Worldwide Hydrogen Provision Scheme Based on Renewable Energy

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Abstract

The threats of climate change and the sustainable supply of clean energy are global challenges that require an international approach to the energy supply. Utilizing the wind and solar energy potential of regions where these renewable sources are especially viable to produce hydrogen by means of water electrolysis represents an attractive option to counter the above-mentioned challenges. Within the scope of this techno economic analysis of a worldwide hydrogen supply infrastructure based on renewable energy, selected regions are assessed on the basis of their wind or solar energy potential. In contrast to established analyses of hydrogen infrastructures, this paper introduces a worldwide allocation approach to the supply hydrogen from strong wind and solar regions to different demand regions on the premise of a global supply cost minimum. The allocation results show a significant dependence of hydrogen export volumes and the oversea transport distances of potential trading partners. Hence, the transnational trading flows of hydrogen derived from wind and solar energy are concentrated in continental regions.

Keywords: Hydrogen supply; renewable energy import; global energy infrastructure; hydrogen trade

1 Introduction

The substitution of fossil fuels requires the integration of renewable energy sources (RES) into the global energy system. Due to the temporal and spatial fluctuation of most RES, in particular wind and solar energy, their integration requires the balancing of supply and demand to ensure the security of supply. This can be achieved by storing and transporting energy using a suitable, climate-friendly medium such as hydrogen. The use of hydrogen represents an attractive option for the substitution of fossil energy sources insofar that, unlike electricity, it can be stored on a large scale and transported without the necessity of power lines. In addition, no climate- or environment-harming emissions are released when it is converted into power [1, p. 3].

The possibilities for producing emission-free hydrogen from RES-generated electricity in countries with high energy requirements, especially industrialized nations, are limited and compete with the direct use of electrical energy. In addition, comparatively high generation costs due to unfavorable climactic conditions limit economically-viable expansion potential in many industrialized countries, such as those in parts of Europe [2; 3] and Asia. The techno-economic energy potential of regions with high RES resources, on the other hand, offers an interesting option to use the generated electrical energy for hydrogen production with only limited direct local competition and then export it to various demand countries [4, p. 8, 38, 39].

The concept of extensive hydrogen integration into the energy economy is a topic that has already been discussed at length and that arose around the mid-1970s after the first oil price crisis [5, p. 911]. According to Moreno-Benito et al. [6] and Goltsov & Veziroglu [5], such an energy economy comprises hydrogen production from conventional or renewable energy sources, as well as its transport, storage and use, and also addresses questions of security of supply. Today, hydrogen is primarily produced by gasification or the reforming of fossil energy carriers, or by water electrolysis with the aid of an electric current. The latter process is known as the power-to-gas concept, and is explained in detail by Schiebahn et al. [7]. If required, the hydrogen produced can be compressed into a gaseous form, stored as a liquid or chemically-bound form before it is further transported by pipeline, truck, train or ship and made available, for example, in the transport sector at filling stations or in heavy industry.

There are different approaches to modeling hydrogen infrastructures which, depending on the objective, consider different aspects and elements of the infrastructure in differing degrees of detail. While the majority of the literature [8; 9; 10; 11; 12; 13] deals with regional infrastructures and therefore mostly ignores elements such as hydrogen refining or overseas transport, only a few analyses have been published on international infrastructures [1; 4; 14; 15; 16; 17]. Most such studies only pursue bilateral approaches. Globally, the networked provision and comprehensive distribution approaches for green hydrogen are not yet known. With respect to the objectives of this work and the requirements of the infrastructure model, an approach to RES potential determination, a regional infrastructure model to map the domestic supply chain in the producer region and elements from bilateral infrastructure models are required. To this end, the aforementioned regional and bilateral infrastructure models can provide useful approaches and modeling elements. Therefore, available and relevant approaches are presented in the following literature, from which the procedure applied in the context of this work was developed.

Reuß [12; 13; 18] assesses domestic hydrogen infrastructure options in terms of supply to the transportation sector. For this purpose, he develops an abstract supply chain model with the individual, flexibly-combinable modules production, storage, conversion, transport, and refueling. Thus, it is possible to compare hydrogen infrastructure options with different technologies and techno-economically evaluate them. The author considers the technology pathways of compressed gaseous hydrogen, LH_2 and liquid organic hydrogen carriers, as well as combinations of the three. On the basis of the average daily throughput of hydrogen, corresponding to total investment costs, the individual technology modules show the specific hydrogen costs (TOTEX) and respective energy demand. The respective scenario framework provides the input data, such as the average daily turnover, available storage capacity and transport distances. Technology parameters such as energy demand, specific investment expenditure, maintenance and repair costs as a percentage of the total investment come from a comprehensive technology database. Figure 1-1 schematically shows the structure of a representative technology module.

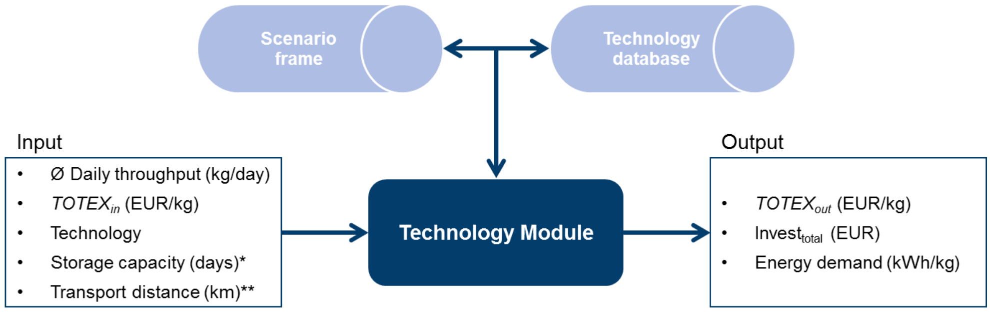

Figure 1-1. Schematic structure of a technology module, *applies to the storage module, **applies to the transport module, representation based on Reuß [18, p. 52]

In a second step, Reuß defines the structure of the supply chain from technology modules. The conversion modules, such as compressors, liquefaction plants, evaporators, hydrogenation and dehydrogenation plants and pumps play a key role here, as they form the connecting elements at the interfaces of the other modules. The entire supply chain analysis yields total costs, greenhouse gas emissions and primary energy requirements. Reuß considers the scaling effects of plant costs on the basis of the respective dimensioning or throughput [12, p. 293]. He assumes the cost function for the pipeline of Mischner et al.[19].

Thanks to its modular structure, Reuß succeeds in making the supply chain flexible and applicable to different regions. An extension of the model using geo-information system (GIS) methods also enables the spatial resolution of production sites, transport routes and consumer locations. However, Reuß does not consider a temporal resolution for the provision of hydrogen.

Building on the work of Robinius [9; 11], who carried out an analysis of land eligibility (LE) for Germany, utilizing suitability factors and thus identifying potential wind turbine sites, while Ryberg (2019) [20; 21; 22; 23] is developing a supra-regionally-applicable approach to determining RES potential in Europe.

The model, “Geospatial Land Eligibility for Energy Systems (GLAES)” [22; 23; 24] developed by Ryberg and based on GIS, offers the possibility of excluding land areas within any region from the use of wind or solar energy. This is performed on the basis of technical, ecological and social availability criteria. For example, water, nature conservation and settlement areas within a defined region are defined as not being available, taking into account a corresponding distance value. The catalogue of criteria essentially includes physical, infrastructural and topographical restrictions relating to natural conservation. Wind turbines or PV modules can then be placed within the remaining available area at an exogenous distance from each other.

Hourly resolved production time series can be determined for each defined generation location and on the basis of globally-available weather data. For wind turbines, this is performed on the basis of a synthetically-determined power characteristic curve, and for PV modules on the basis of the irradiation angle and module temperature. From this, average full load hours (FLH) can be calculated for each turbine and module and spatially-assigned to the respective generation location.

The potential of wind energy and photovoltaics that can be used for hydrogen production is usually estimated in the literature with respect to constantly assumed full-load hours without spatial resolution. Fasihi et al. [25, p. 5] assume a flat rate of 6,840 full load hours for a hybrid wind PV power plant. Watanabe et al. [17, p. 549] proceed in a similar way by assuming more than 4,000 full load hours of wind generation in Patagonia without spatial resolution.

Kamiya et al. [14] show the possibility of low CO_2 hydrogen being supplied to Japan by means of Australian lignite. In the course of the planned conversion of the energy economy to hydrogen in Japan [26, p. 205] and the concept presentation on the occasion of the Olympic Summer Games 2020 [27] in Tokyo, Kamiya et al. show the technical feasibility and resulting import costs of a bilateral hydrogen infrastructure. In their study, hydrogen is produced using lignite gasification in the state of Victoria, Australia, with CO_2 produced in the gasification process captured and stored underground (i.e., Carbon

Capture and Storage, or CCS). The hydrogen is then transported by pipeline over 80 km to the coast, where it is liquefied, temporarily stored and then shipped to Japan by liquid hydrogen tanker (LH_2 tanker). The annual hydrogen production amounts to 225,500 tons (~7.5 TWh_{H2}). According to the assumptions and calculations, the total plant costs amount to the equivalent of EUR 6.73 billion. Hydrogen production accounts for 30% of this, the liquefier for 33% and the LH_2 tankers for about 13%. In terms of operating costs, electricity costs account for the largest share (43%). Liquefaction is particularly energy-intensive, accounting for 47% of electricity consumption. The specific import costs in Japan amount to 2.93 EUR/kgH_2 (0.08 EUR/kWh). The breakdown of import costs by the infrastructure element is shown in Figure 1-2. Accordingly, production costs contribute 29% to the import costs, while liquefaction makes up 33%.

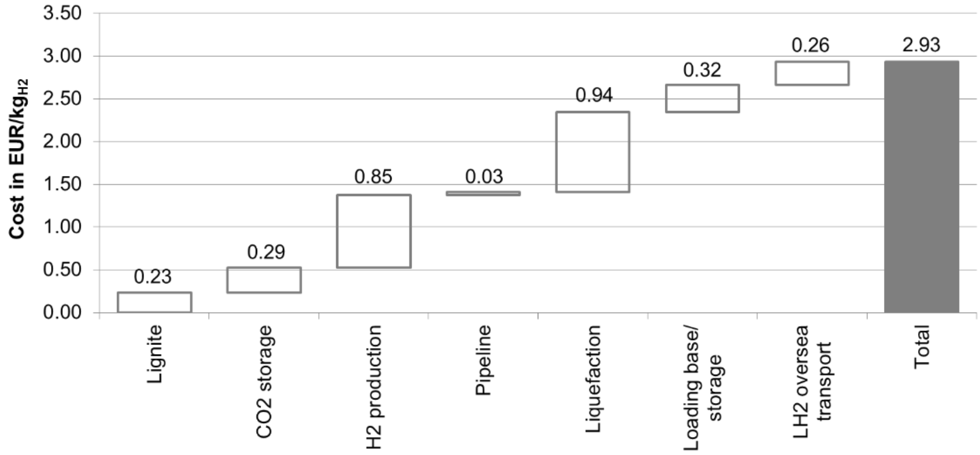

Figure 1-2. Breakdown of hydrogen import costs of 2.93 EUR/kgH2 for hydrogen exports from Australia to Japan, according to Kamiya et al. [14, p. 14].

Watanabe et al. [17] carry out cost estimates for hydrogen imports from Patagonia to Japan. The authors assume that electricity from wind energy is used for electrolysis and hydrogen liquefaction in the windy province of Santa Cruz. In contrast to many other studies, Watanabe et al. consider the domestic transportation of hydrogen via pipeline between production and liquefaction. The liquid hydrogen is then transported by LH_2 tanker to Japan, where it is vaporized and converted back into electricity in a hydrogen turbine.

Wind energy capacities and the investment costs for power generation are determined on the basis of three different scenarios with regard to the degree of expansion of wind energy and the design of the wind turbines. The expansion capacities of the wind power are between 60.4 and 77.5 GW, while the average full load hours of the power generation are assumed to be 4,380 h/a. Following electrolysis, just less than 5 million tons of hydrogen are available each year. Depending on the different degrees of expansion, different pipeline lengths are taken into account. Similarly, liquefaction and storage capacities are dimensioned according to the scenarios. Watanabe et al. draw on LH_2 tanker concepts with capacities of 850 and 4,460 tons and investment costs per tanker of 75 and 225 million EUR, respectively.

Following landing, storage and evaporation, the hydrogen is converted into electricity in a hydrogen turbine in Japan. Depending on the capital costs (0.5-5%), hydrogen supply costs of 13.6 to 18.3 EUR-ct/kWh_{H2} can be determined. The largest part of the costs considered here are attributable to production and overseas transport. The composition of hydrogen import costs in Japan is shown in Figure 1-3. On the basis of their assumptions and calculations, the authors conclude that the import of hydrogen with subsequent conversion back into electricity is not yet economically-competitive.

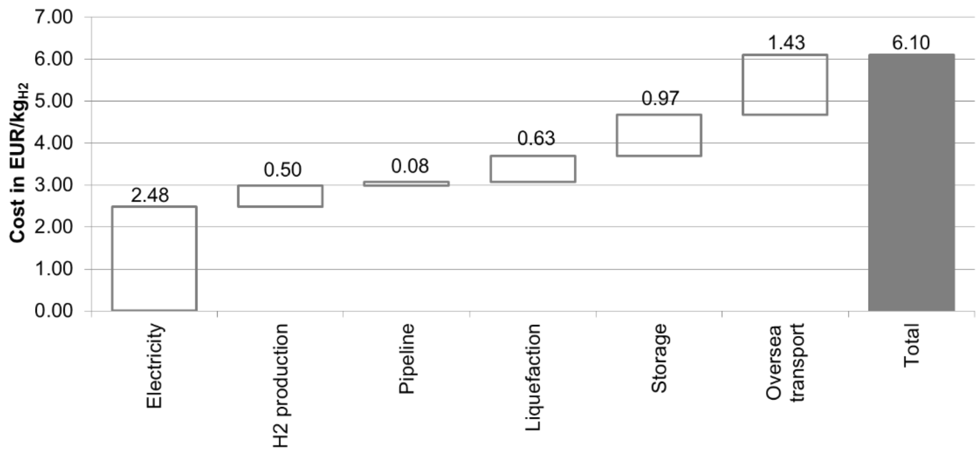

Figure 1-3. Breakdown of hydrogen import costs for LH_2 imports from Patagonia to Japan at a capital cost rate of 5%, according to Watanabe et al. [17].

In contrast to other concepts of international hydrogen infrastructures, Watanabe et al. consider in their study, as mentioned above, the domestic transport of hydrogen between the production sites and port. This methodological approach fully maps the required infrastructure and enables the identification of cost drivers. However, the respective technical infrastructure elements are depicted fairly roughly and without degrees of freedom with respect to dimensioning. Therefore, the applicability to other regions and scenarios is highly limited.

The findings of the considered country-specific analyses, however, can only be applied to other countries and regions to a limited extent, as the geographical and climatic conditions vary considerably from one country to another. Regional infrastructures for the production and supply of hydrogen as a nearly emission-free energy carrier on a national or regional level are the subject of numerous studies and often have a spatial resolution to map transmission and distribution. The model approaches taken by Reuß [12; 13; 18] and Ryberg [20; 21; 22; 23] discussed here are spatially-resolved via geo-information systems and therefore serve to meet the challenges outlined above.

A general requirement for future energy infrastructures is economic competitiveness. In accordance with sustainability, energy infrastructures today should also satisfy the criteria of ecological compatibility and offer a high degree of supply security. Thus, costs, the primary energy demand to cover final energy demand and possible greenhouse gas (GHG) emissions are the assessment criteria on which this analysis is based. Furthermore, the RES potential determination and hydrogen infrastructure conception require consistent and internationally-transferable modeling approaches. As the characteristics of the assessment variables within the framework of the supply infrastructure also depend on transport distances and storage capacities, the model approach for determining the RES potential of renewable energy technologies must ensure the spatial and temporal resolution of the results. Analogous to the potential estimation and hydrogen supply on the supply side, the demand side must be considered spatially-resolved. Meeting the estimated worldwide hydrogen demand requires a distribution approach that allows an assessment to be conducted that incorporates the selected criteria without being dependent on additional criteria not considered in this study. The coupling of models for determining RES potentials and for a uniform and internationally transferable infrastructure to distribute the global supply of hydrogen would make it possible to assess the economically viable hydrogen flows and associated costs. Thus far, however, there is no such comprehensive concept for a worldwide infrastructure for the provision and allocation of renewable hydrogen.

This paper analyzes the techno-economic hydrogen production potential of internationally preferential regions for onshore wind energy and photovoltaics. The aim is to design and evaluate a worldwide infrastructure for the allocation of the hydrogen supply with regard to projected global demand in the target year 2050. Firstly, the techno-economic generation potential of hydrogen based on wind energy and photovoltaics in selected regions is determined. Therefore, the supply and cost curves of hydrogen supply are derived by applying different models for determining RES potentials and depicting a domestic hydrogen infrastructure. With the help of an allocation approach, the cost-optimal hydrogen demand coverage in 2050 can be identified. In the context of this analysis, minimizing the total costs is of particular interest in order to be able to evaluate expansion strategies and the location advantages for RES-intensive regions. At the same time, whether the import of renewable hydrogen is an economical and sustainable alternative to directly competing fuels is examined.

2 Methodology

2.1 Design of the worldwide hydrogen supply chain

The focus of this section is on relevant methodological approaches for mapping hydrogen production, transport, conversion and storage within domestic infrastructures. The supply chain for hydrogen within the producing regions consists of four elements that can be both energetically and economically described:

- Hydrogen production
- Pipeline transport
- Refining
- Storage

In addition, there is an upstream module for RES electricity production based on the work of Ryberg [20; 21; 22; 23] and an overseas transport module for the export of hydrogen to demand countries. The complete model overview is shown in Figure 2-1. A detailed description of the applied RES potential and hydrogen supply chain models can be found in Heuser et al. [28]. There, the authors analyzed a bilateral trading link between Patagonia and Japan for CO_2-free hydrogen.

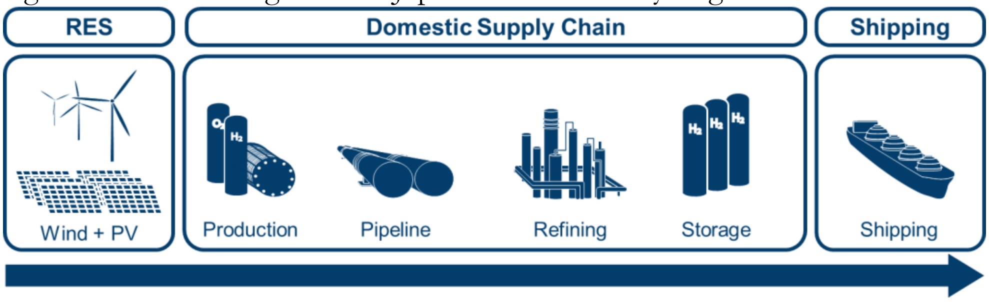

Figure 2-1. General representation of the modelled hydrogen infrastructure.

The hydrogen infrastructure built up in this way covers all steps, from electricity generation to delivery to the destination port. After electricity is generated via wind turbines or PV modules, respectively, it is transferred to the electrolysis sites in the park centers determined by the cluster algorithm. The hydrogen is then produced there and transported by pipeline to the nearest harbor. At this selected coastal location, the hydrogen is liquefied in order to make storage and subsequent overseas transport economically viable. On the basis of the supply and cost curves for electricity generation, the corresponding supply and cost curves for hydrogen supply in the respective producing regions are derived after calculating the cost shares. Together with the spatially-resolved global hydrogen demand, these supply and cost curves form the basis for a cost-optimal distribution of hydrogen by ship transport. The subsequent domestic infrastructure in the respective demand countries is not a subject of this paper.

After selecting the preferential regions to be investigated on the basis of global wind and solar energy potential atlases [29; 30; 31; 32], the GLAES model developed by Ryberg [20; 21; 22; 23] is used to determine land availability for wind turbines and PV modules in these regions. Depending on the climactic characteristics of the respective region, either wind turbines or PV modules are placed in the available area at previously defined intervals. Using a cluster algorithm, the locations are divided into wind or PV parks and internally networked. At these locations, a simulation of the power generation is then carried out with the aid of spatially- and temporally-resolved historical weather data from NASA [33; 34] and potential atlases for wind speeds [29; 31] and solar irradiation [32]. This results in generation time series and full load hours that are derived from these, and of the respective generation plants for each defined location or for the entire region. Different degrees of expansion of wind energy or photovoltaics can be defined on the basis of the minimum full load hours of the plants and serve as support points for the supply and cost curves of electricity generation. The generated electricity is concentrated in the park centers and used exclusively for hydrogen generation by means of electrolysis. An optimal curtailment of the electricity generation with regard to the hydrogen production costs leads to higher electrolysis full load hours and thus to a reduction in the hydrogen cost.

Reuß [12; 13; 18] defines individually-combinable technology modules that show the required investment costs, energy demand and specific hydrogen costs. The average daily turnover of hydrogen, the hydrogen costs and the corresponding module parameters are processed as input variables in each module with the result passed on to the next module. The module parameters are taken from a technology database that has been partly drawn from Reuß [13] and Krieg [8]. In this paper, these technology modules are used and, if necessary, adapted for the domestic supply chain due to their modular structure and flexibility in application. The input variables for the entire supply chain are the wind turbine or PV plant locations with the associated full-load hours, as well as the supply and cost curves for electricity generation. In addition, the modules from Reuß were adapted such that generation time series for electricity before and after hydrogen electrolysis can also be processed as input and output variables. The hourly resolved energy flow, in the form of electricity or hydrogen, is transferred to the respective module and, after determination of the own energy consumption and efficiency-related losses, passed on to the following module. In this way, the efficiency of the infrastructure with respect to the primary energy demand is determined for all elements. Following production, the hydrogen is compressed and transported by pipeline to the coast of the target region. There, it is liquefied to make the necessary storage and overseas transport economical. The domestic infrastructure, spanning hydrogen production to provision at the coast, is represented by technology modules as developed by Reuß [12; 13; 18]. The modeling of the domestic supply chain is completed with coastal storage. A temporal resolution of the hydrogen supply is no longer necessary after the implementation of storage, as the storage enables a constant hydrogen withdrawal. The initial parameters of the supply chain are the annual amount of hydrogen provided, which depends on the RES expansion scenario, along with the associated specific hydrogen cost curves. These costs include renewable power generation and the entire infrastructure described above. The full costs of the infrastructure are allocated to the hydrogen produced and ultimately provided in the form of specific costs using the annuity method. The investment costs of a module depend on its power size or capacity. Analogous to the calculation of the electricity production costs, the capital costs and fixed operating costs are calculated as a function of the investment costs. The variable operating costs result from the specific energy and raw material requirements per unit of hydrogen. Within the context of this work, renewable electricity and hydrogen are used as energy carriers for operation of the infrastructure. Water is the only raw material used for electrolysis. In each component of the infrastructure chain, the specific hydrogen costs incurred in previous steps are assumed as inputs and, in the case of hydrogen losses, also as energy costs. After the addition of the costs incurred in the respective module in relation to the amount of hydrogen produced, the new specific hydrogen costs result. On the basis of the power generation costs of the respective degrees of expansion in conjunction with the module-specific cost shares of the hydrogen supply chain, the supply and cost curves for the hydrogen supply at the selected coastal location result. These supply and cost curves, calculated for each target region, form the basis for the worldwide cost-optimal allocation of hydrogen.

2.1 Selection of preferential regions

One aim of this study is the estimation of hydrogen production potential on the basis of wind energy and photovoltaics in particular regions rich in these resources. Based on global observations of the mean wind speeds of the Global Wind Atlas (GWA) [29] and solar irradiation of the Global Solar Atlas (GSA) [32], regions with especially high wind and radiation intensity are identified. In addition, only regions or countries with direct access to the coast are selected to ensure the provision of larger quantities of water for hydrogen production and to enable supply at port locations.

Based on Figure 2-2, regions at the upper end of the wind speed scale are selected. These regions are colored red in the figure. In particular, the regions of the westerly wind zone between 40° and 60° northern and southern latitude are of interest, which is especially evident at the southern tip of South America and on the western coasts of Canada and Europe. Despite high average wind speeds, regions such as Greenland are excluded due to ice cover, as well as Tibet and Nepal due to lack of coastal access, altitude and difficulty of access. At the same time, in some countries only the windiest sub-regions are taken into account. In Argentina, the analysis is limited to the southern region of Patagonia, and in China to Inner Mongolia. The selection of windy regions includes the Canadian provinces of British Columbia, Newfoundland and Québec, as well as Chile, the Argentinean part of Patagonia, Iceland, Norway, the United Kingdom and Ireland, along with the autonomous region of Inner Mongolia in China (see Figure 6.1).

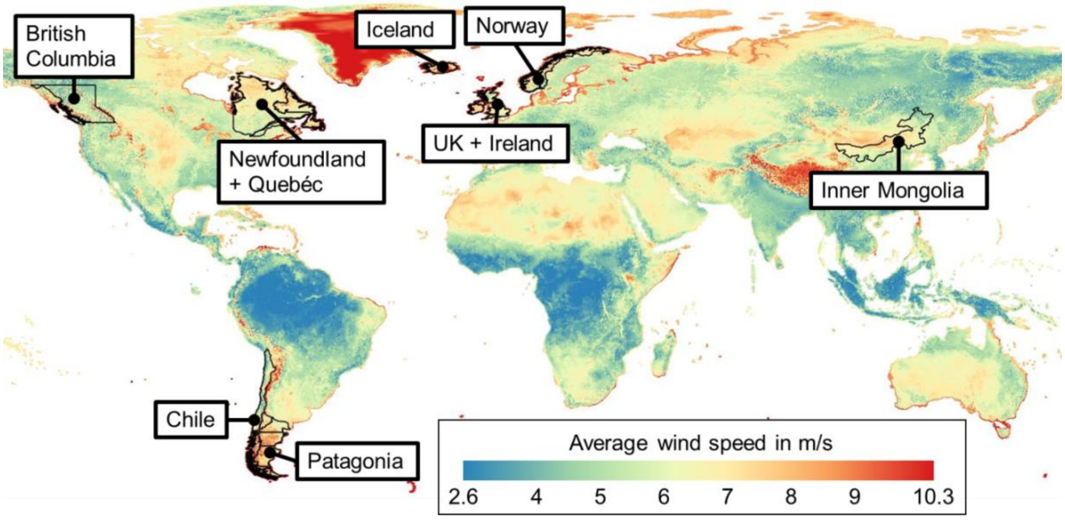

Figure 2-2. Selection of preferential regions with high presumed wind potential based on the mean wind speed at 50 m height, GWA [29].

Analogously to the selection of regions with strong winds, the determination of sunny areas is carried out using the GSA in Figure 2-3. Due to high average irradiation, the tropical and subtropical zones are of particular interest here. Arid to semi-arid areas, such as desert regions, are particularly suitable for the harvesting of solar energy. For the reasons already mentioned, considerations of some particularly large countries, such as the USA or China, are limited to individual regions with high irradiation. The selected solar radiation-rich regions include the states of California, Nevada, New Mexico, Arizona and Texas of the USA, along with Mexico, Peru, Chile, Western Sahara, Morocco, Algeria, Libya, Egypt, Namibia, South Africa, Saudi Arabia, Oman, Australia and selected provinces of China.

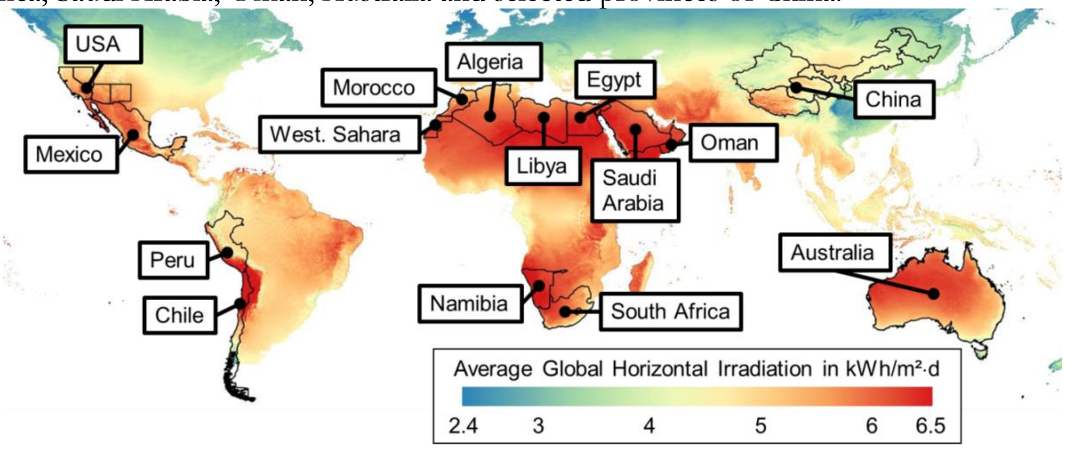

Figure 2-3. Selection of regions with high solar radiation as a proportion of global radiation, GSA [32].

2.2 Estimation of prospective world hydrogen demand

For the assessment of prospective German demand, three different demand scenarios in the transport sector are considered, which can be seen in Figure 2-4. An estimation of future worldwide hydrogen demand with a bottom-up approach for each individual country is not possible due to inconsistent or non-existent data. For this reason, the future hydrogen demand for the transport and industrial sectors in Germany is first estimated and then scaled to the world regions with the help of the expected global final energy demand of the World Energy Outlook of the International Energy Agency [35].

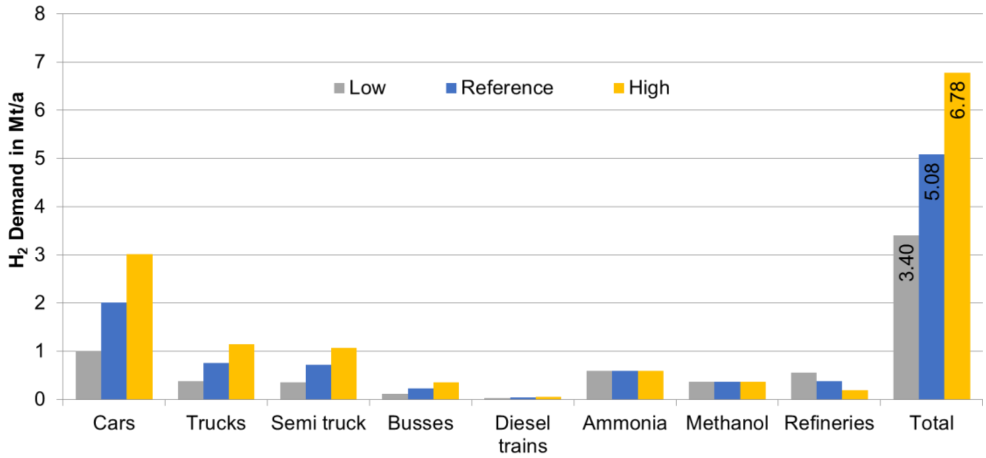

Figure 2-4. Scenario assumptions for hydrogen demand in the transport and industrial sectors of Germany in Mt/a for the year 2050

The demand quantities of the Reference scenario are shown in Figure 2-5. The total global demand for hydrogen in the Reference scenario amounts to more than 365 Mt_{H2}/a. With almost 170 Mt_{H2}/a, almost half of this is consumed by Asia Pacific, with China again accounting for almost half of the Asian Pacific demand. In turn, India and Southeast Asia each account for about a quarter of Asian Pacific demand.

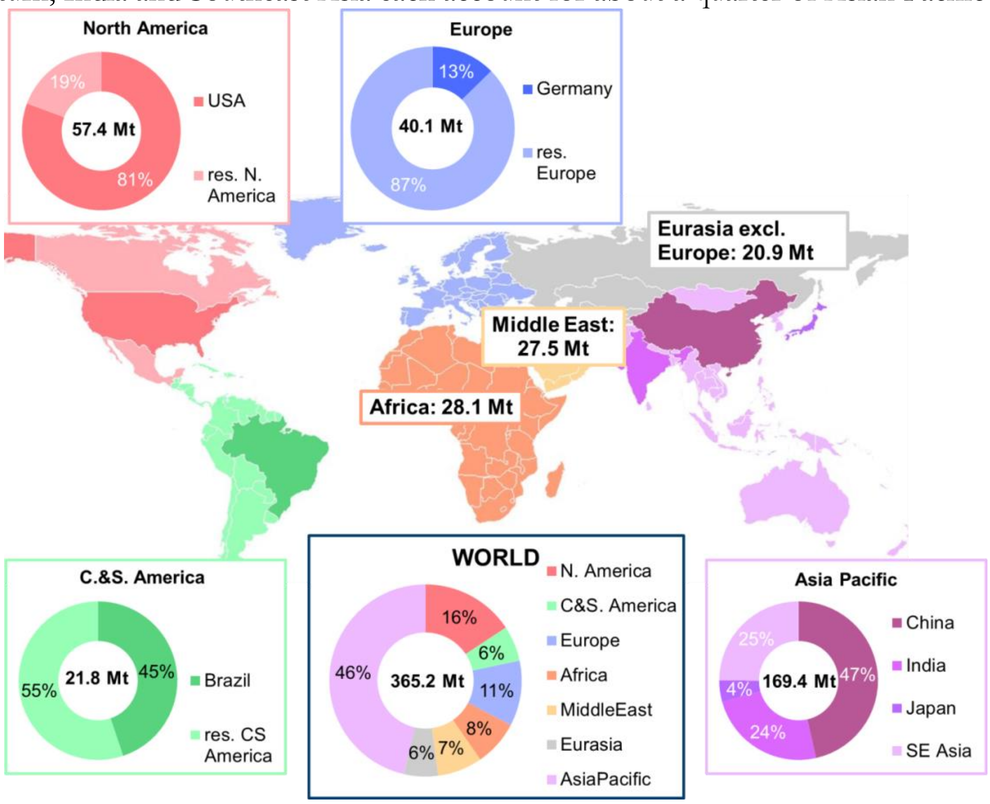

Figure 2-5. Estimated future global hydrogen demand by world region in the Reference scenario, with regional classification based on IEA [35].

The entire North American continent equates to about one third of Asian Pacific demand, with the future demand of the United States about four times higher than that of Canada and Mexico combined. The demand in Europe is only about a quarter of that in Asia Pacific, meaning that the needs of Europe, India and Southeast Asia are roughly on par. The requirements of the other world regions are of a similar order of magnitude of between 20 and 30 Mt_{H2}/a. The relative proportions of requirements are constant across all three scenarios, as only the Reference value of future German requirements changes. Therefore, the absolute results of the three requirement scenarios are presented in Table 2-1 as an overview. For the low scenario, the total requirement is around 245 Mt_{H2}/a, while the total requirement in the high scenario is almost twice as high.

Table 2-1. Estimated future worldwide hydrogen demand depending on the three defined demand scenarios, with the regional classification based to IEA [35].

World region	Prospective Hydrogen Demand in Mt_{H2}/a		
	Reference	Low	High
North America	57.4	38.4	76.6
Of which USA	46.3	31.0	61.8
Central and South America	21.8	14.6	29.0
Of which Brazil	9.8	6.5	13.0
Europe	40.1	26.8	53.5
Of which Germany	5.1	3.4	6.8
Asia Pacific	169.4	113.5	225.9
thereof China	78.8	52.8	105.0
Of which India	40.9	27.4	54.6
Of which Japan	7.4	5.0	9.9
Of which South-east Asia	42.3	28.3	56.4
Eurasia	20.9	14.0	27.8
Middle East	27.5	18.4	36.6
Africa	28.1	18.8	37.5
Total	365.2	244.5	486.9

2.3 Allocation Approach to meet prospective world demand

Overseas transport is mapped with the aid of a liquid hydrogen tanker concept by Kawasaki Heavy Industries [14], previously outlined by Heuser et al. [28]. The specific cost contribution of the overseas transport results from the investment and operating costs of the tanker in relation to the already described technology modules. Depending on the transport distance to be bridged, this results in a function of the overseas transport costs related to the hydrogen quantity (cf. Figure 2-6).

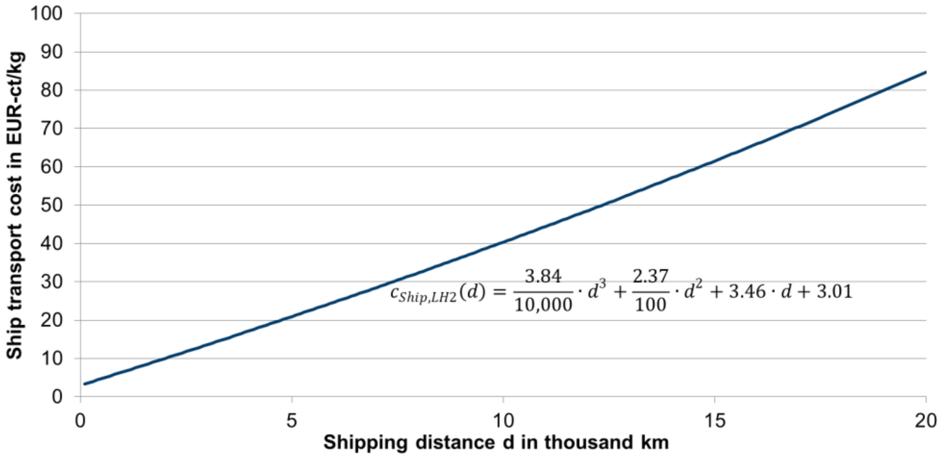

Figure 2-6. Cost curve of LH_2 ship transport as a function of distance

The allocation of the hydrogen supply to cover the estimated global demand for hydrogen is determined by minimizing the overall global costs. The mathematical transport problem [36] is used for this purpose with the aim of minimizing the global cost function. This approach offers the optimal allocation of the hydrogen resource on the basis of the provision costs and overseas transport costs. The provision costs of a unit at the supply locations are $c_{exp,i}$ and the transport costs from A_i to B_j are exactly $c_{trans,ij}$. The absolute global hydrogen supply costs C_{global} result in accordance with the target function, to be minimized as follows:

$$C_{global} = \sum_{i=1}^{m}\sum_{j=1}^{n}(c_{exp,i} + c_{trans,ij}) \cdot x_{ij} \tag{1}$$

$$\sum_{j=1}^{n} x_{ij} \leq a_i \ \forall\, i \ \in [0, \dots, m] \tag{2}$$

$$\sum_{i=1}^{m} x_{ij} = b_j \ \forall\, j \ \in [0, \dots, n] \tag{3}$$

$$x_{ij} \geq 0 \ \forall i \ \forall j \tag{4}$$

In this way, the hydrogen is distributed in a cost-optimized way in terms of the specific provision and overseas transport costs, and the demand is precisely met. The import paths to Germany and the associated import costs depend on the global cost optimum.

In contrast to the total cost-optimal solution for hydrogen distribution, the world market for oil and natural gas is not based on marginal costs, but is profit-oriented or sometimes politically motivated due to differing economic and political interests [37, p. 136-143]. A global cost optimum in oil and gas trading must not necessarily be in the interest of all market participants. However, the approach against the transport problem allows for the assessment of the influence of transport costs on global distribution and the degree of market segmentation.

Figure 2-7 provides an exemplary overview of the entire model structure: The upper left part of the figure (highlighted in green) shows the domestic infrastructure of an exemplary producer region. In turn, the transport cost curve for overseas transport is defined below as a function of the distance, mode of transport and the selected drive (highlighted in violet). A cost-optimal allocation approach (blue background) is used to cover global hydrogen demand at optimal costs. The final structure of the cost breakdown can be found in the lower right-hand area of the graph.

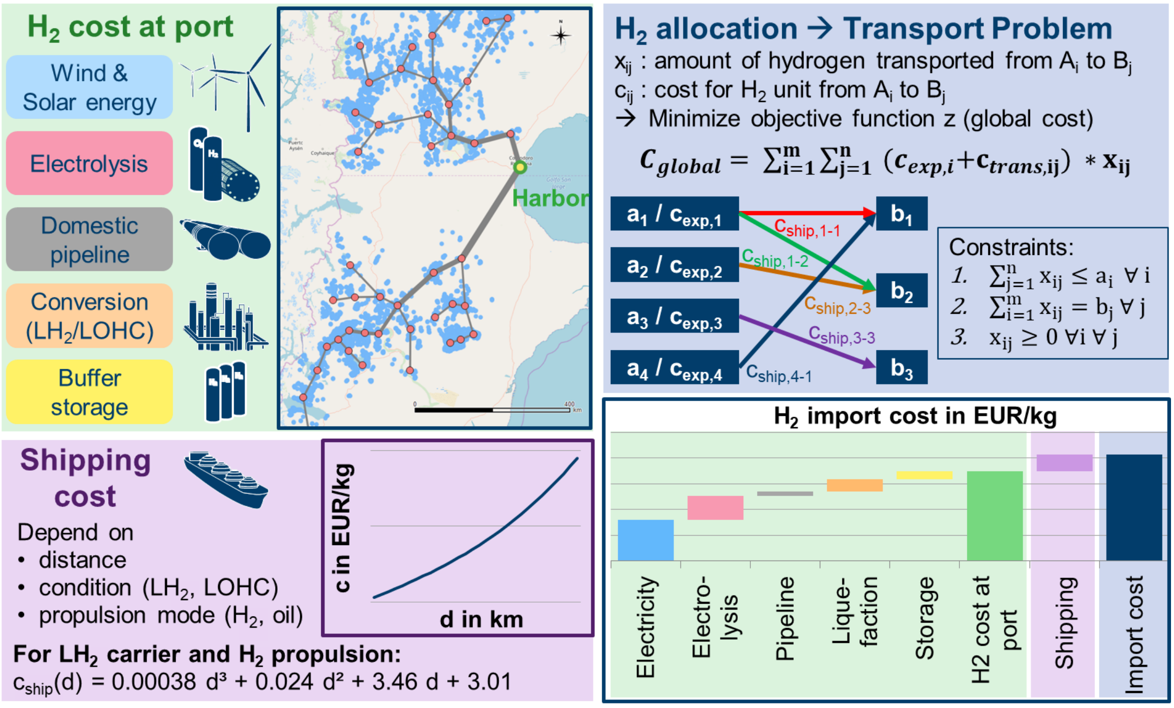

Figure 2-7. Comprehensive overview of the global hydrogen infrastructure.

3 Results

3.1 Region-specific supply and cost curves

As mentioned in section 2.1, a detailed description of the methodology utilized to determine the supply and cost curves for a hydrogen supply based on renewable energy has been published by Heuser et al. [28]. A comprehensive methodological overview is displayed in Figure 2-7.

Figure 3-1 shows the H_2 supply quantities and associated costs for the four highest potential windy regions of Patagonia, Newfoundland, Inner Mongolia and Québec.

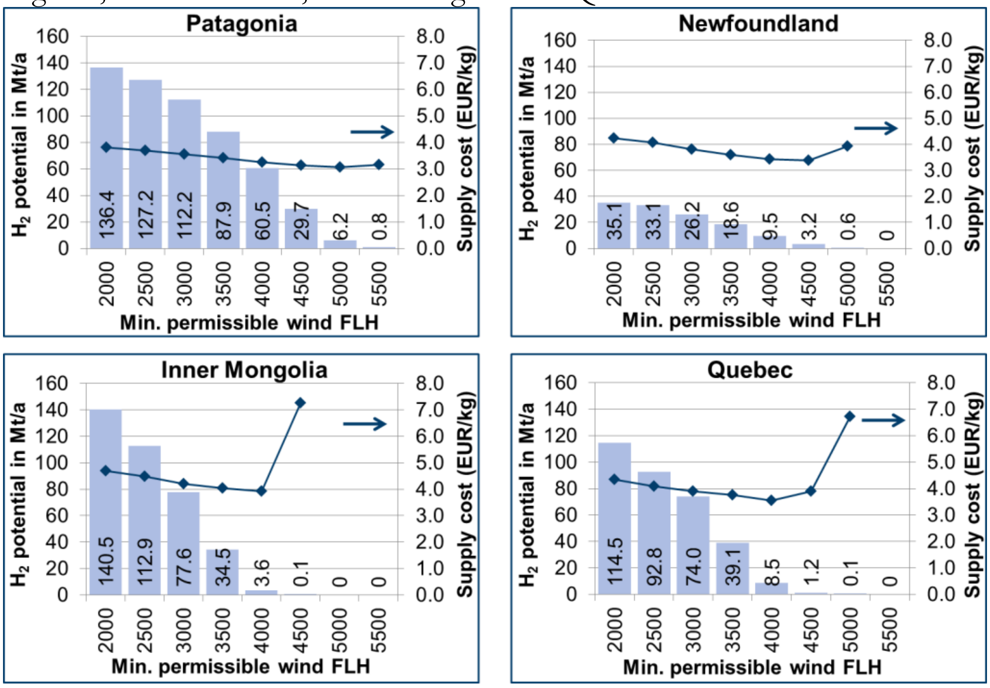

Figure 3-1. Hydrogen supply and cost curves for supply in windy regions with high potential. Supply quantities in megatons (the bar charts show the supply quantities, while the line charts show the associated supply costs without the subsequent ship transport).

Inner Mongolia has the highest potential, of over 140 Mt_{H2}, with the highest level of wind energy (min. 2,000 FLH). This potential decreases comparatively quickly as the degree of expansion does. With a limit value of at least 4,000 FLH, the amount of hydrogen provided annually is only 3.6 megatons. The supply situation in Québec is similar. With an increase in the minimum full-load hours to 4,000, about 7% of the total quantity remains. The full potential in Patagonia is smaller than that in Inner Mongolia. Here, however, the full-load hour distribution of the wind turbines is much more even. For this reason, the amount of electricity provided decreases much more slowly. At a minimum of 4,000 FLH, almost half of the total potential hydrogen can still be provided. Compared to the three regions mentioned above, the supply potential in Newfoundland is much smaller. In contrast to neighboring Québec, the potential does not decrease quite as much as the degree of expansion. With at least 4,000 full-load hours of wind, about one quarter of the total potential remains.

Patagonia has the lowest provisioning costs, which are between 3.80 and 3.06 EUR/kg_{H2} across all expansion levels. Since the electricity production costs of wind energy decrease with increasing minimum full load hours, the costs for hydrogen production are also reduced. Only in the smallest expansion level is a renewed increase in costs noticeable. This is due to the only moderately utilized pipeline and the lack of economies of scale in liquefaction; an effect that is even more evident in Inner Mongolia and Québec. Here, due to the size of the area, a comparatively long pipeline section is required for the transmission of hydrogen to the port location at any degree of expansion. In combination with higher costs for longer microgrids in the wind farms and higher specific liquefaction costs, this leads to a strong increase in costs for small expansion stages.

The windy regions with smaller hydrogen supply potential are discussed in Figure 3-2. In Chile, even with at least 6,000 FLH, some 100,000 t_{H2} per year can still be provided. In Iceland, the levels of expansion reach a limit of 5,000 FLH. This results in comparatively low electricity generation costs and, in conjunction with low infrastructure costs due to shorter domestic transport distances, supply costs for Chile and Iceland of between 3 and 4 EUR/kg_{H2}. In all other regions, no wind turbine reaches a minimum of 5,000 FLH. Therefore, the deployment costs here are usually above 4 EUR/kg_{H2}. As with the regions discussed in Figure 3-1, there are also slight cost increases in the smaller regions for the smallest expansion levels. This increase is especially evident in British Columbia, as it occurs at a lower limit of at least 3,500 FLH, while the phenomenon is less pronounced in the case of Ireland, where the costs are lower than in the other countries at only one level of expansion.

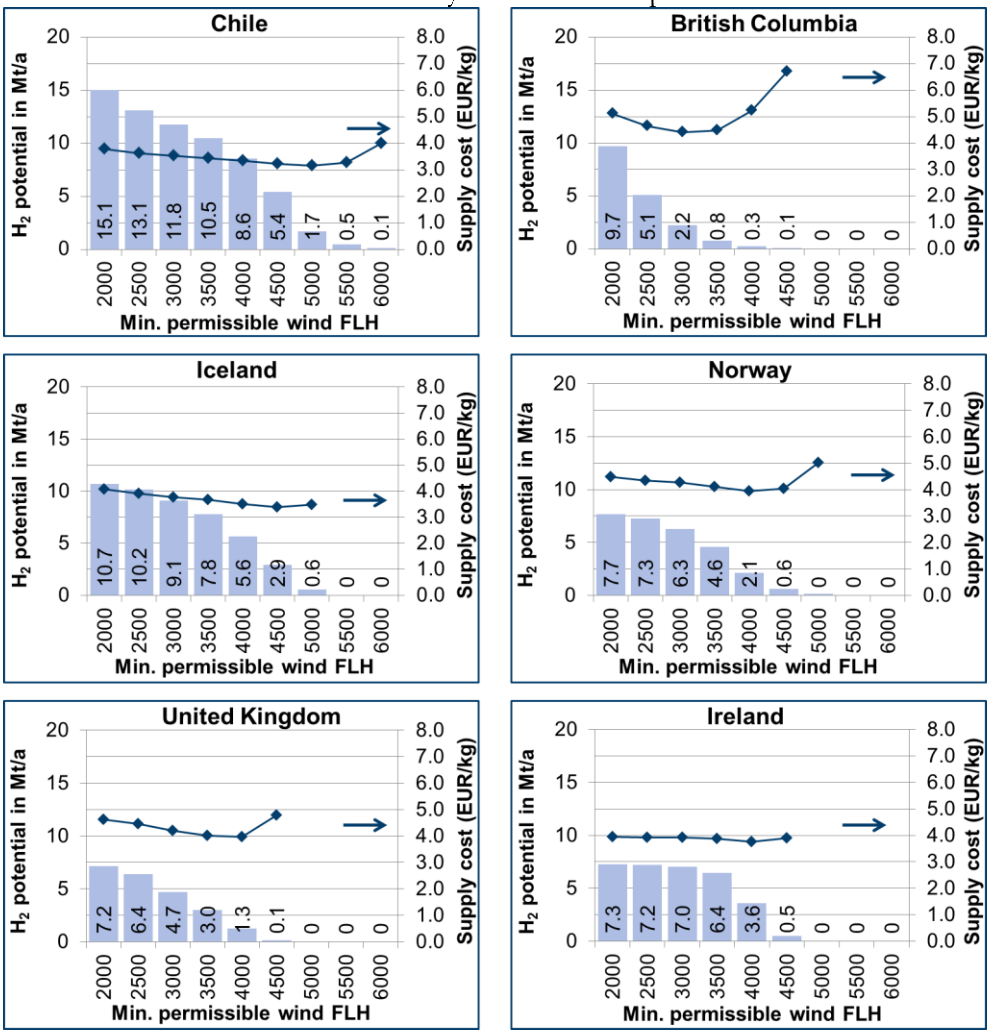

Figure 3-2. Hydrogen supply and cost curves for supply in windy regions with low potential. Supply quantities in megatons (the bar charts show the supply quantities while the line charts show the associated supply costs without the subsequent ship transport).

The total supply potential across the selected windy regions amounts to just under 485 Mt_{H2}/a in the highest degree of expansion (min. 2000 FLH). This amount would theoretically be sufficient to cover almost 15% of global final energy demand in 2015 [35, p. 648] and exceeds current annual hydrogen production by a factor of nine [38, p. 247-251]. Furthermore, there are more or less pronounced minima for all cost curves in windy regions. From this, it can be concluded that there is a cost-optimal degree of expansion of wind energy with respect to hydrogen supply. Contrary to the obvious assumption that hydrogen supply was most cost-efficient with the smallest possible degree of expansion and correspondingly high full load hours of electricity generation, the cost-optimal supply quantities for smaller regions are between 1.3 and 3.6 Mt_{H2}/a and for larger regions between 3.2 and 8.5 Mt_{H2}/a.

The supply and cost curves of the sunny preferential regions can be divided into three potential categories. The results for the regions with the highest supply are shown in Figure 3-3. In principle, the supply potential is shown on the basis of 5% of all theoretically installable PV modules with the highest full-load hours. For individual regions, these expansion levels are extended by one or two additional points (best 25% and 50%).

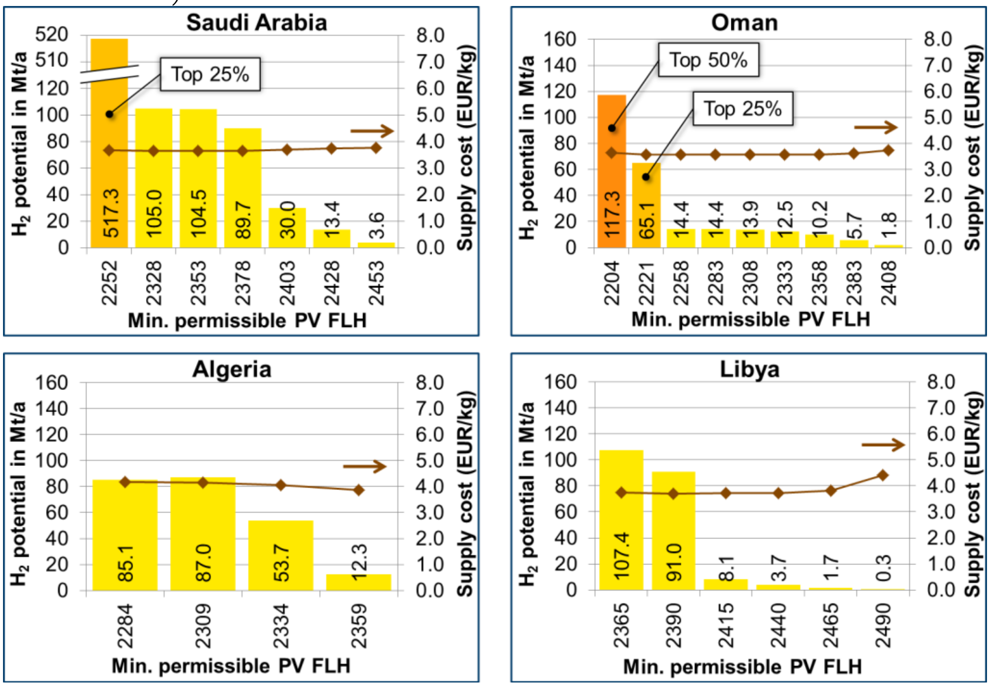

Figure 3-3. Hydrogen supply and cost curves for supply in sunny regions with high potential. Supply quantities in megatons (the bar charts show the supply quantities, the line charts the associated supply costs without subsequent ship transport).

In Saudi Arabia, more than 517 Mt_{H2}/a can be provided if 25% of all locations (min. 2,252 FLH) are taken into account. If the degree of expansion is reduced to 5% (min. 2,328 FLH), an annual potential of 105 Mt_{H2} remains. Starting from this support point, the lower full load hour limit is increased by 25 h/a up to about 3.6 Mt_{H2}/a remaining at a minimum of 2,453 FLH. While the hydrogen supply is significantly reduced as the degree of expansion decreases, the supply costs remain relatively constant. This effect can also be seen in the example of Oman. Even with an additional expansion to 50% of all possible PV sites (min. 2,204 FLH), the costs hardly change. In Algeria, only the smallest degree of expansion results in a significant cost reduction. In Libya, the opposite effect is evident. Because of the necessary pipeline connection between the generation sites and the port city of Benghazi, the costs increase with a low annual supply volume. Although 25% of all PV sites are considered in Saudi Arabia, 50% in Oman and only 5% in Algeria and Libya, a total of 827 Mt_{H2}/a could be provided in these four regions. This magnitude illustrates the enormous potential of these sun-rich, resource-optimal regions. However, none of the regions reaches the low cost levels of Patagonia, Chile or Iceland in their cost-optimized wind energy expansion levels.

Six of the 15 sun-rich regions offer medium provisioning potential. The corresponding results of the supply and cost curves are shown in Figure 3-4. Here, the analysis of three regions was also extended by an additional 25%. For these three regions, however, the costs remain comparatively constant. Only in the case of very small supply quantities at the lowest expansion levels do the costs increase slightly due to underutilized infrastructures. Chile has the lowest costs of the region selection at this point. At around 3.55 - 3.60 EUR per kg_{H2} , these are in the range of the costs in Oman and below those of Saudi Arabia. This is due to the irradiation-rich altitude of the Atacama Desert, where most of Chile's PV modules are placed.

In Australia, a drastic decline of almost 90% in the supply volume between the second and third stage of expansion is evident. This is demonstrated by the extremely narrow full-load hour window in which most PV modules are placed. A similar effect can be observed in Egypt. Here, too, the hydrogen supply drops by 70%, from 42.5 to 12.4 Mt_{H2}/a, without any significant change in the specific supply costs. In the smallest expansion stage, the costs increase slightly again on the basis of transport.

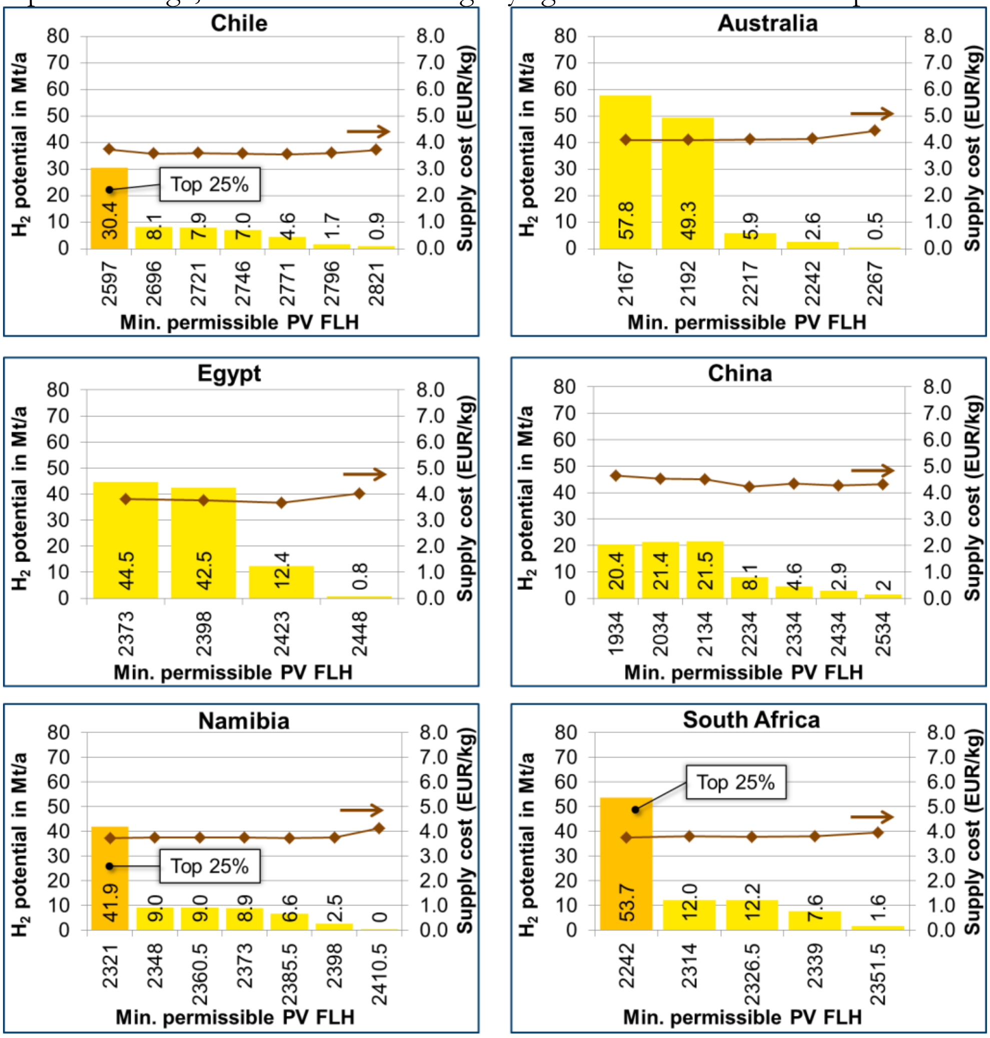

Figure 3-4. Hydrogen supply and cost curves for supply in sunny regions with medium potential. Supply quantities in megatons (the bar charts show the supply quantities, while the line charts show the associated supply costs without the subsequent ship transport).

In the remaining five regions (see Figure 3-5), lower hydrogen potentials can be observed due to moderate land availability and lower full load hours. This comparatively low full-load hour level also ensures that the costs are, in most cases, above 4 EUR/kg_{H2}. Only in Peru the minimum full-load hours are significantly higher than in the other regions due to the stronger irradiation at the country's elevations. Accordingly, the electricity generation and ultimately also the hydrogen supply costs are lower. Nevertheless, they do not reach the low level of neighboring Chile.

If one sums up the potential of all regions with high solar irradiation at the highest levels of expansion, the annual hydrogen potential is over 1,105 Mt_{H2}. If the potential of the regions with high wind volumes of 485 Mt_{H2} is added up, the sum of 1,590 Mt_{H2} (~ 53 PWh) corresponds to almost half of worldwide annual final energy consumption in 2015 [35, p. 648].

In contrast to the cost curves of wind-rich regions, the specific hydrogen costs based on photovoltaics are much more constant and thus relatively independent of the respective degree of expansion. The costs are in a much narrower range of between 3.55 and 4.60 EUR/kg_{H2}. Nevertheless, hydrogen supply on the basis of very small degrees of PV expansion is usually somewhat more cost-intensive. This effect can be observed for both windy and sunny locations.

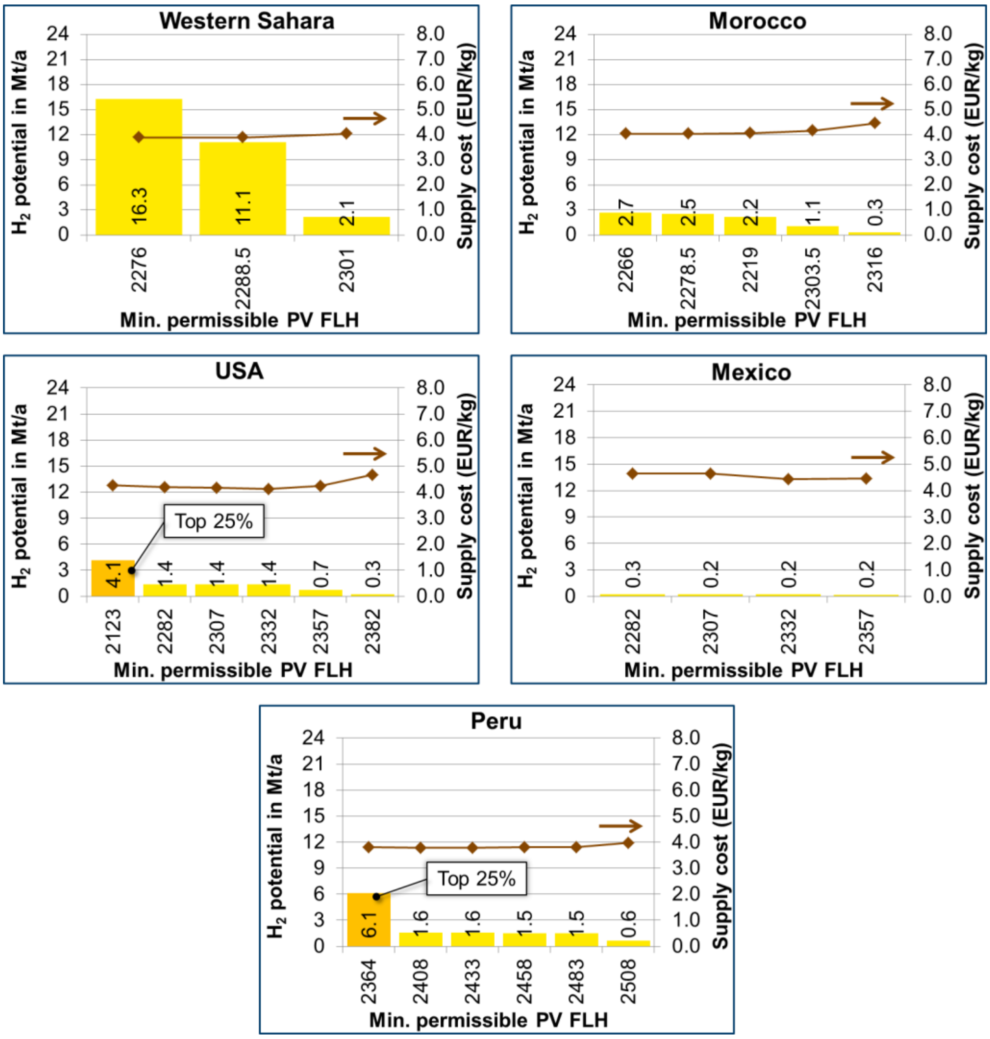

Figure 3-5. Hydrogen supply and cost curves for supply in sunny preferential regions with low potential. Supply quantities in megatons (the bar charts show the supply quantities, while the line charts show the associated supply costs without subsequent ship transport).

3.2 Cost-optimized hydrogen allocation results

In the Reference scenario, the previously determined global hydrogen demand of 365.2 Mt_{H2}/a is covered by a total of nine windy and four sunny regions. Figure 3-6 shows the international hydrogen flows from these to the seven demand regions. The import quantities of the demand regions are given, which in total correspond to the respective annual demand displayed in Figure 2-5. The distribution of these flows is based on the spatial resolution selected in the previous section.

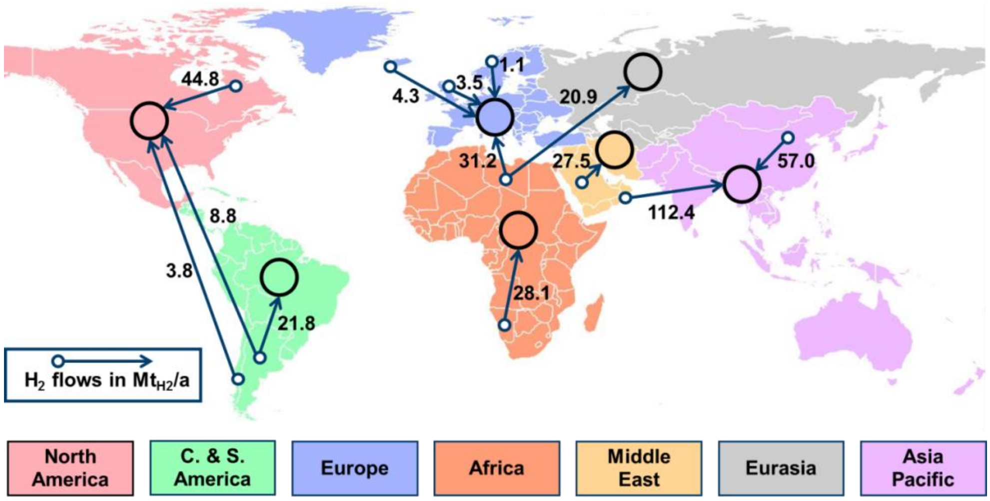

Figure 3-6. Total cost-optimal hydrogen allocation to meet global demand in the Reference Scenario (own calculation), with regional classification according to the IEA [35].

The majority of North America's hydrogen requirements are met by the windy Canadian regions of Québec and Newfoundland. This is due, on the one hand, to the large supply from these areas and, on the other hand, to low transport costs due to the short distances. The remaining 22% of the hydrogen comes from the South American regions in Chile and Patagonia. Slightly higher transport costs are accepted here, as the provision costs for hydrogen from wind energy are particularly low here.

Due to Patagonia's comparatively large potential, South America can fully supply itself with wind energy-based hydrogen. Africa and the Middle East are also self-sufficient, with Namibia and Saudi Arabia supplying the necessary quantities of solar-based hydrogen. In this scenario, Eurasia's cost-optimized supply of hydrogen from Libya is achieved by importing it.

In Europe, the supply of hydrogen is somewhat more diversified, with about 22% of European demand being covered by wind-generated power in Northern Europe. This includes all German demand, as the oversea distances from Iceland, Norway and the British Isles to the northern coast of Germany are comparatively short. The remaining European demand is covered by imports from Libya via the Mediterranean.

The entire Asia Pacific region is served by two sources. Initially, the wind potential of Inner Mongolia will be used for a large part of China's supply. Approximately 66% of total Asian Pacific demand will be met by Oman, due to its geographically-favorable location and the almost constant and comparatively favorable supply costs, whereby the entire potential determined (degree of expansion of 50%) is used. As the provision costs of Oman do not show any significant dependence on the degree of development and oversea transport costs to the Asia Pacific region are comparatively low, full exploitation of the potential is particularly advantageous here.

Overall, the Reference scenario features a spatially more regionalized supply structure. There is no hydrogen exchange between the American continents and other parts of the world. Although Europe and Eurasia import a large part of their hydrogen demand from nearby Libya, African demand is met intra-continentally. The situation is similar in the Middle East, which exports a considerable amount of hydrogen to Asia Pacific, but otherwise supplies itself. Although windy regions such as Patagonia or Chile achieve the lowest supply costs of all regions in the cost-optimized degree of wind energy expansion, the convex structure of the cost functions and the large distances to regions such as Europe or Asia Pacific prevent corresponding hydrogen flows. While almost all windy regions are part of the optimization solution, only four of the 15 regions with high solar irradiation export hydrogen. These regions have comparatively low supply costs on the one hand and are geographically favorable on the other hand. However, other sunny regions such as Peru and Chile are not able to assert themselves due to their geographical locations and the nearby windy region of Patagonia, despite comparably low supply costs.

With reduced world demand for hydrogen according to the "Low" scenario, the allocation structure, shown in Figure 3-7, results. Compared to the Reference Scenario, the structure changes only slightly towards greater regionalization. Patagonia's wind potential is no longer used to partially supply North America, but to supply Africa. Thus, wind-based hydrogen from Patagonia replaces Namibia's solar-based hydrogen. The use of North European wind potential remains unchanged compared to the Reference scenario. The reduction in demand is merely followed by a reduction in Libyan hydrogen imports. While the number of wind-rich regions considered remains constant, Saudi Arabia falls out of the solution due to higher supply costs compared to Oman. Accordingly, Asia Pacific will continue to be supplied with hydrogen produced with the wind energy of Inner Mongolia and solar energy of Oman. It can therefore be concluded that limiting the degree of expansion in Oman to 50% in the Reference scenario will lead to Saudi Arabia's inclusion in the solution. As soon as the potential from Oman is no longer fully exploited in Asia Pacific, enough hydrogen will remain to supply the Middle East.

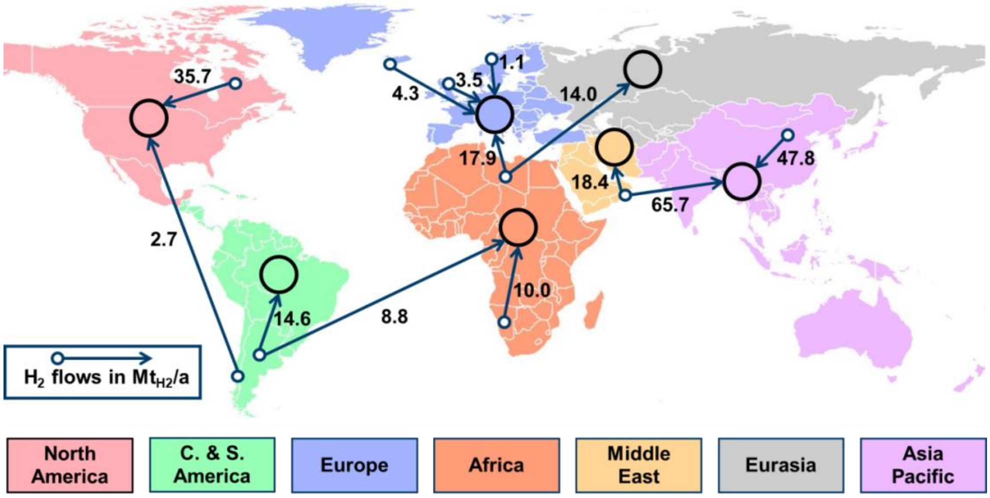

Figure 3-7. Total cost-optimal hydrogen allocation to cover global demand in the "Low" scenario (own calculation), with regional classification according to the IEA [35].

Figure 3-8 shows the cost-optimal hydrogen distribution in the "High" scenario. The increase in demand in North America is compensated by hydrogen from Iceland, in addition to an increase in import volumes from Canada and South America. In Europe, the import then shifts slightly from Northern European regions to hydrogen originating in Libya. The aforementioned effect of the full use of potential in Oman, already observed in the Reference Scenario, reoccurs in this case. The costs of supplying China with its own wind-based hydrogen exceed those of importing it from Oman. At the same time, the potential of Oman is not sufficient for Asian Pacific demand. Hydrogen is imported from Saudi Arabia, Australia and, to a small extent, British Columbia.

Apart from the negligible import of hydrogen from Canada to Asia Pacific, a regionalized supply structure is evident, even with high world demand. Compared to the Reference scenario, new supply sources are only required for North America and Asia Pacific. Thus, hydrogen is exported from all windy and from 5 of 15 sunny regions. The lack of exploitation of the solar potential in the other North African regions and the higher-lying South American regions around the Atacama Desert is particularly noteworthy. The reasons for this are the relatively small differences in the constant cost curves in North Africa and the geographically-unfavorable location of Peru and Chile.

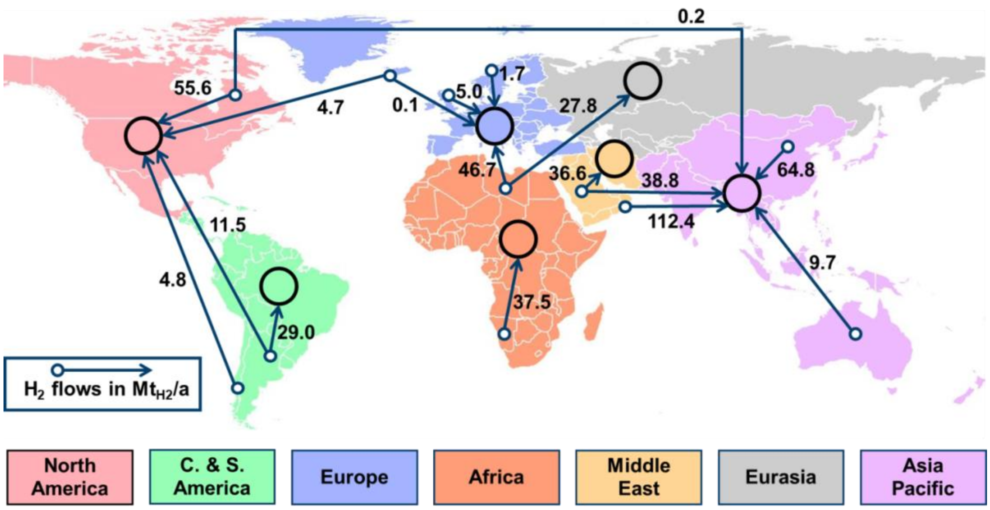

Figure 3-8. Total cost-optimal hydrogen allocation to cover global demand in the "High" scenario (own calculation), with a regional classification according to IEA [35].

The import quantities, analyzed previously, result from hydrogen distribution with the lowest absolute total costs. These are calculated as the product of export volumes and specific supply costs as well as transport costs. The export costs resulting in the respective cost optimum of the three demand scenarios are shown in Figure 3-9, together with the corresponding export quantities of the producing regions. The windy regions are highlighted in blue in the figure, the sunny ones in yellow. Due to the demand for hydrogen for ship transport, the sum of the supply quantities in the respective scenarios is slightly higher than the total global demand.

The supply costs of the wind-rich regions are very close to the respective cost minimum in all demand scenarios. Patagonia and Chile, for example, export between 3.00 and 3.10 EUR/kg_{H2} or 3.05 and 3.15 EUR/kg_{H2} at the harbor depending on the scenario.

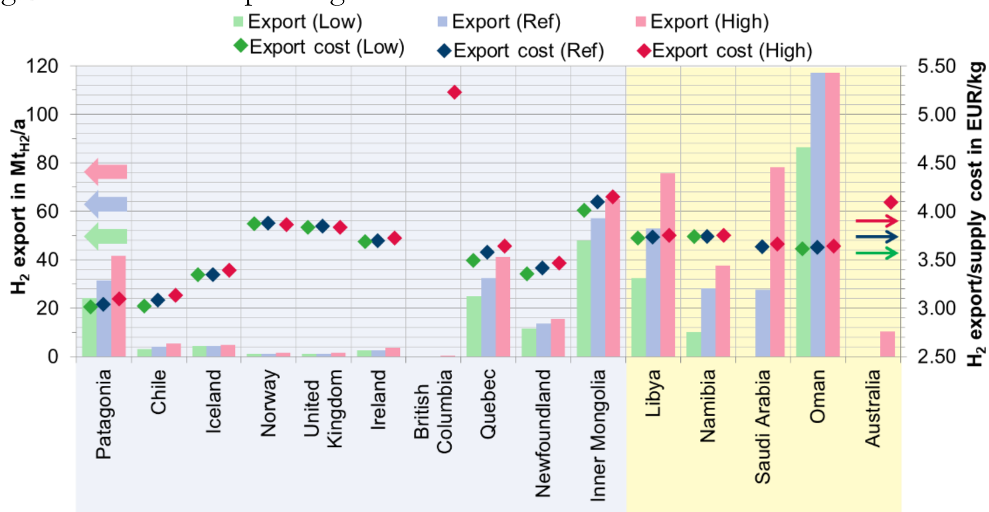

Figure 3-9. Export volumes and costs by producer region and scenarios.

In the optimal European regions for wind energy, export volumes and costs remain relatively constant and independent of the respective demand scenario. On the other hand, Canadian regions experience a slight increase in costs as global demand increases. This is due to the increase in expansion levels required to meet North American hydrogen demand and the associated higher LCOE in Québec and Newfoundland. The same effect can be seen in relation to the increasing Chinese demand in Inner Mongolia. The export of 0.2 Mt_{H2}/a from British Columbia to Japan in the "High" scenario is associated with fairly high costs due to the low degree of expansion of wind energy, but at the same time is to be seen more as an outlier due to a negligible global cost advantage in the optimization model.

Depending on the demand scenarios, the growth rates of export volumes from sunny regions are much more pronounced than in the case of windy regions. Due to the almost constant specific supply costs, the export costs in Libya, Namibia, Saudi Arabia and Oman hardly noticeably change. The export of Australian hydrogen to Japan is due to the 50% PV expansion limit in Oman already achieved in the Reference Scenario. The export costs there are much lower than in Australia. At the same time, the transport costs between Saudi Arabia and Japan are just high enough so that Australia, which is closer to Japan, has a slight cost advantage.

Figure 3-10 shows the import volumes of the demand regions and the corresponding import costs depending on the three demand scenarios. In most regions, import costs increase slightly as demand does. The cost level of supply in North America and the USA is roughly on par with the supply costs in Québec and Newfoundland, as most of the hydrogen is imported from these regions and there are no or only minor overseas transport costs. However, the effect of the increasing expansion of Canadian wind power is reflected in the rising import costs in North America in general and the USA in particular.

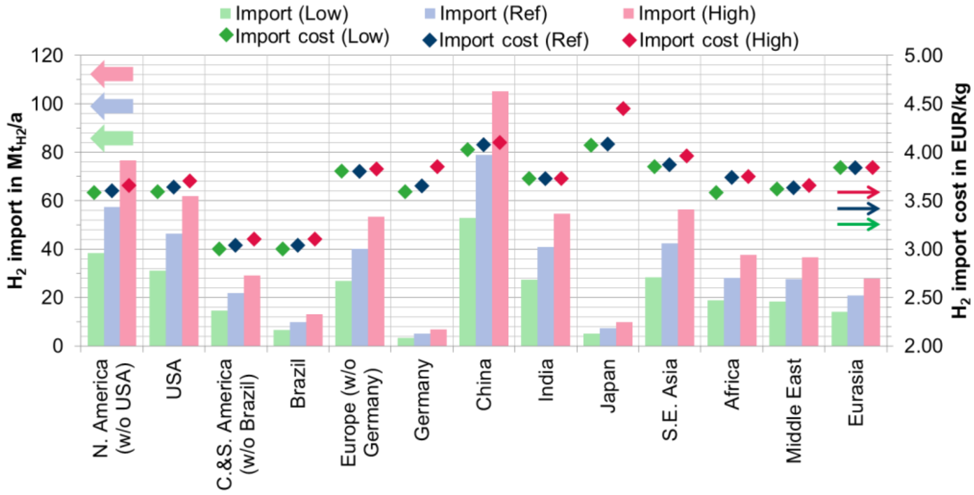

Figure 3-10. Import volumes and costs by demand region and scenarios; regional classification according to the IEA [35].

As no overseas transport is required to supply South America with wind energy-based hydrogen from Patagonia and Chile, the export and import costs of the regions there are the same.

The import costs for supplying Europe, with the exception of Germany and Eurasia, remain fairly similar due to the almost constant supply costs of Libya. In contrast, import costs in Germany, which are still below the costs of Europe in the Reference and "Low" Scenarios, rise to the same level. This is due to the allocation change from Icelandic hydrogen to the North American continent and thus to the increased supply of Germany by the British Isles and Norway.

The costs of supplying China with wind energy are amongst the highest of the three demand scenarios, at over 4.00 EUR/kg_{H2}. Furthermore, these are characterized by a slight increase, similar to that for North America. India benefits from the relatively short transport distance to Oman and, accordingly, shows no change in costs across all scenarios due to the constant supply costs there. The increased import costs for Japan in the "high" scenario result from the bottleneck in Oman described above and the higher export costs for Australia. Without exogenous limitation of the PV expansion rate in Oman, it can be assumed that Japanese import costs will remain slightly above 4.00 EUR/kg_{H2}, even with increased demand in the Reference scenario.

Overall, import costs vary globally between around 3.00 EUR/kg_{H2} (Central and South America, “Low” scenario) and 4.50 EUR/kg_{H2} (Japan, “High” scenario). Most regions are between 3.50 and 4.00 EUR/kg_{H2}, regardless of total global demand. Although the global demand for hydrogen in the "High" scenario is about twice as high as that in the "Low" scenario, import costs change only slightly. This is due, on the one hand, to the oversupply of hydrogen of 1,590 Mt_{H2}/a compared to the demand between 250 and 500 Mt_{H2}/a, and on the other hand to the cost-stable supply in sunny regions.

4 Discussion

A comparison of selected import cost results from this study with values from the literature is shown in Figure 4-1. Kamiya et al. [14] calculate import costs of the equivalent of 2.93 EUR/kg$_{H2}$ for hydrogen imports from Australia based on lignite with CCS. In the context of this study, the hydrogen allocation results in import costs for Japan of 4.00 EUR/kg$_{H2}$ in the Reference scenario. This difference in the results is due to different supply costs as only renewable energy based hydrogen is considered, on the one hand, and higher transport costs on the other hand. In the Reference scenario, hydrogen is imported from Oman at supply costs of about 3.55 EUR/kg$_{H2}$. To this must be added the average transport costs of a good 0.45 EUR/kg$_{H2}$. These are higher than the specific transport costs from Australia to Japan of about 0.30 EUR/kg$_{H2}$. As the supply of PV-based hydrogen in Australia already incurs costs of around 4.00 EUR/kg$_{H2}$, it is not economically competitive exporting to Japan. In a direct comparison of the two import options of lignite-based hydrogen from Australia and renewable hydrogen from Oman, there is a cost advantage for the first option, but under the premise of emission-free hydrogen supply the second option is preferable.

On the basis of hydrogen supply costs in Patagonia of about 4.67 EUR/kg$_{H2}$, Watanabe et al. [17] calculate import costs of 6.10 EUR/kg$_{H2}$ in Japan. Although the cost contributions of the domestic infrastructure in Patagonia in this study hardly differ from those stated by Watanabe et al., their import costs are almost 58% higher due to high generation costs resulting from higher invest costs and lower full-load hours.

The European import costs of liquid hydrogen from Africa cited in the work of Teichmann et al. [16] are 5.37 EUR/kg$_{H2}$ and thus significantly higher than the results reported in this study. For the import of PV-based hydrogen from Libya to Europe, costs of 3.94 EUR/kg$_{H2}$ are calculated in this analysis. In addition to the supply costs for hydrogen in Africa of 4.33 EUR/kg$_{H2}$ determined by Teichmann et al., this is due in particular to the significantly higher specific overseas transport costs of over 1.00 EUR/kg$_{H2}$.

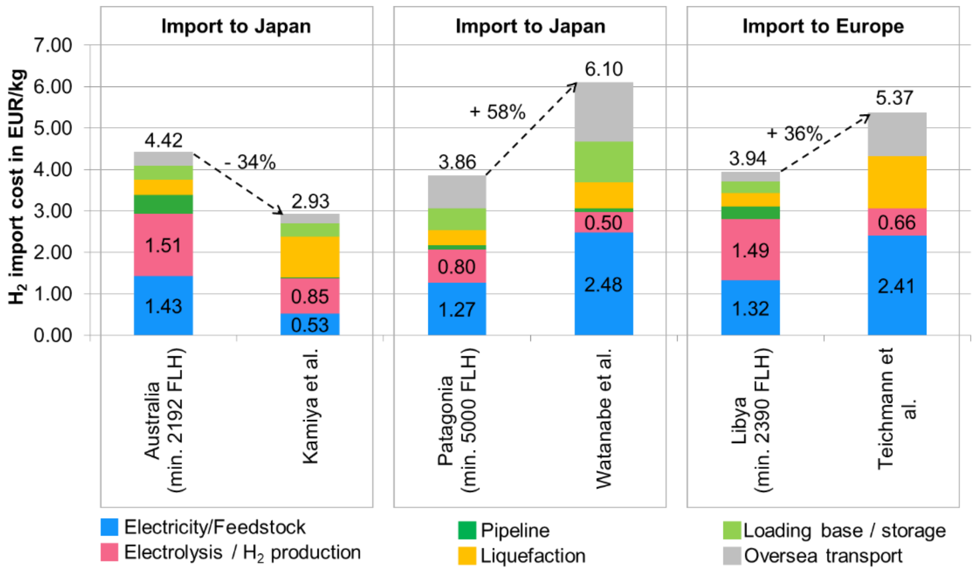

Figure 4-1. Classification of selected results in the current study scenario. Literature values based on Kamiya et al. [14], Watanabe et al. [17] and Teichmann et al. [16].

Fasihi et al. [15] evaluate the import to Europe of synthetic diesel on the basis of hydrogen produced in Patagonia from renewable sources. The authors indicate import costs of 75.54 EUR/MWh$_{Diesel}$. In comparison, the import costs for hydrogen in the Reference scenario of this study are in the range of 3.80 EUR/kg$_{H2}$ and 114 EUR/MWh$_{H2}$. This cost difference is, on the one hand, due to the domestic transport and storage infrastructure not considered by Fasihi et al. and, on the other, due to more favorable cost and efficiency assumptions regarding electrolysis. Considering the use of both energy sources for the fuel supply of passenger cars and also assuming a fuel demand of 0.7 kg$_{H2}$ per 100 km for a fuel cell vehicle and 3.3 l$_{Diesel}$ per 100 km [18] for a conventional diesel vehicle, the route-specific energy demands result in 23.3 kWh_{H2} per 100 km for the fuel cell vehicle and 47 kWh_{Diesel} per 100 km for the diesel vehicle. This results in distance-specific costs per 100 km of 2.66 EUR for the fuel cell vehicle and 3.55 EUR for the diesel vehicle. Accordingly, there is a clear cost advantage for of imported hydrogen compared to imported synthetic fuels. However, this assessment does not include the domestic infrastructure in the importing country. For a complete assessment, corresponding cost contributions must be additionally taken into account [13].

In a study by Fraunhofer IWES [4], the authors provide import costs of the equivalent of 3.62 - 3.87 EUR/kg_{H2} and a primary energy demand range of 72 - 66 kWh/kg_{H2} for the import of liquid hydrogen from renewable energy-optimal regions to Germany in 2050. Despite the lack of spatial resolution and the significantly shorter time span of considered historical weather years, this study is very close to the results reported here, which is due to the similar cost assumptions for wind turbines, PV modules and electrolysis, as these plants account for the major cost proportions for the hydrogen supply.

The analysis of a cost-optimal allocation of the hydrogen supply shows the influence of the different characteristics of the supply cost curves in windy and sunny regions. Due to the opposite effect of decreasing LCOE and increasing specific infrastructure costs with decreasing wind capacity expansion, the supply cost curves (cf. Figure 3-1 and Figure 3-2) show a comparatively pronounced minimum. In the global cost optimum, export volumes in wind-rich regions are close to these respective cost curve minima. It follows that, depending on the global demand for hydrogen, cost-optimal levels of wind energy expansion exist in the preferential regions. Hence, a diversified use of the global supply of wind-based hydrogen for cost-efficient hydrogen supply makes sense. Due to the fact that, in sunny regions, the supply costs are almost independent of the degree of expansion, the export of PV-based hydrogen is concentrated in a few optimal regions with low supply cost levels. In particular, the regions of Oman and Saudi Arabia in the Middle East and Libya in the North of Africa should be mentioned here, as they are suitable for supplying the large demand regions of Europe and Asia due to their favorable geographical locations. Against the background of the resulting dependency on a few sun-rich preferential regions, especially in the Middle East and North Africa, socio-political stability must be taken into account in order to avoid the effects of potential supply crises and conflicts. As this study considers the exclusive use of generated electricity for hydrogen supply, no use of comparatively cheap renewable energy for covering the respective domestic electricity demand is intended. With regard to the initially-formulated goal of a sustainable energy supply, exclusive energy export is to be discussed in comparison to prioritizing the coverage of domestic demand. Thus, the issue of the social acceptance of a massive RES expansion, which is not part of the present study, must be taken into account.

5 Summary and Conclusion

Based on the hydrogen supply potential from wind and solar energy and an estimate of future global hydrogen demand, this work presents the cost-optimal allocation results within the framework of a global hydrogen infrastructure. For three demand scenarios, the respective international hydrogen flows in the global cost optimum and the associated export and import costs are determined. Depending on the scenario, global hydrogen demand is 365.2 Mt_{H2}/a (Reference), 244.5 Mt_{H2}/a (Low) and 486.9 Mt_{H2}/a (High). Due to the significant cost factor of overseas transport, a regionalized supply structure results. Renewable hydrogen is sourced from almost all windy, but only from a few sunny, regions. The associated import costs are between 3.00 and 4.50 EUR/kg_{H2} and comparatively independent of the respective demand scenario. The energy efficiency of the individual supply paths is varying from 43 to 56%. The primary results of the analysis show:

- The international hydrogen supply of the regions exceeds the expected global hydrogen demand by a factor of three, even in the highest demand scenario.
- Regardless of the demand scenario, a regionalized supply structure results. This is characterized by a high degree of self-supply or supply from the immediate vicinity.
- Stronger adjustments of global demand influence the import costs only to a minor extent, as the export from windy regions is close to the cost minimum and the export costs in sunny regions are somewhat independent of export quantity.

- A reduction in the global supply mainly influences the import costs in Germany and Asia Pacific, whereas Japan benefits from a supply reduction, as more cheap wind-based hydrogen is exported to Asia Pacific.

The following central conclusions can be derived from this analysis of a worldwide infrastructure for hydrogen supply based on renewable energy:

- Due to the cost-optimal expansion of wind energy, a diversified and limited hydrogen supply from windy regions is economically reasonable. In contrast, a massive expansion in a few, geographically favorably located, sunny preferential regions is possible.
- The largest cost contributions within the hydrogen infrastructure are made by electricity production, electrolysis and oversea transport. Due to the high specific oversea transport costs, a regionalized supply structure will result, similar to international natural gas trading. These costs are significantly influenced by the following:
    - The full-load hours of electricity generation and hydrogen production;
    - The investment costs of RES plants and electrolysis;
    - The distances between hydrogen sources and sinks;
    - The specific costs of oversea transport.

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