Clean Hydrogen: Important Aspects of Production, International Cooperation, and Certification

Part 2 of the GJETC Study on a Hydrogen Society

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Tokyo / Wuppertal, June 2020

Imprint

Publisher

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This GJETC Study received financial support from the German Federal Environmental Foundation (DBU), the Stiftung Mercator Foundation, Essen, Germany, and the Ministry of Economy, Trade and Industry (METI).

sponsored by

DBU Deutsche Bundesstiftung Umwelt

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Content

1. Introduction

Clean hydrogen with low greenhouse gas emissions from production to use could be an energy carrier that plays an important role in decarbonising our economies and societies. This study by the GJETC has, therefore, the metaphore "hydrogen society" in its title, which is quite popular in Japan, although less so in Germany. Clean hydrogen can be green or blue hydrogen or other forms of hydrogen (see box on key terminology at the end of this introduction).

During the Japanese fiscal year 2018, a first study co-funded by the ministries of economic affairs in Germany (BMWi) and Japan (METI) analyzed the current status of hydrogen deplyoment and policies as well as the role of hydrogen in future energy systems in both countries, and hydrogen supply chains[1].

It showed, i.a, that there is the need to

(a) bring down costs and improve technologies regarding (1) renewable power generation (for green hydrogen), (2) electrolysis (for green hydrogen), (3) CO_2 capture transport and storage (for blue hydrogen), (4) long-distance hydrogen transport, (5) transformation of natural gas distribution infrastructures into hydrogen-ready infrastructures and finally (6) hydrogen ready-application technologies;

(b) explore an international governance scheme that safeguards GHG standards and broader sustainability for H_2 supplies in order to advance and take into account points (1) to (4) above. These joint efforts should also aim to safeguard investment security for overseas investments in green or blue hydrogen and to safeguard a competitive H_2 market especially in the ramp-up phase.

In particular, there is the need to explore technical, safety, and environmental / sustainability standards and certfication for green and blue hydrogen as soon as possible to define 'clean' hydrogen in a transparent and comparable way, which would stimulate trust in internationally traded clean hydrogen.

This second part of the GJETC study on the "hydrogen society" therefore mainly aims to deepen the analysis on potential criteria for clean hydrogen that is sustainable and low-carbon as well as other aspects of a possible international certification scheme.

Starting from a summary of the literature on potentials and costs for green and blue hydrogen as well as general considerations for what could be criteria for a certification

[1] Jensterle et al. (2019). *The role of clean hydrogen in the future energy systems of Japan and Germany.*

scheme for clean hydrogen in chapter 2, the study sets out to assess blue and green hydrogen with respect to these criteria in chapters 3 and 4. In order to inform this assessment, it also addresses crucial aspects of clean hydrogen production, which are CCS technology and potential for blue hydrogen and the additionality of the electricity from renewable energies used for electrolysis of green hydrogen. Chapter 4.4 furthermore discusses potential sources of CO_2 to convert green hydrogen further to other synthetic fuels.

Building on the findings from chapters 3 and 4, the study concludes on important aspects of a possible international certification scheme for clean hydrogen in chapter 5. Chapter 6 discusses the potential for international cooperation on clean hydrogen, and the roles Germany and Japan could play in it.

Finally, on a separate aspect, chapter 7 holds a brief analysis of the potential applications of hydrogen in the industry sector.

Key terminology as used in this study[2]

Green hydrogen *is used to designate low-carbon hydrogen produced from renewable energy sources such as renewable power (via water electrolysis) or biomass.* ***Blue hydrogen*** *is used to designate low-carbon hydrogen, produced from non-renewable energy sources, typically from natural gas and brown coal, with use of carbon capture and storage (CCS) technology.* ***Clean hydrogen*** *is used in this study as an umbrella term for green and blue hydrogen.*[3] ***Grey hydrogen*** *is used to designate hydrogen produced from non-renewable energy sources without CCS technology.*

As for the differentiation between hydrogen, and hydrogen based fuels in this study: While hydrogen is indeed a form of a synthetic fuel, for greater clarity in this study, we use the terms ***hydrogen*** *and* ***other synthetic fuels*** *separately;* ***hydrogen*** *is used to designate hydrogen in molecular form (H_2), while the term* ***other synthetic fuels*** *(or* ***non-hydrogen synthetic fuels****) is used for synthetic fuels other than hydrogen in molecular form.* ***Power-to-X (PtX)*** *is used in this study in reference to the entire process of using electricity to produce hydrogen and hydrogen-based synthetic fuels.*[4]

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2 based on Jensterle et al. (2019). op.cit.

3 The level of "cleanliness" of course depends on the lifecycle environmental impacts. See also chapters 2, 3, and 4 of this study.

4 The term PtX also includes power-to-heat (PtH), which is however not relevant for the present study and is not referred to when the term PtX is used.

2. Green and blue hydrogen, and criteria for certification of clean hydrogen

2.1 Hydrogen potential, GHG emissions, and costs today and in the future

In the last few years, many studies have examined the potentials and costs of hydrogen for reducing GHG emissions. This chapter serves to briefly summarize important findings from the study informing the GJETC in the first year[5] and other sources.

(1) Potential

Both in Germany and Japan, most of the hydrogen used in the industry sector at present is produced from fossil fuels without CCS/CCU (grey hydrogen). Although Germany is one of the largest countries in terms of sub-bituminous and lignite reserves (36,100 mil. tonnes[6]), given public resistance to CCS in this country, blue hydrogen production is considered difficult in Germany. Also, because Japan is not endowed with fossil fuel reserves, it is unlikely for Japan to produce blue hydrogen domestically.

Electrolysis using renewable power is identified as an important means for hydrogen supply in the future in both countries. Germany is a leader in green hydrogen production pilot projects (Power-to-Gas (PtG) projects), and a few projects with larger systems (100MW) are also announced. PtG pilot projects are also conducted in Japan although it is at smaller scale compared with Germany.

Since renewable power generation cost is still high in Japan, importing clean hydrogen is considered more economic than domestically produced green hydrogen in the short- to medium-term. Germany may also need to import green hydrogen from overseas to achieve the country's GHG emission reduction target[7].

Our previous study identified countries with high potential of blue hydrogen supply and economic green hydrogen supply as shown in Figure 1.

[5] Jensterle et al. (2019). *op.cit.*

[6] BP (2019), *BP Statistical Review of World Energy 2019*.

[7] Jensterle et al. (2019). *op.cit*.

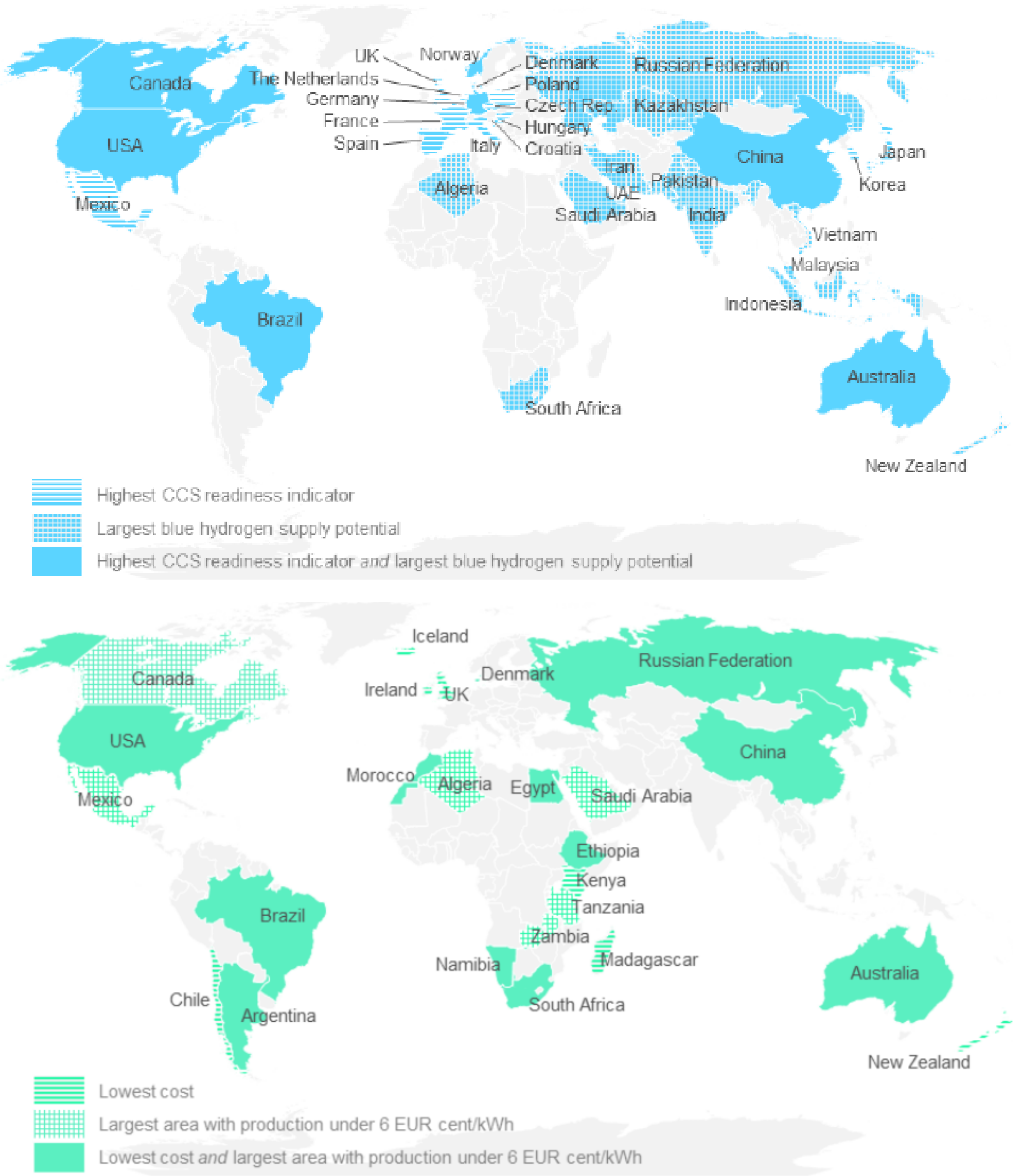

Figure 1: Blue hydrogen (above) and green hydrogen (below) supply potential globally

Source: Jensterle et al. (2019). *op.cit.*

(2) GHG emissions

The GHG emissions originating from hydrogen production are different, depending on technologies (Figure 2).[8] Hydrogen produced from fossil fuels does not necessarily record the highest CO_2 intensity. Rather, using electricity from natural gas or coal for electrolysis could result in higher CO_2 intensity than grey or blue hydrogen due to the conversion

[8] International Energy Agency (IEA) (2019). *The Future of Hydrogen.* p.53

losses during electricity generation. For grey hydrogen, the carbon intensity of hydrogen from natural gas is less than half of that of coal. If CCUS is applied, hydrogen produced from natural gas with CCUS presents the least CO_2 intensity next to hydrogen produced from renewable or nuclear electicity, and the higher the capture rate of CCUS is, the lower will be the CO_2 intensity of blue hydrogen.

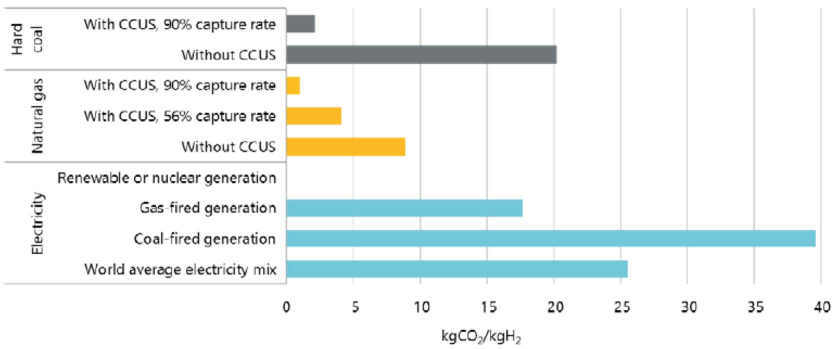

Figure 2: CO_2 intensity of hydrogen production

Source: IEA (2019); *op.cit.*

Life-cycle assessment of the GHG emissions with regard to hydrogen production, supply, and use reminds of the importance to pay attention to factors other than hydrogen production technology. Not only how the hydrogen is produced but also whether the hydrogen is produced on-site or off-site leads to different CO_2 emission intensity, because CO_2 is emitted during hydrogen delivery, storage, and filling (Figure). When the same production technology is applied, off-site hydrogen production process adds more CO_2 intensity than on-site cases. Also, different hydrogen transport methods result in different CO_2 emissions intensity. Analysis suggests that compressed hydrogen transport is less carbon intensive compared with liquefied hydrogen transport in Japan.

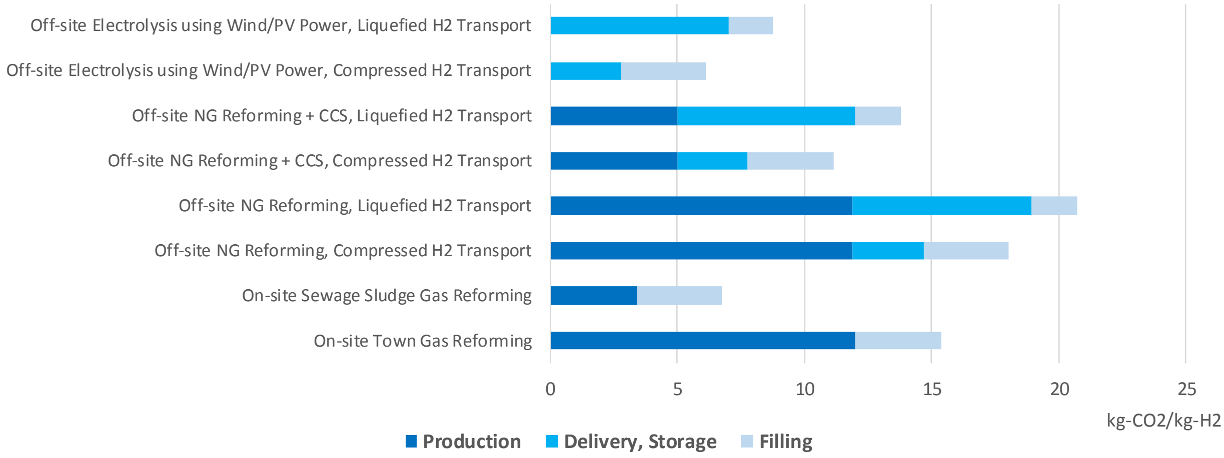

Figure 3: CO_2 intensity of hydrogen Production, Delivery&Storage, and Filling in Japan

Note: NG=Natural Gas

Source: Depicted by IEEJ using data input from CO_2 free Hydrogen Committee (2018) (data supplied by Mizuho Information and Research Institute)[9]

In the 1st year study[10] for the GJETC, similar results, integrating emissions from hydrogen production, storage, transformation, transport, and filling/distribution for the situation in Europe were presented (Figure 4).

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[9] CO_2 free Hydrogen Committee, organized by the Ministry of Economy, Trade and Industry (METI), Government of Japan (2018). *Report on CO_2 free Hydrogen* (*in Japanese*). Available at: https://www.meti.go.jp/report/whitepaper/data/pdf/20170307001_01.pdf

[10] Jensterle et al. (2019). *op.cit.*

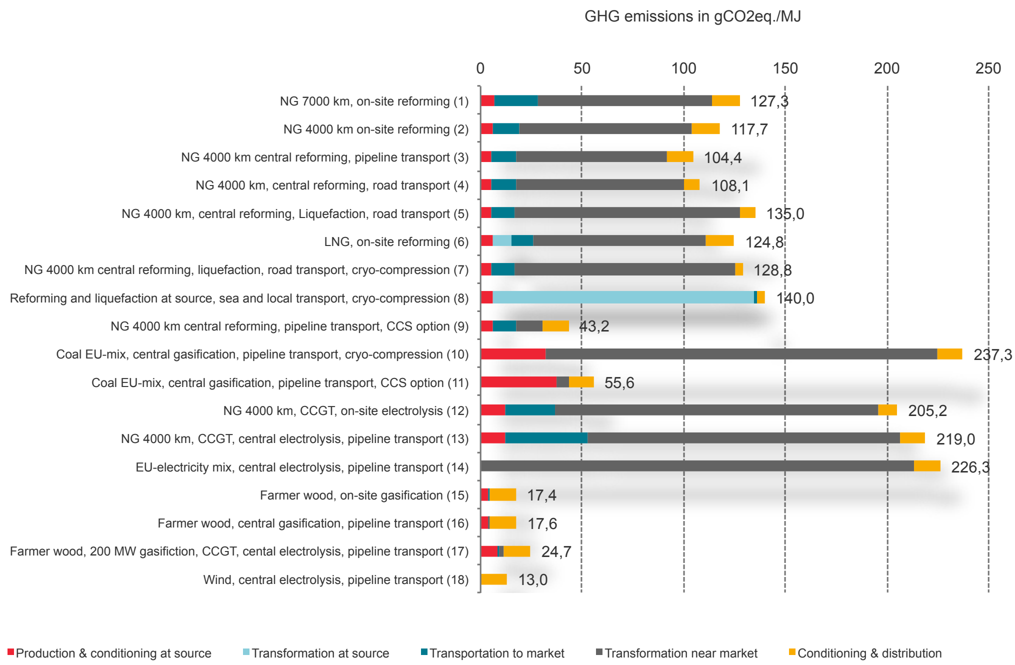

Figure 4: CO_2 intensity of hydrogen supply options

Source: Jensterle et al. (2019). *op.cit.*

Evaluation of the CO_2 intensity of hydrogen delivery and storage is more complicated. This is because carbon intensity that applies the same hydrogen delivery and storage method may vary from one case to another. For example, hydrogen liquefication is highly electricity intensive. The process using electricity supplied from renewable energy would cause little CO_2 emission. However, if electricity supplied from the grid is utilized, the CO_2 emission would be affected by the carbon intensity of the grid power.

(3) Costs today/in the future

Hydrogen production and supply costs are explained by costs of fossil fuels (coal or natural gas)/ renewable electricity, plant costs (steam reforming and CCUS, electrolysers, storage, transportation), operation costs, and other factors. Whether CCS is equipped or not makes a cost difference between blue hydrogen and grey hydrogen, that is, blue hydrogen is more expensive than grey hydrogen since CCS boosts the hydrogen production costs. For green hydrogen, the electrolyser plays a critical part in production costs because the electrolyser is still costly as a capital expenditure and, therefore, the electrolyser requires a high capacity factor to make economic sense. Hence, the cost of green hydrogen would change, depending on how much the cost of electrolyser will be reduced by technology advancement and how long the electrolyser could work. The

IRENA's study suggests that green hydrogen can be competitive with blue hydrogen even today, but only if low-cost wind power (USD23/MWh) presently available and a low-cost electrolyser of USD200/kW, which is seen in very limited projects today, are applied (Figure 5:).[11]

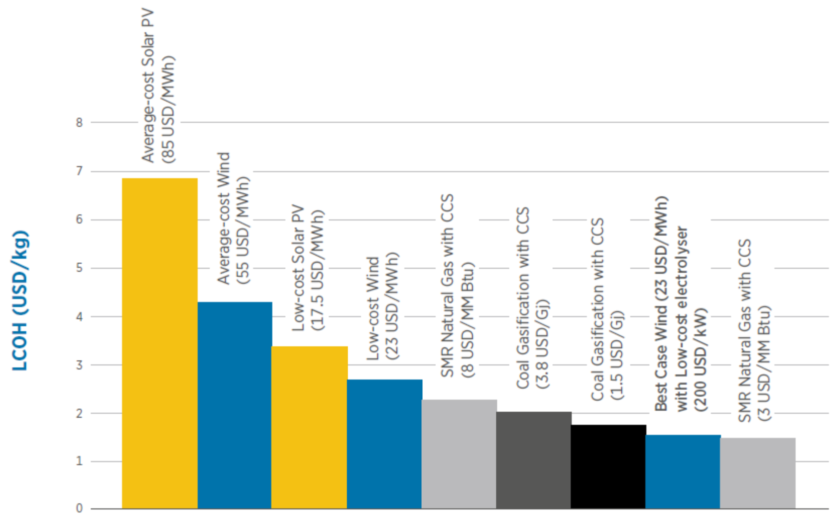

Figure 5: Hydrogen production costs from renewable and fossil fuels today

Source: IRENA (2019). *op.cit.*

It is likely that the production costs of green hydrogen will still be more expensive in most cases than those of blue hydrogen and grey hydrogen in 2030. The IEA study shows that grey hydrogen using natural gas is estimated to be the cheapest option mainly because natural gas will remain most cost competitive (Figure 6).[12]

However, green hydrogen is estimated to become cheaper than hydrogen produced through electrolysis from grid electricity already by 2030, although the analysis of the latter apparently did not include costs from a CO_2 price.

[11] IRENA (2019): *Hydrogen: A renewable energy perspective.* Pp. 28-29

[12] IEA (2019): *The Future of Hydrogen.* Pp. 52-53.

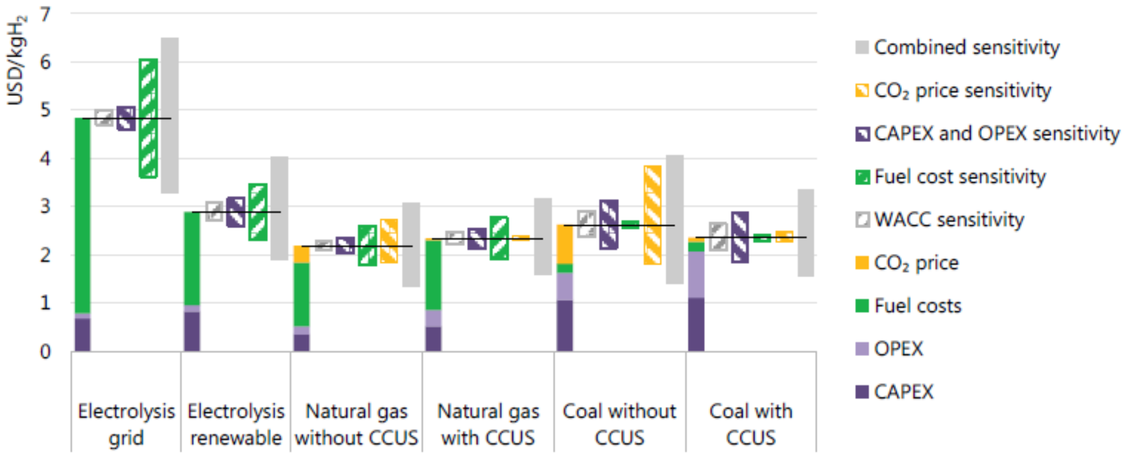

Figure 6: Hydrogen production cost in 2030 (estimated by IEA)

Source: IEA (2019); op.cit.

Japan clearly sets a target of hydrogen supply costs including production, transport, and storage costs in its Basic Hydrogen Strategy (2017). Japan aims to reduce them to JPY30 (€0.23)/Nm^3 (USD3.0/ kgH_2) by 2030 and to lower further to JPY20 (€0.15)/Nm^3 (USD2.0/ kgH_2) afterwards in order to make hydrogen competitive to the same level of imported fossil fuels like LNG. [13]

In the case of Japan, imports of green hydrogen may be more reasonable than hydrogen produced domestically. For Japan's industrial sector, the IEA estimated that importing electrolytic hydrogen from Australia at USD5.5/kgH_2 would be cheaper than domestic production at USD6.5/kgH_2. For the EU, however, the same study estimates similar costs for both imported and domestic electrolytic hydrogen of USD4.0/kgH_2 to USD 4.5/kgH_2. [14]

As an example for comparison, Japan's import LNG price is $10/MMBtu (2019 average), which is equivalent to USD1.4/kgH_2. This is still much cheaper than today's green or blue hydrogen production cost, but Japan's long-term cost target of USD2.0/ kgH_2 is not much above this current equivalent LNG price.

[13] Ministerial Council on Renewable Energy, Hydrogen and Related Issues, Government of Japan (2017): *Basic Hydrogen Strategy*.
Yearly average exchange rate of 2018: €1=JPY130.35 (Bank of Japan)

[14] IEA (2019). *op.cit.*, p.82.

2.2 Criteria for sustainable and low-carbon hydrogen

The previous section shows: If hydrogen is to play a major role in future energy systems, it is evident that the use of hydrogen must have a *positive climate impact* and only *sustainably produced* hydrogen can be used to substitute conventional fossil fuels. Paths of developments involving unsustainable production processes or creating lock-in effects need to be avoided (as a warning example for potentially detrimental consequences regarding public acceptance, the introduction of crop-based biofuels in the EU with its lacking or unclear certification can be taken[15]). Therefore, it is essential to establish appropriate sustainability criteria with concrete and specific indicators that can be integrated into international standards and certification. These should address *overall the CO_2 balance of hydrogen* in comparison to that of the fossil fuels replaced, based on lifecycle assessments that take into account upstream emissions of electricity and fuel production required for all production processes, including water desalination and land use, where required. The *development of sustainability criteria and the establishment of a respective certification scheme should be initiated in the near future*, before a large market for hydrogen develops.

Based on the sustainability criteria that Bracker (2017) and Agora Verkehrswende et al. (2018) have developed, Jensterle et al. (2019) identify the following key aspects.

GHG emission balance: A minimum threshold of GHG emission reduction needs to be defined that is achieved by using hydrogen instead of fossil fuels for the respective application. The threshold has to refer to the entire hydrogen production chain, both for green and blue hydrogen. A threshold of e.g. 70% would be in line with the threshold defined in the EU's Renewable Energy Directive for advanced biofuels to be renewable energy. In those cases, in which green or blue hydrogen simply replaces fossil fuels or grey hydrogen feedstocks without or with only a minor change in conversion efficiency, the comparison can be based on the hydrogen supply chain only. If the energy use technology changes too, as it is the case with fuel cells instead of internal combustion engines, hydrogen produced in a less 'clean' way may also achieve significant GHG reductions. It needs to be assessed how this can be considered in the indicator 'GHG emission balance' and hence in certification. This report contributes to such an assessment (see chapter 5.3).

For blue hydrogen: Sustainability of CC(U)S: It needs to be assessed, a) which share of the CO_2 from hydrogen production can be captured and what is the resulting GHG emissions factor of the blue hydrogen produced (see chapter 2.1 and Figure 7); and b) whether the

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[15] Kasten & Heinemann (2019), *Kein Selbstläufer: Klimaschutz und Nachhaltigkeit durch PtX*. p. 6-8.

storage or use of the CO_2 captured shows no risk of "leakage". In the case of storage, the questions are whether it is b1) long-term safe and sustainable in terms of other criteria that may be relevant, and b2) does not use up storage capacity that may be needed in the future for long-term stabilization of the climate, e.g. for storing unavoidable GHG emissions from industry processes or transport, or for net CO_2 removals from the atmosphere, e.g. through storage of CO_2 from biomass energy (BECCS) or direct air capture. In the case of CO_2 use, the question is b3) whether the CO_2 will ultimately be released to the atmosphere, and what would be the baseline emissions for that case, from a counterfactual alternative process and material than the one using the CO_2 from blue hydrogen production. While questions b1) and b2) are analyzed in chapter 3, a more general discussion on question b3) is included in chapter 4.4.

For green hydrogen: Electricity demand and additionality of renewables: It has to be ensured that the electricity for the *entire* hydrogen production process is generated from *additional* renewable energy capacities. In practice it has yet to be decided, how to *define the additionality* of renewables. This is an open question and needs to be discussed. This will be done in chapter 4. Among others, the following options for defining additionality are discussed in the literature and will be analysed:

- The most rigourous approach would be to only accept amounts of RES electricity generation as additional, which exceed the demand in a systemwide 100%+ RES situation as additional.
- However, it may also be justified to include RES electricity that is exceeding 100% of regional demand and cannot be transported to distant centres of demand (e.g. Patagonia, Argentina, in the future, or some regions in Northern Germany, where already today there are phases of the year, when RES electricity generation mainly from wind has to be curtailed, however not always in a 100% RES situation).
- Or should the criteria also allow for an economic/political link, e.g. for RES-E capacity purpose-built for electrolysis in a system distant from 100% RES-E share? This argument has been raised in the German RES support system with auctions for a maximum amount of capacity defined by the government. If the capacity defined and auctioned is increased by a certain amount for the purpose of providing electricity for electrolysis, can this then be seen as additional to the baseline policy? Or is it anyway urgently needed to accelerate decarbonisation of the electricity system itself?

  In such a situation, assessment and decision tools are also needed to ensure that using the best renewable power production sites for hydrogen intended for exports does not affect domestic decarbonisation efforts or costs particularly in developing/emerging countries.

Water usage: The production of green and blue hydrogen needs to ensure that it does not negatively affect the water supply in the respective regions. In arid regions, water supply will have to be covered by additional seawater desalination plants powered by RES-E. In non-arid regions, compliance with sustainable water management plans needs to be ensured.

Land use: The regional/local situation needs to be assessed in order to avoid land-use conflicts (e.g. with space for settlements, food production, nature reserves, other infrastructure). Hydrogen production and RES-E generation should be prohibited in nature protection areas or other regions with high environmental value.

Social and economic impact: The establishment of renewable energy and hydrogen production facilities and infrastructure must not negatively impact local communities. Instead, they should rather contribute to sustainable economic development and welfare in the respective regions. A share of the revenues should be used to fund regional development programs, and local actors should be involved in the planning procedures, in order to establish a fair partnership between importing and exporting regions. The social and economic context of hydrogen production should be monitored. As said above, it also needs to be ensured that using the best renewable power production sites for hydrogen intended for exports does not affect domestic decarbonisation efforts or costs particularly in developing/emerging countries.

Criteria in existing certification schemes and further development

Currently, a number of certification schemes exist which adress a part of the above-mentioned sustainability criteria. The definition of "clean" hydrogen and energy sources in the existing certification schemes[16] varies from green to blue hydrogen. CertifHy, Standard CMS 70 TÜV SÜD and Clean Energy Partnership or the California bill 1505 define thresholds for GHG emission reduction (of 30-75%), however, sometimes against conventionally produced hydrogen, and only sometimes against fossil fuels for the same use. Regarding the life cycle of the hydrogen production chain, however, almost all certification schemes only cover the production, except for the TÜV SÜD which also considers the energy use in transport. The question of the additionality of renewable electricity generation is only addressed by the Standards CMS70, TÜV SÜD and the Clean Energy Partnership (defining plants not to be older than e.g. 3 years or minimum shares

[16] CertifHy, Standard CMS 70 TÜV SÜD, Clean Energy Partnership (CEP), Aichi Prefecture, AFHYPAC, DECC, HRS, California bill 1505

of new renewables). Water demand, land use, and social impacts are considered in none of the existing certification schemes (see Figure 15 in the appendix).

A potential certification scheme for sustainable hydrogen

Jensterle et al. (2019) identify CertifHy, as the first Guarantee of Origins system developed and proposed for green and low-carbon hydrogen in Europe, to be a potential starting point for an international certification scheme that reflects all relevant sustainability criteria and needs to be established.

As an adaptation to CertifHy, the urgency of mitigating climate change requires that the threshold for GHG emission reduction should be increased in order to achieve high savings from the start. CertifHy requires 60% of reduction compared to conventional hydrogen, which is equivalent to 36.4 g CO_2/MJ_{H2} but only for hydrogen production. A priori, it would be desirable to increase the thresholds in a life-cycle assessment, e.g. to

- 60-75% for the *hydrogen supply chain* compared to *natural gas*, for uses in which green or blue hydrogen replaces fossil fuels in the same combustion technology or process,
- to 75% for the *hydrogen supply chain* compared to conventional hydrogen, if the former is replaced by green or blue hydrogen as a feedstock,
- and to 75% in a *well-to-wheel assessment* for uses in transport or other sectors, in which fuel cells are replacing internal combustion engines or combustion turbines.

This proposal takes into consideration that the resulting GHG emissions and reductions differ according to the use of hydrogen. In the first two cases, the hydrogen supply chain is what matters; in the third case, the technology for using the hydrogen may be more efficient than conventional technologies, adding to GHG reductions but at the same time reducing the reduction requirements for the hydrogen supply chain[17]. These standard cases may need to be further differentiated according to sources and uses of hydrogen, in order to avoid the need of an individual case-by-case assessment, and thus improve applicability of the certification. In addition, as the certificates will consider and differentiate the use, and not only the supply, of hydrogen, measures against fraud (by declaring a more favourable use for hydrogen that may allow higher emissions in the supply chain) will be needed.

[17] TÜV Süd's CMS 70 standard has such a differentiation, but it does not seem completely plausible to us.

Looking at the results on GHG emissions of green and blue hydrogen production or supply chains in the GJETC first year study[18] and the recent IEA (2019) study, we found that both green hydrogen with clearly additional RES electricity and blue hydrogen with 90 % of CO_2 capture (i.e., from both the feedstock/reaction and the combustion for heating the process) may be able meet the criteria for the first case proposed above (Figure 7 and Table 1). It will be analysed with more detail in the following chapters, which emissions reduction thresholds are achievable and appropriate for green and blue hydrogen in which of the above three cases.

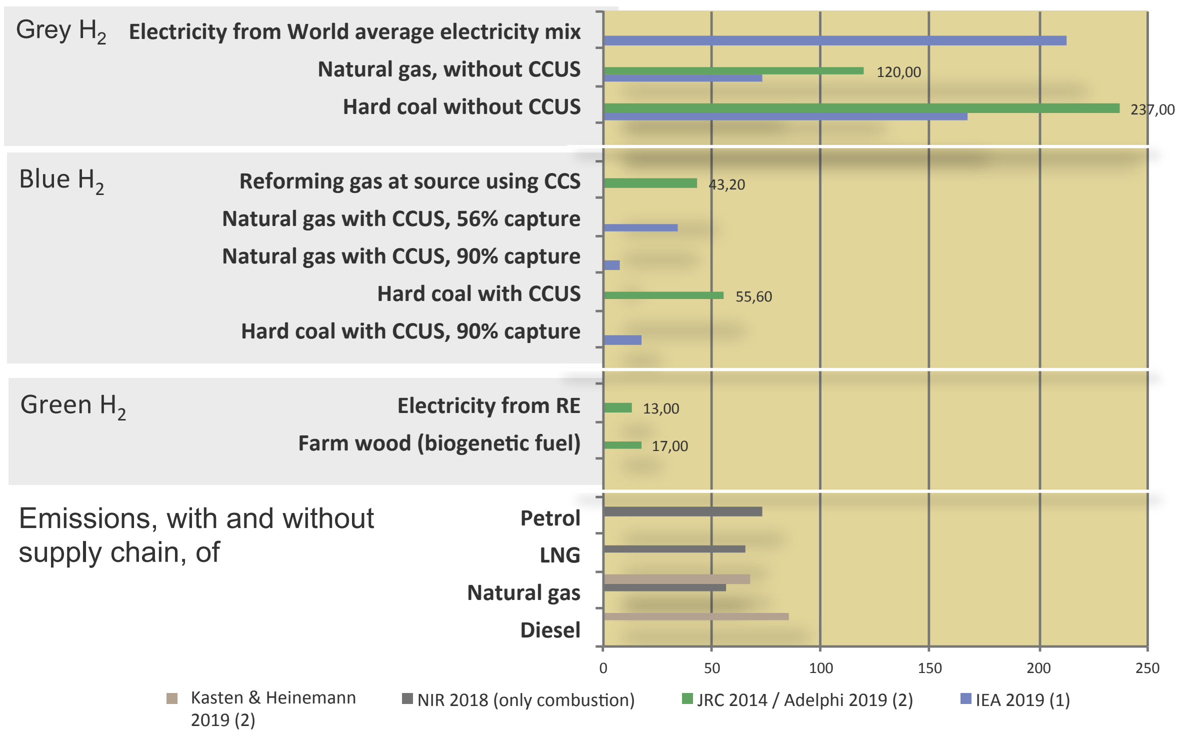

Figure 7: GHG emission intensities of hydrogen production or supply in g CO_{2eq} / MJ H_2, using different technologies, in comparison to fossil fuels for transport and power generation

Source: Wuppertal Institute, based on the sources cited in the graph

Note: (1) production and CO_2 only; (2) whole supply chain and all GHG in CO_{2eq}

[18] Jensterle et al. (2019). op.cit.

Hydrogen supply chain		Study					
		IEA 2019 (1)	JRC 2014 / Adelphi 2019 (2)	NIR 2018 (combustion only)	Kasten & Heinemann 2019 (2)	Reduction vs. natural gas (NIR)	Reduction vs. natural gas (Öko-Institute)
Grey H_2	Hard coal without CCUS	167,1	237,3	*			-254%
	Natural gas, without CCUS	73,4	100,0 – 130,0	*			-79%
	Electricity from World average electricity mix	212,6	*	*			
Blue H_2	Hard coal with CCUS, 90% capture	17,0		*		70%	
	Hard coal with CCUS		55,6				17%
	Natural gas with CCUS, 90% capture	7,5	*	*		87%	
	Natural gas with CCUS, 56% capture	34,2	*	*		39%	
	Reforming gas at source using CCS	*	43.2	*			35%
Green H_2	Farm wood (biogenetic fuel)	*	17,0	*			75%
	Electricity from RE	*	13,0	*			81%
Combustion-related emissions of	**Petrol**	*	*	73,3			
	LNG	*	*	65,6			
	Natural Gas	*	*	55,9	66,9		
	Diesel				85		

Table 1: Data in g CO_{2eq} / MJ H_2 on GHG emission intensities of hydrogen production or supply, using different technologies, in comparison to fossil fuels for transport and power plants

Source: Wuppertal Institute, based on the sources cited in the table

Note: (1) production and CO_2 only; (2) whole supply chain and all GHG in CO_{2eq}

The minimum GHG reduction thresholds should be tightened to achieve fully decarbonised hydrogen supply and use in the future. Therefore, technology and market development should be monitored constantly. The life cycle assessment of the hydrogen production chain should include production, transport and storage of hydrogen (but also of natural gas as the benchmark). Adequate criteria on the additionality of renewable electricity generation as well as for the sustainability of CC(U)S, and monitoring processes for the Guarantees of Origin (GoO) still need to be defined, as well as the additional disclosure of information on water usage and (sustainable) land use in the Guarantees of Origins. Regarding social impacts, indicators on the involvement of local actors, additional investment and reduction of poverty could be included.

It should be discussed, whether nuclear-based hydrogen should be included in the certification, facing the political acceptance that could be affected in countries, which phased or are phasing out nuclear energy. If nuclear-based hydrogen is included, the same additionality considerations as for RES electricity apply. In addition, special sustainability criteria on nuclear-based hydrogen should be involved, e.g. on nuclear operational safety, waste, and decommissioning.

The open questions regarding the sustainability of CC(U)S and the additionality of renewable electricity generation will be discussed in Chapters 3 and 4, respectively. This will also include a qualitative assessment of the other criteria for blue and green hydrogen. A general analysis of these criteria leading to concrete recommendations for the certification scheme can't be provided here for lack of budget. Chapter 5 will then conclude on potential concrete requirements for an international certification scheme.

Table 2 summarizes the criteria discussed here for a possible future certification scheme for clean hydrogen.

	CertifHy	Suggestions for future certification scheme
GHG balance	At least 60% compared to hydrogen produced by natural gas	At least 60-75% compared to natural gas or conventional hydrogen, depending on use (see text above); constant monitoring of technology and market development for respective tightening of thresholds over time
Life cycle of the hydrogen production chain covered	Only production	Production, transport, storage of hydrogen (also of natural gas); for use in fuel cells/transport, also including the use
Energy source / definition of clean hydrogen	Green and blue hydrogen	Green and blue hydrogen meeting the criteria
Additionailty of renewable electricity generation	-	Criteria and monitoring processes for GoO (tbd)
CCUS for blue hydrogen	-	Special sustainability criteria (tbd)
Water demand	-	Additional disclosure of information on water use in GoO
Land use	-	Additional disclosure of information on (sustainable) land use in GoO
Social impacts	-	Criteria for involvement of local actors, additional investment, and reduction of poverty (tbd)

Table 2: Suggestions for a future international certification schemes for clean hydrogen in comparison to CertifHy criteria

3. Possible standardization and sustainable potential of CCUS and assessment of criteria for blue hydrogen

3.1 Standardization of CCUS-based H_2 production pathways

There are many pathways of hydrogen production since it can be produced from fossil fuels through a chemical process or from electricity using electrolysis. A blue hydrogen supply chain starts with production of fossil fuels, which are the feedstock for hydrogen production in methane steam reforming or autothermal reforming using natural gas[19], or coal gasification (Figure 8). A large part of the CO_2 emitted from the hydrogen production phase is captured and stored underground. Then, hydrogen is transported to end-users for final consumption. In this pathway, carbon capture and storage (CCS) is the critical process, which differentiates blue hydrogen from grey hydrogen. Therefore, how the criteria for CCS are developed in terms of sustainability as well as technical reliability may become a turning point of whether blue hydrogen would be utilized in the future.

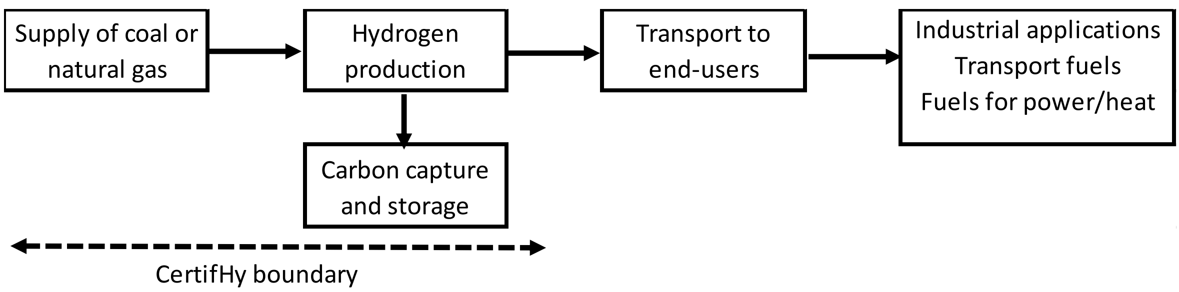

Figure 8: Blue hydrogen supply chain and the CertifHy boundary

Source: IEEJ

CCS has to be sustainable and reliable in the long-term to improve credibility of blue hydrogen as a possible measure to lower GHG emissions. To promote deployment and safe operation of CCS worldwide, international standards on CCS have been developed at the Technical Committee (TC) 265 (carbon dioxide capture, transportation and geological storage) of International Organization for Standardization (ISO) since 2011. Focusing on

[19] Another potential hydrogen production process using natural gas is methane pyrolysis in a high temperature reactor. The reaction results in hydrogen and solid carbon as products. This both avoids the need for CO2 capture and allows using the solid carbon by-product e.g. for producing batteries or light-weight construction materials. The resulting hydrogen has sometimes been called „turquoise“ hydrogen (e.g. Energate 2019).

CO_2 emitted from large stationary point sources, ISO/TC265 (2016) intends "to prepare International Standards for the design, construction, operation, environmental planning and management, risk management, quantification, monitoring and verification, and related activities in the field of carbon dioxide capture, transportation, and geological storage."[20]

Six working groups are formed under ISO/TC 265: capture, transportation, storage, quantification and verification, cross cutting issues, and enhanced oil recovery (EOR) issues. Eight international standards, at least one from each working group, have been published so far and four more standards are under development. For instance, one of the international standards titled "Lifecycle risk management for integrated CCS projects" (ISO/TR 27918) provides information for the potential future development of a standard for overall risk management for CCS projects. Identification of the risks associated with all CCS processes would be useful for risk management. In this way, deployment of international standards will help to provide a common basis to implement CCS, reduce barriers to invest in CCS projects, expedite relevant policy development, and encourage safe operation. However, whether or not issues regarding utilization of CO_2 has to be covered by the ISO/TC 265 was put on the table before, still it seems undecided. International standards for CCS present guidelines that CCS developers have to follow in common regardless of a CCS project site. Hence, CO_2 storage has at least the rules to look into for standardization.

In parallel, carbon capture and utilization (CCU) is recently getting attention in more countries worldwide as a promising technology to reduce CO_2 emissions and to secure the stable supply of new resources.

CCU technologies include mainly fuels (microalgae biofuels, CO_2-derived fuels, and gas fuels), chemical products (oxygenated compounds, biomass-derived chemicals, and commodity chemicals), and minerals (concrete products, concrete structures, and carbonate). However, there are many issues to overcome. For instance, it is necessary to secure clean hydrogen for fuels and some chemical products. On the other hand, producing carbonates does not need clean hydrogen but it is challenging to separate effective components such as calcium and/or magnesium compounds from industrial byproducts. CCU technologies present various potentials to utilize CO_2. To facilitate CCU technology development, further study and evaluation on economic feasibility and CO_2 reduction impacts in a supply chain are necessary steps to be taken.

[20] International Organization for Standardization/Technical Committee 265 (2016). "Business Plan."

The Japanese government supports innovation in carbon recycling technologies and systems that would be needed for CCU. The two following events highlight such expectations for CCU: a Roadmap for Carbon Recycling Technologies was announced in June 2019, and the International Conference on Carbon Recycling 2019 was held in Tokyo in September 2019.

In Germany too, there are large-scale research, development, and demonstration efforts in CCU, for example in the Federal government's Energy Research Programme.

3.2 Qualitative assessment of blue hydrogen production pathways with respect to the criteria for sustainable and low-carbon H_2

(1) Assessment of criteria for blue hydrogen

Currently, there is no criteria to assess sustainability and the extent of decarbonization of blue hydrogen production pathways that include all processes. The only available criteria is those of CertifHy, which partially covers the hydrogen production pathway. CertifHy, for example of a certification scheme, sets a benchmark emissions intensity value for caclulating eligibility of the guarantees of origin (GoO) scheme at 91g CO_2/MJ_{H2}.[21] The benchmark process is state-of-the art steam methane reforming (SMR) in large installations. To be qualified as CertifHy Low-carbon hydrogen, the carbon footprint of hydrogen produced must be equal to or lower than a specified limit at 36.4g CO_2/MJ_{H2}, which requires a 60% reduction from the benchmark. However, in chapter 2.2 we proposed that a future certification scheme should use natural gas as the benchmark for any combustion-related processes, such as power plants or CHP systems. The lifecycle emissions of natural gas supply and combustion are around 67g CO_{2eq}/MJ_{H2} (Table 1)[22]. Requiring, for example, a reduction of 60 or 75% compared to this benchmark would mean that the carbon footprint of hydrogen *supplied to final use* would have to be below 26.8 or 16.8 g CO_{2eq}/MJ_{H2} respectively. This will be further discussed in chapter 5 below.

Figure 9 shows GHG emissions of several hydrogen *production* routes. Based on the JRC report (2014)[23] that is referred for data of coal and natural gas cases, GHG emissions of extraction and processing of raw materials to hydrogen production are taken into

[21] CertifHy (2019). CertifHy-SD Hydrogen Criteria, CertifHy Scheme Subsidiary Document. p. 7.

[22] based on Kasten & Heinemann (2019). op.cit.

[23] Joint Research Centre (2014). WELL-TO-TANK; Report version 4.a: JEC WELL-TO-WHEELS ANALYSIS, JRC Technical Report

consideration in alignment with the boundary of CertifHy. In addition, the carbon footprint of hydrogen produced from the current electricity mix in Germany and Japan is also estimated.

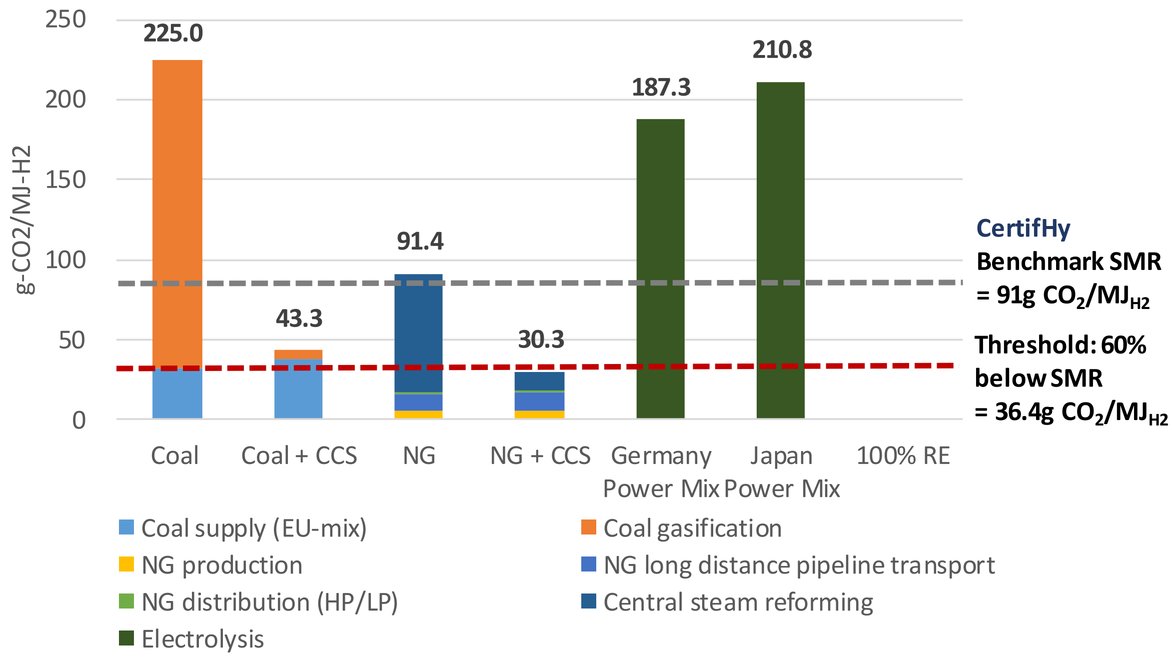

Figure 9: GHG emissions of hydrogen production pathways in comparison with the CertifHy benchmark and threshold values

Source: data from JRC (2014) and IEEJ estimation

NG = natural gas; SMR = steam methane reforming; RE = renewable energies

In this figure, hydrogen produced from 100% renewable power is the most environment friendly with no GHG emission. Then blue hydrogen, which is hydrogen from natural gas reforming with CCS and coal gasification with CCS, follows, demonstrating relatively low GHG emission impact. It is technically acknowledged that CCS has potential to contribute to substantial reduction of GHG emissions in the hydrogen production process. The CE Delft study (2018) shows that the CO_2 footprint of blue hydrogen production from natural gas is comparable with that of green hydrogen.[24] The figure illustrates that a case of natural gas reforming at a central large-scale reformer with CCS meets the criterion of CertifHy Low-carbon hydrogen, while that of coal gasification with CCS is yet to reach the threshold. This is mainly due to the emissions from coal supply. If this could be decarbonised, coal gasification with CCS might be able to reach the threshold too.

[24] CE Delft (2018): *Feasibility study into blue hydrogen*. Pp. 37-40

However, the fact that blue hydrogen produced from coal gasification is not able to meet the CertifHy scheme implies a possibility of losing opportunities to utilize a large amount of unexploited energy resources that are distributed almost evenly worldwide. As Figure 1 in chapter 2.1 illustrates, since the countries with high potential of blue hydrogen are scattered worldwide and geopolitically more stable compared with the Middle East, blue hydrogen is expected to enhance the energy security of energy import countries. This is a vital element for a country like Japan which heavily relies on the Middle East for oil and natural gas.

Another concern is that even natural gas with CCS may not meet the CertifHy Low-carbon hydrogen standard even when SMR is applied to produce hydrogen, because additional CO_2 emissions will be changed, depending on the extraction method, transport modes of natural gas, either by pipelines, trucks, or ships, and transport distance. On the other hand, looking at the details of figure 9 above, if GHG emissions from natural gas production and transport can be partly or mostly avoided, e.g. by producing hydrogen close to the natural gas production site, blue hydrogen may be able to meet stricter emissions standards.

If criteria for blue hydrogen become more stringent than the CertifHy Low-carbon hydrogen level, it will need further reductions in the processes along the production and supply chain. If this can't be achieved, more stringent criteria will be likely to overshadow benefits of blue hydrogen such as utilization of fossil fuels available and energy security enhancement. Nevertheless, as certain criteria are necessary to tackle climate change for sure, the blue hydrogen supply chain needs some measures to reduce GHG emissions further. Effective approaches are to develop technologies which will improve energy efficiency in each process and foster decarbonization of energy input, which will consequently help blue hydrogen to pass the sustainability criteria.

In both cases of the power generation mix in Germany and Japan, GHG emissions of hydrogen production through electrolysis are much higher than the benchmark emissions intensity threshold of CertifHy, and especially Japan's figure is close to the case of hydrogen production via coal gasification without CCS. This indicates that even if electrolysis is technically advanced and economically available, electrolysis onsite will not be a sustainable choice unless the power sector is largely decarbonized like in Norway, where hydropower accounts for 95% of power generation mix (see also the discussion in chapter 4.1 on criteria for green hydrogen from electrolysis).

If the GHG emission impact is assessed in blue hydrogen production and supply pathways, an approach of 'well to wheels' seems appropriate because GHG emissions are observed more or less in all processes from extraction of fossil fuels to the final consumption phase, including industrial applications and fuels for transport and power generation. This has been the approach in the results presented in the year 1 study[25] (see table 2 in chapter 2.2).

Nevertheless, the life-cycle assessment of GHG emissions makes it difficult and complicated to develop the criteria for blue hydrogen, because the carbon footprint will be different in each case due to various production routes and applications. For example, IEEJ estimated CO_2 emissions in a case of blue hydrogen produced in Australia and transported to Japan. Suppose that 90% of CO_2 is captured and EAGLE (coal energy application for gas, liquid and electricity) gasification technology,[26] a high gasification efficiency technology, is applied in Australia, CO_2 emission of blue hydrogen production is estimated to be 15.8 g CO_2/MJ_{H2},[27] which is significantly lower than e.g. the CertifHy Low-carbon hydrogen threshold. If CO_2 emissions from coal production in Australia and delivery processes within Australia are added, however, blue hydrogen from coal gasification with CCS may not be qualified under the CertifHy scheme. In addition to the transport distance, how hydrogen is carried either in a compressed or liquified form, or converted to ammonia or methylcyclohexane (MCH) would make a difference of CO_2 emissions. This indicates that the blue hydrogen production process is proved to be likely low-carbon, but it is necessary to make blue hydrogen a sustainable method even when it is analyzed in a life-cycle perspective.

(2) Challenging issues of CCUS

While CCS is expected to provide a possibility to reduce CO_2 emissions at large scale and recognized as an important technology to tackle climate change, the technology faces some hurdles that hinder implementation of the CCS projects. First, CO_2 capture and storage may not be as certain as envisaged. There is a risk of CO_2 leakage from a stored reservoir underground as a result of sudden events such as well blowouts and gradual CO_2 movement within or out of a geological storage. Possible CO_2 seepage necessitates an appropriate site selection, effective monitoring methods, uncertainty assessment, and estimation of potential CO_2 seepage in the long-term. Determining an acceptable level of CO_2 leakage during capture is also a difficult issue. Reportedly, although CCS is expected to capture up to 90% of the carbon emissions, the current CCS projects achieve far lower capture rates.[28]

[25] Jensterle et al. (2019). op.cit.

[26] Osaki CoolGen Corporation. Available at: https://www.osaki-coolgen.jp/en/technology/

[27] IEEJ own estimation

[28] Financial Times (August 20, 2019). *Coal industry stakes survival on carbon capture plan.*

The second primary issue is the difficulty of establishing economic feasibility. In the most of the about 20 CCS projects currently in operation, CO_2 is utilized for enhanced oil recovery (EOR).[29] EOR helps a CCS project to be profitable because CO_2 injection works to produce additional oil which brings in more income. Otherwise, government financial support is necessary to carry out a CCS project. Besides, the current CO_2 market price does not make CCS financially sound. CCS would be economically feasible at a carbon price level of €50/mt,[30] which is more than twice the current EU-ETS carbon price at around €22/mt as of June 2020. Figure 10 of electricity generation costs in the US shows that coal plants with CCS are more costly than those without CCS, for that the current cost of capturing CO_2 at $60 per ton translates into a cost of approximately $60 to $65 per MWh, which is the additional cost for the coal plants with CCS. It also illustrates that coal plants without CCS are getting difficult to keep cost competitiveness with solar and wind resources.

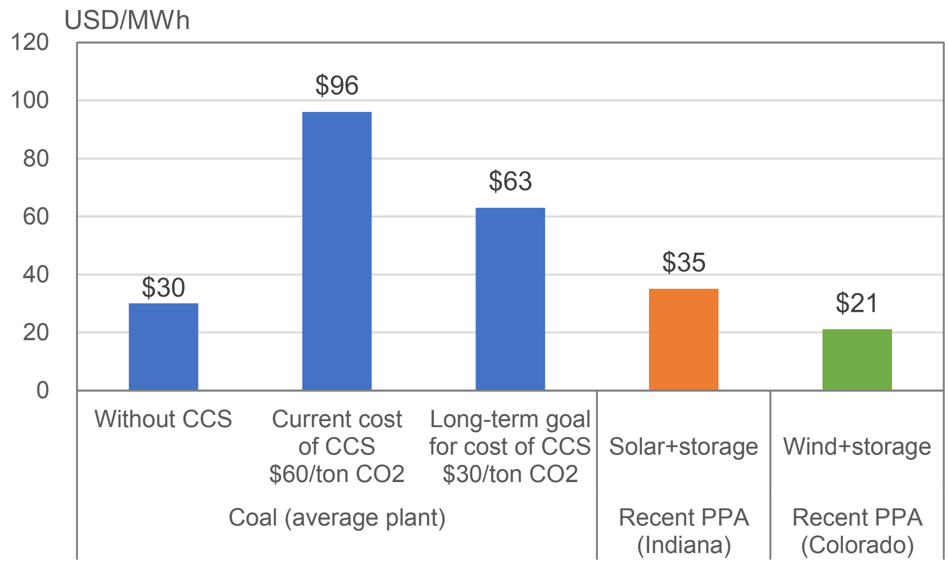

Figure 10: Electricity generation cost for different types of power plants

Source: Schlissel and Wamsted (2018)[31]

For instance, Boundary Dam has an overall capture rate of 51%.

[29] IRENA (2019). op.cit., p.16

[30] CE Delft (2018). op.cit., p.14

[31] Shlissel, David and Dennis Wamsted (2018). *Holy Grail of Carbon Capture Contintues to Elude Coal Industry*. Institute for Energy Economics and Financial Analysis. P.3

Lastly, public acceptance is fundamentally critical for implementation of CCS. Since technical, financial, social and environmental uncertainties are involved in CCS processes and it requires substantial investment, the local government and population need to be fully informed about benefits and risks of a planned CCS project. Information substantiated by data analysis would be helpful to foster understanding of CCS among concerned communities.

Despite a potentially crucial role of CCS in climate change, commercialization of CCS has been limited due to problems mentioned above. EOR is not the only technology that utilizes CO_2 captured as a resource. Other carbon utilization technologies have been advanced to produce recycled materials and fuels through mineralization, artificial photosynthesis and methanation, which is expected to control CO_2 emissions to the air.[32]

CCU is a promising technology in the medium- or long-term, but there is substantial room to improve for commercial usage. In specific, CCU is not economically justified yet, technology enabling CCU needs to be advanced further, and the scale of CO_2 emission reduction is much smaller compared with CCS. One more challenging issue is to lower green and blue hydrogen costs. A reasonable price of green and blue hydrogen will be required for carbon to be utilized for industrial products and fuels. If some of these issues are solved, CCU will be more useful to lower CO_2 emissions.

(3) Water usage, land use and other environmental and social impacts in blue hydrogen production

As touched upon in Chapter 2, prevention of any negative impacts on the local areas has to be ensured for blue hydrogen production. It is needless to say that thorough and prudent evaluation on water usage is crucial to carry out a blue hydrogen project. In the blue hydrogen production process, CO_2 is captured after the water-gas-shift reactor is used to convert from CO to CO_2 or hydrogen is separated from synthesis gas. This water-gas-shift reaction process takes place at 350-500℃ and requires additional water input.[33] The extra water requirement for blue hydrogen production should not limit water supply to the local areas.

Issues of the land use and the related environmental impacts are due mainly to CCS projects. In addition, there are the land requirements and environmental and social consequences associatied with extraction of the coal and natural gas used for the blue hydrogen production. These have to be assessed in relation to the land use and

[32] Ministy of Economy, Trade and Industry (2019): *Roadmap for Carbon Recycling Technologies*. p.1.

[33] CE Delft (2018). *Op.cit*. pp. 10-11

environmental and social impacts caused by the extraction of the fossil fuels replaced by the blue hydrogen. However, these may also be in a different region than those for the fuels extracted for blue hydrogen production.

Regarding the land use for CCS, CO_2 storage underground has to be legally permitted and contractual agreement between developers and land owners is vital. In the Netherlands, for example, CO_2 capture underground was prohibited after a CCS demonstration project planned in Barendrecht was cancelled.[34] Hence, a legal or regulatory environment that is articulate and well-designed would help avoid conflicts of land use among the stakeholders.

Furthermore, the possible environmental impacts associated with blue hydrogen production have to be seriously taken into consideration in order to achieve public acceptance as well as the legal and regulatory environment needed. Since there are uncertainties involved in the CCS projects, even with the use of advanced technology available at present, it seems difficult to deny the possibility of CO_2 leakage to surrounding geological formations or groundwater from the CCS operations, or earthquake triggered by CO_2 injection. It is not easy to foresee the probability of incidents that might be caused by the CCS operations as they may emerge many decades after. If the concerned local communities are not properly involved from the planning phase of the CCS project, the NIMBY (not in my backyard) problem may rise from the local residents. An objective assessment on how much the CCS project will offset CO_2 emissions will help the public understand about the benefits of CCS, although fossil fuels are used to produce hydrogen.

3.3 Size of the safe CO_2 storage capacity for CCS worldwide in comparison to the potential needs for uses, and aspects of a fair distribution

An important precondition for the production and use of blue hydrogen is the availability of safe CO_2 storage capacity for the CCS involved in blue hydrogen production. Therefore, this total potential for CCS needs to be analyzed. However, there are other potential uses of the available safe CO_2 storage capacity for reducing CO_2 emissions or even for net removal from the atmosphere. Achieving distributional justice between these uses and between different states or even regions as well as acceptance for CO_2 storage among affected stakeholders will be crucial. If capacities are limited in comparison to demands, it will need to be discussed in principle, whether UNFCCC member states move fast towards

[34] *Ibid*. p. 15

energy efficiency, renewable energies and green hydrogen, using the existing CO_2 storage capacities as a contribution to a net removal and storage of CO_2 from the atmosphere. Or whether states want to continue the next 20, 30 years to exploit the remaining storage capacities for the use of fossil and fossil-derived energies, including blue hydrogen.

Therefore, this chapter analyzes both the potential safe CO_2 storage capacity available worldwide, and the demand in different sectors that may result from the emissions scenarios modelled for the IPCC. It then continues to discuss criteria for a fair distribution in case of scarce capacities, using the North Sea region as an example.

Global carbon storage capacity

The IPCC (2019)[35] estimates a range for the global technical carbon storage capacity from 1.680 $GtCO_2$ to 24.000 $GtCO_2$. The by far biggest reservoir type is represented by deep saline formations, followed by oil and gas fields, and only small shares existing in unminable coal seams (ECBM)[36]. The wide range of the estimation shows the difficulties to quantify the storage capacities.

Reservoir type	**Lower estimate of storage capacity ($GtCO_2$)**	**Upper estimate of storage capacity ($GtCO_2$)**
Oil and gas fields	675 [a]	900 [a]
Unminable coal seams (ECBM)	3-15	200
Deep saline formations	1000	Uncertain, but possibly 10^4

[a]) *These numbers would increase by 25% if "undiscovered" oil and gas fields were included in this assessment.*[37].

Table 3: Storage capacity for several geological storage options.

Note: The technical storage capacity includes storage options that are not cost-effective

Source: IPCC Special Report on CCS (2005)

Facing the scale needed to achieve a significant and meaningful reduction in CO_2 emissions through CCS, more knowledge is needed about the CO_2 storage capacity[38]. The

35 IPCC Special Report on Climate Change and Land (2019), p. 972.

36 IPCC Special Report on CCS (2005), p. 221.

37 ibid.

38 Carbon Sequestration Leadership Forum (2007), p. 33.

Carbon Sequestration Leadership Forum (CSLF) system tried to classify, define and assess the CO_2 storage capacity, and uses a "Techno-Economic Resource-Reserve pyramid" and respective reduction coefficients to divide the storage capacity into four subsets which account for additional constraints. The figure below shows that the stated theoretical capacity may decrease to a small fraction when additional factors like use restrictions, acceptance and costs are considered. CCS technology still struggles with problems of acceptance. The risks of leakage, the occurence of sudden outbreak and earthquakes, unexpected intrusion of salt water into the groundwater, acidification of marine eco systems or development of CO_2 lakes on the seabed that destroy marine life are serious concerns to decisionmakers and citizens.

Theoretical Capacity: available pore volume of the target formation and area for CO_2 storage

Effective Capacity: physical constraints, reservoir properties and injection technology.

Practical Capacity: economic constraints, factors of geology, engineering and economy (capital costs, operation costs, discount rate, regulations, public awareness and economic incentives)

Matched Capacity: residual capacity after considering CO_2 sources.

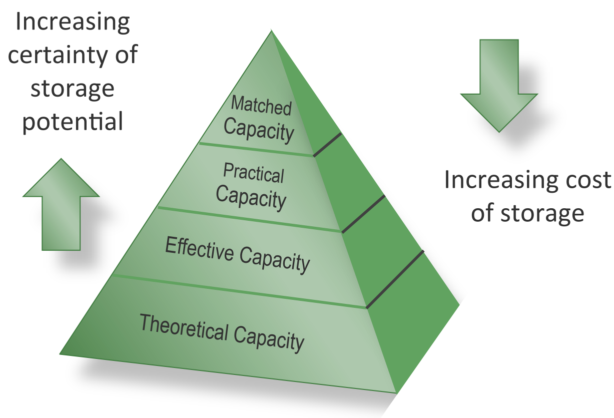

Figure 11: Techno-Economic Resource-Reserve pyramid for CO_2 storage capacity in geological media within a jurisdiction or geographic region

Source: modified from CSLF (2005); Bradshaw et al. (2006).

Unfortunately, the CSLF did not provide a quantified estimate of these types of CCS capacity.

Safe storage capacities in comparison to the needs for potential uses

In contrast to the storage capacities, the amount of CO_2 that needs to be stored via CCS *over this century* in 1.5 °C pathways with no or limited overshoot of emissions before 2050, which needs to be removed after 2050, is estimated from being zero to more than 1,200 $GtCO_2$. For 1.5 °C pathways with high overshoot, the amount of CCS needed by the year 2100 is typically estimated some 20 to 30% higher, but only few outliers calculate storage needs above 1,400 $GtCO_2$.[39] This would not exceed the identified technical storage capacity of at least 1,680 $GtCO_2$. However, as said above, the practical and matched capacity could be much smaller, particularly if safe storage capacities are located far away from sources of CO_2 through carbon capture.

What are the sectors and sources that may compete for the storage capacity? In 2050, the IPCC estimates that the industry (including cement, steel and chemical industry) will need a storage capacity for CO_2 of 3,000 million tons per year[40]. However, the LUT University (2019) estimates the necessary storage capacity for cement industry from 3,836 to 7,752 million tons per year[41]. Rogelj (2018) also estimates up to 50 EJ/y for gas-fired power production and 40 EJ/year for coal. With a capture efficiency of 90%, this would create storage demand for ca. 3,000 and 3,500 million tons of CO_2 respectively per year. Assuming a global demand of 19,000 PJ of hydrogen in 2050[42], fully providing this from blue hydrogen production, based on natural gas with CCS (capture efficiency of 90%), would lead to 1,283[43] million tons of CO_2 needed to be stored per year. Hydrogen production based on hard coal in such a scenario would lead to 2,907[44] million tons of CO_2 to be stored per year. Some scenarios also assume the use of biomass power plants and CCS, which will effectively remove CO_2 from the air. The same will be the case, if direct air capture is used and the CO_2 is stored underground.

Table 4 summarizes these findings.

[39] IPCC 2019 / Rogelj et al. (2018): *Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development.*

[40] Ibid.

[41] LUT University / Energy Watch Group (2019): *Global Energy system based on 100% Renewable Energy : Power, Heat, Transport and Desalination Sectors.*

[42] IRENA (2019b): *Global energy transformation: A roadmap to 2050 (2019 edition).* p. 28.

[43] Storage need for 1 PJ blue H_2 from natural gas with CCUS, 90% capture: 67.500t CO_2 (IEA 2019, own calculation). [based on emissions of 7,5gCO_2 $*10^6$ per PJ of grey hydrogen]

[44] Storage need for 1 PJ blue H_2 from hard coal with CCUS, 90% capture: 153.000t CO_2 (IEA 2019, own calculation). [based on emissions of 17,0gCO_2 $*10^6$ per PJ of grey hydrogen]

Point sources	Scenario	CO_2 storage needs 2050		**Cumulative by 2100**
		Assumed CO_2 capture efficiency	Storage needs (million t / year)	Storage needs ($GtCO_2$)
Industry (Cement, chemical,steel iron)	IPCC 2018		3,000	210[B]
Fossil power plants (with CCS)	IPCC 2018: up to 50 EJ/y for gs and 40 EJ/year for coal	*	Natural gas[A] 3,010 Coal [A] 3,470	Natural gas[A] 210.7[B] Coal [A] 242.9[B]
Blue hydrogen (natural gas with CCS)	IRENA 2019	90%	1,283	51.3[C]
Blue hydrogen (hard coal with CCS)	IRENA 2019	90%	2,907	116.3[C]
BECCS	IPCC 2018			up to 300.0
Direct Air Capture	LUT 2019		200[45]	14[B]
Total need for CCS	IPCC 2018			up to 1,200[46]

Table 4: Global emissions and storage needs in different sectors 2050

Notes:

A: Emission factors taken from Kasten & Heinemann 2019 (natural gas) and UBA 2016 (coal);

B: Calculated assuming the annual storage needs for 70 years (from 2030 to 2100); C: Calculated assuming the annual storage needs for 40 years (e.g. from 2025 to 2065, using the assets for an assumed technical lifetime before green hydrogen takes over)

Fair distribution and experiences from the North Sea area

Apparently, practical and matched carbon storage capacities will remain limited worldwide and strong usage competition is to be expected in the future.

45 LUT University (2019): http://energywatchgroup.org/wp-content/uploads/EWG_LUT_100RE_All_Sectors_Global_Report_2019.pdf

46 Rogelj, J., et al. (2018): *Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development.*

Therefore, achieving distributional justice and acceptance for CO_2 storage among affected stakeholders will be crucial. The differing urgency in industries for CCS could form one important criterion for priority access to the limited storage capacities. Emerging technical alternatives[47] and their economical assessment would have to be considered or be the basis for reassessment. However, also the geographical spread of storage sites makes it necessary to negotiate usage of storage sites between stakeholders. States and regions with respective geological preconditions could benefit, but would also have to carry the risks. Historical debts of industrial states (GHG emissions) would have to be taken into account for a fair distribution. Finally, despite extensive research and technical reports, geological storage will entail risks (e.g. leakage)[48]. Private companies will hardly be able to assure the necessary long-term storage. This needs to be considered especially when single states that have access to sufficient storage capacities, will receive large amounts of CO_2 from other states. A framework for a fair and safe distribution needs to be discussed.

How difficult distributional issues are, can be learned from CCS deployment in the North Sea gas fields. Since 2008, Norway with its state-owned companies Equinor and Gassnova has realized two large-scale projects, the Sleipner plant and the Snøhvit plant to store CO_2. By 2017, 20 million tons of carbon dioxid were stored and it is planned to increase the capacity in order to absorb CO_2 from several emissions sources. Recently, an increased focus on joint collaboration between the Nordic countries has emerged to create synergies. In 2019, Equinor signed Memoranda of Understanding on the development of value chains at European level with seven European companies, as an important step on the way to a European infrastructure[49]. These companies include the German-based cement manufacturer Heidelberg Cement and steel maker ArcelorMittal, which also has operations in Germany. Apparently, Norway benefits from the large storage capacities in the North Sea and would be able to supply significant amounts of hydrogen to other countries. Norwegian production of blue hydrogen for e.g. Germany,

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[47] e.g. direct electrification, green hydrogen for the steel and chemical industry or recycling or smaller local storage sites in cement industry

[48] The Norwegian Ministry for Foreign Affairs emphasizes that all projects would exceed the wide-ranging safety requirements imposed by the Norwegian legislator in order to live up to the claim of globally leading environmental standards. Critics of CCS, however, point to the fact that the seabed of the North Sea has been perforated through 10.000s of drillings in the search for gas and oil. The fear of induced seismicity, morbidity issues, effects on public health, farming, the risks to the environment, marine life, existing activities such as fishing due to uncontrolled leaks or the decreasing value of property exists. It is perceived as something new, unknown and potentially risky.

[49] https://www.equinor.com/en/news/2019-09-cooperation-carbon-capture-storage.html

would help reducing German CO_2 emissions. Or Germany could produce blue hydrogen with Norwegian gas and transport the CO_2 to Norway to be captured and stored.

As the following graph shows, in Germany the potential demand for carbon storage is estimated to be much higher than the available capacity, while in Norway, capacity is much higher than CCS demand. If blue hydrogen is considered an option for Germany and other countries, the CO_2 should therefore probably be stored in Norway. Where the hydrogen should be produced, will depend on the relative capacities and costs of transporting hydrogen and natural gas. However, there are other countries, including France and Poland, where the demand for CCS may also exceed domestic capacities.

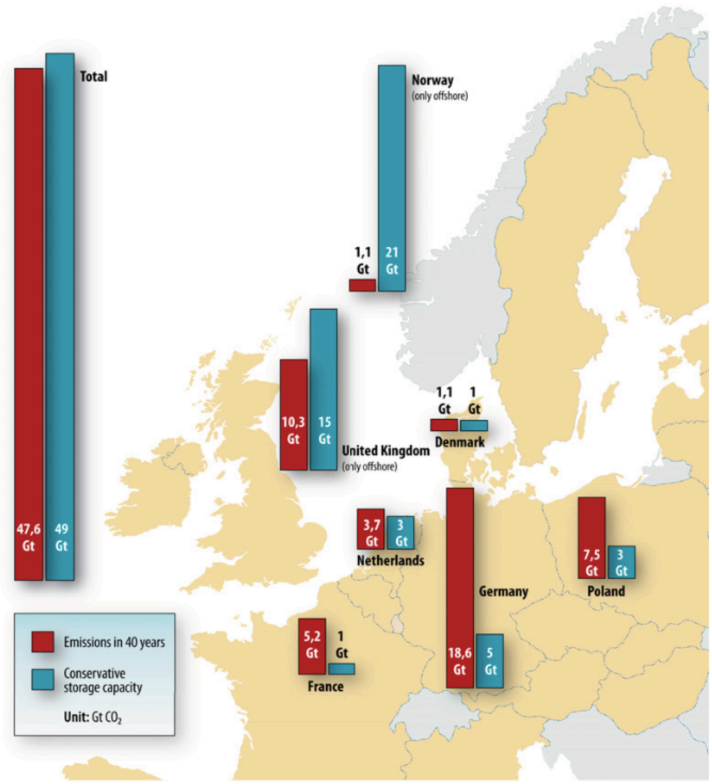

Figure 12: Overview of conservative capacity estimates of CO_2 storage in Germany´s neighbouring countries compared with 40 years of emissions from large point sources.

Source: Höller & Viebahn (2011)[50]

If storage sites like the North Sea should be deployed in the extent needed, people living in the Nordic region would have to accept increasing CCS activities. However, it is notable that no large scale CCS projects have been realized in nearby geological formation or

[50] Höller, Samuel and Peter Viebahn (2011): *Assessment of CO_2 storage capacity in geological formations of Germany and Northern Europe.*

other countries bordering the North Sea. Different from Norway, municipalities in Sweden and Denmark opposed and stopped similar CCS projects[51]. Public acceptance is recognized as being crucial for the implementation of CCS deployment. Geographical and spatial characteristics, local awareness and perception of CCS, managing risks, ensuring distributional justice and providing economic benefits for the local community hosting the CCS infrastructure, taking its history, current identity and future plans into consideration may support local acceptance.

CCS is a critical technology for Australia, where there are abundant coal and natural gas reserves, because it will help the country to utilize these fossil fuels continuously as major export commodities as well as to decarbonize the economy. Australia is estimated to have over 400 gigatons of CO_2 storage capacity[52]. Among the large-scale CCS projects undertaken, in 2019, the Gorgon CO_2 injection project, the first case in Australia, started operations and will be the world's largest dedicated geological storage facility, which captures and injects 3.4 to 4 million tons of CO_2 each year into a deep underground reservoir when it is fully operational. In Australia, CCS is categorized into low emission technologies, but it is controversial if it is legitimate for CCS to receive clean energy investment funding.

In any case, further research needs to be conducted. It may be useful for CCS developers and authorities in guiding their communication efforts. Political discussions and a joint statement of intention and joint regional strategy for CCS infrastructures, especially between cooperating countries will be needed and could be considered to create a framework for cooperation and to provide predictability for involved parties. Even though offshore storage sites appear as a major advantage, it will include other stakeholders than for onshore storage that should be subject to attention. As the use of the sea for different purposes increases, early communication with sea use stakeholders should be an integral part of communication efforts, and also onshore pipelines that will be needed for transport of CO_2 towards the sea could be a challenge.

[51] Haug & Stigson (2016): *Local Acceptance and communication as crucial elements for realizing CCS in the Nordic region.* In: Energy Procedia 86, p.315-323.

[52] Global CCS Institute (2019). *The Global Status of CCS 2019*. p.53

4. Ensuring the additionality of electricity from renewable energy used in the production of green hydrogen

It has been discussed that ensuring the additionality of electricity from renewable energy used in the production of green hydrogen is crucial to ensure sustainable production of this type of hydrogen (see chapter 2.2[53]). This chapter will analyse the respective options in more detail and draw conclusions on political standards for *defining*, as well as on policy options for *ensuring* additionality. Furthermore, green hydrogen can also be used to produce green synthetic fuels, using CO_2. The last subchapter discusses potential sources of CO_2 for producing synthetic fuels from green hydrogen.

4.1 Technical or economic options for defining and ensuring additionality

In chapter 2.2, we identified three potential basic options for ensuring the additionality of electricity from renewable energy used in the production of green hydrogen:

1) Only accepting amounts of RES electricity generation as being additional, which exceed the demand in a *systemwide* 100%+ RES situation.
2) Allowing RES electricity that is exceeding 100% of *regional* demand and cannot be transported to distant centres of demand.
3) Allowing an *economic/political* link, e.g. for RES-E capacity purpose-built for electrolysis in a system distant from 100% RES-E share.

What are important aspects for judging which of the three approaches should be allowed for the definition of additionality, and hence, of green hydrogen? How can the additionality be monitored and certified in each case?

In addtion to *full* additionality, it could also be discussed to allow *partial* additionality, as long as the criteria for GHG emission reductions in the whole supply and use chain compared to certain benchmarks as discussed in chapter 2.2 are met. Partial additionality would mean combining green electricity from fully additional RES-E sources with a certain share of 'grey' grid electricity. This could be a way to increase annual operating hours of electrolysers and thereby reduce hydrogen production costs. It will also be discussed for the three options.

[53] If nuclear-based hydrogen is included, the same additionality considerations as for RES electricity will apply. In addition, special sustainability criteria on nuclear-based hydrogen should be involved, e.g. on nuclear operational safety, waste, and decommissioning.

1) RES electricity generation is defined as additional, if it exceeds the demand in a *systemwide* 100%+ RES situation

Definition of additionality

This is the clearest and most rigorous approach to define *full* additionality. Amounts of RES electricity generation, which exceed the demand in a systemwide 100%+ RES situation, can only be stored or lost. So there are clearly zero CO_2 emissions allocated to these amounts if they are stored, as the electricity demand pre-existing before electrolysis is already covered from 100% renewables in such a situation. Electrolysis is one form of storage. Hydrogen produced from these resources is, therefore, clearly green hydrogen.

If *partial* additionality is allowed, in this option 1) it will mean allowing the production of hydrogen also at certain times outside the 100%+ RES situation, using grid electricity.

Monitoring additionality

The amounts available for this definition are easy to monitor for any trading period of e.g. 15 minutes in the year, by comparing total generation from renewable energies and total demand in the system, and excluding that any fossil-fueled power plant is feeding into the grid. Nuclear or any other (nearly) GHG-free power generation exceeding demand could be allowed too, depending on national policy.

In supranational electricity systems coupled from several national transmission systems, such as in Germany, the unavailability of sufficient transport capacity to export the excess electricity to neighbouring systems would also need to be proven through the existing forecasting systems and statistics on capacity availability or constraints.

For *partial* additionality, there is the need to calculate the share of grid electricity that can be blended in, calculating backwards from the GHG emission reduction criterion for clean hydrogen, using the emissions in the other stages of the hydrogen supply and use chain and the GHG emission intensity of incremental grid electricity as input data.

Other relevant aspects

However, few national electricity systems (or supranational electricity systems coupled from several national transmission systems) currently have RES-E shares and capacities high enough to exceed 100% RES-E (or GHG-free) generation. Such situations may start to arise when the annual average RES-E share exceeds ca. 60%[54]. This will mean that *fully*

[54] For example, a simulation presented in Agora (2015) for 55 % of RES-E share in Germany shows such a situation for two hours around noon on a Friday in August

green hydrogen defined in this way of *full* additionality would only become available in the medium-term future – e.g. in Germany towards 2030, if the current target of 65 % for the average annual share of RES-E in 2030 is achieved. In addition, it could be costly in the beginning, since the hours of the year with this *full* additionality situation, and hence the operating hours of the electrolysers, would be quite low (a few hundred to 2,000 hours per year). However, these hours would increase with the average annual share of RES-E increasing further towards 100%, and the price of electricity would be quite low in these situations. Allowing *partial* additionality would also increase the operating hours, however probably not a lot in many cases: If the GHG emissions reduction criterion is set, e.g. at minus 70% vs. natural gas for hydrogen production, around 10 to 15 % of the total electricity used for electrolysis could come from fossil power plants through the grid, depending on its marginal generation sources. 15% would be possible with combined-cycle gas turbine generation (CCGT) at 60% efficiency, while a mix of coal and CCGT would only allow for 10%. At minus 60% GHG emissions vs. natural gas, the allowed share could be between 12 and 19%. This would offer some potential for reducing production costs through higher operating hours, although not much.

2) RES electricity generation is defined as additional, if it exceeds 100% of the *regional* demand and cannot be transported to distant centres of demand

Definition of additionality

Looking at the problems for meeting the strictest criterion 1) in many countries, both for domestic and internationally traded green hydrogen, it may also be justified to include RES electricity that is exceeding 100% of *regional (i.e., sub-national)* demand and cannot be transported to distant centres of demand. Although building transmission lines may be an alternative, this may take time, during which the excess capacity could be used to produce hydrogen. Such situations are conceivable, e.g., in Patagonia, Argentina, or Western Australia for future large-scale green hydrogen production projects and the corresponding wind and solar PV generation arrays. Similar situations exist already today in some regions in Northern Germany, where there are phases of the year, when RES electricity generation mainly from wind has to be curtailed due to grid bottlenecks. However, there is not always a 100% RES-E situation in these regions, as there still are nuclear and fossil-fueled power plants in operation. Such cases of regional excess capacity above 100% RES-E are in effect very similar to those under option 1). The definition of *partial* additionality would also be equal to option 1).

Monitoring additionality

The monitoring would be done in the same way as for option 1), but for a regional transmission or even distribution network system. In addition, the unavailability of sufficient transport capacity to export the excess electricity to neighbouring systems would also need to be proven. For *partial* additionality, there is the need to calculate the share of grid electricity that can be blended in, in the same way as for option 1).

Other relevant aspects

The problem of initially low numbers of hours or excess RES electricity and, hence, low operating hours of electrolysers would be the same as for option 1). However, regional excess capacities could emerge much sooner than at the larger national system level, enabling earlier production of green hydrogen.

3) RES electricity generation is defined as additional, if there is an *economic and/or political link*, e.g. for RES-E capacity purpose-built for electrolysis

Given the problems that A) options 1) or even 2) may be unavailable for many years to come in a system still very distant today from 100% RES-E share situations, but that hydrogen-based energy systems and infrastructures need to be built soon to be available on time for achieving climate targets, and B) hydrogen production cost strongly depends on the annual full-load hours, which may be low for options 1) and 2), there is the need to discuss if alternative definitions of additionality may be justifiable.

Definition of additionality

Option 3) defines additionality through an economic/political link, e.g. for RES-E capacity purpose-built for electrolysis.

The *political link* could be made in a RES support system with auctions for a maximum amount of capacity defined by the government, as e.g. in Germany. If the capacity politically defined and then auctioned is increased by a certain amount for the purpose of providing electricity for electrolysis, this amount of capacity and the consequent amount of electricity generation could be seen as *additional to the baseline policy*. However, there could be the counterargument that this capacity and generation is anyway urgently needed to accelerate decarbonization of the electricity system itself, and RES-E targets should therefore be increased anyway. Here, we therefore see the need for international political agreement on whether this option of political linkage would be allowed in an international certification system. It could also be defined as a form of *weak* additionality.

An *economic link* could also be made by a company building RES power plants *outside of the public support scheme* for electricity or hydrogen (such as a FIT scheme) to produce hydrogen for its own purposes, e.g. in production or transport of goods. This could be seen as *fully* additional if there is no grid connection of the power plant plus electrolyser unit. However, this would most likely be less cost-effective than operating this unit with an electricity grid connection in order to increase the operation hours of the electrolyser, cover periods of low self-generation, and sell eventual surplus power. In that case, still the part of the hydrogen generated from electricity equivalent to the annual production of the RES power plants could be seen as *fully* additional in economic terms, at least for PV and wind power plants. Let us remind that this would require no use of public support schemes for either electricity or hydrogen. Otherwise, it may be allocated to the political link sub-option. With blending in an amount of grid electricity that is compatible with meeting the GHG reduction thresholds for the hydrogen produced, it would be *partial* additionality.

Monitoring additionality

If the *political* link is accepted, it will be easy to monitor in principle: the baseline is the orginal annual or multiannual auctioning target set directly or derived from a target for the RES-E share in a certain future year. Any amount auctioned for bids above this original auctioning target for the purpose of producing green hydrogen could be seen as additional. However, such a system will create a political bargaining incentive to set future "baseline" RES-E targets lower than what could be possible. If international agreement is achieved on including this political link to a certification system for green hydrogen, an option to counterbalance this incentive could be to require that the states concluding this agreement should commit to an ambitious RES-E expansion target and pathway, e.g. at least to a 100% RES-E (or nearly-zero-carbon power) target for no later than 2050 and a linear expansion pathway towards this target. Alternatively, a political consensus might determine that only a certain share, e.g. 50%, of the hydrogen produced in this way is accepted as additional.

For the *economic* link, monitoring is easy in case of off-grid power plant & electrolyzer units without public support. For grid-connected units and *full* additionality, the power generation of the RES unit has to be monitored and disclosed. For *partial* additionality, the allowed share of grid electricity has to be calculated in the same way as for options 1) and 2).

For biomass, there could be other necessary energy uses in order to decarbonize the country; this needs to be proven if biomass-based power is to be used.

4.2 Qualitative assessment of these options with respect to the criteria for sustainable and low-carbon H_2

How can these three options of additionality be assessed in terms of their sustainability? The criteria of the green energy source, the GHG balance and additionality have been discussed in the previous chapter 4.1. This chapter analyzes the sustainability criteria regarding social impacts, water demand, and land use.

Social impacts

Local acceptance of renewable energy systems depends heavily on the size of the system and the production volume. However, the necessary production capacities will go hand in hand with a high space requirement for wind power plants, ground-mounted PV and particularly if biomass-based electricity is used for electrolysis to produce green hydrogen. If land is scarce or densely populated, there may be a lack of acceptance for additional renewable electricity generation plants that are built exclusively or predominantly for hydrogen production and thus arise in addition to the expansion needs for decarbonising electricity. In this case, green hydrogen production and use will be mainly feasible through imports of renewable electricity, hydrogen, or other synthetic fuels.

However, the acceptance of the production and export of renewable energy in other countries will also depend to a very large extent on how the projects are implemented: If the country of production benefits and the local population perceives more positive than negative effects, the acceptance on site is considered highly valued. It is important that the potential exporting countries are given development opportunities through the new technology, e.g. by the creation of jobs and added value, improvement of the individual economic perspective, potential co-benefits with regard to electricity availability and infrastructure, and avoidance of negative social effects.

What needs to be monitored are the effects that the production facilities have on the decarbonization of the energy system in the respective production country and whether there are possible negative effects on the costs of electricity generation on site. This is where opinions differ. Environmental associations and the Öko-Institut[55] emphasize that the decarbonization of the production countries has priority over synthetic fuel production and that the best locations for renewable electricity generation must not only

[55] Kasten&Heinemann (2019), *op.cit.* p. 15

be used for export-oriented hydrogen or other fuel production. Industry players do not see this risk. There is likely to be a need for further research here.

With regard to this criterion, the three discussed options for additionality of the renewable electricity will probably not differ a lot within a country, except for the timing and exact location of electrolysers; they will rather differ between domestic hydrogen production in the country of hydrogen demand and international trade with exporting and importing countries. Under additionality option 2), the electrolysers will be built in regions with early excess green power capacities, whereas in option 1) they may be built later and closer to centres of demand. Option 3) may be similar to option 2), using the best green power generation sites for early development of green hydrogen production. Many positive or negative social impacts are likely region- or even site-specific. To the extend that the three options lead to a different distribution of electrolysers in time and space, they may therefore lead to different net impacts. There will be similar relative impacts of the three options within a hydrogen exporting country. In addition, options 1) and 2) will not hamper domestic decarbonization and distort power prices in these countries, since they require that already 100 % of the power demand is covered by renewable energies, but may even accelerate decarbonization if further renewable energy generators are built for the electrolysis. The risk of hampering domestic decarbonization and distorting power prices is much higher for option 3). For other social impacts, the differences may be much stronger between domestic hydrogen production or production in a hydrogen exporting country.

Water demand and land use

From a sustainability perspective, it is indisputable that renewable energy capacities must not have negative impacts on the local drinking water supply for agriculture and households. Green hydrogen production will require significant amounts of water for the electrolysis. If biomass-based electicity is used as an input, there will also be high water demands for irrigation in many countries. However, to set up production capacities for green hydrogen and additional renewable energy facilities in regions with water scarcity may have both, negative and positive effects on a local level: on the one hand, there could be increasing water costs and scarcer water availability. Regions with high solar radiation apparently suit the best for solar power, but are often the most arid regions (e.g. Middle East, North Africa). Increasing installations of large utility-scale systems based on renewable energies may strongly affect local communities and not only lead to positive effects. Terrapon-Pfaff et al (2019)[56] analyzed, on a local level, a solar thermal power plant in Morocco. They showed how during the plant construction and plant operation phase also negative effects from renewable energy facilities on the water availability are to be expected if no respective countermeasures are implemented (a list of about 30 local indicators was used to conduct the impact assessment. In desalination plants, local ecological damage can also occur due to the return of the brine enriched with salt and chemicals to the environment. On the other hand, as a positive effect, local communities could also benefit through increased water availability due to sea water desalination facilities built for the electrolysis[57].

Sustainability criteria must be defined in order not to deteriorate the water availability and quality at the respective production location through renewable energies and hydrogen production. This is an important prerequisite for avoiding discussions similar to the tank-plate problem with biofuels and the resulting potentially low acceptance[58].

For plants supported by policy measures, the implementation of sustainability measures and their independent evaluation should be mandatory.

Regarding *land use*, involved stakeholders call for usage criteria that specify areas of land worth protecting, which are defined in a similar way to biofuels under the Renewable Energy Directive[59].

For the assessment of the area potential, *criteria for the assessment with regard to the renewable electricity generation* as well as the usage potential of the electricity have to be developed. Such evaluation criteria are the prerequisite for the development of verification procedures with regard to electricity and CO_2 purchases[60].

The space used for all plants along the value chain must comply with the applicable standards for the protection of biodiversity and carbon storage in soils and biomass.

Participation procedures of the local population and compliance with possible distance regulations are the minimum standard for the construction of green hydrogen systems. In the long term, further investigations are necessary in order to be able to assess the

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[56] Terrapon-Pfaff et al (2019): *Social impacts of large-scale solar thermal power plants: Assessment results for the NOORo I power plant in Morocco.*

[57] Kasten & Kühnel (2019): *Positionen zur Nutzung strombasierter Flüssigkraftstoffe (efuels) im Verkehr, Darstellung von Positionen verschiedener gesellschaftlicher Akteure zum Einsatz von efuels im Verkehr.*

[58] Ibid.

[59] Ibid.

[60] Ibid.

maximum use of space and the resulting, socially accepted green hydrogen or PtX expansion per region.

A sustainability assessment based on local indicators needs to be conducted that includes effects on water and land supply, changing costs, possibilities to adapt or participate for the affected population, and protection of the biodiversity.

It is important in order to minimize risks for the affected communities, but also for respective investors and companies. Further research on such an impact assessment, defining standardized criteria, as well as evaluating and managing the impacts of large-scale renewable energy and green hydrogen projects need to be continued.

How do the three options differ with regard to sustainable water usage and land use?

The potential impacts of green hydrogen production with regard to these criteria will also be very specific to countries, regions, or even sites. The three options fo defining additionality of the green electricity will, therefore, show the same principal similarities or differences between each other as discussed for the social impact criterion above.

Particularly for option 3, assessment and decision tools are also needed to ensure that using the best renewable power production sites for hydrogen intended for exports or for companies' hydrogen production does not negatively affect domestic decarbonization efforts or costs, nor affordable power or hydrogen supply for consumers and other companies, as well as water and land use, particularly in developing/emerging countries.

	Option 1) Excess green power	**Option 2) Regional excess green power**	**Option 3) Political or economic link**
Energy source / definition of clean hydrogen	Green electricity with full or partial additionality	Green electricity with full or partial additionality at regional level	Green electricity with full or partial additionality due to political or economic link
GHG balance	target values to be determined; calculated according to definition in chapter 4.1, over life-cycle chain	target values to be determined; calculated according to definition in chapter 4.1, over life-cycle chain	target values to be determined; calculated according to definition in chapter 4.1, over life-cycle chain
Additionailty of renewable electricity generation	strong (physical) additionality as defined in chapter 4.1	strong (physical) additionality as defined in chapter 4.1	weak (political or economic) additionality as defined in chapter 4.1
CCUS for blue	not relevant	not relevant	not relevant

	Option 1) Excess green power	Option 2) Regional excess green power	Option 3) Political or economic link
hydrogen			
Water demand	Assessment criteria and indicators to be developed. Impact can be positive if desalination or other water supply for electrolysis produces "spill-over" for local communities; or negative if existing scarce water resources are used for electrolysis (or irrigation of bioenergy plantations)	Assessment criteria and indicators to be developed. Same potential impact as for Option 1) but may occur earlier and in different places	Assessment criteria and indicators to be developed. Same potential impact as for Option 1) but may occur even earlier and yet in different places than Option 2)
Land use	Assessment criteria and indicators to be developed Land use conflicts may arise particularly if green electricity used for electrolysis is based on agricultural biomass, but are possible for ground-mounted PV and onshore wind too, depending on loation.	Assessment criteria and indicators to be developed Same potential impact as for Option 1) but may occur earlier and in different places	Assessment criteria and indicators to be developed Same potential impact as for Option 1) but may occur even earlier and yet in different places than Option 2)
Social impacts	Assessment criteria and indicators to be developed Social impact may be small (100 % RES-E supply is already achieved) or positive (e.g. employment, economic development), but there may be social and acceptance problems in case of negative water and land use impacts	Assessment criteria and indicators to be developed Same potential impact as for Option 1) but may occur earlier and in different places	Assessment criteria and indicators to be developed Same potential positive impact as for Option 1) but bears a much higher risk of hampering domestic decarbonization and distorting power prices; may also occur earlier and in different places

Table 5: Qualitative assessment of the three options for defining additionality of renewables-based electricity

4.3 Political standards for defining and options for ensuring additionality

A compromise needs to be found between immediate GHG emissions reductions and the need to develop hydrogen supply and use technologies and infrastructures already in the short to medium term, so that they are ready when the supply chains for green and blue hydrogen will have been built.

This compromise could be to allow hydrogen from electrolysis to be labelled as green hydrogen under either of the following conditions:

1. Hydrogen with a *proven political and/or economic link* to additional green electricity production capacity, for an interim period of between 5 and 10 years from now on, and meeting the other sustainability criteria;
2. Hydrogen that meets, through *partial physical additionality,* the specific GHG emissions threshold for clean hydrogen adopted in an agreed international and/or national certification scheme, as well as the other sustainability criteria.

4.4 Potential sources of CO_2 for producing synthetic fuels from green hydrogen

The CO_2 source is relevant for the climate protection effect

The chemical synthesis from green hydrogen into hydrocarbons (methane, diesel, kerosene, plastics, chemicals) is a potential means to reduce CO_2 emissions of combustion processes or the eventual decay of plastics or chemicals. The synthesis requires CO_2 as a resource input. The green hydrogen provides the climate-neutral energy source, while the CO_2 can be neutral during combustion of the fuel, if it was originally taken from the atmosphere or would have been released to it anyway. However, if the CO_2 source is unsuitable, for example if fossil fuel is intentionally burnt to obtain CO_2 for producing synthetic fuels, such a CO_2 source may produce hydrocarbons that are equivalent to fossil substances in terms of their specific GHG emissions and do not contribute to any GHG reduction[61]. For example, this is why it does not make sense to produce synthetic fuels from blue hydrogen: blue hydrogen is produced from fossil fuels with separation of the CO_2. If synthetic fuel were produced by recombining the blue hydrogen with the CO_2 and then burnt, the CO_2 would be released to the atmosphere just as if the original fossil fuel was burnt.

[61] Kasten & Heinemann (2019), *op. cit.*

CO_2 from industry processes

From an economic point of view, carbon capture from industrial point sources is attractive, as industrial and combustion processes produce concentrated CO_2. High availability of CO_2 at one location and the low energy requirement for CO_2 capture form a clear advantage. Proponents argue further that in some industrial processes, there are unavoidable CO_2 emissions (e.g. lime burning in cement klinker production), and such CO_2 emissions will continue to be generated for several decades despite the industry's climate protection efforts.

However, as long as there are no suitable criteria for avoiding additional CO_2 emissions, synthetic fuel production with CO_2 from these sources is associated with a high risk of additional CO_2 emissions and a slower transformation of the industrial sector. Synfuels based on these CO_2 sources can therefore have the same climate impact as their fossil alternatives simply by using CO_2. In fact, the use of CO_2 could lead to lock-in effects, stabilizing such production processes, slowing down emissions reduction and the transformation of industrial processes, and increasing the CO_2 release beyond the reference required for climate protection. Finally, carbon capture in industrial processes also significantly reduces the efficiency of production processes, and as long as fossil resources are used in industrial processes, these can’t be considered a fully renewable CO_2 supply.

Biomass and direct air capture

The use of biogenic and atmospheric carbon sources can allow a circular process of CO_2 without causing an additional greenhouse gas effect. The use of CO_2 from sustainable biomass and the air are the only renewable sources that do not cause GHG emissions, if the necessary sustainability rules for biomass use and energy supply are observed.

Biomass

The advantage of *biomass combustion* is that an “indirect” renewable carbon cycle can be created here, and sequestration costs will be low, if the biomass is used in larger power and/or heat generation plants. From a sustainability perspective, the same usage criteria apply to the CO_2 source from biomass combustion as in the existing discussion about biomass use. The disadvantage of this CO_2 source is the limitation of the available amount of sustainable carbon and the low availability of biomass at some preferred solar and wind power locations. In addition, there could be competition for the use of biofuels in the transport sector that is difficult to decarbonize, or in terms of land use for food production.

Direct air capture

The clear advantage of *Direct Air Capture* is that CO_2 from the air is available in large quantities, and that there is a direct carbon cycle when using it. It is therefore often considered as the central carbon source for PtX applications in the long term[62]. There are no other sustainability issues apart from possible effects on land use.

A disadvantage of DAC, however, is the state of the art (CO_2 separation from the air is in the demonstration and development phase) and the economic disadvantages compared to the other sources of supply that result from the low concentration of CO_2 in the air (only 0.4 per mille can be taken from the atmosphere). The technology will therefore only be available in practice in the medium term and as a comparatively expensive option. In addition, it will need excess or dedicated green electricity for operating the DAC plants. Technology-specific funding for the further development and scaling of the technology appears to be expedient.

Conclusion

Sustainable and cheap CO_2 will be a scarce commodity. In the longer term future, when power generation and industry may have been converted to a carbon-neutral operation without fossil fuels, CO_2 will not only be in demand as an ingredient to energy carriers, but also for material use in basic and specialty chemicals, where only partial alternatives exist. The material use is to be preferred. In the event of strong competition for use and high demand, more and more expensive and space-intensive direct CO_2 capture from the air will have to be resorted to. As a consequence, for CO_2 applications, for which there are no alternatives, an unsuitable allocation of CO_2 leads to unnecessarily high costs and possibly to quantitative bottlenecks for CO_2 sourcing. The long-term storage of CO_2, which may be necessary in the long term for the generation of negative emissions, could also be affected by this competition effect.

In order to avoid higher costs and possibly availability restrictions of climate-friendly options in these applications, a priority allocation of the available CO_2 in PtX applications with a high efficiency potential or in applications with few alternative technology options to greenhouse gas-neutral hydrocarbons could help. The exclusion or limitation of

[62] Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018): *The Future Cost of Electricity-Based Synthetic Fuels.*

industrial CO_2 sources for synfuel production would prevent this risk[63] . A compromise could be to develop suitable criteria that allow the use of fossil emissions in PtX products at least for a temporary transition phase and at the same time ensure that no or only a few additional GHGs arise with PtX production[64].

[63] Kasten&Heinemann (2019), *op.cit.* p. 20; Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018), *op. cit.*

[64] Kasten & Heinemann (2019), *op. cit.* pp. 20-21

5. Conclusions on an international certification scheme for clean hydrogen

5.1 The potential role of blue and green hydrogen in building up a hydrogen society

Based on the analysis provided in chapter 3, blue hydrogen should work as a transition measure that enables CO_2 reduction at large scale until green hydrogen becomes more available and affordable. An advantage of blue hydrogen is to enable unexploited fossil fuels to be utilized in an environmental manner and to enhance energy security. To make blue hydrogen acceptable, CCS technology needs to be advanced in order to improve safety, reduce costs, and receive public support.

In contrast to blue hydrogen, green hydrogen can be zero-carbon in production if the electricity used is from *additional* green, i.e. renewable energy-based generation. Proving this as *full* additionality on a system level in physical terms may only be possible in the long term in many countries, because it requires that 100% of the electricity demand before electrolysis is covered from green electricity. Therefore, chapter 4 discussed potential alternatives to allow for earlier deployment of electrolysis-based hydrogen and its consideration as 'green'. Like for blue hydrogen, reducing costs is an important goal.

After all, a compromise needs to be found between immediate GHG emissions reductions and the need to develop hydrogen supply and use technologies and infrastructures already in the short to medium term. The following strategic and policy principles for such a development based on green hydrogen appear adequate; the fourth principle also applies to use of blue hydrogen[65]:

"1. The electricity for the operation of the electrolysis plants should come from additional renewable energy plants. These need to be added and the national expansion targets for renewables increased accordingly. And: Hydrogen does not go green by buying proof of origin for the electricity you need.

2. The electrolysis plants should react flexibly to the feed-in of renewable energies. Technically, this is possible for most types of plants; however, the framework conditions must ensure that the electrolysers are also operated in accordance with the wind and PV feed-in.

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[65] translated from Heinemann (2019): *Nachhaltigkeit in die Nationale Wasserstoffstrategie*.

3. No network bottlenecks should be exacerbated by the operation of the electrolysis plants. Otherwise it can be expected that the total system costs will increase unnecessarily. Electrolysis plants should therefore preferably be set up before network bottlenecks.

4. Hydrogen should be directed into applications in which no or only limited alternatives to achieving climate neutrality are expected in the long term. Funding should therefore not only stimulate the production of hydrogen, but also "hydrogen readiness" in the application areas and infrastructures at an early stage. Energy efficiency measures, electrification and other climate protection solutions in other areas of application must not be delayed by the introduction strategy of hydrogen technologies.

With these requirements for a funding strategy, firstly, the climate advantage of hydrogen can be ensured, secondly, investment security can be guaranteed, and thirdly, hydrogen can be credibly developed as a robust climate protection option on the way to climate neutrality. The next ten years should be used to prepare the long-term developments necessary for this.

Incidentally, these requirements must also apply to imported hydrogen. A climate neutrality strategy for Germany and Europe will require relevant imports of hydrogen and its secondary products in the medium term. In addition, there are additional requirements, for example with regard to water or land use and the balance with the climate protection strategies of the exporting countries. The definition of comprehensive sustainability criteria for domestic and imported hydrogen must therefore be a central part of the national hydrogen strategy."

Such comprehensive sustainability criteria obviously should cover both blue and green hydrogen in an integrated and non-discriminatory manner, and optimally would do so no matter if it is domestically produced or internationally traded. Therefore, we first need to address this aspect in chapter 5.2, before concluding in what could be adequate certification criteria for blue and green hydrogen in chapter 5.3.

5.2 General aspects of an international certification scheme for clean hydrogen

In order to analyse the GHG reduction potential, it will be necessary to compare the whole value chain from clean hydrogen production and supply to its use in different applications with the traditional energy sources and use technologies. This is why in chapter 2.2, we suggested to base a certification on this "well-to-wheel" principle.

However, the result of such comparisons first makes the GHG reduction criterion dependent on the hydrogen application, and second even on the conditions for hydrogen distribution and dispensing in different countries.

For example, in chapter 2.2, we identified at least three different routes of clean hydrogen application:

1. Uses, in which green or blue hydrogen replaces fossil fuels in the same combustion technology or process. In this case, the *benchmark* for clean hydrogen would be *natural gas as the fossil fuel with the lowest GHG emissions*, and the *hydrogen supply chain including distribution to the site of use* would be the relevant system to assess.
2. Using green or blue hydrogen as a feedstock. The *benchmark* for clean hydrogen would be *conventional hydrogen*, and the *hydrogen supply chain including distribution to the site of use* would be the relevant system to assess.
3. Uses in transport or other sectors, in which fuel cells are replacing internal combustion engines or combustion turbines. The *benchmark* would be *using fossil fuels in engines or turbines*, and a *well-to-wheel assessment* would be the relevant systems perspective. A similar principle of analysis would apply to other applications, in which hydrogen is coupled with new processes, such as in hydrogen steel-making.

For these differences in hydrogen applications and national distribution and use conditions, we may conclude that a comprehensive international hydrogen certification system could have two separate parts:

1. An *international certification system for clean hydrogen traded internationally*. The adequate systems boundary would be a *well-to-border gate* assessment of specific GHG emissions combined with other sustainability criteria, as discussed in chapters 2.2, 3, and 4. Stopping the assessment at the border gate would exclude the differences in hydrogen applications as well as national distribution and use conditions, and thus avoid discrimination between different sources of clean hydrogen. Setting a universal absolute threshold level of specific GHG emissions until the border gate will avoid using and defining a benchmark.

2. An *internationally agreed national certification system* for
   a) domestic parts of the supply and use chain ("*border gate to wheel*")
   b) domestically produced and used hydrogen ("*well to wheel*").
   This would determine assessment criteria, principles, and methods, as well as which data to publish, but no universally applicable numbers for benchmarks or thresholds.

Both parts together should certainly achieve **significant GHG reductions** for each application case or sector in the *well-to-wheel* assessment. A level of **60% or more compared to the relevant benchmarks would be desirable**. However, it seems appropriate to allow **some flexibility** for nationally determined levels of benchmarks or thresholds for GHG reductions, given the differences in sectoral priorities for achieving highest GHG emissions reductions or in availability of low-carbon energy resources both for hydrogen and its alternatives. Still, the assessment principles and methods, and publication requirements of the international certification system would need to be followed.

In the following chapter 5.3, we will analyse which thresholds of GHG emissions could be appropriate for blue and green hydrogen.

5.3 Adequate certification criteria for blue and green hydrogen

5.3.1 Potential specific GHG emission threshold level for internationally traded clean hydrogen

First, we will analyse the potential universal absolute threshold level of specific GHG emissions until the border gate that blue and green hydrogen could meet.

From chapters 2 and 3 and the sources cited therein, we found the following values for production of blue hydrogen:

a) from coal: 17 g CO_{2eq}/MJ_{H2}[66]; 15.8 g CO_{2eq}/MJ_{H2} for hydrogen production in Australia[67]; 43.3 g CO_{2eq}/MJ_{H2}[68].

b) from natural gas: 7.5 g CO_{2eq}/MJ_{H2}[69]; 30.3 g CO_{2eq}/MJ_{H2}[70].

[66] IEA (2019), *op. cit.,* with 90 % capture; coal supply is not included)

[67] IEEJ calculations cited in chapter 3.1, with 90 % capture and EAGLE gasification technology; excluding emissions of coal production in Australia

[68] JRC (2014), *op. cit.*; of which coal supply is 37.5 g CO_{2eq}/MJ_{H2} and hydrogen production through coal gasification with CCS is 5.8 g CO_{2eq}/MJ_{H2}

[69] IEA (2019), *op. cit.,* with 90 % capture; natural gas supply is not included

[70] JRC (2014), *op. cit.*; of which natural gas supply is 5.8 g CO_{2eq}/MJ_{H2} for producton and conditioning at source plus 12 g CO_{2eq}/MJ_{H2} for pipeline transport to market, and hydrogen production through steam

These numbers are spanning quite a large range for hydrogen production already. However, the range is mostly due to the emissions from coal and natural gas supply. These are likely due to the fuels and electricity used for coal mining and transport as well as gas extraction and transport. This could, therefore, be reduced by e.g. using green electricity and hydrogen fuel cell trucks and equipment for coal mining. This would probably not increase the cost of the blue hydrogen significantly.

We therefore conclude that blue hydrogen production could be achieved with GHG emissions as low as around 20 g CO_{2eq}/MJ_{H2}.

For green hydrogen, typically emissions for production from green electricity are assumed to be 0 g CO_{2eq}/MJ_{H2}[71]. However, as discussed in chapter 4, in a strict sense this will only be the case if there is full physical additionality of the green electricity. A threshold of 20 g CO_{2eq}/MJ_{H2} would allow blending in a certain share of electricity from fossil fuels. According to own calculations, this could be between 10 and 14 % (upper value: combined-cycle natural gas power plant). This would, in turn, enable an increase in electrolyser operation hours of between 11 and 17%. Although this is not much, it would improve cost-effectiveness of the electrolyser process. On the other hand, if political additionality is allowed along the principles outlined in chapter 5.1 (i.e., increasing national targets for green electricity expansion, requiring flexible electrolysers and situation before grid bottlenecks), the GHG emissions for green hydrogen production will per se be 0 g CO_{2eq}/MJ_{H2}.

In addition to production, the emissions from transport of hydrogen to the border gate of the importing countries need to be included the calculation. These will depend on the distance (e.g. the way from Norway to Germany is shorter than from Morocco to Germany, and much shorter than from Australia to Japan or from Chile to either Japan or Germany) as well as on the means of transport – pipeline or vessel, and even the form of gas or liquid carried, e.g. liquified hydrogen or methylcyclohexane.

According to the JRC (2014) study, e.g. the process with central steam reforming and liquefaction would emit ca. 35 g CO_{2eq}/MJ_{H2} more than the process with central steam reforming but no liquefaction. However, this could again be reduced by using green electricity for the liquefaction process.

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reforming with CCS is 12.5 g CO_{2eq}/MJ_{H2}. The value for hydrogen production at the gas production site would therefore be 18.3 g CO_{2eq}/MJ_{H2}

[71] IEA (2019), *op. cit.;* JRC (2014), *op. cit.*

In order to stimulate innovation and efforts for reducing transport distances and emissions, the extra GHG emissions allowed for transport to the border gate should not exceed 10 g CO_{2eq}/MJ_{H2}.

Together with the 20 g CO_{2eq}/MJ_{H2} discussed above for clean hydrogen production, this would yield a potential total maximum universal absolute threshold level of specific GHG emissions until the border gate of 30 g CO_{2eq}/MJ_{H2}. This would be around half of the border-gate GHG emissions of natural gas, the fossil fuel with the lowest GHG emissions, so enable significant GHG emissions reductions of at least 50 % from the start. It would be defined to include both production and transport, to allow flexibility between both.

As soon as technology developments allow, this threshold should be reduced further, eventually to zero by 2050 the latest. Therefore, the system should also provide incentives to go below the maximum universal absolute threshold level sooner than its revisions in order to prevent lock-in effects. For example, a second 'clean premium' level of GHG emissions 30 or 50% less than the maximum universal absolute threshold level could be set.

In addition, the clean hydrogen should meet further sustainability criteria on water and land use, and social justice, as discussed in chapter 2.2.

5.3.2 Potential well-to-wheel GHG reductions and corresponding specific GHG emissions requirements for clean hydrogen

For assessing whether the total supply and use chain (well to wheel) emissions can be reduced by at least 60 or 70 % as it would be desirable, we have to differentiate by types of applications. We can only do this for the three major types of applications discussed above. Still, this can inform national policy-making in Germany, Japan, and other countries on what could be appropriate threshold values for the national part of the international certification system and for domestically produced green hydrogen, at least for these types of applications.

Case 1) Uses, in which green or blue hydrogen replaces fossil fuels in the same combustion technology or process.

This case concerns, for example, the use of hydrogen in thermal power plants or gas boilers. Although these technologies may need to be modified to use hydrogen instead of fossil fuels, the basic processes are the same. In this case, the *benchmark* for clean hydrogen would be *natural gas as the fossil fuel with the lowest GHG emissions*, and the *hydrogen supply chain including distribution to the site of use* would be the relevant system to assess.

A 60% or 70% reduction would mean that the carbon footprint of hydrogen *supplied to final use* would have to be below 26.8 or 20.1 g CO_{2eq}/MJ_{H2} respectively. In addition to the production and transport emissions, these would include GHG emissions from domestic transport, storage, and dispensing. According to the JRC (2014), the difference between production and total life-cycle, i.e. storage, transport, dispensing, is around 13 g CO_{2eq}/MJ_{H2}. A clean hydrogen just meeting the threshold value we derived in chapter 5.3.1 of 30 g CO_{2eq}/MJ_{H2} would thus cause total GHG emissions of supply of 43 g CO_{2eq}/MJ_{H2}. This would not meet either of the desired 60 or 70% total reduction in this case.

Therefore, domestic storage, transport, and dispensing would need to be decarbonised too, in order to meet at least the 60% threshold (26.8 g CO_{2eq}/MJ_{H2}) when using domestic blue hydrogen or internationally traded clean hydrogen: e.g., through hydrogen ships and trucks for transport, and green electricity for pipelines and compressors.

Still, internationally traded clean hydrogen would need to be cleaner than the maximum threshold of 30 g CO_{2eq}/MJ_{H2}. And 70% total supply chain reductions (20.1 g CO_{2eq}/MJ_{H2}) would likely be out of reach for coal-based blue hydrogen (16 to 17 g CO_{2eq}/MJ_{H2} in production alone). Blue hydrogen from natural gas with 90% capture has 7.5 g CO_{2eq}/MJ_{H2} for production[72]. Adding the 13 g for distribution will yield 20.5 g CO_{2eq}/MJ_{H2}. So this could be well below the 60% well-to-dispenser threshold and with some optimisation in the supply chain may also be able to get to 70%. However, it would need to avoid methane emissions from natural gas production and pipeline transport (JRC 2014). Hence, if CCS off the Norwegian coast could be proven to have long-term stability and sustainability, blue hydrogen from Norway could be an option for Germany meeting even the 70% threshold.

Conclusion on case 1): For blue hydrogen to have a chance, a 60 % threshold vs. natural gas appears feasible. Green hydrogen and possibly blue hydrogen from natural gas could even achieve 70 %. Again, it may be an option to establish two levels of national certification for this case, e.g. 'clean' hydrogen = 60%; 'clean premium' = 70% of well-to-dispenser GHG emissions reductions vs. natural gas.

Case 2) Using green or blue hydrogen as a feedstock.

The *benchmark* for clean hydrogen use as a feedstock in industrial processes would be *conventional hydrogen* (91 g CO_{2eq}/MJ_{H2} according to CertifHy), and the *hydrogen supply chain including distribution to the site of use* would be the relevant system to assess.

[72] IEA (2019)

This case has the same benchmark as the CertifHy certification scheme, and with 60% of reduction also the same value of 36.4 g CO_{2eq}/MJ_{H2}, however it would be defined on a well-to-dispenser calculation. 70% of reduction would be equivalent to 27.3 g CO_{2eq}/MJ_{H2}, very close to the 60% for case 1) but already below the threshold level suggested for internationally traded clean hydrogen.

So for applications in case 2), clean hydrogen could be defined via the threshold level suggested for internationally traded clean hydrogen plus 6 g CO_{2eq}/MJ_{H2}, and 'clean premium' in the same way: 'clean premium' level for internationally traded hydrogen plus 6 g CO_{2eq}/MJ_{H2}.

- The absolute GHG reductions for this case would be higher than in case 1), so if industry currently uses conventional hydrogen produced e.g. by methane steam reforming without CCS as a feedstock, this application of clean hydrogen will yield higher benefits for the climate than e.g. using it in power plants. On the other hand, why should this case be allowed higher GHG emissions for the clean hydrogen?

So could there be a joint definition for well-to-dispenser 'clean' hydrogen and 'clean premium' hydrogen in g CO_{2eq}/MJ_{H2}? This would avoid the need for efforts to prevent fraud that could arise through buying clean hydrogen certified for case 2) and using it in case 1) applications.

However, using the thresholds for case 2) (e.g. 36 and 27 g CO_{2eq}/MJ_{H2} for clean and clean premium hydrogen) would reduce the savings in case 1) to 46 and 60%, respectively, while using the thresholds for case 1) (e.g. 27 and 20 g CO_{2eq}/MJ_{H2}) would risk to exclude blue hydrogen from coal.

Case 3) Uses in transport or other sectors, in which fuel cells are replacing internal combustion engines or combustion turbines.

- The *benchmark* would be *using fossil fuels in engines or turbines*, and a *well-to-wheel assessment* would be the relevant systems perspective. A similar principle of analysis would apply to other applications, in which hydrogen is coupled with new processes, such as in hydrogen steel-making.

For example in transport, the GHG emissions reductions in this case will depend on the relative efficiency of fuel-cell vehicles (FCV) vs. vehicles with internal combustion engines. Diesel has 85 g CO_{2eq}/MJ of emissions. The fuel efficiency of FCV is roughly twice that of Diesel cars[73]. Therefore, a reduction of 60% can be achieved with hydrogen supplied at ca. 66 g CO_{2eq}/MJ_{H2}, while hydrogen with around 50 g CO_{2eq}/MJ_{H2} would even reduce per

[73] DLR et al. (2015)

km GHG emissions by 70% (own calculations). This should be easy to meet with blue hydrogen and also with hydrogen from electrolysis, with 24% (mix coal/gas; 70% reduction) to 47% (CCGT with natural gas; 60% reduction) of the electricity coming from fossil fuel power plants. Even 75% of reductions would be within reach for blue hydrogen, being equivalent to ca. 41 g CO_{2eq}/MJ_{H2} for the hydrogen.

However, as for case 2), the question arises whether it would be justified to differentiate certification criteria between application cases within a country.

6. Potential for international cooperation on clean hydrogen, and the potential role of Germany and Japan

Hydrogen could be an energy carrier of bringing low cost renewable energy or transporting unutilized fossil fuels from one part of the world to another. As shown in Figure 1, the last year's study[74] identified countries that have large potential for low-cost green hydrogen as well as those with high potential of blue hydrogen. This chapter looks at possibilities of international cooperation between producers and importers of clean hydrogen and the roles that Germany and Japan could take to promote such cooperation, from three perspectives, i.e., the supply side, the demand side, and the international standards.

On the demand side, countries with high priority of promoting hydrogen applications while facing a high production cost of domestic clean hydrogen, such as Japan or South Korea as well as Germany, could become importers in the early phase. In the longer term, when the market for clean hydrogen applications scales up, clean hydrogen is likely to be traded more actively in the international market.

However, the following conditions need to be fulfilled to establish an international supply chain for clean hydrogen:

(a) the supply side: supply costs for clean hydrogen, including costs of production, shipping, storage, and delivery, should be competitive;

(b) the demand side: the market for clean hydrogen requires to be scaled up to ensure enough off-takers;

(c) the international standards: common definition and criteria for clean hydrogen, and its certification method agreed at the international level need to be established (cf. chapter 5).

(a) Supply side

Looking at the supply side of clean hydrogen, though the supply cost of clean hydrogen is still high and international shipping of hydrogen has not started yet, Japan and Germany are making efforts of working with potential producers for developing the international clean hydrogen supply chain. For example, a pilot project which Japan and Australia aiming at commercializing the international hydrogen supply chain is underway with

[74] Jensterle et al. (2019), *op. cit.*

supports from the New Energy and Industrial Technology Development Organization (NEDO), Japan, and Australia's Federal Government and State Government of Victoria. Key components of the project include: hydrogen production using brown coal gasification with CCS, as well as international hydrogen shipping with liquefied hydrogen as the carrier. The pilot project operation will be conducted in 2020-2021. The CO_2-free Hydrogen Energy Supply-chain Technology Research Association (HySTRA) was formed in 2016 by several Japanese companies. In addition, another pilot project focusing on international transportation of hydrogen by methylcyclohexane (MCH) is also underway and the project started first shipping on December 18, 2019. [75] Furthermore, the GAC (Green Ammonia Consortium) aims to establish a CO_2-free ammonia (NH_3) supply chain in the mid of the 2020s.

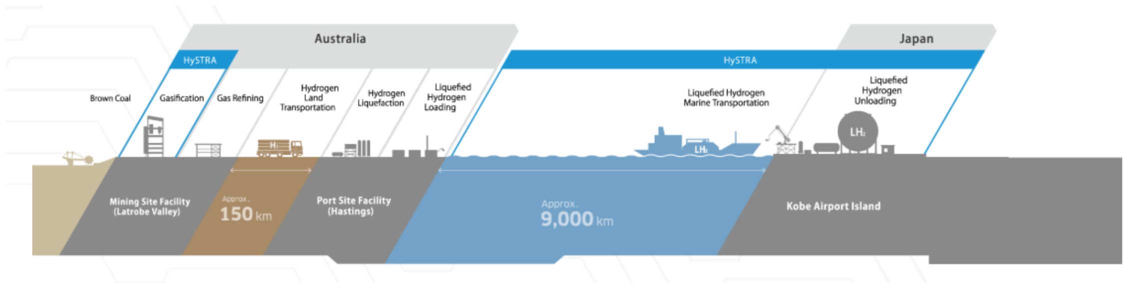

Figure 13: Hydrogen Energy Supply Chain Project between Australia and Japan

Source: HySTRA[76]

As another case, German conglomerate Siemens announced that it would be a partner for a 5GW green hydrogen project "Murchison Renewable Hydrogen Project" in West Australia.[77] The company will provide electrolyzer technology for the project. Besides the local use for the transport sector and gas pipeline blending, green hydrogen produced from combined wind and solar power is expected to be exported to potential Asian markets, notably Japan and Korea.

[75] AHEAD (December 18, 2019). "- World's first international transport of hydrogenForeign-produced hydrogen has arrived in Japan for the first time from Brunei Darussalam." Available at: https://www.ahead.or.jp/en/pdf/20191218_ahead_press.pdf

[76] HySTRA. Available at: http://www.hystra.or.jp/en/project/

[77] Siemens (8 October, 2019). "New Renewable Hydrogen Project at Australia's Best Combined Solar and Wind Site Announced." Availablle at: https://new.siemens.com/au/en/company/press-centre/2019/murchison-renewable-hydrogen-project.html

In Europe, Norway is a potential supplier of both blue and green hydrogen at low cost, including to Germany. Morocco, Algeria, Egypt, Turkey, and Russia are other potential suppliers of green hydrogen that could be linked to Germany with hydrogen pipeline infrastructures[78].

Technology feasibility and maturity is the foundation for establishing the international clean hydrogen supply chain. As the above examples show, Germany and Japan, which are leading the world in technology and manufacturing, can help build the hydrogen supply chain as technology providers – but also as hydrogen importers creating early and significant demand, as will be discussed in the next section.

(b) Demand side

Scaling up the market for clean hydrogen is on the other end of the international hydrogen supply chain equation. Today, hydrogen is already used in several industrial sectors such as chemicals and oil refinery; this is for example an important use in North Rhine-Westphalia, Germany, as well as the adjacent Netherlands. Semiconducter industry sector and food industry sector are also promising markets for clean hydrogen though they are smaller-scale. This is because the supply cost of grey hydrogen used in these industries is high, which makes clean hydrogen more competitive. Substitution of the current fossil-fuel-based hydrogen is one of the potential market segments for clean hydrogen in the short term.

In the longer term, according to the IEA's analysis[79], Iron and Steel, road freight transport, marine and aviation transport, buildings (switching to 100% hydrogen), and electricity storage are expected to have high potentials for clean hydrogen demand. Chapter #7 presents further information on future potential hydrogen use in industry.

Germany and Japan have both gained experiences on hydrogen applications though each country focuses on different areas. Since Germany is more experienced in green hydrogen and Power-t-X (PtX), there are more than 50 PtX projects in operation or planning. In the Germany's PtX projects, clean hydrogen is sold to a nearby hydrogen refueling station, injected to natural gas pipeline, or used for producing carbon neutral synthetic fuel. For example, in the Westküste 100 project, green hydrogen produced from offshore wind surplus will be combined with CO_2 captured from a cement mill to produce carbon neutral synthetic methanol that will then be refined into aviation fuel (synthetic kerosene). The

[78] Jensterle et al. (2019b): *Grüner Wasserstoff: Internationale Kooperationspotenziale für Deutschland.*

[79] IEA (2019). *Op.cit*. Pp.169-170

Westküste 100 project will start from a electrolysis capacity of 30MW and then is expected to be further scaled up to 700 MW.[80] There is a salt cavern on the land of the project, so a large amount of green hydrogen can be stored and eventually be transported to other end use destinations including injection into the natural gas network. Raffinerie Heide, a refinery company, plays a central role in the project, with other partners such as industrial giant Thyssenkrupp, EDF Energy, Orsted, and others.

Figure 14: Concept of the Westküste 100 project

Source: adapted from Westküste 100[81]

On the other hand, Japan focuses on residential fuel cells and fuel cell vehicles as well as hydrogen power generation. Japan is the world's largest market for the residential fuel cell (Ene-Farm). As of the end of 2018, there are more than 0.27 million Ene-Farms installed in Japan and the government aims to increase its installations to 5.3 million by

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[80] Raffinerie Heide (20 May, 2019). "Cross-sector partnership: Green hydrogen and decarbonization on an industrial scale." Available at: https://www.heiderefinery.com/en/press/press-detail/cross-sector-partnership-green-hydrogen-and-decarbonization-on-an-industrial-scale/

[81] Westküste 100. Available at: https://www.westkueste100.de/

2030.[82] Japan is also leading the fuel cell vehicle development. Japanese car manufactures, Toyota and Honda, are among the few original equipment manufacturers that have launched commercial types of fuel cell vehicles. Germany has a first fuel cell train in operation and is expanding its fleet of fuel cell buses, although still at low numbers. Besides, in Japan's hydrogen strategy, hydrogen for large scale power generation is one of the essential areas for scaling up the domestic market for clean hydrogen. A pilot plant of hydrogen gas turbine is developed in the port city Kobe, and the government also sets a target to commercialize hydrogen power generation by 2030. [83] Also in Germany, scenario modelling for a decarbonised future energy system predicts that in the medium to long-term, most of the flexible gas-fired power plants that will be required as back-up for a stable electicity supply will be converted to clean hydrogen[84].

As the above examples show, Germany and Japan are making efforts on commercialization and cost reduction of hydrogen application technologies. These efforts are expected to contribute to not only the expansion of domestic markets in the two countries but also the global market for clean hydrogen. The market expansion is one of the prerequisites for the global clean hydrogen supply chain to emerge.

Therefore, joint research, development, demonstration, commercialization, and standardization efforts by Germany and Japan would be useful particularly in the following areas:

- Replacing grey hydrogen in existing industrial uses, as well as using clean hydrogen in new production processes to replace fossil fuels;
- Fuel cell technologies in transport, including trains, buses, trucks, ships, and cars;
- Hydrogen-based advanced power plant technologies.

(c) International standards

Unlike conventional energy commodities, one of the drivers for the international clean hydrogen supply chain is to decarbonize the energy system. Therefore, a proof of hydrogen's environmental value is necessary for both suppliers and users. This calls for common definition and criteria for clean hydrogen as well as its certification method agreed internationally. As described in the analysis of Chapters 2, 3, 4, and 5, however,

[82] Ministry of Economy, Trade and Industry (2019). *Strategic Roadmap for Hydrogen and Fuel Cells (2nd revision)*. Available at: https://www.meti.go.jp/press/2018/03/20190312001/20190312001-1.pdf

[83] *Ibid.*

[84] Jensterle et al. (2019). *Op. cit.*

there are some developments on clean hydrogen standards and certification at national or regional levels, but international standards are still absent.

Germany and Japan with their different advantages are expected to work together to establish the international standards for green hydrogen. Germany is one step ahead in green hydrogen; standards for green hydrogen are already developed (German TÜV SÜD CMS 70 Standard (Version 12/2017, TÜV SÜD 2017)). In addition, there is the proposed CertifHy standard at EU level, which also covers blue hydrogen. However, as discussed above in chapter 2, they all need to be further advanced. On the other hand, although there are no national standards for clean hydrogen in Japan yet, Japan has gained more experiences on blue hydrogen production and international hydrogen shipping through several pilot projects. Therefore, the two countries can contribute to the debate on clean hydrogen criteria and certification from different perspectives (cf. chapter 5).

7. Hydrogen application in the industrial sector

As an effective way to tackle climate change, clean hydrogen is expected to be utilized in the industry sector that is hard to decarbonize. Currently, hydrogen is used as a feedstock, and generated and captured either specifically for this use (grey hydrogen) or sometimes as by-product in a production line. This grey hydrogen could be replaced by clean hydrogen, i.e. blue or green hydrogen meeting a certain Certification Standard (cf. chapter 2, chapter 5). On the other hand, CO_2 emissions cannot be avoidable in some processes (such as conventional steel- or cement-making). A new attempt is to apply hydrogen with an advanced technology to reduce CO_2 emissions in these processes. For this purpose, demonstration projects have been conducted worldwide to encourage technology innovation, which is applicable to the industry sector.

In Japan, in addition to efforts of CO_2 emission reductions through energy efficiency improvement, the iron and steel industry has committed to technology development in order to decrease CO_2 emissions. This industry-wide collaboration has been pursued in the research project "CO_2 Ultimate Reduction System for Cool Earth 50 (COURSE 50)" funded by New Energy and Industrial Technology Development Organization (NEDO) under the project "Environmentally Harmonized Steelmaking Process Technology Development" since 2008.

The COURSE 50 aims to develop two different technologies in the steelmaking process; one is CO_2 emission decrease via hydrogen reduction and the other one is CO_2 capture – separation and recovery – from blast furnace gas, which is consequently expected to reduce CO_2 emissions by approximately 30% overall.[85] The long-term target of the COURSE 50 is to enable these technologies for use by 2030, and to commercialize and deploy them by 2050. This section focuses on the former technology since the latter is out of scope of the report.

The technology developed in COURSE 50 is hydrogen reduction of iron ore. In the steelmaking processing, it is necessary to reduce oxygen from iron ore in blast furnace. When iron ore is reduced with CO e.g. from coal, which is a conventional method, CO_2 is emitted. Alternatively, clean hydrogen is used for reduction of iron ore, which generates H_2O instead of CO_2 and, thus, is considered environmentally friendly. There is a first installation of this kind in Northern Sweden; and German steel company Thyssen Krupp

[85] The Japan Iron and Steel Federation. "Outline of COURSE 50."

Available at: https://www.jisf.or.jp/course50/outline/index_en.html has announced to partly or fully convert its steel plants in Germany to hydrogen starting in the next years.

Although this technology development presents potentials to utilize more hydrogen in the industry sector, the hydrogen cost stands in the way of hydrogen utilization in the iron and steel industry. The technology to use hydrogen for reduction of iron ore has not been commercially applied since hydrogen production costs are so high that it is not economically feasible. As mentioned earlier, Japan's targeted hydrogen supply costs are JPY 30 (USD 0.27)/$Nm^3$by 2030 and JPY 20 (USD 0.18)/Nm^3 afterwards. However, the iron and steel industry estimates that USD 0.077/Nm^3 is the hydrogen supply cost required for carbon reduction ironmaking.[86] This gap between the government target and the industry's condition needs to be narrowed to make hydrogen utilization feasible applications.

[86] Shindo, Kosei (2019). "A challenge towards Zero-carbon STEEL" presented at Hydrogen Energy Ministerial Meeting on September 25th, 2019, in Tokyo.

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Appendix

Figure 15: Criteria for green / blue hydrogen in existing certification schemes

Criteria	Aichi Prefecture (Japan)	AFHYPAC (France)	DECC (UK)	HRS (Denmark)	California bill 1505 (US)
GHG balance / Threshold for GHG emission reduction	**No emission thresholds** defined	**No emission thresholds** defined	**No emission thresholds** defined	**No emission thresholds** defined	For the usage of hydrogen in transport a **minimum of 30% relative to gasoline**
Life cycle of the hydrogen production chain covered	Production				Well-to-wheel emissions, but restricted to usage of hydrogen in transport only
Energy source / Definition of clean hydrogen	**Green hydrogen:** #) RE electrolysis / steam reforming using biogas **Blue hydrogen** #) Grid electricity combined with green electricity certification to compensate the CO2 emissions associated with H2 production or fossil fuels combined with the J-Credit to compensate the CO2 emissions associated with H2 production	**Green hydrogen** produced from renewables; also allows at least for green hydrogen production by biomethane/biomass.	**Green and blue hydrogen** (the CertifHy explicitly also allows for hydrogen production from nuclear electricity which diverges from the blue hydrogen definition in this study); also allow at least for green hydrogen production by biomethane/biomass.	**Green hydrogen** produced from renewables (the only definition that restricts green hydrogen production to electrolysis of renewable electricity)	**Green hydrogen** production also by biomethane/ biomass.
Additionality of renewable electricity generation	*	*	*	*	*
Water demand	*	*	*	*	*
Land use	*	*	*	*	*
Social impact	*	*	*	*	*

Criteria	**CertifHy**	**Standard CMS 70 TÜV SÜD**	**Clean Energy Partnership (CEP)**
GHG balance / Threshold for GHG emission reduction	At least 60% compared to hydrogen produced by natural gas.	At least 75% for hydrogen produced by electrolysis from RE; At least 60% for other production methods for plants commissioned since 2017 (before 50%)	At least 75% for hydrogen produced by electrolysis from RE; At least 60% for other production methods for plants commissioned since 2017 (before 50%)
Life cycle of the hydrogen production chain covered	Only production	Production and transport to the point of usage and usage itself	Only production
Energy source / Definition of clean hydrogen	Green and blue hydrogen	Green hydrogen; use of RE to be proved by guarantees of origin, within the EU in accordance with the EU-RED 2009/28/EC	Green hydrogen; Electricity certified by TÜV-Nord Ökostrom / TÜV-Süd Ökostrom / Grüner Strom Label / OK Power.
Additionality of renewable electricity generation	*	At least partly: defines minimum threshold for hydrogen produced from electricity generated by new RE plants #) at least 30% from plants that are not older than 3 years at the time of first certification #) The share of "new" renewables in the renewable electricity has to be at least: Small HP (<2MW): 10% / Wind power: 7,5% / Solar power, geothermal, biomass: 5% / Biogas, biomethan: 3%; initial commissioning after Jan 2000	At least partly: defines criteria for the age of RE power plants that have to be fulfilled if certificates are used as evidence of energy sources (at least one third of the electricity sold is generated in new plants not older than 6 yrs. old; another third in plants not older than 12 yrs).
Water demand	*	*	*
Land use	*	*	*
Social impact	*	*	*