for domestic green hydrogen production and consumption appear to be China, India and the United States: all present a large production potential at low LCOH (USD 0.65/kgH_2 to USD 0.78/kgH_2) mainly because of their high-quality solar resources. European countries such as France, Germany, Italy and Spain are characterised by a higher LCOH, around USD 0.8/kgH_2 to USD 1.1/kgH_2. The production potential is usually quite large even for these countries; only Italy has a lower economically viable potential (1 000 petajoules at LCOH lower than USD 1.15/kgH_2) due to its orography and dense urbanisation. On the other hand, the United Kingdom presents a higher LCOH (USD 1/kgH_2 to USD 2/kgH_2) mainly because of its poor solar resource quality.

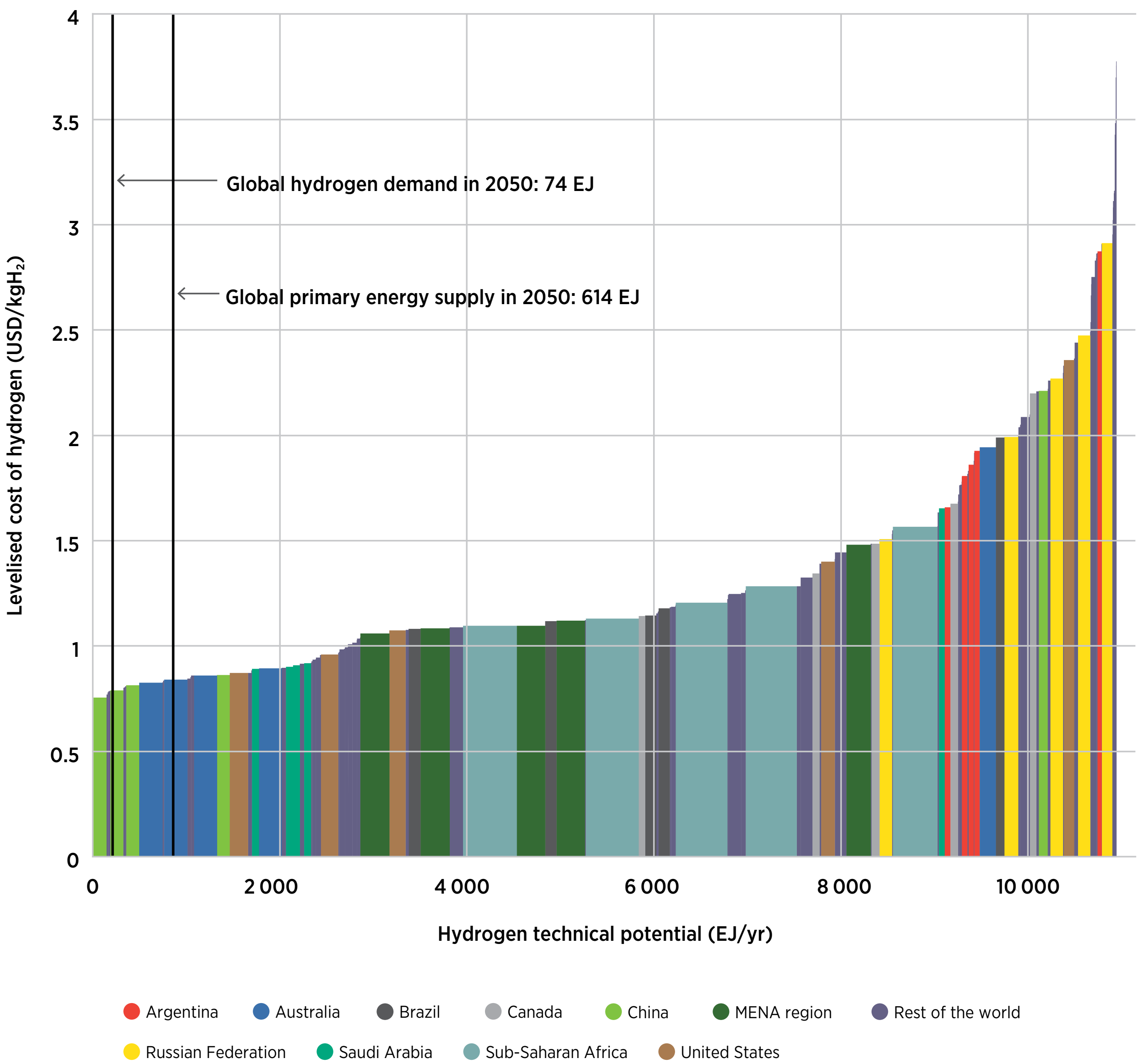
FIGURE 3.10. Levelised cost of hydrogen range in 2050 derived from supply-demand analysis



Notes: Levelised cost of hydrogen derived from supply-cost curves of individual countries and regions based on their estimated hydrogen demand for 2050. Water availability for electrolysis is considered in the hydrogen supply-cost curves.

An additional assessment was made for relevant countries only for the 2020 cost scenario. The resulting LCOHs are found to be equal to USD 85/MWh and USD 190/MWh and if compared with the costs of natural gas of 2020-21 of around USD 30/MWh (Statista, 2021), are still not competitive enough. The costs produced by this assessment for the year 2050 under optimistic cost assumptions range from USD 0.65/kgH_2 to USD 1.5/kgH_2 considering a production potential of 9 000 EJ/year, considering water scarcity as an exclusion criterion (Figure 3.11). This potential hydrogen supply is many times the value of the future global hydrogen demand (in all sectors) of 74 EJ/year as well as the total global final energy demand (614 EJ/year). These two demands could be met by supply with LCOH of USD 0.7/kgH_2 and USD 0.8/kgH_2, respectively.

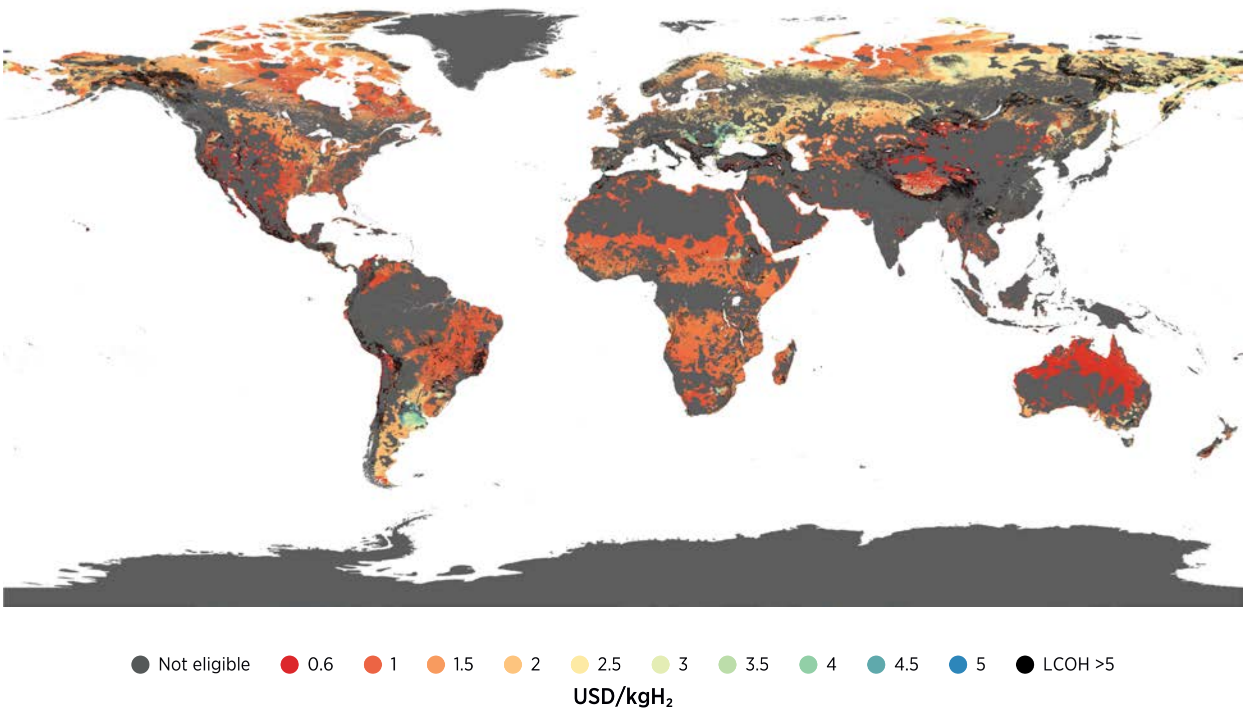
FIGURE 3.11. Global supply-cost curve of green hydrogen for the year 2050 under *optimistic* assumptions



Note: The land exclusion criteria account not only for land typology, protected areas, slope and population density, but also for water availability. The cost assumptions are those of the 2050 *optimistic* scenario, reported in Figure 2.1. The WACC values are also those of the *optimistic* scenario shown in Figure 2.2. Electrolyser CAPEX and efficiency set to USD 134/kW_e and 87.5% (HHV).Here water scarcity is not included among the exclusion criteria.

Figure 3.12 shows the global allocation of hydrogen production and its cost for the year 2050 under optimistic assumptions. In this case water availability was also accounted for. It can be seen, in comparison with the 2030 scenario map (Figure 3.7), that areas where the cost of hydrogen had increased to values above USD 5/kgH_2 are now below this value. An example of this phenomenon is the Pampas region in Argentina, which is almost exclusively used for agriculture (*i.e.* croplands). Therefore, the only viable hydrogen generation system is through wind onshore, which has almost three times the CAPEX of PV (USD 333/kW of solar PV versus USD 912/kW). These generation systems are also affected by the high WACC in Argentina of almost 13%.

FIGURE 3.12. Global map of levelised cost of green hydrogen in 2050 considering water scarcity



Notes: Geospatial distribution of LCOH lower than USD 5/kgH_2 for 2050 under optimistic assumptions, see notes of Figure 3.6 for specific values. In this representation land exclusion criteria also accounts for water availability.
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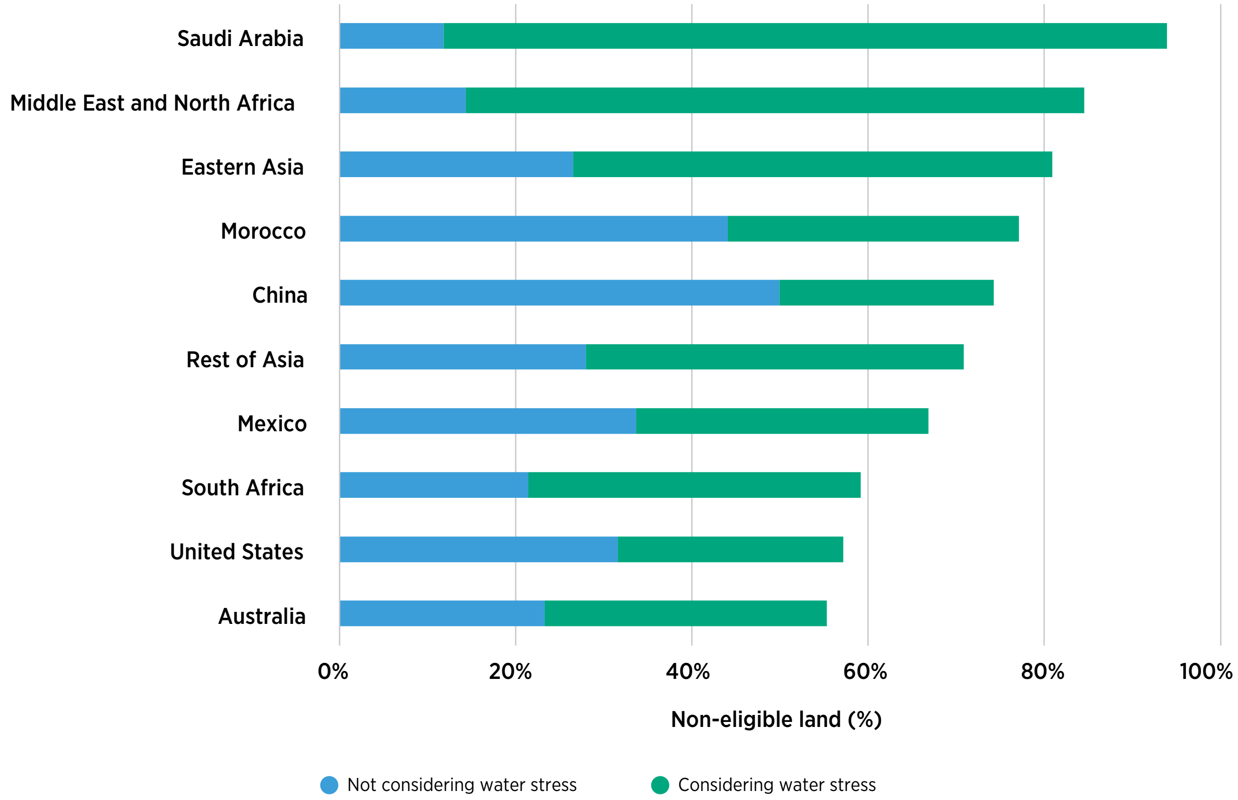
On the other hand, Figure 3.12 provides a view of the regions in which the inclusion of water availability as an exclusion criterion has the highest impact. Some of the most promising areas are strongly undermined by the lack of water sources. Northern China, south-western Australia and arid zones in general are not suitable for the production of green hydrogen if water availability is considered, despite showing great potential in producing among the lowest-cost hydrogen. The most affected regions by water scarcity are Saudi Arabia and the Middle East/North Africa region, which see their economic potential below USD 2/kgH_2 decrease by 94% and 84%, respectively (Figure 3.13). China, with the exclusion of the its northern territories (which would present a high yield of low-cost hydrogen) decreases its economic potential (lower than USD 2/kgH_2) by 59%.

FIGURE 3.13. Effect of water constraints on land eligibility for on site production of green hydrogen



Note: Land exclusion criteria regard land typology, protected areas, terrain slope and population density. The impact of water availability as an exclusion criterion is highlighted.

It is necessary to add that remoteness was not included as an exclusion criterion. Therefore, remote areas, namely Northern Canada, Siberia and the Tibetan Plateau, were included in the assessment. Realistically, even though in some cases these areas might produce competitively priced hydrogen, the necessary investment in infrastructure (if technically possible) to connect production to demand of potential offtakers would significantly increase the cost.

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