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The role of clean hydrogen in the future energy systems of Japan and Germany

Miha Jensterle, Jana Narita, Raffaele Piria, Sascha Samadi, Magdolna Prantner, Kilian Crone, Stefan Siegemund, Sichao Kan, Tomoko Matsumoto, Yoshiaki Shibata, and Jill Thesen

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The role of clean hydrogen in the future energy systems of Japan and Germany

An analysis of existing mid-century scenarios and an investigation of hydrogen supply chains

Miha Jensterle, Jana Narita, Raffaele Piria, Sascha Samadi, Magdolna Prantner, Kilian Crone, Stefan Siegemund, Sichao Kan, Tomoko Matsumoto, Yoshiaki Shibata and Jill Thesen

Executive summary

In the context of the German-Japanese Energy Policy Dialogue between the German Federal Ministry of Economic Affairs and Energy (BMWi) and the Japanese Ministry of Economy, Trade and Industry (METI), hydrogen has been identified as having potential for closer cooperation. This study aims at supporting mutual learning and at exploring undeveloped fields of collaboration by providing an analysis on similarities and differences in the respective debates, strategies and policies.

After a short introduction to the technologies and economics of the production, transport, storage and usage of hydrogen and of other synthetic fuels, **Chapter 1** provides an overview of demand-side deployment by sector (residential, transport, industry, power generation and power-to-x) for both countries, as well as of their hydrogen policy debates, key institutions, R&D programs and demonstration projects. Finally, a short survey on relevant international platforms and initiatives in which Japan and Germany participate is presented. On the basis of a meta-analysis of the role of hydrogen in 18 long-term energy system scenarios for Germany and 12 scenarios for Japan, **Chapter 2** of this study draws conclusions on the possible future role of hydrogen in the transformation of the energy systems in Japan and Germany. Subsequently, **Chapter 3** discusses sustainability criteria and certification schemes for clean hydrogen, compares the GHG intensity of different hydrogen supply chains and provides a data-based analysis to identify countries which could become important suppliers of clean hydrogen.

Germany and Japan have both gained substantial **experience with hydrogen production and applications**, albeit with focus on different sectors (see chapters 1.2 and 1.3). They also share similar drivers for hydrogen development (chapters 1.4.1 and 1.5.1) and, of course, similar technical and economic opportunities and challenges (chapter 1.1). However, there also are relevant differences in the policy priorities and approaches (chapters 1.4 and 1.5).

Japan's plans for a "hydrogen-based society" were first introduced in the 4th Strategic Energy Plan of 2014 and further developed in the Strategic Roadmap for Hydrogen and Fuel Cells of 2016. With the **Basic Hydrogen Strategy of 2017, Japan was the first country in the world** to publish a comprehensive government plan for hydrogen and fuel cell technology development. Germany has been pursuing a very ambitious paradigm shift to an energy system based on renewables – known as the *Energiewende* – with increased determination since the turn of the century. While in the earlier years the focus was on increasing renewable energy production, recently, the German debate has started to also revolve around the long-term role of hydrogen. Currently, the German federal government is in the process of adopting the **first German National Hydrogen Strategy**, expected to be released by the end of **2019**.

Notwithstanding differing emphases and patterns, the two countries share **three main drivers** for hydrogen development and deployment: climate mitigation and other environmental goals, energy supply diversification, and technological leadership.

Long-term energy scenarios for both countries analysed in this study assume similar **climate mitigation** targets: Germany aims at 80% to 95% greenhouse gas (GHG) emission reductions by 2050 in comparison with 1990, Japan at 80% by 2050 in comparison to 2010. As discussed in more detail below, hydrogen is expected to play an important role for decarbonising industrial processes, segments of the transport sector and, to a smaller extent, heating supply and the power system. Both countries are currently profoundly dependent on oil, natural gas and coal imports and are thus vulnerable to geopolitical shocks affecting the extraction countries or supply routes. Therefore, the **diversification of the imported energy** carriers, origin countries and supply routes is an important driver for the use of hydrogen in both countries. Green hydrogen also offers the opportunity of substituting a share of imported fossil energy carriers with domestic energy production. **Technological leadership** in a field which might become a keystone of the future global energy system is additionally an important driver for both countries; as each are already seen as leaders in key hydrogen technologies.

So far**, Japan has more experience in deploying demand-side applications**, especially in the building sector (250,000 CHP units in Japan, versus 5,500 in Germany) and in the transport sector (2,400 versus 500 cars). **Germany has so far focused more on the supply side**, with more than 50 Power-to-X (PtX) projects in planning or operation (versus 3 in Japan) and plans to drastically increase the electrolyser capacity during the next few years. Germany also has more than 500 uninterruptible power supply systems in operation whereas no hydrogen-based UPS systems are in operation in Japan. The complementarity of the two backgrounds suggests a good potential for technical cooperation and mutual learning.

On the **demand side**, Japan's government has, for a longer time, pursued a more proactive market introduction policy through setting targets and providing support through public-private partnerships and investment subsidies (such as for Ene-Farms). Germany has traditionally pursued a more hands-off strategy for hydrogen technologies market introduction, offering less intensive subsidies for residential fuel cell-based CHP systems and UPS systems and leaving it to equipment producers to take the initiative to launch products. It is only recently that Germany has increased its activities in supporting hydrogen deployment, especially since the start of the second National Innovation Programme Hydrogen and Fuel Cell Technology (NIP) in 2017.

In regards to **R&D programs**, both countries offer support and deliver hydrogen **demonstration projects**. Japan is pursuing large hydrogen production facilities projects overseas to explore the possibilities of large-scale hydrogen imports. On its part, Germany has so far focused more on domestic R&D projects, including not only equipment testing, but also for legal frameworks and market governance.

Chapter 2 of the present study provides **a meta-analysis of the role of hydrogen in long-term energy system scenarios for Germany and Japan**. The meta-analysis covers 18 scenarios for Germany, based on 6 studies published from 2015 onwards; for Japan, it covers 12 scenarios from 8 studies, plus one official government document. The chapters 2.1 (Germany) and 2.2 (Japan) analyse and compare the studies and scenarios in regards to the respective countries, looking at the main drivers assumed to influence the demand for hydrogen (and other synthetic fuels) between 2030 and 2050, among other topics. Chapter 2.3 provides a cross-country comparison of the scenarios, pointing to similarities and differences between the two countries. The main outcomes of this analysis are:

- Hydrogen is likely to play a relevant role in the energy systems of both Japan and Germany by 2050 (however with a limited role until 2030) if their climate targets are to be achieved. There is a strong **positive correlation** between the level of **ambition in GHG emissions reductions** and the **relevance of hydrogen** – scenarios assuming 95% reduction in GHG emissions tend to lead to a much higher requirement for hydrogen and hydrogen based synthetic fuels than scenarios assuming an 80% reduction.

- Most German scenarios for 2050 feature hydrogen demand levels between 300 and 600 PJ per year, or up to 10% of the total primary energy demand. Japanese 2050 scenarios feature a total hydrogen demand between 600 and 1,800 PJ.
- A significant **point of divergence** between both countries' scenarios is the relationship between **hydrogen and other synthetic fuels**. While the Japanese scenarios barely mention the possibility of producing non-hydrogen synthetic fuels, all but one of the German scenarios analysed in this study envision a larger role (often much larger) for other synthetic fuels than for hydrogen in the end use sectors (Table 13); perhaps most tellingly, even one of the two German scenarios assuming that hydrogen technologies play a central role envisions a greater final energy demand for other synthetic fuels than for hydrogen in 2050. The key advantages of some non-hydrogen synthetic fuels are that existing infrastructures and end use appliances can be used, and that they can be blended with fossil fuels.
- Another significant difference lies in the fact that, in Germany, hydrogen is generally regarded as a versatile molecule that helps to integrate renewables into the energy system. Therefore, the German short and medium term scenarios exclusively envision **green hydrogen**, whereas Japan's Strategic Roadmap for Hydrogen and Fuel Cells envisions establishing global **blue hydrogen** supply chains first, and green hydrogen supply chains adopted after 2040. (See terminology text box in chapter 1.1.)
- The short and medium term strategies generally fall **in line with the main drivers for both countries**' energy strategies. For both Germany and Japan, hydrogen technologies are a promising element of their long term industrial policy. Apart from that, Germany exhibits bigger climate ambitions, while Japan more strongly emphasises the need to improve its energy security.
- Scenarios for Germany also diverge from those for Japan in terms of **hydrogen supply sources**. While German scenarios consider it realistic to produce at least part of the hydrogen **domestically** (or even the entire hydrogen needs, while other synthetic fuels would be imported), Japan focuses on hydrogen **imports** from overseas in the form of liquefied hydrogen, chemically stored as ammoniac or in LOHC. However, some of the Japanese scenarios do mention the domestic production as an option.
- The **role of domestic PtX** is much bigger in German scenarios than in the Japanese as German scenarios generally assume that significant shares of hydrogen can be produced domestically, and because they assume considerably higher shares of intermittent renewables in the German electricity systems. However, at least one of the Japanese scenarios values the ability of PtX applications to provide flexibility to the power system.
- Both **countries differ in terms of end-use sector priorities**: Japanese scenarios see hydrogen used mostly for power generation, and to a smaller extent, in transport and industry. The German scenarios envision that hydrogen and other synthetic fuels will mainly be used in transport and industry and, to a lesser extent, for heat supply and for power generation.
- Regarding the infrastructural needs related to the use of hydrogen, German scenarios either assume that hydrogen will be **blended with natural gas** in the existing gas infrastructure as far as technically possible, and/or that the **existing gas infrastructure** will be modified in order to accommodate higher shares of hydrogen, and/or that **separate hydrogen pipelines** will be newly built (or converted from

former natural gas use) to connect hydrogen production sites with hydrogen demand locations. For hydrogen use in transport, it is generally assumed (explicitly e.g. in Hecking et al. 2018) that the hydrogen will be transported to filling stations using trucks[1]. Japanese scenarios don't consider the infrastructural needs in detail.

Based on current German literature, Chapter 3.1.1 of the present study outlines the direction of the current debates in Germany about possible **sustainability criteria for the definition of green hydrogen.** These focus on the lifecycle GHG emissions balance of green hydrogen compared to conventional fossil fuels for the same application, on the additionality of renewable electricity production; on the sustainability of the usage of water and land needed for the electrolysers and the renewable energy capacity; as well as on the social and economic impact on regional communities. Chapter 3.1.2 shortly describes various **existing standards and certification schemes for clean hydrogen** which have been or are currently being established in Japan, Germany and other EU countries, as well as an example from California. Chapter 3.1.3 compares the various standards and certification approaches for *clean* hydrogen presented in the previous chapter, also in light of the *green* hydrogen sustainability criteria presented described in chapter 3.1.1. While discussing future standards for clean hydrogen, it will be crucial to strike the right balance between environmental soundness, practicality of the implementation and realistic economic considerations. In addition to failing to ensure environmental benefits of using clean hydrogen, too lax sustainability standards could be seen as greenwashing by the public which could erode the support for clean hydrogen. On the other hand, too strict sustainability standards early on might slow down the development of a global clean hydrogen supply chain.

Chapter 3.2 presents a comparison of the **GHG intensity associated with 18 different hydrogen supply chains** based on different primary energy sources (natural gas, coal, EU-electricity mix, biomass and wind), largely based on analysis carried out by the Joint Research Centre of the European Commission and published in 2014. The analysis shows that the **energy source** is **the most significant individual factor for GHG intensity of hydrogen supply chains**. For example, green hydrogen stemming from electrolysis based on renewable electricity features much lower lifecycle GHG emissions than hydrogen produced by any process based on fossil fuels without CCS. Without CCS, hydrogen from natural gas, the most widely used energy source for hydrogen production today, has about half the GHG intensity of hydrogen produced from coal via gasification. CCS can significantly reduce the GHG intensities of fossil fuels-based hydrogen: with CCS, hydrogen from natural gas has GHG intensity comparable to hydrogen from coal. However, green hydrogen produced by electrolysis from renewable electricity still is between 40% and 75% less GHG intensive than blue hydrogen, depending on the specific supply chains. If hydrogen is based on the current German and Japanese power mixes, the dominance of fossil fuels results in grey hydrogen GHG intensities comparable to those of coal gasification without the use of CCS, which do not contribute to overall GHG emissions reductions.

Finally, chapter 3.3 provides an **analysis of potential clean hydrogen supplying countries**, differentiating between green hydrogen (based on renewables) and blue hydrogen (based on fossil fuels with CCS). For **green hydrogen,** the analysis is based on a model of the Finnish university LUT which combines granular data about wind and solar generation potential in small regions (less tan 50x50 km at equator) all over the world with a

[1] However, the federal hydrogen agency NOW assumes that in the long term, in case of a strong market uptake, pipelines might become relevant on certain routes.

cost optimisation of hydrogen production system based on wind, solar, batteries and electrolysers. The results are presented focusing on one hand on the countries with the cheapest green hydrogen resources and on the other hand on the countries which have a particularly large potential for relatively low-cost green hydrogen production. Argentina, Australia, Brazil, China, Egypt, Ethiopia, Namibia, Russia, South Africa and the USA belong to the top 20 under both categories. For **blue hydrogen**, the analysis largely relies on data from BP concerning the available reserves of fossil energy sources and on the CCS readiness indicator of the Global CCS Institute. The following countries rank top 20 in both categories: Australia, Brazil, Canada, China, Germany, Norway and USA. However, taking into account Germany's decision to phase out coal mining – already implemented for hard coal and in the process of being enshrined in law for brown coal – as well as the lack of public acceptance for carbon storage on German soil, Germany is very unlikely to become a blue hydrogen producing country.

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List of Abbreviations

AAGR	Annual real GPD growth rate
Acatech	Deutsche Akademie der Technikwissenschaften (National Academy of Science and Engineering)
ADEME	French Environment and Energy Management Agency
AEL	Alkaline electrolysers
AEP	Annual energy production
AFHYPAC	French Association on Hydrogen and Fuel Cells
AHEAD	Advanced Hydrogen Energy Chain Association for Technology Development
BDB	Betreiber-Datenbasis (operator database)
BMU	German Federal Ministry for Environment, Nature Conservation and Nuclear Safety
BMVI	German Federal Ministry of Transport and Digital Infrastructure
BMWi	German Federal Ministry for Economic Affairs and Energy
CCGT	Combined cycle gas turbines
CCS	Carbon capture storage
CCU	Carbon capture and utilisation
CEP	Clean Energy Partnership
CFD	Computational fluid dynamics
CHP	Combined heat and power
DECC	Department of Energy & Climate Change
dena	Deutsche Energie-Agentur (German Energy Agency)
DGEC	Directorate General for Energy and Climate
DPR	Detailed project report
EOGR	Enhanced Oil and Gas Recovery
EVs	Electric vehicles
FCH-JU	Fuel Cells and Hydrogen Joint Undertaking
FCEVs	Fuel cell electric vehicles
FIT	Feed-in tariff
GIS	Geographic information system
GoO	Guarantees of Origin
HRS	Hydrogen refuelling station
HT	High-temperature
HyRaMP	European Regions and Municipalities Partnership for Hydrogen and Fuel Cells
ICE	Internal combustion engine
ICEV	Internal combustion engine vehicle

IEA	International Energy Agency
IEEJ	Institute of Energy Economics Japan
INDC	Intended Nationally Determined Contribution
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
IRENA	International Renewable Energy Agency
IRR	Internal rate of return
JRC	Joint Research Centre
JIVE	Joint Initiative for hydrogen Vehicles across Europe
KOH	Conductive potassium hydroxide
LIDAR	Light detection and ranging
LH2	Liquid hydrogen
LIS	Electromobility and charging infrastructure
LNG	Liquefied natural gas
LOHC	Liquid organic hydrogen carriers
LT	Low-temperature electrolysis
LPG	Liquefied petroleum gas
MCP	Measure-correlate-predict
MCFC	Molten carbonate fuel cell
METI	Japanese Ministry of Economy, Trade and Industry
MHPS	Mitsubishi Hitachi Power Systems
MI H2 Challenge	Mission Innovation Renewable and Clean Hydrogen Challenge
MKS	Mobilitäts- und Kraftstoffstrategie
NECP	National Energy and Climate Plan
NEDO	New Energy and Industrial Technology Development Organisation
NG	Natural gas
NIP	National Innovation Programme Hydrogen and Fuel Cell Technology
NOW	National Organisation for Hydrogen and Fuel Cell Technology
PAFC	Phosphoric acid fuel cell
PEFC	Polymer Electrolyte Fuel Cell
PEM	Proton exchange membrane
PEMEL	Proton exchange membrane electrolysers
PEMFC	Proton exchange membrane fuel cell
PtG	Power-to-gas
PtH	Power-to-heat
PtH2	Power-to-hydrogen
PtX	Power-to-X
RED	Renewable Energy Directive

R&D	Research and development
RD&D	Research, design and development
SMR	Steam methane reforming
SO	Solid oxide
SODAR	Sonic detection and ranging
SOE	Solid oxide electrolyser
SOEC	Solid oxide electrolyser cells
SOFC	Solid oxide fuel cell
TCP	Hydrogen Technology Collaboration Program
UPS	Uninterruptible power supply systems
WACC	Weighted average cost of capital

1 Hydrogen deployment and policies in Germany and Japan

Both Germany and Japan have substantial experience with traditional hydrogen application in industry, such as refineries and ammonia. However, concerning the development of clean hydrogen the two countries have laid their emphases differently.

The German federal government has provided extensive financial support for RD&D related to innovative hydrogen technologies, but it supported only to a lesser extent market introduction, value chain development and applications; abstaining, so far, from actively trying to shape the energy market so as to facilitate more widespread uptake of hydrogen applications. This has led to hydrogen technologies being widely seen as ready to assume a bigger role, and calls to the private sector for the necessary policy framework to allow their wide-scale deployment.

On the other hand, Japan's government has taken a much more hands-on approach. The Ministry of Economy, Trade and Industry has laid out a well-defined hydrogen strategy which is being pursued, among others, through the Institute of Energy Economics Japan (IEEJ), New Energy and Industrial Technology Development Organisation (NEDO), and strategic partnerships with Japan's technology corporations. Moreover, it put an emphasis on a quick transition from research and development into the market activation phase, betting on a handful of products deployed on large scale (such as the Ene-Farms, chapter 1.3.1).

Germany has more experience with production of green hydrogen, which fits well with its role as one of the global leaders in solar PV and wind technologies. Currently, Germany hosts 50 demonstration projects for Power to Gas (PtG) technology based on renewable electricity being demonstrated in MW scale (Rasmusson 2018, Golling et al. 2017). In 2015, less than 1% of the German hydrogen production was through water electrolysis (NOW, 2016). Two projects with electrolysis capacity of 100 MW each have been announced in 2018.

Japan has meanwhile focused on meeting its future demand with hydrogen produced from fossil raw materials, primarily natural gas via steam methane reforming (SMR) and coal via gasification. Mass deployment of carbon capture and storage (CCS) is envisioned for the future, primarily near the point of primary energy source extraction. Japan has more experience with fuel cell applications in the heating and transport sectors, where it is the global leader in terms of number of units deployed (be it CHP plants, fuel cell vehicles or the related infrastructure).

1.1 Introduction on hydrogen production and use

This chapter briefly summarizes the means of hydrogen production, transport and storage as well as the different usage cases for hydrogen.

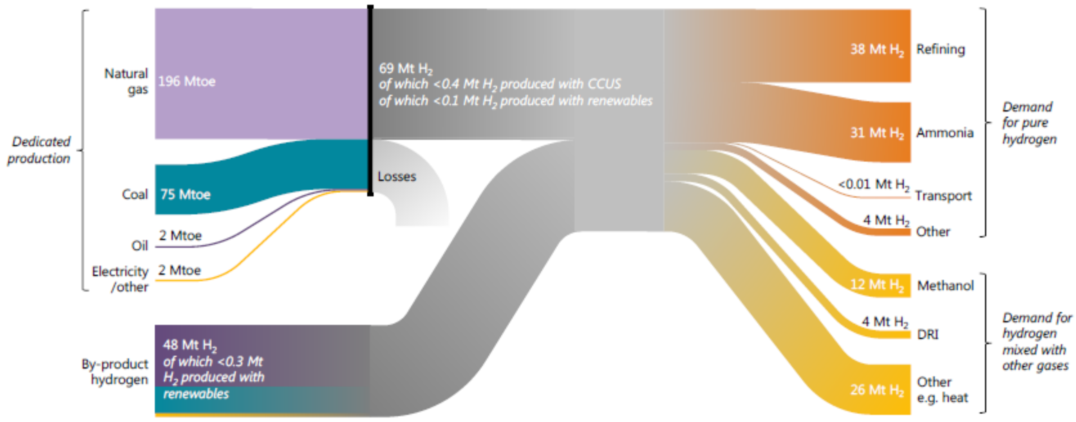

Figure 1: Today's hydrogen value chains
Source: IEA (2019)

Key terminology as used in this study

__Green hydrogen__ is used to designate low-carbon hydrogen produced from renewable sources such as renewable power (via water electrolysis) or biomass. __Blue hydrogen__ is used to designate low-carbon hydrogen, produced from non-renewable sources, typically from natural gas and brown coal, with use of carbon capture and storage technology. __Clean hydrogen__ is used in this study as an umbrella term for green and blue hydrogen.[2] *__Low-carbon hydrogen__ designates green, blue and nuclear-power derived hydrogen; the term is not is generally used in this study except where nuclear-derived hydrogen is explicitly included. __CO_2-free hydrogen__ is often used in Japan to designate low-carbon hydrogen (without explicitly mentioning nuclear power as a possible source), but is not used in this study.*

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.[3]

1.1.1 Hydrogen production

The various processes used to produce hydrogen are described in other sources (Shell 2017, IEA 2019). As of today, almost all hydrogen is produced from fossil fuels, releasing the entire carbon content into the atmosphere (CertifHy 2019d). The CO_2 could be captured and

[2] The level of “cleanliness” of course depends on the lifecycle environmental impacts. For example, in the case of green hydrogen one should consider the low but not absent greenhouse gas (GHG) emissions caused by the production of the renewable energy systems and of electrolysers. As for gas based blue hydrogen, one should consider the sometimes substantial share of the CO_2 that remains uncaptured and, in the case of CCU processes, how long the CO_2 remains chemically bonded. Especially in the case of coal-based processes, other toxic emissions may also be significant.

[3] 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.

stored underground (CCS) or used for other processes (carbon capture and utilisation, CCU), for example, the production of hydrogen-based fuels such as synthetic methane (JRC 2014, Mizuho Information and Research Institute Inc. 2018). As long as the CO_2 used for CCU processes has a fossil origin, it impacts the climate as it's released into the atmosphere. Some CCU applications, such as production of construction materials, bond the CO_2 long-term, possibly for centuries; others, such as synthetic fuels, only for weeks or months.

Another option is producing hydrogen via water electrolysis. With assistance of electric power, water molecules are split into hydrogen and oxygen. The most common technologies are alkaline electrolysers (AEL) or proton exchange membrane electrolysers (PEMEL). Solid oxide electrolyser cells (SOEC) may offer better efficiency in the future, but are not a mature technology as of yet (IRENA 2018). The economics of hydrogen production by electrolysis depend to a large extent on electricity prices and the electrolyser CAPEX. Electrolysis is very energy intensive, with current efficiency rates typically just below 70%. Therefore, hydrogen electrolysis based on a power mix with a high fossil share is not interesting from a climate or energetic point of view (Kasten et al. 2019).

At current price levels, electrolysis based on renewable electricity (green hydrogen) is more cost-intensive than steam reforming or coal gasification without CCU/CCS. Green hydrogen can become more competitive, assuming a continuation of the downward trend of renewable power costs, learning and scale effects for electrolysers, a strong policy framework including an effective carbon pricing and restricting the other environmental and health impacts of natural gas (e.g. methane leaks) or coal (e.g. mercury and other harming emissions).

Hydrogen can also be produced from biomass through thermo-chemical (gasification or pyrolysis of solid or liquid biomass, or reforming and partial oxidation of biogas, biomethane or bioethanol) or bio-chemical processes (with the use of microorganisms). However, current quantities of hydrogen production from biomass are negligible and the bio-chemical processes have not yet reached market maturity.

1.1.2 Hydrogen transport and storage

Hydrogen can be stored and transported in pure form, blended with natural gas or bound in larger molecules such as ammonia or liquid organic hydrogen carriers (LOHCs). According to a literature review by IRENA (2018), blending is currently generally possible to about 20%vol without considerable modifications to the gas network. For transport in pipelines, hydrogen must be compressed to the system pressure (2 – 4 MPa). Pure hydrogen pipelines can be built anew, or created by converting existing gas pipelines.

Hydrogen in liquid form has a much higher energy density than hydrogen compressed at moderate pressures, making it more suitable for transport and storage. However, hydrogen liquefaction requires temperatures below -253°C and is very energy intensive. Compressed hydrogen (up to 700 bar) is usually transported via road trucks, trains or barges.

Hydrogen can also be chemically bonded. Materials which enable this include metal hydrides, liquid organic hydrogen carriers (LOHCs, deployed by Japan, see the Brunei pilot project, chapter 1.5.4), carbon and other nanostructures, and reversible hydrocarbons. Generally, these technologies are considered feasible but not yet market-ready.

1.1.3 Hydrogen use

Hydrogen can be used directly in pure form, or as the basis for the synthesis of liquid or gaseous hydrogen-based fuels such as synthetic methane or synthetic diesel, as well as for other energy carriers such as ammonia (dena 2018a).

By far, most of the hydrogen is currently used in the **industrial sector**, mainly in refineries and for the production of ammonia and to a smaller extent to produce methanol and other chemicals, and in steel production (see Figure 1 above). In the medium and long term, the potential for growth of hydrogen use in industrial applications is limited, while other sectors have a much larger growth potential (IEA 2019).

In the **residential sector**, hydrogen is used in fuel cell-based cogeneration applications (also called combined heating and power, CHP). Most commonly used are proton electrolyte membrane (PEM) and solid oxide (SO) fuel cell technologies. Both types of cells in CHP can be either heat- or power-driven and can be deployed as mini or micro CHPs due to their compact sizes. They can either be fuelled with hydrogen directly or with natural gas or biogas where conversion into hydrogen takes place inside the unit. If the heat produced is of sufficiently high temperature, such a system can also provide cooling via adsorption (tri-generation).

In a decarbonized **transport sector**, hydrogen becomes especially interesting when the ranges and loads of vehicles increase and more energy must be stored on board. Fuel cell vehicles (FCEVs) such as buses, trucks, long-distances passenger vehicles and trains as well as certain shipping options are the applications where hydrogen might establish itself in the future.

Hydrogen can be used for **power generation** as it can be converted into electricity using a combustion process or a fuel cell. Combustion can take place in a stationary internal combustion engine (ICE) both of reciprocating (found in most cars) and rotary type (such as turbines). Fuel cell-based power generation are mainly deployed as uninterruptible power supply systems (UPS). These can be considered a mature technology and are available over a wide capacity range. Their main function is to provide backup power for critical processes such as hospitals, communication infrastructure and similar in case of black-outs and in remote locations. Their upsides are reliability, durability and low maintenance costs.

1.1.4 Hydrogen, other synthetic fuels and direct use of electricity

For applications in the transport and heating sector, the direct use of electricity, when compared to green hydrogen and other synthetic fuels, has the advantage of lower efficiency losses across the entire conversion chain.

According to Agora Verkehrswende et al. (2018), for the transport sector overall efficiencies from the point of feeding the power into the grid to the wheel are 69% for electric vehicles (EVs), 26% for FCEVs and 13% for synthetic fuel internal combustion engine vehicles (ICEVs). In other words, compared to an EV, a hydrogen FCEV requires 2.6 times more energy, and a synthetic fuel ICEV 5.3 times more energy. However, the comparative FCEV efficiency improves with increasing energy needs resulting from heavier vehicles and long distance requirements (e.g. in freight transport).

For heating, an electric heat pump with a COP of 3 delivers a 285% overall efficiency, compared to a combined efficiency of 45% for an FC CHP system, and 50% for a gas condensing boiler (Agora Verkehrswende et al. 2018). In other words, compared to such a heat pump, a gas condensing boiler uses 5.5 times as much energy, and FC CHP 6.3 times as much. It must be noted, however, that with an FC CHP, almost half of the energy derived from hydrogen is in the form of electricity.

In terms of energy storage capacities and timespans, it is generally assumed that batteries will remain competitive as short term (up to 1 or several days) energy storage. On the other end of the spectrum, synthetic fuels other than hydrogen (gaseous and liquid) are best suited for seasonal energy storage. Hydrogen is typically considered to fall somewhere in between. Different sources provide diverging estimations; some consider it to be closer to batteries in terms of capacity and discharge rates, while others consider it to be slightly below those of synthetic gas (Paulus 2014, Bogdanov et al. 2019). It is thinkable that both solutions establish themselves in the future, as hydrogen can be stored short-term and close to where it is consumed in storage tanks or long-term and centrally alongside synthetic gas in salt caverns and pore storages.

In a deeply decarbonised energy system, a further advantage of a significant use of renewables-based hydrogen or hydrogen-based synthetic gases (PtG) is that it can provide energy storage services based on existing gas infrastructure, thus reducing the need for power grid expansion (Ecke and Fricke 2018).

1.2 Overview of deployment by sectors - Germany

The following chapter provides an overview of the current state of deployment of different demand-side hydrogen applications by sector.

1.2.1 Residential sector

Fuel cell-based mini- and micro-CHP systems are available on the German market, similar to the Ene-Farms in Japan; although their market uptake has been much slower than in Japan. However, thanks to a support scheme from the Ministry of Economic Affairs and Energy (BMWi), deployment speed significantly increased recently: with more than 3,600 new micro-CHP units installed in 2018, the total number in operation almost tripled to 5,500 units and is expected to further increase in 2019 (NOW 2018, Blockheizkraftwerk.org 2016, McKinsey & Company 2017). Similar to Japan, the price is currently a major obstacle for the market diffusion of these systems. The price of a 700 kWh_{el} system by SenerTec (including a 20 kW peak load boiler, hot-water tank and the heating loop) is about 20,000 EUR before taxes and subsidies.[4] The market potential is nevertheless large; Herrmann et al. (2017) have estimated that about 3 million (or about one sixth of all) buildings in Germany can be equipped with a fuel cell-based CHP (Herrmann, Block and Hildebrandt 2017).

The first apartment complex-scale systems have been contracted in 2017 which produce hydrogen from excess renewable power, store it and use it in a fuel cell-based CHP system or combusted in a boiler (Krog 2017, IWR Online (2018). Apart from that, a number of systems have been installed in residential and tertiary sector where not hydrogen but rather synthetic gas is produced (such as EXYTRON's Climate friendly living, Chapter 1.4.4) (Strategieplattform Power to Gas 2019). Table 1 provides three examples of CHP-based projects in Germany.

[4] Information obtained by telephone from SenerTec representative on 19.02.2019

Table 1: Pilot projects in residential sector in Germany

	Exytron climate-friendly living	Sustainable energy supply for buildings	Energy park
Input power	max. 62,5 kWel	52 kWel	max. 6 MWel (3 x electrolysers each 2 MWel)
H_2-production	10 Nm³/h	10 Nm³/h	PEMEL max. 1,000 Nm³/h
SNG production	2,5 Nm³/h	2,5 Nm³/h	None
CO_2 source	Own SNG combustion, CHP and gas-fired boilers	None, CO_2 is part of cycle	None
Waste heat utilisation	None	Heat exchanger, buffer tank	None

Source: Own compilation based on Strategieplattform Power to Gas

1.2.2 Transport

For Germany, the IEA (2019) lists the number of operational fuel cell passenger vehicles at about 500 (IEA 2019). The number of fuel cell busses in operation stands at 15, with additional 50 approved for deployment, with suppliers having experienced difficulties meeting the demand. Most buses are part of various pilot projects (for example BIC H2, Chapter 1.4.4). Germany is currently in 4th place globally with 75 operating hydrogen refuelling stations and another 28 in planning or construction; by the end of 2019, the total number should reach 100 stations (H2 LIVE 2019). In contrast to Japan, these are not as concentrated in the few of the largest cities but distributed more evenly.

In 2018, the first hydrogen-powered fuel cell train in Germany started service on a non-electrified line. In naval applications, fuel cell technologies have seen so far very limited deployment (a tourist ship in Hamburg is the only identified operational example where a hydrogen fuel cell is used for propulsion; fuel cell-based auxiliary power units are also used in naval applications), but are currently being tested in several research and pilot projects (Institute for Combustion Engines VKA 2018).

1.2.3 Industry

According to NOW, the yearly hydrogen production in Germany amounts to around 15 billion Nm^3. About three quarters are produced and used in refineries and chemical industry (NOW 2016). Currently, several hydrogen-related research or demonstration projects are underway in the industry sector. Carbon2chem (chapter 1.4.4) aims at capturing gasses from steel production to be used in chemical industry, including hydrogen and CO_2; Kopernikus-P2X project focuses on a number of hydrogen-related processes which could be valuable for the industry, and includes 27 industrial companies; GrInHy aims to develop a reversible generator based on the Solid Oxide Cell technology (Thyssenkrupp 2018, BMBF 2019, Green Industrial Hydrogen 2019).

1.2.4 Power generation

Like in Japan, research on hydrogen combustion in gas turbines is underway in Germany, for example at the Technische Universität Berlin (Hydrogeit 2016). Current developments by Siemens allow operation of turbines on a fuel mix with up to 60% hydrogen content; future activities are expected to focus on the development of turbines operating with pure hydrogen (TMI Staff & Contributors 2019).

With regard to UPS systems, an alliance of stakeholders from the research and industry sectors called Clean Power Net was formed in 2010 to advance the market uptake of fuel cell UPS applications (Clean power net 2019). Between 2010 and 2016, around 200 fuel cell systems have been installed as back-up power supply for the digital radio network of critical institutions (police and fire stations etc., Clean power net 2019a). They were supported by R&D-funding of the Federal Ministry of Transport and Digital Infrastructure (BMVI). In order to be eligible, the systems must provide 72 h of isolated operation; their typical power output was below 20 kW. In addition, 505 fuel cell UPS-systems for the digital radio network were supported under the funding guideline for market activation of the BMVI in 2018. These projects are mostly in realisation at the moment (NOW 2018a).

There are several more fuel cell demonstration projects in different areas of application such as traffic control, security systems, oil and gas energy, water supply, measuring stations and sensor technology, with limited numbers of systems deployed at this point (Information obtained directly from NOW).

1.2.5 Power-to-X

In 2019, 50 Power-to-Gas (PtG) plants were in planning or operation in Germany, with a total electrical capacity of over 55 MW (PV-Magazin 2019). Some of these test and pilot projects sell hydrogen to tank stations or industrial customers. The first project with an electrolyser capacity of 10 MW is expected to start operating in early 2020 (Shell 2019).

In a further step towards larger systems, plans to build a 100 MW PtG plant in northern Germany have been announced by the power transmission system operator Tennet in cooperation with two gas transmission system operators, Gasunie Deutschland and Thyssengas. This project intends to take advantage of the region’s vast wind potential. Partial operation is expected to start in 2022. In early 2019, Amprion, another power transmission system operator, together with Open Grid Europe, a gas transmission system operator, announced plans to build another 100 MW PtG plant, with an estimated investment volume around 100 million EUR. The project envisions using current hydrogen pipelines as well as adapting an existing gas network for transportation of pure hydrogen gas. Both of these plants are the first of their kind in Germany (IWR 2019).

1.3 Overview of deployment by sectors - Japan

1.3.1 Residential sector

In Japan’s residential sector, a fuel cell heat and power co-generation system called Ene-Farm is the most utilized hydrogen technology (Figure 2). By providing higher efficiencies compared to separate use of hydrogen for generating heat and electricity, it lowers the operating costs and reduces the CO_2 footprint. Further decarbonisation is possible by completely substituting the natural gas with clean hydrogen in the future. The Ene-Farm also improves resilience in situations such as blackouts and hot water shortages. Currently, two types of Ene-Farms are available (Table 2).

Table 2: Ene-Farm Products in Japan

Company	Aisin Seiki	Panasonic
Application	SOFC	PEFC
Power generation output	50 – 700 W	200 – 700 W
Efficiency (LHV)	Power: 52% Heat recovery: 35%	Power: 39% Heat recovery: 56%
Dimensions (mm)	W780 × D330 × H1,220	W400 × D400 × H1,750
Tank capacity/water temperature	28 l / approx. 70 ℃	140 l / 60 – 80 ℃
Fuel	City gas / propane gas	City gas / propane gas

Source: Own compilation by IEEJ based on information from Ene-Farm partners

Despite the steady increase in numbers of Ene-Farms since their introduction, their share is still marginal, due to two main factors. The first is the high initial cost of a unit. In 2016, the price of an Ene-Farm was JPY 1,130,000 (~ 9,000 EUR) for the Polymer Electrolyte Fuel Cell PEFC type and JPY 1,350,000 (~ EUR 11,000) for the SOFC type.[5] This typically represents a considerable mark-up compared to other heat supply systems. The second hurdle is unit dimensions, often making Ene-Farms too large for installation in individual units of apartment complexes. These constitute around 40% of total housing capacities in Japan, while 98% of Ene-Farms have so far been installed in detached houses. On both of these points, technical progress can potentially provide improvements. Despite the hurdles, 250,000 units have been installed since its introduction to the market until July 2018. The target stands at 5,300,000 units by 2030 (Ehret 2018). This makes Japan the undisputed market leader in stationary fuel cells applications for residential buildings (IEEJ own data, unpublished, 2019).

[5] Exchange rates applied throughout this study are 1 JPY ~ 0.80 EUR cent and 1 USD ~ 0,89 EUR (29.03.2019)

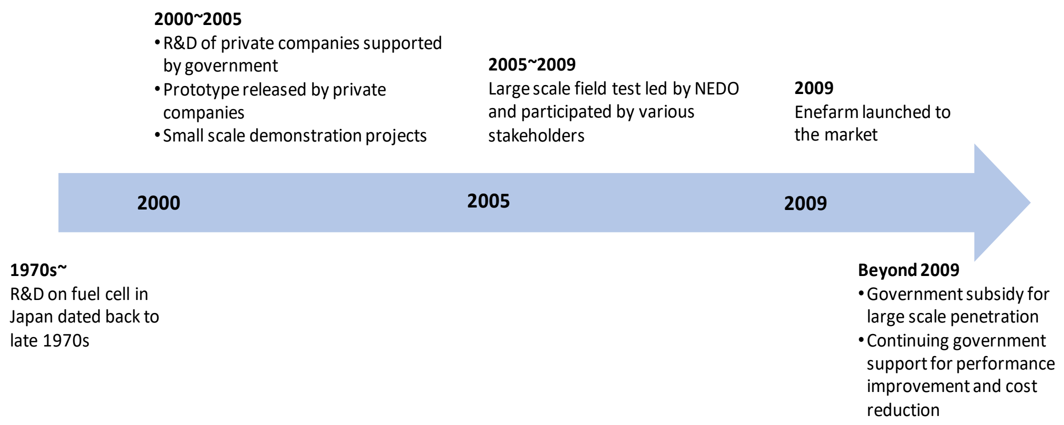

Figure 2: Brief history of Ene-Farm development in Japan
Source: Nagata (2014)

1.3.2 Transport

In Japan, serial production of fuel cell passenger vehicles was launched in late 2014 with the Toyota Mirai. By March 2018, the number of FCEVs in the end market use has risen to 2,440 (IEEJ own data, unpublished, 2019). Currently, Toyota's MIRAI and Honda's CLARITY FUEL CELL are available in the market (Table 3). Toyota has also commercialized the SORA fuel cell bus in March 2018; five of these are currently operational in Tokyo. Deployment of FC buses is expected to provide a stable hydrogen demand, based on the estimation that hydrogen consumption of a fuel cell bus equals that of about 45 fuel cell passenger cars. No rail fuel call applications have been deployed yet.

Table 3: FCEVs and FC bus in Japan

	Toyota MIRAI	***Honda CLARITY FUEL CELL***	***Toyota FC bus SORA***
Price (excluding tax)	JPY 6.74 million (~EUR 54,000)	JPY 7.1 million (~EUR 57,000)	JPY 105 million (~ EUR 850,000)
Range	650 km	750 km	200 km
Refuelling time	5 kg / 3 minutes		15 kg / 10 - 15 minutes

Source: Own compilation by IEEJ based on information from Toyota and Honda

One crucial issue has been the development of hydrogen refuelling stations. As of May 2018, there were 108 hydrogen refuelling stations including planning and construction stages, making Japan the global leader. Most of them are located in the four major cities (Tokyo, Osaka, Nagoya, and Fukuoka).

What is deterring the development of hydrogen refuelling infrastructure in Japan are primarily high investment costs. The cost of building a hydrogen refuelling station is estimated at about JPY 350 million (~ EUR 2.8 million), which is much higher than the cost for a gasoline station of JPY 100 million (~ EUR 800,000). Ultimately, the price of hydrogen for FCEVs is affected partially by the costs of building and operating a hydrogen refuelling station. There is a general notion that a chicken and egg problem in Japan exists with regard to hydrogen technologies deployment: Uncertainty about hydrogen demand has a negative effect on infrastructure investments; in turn, the availability of refuelling stations is fundamental to reducing consumers' anxiety about purchasing FCEVs.

1.3.3 Industry

Hydrogen use in Japan's industry sector was approximately 15 billion Nm^3 in 2014, most of which was captive use in refineries (71%), ammonia production processes (16%) and petrochemical plants (10%). Other applications such as semiconductor, metal and glass take up around 3% (IEEJ own data, unpublished 2019). Industrial gas suppliers provide hydrogen from on-site hydrogen generators installed in the plants. Apart from that, hydrogen is transported to the plants in compressed hydrogen or liquefied hydrogen form.

Fuel cells CHP systems of larger sizes for industrial and commercial applications are still in the early stage of market development. In Japan, SOFC is the technology that the government is prioritising for industrial and commercial use. The target of launching fuel cell-based systems for industrial and commercial use in 2017, set in "the Strategic Roadmap for Hydrogen and Fuel Cells," was actually achieved in the same year, as three different SOFC cogeneration systems entered the market (Table 4). Two further companies also planned to launch their products by the end of Fiscal Year 2018, i.e. March of 2019. Currently, Molten Carbonate Fuel Cell (MCFC) has not been commercialized yet and deployment of a Phosphoric Acid Fuel Cell (PAFC) cogeneration system has been bogged down by issues like maintenance costs, although it was already made available in 1998.

Table 4: Fuel Cells for Commercial and Industrial Use in Japan

Company	Mitsubishi Hitachi Power Systems	Miura	Kyocera	Fuji Electric		Hitachi Zosen
Application	SOFC＋micro gas turbine	SOFC	SOFC	PAFC	SOFC	SOFC
Power generation output	250 kW/1,350 kWSOFC:22 7kW/1,140	4.2 kW	3 kW	100 kW	50 kW	20 kW
Electrical efficiency (LHV)	55%	48%	52%	42% - 48%*	55%	Above 52%
Heat recovery rate (LHV)	-	42%	-	-	30%	-
Overall energy efficiency (LHV)	73% - 76%	90%	90%	91% - 93%*	85%	90%
Launched year	2017	2017	2017	1998	FY 2018**	FY 2018**

** Depending on fuel (city gas/biogas/pure hydrogen); ** FY 2018 ends in March of 2019 in Japan.*
Source: Own compilation by IEEJ based on METI information

1.3.4 Power generation

Japan has set itself the target of commercializing hydrogen-based power generation around 2030, and is presently conducting R&D and demonstration projects which aim to develop combustors that can fire hydrogen mixed with natural gas, or ultimately, hydrogen alone. The government directed that the premixed flame combustion method or a new combustion method which does not need water/steam dilution should be pursued for hydrogen power generation utilizing a large-scale gas turbine. With large-capacity CHP systems already available on the Japanese market (see chapter 1.3.3), fuel-cell power generation is considered to be mature enough for deployment at scale, at least from the technical perspective.

1.3.5 Power-to-X

PtX in Japan is still in the early demonstration stage. Besides the FH2R project described in the chapter 1.5, there are several other demonstration projects where the scale is much smaller. There are currently three PtG pilot projects in operation in Japan (Table 5).

Table 5: Overview of other major power-to-gas demonstration project supported by NEDO

Project Overview	Stakeholder	Main purpose	Technology
• Storage of renewable power in the form of hydrogen (MCH)	• Chiyoda Corporation • Yokohama National University	• Storage of wind power in the form of hydrogen • Grid service by electrolyser	• Alkaline water electrolysis • MCH for hydrogen storage • Fuel cell (SOFC)
• Stabilization of variable renewable power output by power-to-gas	• Toyota Tsusho Corporation • NTT FACILITIES, INC. • Kawasaki Heavy Industries, Ltd. • Hrein Energy Inc. • Technova Inc. • Muroran Institute of Technology	• Using excess wind power to produce hydrogen • Supply hydrogen to a heat supply boiler in the nearby community	• Alkaline water electrolysis • MCH for hydrogen delivery • Hybrid hydrogen boiler (with LPG) and fuel cell (PEFC)
• Stand-alone emergency electricity supply system by solar PV, electrolyser, and fuel cell	• Tohoku University • Mayekawa MFG. CO., LTD.	• Solar power storage by hydrogen • Stand-alone electricity supply system	• PEM water electrolysis • Liquid hydrogen/hydrogen storage alloys • Fuel cell (PEFC)

Source: own compilation based on NEDO (2016)

One of the major barriers of PtG in Japan is that the cost of hydrogen production via electrolysis from renewable power is very high. The current CAPEX levels for electrolysers in Japan lie between 150,000 and 200,000 JPY/kW (~ 1,200 – 1,600 EUR/kW). In comparison, IRENA (2018) cites typical CAPEX levels at 750 and 1,200 EUR/kW for alkaline and PEMEL, respectively (IEEJ own data, unpublished, 2019, IRENA 2018). Further, renewable power cost levels are currently twice as high as those in Europe; the government has set the 2030 targets to 7 JPY/kWh (~ 0.06 EUR/kW) for solar PV and 8 - 9 JPY/kWh (~ 0.07 EUR/kW) for wind, which is still higher than the current international lowest levels (ANRE 2018). A low-cost renewable power supply could present itself from the renewable power projects after their guaranteed feed-in tariff (FIT) period has expired. FIT in Japan started in 2012, and with FIT periods for large scale wind and solar PV both lasting 20 years, first projects will run out in 2032.

1.4 Overview of policy - Germany

1.4.1 Political drivers

Climate and energy policies are the main driver for green hydrogen development and deployment in Germany. Although Germany succeeded in reducing its greenhouse gas emissions by 31% in 2018 in comparison to 1990 (UBA 2019b), its national targets for 2030 (-55%), 2040 (-70%) and 2050 (between -80 and -95%) are very ambitious. A large majority of the population supports these targets and considers them a high priority. Accordingly, nearly all political parties are strongly committed to Germany's climate and energy targets. Given the higher costs and technical challenges in other sectors, such as industry and agriculture, achieving the climate targets requires a virtually complete decarbonisation of the energy sector, including electricity, heat and transportation. Especially for the latter, as well as for some industrial processes, a widely held view is that a significant use of green hydrogen and other renewables-based synthetic fuels are essential to achieve Germany's energy and climate targets at acceptable costs.

Regarding the power sector, green hydrogen and other renewables-based synthetic fuels can play an important role in balancing very high shares of variable renewables which are expected to become the prevailing electricity source in Germany over the course of the next years. Green hydrogen and other renewables-based synthetic fuels can provide large scale seasonal storage services.

Regarding the transportation and heating sectors, in view of reducing GHG emissions and local air pollution, German energy strategy has so far focused mainly on energy savings and energy efficiency (e.g. building insulation, reduction of motorised individual transport) and on electrification (e.g. heat pumps, electric vehicles). However, these two approaches are insufficient to achieve a complete decarbonisation in these sectors (chapter 2.1). Green hydrogen or other renewables-based synthetic fuels are therefore expected to play an important role, especially for long distance road freight transport, shipping, air transport as well as for a series of industrial processes.

Last but not least, technological leadership and export opportunities also represent an important driver for deployment of hydrogen technologies in Germany. German companies are leading in several hydrogen technologies, and therefore push for Germany to become an early adopter as a way of facilitating technology learning and economies of scale. Technology providers as well as power and gas transmission network operators have engaged in extensive R&D activities, equipment testing and pilot projects.

Given these drivers, there is a wide consensus that in the medium and long term, hydrogen produced in and imported to Germany should and will be clean. From a climate policy point of view, efforts to substitute natural gas are pointless if the hydrogen originates from SMR or from coal gasification without CCS. Whether the clean hydrogen used in Germany should only be green or could also be blue (see text box at the beginning of chapter 1.1 for the definitions of this terminology) is a more open debate. Due to strong public opposition[6], the implementation of CCS on German soil in the foreseeable future is very unlikely. However, the growing awareness for the urgency of climate action could lead to increased political acceptance for imported blue hydrogen.

1.4.2 Major policies

Currently, the German federal government is in the process of adopting the **first German National Hydrogen Strategy**, expected to be released by the end of **2019**. To date, in its National Energy and Climate Plan (NECP), currently under development and required to be submitted to the European Commission by the end of 2019, only one quantitative target specifically refers to hydrogen or hydrogen technologies (BMWi 2019b).

1.4.3 Initiatives, partnerships, platforms and institutions on national and European level

Germany participates in global, European and domestic initiatives concerned with hydrogen technologies. Following is an overview of the most visible ones in Germany and Europe. International initiatives are summarized in Chapter 0.

Fuel Cells and Hydrogen Joint Undertaking

The Fuel Cells and Hydrogen Joint Undertaking (FCH-JU) is a European initiative including the European Commission, industrial stakeholders represented by Hydrogen Europe, and stakeholders from the research sector represented by Hydrogen Europe Research. This public-private partnership focuses on supporting R&D and demonstration projects in fuel cell and hydrogen energy technologies. The first phase (2014 – 2020) has a budget of 1.3 billion EUR. The second phase will focus on reducing costs of hydrogen technologies across different sectors (FCH 2019).

European Hydrogen Initiative

The European Hydrogen Initiative was signed by 25 European countries in 2018. Its foci lie on conversion of hydrogen to renewable methane, direct injection into the gas grid, short- and long-term energy storage, sector integration and coupling as well as use of hydrogen technologies in industrial and transport sectors (FMRAST 2018).

[6] Plans for carbon storage in Germany have been abandoned due to public opposition based on two very different drivers and sets of people. On one hand, there was a widespread general opposition, supported also from several influential environmental NGOs, to CCS projects applied to (brown) coal power plants. This opposition was based on the argument that the power sector can be more effectively and more cheaply decarbonised by achieving very high, up to 100%, shares of renewables. For technical and economic reasons, large CCS coal power plants would not be compatible with a power system dominated by variable renewables. This argument is still valid, as Germany is in the process of agreeing a complete phase out of coal power plants, following the example of several other European countries. However, this argument does not apply to the use of CCS for industrial processes that cannot be (easily) electrified. The second reason for opposition is scepticism about the safety of carbon storage, which triggered fierce opposition from the local population of the areas close to the planned CO_2 pipelines and storage sites.

German – French cooperation on energy transition

Based on a directive passed by both countries, joint R&D activities to promote sustainable energy supply for Europe will be eligible for funding, addressing, among other issues, renewable energy conversion and storage. Hydrogen and fuel cells are specifically mentioned as target technologies. The funding is administered by Projektträger Jülich (BMBF 2019a).

7th Energy Research Programme

The Federal Government adopted its 7^{th} Energy Research Programme in September 2018. Compared to its predecessor, it increases the support for research, development, demonstration and trial of technologies across all domains of energy. At the same time, it broadens the scope of funding, sets a stronger focus on sector coupling (in particular on interfaces with the transport sector), and increases its engagement in international cooperation. A special role is given to supporting large-scale field testing (*Reallabor*, the German term used to describe it, roughly translate into real-environment laboratory), including hydrogen production by water electrolysis. Approximately EUR 6.4 billion has been earmarked for funding until 2022 (PtJ 2019).

National organisation for hydrogen and fuel cell technology / National innovation programme hydrogen and fuel cell technology

The National Organisation for Hydrogen and Fuel Cell Technology (NOW) constitutes one of the key stakeholders as the partner of the German Government for hydrogen technologies and sustainable mobility. Acting as link between politics, academia and industry, the NOW coordinates and facilitates activities in various national and international networks. Beyond the national activities, the NOW represents the German ministries in the networks of the IPHE, IEA and IC-8, linking national to the international activities and developments. Within various European networks, NOW is strongly involved in the policy and regulatory, work as well as coordination of funding programs. It is also involved in specific bilateral partnerships with the goal of strengthening Germany's technology leadership and addressing specific aspects of technology cooperation, e.g. within the Sino-German collaboration on regulation, the long standing partnership with NEDO with focus on PtX and hydrogen infrastructure, etc.

Some of NOW's most visible tasks are coordinating the National Innovation Programme Hydrogen and Fuel Cell Technology (NIP), as well as the funding guidelines Electromobility and Charging Infrastructure (NOW 2019a). In addition, the program for the mobility and fuels strategy (Mobilitäts- und Kraftstoffstrategie, MKS) has been set up to enable projects associated with the use and production of alternative fuels, including by PtX. On behalf of the Ministry of Environment (BMU), the Export Initiative Environmental Technologies extends the activities to evaluate and enable the use of hydrogen and fuel cell technologies worldwide.

NIP I ran from 2007 to 2016 and represented the overarching platform for hydrogen technologies research. Over this timespan, it generated investments of 1.4 billion EUR in the hydrogen and fuel cell technologies, provided in roughly equal sums by the private and the public sector. Among recipients were about 240 private sector entities and about 50 research institutes. It focused heavily on basic research and demonstration projects while support for market introduction only amounted to about 1% of overall funding. The transport sector received just under half of the funding (McKinsey & Company 2017).

NIP II was started in 2017 and is foreseen to run until 2026. While in terms of sectors, the transport remains in focus, more funding will go towards market introduction and integrated projects in hydrogen regions (NOW conducted a survey in 2018 of all major electrolysis technology providers and came to the conclusion that the technology is ready for the market (Smolinka et al. 2018)). The NIP II website currently lists 13 running projects (NOW 2019b). The overall investments for the second phase of the NIP are foreseen to exceed 2 billion EUR, mostly provided by the private sector. NOW and Projektträger Jülich are jointly coordinating the programme (BMVI 2016).

Strategic platform Power-to-Gas

An important role has also been played by the Strategic platform Power to Gas, initiated by the German Energy Agency (Strategieplattform Power to Gas 2019). Its intention is to facilitate cooperation among relevant actors in order to promote market-ready technologies and facilitate market their entry. To date, it has generated more than 40 research and pilot projects, 24 of them already in operation and addressing all stages of hydrogen life cycle.

Global alliance power fuels

dena initiated the Global Alliance Power Fuels in 2018 with the aim of bringing international industrial enterprises together and building a broad network of partners from research, politics, and society in order to develop international markets for synthetic fuels from renewable energies (dena 2018b).

Federal-state and regional initiatives

Regional initiatives are also underway in Germany, for example the Fuel Cell Initiative of Baden Wuerttemberg, a network which aims to promote development and expansion of sustainable energy generation and storage technologies based on fuel cells and batteries in mobile, stationary and portable application, as well as infrastructure (BBA-BW 2019). Another example is the Coordination Centre of the Bavarian Hydrogen Initiative, which manages public relations activities concerning the topic of hydrogen, conducts energy and economic analyses and formulates long-term strategies for promotion of hydrogen (wiba 2009). The hySOLUTIONS in Hamburg is a public-private partnership promoting the application of fuel cells and hydrogen as well as electric drive and supply systems (hySolutions 2017). The Fuel Cell and Hydrogen Network North-Rhine Westphalia connects relevant actors in the field of fuel cell and hydrogen to bolster the development and market integration (EnergieAgentur NRW 2019). On the regional level, Germany is represented in the European Association for Hydrogen, Fuel Cells and Electromobility in European Regions (HyER) which was established to represent member states' interest on hydrogen and fuel cells in the 7th Energy Research Programme (EnergieAgentur NRW 2008).

1.4.4 Demonstration and pilot projects

Following is a list of 5 demonstration and pilot projects which is non-exhaustive but aims to outline the diversity of the hydrogen-related pilot projects currently underway in Germany. Since many projects cover more than one sector, a break-down of the projects by sectors has not been conducted.

HYPOS East Germany

The Hypos project was started in 2013 with the aim to develop a Germany-wide network of hydrogen stakeholders and currently has over 100 members from the private sector, research institutions and academia. While also serving as a platform for knowledge generation and sharing, its most visible success has been the development of the HYPOS model hydrogen region for green hydrogen production, storage, transport and use connecting sectors transport, heating and in industry. HYPOS seeks to identify niche and entry hydrogen applications which have the potential to be some of the first economically viable green hydrogen use cases (HYPOS 2019).

The HYPOS model region is concentrated in the former eastern states of Saxony and Saxony-Anhalt and built around a 150 km hydrogen pipeline, the second largest in Germany. The location offers sufficient renewable energies supply potential, demand from industrial and residential sector, the possibility of using salt caverns for storing of hydrogen, and existing pipeline infrastructure. The project’s website currently lists 25 individual projects.

BIC H2

The regional public transport operator in the region around Cologne has been using hydrogen-powered fuel cell buses on regular lines since 2011. This has been part of the company’s internal project designed to achieve a zero-emissions fleet operation. Initially, 30 fuel cell buses and 2 refuelling stations have been introduced with the aim of demonstrating the technology’s readiness for large-scale deployment. The project is accompanied by private-sector technology manufacturers and research institutions which provide monitoring and evaluation. The project clearly states that one of its goals is to send a message to the policymakers that the hydrogen technologies have matured (NOW 2019c).

BIC H2 is part of a EU-supported umbrella initiative JIVE (Joint Initiative for hydrogen Vehicles across Europe) which aims to deploy 139 fuel cell buses across the EU, bundling the orders with the aim of strengthening the buyer’s bargaining position towards producers, facilitate investments in R&D and price competition on the side of the producers, promote standardisation, expedite infrastructure deployment and generate knowledge (Fuel Cell Electric Buses 2019).

Energiepark Mainz

Energiepark Mainz was funded by the Federal Ministry of Economic Affairs and Energy (BMWi) and ended in 2015 with the construction of an electrolysis plant with a peak capacity of 6 MW_{el} which absorbs excess wind energy. The produced hydrogen can temporarily be stored on site and distributed to various industrial, mobility and power generation applications. Further, the project aims to develop a new plant operation concept which improves its economic viability (Strategieplattform Power-to-Gas 2019e).

Climate friendly living

An example of a comprehensive project in the residential sector is the Exytron’s Climate-friendly living in Augsburg from 2018. A renovation of a building from 1974 included refitting it with a PtX facility which absorbs excess renewable power and converts it into synthetic gas which is temporarily stored on site. The subsequent combustion takes place in a condensing boiler-based CHP system, supplying 70 apartments with electricity and heat. The renovation also included a roof-mounted PV power plant (Strategieplattform Power to Gas 2019).

Carbon2Chem

In 2018, Thyssenkrupp commissioned a pilot plant to use metallurgical gases for synthetic methanol production. The Carbon2Chem project, partly financed by the Federal Ministry of Education and Research, is focusing on using the CO_2 produced during steel production for chemical products. The large scale of the project, if successful, would mean that considerable quantities of CO_2 could be converted into precursors for fuels, plastics or fertilizers instead of released into atmosphere (dpa 2018).

1.5 Overview of policy - Japan

1.5.1 Political drivers

From Japan's perspective, hydrogen as energy carrier is seen as fulfilling three different roles. Firstly, while the need for decarbonisation of the country's energy system is becoming ever more pressing, Japan's option for low-carbon fuels is limited: high cost of renewable electricity, limited potential for CCS, and uncertainties regarding nuclear power. Given this situation, high expectations are connected with clean hydrogen. The second is improving Japan's energy security. This issue has shaped Japan's energy policy ever since the first oil crisis in 1973 (Thorarinsson 2018). Because clean hydrogen can be produced in different ways, for example from fossil fuels with use of CCS or by water electrolysis using renewable power, hydrogen can contribute to Japan's energy supply becoming more diversified. The third is the development of new export technologies for the hydrogen economy. Japan is the world's leading country in stationary fuel cell technologies and Japanese automotive companies are on the cutting edge of fuel cell vehicle manufacturing.

1.5.2 Major policies

The direction of energy transition set by the government is mapped in the Strategic Energy Plan. The latest Strategic Energy Plan (5th Strategic Energy Plan) was released in 2018. Although the pathway of energy transition towards 2030 is clearly set out with quantitative targets, there is only a general picture of what the energy system will look like in 2050, without any clear targets. The 5th Strategic Energy Plan contains a chapter dedicated to hydrogen. The discussion of future development of hydrogen is independent from the energy mix targets for 2030 since use of hydrogen is expected to scale up only after 2030.

The detailed roadmap towards the hydrogen-based society (the term introduced by the 4th Strategic Energy Plan) can be found in the Basic Hydrogen Strategy and the Strategic Roadmap for Hydrogen and Fuel Cells (see below), two policies specifically dedicated to hydrogen and fuel cells. In them, both the application of hydrogen and fuel cell technologies and the supply of clean hydrogen are discussed. Power and mobility sector are envisioned to make the largest share in hydrogen demand. Despite the important role of stationary fuel cells in the hydrogen-based society, the policies don't clearly address the issue of whether their demand for hydrogen is to be covered by clean hydrogen or by onsite natural gas/LPG reforming. Both policies envision that both, imported clean hydrogen, and hydrogen produced from domestic renewable resources will be the main sources for hydrogen supply in the future.

The 5th Strategic Energy Plan (2018)

The Hydrogen-based society was already part of the 4th Strategic Energy Plan from 2014, granting hydrogen and fuel cell technologies a central role in Japan's energy strategy, and ensuring it a strong government support. The 5th Strategic Energy Plan again emphasizes the importance of hydrogen's role and lays out the pathway and targets. For hydrogen use, the 5th Strategic Energy Plan particularly focuses on the mobility and power sectors. Apart from that, further expansion of the deployment of stationary fuel cells is a priority. For the time being, the stationary fuel cell applications will continue to use hydrogen derived from natural gas and LPG via reforming. For hydrogen supply, imports of clean hydrogen as well as domestic PtX applications are seen as the two main important sources. The targets in the 5th Strategic Energy Plan are in line with the Basic Hydrogen Strategy and Strategic Roadmap for Hydrogen and Fuel Cells (METI 2018a).

Basic Hydrogen Strategy (2017)

The Basic Hydrogen Strategy is the first comprehensive government plan for hydrogen and fuel cell technology development, summarizing and streamlining various supporting programs by different ministries. Although the strategy covers all aspects of development of the hydrogen-based society, it is essentially a summary of all the issues that have already been discussed. The mid- and long-term targets set out in this Basic Hydrogen Strategy are generally in line with those in the Strategic Roadmap for Hydrogen and Fuel Cells (METI 2017).

Strategic Roadmap for Hydrogen and Fuel Cells (released in 2014 and revised in 2016)

The Strategic Roadmap for Hydrogen and Fuel Cells was drafted by the Council for a Strategy for Hydrogen and Fuel Cells (with METI in the role of the secretary) in 2014 and revised in 2016 (METI 2016). The roadmap envisioned three phases for hydrogen and fuel cell development in Japan:

- **Phase 1**: Dramatic expansion of hydrogen mobility applications and deployment of stationary fuel cells (in the short term using on-site natural gas/LPG reforming instead of clean hydrogen).
- **Phase 2**: Full-fledged introduction of hydrogen power generation and establishment of a large-scale hydrogen supply system by the second half of the 2020s; commercialization of large-scale & long-distance hydrogen transport technologies.
- **Phase 3**: Establishment of a clean hydrogen supply system by around 2040.

Table 6 provides targets related to hydrogen as defined by the documents central to Japanese official energy strategy.

Table 6: Overview of Hydrogen and Fuel Cell technology status and future development targets in Japan

	Present	2020	2030	2030 ~ 2050
Consumption and price	• H2 consumption: 200 ton/y (excluding H2 used in industry) • Hydrogen price: JPY 100/Nm3 (H2 refuelling station)	• H2 consumption: 4,000ton/y	• Commercialized hydrogen supply chain • H2 consumption: 300,000 ton/y • Hydrogen CIF price: JPY 30/Nm3	• H2 consumption: more than 10 mil. ton/y (depending on H2 power generation) • Hydrogen CIF price: JPY 20/Nm3
Hydrogen production	• Produced from fossil fuel, by product from industrial process			• Clean hydrogen
Coal + CCS	• Demonstration project in Australia	• Establishment of core technologies (brown coal gasification, CO2 capture, etc.)		• Large scale hydrogen supply from brown coal + CCS
Natural gas +CCS	• Natural gas reforming is already matured technology CCS is still in pilot stage			
Electrolysis using RE electricity	• Demonstration projects	• Electrolyser cost target: JPY 50,000/kW	• Commercialization around 2032	• H2 production using domestic RE electricity is competitive against imported clean H2
Hydrogen pipeline	• Demonstration projects	• Demonstration of hydrogen town near the Tokyo Olympic/Paralympic village	• Hydrogen pipeline network near the hydrogen receiving terminal	
Compressed hydrogen	• Established technology for domestic delivery			

Liquefied hydrogen	• *Established technology for domestic delivery *R&D and pilot project for large scale international shipping and storage		• Commercialization of liquid hydrogen supply chain	• Large scale international shipping of hydrogen
Organic Hydride (MCH)	• R&D and pilot project (shipping from Brunei to Japan, supported by NEDO)	• Commercialization of MCH hydrogen supply chain after 2025		
Ammonia	• Established technology	• Ammonia (produced from clean H2) blended with coal for power generation	• Ammonia (produced from clean H2) gas turbine for power generation	
Stationary fuel cell (residential)	• PEFC: JPY 1,400,000/unit • SOFC: JPY 1,750,000/unit • Penetration: 220,000 unit *Ene-Farm with onsite NG/LPG reforming • Payback time: 18 years	• *PEFC: JPY 800,000/unit • *SOFC: JPY 1,000,000/unit • *Payback time: 7~8 years	• Penetration: 5.3 mil. unit • Payback time: 5 years • Large scale Ene-Farm: power generation efficiency higher than 60%	• Penetration of Ene-Farm using clean H2
Fuel cell vehicle	• H2 refuelling station: 100 • FCEV: 2,500 • FC bus: 2 • FC forklift: 40	• H2 refuelling station: 160 • FCEV: 40,000 (200,000 by 2025) • FC bus: 100 • FC forklift: 500	• H2 refuelling station: 900 • FCEV: 800,000 • FC bus: 1,200 • FC forklift: 10,000	• Replacing conventional fossil fuel vehicles and buses • Fuel cell truck, fuel cell ship, other applications in the transportation sector
Hydrogen power generation	• R&D and demonstration		• H2 power generation cost: JPY 17/kWh • Capacity: 1GW	• H2 power generation cost: JPY 12/kWh Installed capacity: 15~30GW • Required hydrogen demand: 5~10 mil. ton/y

Industry application	• Hydrogen from fossil fuel	• Using clean hydrogen to substitute other fossil fuel in the industrial process

Source: Own compilation by IEEJ based on Strategic Roadmap for Hydrogen and Fuel Cells, Basic Hydrogen Strategy, 5th Strategic Energy Plan, Council for a Strategy for Hydrogen and Fuel Cell and Tokyo Gas Press Release (Tokyo Gas 2018).

1.5.3 Initiatives, partnerships, platforms and institutions

In Japan, there are several initiatives and platforms formed by private companies, which are supported by the government or government-affiliated institutions, and are in charge of promoting the demonstration and commercialization of hydrogen technologies.

HySTRA (Hydrogen Energy Supply-chain Technology Research Association)

HySTRA was formed by four private companies in 2016 (Kawasaki Heavy Industry (KHI), J-Power, Iwatani Corporation, and Shell Japan) and supported by NEDO to demonstrate the viability of brown coal gasification and hydrogen refining at Latrobe Valley in Australia, aiming to establish a Japan-Australia hydrogen supply chain.

AHEAD (Advanced Hydrogen Energy Chain Association for Technology Development)

AHEAD is an association formed in 2017 by Mitsubishi Corporation, Nippon Yusen, Chiyoda Corporation, and Mitsui & Co. with support from NEDO (AHEAD 2017). It is responsible for carrying out the Japan-Brunei Hydrogen Supply Chain project which aims to demonstrate the viability of long-distance methyl cyclohexane (MCH) hydrogen transport.

Advanced research project on hydrogen application technologies

The foci of this project lie on scientific research aimed at improving performance of electrolysis technologies, R&D of large-scale hydrogen application technologies, research on high efficiency power generation technologies and research on energy carrier systems. The program runs from financial year 2014 to financial year 2022; in 2018, the funding was about 0.9 billion JPY (~ 7 million EUR) (NEDO 2019a).

R&D on technologies for building hydrogen society

This programme targets R&D and demonstration projects for hydrogen production from renewable energy, hydrogen transportation and storage, as well as hydrogen supply chains focusing on hydrogen production from overseas energy resources. It also concerns itself with R&D on hydrogen gas turbines and is trying to identify the direction of future technology development. The program runs from financial year 2014 to financial year 2020; in 2018, the funding was about 8.9 billion JPY (~ 72 million EUR) (NEDO 2019a).

R&D on hydrogen application technologies

The focus lies on FCEVs and hydrogen refuelling stations, in particular on research to support the streamlining of domestic regulation and consistency with international standards. Further, it strives to achieve cost reductions for FCEVs and hydrogen refuelling stations, and improve the safety of hydrogen refuelling stations. It also focuses on research of global policy, market, and R&D trends for clean hydrogen. The program ran from financial year 2013 to financial year 2017 and had a funding of about 4.1 billion JPY (~ 33 million EUR) (NEDO 2019a).

Initiatives by the Tokyo Metropolitan Government

For the Olympic and Paralympic Games 2020 in Tokyo, the Tokyo Metropolitan Government, supported by the national government, is taking efforts for implementing several hydrogen production and utilization facilities. A fund of about 40 billion JPY (around 322 million EUR) has been set up to be used for several purposes such as an increase in demand for passenger FCEVs, the introduction of fuel-cell buses, as well as the establishment of hydrogen refuelling stations in Tokyo, concentrated in areas relevant for transportation of athletes, officials and visitors to the Olympic Games. Further, implementation of green hydrogen supply systems which use renewable power from areas surrounding Tokyo is supported. For establishing a hydrogen supply system, the Tokyo Metropolitan Government is also promoting the introduction of technologies such as hydrogen pipelines and hydrogen fuel cells. An education centre was also opened in 2016 with the task of providing information about hydrogen energy to the public and interested companies (Tokyo Metropolitan Government 2018).

1.5.4 Demonstration and pilot projects

The New Energy and Industrial Technology Development Organization (NEDO) is the main government agency supporting and overseeing research and demonstration projects on hydrogen and fuel cell technologies. Following is a list of three visible projects which focus on hydrogen (the list is not exhaustive).

Japan-Australia Hydrogen Supply Chain Project

This pilot project aims to demonstrate hydrogen production from brown coal and large scale international hydrogen shipping in the form of liquid hydrogen. The project is comprised of 5 parts: (1) brown coal gasification, (2) hydrogen refinery, (3) hydrogen liquefaction, liquid hydrogen storage, export terminal, (4) liquid hydrogen shipping, and (5) liquid hydrogen reception via receiving terminal (Figure 3).

Supported by NEDO, four private companies – Kawasaki Heavy Industry (KHI), J-Power, Iwatani Corporation, and Shell Japan – formed the CO_2-free Hydrogen Energy Supply-chain Technology Research Association (HySTRA, chapter 1.5.3) in 2016 to demonstrate parts (1), (4), and (5) (HySTRA 2019). Demonstration of parts (2) and (3) is supported by the Australian government and will be carried out by Kawasaki Heavy Industry, J-Power, Iwatani Corporation, Marubeni Corporation, and AGL Energy Limited. Hydrogen production and transportation will take place for one year between 2020 and 2021. Pending results of the pilot project, the decision for a commercial uptake that is planned to potentially include CCS will be made in the 2020s (HESC 2019). It is assumed that the large scale liquid hydrogen supply chain could probably be commercialized in the 2030s (J-Power 2018).

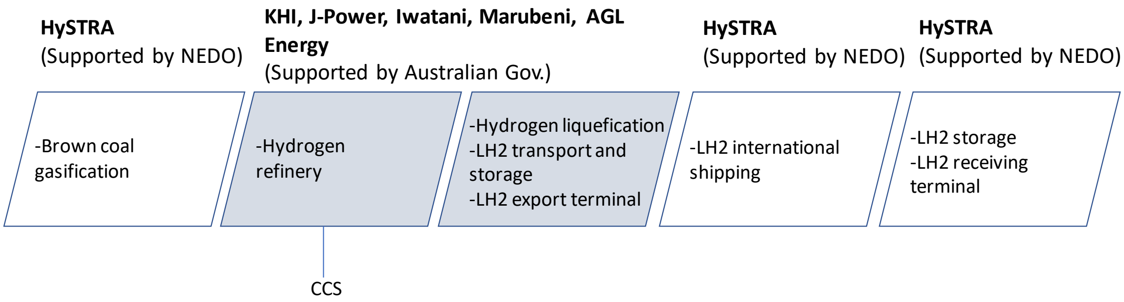

Figure 3: Overview of the Japan-Australia hydrogen supply chain project
Source: Own depiction by IEEJ based on HySTRA information

Japan-Brunei Hydrogen Supply Chain Project

The main purpose of the project is to demonstrate the viability of hydrogen transportation in the form of MCH. Hydrogen produced from natural gas steam reforming in Brunei is mixed with toluene to form MCH for subsequent shipping to Japan. At the receiving end, a dehydrogenation process is required. The advantage of using MCH as the carrier for large-scale hydrogen transportation is that it can be stored and transported under ambient temperature and pressure with relatively high energy density. The technology used for MCH formation and hydrogen production from MCH called SPERA is developed by the Chiyoda Corporation, a leading Japanese company specialized in engineering, procurement and construction. Figure 4 provides an overview of the project.

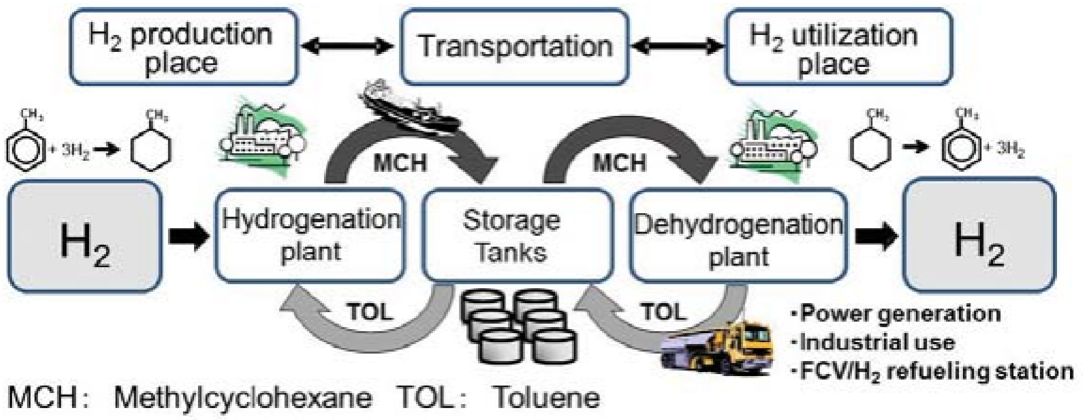

Figure 4: Overview of the H2-MCH-H2 scheme
Source: JASE-W (2014)

The project is supported by NEDO and was announced in 2017 (NEDO 2017). AHEAD (Advanced Hydrogen Energy Chain Association for Technology Development, chapter 1.5.3), an association formed by Mitsubishi Corporation, Nippon Yusen, Chiyoda Corporation, Mitsui & Co. in 2017, is responsible for project implementation (AHEAD 2017). The shipping of hydrogen is envisioned to start in January 2020 with capacity of up to 210 tonnes of hydrogen per year. Pending the results of the demonstration project, it is assumed that large scale hydrogen supply chain using MCH could be commercialized after 2025.

Power to gas: Fukushima Hydrogen Research Field

The largest PtX demonstration project in Japan is located at Namie-cho, Fukushima prefecture (Fukushima Hydrogen Research Field, FH2R). Hydrogen is produced by a 10 MW alkaline electrolysis hydrogen production plant. The project aims to demonstrate the entire PtX supply chain, from hydrogen production by renewable electricity to hydrogen storage and delivery, and finally to hydrogen end-use applications such as fuel cell passenger vehicles and buses, stationary fuel cells etc. The project's second objective is the demonstration of hydrogen technologies in power-to-hydrogen-to-power application used for providing grid stability. Figure 5 provides an overview of the project.

The project consortium consists of Toshiba Energy System & Solutions Corporation, Tohoku Electric Power Co., Inc. and Iwatani Corporation. The facility will start operation around 2020 with planned hydrogen production capacity of up to 900 tonnes per year.

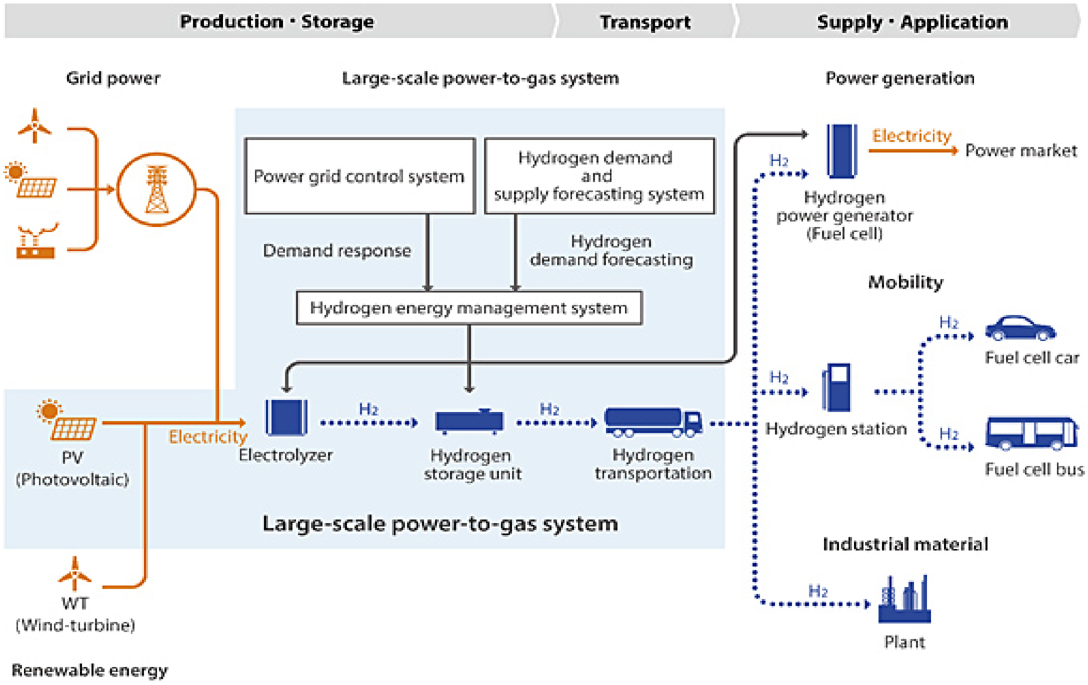

Figure 5: Overview of the Fukushima Power to Gas demonstration project
Source: NEDO (2018b)

International initiatives

Table 7 shows selected countries' participation in the most visible intergovernmental initiatives (private initiatives such as the Hydrogen Council are not shown as they cannot be allocated to individual countries). Following subchapters provide a short description of these initiatives.

Table 7: Countries' participation in international initiatives

	IEA Hydrogen TCP	IPHE	Mission Innovation H2 Challenge	Hydrogen Energy Ministerial Meeting
Germany	X	X	X	X
Japan	X	X	X	X
Australia	X	X	X	X
Austria	X	X	X	X
Belgium	X			
Brunei				X
Canada		X	X	X
Chile			X	
China	X	X	X	X
Denmark	X			
EU	X	X	X	X
Finland	X			
France	X	X	X	X
Greece	X			
Iceland		X		
India		X	X	
Israel	X			
Italy	X	X		X
Korea	X	X		X
Lithuania	X			
Mexico			X	
New Zealand	X			X
Norway	X	X	X	X
Poland				X
Qatar				X
Russia		X		
Saudi-Arabia			X	
South Africa		X		X
Spain	X			
Sweden	X			
Switzerland	X			
The Netherlands	X	X	X	X
UAE				X
UK	X	X	X	X
USA				X

Source: Own depiction based on various sources

1.5.5 IEA Hydrogen TCP

The Hydrogen Collaboration Programme (TCP) of the International Energy Agency (IEA) is designed to accelerate the deployment of hydrogen technologies. If focuses on seven main areas: technology, energy security, environment, economics, market, deployment and outreach. It aims to leverage international cooperation, foster information exchange and facilitate R&D activities (IEA 2019c).

1.5.6 International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE)

IPHE is an 18-country, inter-governmental partnership with the stated objective of facilitating the transition to hydrogen-based clean energy systems across all sectors and applications by activating the market potential of hydrogen and fuel cells technologies. The main focus of IPHE is harmonisation of regulation, codes and standards, and to serve as a high-level platform for exchanging information concerning technologies, policies etc. (IPHE 2019).

1.5.7 IC-8 of the Mission Innovation

The 8th innovation challenge (IC-8) of mission innovation aims to facilitate the deployment of hydrogen technologies at scale in order to enable a world market for hydrogen. It contributes the applied approaches on innovative projects to the international networks of the hydrogen and fuel cell Technology Collaboration Programmes of the IEA (chapter 1.5.5) and International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE; chapter 1.5.6) addressing hydrogen on the policy level as well as from the industry perspective of the Hydrogen Council (Mission Innovation 2019).

1.5.8 Hydrogen Energy Ministerial Meeting

The Japanese government initiated and hosted the first Hydrogen Energy Ministerial Meeting in Tokyo in October 2018 with participation of cabinet members and government officials from 21 countries. The Tokyo Statement by the chair of the meeting, Minister Seko of METI, summarizes the main outcomes (METI 2018b). According to the statement several international efforts are necessary for realizing the hydrogen society:

- International cooperation on technologies and the harmonization of regulation, codes and standards in order to speed up a decrease in costs for hydrogen supply and hydrogen products, such as FCEVs;
- International cooperation on expanding utilization of hydrogen, for instance by improving the safety of hydrogen at hydrogen refuelling stations and storage facilities, and by establishment of hydrogen supply chains;
- Research and evaluation of the potential economic impacts of hydrogen and its potential to reduce emissions;
- Increasing awareness and understanding of hydrogen by communication and education in order to stimulate the growth of investments in business related to hydrogen.

The second Hydrogen Energy Ministerial Meeting is to be held in September 2019.

1.5.9 Hydrogen Council

The Hydrogen Council is a global initiative of private stakeholders from the energy, transport and industry sectors which have an interest in fostering hydrogen as one of the pillars of energy transition. Their foci lie on facilitating the commercialisation of hydrogen and fuel cell technologies, as well as encouraging public stakeholders to commit to supporting hydrogen through appropriate policies and supporting schemes. Both German and Japanese companies have a strong presence in the Hydrogen Council (Hydrogen Council 2019).

2 Meta-Analysis of existing scenarios concerned with the role of hydrogen in the future energy systems of Germany and Japan

This chapter provides a meta-analysis of the role of hydrogen in long-term energy system scenarios for Germany and Japan, looking among others at the main drivers assumed to influence the demand for hydrogen (and other synthetic fuels) between 2030 and 2050. Chapter 2.3 provides a cross-country comparison of the scenarios, pointing to similarities and differences between the two countries.

2.1 Analysis of German scenarios

The Wuppertal Institute and dena identified 18 relevant scenarios from six different studies. These studies and scenarios were selected in consultation with BMWi based on their topicality (publication no earlier than 2015), the level of detail regarding the future role of hydrogen in the German energy system, and data availability. The six studies and 18 scenarios analysed (referred to in the following chapters as “analysed scenarios”) in this meta-analysis are presented in the Table 8.

For all these scenarios, detailed data and information concerning the overall energy system and specifically the role of hydrogen was extracted from the studies. In some cases, the authors of the studies were contacted and asked to provide relevant information which was unavailable in the studies themselves.

Depending on the original research question and focus of the studies, the respective scenarios elaborate the future role of hydrogen in varying degrees of detail. In particular, the studies by Hecking et al. (2018), Ausfelder at al. (2017) and Repenning et al. (2015) provide a very extensive analysis on the future demand of hydrogen. The scenarios developed by Bothe et al. (2017) focus mainly on the future role of the German gas infrastructure. Hobohm et al. (2018) developed their scenarios to analyse particularly the future role of liquid energy carriers in the German energy system. Henning and Palzer (2015) were mainly interested in the overall costs of the German Energiewende. The foci of these latter three studies include only some aspects of what is at interest in the study at hand. Therefore, it was decided to focus on scenarios from the studies by Hecking et al. (2018), Ausfelder et al. (2017) and Repenning et al. (2015) when discussing the potential future role of hydrogen in the German energy system in this chapter, especially when making quantitative comparisons in the form of tables and figures. Specifically, the following six scenarios were chosen as the main scenarios on which the meta-analysis focuses on (referred to in the following chapters as “scenarios in focus”):

- “KS95” from Repenning et al. (2015)
- “85_H2”, “85_offen” and “85_PtG” from Ausfelder et al. (2017)
- “TM80” and “TM95” from Hecking et al. (2018)

Table 8: Overview of the studies analysed in this study

Publication		**Mitigation scenarios**	
Title / Author(s), year	**Initiating institution(s) /** Executing institution(s)	**Name /** Description	**GHG reduction** (2050 vs. 1990)
Klimaschutzszenario 2050 - 2. Endbericht Repenning et al. **(2015)**	**Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit (BMU)** Oeko-Institut e.V. Fraunhofer Institut für System- und Innovationsforschung (ISI)	**Mitigation scenario 80** • National and EU GHG emission mitigation ambition	**80%**
		Mitigation scenario 95 • National and EU GHG emission mitigation ambition • Use of industrial CCS • use of domestic renewable energy sources	**95%**
Der Wert der Gasinfrastruktur für die Energiewende in Deutschland - Eine modellbasierte Analyse Bothe et al. (2017)	**Vereinigung der Fernleitungsnetzbetreiber (FNB Gas e.V.)** Frontier Economics IAEW 4Management EMCEL	**Electricity and gas storage** • End users mainly use electrical devices. • Storage: electricity storage and temporarily storage in gas form and reintroduced (power-to-gas-to-power) • Energy transport is generally electricity-based, gas transport is no longer required.	**95%**
		Electricity and Green Gas • End users mainly use electrical devices. • Storage: electricity storage and temporarily storage in gas form and reintroduced (power-to-gas-to-power) • Energy transport: on an electricity basis. • Gas transport: no longer required.	**95%**

Status und Perspektiven flüssiger Energieträger in der Energiewende Hobohm et al. (2018)	**Mineralölwirtschaftsverband e.V. (MWV)** **Institut für Wärme und Oeltechnik e.V. (IWO)** **MEW Mittelständische Energiewirtschaft Deutschland e.V.** **UNITI Bundesverband mittelständischer Mineralölunternehmen e. V.** Prognos AG Fraunhofer-Institut für Umwelt-, Sicherheits- und Energietechnik (UMSICHT) Deutsches Biomasseforschungszentrum (DBFZ)	**PtX 80** • Climate protection in Europe/world remains on current trend • Crude oil price on the world market 115 USD2015/bbl., • RE Installed power 230 GW, PtX use, no CCS use	**80%**
		PtX 95 • Ambitious Climate protection in Europe/world • Crude oil price on world market 50 USD2015/bbl.; • RE Installed power 230 GW, PtX use, CCS use	**95%**
Was kostet die Energiewende? Henning and Palzer (2015)	**Bundesministerium für Wirtschaft und Energie (BMWi)** Fraunhofer-Institut für Solare Energiesysteme (ISE)	**80/low/CH4** • Low rate of energetic modernisation of buildings stack • Transport carrier CH4 • Use of coal power plants until 2050	**80%**
		80/low/H2/ • Low rate of energetic modernisation of buildings stack • Transport carrier H2 • Use of coal power plants until 2050	**80%**
		80/low/electronic • Low rate of energetic modernisation of buildings stack • Transport carriers electricity • Coal power plants in use until 2050	**80%**

		80/ambitious/Mix • Ambitious rate of energetic modernisation of buildings stack • Mixed transport carriers Mix • Ambitious timeline for coal phase-out	**80%**
		90/ambitious/Mix • Ambitious rate of energetic modernisation of buildings stack • Mixed transport carriers Mix • Ambitious timeline for coal phase-out	**90%**
"Sektorkopplung" - Untersuchungen und Überlegungen zur Entwicklung eines integrierten Energiesystems Ausfelder et al. (2015)	**Nationale Akademie der Wissenschaften Leopoldina** **acatech – Deutsche Akademie der Technikwissenschaften** **Union der deutschen Akademien der Wissenschaften** DECHEMA innogy acatech KIT Wuppertal Institut Fraunhofer-Institut für Solare Energiesysteme (ISE) EnBW ifo Institut TU Dortmund RWI Ruhr-Universität Bochum TU München	**85_offen** • Technology composition is determined endogenously • Transport and heating technologies are open • H2 in the gas network reaches 5vol% • Process heat demand of industry is approx. 440 TWh	**85%**
		85_H2 • Car/truck sector is strongly based on H2 • Process heat demand of industry approx. 440 TWh	**85%**
		85_PtG • Heat pumps limited to 40% market share • BEV cars/trucks are limited to 50% market share • H2 in the gas grid 5vol% • Industry process heat demand declines by -0.5%/a.	**85%**

dena-Leitstudie Integrierte Energiewende Hecking et al. (2015)	**dena together with 60 industry partners** dena ewi Energy Research Scenarios gGmbH	**EL80** Increased energy efficiency and electrification in all sectors, leading to a significant increase in electricity demand. Synthetically generated energy sources are taken into account when they become absolutely necessary.	**80%**
		EL95 Increased energy efficiency and electrification in all sectors, leading to a significant increase in electricity demand. Synthetically generated energy sources are taken into account when they become absolutely necessary.	**95%**
		TM80 Increased energy efficiency, broader variation in technologies and energy sources used	**80%**
		TM95 Increased energy efficiency, broader variation in technologies and energy sources used	**95%**

Source: Own compilation based on scenario parameters

The six scenarios in focus present the future role of hydrogen in a detailed way, taking into account the interplay between various sectors, technological innovations and infrastructural needs. They offer a comprehensive description of the possible German energy system and energy flows from primary energy sources to final consumption in the time horizon until 2050. For these reasons, they were chosen to represent the backbone of the meta-analysis and are referred to in all the major steps of the meta-analysis. The rest of the 6 studies and 18 scenarios identified as relevant but not taken into focus are referenced selectively where they are able to offer further relevant insights. In the following subchapter, the three studies and the six scenarios in focus are introduced in more detail.

2.1.1 Studies and scenarios in focus

2.1.1.1 Klimaschutzszenario 2050 – 2. Endbericht

The study "Klimaschutzszenario 2050 – 2. Endbericht" was commissioned by the Federal Ministry for the Environment, Nature Conservation, Construction and Nuclear Safety and published in 2015. It evaluates whether or not and how the targeted emission reduction of 80 to 95% by 2050 (relative to 1990) can be achieved. It identifies the strategies and measures necessary to reach the climate targets and analyses the resulting cost-benefit for consumers and the economy. These questions are examined once in the context of a climate protection scenario with an 80% reduction in GHG emissions (KS80) and once in the context of a climate protection scenario with a 95% reduction in GHG emissions (KS95). The report is the second iteration; due to the continuously-evolving energy policy framework, a first version from 2014 was updated in the following year. The study forms the scientific pretext for the federal government's Climate Action Plan 2050, a strategy paper released in 2016, which outlines emissions reduction targets for each sector.

In its choice of scenarios, it does not attempt to compare different technology paths, but rather to evaluate a feasible development of the German energy system that would be compatible with Germany's long-term emissions targets. In the reference scenario, based on the policy measures in place in 2012, all emission reduction targets are missed. Only gross electricity consumption is reduced as planned. In KS80, the less ambitious end of the 2050 GHG emission reduction target is achieved without the use of carbon capture and storage (CCS). In KS95, the more ambitious end of the 2050 GHG reduction targets is achieved, but here CCS for industrial emissions is a central part of the technology mix.

For KS95, a drastic reduction of emissions in all sectors is necessary. CCS technology is expected to be used to reduce industrial process emissions in particular. If this technology were not available, the 2050 GHG emissions would be almost twice as high as they are in KS95. KS95 also assumes a much broader penetration of technologies such as power-to-heat or synthetic fuel production via PtX than KS80.

A high to very high CO_2 price is assumed in both KS80 and KS95, which is intended, among other things, as an incentive for investments in renewable energies. The renewable energy investment paths of the two scenarios are very different from 2020 on. Both scenarios show that the German government's intermediate GHG reduction targets between 2020 and 2040 are sufficient to achieve a GHG reduction of 80% by 2050, but for a 95% reduction, the intermediate targets must be set more ambitiously.

2.1.1.2 ‚Sektorkopplung' – Untersuchungen und Überlegungen zur Entwicklung eines integrierten Energiesystems

The study "‚Sektorkopplung' – Untersuchungen und Überlegungen zur Entwicklung eines integrierten Energiesystems" ("Sector Integration – Examination and Considerations for the Development of an Integrated Energy System") by the Deutsche Akademie der Technikwissenschaften (National Academy of Science and Engineering, Acatech), the Nationale Akademie der Wissenschaften (German National Academy of Sciences) and the Union der deutschen Akademien der Wissenschaften (Union of the German Academies of Sciences and Humanities), published in 2017, outlines possible scenarios in which Germany's current GHG reduction targets can be achieved with increasing sector integration. The study attempts to identify the necessary measures – both on national and EU level – that ought to be taken now to reach the future emission reduction targets.

For the future energy system, four complementing scenarios of sector coupling are derived, all of which target an 85% emissions reduction by 2050 relative to 1990, but are based on distinct technology pathways. In the first scenario, electricity is used in a direct manner, including increased use in heating and transport. A second scenario examines the use of hydrogen as an energy carrier in all sectors, with hydrogen production based on renewable electricity. A third scenario analyses the conversion of hydrogen into synthetic gases, fuels and combustibles. Finally, a fourth scenario assumes increased energy generation from biomass, solar thermal and deep geothermal energy to reach the climate targets. The choice of scenarios mirrors the goal to compare different technology routes individually and assess the effects of sector coupling technologies such as hydrogen and PtG versus an energy transition that is solely focused on renewable electricity. In directly comparing a hydrogen-based energy system with a system based on synthetic methane, it is able to quantify the trade-off between the benefits of higher energy efficiency (hydrogen route) versus the use of existing infrastructures, grids and applications (methane route).

In all scenarios, generation from solar and wind power is increased, along with energy efficiency. To ensure a stable supply of electricity despite the intermittency of renewables, back-up power plants and/or energy storage facilities are installed, such as pumped hydro storage power plants and batteries as short-term storage facilities and easily storable fuels and combustibles for longer term storage.

The analysis arrives at the conclusion that the conversion of the energy system from fossil fuels towards renewable energies and the transformation of the regulatory system are only possible through strong sector coupling and an integrated energy transition. In order to achieve the necessary market conditions, changes in the regulatory framework are necessary. These changes should primarily consist of a CO_2 price signal across all sectors, leading to harmonised and equal conditions between fossil and renewable energies on the one hand and between the electricity, heat and transport sectors on the other. At the same time, price levels should be chosen so as to incentivise innovation and new investment and realistically reflect all costs, including infrastructure and environmental aspects. Since the system costs of the energy system transformation are generally covered by the end consumers, the distributional effects should be taken into account and cushioned when the regulatory framework is redesigned.

2.1.1.3 dena-Leitstudie Integrierte Energiewende

The “Pilot Study Integrated Energy Transition” by the German Energy Agency (dena), published in 2018, compares and analyses different scenarios that achieve Germany’s 2050 GHG reduction targets. The study follows a strongly cross-sectoral approach aimed at assessing implementation challenges and societal issues, and, if necessary, supplementing the current policy trajectory with further recommendations. In principle, the study identifies GHG reductions of both 80% and 95% as feasible by 2050. However, it clearly emphasises that much stronger measures must be taken in all sectors, the framework conditions adapted and the distribution of costs discussed.

The parameters and technology choices were based on feedback from a large group of research and corporate partners obtained by an iterative process. Based on this input, an energy system model selects cost-optimized paths for the energy transition endogenously. The study distinguishes between two possible energy system developments. On the one hand, it identifies electrification scenarios that exploit all the potential for converting plants and processes to using electricity directly. In this case, two thirds of the total energy demand is covered by renewable electricity by 2050. Hydrogen and solar thermal energy only play a supplementary role. On the other hand, the study presents technology mix scenarios in which the climate targets are achieved with a combination of energy carriers, aiming to reach the climate targets at the lowest cost. Here, more emphasis is placed on the use of innovative processes and energy sources. In addition, the energy sources gas and oil, which can be easily stored, will cover possible peaks in energy demand in an increasingly climate-neutral form. By deriving these two distinct narratives, the study attempts to assess the benefits of a technology-neutral approach to energy policy, versus one that is focusing primarily on energy efficiency and electrification.

In the electrification scenarios, buildings, industry and transport sectors find themselves under increased pressure to reduce final energy consumption. Possible transformation paths between the electrification scenarios and the technology mix scenarios already differ significantly by 2030. By 2050, the paths based on a broad energy and technology mix are much more cost-effective than those based on the electrification. Further, systems with a diversified mix of technologies offer larger flexibility and can react more quickly to unpredictable developments.

In order to achieve the climate targets, the study identifies a set of unavoidable measures: an increase in energy efficiency in all sectors, a grid expansion beyond the one planned currently, and further development of grid regulation. In addition, it highlights the necessity of synthetic fuels as a third pillar of energy policy to decarbonise applications that cannot (or only with difficulty) directly use renewable electricity. The demand for these fuels depends largely on the level of climate ambition: in the scenarios that achieve the 95% target the demand is about three times as high as in the scenarios that achieve the 80% target.

2.1.2 Demographic and economic framework conditions

2.1.2.1 Demographic Development

In their assumptions regarding the future development and composition of the German population, the three studies took slightly different approaches. Repenning et al. (2015) use an endogenous population model, which forms part of ASTRA-D, the integrated model simulating economic activity, transport and demographic developments. Hecking et al. (2018) base their analysis on data provided by destatis, the Federal Statistical Office of

Germany (Destatis 2015). Ausfelder et al. (2017) do not report their demographic assumptions.

Crucially, both Repenning et al. (2015) and Hecking et al. (2018) use comparable parameters on the most important determinants of demographic composition. They assume continuity in the current trend of fertility rate which stands around 1.4 children per woman. Net migration, which increased in the last decade, is assumed to continue on a net positive level. Similarly, life expectancy is assumed to continue on its current trend, achieving a moderate increase until the middle of the century. Table 9 compares these assumptions.

Table 9: Comparison of demographic assumptions

	Model/Source	**Fertility rate**	**Annual net migration**	**Life expectancy**
Repenning et al.	Endogenous (ASTRA-D)	1.4	> 200,000	Moderate increase
Hecking et al.	Exogenous (Destatis)	1.4	200,000	Moderate increase
Ausfelder et al.	Not reported	Not reported	Not reported	Not reported

Source: Own compilation based on scenario parameters

Figure 6 below shows the development of total population. Despite increasing life expectancy and positive net migration, the fertility rate below replacement rate leads to an overall decrease in population until 2050 in both studies. Due to similar input parameters, total population follows a similar trajectory. However, there is a considerable difference in the overall number of around two million people throughout the analysed period. This difference can be explained by different starting points. The likely cause is the exceptional net migration of 1.2 million people in 2015 (the same year when Repenning et al. (2015) was published while Hecking et al. (2018) was published in 2018). In the composition of the population, the reported parameters lead to an increase in the average age of the population.

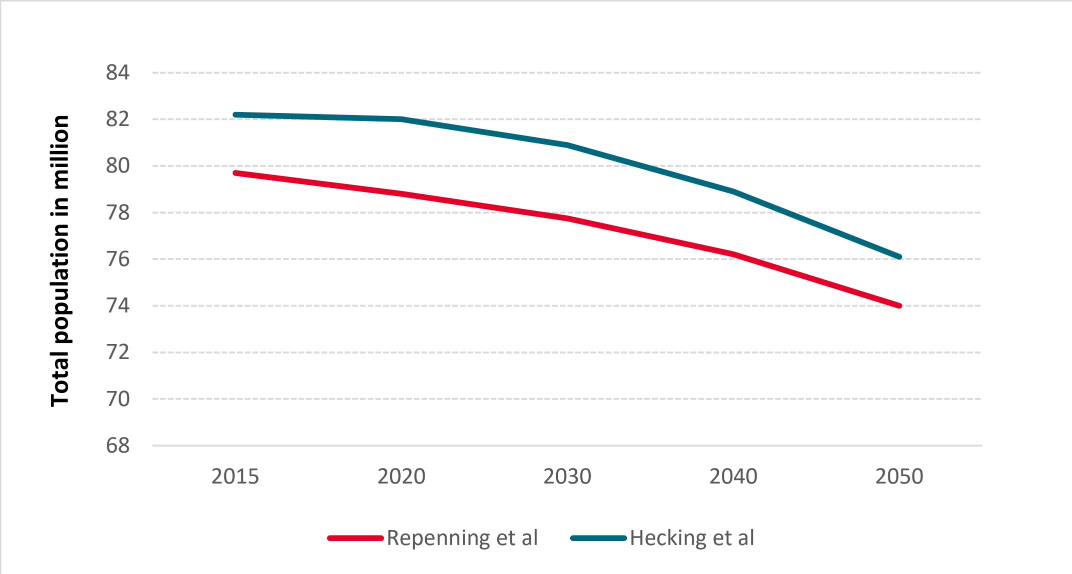

Figure 6: Total population trajectories
Source: Own depiction based on scenario parameters

Both studies assume that the current trend towards smaller household sizes continues, resulting in a moderate increase in the number of households up until 2030/2035. This leads to increases in the demand for living space and heating, despite a decreasing population.

2.1.2.2 Economic Development

Besides the assumptions on population growth and composition, economic development constitutes another important determinant of energy consumption. Ausfelder et al. (2017) does not report their economic assumptions. Both Repenning et al. (2015) and Hecking et al. (2018) base their assumptions on various external sources. Figure 7 shows the resulting growth rates. Evidently, Repenning et al. (2015) assumes a rather moderate growth path compared to the stronger growth in Hecking et al. (2018), as displayed in Figure 8.

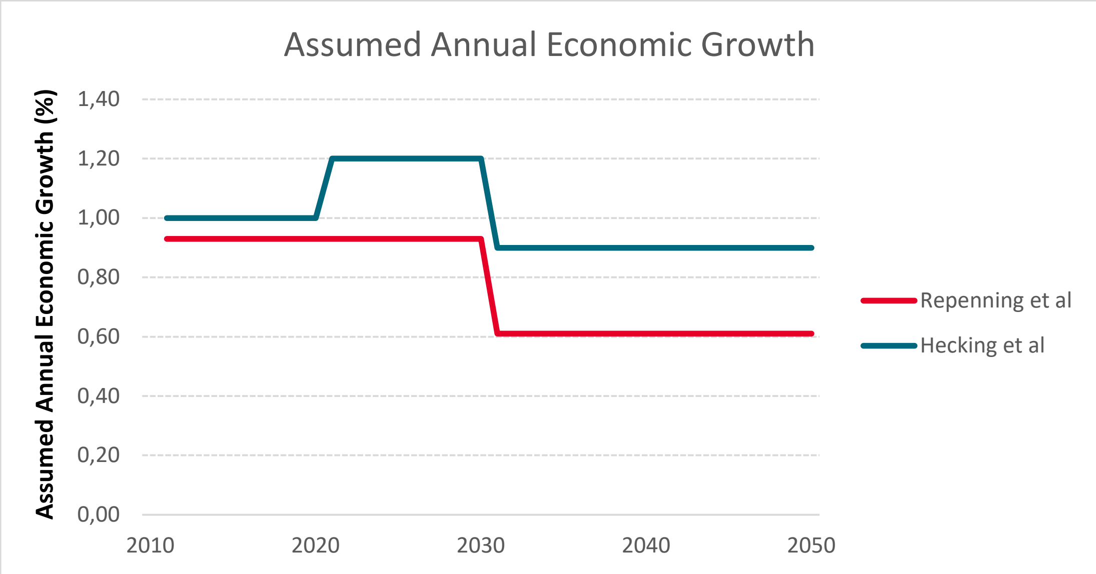

Figure 7: Assumptions on Economic Growth
Source: Own depiction based on scenario parameters

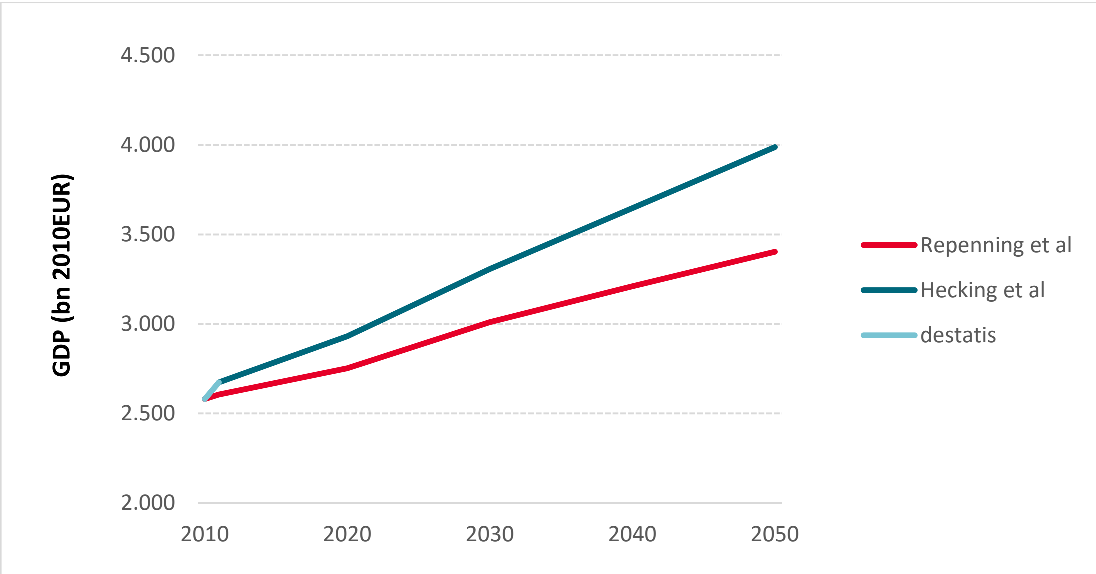

Figure 8: GDP Projections (in billion 2010 EUR)[7]
Source: Own depiction based on scenario parameters

Hecking et al. (2018) further make assumptions on the growth rates of various industry sectors, which are used to determine their respective need for input materials and energy demand. The model ASTRA-D used in Repenning et al. (2015) similarly calculates the gross value added for each sector in the projected period.

[7] Values for Hecking et al., which are reported in 2005 EUR, have been converted using destatis data on inflation.

2.1.3 Key energy characteristics

All of the German scenarios in focus adhere to the current energy policy targets of the German government, among which is the shutdown of all nuclear power plants by 2022. The 2050 GHG emission reductions achieved in all six of the scenarios in focus are also in line with the long-term target set by the German government of between 80% and 95% reductions in 2050 compared to 1990.

The assumptions about the future use of carbon capture and storage (CCS) vary among the scenarios. While none of the scenarios in focus with moderate GHG emission reduction targets (80% to 85% reductions by 2050 compared to 1990) make use of the CCS option, four of the six scenarios with 95% GHG reductions (KS95, PtX 95, TM95 and EL95) introduce CCS technology in order to capture and store difficult-to-avoid CO_2 emissions from industrial processes. The amount of CO_2 captured and stored in these four scenarios differs, ranging from 16 Mt CO_2eq/year (TM95 and EL95) to 56 Mt CO_2eq/year (PtX 95). Unlike in the industry sector, CCS technology is not assumed to be used in any of the scenarios in focus to abate emissions from coal or natural gas power plants.

2.1.3.1 Final energy demand

Most of the scenarios in focus provide data for final energy demand for both 2030 and 2050 (exceptions are scenarios from Ausfelder et al. (2017) and Henning and Palzer (2015)). Final energy demand in 2030 is estimated by the scenarios to decline from just over 9,300 PJ in 2017 (AG Energiebilanzen 2019) to between 5,753 PJ (KS95) and 7,501 (TM80) for the scenarios in focus, and staying as high as 8,507 PJ for the scenarios outside the main focus (PtX80/95, not depicted in Figure 9). In 2050 the final energy demand is assumed to decrease further, to between 3,988 PJ (KS95) and 6,026 (TM80) for the scenarios in focus, and staying as high as 7,315 PJ for the scenarios outside the main focus (PtX80/95, not depicted in Figure 9).

Final energy demand reductions in the TM80, TM95 and KS95 are mainly assumed to be achieved through further efficiency improvements. Examples include the switch to more efficient industrial processes, increased share of recycling, increased electrification (since in many cases, this enables the use of more efficient technologies), and more effective use of waste heat. The scenarios agree that in order to reach Germany's 2050 climate targets, comprehensive energy efficiency measures in each sectors are inevitable.

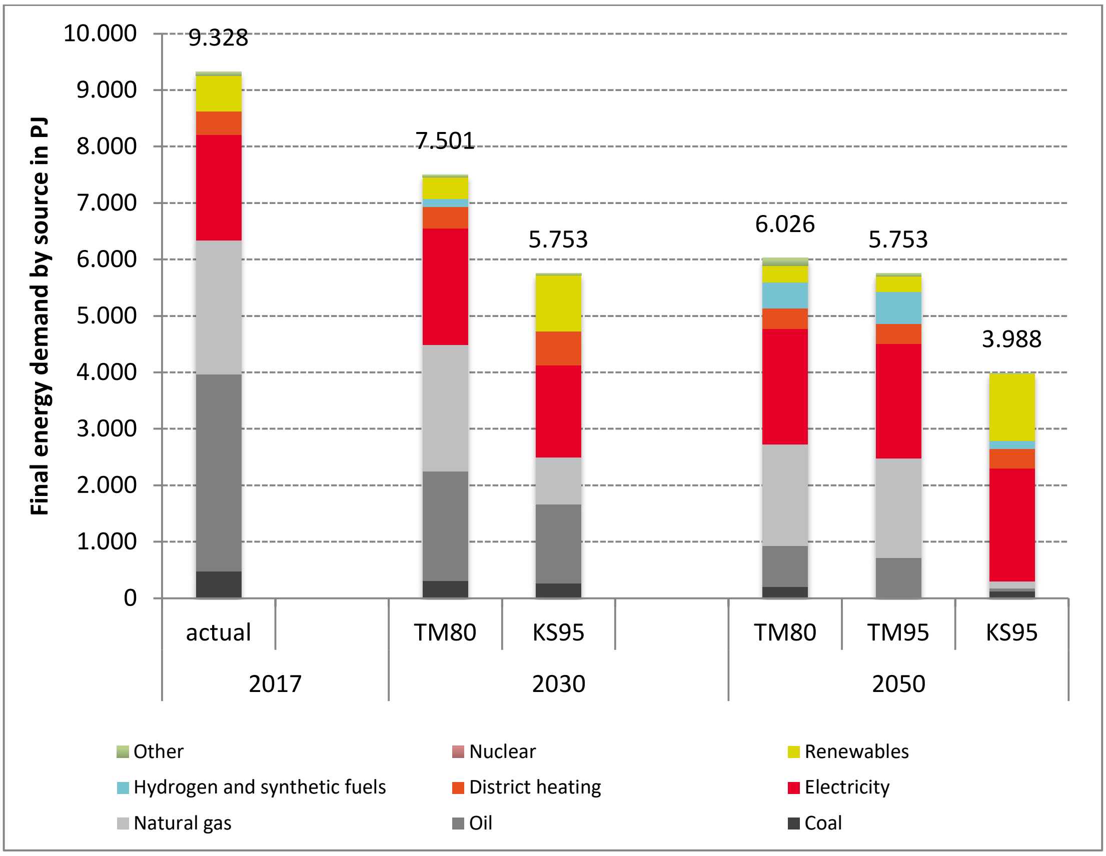

Figure 9: Final energy demand by source in selected scenarios in 2030 and in 2050 (in PJ)[8]

Source: Own depiction based on scenario parameters

In scenarios TM80, TM95 and KS95, the role of electricity in final energy demand increases over time, while the shares of coal and oil decrease. The share of renewables excluding electricity (biomass, solar thermal, geothermal heat) in final energy consumption increases considerably in some of the scenarios in focus, notably in the scenarios from Repenning et al. (2015), where it increases from 7% in 2017 to 30% by 2050 (KS95). Hydrogen and other synthetic fuels begin to play a relevant role in final energy demand in many of the scenarios in focus from about 2030 on. In TM95, for example, the consumption of hydrogen increases to 562 PJ by 2050, reaching a share of 10% (Table 10).

[8] Until 2030, the climate targets (and thus the final energy demand) in scenarios TM80 and TM95 are identical. After 2030, the TM80 and TM95 scenarios follow different GHG reduction paths, therefore their final energy demands are different.

Table 10: Shares of electricity, hydrogen and other synthetic fuels in the total final energy demand for selected scenarios

	Actual (2017)	TM80	TM95	KS95	TM80	TM95	KS95
			2030			*2050*	
Share of **electricity** in the total final energy demand	20%	27%	27%	28%	34%	35%	50%
Share of **hydrogen** in the total final energy demand	0%	0%	0%	0%	11%	10%	8%
Share of **other synthetic fuels** in the total final energy demand	0%	0%	0%	0%	15%	36%	9%

Source: Own compilation based on scenario parameters

Figure 10 shows an overview on the final energy demand by sector in selected scenarios in 2030 and 2050. It has to be noted that the sector breakdown of the selected scenarios was not uniform. In the KS95 scenario, the final energy demand was divided into commercial, residential, industry and transport sectors. Hecking et al. (2018) differentiates between industry, transport and buildings in their scenarios (TM80 and TM95). “Buildings” stands here for the total final energy demand of the residential sector, as well as the final energy demand for space heating, cooling, hot water and lighting of the commercial and industrial sectors. “Industry” covers the final energy consumption for mechanical energy, process heating and cooling needs of the industrial and commercial sectors.

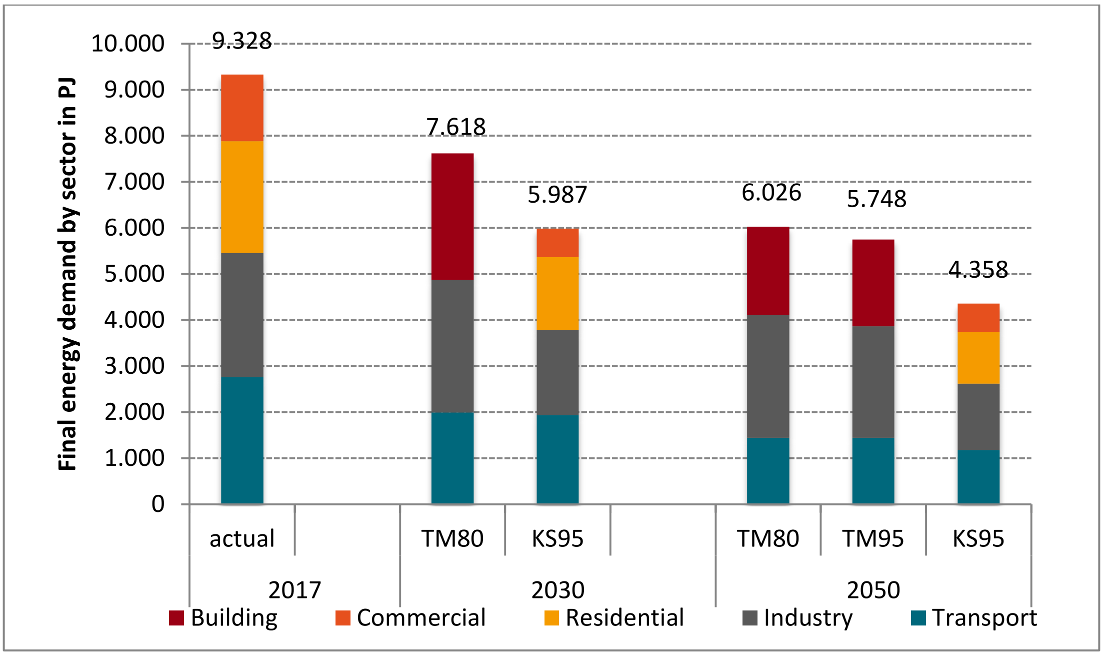

Figure 10: Final energy demand by sector in selected scenarios in 2030 and 2050 (in PJ)

Source: Own depiction based on scenario parameters

In the KS95 scenario, the final energy need of the residential sector decreases by 54% by 2050. The commercial sector reduces its final energy demand by 57%, the industrial sector by 47%. The transport sector decreases its final energy need by 57% (Repenning et al. 2015).

In scenarios TM80 and TM95, the final energy demand of the transport sector drops by 47% by 2050. The final energy consumption of the building sector in both of these scenarios decreases by 50%. Although the overall final energy demand of the building sector is roughly the same, there is a difference in the structure of the final energy sources between the TM80 and TM95 scenarios. The TM95 scenario assumes a greater use of electricity for heat generation. TM80 and TM95 also diverge in terms of overall final energy demand of the industry. In the TM80 scenario, the final energy demand in the industry decreases by 1% until 2050. The non-energy consumption decreases by 15% until 2050. In the TM95 scenario, the final energy consumption of the industry decreases more rapidly – by 10% by 2050 – due to further energy efficiency gains. With regard to non-energetic consumption, scenario TM95 assumes different production processes in the ammonia production. Therefore the non-energetic use of natural gas in scenario TM95 is about 72 PJ higher than in TM80 (Hecking et al. 2018).

2.1.3.2 Primary energy supply

The development of primary energy supply is closely connected to the changes in final energy demand. More efficient energy transformation processes, especially the increasing efficiency of power generation (with the decline in relatively inefficient thermal power plants) lead to a further decrease in primary energy need in all the scenarios in focus. By 2050, primary energy demand in all of the scenarios in focus is considerably lower than today, in most cases about 40 to 50% below current levels.

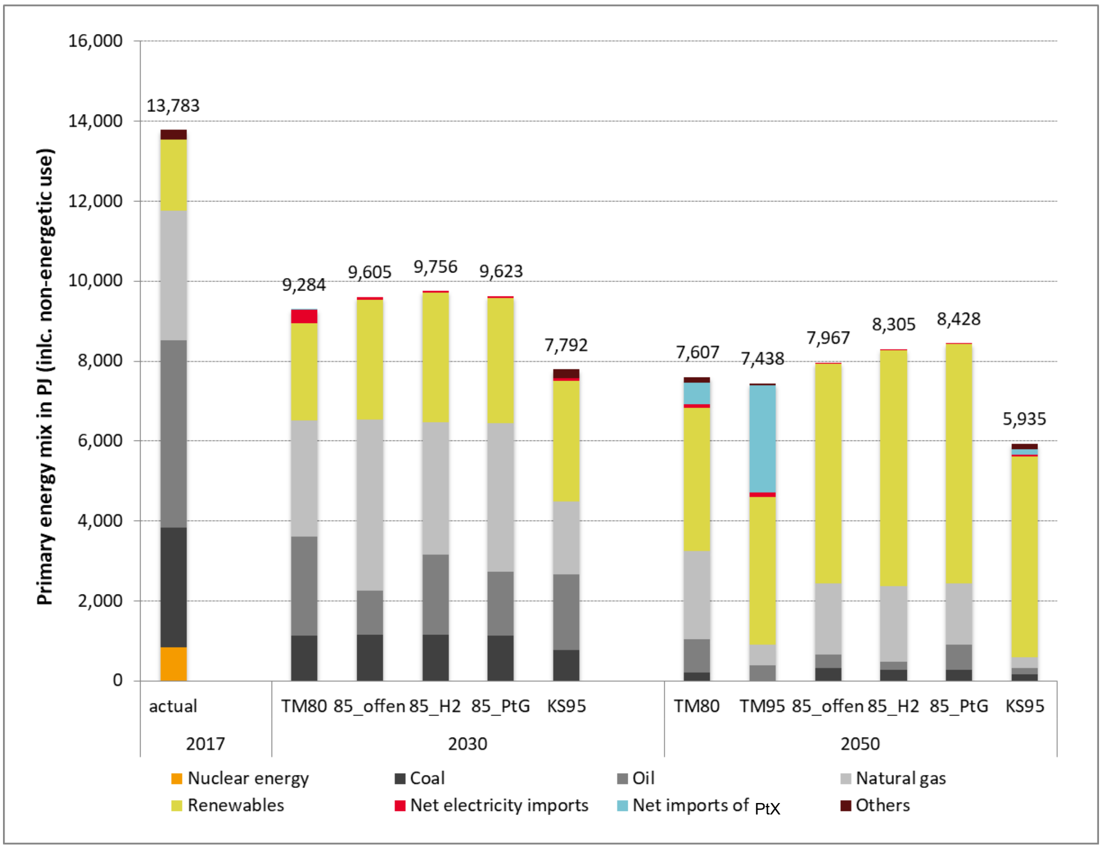

Figure 11: Primary energy mix of selected scenarios (in PJ, including non-energetic use)

Source: Own depiction based on scenario parameters

Figure 11 shows the primary energy mix of the six scenarios in focus in 2030 and 2050. In all of the scenarios in focus, nuclear power is phased out by 2022 and use of coal is reduced by more than half by 2030. By 2050, coal does not play a relevant role in these scenarios anymore. If the recommendations of the Commission on Growth, Structural Change and Employment, commonly known as the Coal Commission, are followed, about two thirds of the current coal generation capacity will go offline by 2030; the end of coal use in the electricity sector is envisioned for 2038 as of latest. Oil use is also reduced quickly in the scenarios, although scenarios differ in terms of pace and the amount of oil still used in the residual sector in 2050. Similarly, the mid- to long-term role of natural gas differs in the scenarios. While most of the scenarios analysed foresee a stable or even increasing consumption of natural gas by 2030 relative to 2017, TM80 and especially KS95 envision a decline in the use of natural gas by 2030. In 2050, natural gas still plays a relevant role in scenarios that achieve an 80% to 85% GHG emissions reduction. In the more ambitious scenarios achieving a 95% GHG emissions reduction, the role of natural gas is however marginal. All of the scenarios in focus agree that the role of renewable energy sources in primary energy supply has to increase significantly, with most of that increase coming from bigger shares of wind and solar PV in the power generation mix (although some of the scenarios also foresee a relevant contribution from biomass, solar thermal energy and/or environmental heat).

All of the scenarios in focus assume that by 2050, either renewable electricity and/or synthetic fuels will be imported (see next two chapters). However, with almost 2,700 PJ of imports of synthetic fuels other than hydrogen by 2050 (constituting 37% of primary energy supply), the scenario TM95 clearly stands out in this regard among the six scenarios in focus. Among all the 18 analysed scenarios, the PtX 95 scenario goes even higher with synthetic fuels imports of more than 3,000 PJ in 2050. At the same time, all scenarios in focus envision a significant decrease in demand for imported fossil energy sources by 2050.

2.1.3.3 Hydrogen demand

Before 2030, none of the German scenarios in focus assume that hydrogen will be used extensively. By 2050 however, five of the six scenarios in focus expect hydrogen to play a considerable role in meeting final energy demand (the exception being 85_PtG from Ausfelder et al. (2015); here it has to be noted that hydrogen nevertheless plays a role as precursor to other synthetic fuels). In these five scenarios, the hydrogen final energy demand ranges from 121 PJ (85_offen) to 562 PJ (TM95) in 2050.

With the 12 German scenarios analysed but outside of the main focus, the hydrogen role is somewhat more ambiguous. Hobohm et al. (2018) expect that hydrogen will not be used widely due to infrastructural constraints. Bothe et al. (2017) see no hydrogen consumption in the scenario “Strom und Gasspeicher” (electricity and gas storage), and makes a simplified assumption in the scenario “Strom und Grünes Gas” (electricity and green gas) that in 2050, half of the domestically produced hydrogen, or 1,161 PJ, is used as final energy carrier, while the other half is converted further into synthetic methane.[9] In three of the five scenarios from Henning and Palzer (2015), hydrogen achieves a considerable share in the final energy consumption, ranging from 205 to 326 PJ per year, while the other two scenarios instead achieve an 80% emissions reduction by focusing either on electrification or on a combination of synthetic and fossil methane.

Overall, five of the 18 scenarios from the 6 studies (TM80, EL80, TM95, EL95, 85_H2, from Hecking et al. (2018) and Ausfelder et al. (2017)) exhibit relatively high shares of hydrogen in total final energy demand, reaching shares of 8 to 15%. These scenarios expect hydrogen to play an important role especially in the transport and industry sectors. They stress the positive characteristics of hydrogen, such as the fact that it can be stored relatively easily (unlike electricity), is free of carbon when consumed (unlike other synthetic fuels), can be produced in a CO_2 neutral way, requires less overall energy than the production of other synthetic fuels, and can be fed into the existing natural gas grid to a certain extent.

Regarding hydrogen use in the transport sector, Henning and Palzer (2015) developed scenarios with a focus on various technical and energy carrier alternatives (with scenarios focusing on hydrogen, methane and electric cars, respectively). Among these, only in the hydrogen scenario (80/gering/H2/n.b.), hydrogen covers a substantial share of the final energy demand for transport with 19% (while the total share of other synthetic fuels in transport is even higher with 20%). Hecking et al. (2018) distinguish between pathways in which the direct use of electricity dominates (EL80 & EL95) and pathways in which a broader future technology mix is assumed (TM80 & TM95). Hydrogen plays an important role in the transport sector in all the four scenarios from Hecking et al. (2018), reaching 331 PJ or 23% of final energy demand in the transport sector for both TM80 and TM95, while use of other synthetic fuels is much higher in the TM than in the EL scenarios. The role of hydrogen differs in the scenarios from Ausfelder et al. (2017) depending on the technology pathway. In

[9] Green gas was defined in this study as a sum of PtX produced from electricity from renewable energy sources and biomethane.

case of the hydrogen-dominant scenario (85_H2), hydrogen makes up 27% of final energy demand in the transport sector by 2050. In the other scenarios, the shares are 10% (85_offen) and 0% (PtG). Table 11 shows the total quantities and shares of hydrogen demand in the transport and industry sectors.

Table 11: Hydrogen demand in transport and industry sectors in selected scenarios

	TM80	TM95	85_offen	85_H2	85_PtG	KS95
			2030			
Demand in transport in PJ	65	65	29	187	0	0
Share in transport in %	3%	3%	2%	10%	0%	0%
Demand in industry in PJ[10]	68	68	0	0	0	0
Share in industry in %	2%	2%	0%	0%	0%	0%
			2050			
Demand in transport in PJ	331	331	122	385	0	0
Share in transport in %	23%	23%	10%	27%	0%	0%
Demand in industry in PJ[11]	133	230	0	0	0	0
Share in industry in %	5%	10%	0%	0%	0%	0%

Source: Own compilation based on scenario parameters

In the industrial sector, from the six scenarios in focus, only those by Hecking et al. (2015) envision the use of hydrogen, as well as those by Hobohm et al. (2018) among the scenarios outside of the main focus. Hydrogen is mainly utilized as a non-fossil raw material, principally for production of ammoniac (Hobohm et al. 2018), and to a smaller extent, in steel and cement production, as well as in the chemical industry (Hecking et al. 2018). The scenarios of Hecking et al. (2018) see hydrogen used extensively only after 2040, with the authors citing expensive investments and long-term innovation cycles of alternative industrial processes. Generally, the shares of hydrogen in the final energy consumption in industry remain below those in transport in 2050, not exceeding 10%.

Apart from the industrial and transport sectors, some scenarios also consider hydrogen for use in the power sector. For example, the KS95 scenario (Repenning et. al 2015) doesn't see hydrogen used in any end use sectors, but rather (and to a limited extent) as energy

[10] In the scenarios TM80/TM95 the subdivision "industry" covers the final energy consumption of mechanical energy uses, process heat and cooling needs of the industrial and commercial sectors, while the final energy need of space heating and cooling, hot water and lighting of the industrial sector was excluded here.

[11] In the scenarios TM80/TM95 the subdivision "industry" covers the final energy consumption of mechanical energy uses, process heat and cooling needs of the industrial and commercial sectors, while the final energy need of space heating and cooling, hot water and lighting of the industrial sector was excluded here. A more detailed explanation is included in sub-chapter 2.1.3.1

storage and flexibility option in the power system. It envisions hydrogen and synthetic methane from 2040 onwards to be used for reconversion to electricity at times when electricity is scarce. In TM80 and TM95, hydrogen is – in addition to consumption in end use sectors – also used as seasonal storage by storing some of the generated hydrogen in the existing gas grid. In EL95 scenario, 432 PJ of hydrogen will be used in the energy sector in 2050.

According to the scenarios from the studies by Hecking et al. (2018) and Ausfelder et al. (2017), the existing German gas distribution and transmission network can carry up to 5 to 10%vol of hydrogen without any significant infrastructural modifications. In order to reach the hydrogen expansion described in scenario 85_H2 (the highest among the scenarios by Ausfleder et al. 2017), the share of hydrogen in the gas grid had to be allowed to reach 30%vol by 2050. The study notes that this will only be possible with considerable and cost-intensive upgrades of the gas grid and several industrial processes (while other studies in focus assume even larger hydrogen demand, they do not explicitly mention the necessary infrastructure upgrades). Generally, pipeline was given the most consideration as the mode of hydrogen transport in the analysed scenarios.

In all of the scenarios in focus, the hydrogen required in end use sectors is produced within Germany based on electricity from renewable energy sources.[12] The argumentation is based in the relatively high costs of long-distance hydrogen transport which makes the domestic production of hydrogen somewhat more attractive; on the other hand, the transport of synthetic fuels other than hydrogen is often considered a more viable option due to their ability to use the existing infrastructure. Hydrogen can also be transported in the form of high-energy products such as ammonia, which is considered a viable option by some industry players, for example Kawasaki steel (Ammonia Energy 2017).

2.1.3.4 Demand for synthetic fuels other than hydrogen

Similar to hydrogen, the expansion of other synthetic fuels consumption is envisioned in the scenarios in focus for the timeframe between 2030 and 2050. Only the KS80 scenario from Repenning et al. (2015) does not foresee the use of synthetic fuels by 2050. The amount of synthetic fuels other than hydrogen to be used in end use sectors is estimated between 344 PJ (KS95) and 2,707 PJ (TM95) in 2050 for the scenarios in focus, and up to 3,545 PJ (PtX 95) across all six studies.

The assumed need for synthetic fuels other than hydrogen varies considerably among the scenarios. In the TM80 scenario, the demand for synthetic methane amounts to 526 PJ by 2050 (similar to the hydrogen demand of 529 PJ). In the TM95 scenario, synthetic methane plays a much bigger role with consumption of 2,268 PJ; in addition, 389 PJ of liquid synthetic fuels are consumed in the TM95 scenario. Unlike hydrogen, other synthetic fuels in the TM80 and TM95 scenario do not yet play a role by 2030.

The scenarios from Hecking et al. (2018) focus more than other scenarios on the use of synthetic gas in the transport sector, arguing that the cost of synthetic methane is considerably lower than those of liquid synthetic fuels. TM95 (Hecking et al. 2018) envisions synthetic fuels other than hydrogen to cover no less than 43% of the final energy demand in the transport sector in 2050. The 85_PtG scenario from Ausfelder et al. (2017) sees a very

[12] With the possible exception of Hecking et al. (2018) which is not entirely clear in this regard. It is possible that a certain share of the hydrogen demand in these scenarios (EL80, TM80, EL95, TM95) is assumed to be imported by 2050.

similar role for these synthetic fuels (39% of the total final energy demand in transport sector); for 85_H2, this share is at 22% and for 85_offen at only 4%. KS95 from Repenning et al. (2015) has the share of synthetic fuels other than hydrogen in final energy demand for transport sector at 30% in 2050. Among the scenarios not in focus, both from Bothe et al. (2017) and the PtX80 scenario from Hobohm et al. (2018) describe high shares of liquid synthetic fuels in the transport sector (PtL). This development takes advantage of the chemical similarity of synthetic liquid fuels to the currently used fossil fuels, allowing further use of present applications and infrastructure without large investments.

In the industrial sector, TM80 scenario (Repenning et al. 2015) does not specify the exact demand for synthetic fuels other than hydrogen in 2050; on the other hand, the TM95 scenario has it relatively high at 39%. All three scenarios from Ausfelder et al. (2017) see it at about half of that value, between 18 and 22%. The KS95 scenario from Repenning et al. (2015) sees no role for other synthetic fuels as final energy carrier in industry. Table 12 shows the total quantities and shares of demand for synthetic fuels other than hydrogen in the transport and industry sectors.

In the TM95 scenario (Hecking et al. 2018), synthetic fuels other than hydrogen will also be used in the buildings sector (544 PJ in 2050). The scenario “Strom und Grünes Gas” from Bothe et al. (2017) also envisions synthetic methane to be used for heating on a large scale. In the scenarios from Ausfelder et al. (2017) synthetic methane will cover between 1 and 6% of the heating demand in 2050 (85_offen 4%, 85_H2 1%, 85_PtG 6%).

In the scenarios from Ausfelder et al. (2017) and Repenning et al. (2015), synthetic fuels other than hydrogen do not play a role in the power sector. The scenarios EL80 and EL95 (Hecking et al. 2018) expect that synthetic methane and biomethane will be used for electricity production on a larger scale. In the EL80 scenario, 4% of the electricity production will be covered by synthetic methane (and 24% from biomethane); in the EL95 scenario 71% of the electricity is produced from synthetic methane (and 29 % from biomethane) in 2050.

Table 12: Synthetic fuel demand in transport and industrial sectors in selected scenarios

	TM80	TM95	85_offen	85_H2	85_PtG	KS95
			2030			
Demand in transport in PJ	0	0	155	40	227	0
Share in transport in %	0%	0%	9%	2%	11%	0%
Demand in industry in PJ[13]	0	0	65	180	101	0
Share in industry in %	0%	0%	4%	11%	6%	0%

[13] In the scenarios TM80/TM95 the subdivision “industry” covers the final energy consumption of mechanical energy uses, process heat and cooling needs of the industrial and commercial sectors, while the final energy need of space heating and cooling, hot water and lighting of the industrial sector was excluded here. A more detailed explanation is included in sub-chapter 2.1.3.1

			2050			
Demand in transport in PJ	n. s.	612	50	331	738	343
Share in transport in %	n. s.	42%	4%	22%	39%	30%
Demand in industry in PJ[14]	n. s.	947	306	335	367	0
Share in industry in %	n. s.	39%	18%	20%	22%	0%

Source: Own compilation based on scenario parameters

In five of the six scenarios in focus, it is assumed that synthetic fuels will entirely be imported from countries with better renewable energy resources. The KS95 scenario is an exception. Here, half of the relatively little synthetic fuel demand is assumed to be met by domestic sources by 2050. Hecking et al. (2018) explicitly mentions the Middle East, North Africa or Central-Asia as possible suppliers because of the availability of cheap renewable electricity and the already existing natural gas connections. Import of $PtCH_4$ is efficiently possible through the existing European natural gas transmission system (Hobohm et al. 2018). Ausfelder et al. (2017) assume that around 1,100 PJ of crude oil per year would need to be replaced by imported by non-hydrogen synthetic fuels by 2050 for reaching an 85% reduction in THG emissions compared to 1990 level. In the TM80 scenario, most of the synthetic methane is assumed to be imported from other EU countries. In the TM95 scenario, most of the synthetic fuel quantities are imported as non-hydrogen synthetic fuels from non-EU countries (73%), followed by imports from countries within the EU (27%).

2.1.4 Discussion on relationship between the roles of hydrogen and other synthetic fuels in the different scenarios

[14] In the scenarios TM80/TM95 the subdivision “industry” covers the final energy consumption of mechanical energy uses, process heat and cooling needs of the industrial and commercial sectors, while the final energy need of space heating and cooling, hot water and lighting of the industrial sector was excluded here. A more detailed explanation is included in sub-chapter 2.1.3.1

Table 13: Role of hydrogen and other synthetic fuels in the German scenarios in focus

Authors	Scenario	Total yearly hydrogen demand in final energy demand in 2050	Total yearly non-hydrogen synthetic fuel demand in final energy demand in 2050	Total yearly PtX demand in final energy demand in 2050	Priority sectors, drivers, messages
Repenning et al. (2015)	KS80	0 PJ	0 PJ	0 PJ	• No use of hydrogen • No use of synthetic fuels
	KS95	328 PJ	344 PJ	672 PJ	• Non-hydrogen synthetic fuel use in transport sector • H_2 production for power generation (reconversion): 20 PJ; • Domestic share of PtL production: 306 PJ
Bothe et al. (2017)	Strom und Gasspeicher	0 PJ	1668 PJ	1,668 PJ	• End users across all sectors mainly use electrical devices; no use for hydrogen in final energy demand • Synthetic fuels other than hydrogen used for energy storage (reconversion in gas-fired power plants) next to electric storage. • Inland energy transport through the power grid. • Non-hydrogen Synthetic fuel demand is imported PtL
	Strom und Grünes Gas	1,161 PJ	2,657 PJ	3,818 PJ	• End users partly use green gas generated in RE-PtG plants in Germany. • It is assumed that 50% of PtG is used as hydrogen in industry and transport, while 50% of is further methanised and used for heating. Synthetic methane final energy consumption thus amounts to 988 PJ, all of it comes from domestic production; • Liquid synthetic fuels are imported and used for transport (Total final energy consumption of 1,669 PJ) • Existing gas infrastructure is used in parallel with power grid for inland

					energy transport.
Hobohm et al. (2018)	PtX80	39 PJ	2,673 PJ	2,712 PJ	• The focus of the study is on the investigation of liquid energy carriers, synthetic natural gas and hydrogen were not investigated in depth. • RE-powered PtX assumes a central role in the German energy system; • However, the role of hydrogen is minor and mostly limited to industry (ammoniac production, 29 PJ); • Most of the H2 generated by PtX is further converted to liquid synthetic fuels for use in transport (58%) and gaseous synthetic fuels for use in the residential sector (20%)
	PtX95	41 PJ	3,545 PJ	3,586 PJ	• Very similar to above with slightly larger shares of PtX in most sectors
Henning and Palzer (2015)	80/gering/CH4/n.b.	0 PJ	915 PJ	915 PJ	• Main transport carrier for the scenario development is methane • Synthetic fuels cover 30% of the final energy demand of the transport sector and 14% of the industry sector
	80/gering/H2/n.b.	326 PJ	763 PJ	1,089 PJ	• Main transport carrier for the scenario development is hydrogen • Hydrogen is mainly used in the transport sector, covering 19% of the final energy demand • Non-hydrogen synthetic fuels are also used widely, covering 20% of the final energy demand in the transport sector and 17% in the industry sector • Hydrogen is produced domestically, power and synthetic fuels are imported
	80/gering/elektrisch/n.b.	0 PJ	508 PJ	508 PJ	• Main transport carrier for the scenario development: electricity • Hydrogen does not play a role • Other synthetic fuels cover 21% of the final energy demand of the transport sector and 9% of the industry sector
	80/amb/Mix/beschl.	205 PJ	683 PJ	888 PJ	• Mixed energy carriers • H2 is used in the transport sector (H2 covers around 12% of the total final energy demand of the transport sector)

					• Non-hydrogen synthetic fuels cover 19% of the final energy demand of the transport sector and 11% of the industry sector • Hydrogen is produced domestically, power and synthetic fuels are imported
	90/amb/Mix/beschl.	205 PJ	1,017 PJ	1,222 PJ	• Mixed energy carriers • Hydrogen is used in the transport sector, covering about 11% of the total final energy demand • Other synthetic fuels cover 33% of the final energy need in the transport sector and 26% in the industry sector • Hydrogen is produced domestically, power and synthetic fuels are imported
Ausfelder et al. (2017)	85_offen	121 PJ	430 PJ	551 PJ	• Mixed energy carriers • Share of hydrogen in the gas network up to 5%vol • Hydrogen is mainly used in the transport sector; PtL also has 12% in the final energy demand in the transport sector • PtX produced from RE and mainly used for low-temperature heating, process heat and transport (PtG is somewhat less important than in other scenarios)
	85_H2	386 PJ	681 PJ	1,067 PJ	• Share of hydrogen in the gas network up to 30%vol • Transport sector relies strongly on hydrogen which reaches a 100% share in final energy consumption in the road transport in 2050; some modes of transport rely on liquid synthetic fuels • Industrial heat generation also relies strongly on hydrogen; • Synthetic methane is produced from RE and fed into the gas network
	85_PtG	0 PJ	1,212 PJ	1,212 PJ	• Share of hydrogen in the gas network up to 5%vol; hydrogen as final energy carrier plays a minor role; • Synthetic methane is produced from RE and fed into the gas network; • 48% of the synthetic fuel need is PtL for the transport sector
Hecking et	EL80	480 PJ	78 PJ	558 PJ	• Hydrogen plays only a supplementary role

al. (2018)					• Electrolysis hydrogen produced mainly in Germany, but synthetic methane imported mainly from other EU countries
	EL95	562 PJ	1,357 PJ	1,919 PJ	• Hydrogen plays only a supplementary role • PtX will be used in the transport (32%), industry (29%) and energy sectors (39%) • Most of the PtX quantities are imported from EU and non-EU countries: In the EL95 scenario, 74% of the total quantity is produced outside of Germany, with imports from non-EU and EU countries of roughly the same order of magnitude. Due to the less favourable conditions for renewable electricity generation (in terms of renewable energy potential and generation costs), only 26% of the total quantity is produced in Germany, especially hydrogen.
	TM80	463 PJ	595 PJ	1,058 PJ	• Climate targets will be achieved by a combination of energy carriers (i.e. H2), aiming to reach the climate aims at the lowest cost. • Electrolysis hydrogen produced mainly in Germany, but synthetic methane imported mainly from other EU countries
	TM95	562 PJ	2,707 PJ	3,269 PJ	• Climate targets will be achieved by a combination of energy carriers (i.e. H2), aiming to reach the climate aims at the lowest cost • 29% of the PtX will be used in the transport sector, 36% in the industry sector, 16% in the building sector and 19% in the energy sector • Most of the PtX quantities are imported from EU and non-EU countries: In scenario TM95, an even larger share of 82% is imported from the non-EU (60%) and the EU (22%). Due to the less favourable conditions for renewable electricity generation (in terms of renewable energy potential and generation costs), only 18% (TM95) of the total PtX demand is covered by domestic production, especially hydrogen. • CCS is necessary, only in Industrial sector after 2040

Source: Own compilation based scenario parameters

Table 13 provides a summary of the role of hydrogen and other synthetic fuels in the German scenarios in focus. The GHG emission reductions can be considered a key driver for the hydrogen and synthetic fuel demand in these scenarios. While scenarios with 80% GHG emission reduction targets typically envision less hydrogen and synthetic fuel demand by 2050, higher targets of GHG emission reductions lead to higher hydrogen and synthetic fuel use in 2050. Repenning et al. (2015) goes from 0 PJ in its 80% reduction scenario to 672 PJ in the 95% scenario; for Hobohm et al. (2018), the total PtX demand goes from 2,712 PJ to 3,586 PJ; for Henning and Palzer (2015) the total PtX demand is between 508 and 915 PJ for the 80% reduction scenarios and 1,222 PJ for the 90% reductions scenario; for Hecking et al. (2018), the total PtX demand is between 558 and 1,058 PJ for the 80% reductions scenarios and between 1,919 and 3,269 PJ for the 95% reductions scenarios.

The scenarios also describe different infrastructural impacts of hydrogen use. Scenarios with higher hydrogen (and total PtX) shares in the final energy consumption which actively use the gas transmission and distribution network exhibit lower overall costs for the development of the necessary infrastructure by 2050 (Ausfelder et al. 2017, Bothe et al. 2017, Hecking et al. 2018). The existing gas transmission and distribution network is deemed to require further investments and maintenance for the future use in light of significantly higher shares of hydrogen in the pipelines. Bothe et al. (2017) estimates the investments for the expansion and renewal of the gas grid to 1,182 million EUR per year by 2050, in addition to expenses for maintenance and repairs of 1,568 million EUR per year by 2050. The overall investments are nevertheless smaller than those associated with a more extensive expansion of electricity grids in scenarios with stronger focus on electricity in final energy demand (Bothe et. al 2017). Apart from the investments for the expansion of the gas and power grid, electrolysers and other equipment necessary for sector coupling and synthetic fuel production also needs to be procured. Hobohm et al. (2018) has estimated the difference in the necessary investments between BAU and the PtX80 and the PtX95 scenarios. For the PtX80, the investments for domestic PtX plants amount to around 5 billion EUR. By 2050, cumulative domestic investments of € 34 billion (PtX 80) and € 59 billion (PtX 95) by 2050 are only slightly above the reference scenario (both values include the investments needed for infrastructure expansion as well as plants to cover the additional demand for hydrogen and other electricity-based synthetic fuels).

In addition to injecting hydrogen into the natural gas grid, the scenarios TM80 and TM95 (Hecking et al. 2018) consider the development and extension of separate hydrogen transmission and distribution pipelines, mainly for industrial consumers. Conversion of former natural gas pipelines necessary for connecting important industrial regions is associated with relatively low conversion costs compared to the construction of new hydrogen pipelines. The two scenarios assume that some of the existing natural gas pipelines will be converted for hydrogen transportation even if at the same time brand new hydrogen pipelines are also built. Hecking et al. (2018) assumes that 90% of the hydrogen needed in industry is supplied by converted pipelines and 10% by newly built pipelines.

2.1.5 Main findings from the analysis of German scenarios

The actual GHG reductions achieved in 2050 have a large effect on the necessary transformation paths. While GHG reductions of 80% across all sectors can essentially be achieved with existing technologies (albeit deployed much more broadly and within the necessary political framework), a further reduction of 15% requires new, qualitatively different solutions. All scenarios from the 6 studies analysed in this chapter with GHG reduction target higher than 80% assume mass deployment of hydrogen (and/or other synthetic fuels) from 2030 onwards. Further, since Germany has decided to phase out its nuclear power plants and CCS in power generation is not a viable option due to low public acceptance, achieving the GHG emissions reduction targets means that renewable electricity must be used as the primary energy source for hydrogen and other synthetic fuels production. The general finding across all scenarios in focus is that Germany's climate protection goals can hardly be achieved (and certainly not in the most cost-effective manner) without large-scale use of green hydrogen and/or other synthetic fuels.

The second essential parameter is technological focus of the chosen transformation paths. These, along with the resulting energy system in 2050 described in different scenarios, are fairly diverse. Here too, the resulting infrastructure and the sector character of final energy consumption depend to a great extent on whether a high degree of electricity-based applications or a broader technology mix is pursued. This is one of the prisms which have to be applied when discussing the future role of hydrogen in Germany's energy sector.

Despite this divergence, another general observation can be made: Among the German academic publications concerning themselves with energy system transition scenarios over the timespan up to 2050 identified by the authors of this study, most generally foresee a bigger role for non-hydrogen synthetic fuels as the source of final energy consumption compared to hydrogen (while hydrogen is of course used as precursor for production of other synthetic fuels). While the hydrogen used as final energy source would be produced domestically, other synthetic fuels are assumed to be either entirely or mostly imported. The reasons for this assumption are manifold. Production costs in Germany – starting with the price of renewable power – are assumed to be higher than in many other parts of the world. This is exacerbated if hydrogen is to be further converted into other synthetic fuels due to additional efficiency losses. Further, renewable energy potential in Germany is limited by the available land surface. Third, unlike hydrogen, long-distance transport of other synthetic fuels can rely on the already existing infrastructure. Large-scale maritime hydrogen imports are not envisioned by the scenarios in the 6 studies analysed in this chapter; Hecking et al. (2018) explicitly mentions high transportation costs as the main reason for this.

Certain trends in the scenarios can nevertheless be observed with somewhat greater confidence than others. In the transport sector, a mix of combustion engine (running either on fossil or synthetic fuels), electric and fuel cell vehicles is expected. It has been argued that due to technical and economic characteristics of competing drive systems, EVs will dominate most modes of transport over shorter distances, while hydrogen and other synthetic fuels will be used in for larger distances (Exponential View 2018). In the industry, hydrogen is likely to increase its role as a non-fossil raw material. In the power sector, hydrogen has potential to assume the crucial role of providing flexibility and both diurnal and seasonal energy storage. It should however be kept in mind that mass deployment of new technologies requires a certain timespan; this holds especially true for infrastructure. If hydrogen technologies are to be used on a mass scale from 2030 onwards, the time necessary for piloting, market uptake, and development of the necessary political framework has to be taken into account (Hobohm et al. 2018, Ausfelder et al. 2017, Hecking et al. 2018).

2.2 Analysis of Japanese scenarios

2.2.1 Demographic and economic framework conditions

The IEEJ surveyed 11 hydrogen scenarios in Japan, plus the government's targets for application and supply of hydrogen. Among the 11 scenarios, 6 have been developed by IEEJ. Two scenarios have been developed by the Institute of Applied Energy (IAE). One scenario was developed by Yoshiaki Shibata and is concerned with methanisation, and 2 scenarios were developed by private companies (Table 14). In addition, the energy system development envisioned by the government strategic plan has also been included. Effort has been made to apply the same methodology to Japanese scenarios as for the German ones. However, differences in scenarios themselves in terms of assumptions, drivers and levels of detail for available data has made this possible only to a limited extent. The analysis of the Japanese scenarios therefore focuses on partially different parameters from those used for the German scenarios. Table 14 displays the assumptions and foci of the Japanese scenarios analysed.

Table 14: Overview of the Japanese scenarios surveyed

Publication		Scenarios	
Title, year	**Executing institution(s)**	**Name /** Description, Foci	**GHG reduction** (2050)
Asia/World Energy Outlook 2016 (The Institute of Energy Economics Japan 2016)	**IEEJ**	**Tech. Adv. Scenario (base scenario) (Scenario 1)** • Bottom-up econometric model • Hydrogen demand in Japan primary energy supply • Final energy consumption • Power generation mix available up to 2040	/
		High CCS power scenario (Scenario 2) • Bottom-up econometric model • Hydrogen demand worldwide	/
		Limited CCS power + low H_2 scenario (Scenario 3) • Bottom-up econometric model • Impact on global GHG emissions	/
		Limited CCS power + high H_2 scenario (Scenario 4) • Bottom-up econometric model • Impact on global GHG emissions	/
Position of Hydrogen Energy and Prospect of Its Introduction Toward a Low-Carbon Society in 2050 in	**IEEJ**	**No CO_2 emission constraints (Scenario 5)** • Optimization (MARKAL model) • Geographic scope: Japan • Hydrogen demand in Japan by sectors	/

Japan (The Institute of Energy Economics Japan 2013)		**CO_2 emission constraint (Scenario 6)** • Optimization (MARKAL model) • Geographic scope: Japan • Hydrogen demand in Japan by sectors	65% CO_2 reduction against 1990 baseline
Experts group on hydrogen penetration action plan (AP research) (IAE 2016, 2017)	**IAE**	**/ (Scenario 7)** • Optimization (MARKAL model) • Bottom up for demand projection • Optimization for supply • Geographic scope: global	50% CO_2 reduction against 1990 baseline
Mid- to Long-term Vision Prospect of energy technologies towards 2050 (IAE 2018)	**IAE**	**/ (Scenario 8)** • Optimization (MARKAL model) • Projection on energy service • Optimization for supply • Geographic scope: Japan • Hydrogen demand in Japan for certain sectors	80% CO_2 reduction against 2015 baseline
Future Potential of Carbon Neutral Methane, Combination of PtG and CCU: Towards Decarbonisation of City Gas (Shibata 2018)	**Yoshiaki Shibata**	**Scenario on hydrogen methane (Scenario 9)** • Optimization for supply • Domestic methane production potential (using RE hydrogen) and price	/
Hydrogen Supply Scenario (Chiyoda Corporation 2017)	**Chiyoda Corporation**	**Hydrogen supply chain (Scenario 10)** • Hydrogen price	/
Potential of Hydrogen Introduction (Insights from the History of LNG) (Kawasaki Heavy Industry 2017)	**Kawasaki Heavy Industry**	**Hydrogen supply chain (Scenario 11)** • Hydrogen demand in power sector • Hydrogen price • Hydrogen demand	/
Strategic Energy Plan (METI 2016)	**Government of Japan**	**Government targets (Scenario 12)** • Primary energy supply • Power generation mix	/

Source: Own compilation based on scenario parameters

The available scenario data shows that assumptions on GDP and population do not vary much among different scenarios. Most of the scenarios assumed that long term real GDP growth rate (up to 2030) is less than 1%, resulting in a population in 2030 numbering about 117 to 120 million. This constitutes a decrease of more than 10 million from the 2016 level of 127 million.

Based on the GDP projections and population assumption, the GDP per capita in Japan is estimated to be between 47,000 and 54,000 EUR per person per annum in 2030. Only scenarios 5 and 6 offer a GDP assumption for 2050; assuming that real GDP growth rate from 2030 to 2050 is around 0.6% per annum and the population has decreased to 97 million in 2050, the GDP per capita in Japan is supposed to be around 63,000 EUR per person per annum in 2050.

For scenarios using a MARKAL-based optimization model (scenarios 5 to 8), constraint on CO_2 emission reduction is an important factor. Scenario 6 by the IEEJ assumes a 65% CO_2 emissions reduction compared to 1990; this target is however hard to compare to the government target where some ambiguity regarding the reference year exists. Scenario 7 is the optimization model for achieving the 50% GHG emission reductions compared to 1990 levels, as set by Japan's INDC (Intended Nationally Determined Contribution). Scenario 8 assumed a 26% CO_2 emission reduction for Japan by 2030 compared to 2013 level and 80% reduction till 2050 compared to 2015 level. The assumption is generally in line with the government's GHG reduction plan.[15]

2.2.2 Key energy characteristics

2.2.2.1 Final energy demand

Data for final energy demand by sector in the 2030s is available in scenario 1 by the IEEJ as well as in scenario 12 (the government target). Results from these scenarios do not show much difference. Total final energy demand in Japan is projected to be between 7,913 and 8,499 PJ in 2030 (taking into account the effects of energy conservation efforts). In 2030, about half of energy demand will come from the industry sector, with buildings (commercial and residential) accounting for between 25% and 30%, and transport for between 25% and 20%. Projection on final energy demand in 2050 is only available in scenarios 5 and 6 by the IEEJ and the scenario 8 by the IAE. They project the final energy demand in Japan in 2050 between 5,862 and 6,448 PJ. Broken down by sectors, the shares of final energy demand in 2050 do not show significant change compared to 2030 (Figure 12)

[15] It should be noted that in the INDC the GHG reduction does not come only from energy sector. Also, the government's long term voluntary GHG reduction plan does not specify the base year for 80% emissions reductions.

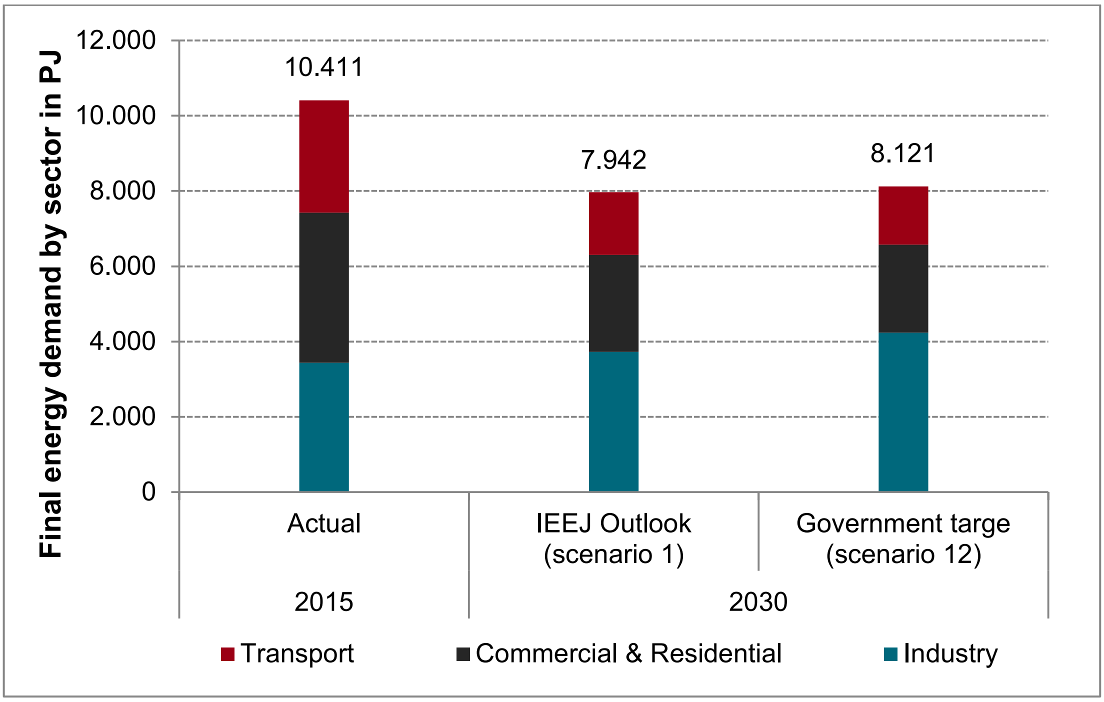

Figure 12: Final energy demand by sectors in 2030 for Japan

Source: Own depiction based on scenario parameters and IEA (2018)

Only scenario 1 specifies final energy consumption by fuel type. According to the projection results, oil will still account for the largest share in final energy consumption in 2030 (no data is available for final energy consumption by fuel type in 2050).

2.2.2.2 Primary energy supply

Data for primary energy supply in 2030 also suggest that the power mix will depend on the CO_2 constraints imposed by the policy. Scenarios 1, 8, and 12 suggest that in 2030, fossil energy sources will still account for 70% to 80% in the total primary energy supply. Scenarios 5, 6 and 8 provide some insights for 2050: scenario 5 assumes no constraints on CO_2 emissions and projects the share of fossil fuel at around 60%. Scenario 6, which assumes a 65% CO_2 emission reduction by 2050 from 1990 level, the share of fossil energy source in the primary energy mix is reduced to below 50%, while Japan is also importing hydrogen to cover around 8% of its primary energy supply. Scenario 8 assumes a constraint of CO_2 emissions to the tune of 80% reductions from 2015 level, and the share of fossil energy sources in primary energy supply reduced to between 29% and 32%. This scenario also envisions hydrogen imports covering between 5% and 13% primary energy demand in 2050.

2.2.2.3 Hydrogen demand

The scenarios analysed in this study estimate the Japanese hydrogen demand in 2030 to between 16.8 and 140 PJ. As mentioned above, the total 2030 final energy demand in Japan is projected to be between 7,913 and 8,499 PJ. Hydrogen is thus expected to have a limited role in 2030. The scenarios however envision that hydrogen demand could rise dramatically between 2030 and 2050, to between 600 and 1,800 PJ (Figure 13). With total final energy demand expected to be between 5,862 and 6,448 PJ, this corresponds to between 9% and 22% of the total final energy demand in 2050.

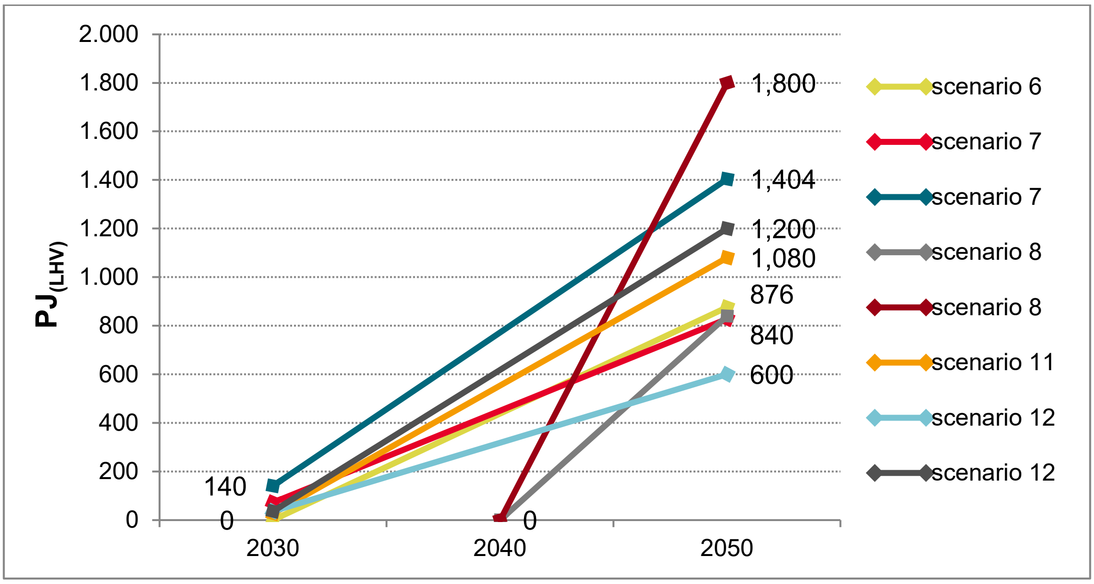

Figure 13: Hydrogen demand envisioned by various scenarios

Source: Own depiction based on scenario parameters

In terms of hydrogen's role in different final energy demand sectors, the scenarios diverge for the year 2030. Scenario 1 and scenario 7 envisioned hydrogen demand in transport sector and possibly industry (oil refineries), with little hydrogen demand for power generation. On the other hand, scenario 11 and scenario 12 see nearly entire hydrogen demand coming from the power sector.

In contrast, for 2050, most scenarios envision the power sector to contribute the bulk of the hydrogen demand. The hydrogen for power generation is expected to be imported as clean (low-CO2) hydrogen. The transport sector is also expected to contribute a considerable part of the demand. Regarding stationary fuel cells, their market penetration is expected to continue in the future; however, scenarios suggest that even in 2050, they won't be running on pure hydrogen but rather use on-site steam reforming due to high costs of the hydrogen infrastructure.[16] Only scenario 7 concerned itself with hydrogen use in the industry sector (in oil refineries). It suggests that hydrogen production units in oil refineries which produce hydrogen from petroleum products could be replaced by clean hydrogen, reducing the total fossil fuel input in oil refineries. The demand for clean hydrogen in oil refineries is estimated to be about 25 PJ in 2030 and about 50 PJ in 2050.

Price is considered a key driver for hydrogen demand in the scenarios. Assumptions on the hydrogen fuel price in the scenarios stand between JPY 20 – 35 per Nm^3 (~ 2.2 – 2.7 EUR/kg). The general view in the scenarios is that the price for hydrogen would need to be below JPY 20 per Nm^3 (~ 1.8 EUR/kg) for hydrogen applications to be competitive. In that sense, the government's target for hydrogen price of JPY 30 per Nm^3 (~ 2.7 EUR/kg) by 2030 and JPY 20 per Nm^3 (~ 1.8 EUR/kg) in the long term can be regarded as reasonable.

2.2.3 Main findings in the Japanese scenarios

Details of hydrogen demand envisioned by various scenarios are summarized in Table 15.

[16] Stationary fuel cell at present is using on-site reforming for hydrogen supply

Table 15: Hydrogen's role envisioned by the scenarios

Scenario	Total yearly hydrogen demand in 2030	Total yearly hydrogen demand in 2050	Further information
Scenario 1	17 PJ	/	• No hydrogen application in power sector
Scenario 2	/	/	• Worldwide no hydrogen power generation because of maximum use of CCS
Scenario 3	/	/	• Hydrogen account for 5% of global power generation in 2050 • Limited use of FCEV • Source of carbon neutral hydrogen supply: fossil fuel + CCS
Scenario 4	/	/	• Hydrogen account for 13% of global power generation • High demand of hydrogen from power sector will help drive down the hydrogen fuel price • As a result, FCEV is expected to account for 8% in global LDV stock in 2050
Scenario 5	/	/	• No hydrogen demand envisioned because there is no constraint on CO_2 emission in this scenario
Scenario 6	/	876 PJ	• All hydrogen demand comes from power sector • Import hydrogen account for 7.6% in total primary energy supply in 2050 • Hydrogen supplied from brown coal + CCS
Scenario 7	72 – 140 PJ	828 – 1,404 PJ	• Hydrogen demand mainly comes from transport and oil refinery (replace of hydrogen production unit) sectors in 2030 • In 2050, power sector accounts for 73% of the total hydrogen demand, transport accounts 24%, and the rest for oil refinery • Fuel price of hydrogen needs to be less than 24 JPY/Nm^3 (2.2 EUR/kg), and preferable lower than 20 JPY/Nm^3 (1.8 EUR/kg)
Scenario 8	/	840 – 1,800 PJ	• Hydrogen account for 5%~13% in total primary energy supply in 2050 • Share of hydrogen in power generation depends on the penetration of nuclear and renewable in power generation: high nuclear and renewable result to low hydrogen power and vice versa

			• Hydrogen is estimated to account for 41%~71% in the final energy demand in transport sector • However, hydrogen's application in transport sector is significantly influenced by hydrogen's use in power sector, high hydrogen demand in power sector will result to high penetration of FCEV
Scenario 9	/	/	• 14%~64% city gas can be replaced by carbon neutral methane (hydrogen produced by water electrolysis using domestic renewable power and domestic CO_2 from carbon intensive industries)
Scenario 10	/	/	• International hydrogen supply chain (hydrogen carrier: MCH) • Hydrogen CIF price: 30 - 40 JPY/Nm^3 (2.7 – 3.6 EUR/kg) in 2030, 25 - 30 JPY/Nm^3 (2.2 – 2.7 EUR/kg) in 2050
Scenario 11	27 PJ	1,080 PJ	• Only envisioned hydrogen for power generation • Hydrogen supply from overseas (hydrogen carrier: liquefied hydrogen) • Hydrogen CIF price: 30 JPY/Nm^3 (2.7 EUR/kg) in 2030, and 18 JPY/Nm^3 (1.6 EUR/kg) in 2050
Scenario 12	36 PJ	600 – 1,200 PJ	• Most of the hydrogen demand from power sector (both for 2030 and 2050) • International hydrogen supply chain commercialized after 2030 • Hydrogen fuel price: lower than 30 JPY/Nm^3 (2.7 EUR/kg) by 2030 and lower than 20 JPY/Nm^3 (1.8 EUR/kg) in the long term

Source: Own compilation based on scenario parameters

The scenarios show that constraint on CO_2 emissions is the precondition for penetration of hydrogen. For example, scenario 5 assumes no CO_2 emissions constraint while scenario 6 assumes a target of 65% CO_2 emissions reduction for 2050 from the 1990 level (other assumptions being the same). Optimization results (least cost of energy system) of these two scenarios show that without a carbon constraint, there is also no demand for hydrogen. Vice versa, hydrogen applications become necessary as CO_2 emission reductions become more ambitious.

Even in scenarios with CO_2 emissions constraints, the penetration of hydrogen varies depending on the development of other technologies. In scenario 8, which assumes an 80% reduction on CO_2 emissions by 2050 compared to the 2015 level, the share of hydrogen in the power generation mix varies considerably, depending on assumptions regarding the shares of nuclear and renewable energies. With high shares of nuclear and renewables, almost no hydrogen is used for power generation, while in the case of limited nuclear and renewables, hydrogen's share rises to around 30%. Discussions in scenarios 2 to 4 suggest that if CCS in combination with thermal power plants can be used to its full potential, there is no need for power generation from hydrogen. However, in case the use of CCS on thermal power plants is limited due to high costs or lacking social acceptance, power generation from hydrogen becomes the preferable option to decarbonise power generation by substituting thermal power generation with one relying on clean hydrogen.

Most of the Japanese scenarios share the view that because of the scale of the demand, the power sector could be the largest hydrogen consumer. This makes the prospect of hydrogen in large scale power generation an important factor in driving down the cost of hydrogen. This in turn would enable hydrogen's penetration in the transport sector. Vice versa, if the demand on hydrogen power generation is low, the adoption levels of FCEV will also likely be low.

The analysed scenarios generally agree that the hydrogen used should be CO_2-free. According to scenarios 10, 11 and 12, hydrogen imports could be as high as 600 to 1,200 PJ in 2050.

While some of the scenarios focus exclusively on imported hydrogen, others assume hydrogen produced by water electrolysis using domestic renewable resources as a viable option as well, with varying degrees of significance. In this case, domestically produced hydrogen would primarily be used for providing flexibility to the power grid rather than for large scale power generation. Only scenario 9 specifically discusses the potential of synthetic fuels other than hydrogen. The scenario envisioned a future with large intermittent renewable power capacities in Japan (solar PV and wind). Hydrogen would be produced from excess renewable power and used to produce carbon-neutral methane from CO_2 captured from carbon intensive industries and power plants. In the scenario, the methane generated in this way could replace 14% to 64% of total city gas demand.

In contrast to the German scenarios, the Japanese scenarios don't envision the non-hydrogen synthetic fuels playing a significant role in the energy system in the timeframe up to 2050. The only exception is the scenario 9, mentioned in the paragraph above. For this reason, for the Japanese scenarios there is no chapter dedicated specifically to synthetic fuel demand, nor to the discussion on relationship between the roles of hydrogen and other synthetic fuels.

2.3 Comparison of Japanese and German scenarios

In the two previous chapters, selected scenarios from Germany (chapter 2.1) and Japan (chapter 2.2) were analysed and compared to other scenarios from their respective country, with a focus on the possible future role of hydrogen in the countries' energy systems. In this chapter, a comparison is made between both countries.

It should be noted that differences in data availability between the scenarios in focus from both countries constitute a challenge for the scenario comparison in this chapter. In general, more data is available for German scenarios than for Japanese scenarios. This has been noted in previous work (Arnold et al. 2017). It is apparently more common in Germany to publish relatively lengthy scenario studies with extensive data on various aspects of the energy system, while in Japan energy scenario publications tend to be shorter and focus more on specific topics, typically providing no full energy system data set. Apart from data gaps, non-uniform definitions also pose a challenge. For example, end use sectors are often defined differently in both countries (and sometimes even within the same country).

In this chapter, the challenge of lacking energy system data especially in the Japanese studies is dealt with by choosing different Japanese scenarios for each of the topics to be analysed. The German scenarios selected for the comparison however remain the same throughout this chapter. To keep the comparisons concise, it was decided to focus on four German scenarios (KS80, KS95, TM80, TM95) from the studies by Repenning et al. (2015) and Hecking et al. (2018). These four scenarios were selected because they provide detailed data on the assumed use of hydrogen in final energy demand and because they represent a wide range regarding the future role of hydrogen in the German energy system, ranging from no use of hydrogen in KS80 to around 560 PJ in 2050 in TM95. These four German scenarios are compared to up to five scenarios from Japan.

It should also be noted that for Chapter 2 in general, and even more so specifically for this section, scenarios were chosen for the analysis in which hydrogen plays a relevant role in the future. This was done to gain relevant insights, including the preconditions which need to be met for hydrogen to become relevant. There are, however, other mid-21st-century energy scenarios for Japan and Germany in which hydrogen plays no or only a minor role in 2050. This is especially true for scenarios with no (strong) CO_2 constraint; hydrogen does not play a relevant role in scenarios which do not meet mid- and long-term climate protection targets, and even in some scenarios which only meet the lower-end GHG reduction targets by 2050 (for example, KS80 by Repenning et al.).

The following subchapter compares key energy system drivers as well as key energy system characteristic for both countries' scenarios. Chapter 2.3.2 will then focus on the role of hydrogen in these scenarios, deriving similarities and differences in the country-specific visions expressed through the scenarios.

2.3.1 Comparison of key energy systems drivers and system characteristics

Scenarios from both Germany and Japan assume that each country's population will decline over the next three decades. In German scenarios this decline is less pronounced than in Japanese scenarios, with the study by Hecking et al. (2018) for example expecting the population to decline from 81.8 million in 2010 to 76.1 million in 2050, a decline by 7%. In Japan, a scenario study by IEEJ (2013) assumes that the Japanese population will decline during the same period from 128.1 million to 97.1 million, a decline by 24%. Alongside the absolute population decline expected, the populations in both countries are expected to become older on average, further decreasing the number of working-age people (Figure 14).

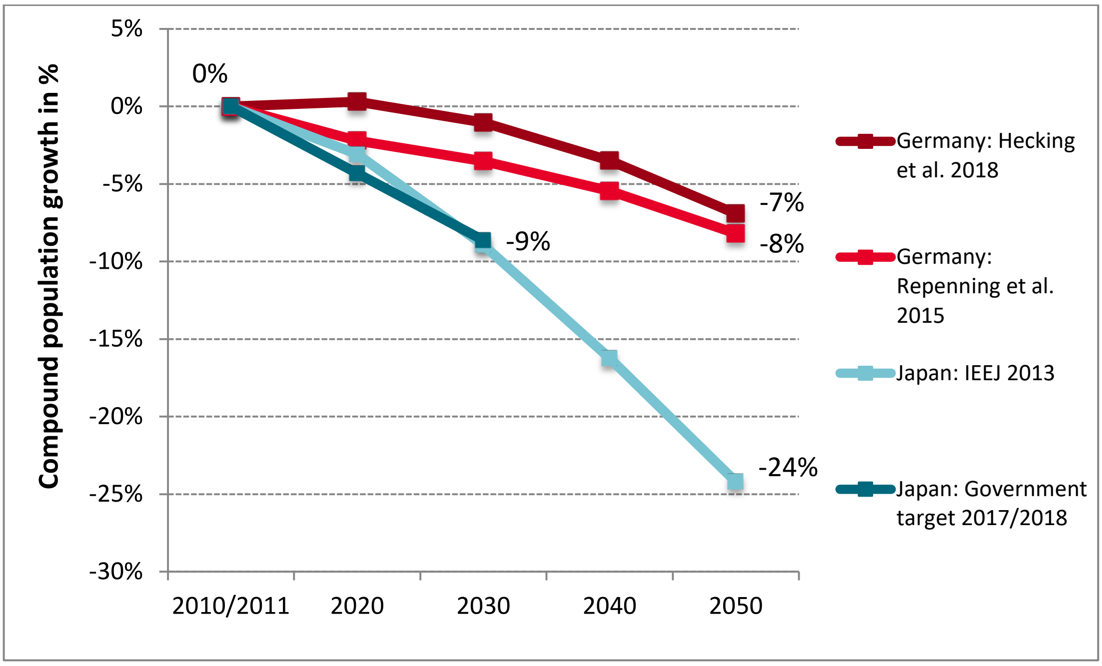

Figure 14: Population change assumed in different scenario studies (relative to 2010/2011)

Source: Own depiction based on scenario parameters

These demographic changes can be expected to curb economic growth in the two countries in the future. The scenario studies that explicitly make assumptions on future economic growth appear to support this notion. In Germany, the study by Hecking et al. (2018) for example assumes an average annual real GDP growth rate (AAGR) of 1.03% from 2011 to 2050, while the study by Repenning et al. (2015) assumes an AAGR of 0.78% from 2010 to 2050. This is both lower than the 1.2% AAGR observed in Germany from 2000 to 2016. The only Japanese scenario study making an explicit assumption on future GDP growth (IEEJ 2013) assumes that the AAGR will stand at 0.65% from 2010 to 2050, lower than the 0.8% observed from 2000 to 2016 (Figure 15).

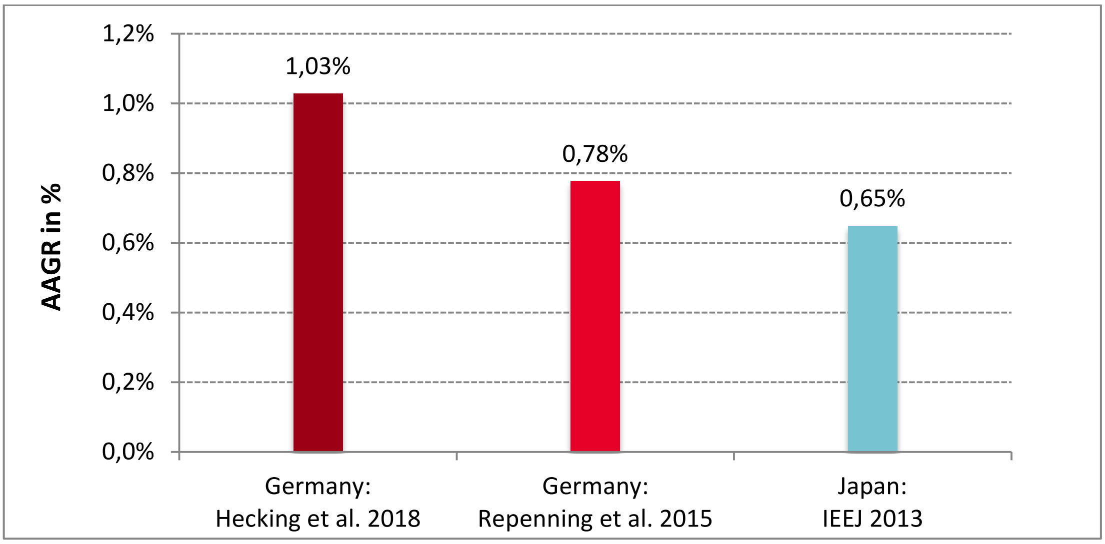

Figure 15: Average annual real GDP growth rates from 2010/2011 to 2050 assumed in different scenario studies

Source: Own depiction based on scenario parameters

The expected decline in population and in future GDP growth in both countries can be expected to have a dampening effect on future energy demand. However, it is unclear (and not discussed within the scenarios in focus) whether and how declining populations and GDP growth rates affect the challenges associated with energy system transformation.

Apart from demographic and economic developments, a country's GHG reduction ambition can also have an effect on the development of its energy system. Both, Japan and Germany have formulated absolute targets for domestic GHG reductions until 2030. Japan aims to reduce its GHG emissions by 26% by 2030, relative to 2013, while Germany aims to reduce its GHG emissions by 55% by 2030, relative to 1990. Using these targets, historic GHG emissions as reported by the UN (2019) and assuming 2030 population levels as projected by the 2017 Revision of World Population Prospects (UN 2017), these targets can be compared on a per capita basis. This method reveals that Germany's 2030 target is significantly more ambitious than Japan's 2030 target.[17] Assuming that both countries are able to realise their respective 2030 reduction targets, Japan's per capita emissions would fall from 10.3 ton in 2015 to 8.6 ton in 2030, a reduction of 17%, while Germany's per capita GHG emissions would fall in the same period from 11.1 ton to 6.9 ton, a reduction of 38% (Figure 16).

[17] It should be stressed that this is a very simple approach to compare different countries' GHG emission reduction targets, as countries' differences in mitigation potential and costs are not taken into account. There are indications that emission reductions are more difficult to achieve and more expensive in Japan compared to Germany. See a more thorough discussion of this topic in Arnold et al. (2017).

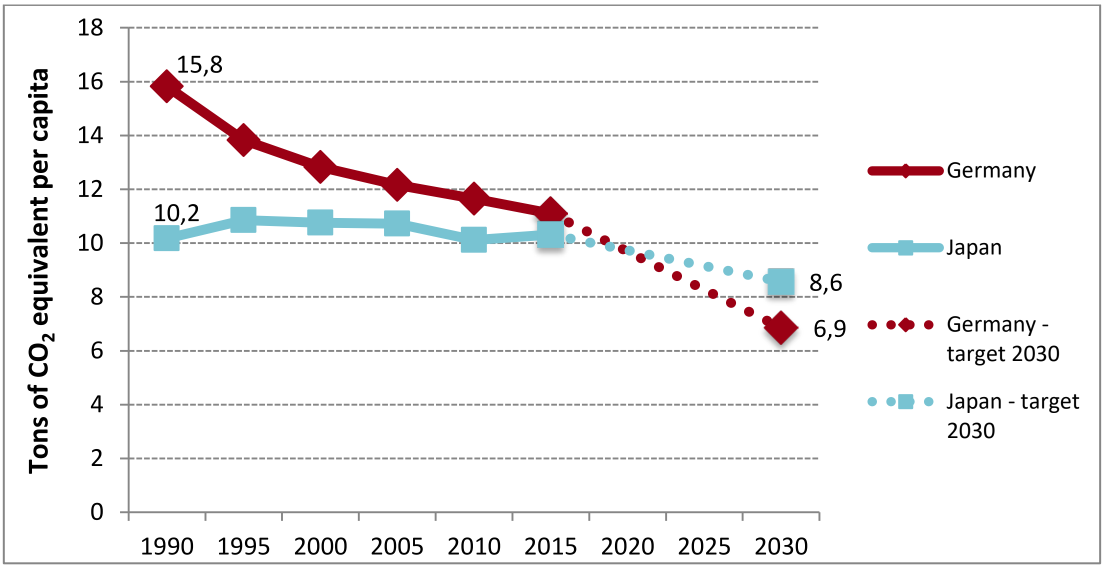

Figure 16: Development of per-capita GHG emissions in Japan and Germany from 1990 to 2015 and possible target-derived development until 2030 (in t CO_2-equivalent)

Source: Own depiction based on scenario parameters

Additionally, the German government has set itself an 80 to 95% GHG reduction target for 2050 (relative to 1990), while the Japanese government has set a target of 80% reductions by 2050 (with some ambiguity regarding the reference year). The differences in the mid- and long-term GHG reduction targets can be used to explain the differences in the level of emission reductions ambition between energy scenarios typically discussed in Japan and those typically discussed in Germany. For example, many government-commissioned energy scenario studies include ambitious scenarios in which Germany reduces its GHG emissions by 95% by 2050, relative to 1990, achieving per capita GHG emissions of less than 1 ton. The Japanese scenario studies analysed typically do not go as high, not exceeding reductions of 80%.

The different levels of ambition are likely one of the factors behind the much faster expected increase in the share of renewables in the primary energy supply in the German scenarios in focus, compared to the analysed Japanese scenarios.[18] In the German scenarios, the share of renewables in the total primary energy supply is expected to increase from 12% in 2016 to at least 26% and up to 39% by 2030. In the Japanese scenarios that provide this information, a very modest increase is expected, from 10% in 2016 to a maximum of 14% by 2030 (Table 16).[19]

[18] An additional reason for the differences in the expansion of renewables is the generally different view in both countries on the future role of nuclear power. In Japan, nuclear power as an alternative carbon-free source of electricity generation is widely expected to play a relevant role in energy supply well beyond 2030, while Germany intents to phase out the use of nuclear power by the end of 2022. Furthermore, another reasons leading to very different shares of renewables in primary energy supply in German and Japanese scenarios can be seen in the perceived or actual differences in renewable energy endowment in both countries (see also Arnold et al. 2017).

[19] Care should be taken when comparing the shares of renewables in primary energy supply between Japan and Germany. While energy statistics and energy scenarios in Japan report primary energy supply using the partial substitution method, Germany (as well as most international organizations such as the IEA) use the physical energy content method (IEA 2019). Using the latter method leads to a lower share of renewables in primary energy supply compared to the former method.

Table 16: Share of renewable energy sources in primary energy supply

2016		2030				
Germany - Actual	**Japan - Actual**	**Germany - TM80 & TM95**	**Germany - KS80**	**Germany - KS95**	**Japan – Government target**	**Japan - IEEJ Outlook**
12%	10%	26%	32%	39%	13% - 14%	10%

Source: Own compilation based on scenario parameters

Similarly, and largely in line with Germany's target for the expansion of renewables in electricity generation with current target of 65% by 2030 (BMWi 2019c), German scenarios expect the share of renewable energy sources in the power mix to continue to increase rapidly in the coming decades. At the same time, nuclear power is phased out in the scenarios until the end of 2022 – again in line with Germany's current energy targets and legislation. As Table 16 shows, electricity generation from renewables is expected to increase in the selected German scenarios from 188 TWh (~ 677 PJ) in 2016 to at least 312 TWh (~ 1,123 PJ) (KS80; an increase of 66%) and up to 434 TWh (~ 1,562 PJ) (TM80 and TM90; an increase of 131%). The contribution will come mostly from wind (both onshore and offshore) as well as solar PV. In the Japanese scenarios, nuclear power is expected to rebound, increasing its contribution from 18 TWh (~ 65 PJ) in 2016 to about 230 (~ 828 PJ) TWh by 2030. The contribution from renewables is expected to grow more modestly in Japan, from 160 TWh (~ 576 PJ) in 2016 to 245 (~ 882 PJ) TWh in 2030. Overall electricity supply is expected to increase slightly in Japan, while in Germany, it is expected to decrease modestly (in the TM80 and TM95 scenarios) to markedly (KS80 and KS95) by 2030 (Figure 17).[20]

[20] However, it should be noted that all German scenarios expect the large net electricity exports of Germany (54 TWh in 2016) to decline or disappear by 2030

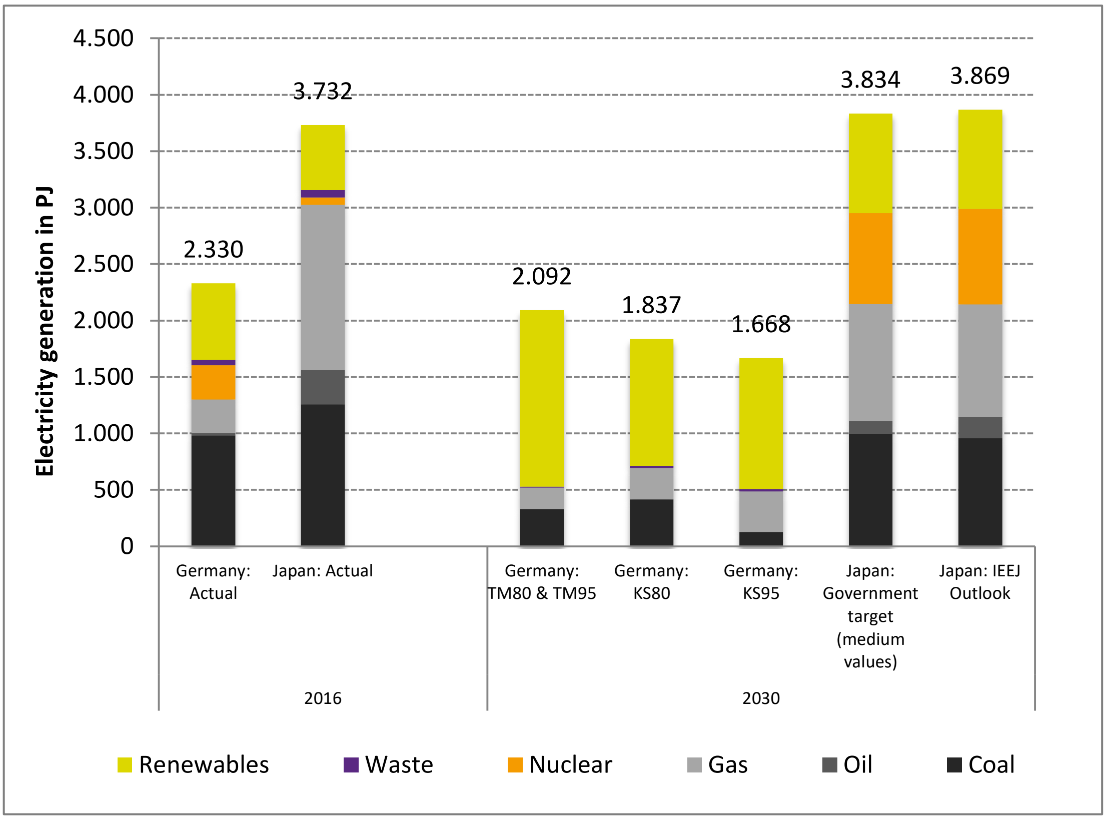

Figure 17: Electricity generation in Germany and Japan in 2016 and in 2030 for different scenarios

Source: Own depiction based on scenario parameters

2.3.2 Comparison of the role of hydrogen in the respective scenarios

In most of the analysed energy scenarios for both Germany and Japan, the use of hydrogen plays a relevant role in the respective energy systems by the middle of the century. As Figure 18 shows, hydrogen is used extensively in 2050 in three of the selected four German scenarios. They assume a demand for between about 300 and 600 PJ of hydrogen in the German energy system.[21] This corresponds to 5% to 10% of the envisioned 2050 primary energy demand. In the Japanese energy scenarios, hydrogen use in 2050 in the five selected scenarios ranges between 600 PJ and 1,600 PJ, which is higher even on a per capita basis than in most German scenarios. The figure also shows that hydrogen use is typically expected to become relevant after 2030 in both Japanese and German scenarios.

[21] As Table 13 shows, one of the analysed scenarios ("Strom und Grünes Gas", by Bothe et al. 2017) not considered for the comparison in this chapter stands out from all other analysed scenarios by assuming an end use sector hydrogen demand of almost 1,200 PJ in 2050.

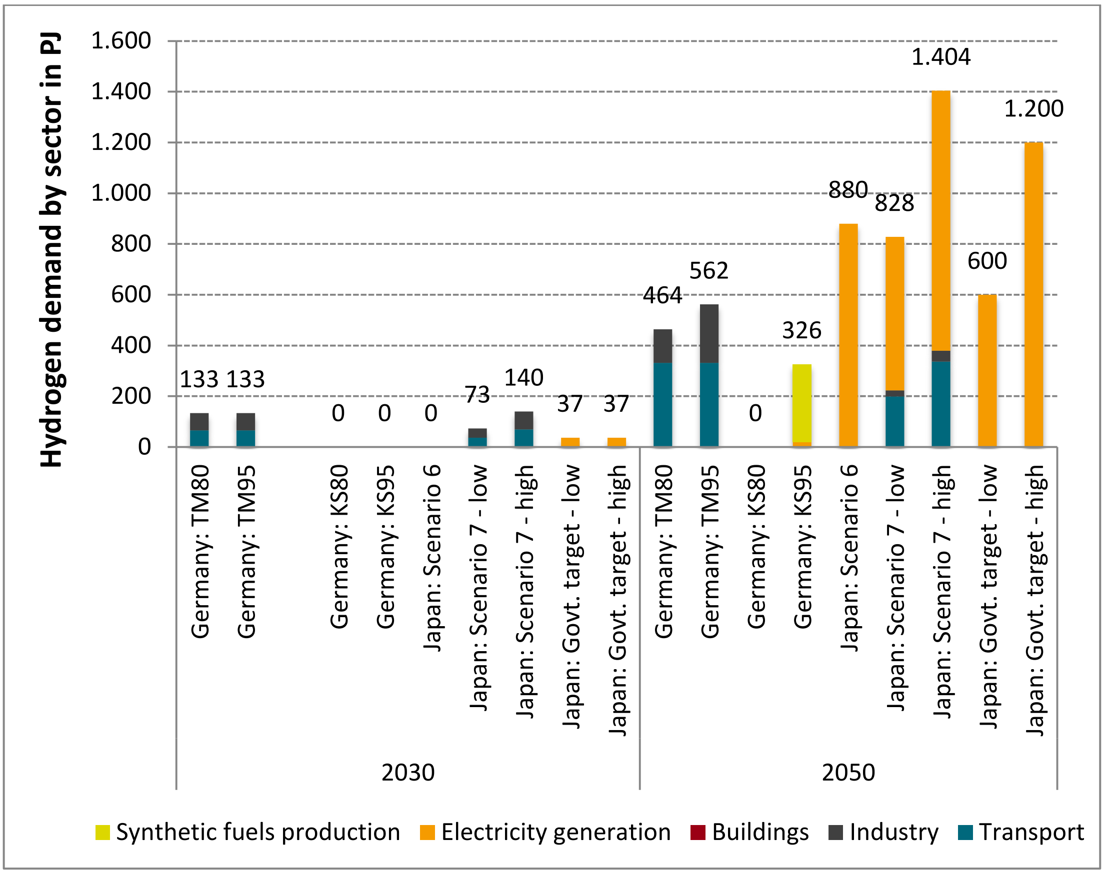

Figure 18: Use of hydrogen in different scenarios in 2030 and 2050 (in PJ)

Source: Own depiction based on scenario parameters

The Japanese scenarios tend to lag behind the German scenarios in terms of hydrogen demand in 2030, but foresee a larger role for hydrogen by the middle of the century. In addition, the role of hydrogen differs considerably between the German and the Japanese scenarios analysed in this study. In the two German scenarios by Hecking et al. 2018, hydrogen is used mainly in the transport sector and to a lesser extent in industry. In the German scenario KS95, hydrogen is also used to provide flexibility and storage in the power sector, but mainly to produce other synthetic fuels which are used exclusively in the transport sector. In Japan, while hydrogen plays a significant role in the transport sector in some of the scenarios (scenarios 1 and 7), it is by and large used mostly for the purpose of power generation.[22]

This is a notable difference between the scenarios analysed for Germany and Japan. In Japan, it has been recognised that hydrogen – a potentially carbon-free source of energy – is necessary to significantly reduce CO_2 emissions of electricity generation. However, the notion seems to be present that a cost-efficient hydrogen production is not viable domestically due to insufficient renewables potential. In Germany, on the other hand, it is widely believed that there is sufficient domestic renewable energy potential (mainly from

[22] It should be noted that apparently some of the Japanese scenarios depicted here as having no use of hydrogen in the transport sector actually foresee some limited use in this sector. However, no exact data is available and in these cases the use of hydrogen in the transport sector can be expected to be limited.

wind and solar) to cover all of or at least the vast majority of the direct[23] electricity demand by the middle of the century, as well as a share of the hydrogen and other synthetic fuels demand. These are to be used mainly in the transport sector as the potential for direct use of electricity is considered to be limited in some applications such as air and marine traffic, and perhaps also in long-distance road applications. For the same reason, some of the German scenarios consider hydrogen necessary for decarbonising industrial and chemical processes such as ammonia production, steel generation and other processes requiring high-temperature heat.

Related to this is the general observation that the future role of hydrogen strongly depends on the efforts to reduce the CO_2 emissions across all sectors. A number of both Japanese and German business-as-usual scenarios with no (significant) carbon constraint show that demand for hydrogen is unlikely to materialise without the necessary climate policy signals. Similarly, German studies, often including both an 80% and a 95% GHG emissions reduction scenario, show that for achieving the lower end of the reduction target, either no (e.g. KS80 vs. KS95) or much less (e.g. TM80 vs. TM 95) hydrogen and/or other synthetic fuels are used, compared to the more ambitious reductions scenarios.

In the German scenarios, it is often assumed that most or all of the required hydrogen is produced domestically through the use of renewable electricity. In the case of the scenario TM95 (Hecking et al. 2018), the vast majority of hydrogen, about 500 PJ, is assumed to be produced in Germany in 2050. It is argued that the long-distance transport of hydrogen is relatively expensive compared to the transport of other synthetic fuels. Similarly, the roughly 300 PJ of hydrogen required in the KS95 scenario (Repenning et al. 2015) are also assumed to be produced in Germany. In these two scenarios, hydrogen electrolysis will become a key source for electricity demand by the middle of the century, constituting the main reason for the increase in electricity demand from 2030 to 2050.

In the Japanese scenarios, as mentioned in chapter 2.2.3, hydrogen is generally assumed to be imported from abroad at least in the short term, from countries with better potential for clean hydrogen generation. At the same time, many of the scenarios see the role of domestic hydrogen production from renewable electricity as unclear.

While only one of the analysed Japanese scenarios discusses the possibility of using synthetic fuels other than hydrogen in the future energy system (scenario 9 assumes that synthetic methane will be fed into the city gas grids to replace some of the natural gas), many of the German scenarios in focus foresee the use of liquid or non-hydrogen gaseous synthetic fuels. Similar to the use of hydrogen, these fuels are typically assumed to be used in the transport sector, and in some scenarios, in industry. Contrary to hydrogen, these fuels are generally assumed in the German scenarios to be imported from abroad, from countries with more abundant renewable energy sources. As in the case of hydrogen, there is a clear positive correlation between the demand for non-hydrogen synthetic fuels and the level of ambition of GHG emissions reduction.

[23] This is in contrast to the „indirect“ electricity demand in the form of synthetic fuels that are assumed to be used in some end use sectors (especially in transport) in most of the more ambitious German scenarios. The electricity required to produce these synthetic fuels is generally thought to be beyond the domestically available renewable energy potential, which is why most studies assume that these fuels will be imported.

3 Hydrogen supply chains

This chapter provides information on three aspects of hydrogen supply chains: the framework for a definition of clean hydrogen (chapter 3.1), GHG intensities of different hydrogen supply chains (chapter 3.2), and potential partner countries for establishing clean hydrogen supply chains (chapter 3.3).

3.1 Framework for a definition of clean hydrogen

As of today, almost the entire global hydrogen production stems from CO_2-intensive processes based on fossil fuels (IEA 2019, see Figure 1 in chapter 1.1). The largest share of hydrogen used in industry originates from steam reforming of natural gas. Steam reforming can alternatively also be based on other fossil fuels such as coal, oil and liquefied petroleum gas (LPG) (CHICH 2016). However, without CCS, these processes release the entire carbon content of the primary energy source into the atmosphere. Taking into account the energy intensity of hydrogen production, in some applications a switch from conventional fossil based technologies to hydrogen stemming from unabated, CO_2-intensive processes may result in a negative climate balance.

Therefore, for countries that consider climate policy as a main driver for developing hydrogen technologies, it is essential to define criteria which make sure that the consumed hydrogen clearly has a positive climate balance, and to establish certifiable standards for this purpose. In view of creating international hydrogen supply chains, it is desirable that the standards and certification procedures are agreed upon and implemented at international level.

In this study, clean hydrogen is used as an umbrella term for green and blue hydrogen (see terminology text box in chapter 1.1). Green hydrogen is produced from renewable sources (with focus on electrolysis from renewable power) and blue hydrogen from fossil fuels in combination with CCS. This definition of blue hydrogen thus also excludes hydrogen stemming from nuclear power.

The following chapter 3.1.1 discusses possible sustainability criteria for green hydrogen. Chapter 3.1.2 describes the existing certification schemes and standards for green and blue hydrogen. Chapter 3.1.3 looks at the similarities and differences between the existing schemes and standards and examines to what extent they meet the sustainability criteria for green hydrogen explored in chapter 3.1.1. It also discusses possibilities for leveraging certification or standards on the international level and how sustainability criteria could be incorporated into them.

3.1.1 Sustainability criteria for green hydrogen

Neither Germany nor Japan has so far adopted sustainability criteria for green hydrogen. The sustainability criteria for biomass foreseen by the EU Renewable Energy Directive (EU-RED) are not directly applicable to hydrogen and other synthetic fuels.

Sustainability criteria for green hydrogen and other synthetic fuels have been developed by Bracker (2017), in a policy paper of the Oeko-Institut, as well as by Agora Verkehrswende et al. (2018). Some key aspects relevant for green hydrogen are:

1. **GHG emission balance:** Both papers suggest a minimum threshold of at least 70% GHG emissions reduction achieved by using hydrogen instead of fossil fuels for the respective application. The 70% threshold is in line with the threshold for advanced biofuels to be considered as renewables according to the EU-RED. The threshold refers to the entire hydrogen production chain. Thus, in case of hydrogen produced by electrolysis, the GHG intensity of the electricity used must be accounted for.
2. **Electricity demand and additionality of renewables:** The electricity needed for the entire hydrogen production process (e.g. including water desalination, where applicable) has to be generated from additional renewable energy capacities. The additionality principle is important to avoid that the additional renewable power purchased to feed the electrolysers (and possibly water desalination) only leads to a redistribution of the same amount of renewable electricity, while actually bringing more fossil-based sources into the mix. However, defining the additionality principle in practice is not always straightforward. Agora Verkehrswende et al. (2018) discusses the strengths and weaknesses of different approaches. Considering that hydrogen and other synthetic fuels would likely be traded internationally to a significant extent, it also raises the question of how the use of the best renewable power production sites for PtG and PtL intended for exports would affect the domestic decarbonisation efforts in developing countries.
3. **Water usage:** The water usage for the hydrogen production chain (including electrolysis and, where applicable, cleaning the PV modules) could negatively affect the water supply in the respective regions. In arid regions, additional seawater desalination plants powered by renewable electricity might be needed. In non-arid regions, a sustainable water supply for hydrogen production should be ensured in compliance with sustainable water management plans.
4. **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 sites and the related renewable energy generation sites should be prohibited in nature protection areas or other regions with high environmental value.
5. **Social and economic impact:** The establishment of renewable energy and hydrogen production facilities and infrastructure should not negatively impact local communities, but instead contribute to sustainable economic development and welfare in the respective regions. In developing countries, a share of the revenues could be used to fund regional development programs. The involvement of local actors in planning procedures and the establishment of fair partnerships between importing and exporting countries is important to avoid negative impacts. The social and economic context of hydrogen production should be monitored.

Bracker (2017) and Agora Verkehrswende et al. (2018) also consider other synthetic fuels apart from hydrogen that require a carbon input: the CO_2 cycle should be closed, i.e. the required CO_2 should stem from biomass, biogas or the atmosphere. As carbon is not needed for the production of green hydrogen this criterion will not be taken into account in the discussion below.

3.1.2 Criteria for green and/or blue hydrogen in existing certification schemes and standards

3.1.2.1 CertifHy

The EU-wide CertifHy scheme was initiated by a consortium of European companies and research centres, financially supported by the European Union through the FCH-JU, and involving a broad set of European and global stakeholders.

CertifHy is developing the first EU-wide Guarantees of Origin (GoO) certification scheme for these two types of "premium" hydrogen: green hydrogen and low-carbon hydrogen. A pilot was launched in January 2019 which covers four audited hydrogen production plants and has so issued the first GoOs (Bioenergy International 2019). The pilot's target is to test the GoO design, procedures, associated costs for the users, etc. (CertifHy 2019a). CertifHy covers the complete certification life cycle of the GoO scheme, including auditing hydrogen production plants, certification of respective hydrogen production batches and the issuance, trade and usage of certificates (CertifHy 2019b).

Definition of "premium" hydrogen types and eligibility criteria

As shown in Figure 19, CertifHy differentiates between green hydrogen and low-carbon hydrogen (CertifHy 2019c). Green hydrogen is produced by renewables, i.e. bio, hydro, wind and solar energy (zero carbon intensity is assumed as the GHG emissions resulting from production of renewable energy generation facilities are not included). Low-carbon hydrogen according to CertifHy can also be produced by nuclear electricity or by fossil fuels in combination with CCS/CCU Including nuclear electricity. In this case, the CertifHy definition diverges from our study's definitions for clean and blue hydrogen.

In order to be eligible for CertifHy certification, the GHG emission intensity for both green hydrogen and low-carbon hydrogen has to be at least 60% below the GHG intensity by hydrogen produced from natural gas, in line with a 60% GHG emission reduction requirement for biofuels in 2018 according to the first EU-RED. The benchmark for natural gas is set to 91 g $CO_{2eq/}MJ_{H2}$, and thus the threshold lies at 36.4 g CO_{2eq}/MJ_{H2} (CertifHy 2019d).

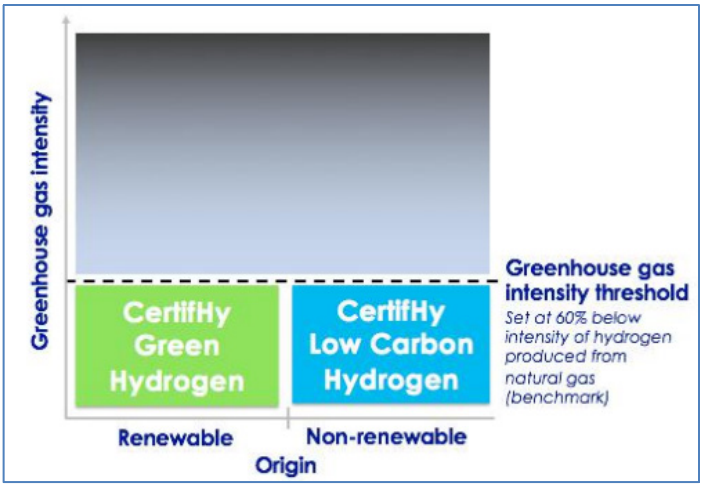

Figure 19: Hydrogen definitions according to CertifHy
Source: CertifHy (2019c)

Guarantees of Origin by CertifHy

With the GoO-system, green hydrogen and low-carbon hydrogen certification becomes available across the EU independently from the site of its production. The CertifHy GoO process is illustrated in Figure 20. The GoO is an electronic document that provides to the final consumer with a guarantee of the origin of the product. Since more than a decade, EU legislation mandates the use of GoOs for making claims regarding the source of renewable electricity; since 2019, the reformed EU-RED expands this to (amongst others) hydrogen (CertifHy 2019c).

The following information is disclosed in the CertifHy GoOs:

- Source of hydrogen (green or low-carbon), and the energy source of the hydrogen;
- The GHG intensity of hydrogen in terms of CO_2 equivalent per unit of energy;
- The hydrogen production plant (location, operator, start date of operation, etc.);
- Time of hydrogen production.

A central registry has the authority to issue, transfer and cancel the GoOs. Hydrogen without a GoO is classified as hydrogen from the “residual mix”.

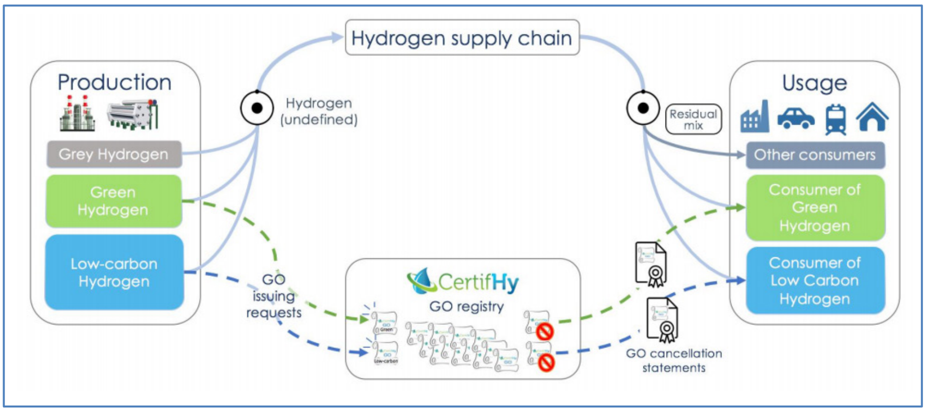

Figure 20: CertifHy GoO Process
Source: CertifHy (2019c)

3.1.2.2 Standard CMS 70 TÜV SÜD on green hydrogen

According to the German TÜV SÜD CMS 70 Standard (Version 12/2017, TÜV SÜD 2017), green hydrogen can be produced in three ways. The first one is by electrolysis of water or saline solution with electricity from renewables. This includes the following conditions:

- Usage of renewable electricity has to be proved by guarantees of origin (in case it is not verifiably generated on site without using the power grid).
- Within the EU, the origin must be verified in accordance with the EU-RED 2009/28/EC (or with §79 EEG 2017 in Germany).
- An increasing use or production of certified hydrogen should at least partly be covered by additional – new – plants. Two options to fulfil the required share of new renewable electricity are given:
    - At least 30% of renewable electricity has to be produced by new plants (i.e. not older than 3 years at the time of first certification; plants older than 10 years can no longer be considered as new). Or
    - The share of “new” renewables in the renewable electricity has to be at least:
        - Small hydropower (< 2 MW): 10% or

- Wind power: 7.5% or
- Solar power, geothermal, biomass: 5% or
- Biogas / biomethane: 3%

In addition, for the second option, the initial commissioning date has to be after 1st of January 2000.

Renewable electricity already receiving state support, e.g. in the form of increased remuneration per kilowatt hour fed into the grid, is not eligible.

The second way is biomethane steam reforming. The origin of the biomethane must be verified by means of proof in dena's biogas register or equivalent. Third way is pyro reforming of glycerine, if this is a by-product of biodiesel production under the Biofuel Sustainability Ordinance. The glycerine must come from a certified plant (Biokraft-NachV 2018). Proof of correct quantity balancing of the glycerine to avoid double counting must be provided.

The standard further defines **requirements for the GHG emissions reduction**. Green hydrogen must have GHG-reduction potential of at least 50% compared to fossil fuels or conventional hydrogen. For hydrogen from electrolysis, the necessary GHG-reduction has to be at least 75%. If hydrogen is not produced by electrolysis, the following requirements apply:

- Use in the transport sector: GHG reduction potential of at least 60% compared to the currently valid comparative value for fossil fuels in the Biofuel Sustainability Ordinance for hydrogen production plants commissioned after 31 December 2016 (at least 50% for plants commissioned before that date). The comparative value for fossil fuels is 83.8 g CO_2e/MJ (Biokraft-NachV, Annex 1, number 19).
- Use other than for transport: GHG reduction potential of at least 60% (for plants commissioned after 31 December 2016) or 50% (for plants commissioned before that date) compared to conventionally produced hydrogen. The comparative value for conventionally generated hydrogen currently stands at 89.7 g CO_2e/MJ.

If hydrogen is produced by electrolysis, GHG reduction potential of at least 75% compared to comparative value for fossil fuels under the Biofuel Sustainability Ordinance (for transport) or compared to conventionally produced hydrogen (for uses other than transport) has to be achieved.

Emission factors for renewable energy have to take into account the operational emissions from energy production (excluding emissions from construction and demolition of generation facilities and from the production of other capital goods). The system boundaries for GHG balancing extend from the production of the input materials/feedstock and the energy used to the delivery of hydrogen to the refuelling station or, in the case of stationary applications, to the consumer. Production and supply chains of input materials and energy are included. Direct emissions from production processes and transports as well as indirect emissions from electricity or heat are taken into account. The emissions from the production of plants, vehicles and buildings lie outside the system boundaries, as does administration and building management. Emissions from the use (combustion) of hydrogen are assumed to be zero.

3.1.2.3 Clean Energy Partnership

The Clean Energy Partnership (CEP) is an initiative coordinated by the (German) National Organisation for Hydrogen and Fuel Cell Technologies (NOW) and supported by the German

Federal Ministry of Transport and Digital Infrastructure. CEP aims at testing the system capability of hydrogen in daily use. It currently consists of 14 companies mainly from the automotive and the oil & gas sectors, including the Japanese car manufacturers Honda and Toyota as well as the German Audi, BMW and Daimler (Clean Energy Partnership 2019).

According to the definition of the Clean Energy Partnership (CEP) (Clean Energy Partnership (2018a), green hydrogen can be produced from:

- Electrolysis using renewable electricity or
- Biomass via certified green thermochemical or biological conversion process. The CO_2 reduction compared to hydrogen production from natural gas reforming has to be demonstrated.

Only the hydrogen production process is considered for the certification of green hydrogen. The compression/liquefaction, transport or provision of hydrogen for passenger cars and buses at the stations are not taken into account.

The following conditions apply for renewable electricity used for electrolysis:

- 100% electricity from renewables, i.e. hydropower, wind, solar, geothermal, biomass, landfill gas, sewage gas.[24]
- The electricity can be traced back to clear sources and the supplier has to disclose these sources. Certificates (a. RECS b. EECS-GoO) can be included as evidence of energy sources. If certificates are used, the age of the installations must be as follows:
    - At least one third of the electricity sold is generated in newly built renewable power plants, i.e. not older than six years.
    - At least a further third of the electricity sold is generated in renewable power plants not older than 12 years.
- Physical direct or swap contracts may be included.
- Electricity has to be certified by one of the following labels:
    - TÜV-Nord Ökostrom,
    - TÜV-Süd Ökostrom,
    - Grüner Strom Label,
    - OK Power.

The green hydrogen used by the companies involved in the CEP fulfils all the criteria and requirements of the TÜV Süd CMS 70 standard and also corresponds to the definition of "green hydrogen" of the CertifHy process. The requirements for GHG emission reductions therefore are the same as defined in the TÜV Süd standard for green hydrogen used in transport (Clean Energy Partnership 2018b).

3.1.2.4 Certification schemes and standards in Japan

Similarly in Japan, there is no clear definition for clean hydrogen yet. The term "CO_2-free hydrogen" is commonly used for hydrogen produced with little CO_2 emissions usually referring to hydrogen produced by fossil fuels in combination with CCS or by renewable electrolysis but not explicitly excluding nuclear power as a possible production source. A government committee on CO_2-free hydrogen discussed the need for establishing a standard and certification scheme in Japan and the revised version of the Strategic Roadmap for Hydrogen and Fuel Cells (released in March 2019) mentioned there is a need

[24] These energy sources are all defined as renewable under the renewable energy surcharge (EEG).

for CO_2 emission reduction along the whole hydrogen supply chain. However, no specific actions for establishing a standard or a certification scheme are observed at the moment. At the regional level, the Aichi Prefecture has started its own certification system for CO_2-free hydrogen in April 2018. It categorizes CO_2-free hydrogen into 2 categories:

1. Hydrogen produced from water electrolysis using renewable electricity or produced by steam reforming using biogas;
2. Hydrogen produced from water electrolysis using grid electricity in combination with green electricity certification to compensate the CO_2 emissions associated with hydrogen production, or hydrogen produced from fossil fuels in combination with the J-Credit to compensate the CO_2 emissions associated with hydrogen production. The J-Credit is issued by the government to certify the amount of GHG emissions that are reduced or removed by sinks such as introduction of energy-saving devices and management of forests.

Companies receive a certificate for the hydrogen if they provide proof for one of the two categories and pass the reviewing process which is carried out by a third party. The offsetting of emissions focuses on the emissions which are directly related to production of hydrogen, not on the life cycle emissions (Aichi Prefectural Government 2019).

3.1.2.5 Other initiatives

Apart from the initiatives described above, further approaches and standards exist; however, these either still have to be finalised, or available information on them is not very detailed. Only a brief summary is provided in this subchapter. The French Association on Hydrogen and Fuel Cells AFHYPAC is working on GoO for green hydrogen produced from renewable energy sources such as renewable electricity and biomethane (AFHYPAC 2016). The Directorate General for Energy and Climate (DGEC) and the French Environment and Energy Management Agency (ADEME) participate in the responsible working group which also aims to identify synergies between the French approach and the European CertifHy project (AFHYPAC 2017).

While the Department of Energy & Climate Change (DECC) of the UK government intends to develop a standard for green hydrogen, the criteria still need to be determined and there has been no progress observed in recent years. As of 2015, DECC defined green hydrogen as low-carbon hydrogen, without taking into account other environmental impacts. The technology-neutral position of DECC also incorporates hydrogen production from fossil fuels in combination with CCS. For the standard, the carbon emissions of the hydrogen produced and used are decisive; however, the emission threshold has yet to be defined. The DECC also points out that a strict threshold could hamper the market development of hydrogen technologies. Furthermore, while agreeing that emission thresholds should become stricter over time, since it is difficult to predict the development of the market, the department is opposed to defining a clear trajectory of threshold adjustments. Instead, they recommend setting clear dates for reviewing the market situation and discussing the threshold development (Department of Energy & Climate 2015).

Further, hydrogen refuelling station (HRS) companies in Denmark have also introduced a green hydrogen certificate as proof of origin. Certification by an accredited certification body is granted for hydrogen generated via electrolysis with CO_2 neutral electricity which is certified by the certification system of electricity distribution companies (HyLaw 2018).

The regulation of hydrogen under the Senate Bill 1505 in California from 2006 does not set standards for a definition of green or blue hydrogen but it determines requirements concerning emissions and renewable share for hydrogen as an alternative fuel in transport. It applies to hydrogen stations co-funded by the government and for all hydrogen stations in California with throughput of 3,500 metric tons/year or higher. The regulation sets the following emission requirements relative to gasoline: 30% GHG reduction (on well-to-wheel basis), 50% reduction of nitrogen oxides plus reactive organic gases (well-to-tank), and no increase of toxic air contaminants (well-to-tank). Furthermore, at least 33.3% of the hydrogen has to be produced from renewable sources (such as biomass, solar thermal, PV, wind, geothermal, landfill gas, ocean wave etc.) (Achtelik 2009, Senate Bill No. 1505).

3.1.3 Assessment

Clean hydrogen production has to guarantee substantial GHG emission reductions compared to the usage of fossil fuels or of conventional hydrogen, and contribute to the transition to a sustainable energy system. Chapter 3.1.1 described sustainability criteria that could be included in a standard or certification scheme for clean hydrogen. This chapter investigates which of the sustainability criteria are addressed to what extent in the existing standards and certification schemes summarized in chapter 3.1.2. The sustainability criteria in chapter 3.1.1 refer to green hydrogen and thus do not allow for hydrogen production from fossil fuels (with CCS/CCU) or nuclear electricity. Nevertheless, except for the criteria concerning the energy sources, the other sustainability criteria (emission balance and system boundaries, water and land use as well as social impact) are relevant for blue hydrogen production as well.

3.1.3.1 Comparison

GHG emission balance and system boundaries

The green hydrogen sustainability criteria in chapter 3.1.1 propose a minimum threshold of 70% GHG emission reduction compared to the usage of fossil fuels, which is in line with the threshold for biofuels under the revised EU-RED. In existing standards and certification schemes, the thresholds for GHG reductions differ: The TÜV standard requires at least a 75% GHG reduction for hydrogen produced by electrolysis from renewable electricity. For other production methods, at least a 60% GHG reduction compared to fossil fuels or conventional hydrogen must be achieved for plants commissioned after 2017 (50% for plants commissioned before). Under the CEP, the same requirements as under the TÜV standard have to be fulfilled. CertifHy sets a threshold at 60% GHG reduction compared to hydrogen production by natural gas. Under the Aichi Prefecture certification system, no emission thresholds are defined and it is sufficient to conduct GHG compensation measures which offset the emissions of hydrogen production. The California bill 1505 requires for the usage of hydrogen in transport a minimum of 30% reduction of GHG emissions relative to gasoline. This is however a requirement for hydrogen in general and not a criterion for defining green or clean hydrogen.

According to the sustainability criteria discussed in chapter 3.1.1, GHG emissions of the whole life cycle of the hydrogen production chain should be considered when defining the emission thresholds. This includes emissions from the production and extraction of the inputs and of the hydrogen production process itself. Additionally, the emissions caused by the transportation of the hydrogen or derivate molecules to the point of usage should be considered. As it stands, the GHG intensity threshold of CertifHy only includes GHG emissions from hydrogen production. The TÜV standard does also take into account emissions after the production of hydrogen, including the transport to the point of usage and usage itself (which is assumed to have zero emissions). The California Bill 1505 considers well-to-wheel emissions, but is restricted to usage of hydrogen in transport only.

Energy source and electricity demand

The sustainability criteria in chapter 3.1.1 refer to renewables-based green hydrogen. Thus, they do not allow for fossil fuels (with CCS/CCU) or nuclear electricity as possible energy sources.

Looking at the existing standards, CertifHy, the certification scheme of the Aichi Prefecture and DECC all enable certification for both 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), while TÜV, CEP, AFHYPAC and HRS in Denmark only cover green hydrogen produced from renewables. The HRS in Denmark is the only definition that restricts green hydrogen production to electrolysis of renewable electricity; all other standards also allow at least for green hydrogen production by biomethane/biomass.

TÜV Süd CMS 70 and CEP are the only standards, which at least partly address the additionality criterion discussed in chapter 3.1.1. TÜV defines a minimum threshold for the certified hydrogen to be produced from electricity generated by new renewable energy plants. The TÜV criterion is not particularly strict: at least 30% of renewable electricity must come from plants no older than 3 years at the time of first certification. CEP defines criteria for the age of renewable power plants that have to be fulfilled if certificates are used as evidence of energy sources. These criteria are not stringent either: at least one third of the electricity sold is generated in new plants no older than 6 years; and another third in plants no older than 12 years.

The other sustainability criteria outlined in chapter 3.1.1, concerning the **water demand, land use and social impact**, are not covered by any of the existing standards and certification schemes identified in this study.

3.1.3.2 Standards for clean hydrogen in bilateral and multilateral cooperation

CertifHy, as the first GoO system for green and low-carbon hydrogen in Europe, could represent a starting point for an international certification scheme. If CertifHy achieves support from policy markets and market actors, it could in the future be formally adopted by the EU, possibly in collaboration with non-EU countries. Since CertifHy differentiates between green hydrogen and low-carbon hydrogen – the latter from fossil fuels with CCS/CCU or nuclear electricity – it can cover both the Japanese and the German approach to low-carbon hydrogen. This would allow both countries to focus primarily on the sort of hydrogen in line with its strategy, while remaining under the same framework, which could arguably help facilitate a future common hydrogen market.

However, in order to achieve broad acceptance in Germany, the CertifHy standards would need to undergo a detailed evaluation and to be further developed and tightened. For Germany and other countries which have chosen to phase out nuclear energy, it might not be politically acceptable to define nuclear-based hydrogen as clean, notwithstanding the globally unresolved problem of nuclear waste disposal and the risk of catastrophic accidents. Moreover, as discussed in detail in chapter 3.1.2, CertifHy presently does not consider most of the sustainability criteria identified as relevant in chapter 3.1.1. Further, the TÜV standard is stricter regarding the emission threshold and the system boundaries.

For instance, the CertifHy scheme currently requires a 60% reduction in GHG intensity compared to hydrogen production by natural gas. Bracker (2017) as well as Agora Verkehrswende et al. (2018) argue for a 70% reduction; this would also be in line with the EU-RED (while the TÜV standard goes even higher, to 75%, for hydrogen produced by electrolysis). To ensure ambitious but realistic GHG emission thresholds for green and low-carbon hydrogen, a constant monitoring of technology and market development would be necessary, with the possibility of gradual tightening of emission thresholds over time.

In addition, especially when talking about international supply chains, it might be important to also include in the system boundaries the GHG emissions resulting from the transportation of hydrogen to the point of end-usage. This is currently not the case under the CertifHy scheme. On the other hand, such a scope expansion involves a certain risk of excessively increasing the efforts for hydrogen certification.

Another important point for discussion is the additionality criterion. On one hand, as seen in chapter 3.1.1, additionality is important to avoid a mere redistribution of renewable energy across different needs and sectors. On the other hand, a too strict additionality criterion could hamper the market development of green hydrogen.

The sustainability criteria concerning water demand, land use and social impact are not presently reflected in existing standards and certification schemes. Considering that at least for green hydrogen, in the future, a substantial share might be produced in arid regions in emerging and developing countries,[25] these criteria should certainly be addressed in order to avoid potential negative impacts in production countries. One possible approach could be that a GoO additionally discloses information on water usage (i.e. water from desalination plants, water management plans implemented and monitored) and land use (i.e. monitoring and reporting requirements for land use management fulfilled). On the other hand, also including the social impact into GoO would likely pose a more complex challenge. For projects in developing countries, the requirements addressing social impacts could for example be defined as the necessity to involve local actors, additional investments and/or reduction of poverty. These requirements would have to be specified in more detail and made measurable before they can be integrated into a certification scheme.

After criteria have been determined and respective standards or certification schemes have been implemented, it is important to conduct independent monitoring, reporting and verification mechanisms in order to ensure compliance. Such a system would also provide information on the development of technology and markets necessary to steer the markets by adjusting the criteria, if necessary.

While a GoO system for clean hydrogen can lead to a shared international definition of green and clean hydrogen, and serve as evidence that the necessary criteria are met for the hydrogen production, additional government regulation and support is important to incentivize an adequate market development for green/clean hydrogen production. The investigation of the relevant framework conditions and regulations is outside the scope of this study. The results of the HyLaw project could serve as a basis for further investigation. The project was funded by FCH2 JU (supported by the EU Horizon 2020 research and innovation programme, Hydrogen Europe and Hydrogen Europe Research) and identified a range of legal and administrative barriers in the EU for the commercialisation of hydrogen and fuel

[25] See chapter 3.3 for countries with largest green and blue hydrogen potential.

cells and gives recommendations for adjustments in the EU regulatory framework (HyLaw 2018).

3.2 GHG intensities of hydrogen supply chains

3.2.1 Data

The GHG intensities for different hydrogen production methods presented in the following chapter are based predominantly on JRC (2014). The values for the selected hydrogen production paths reflect the European situation and are deemed valid for Germany, despite the higher GHG intensity of its electricity mix compared to the EU average. According to Shell (2017), this does not lead to fundamentally different conclusions. Moreover, the values in JRC (2014) fall in the same order of magnitude as existing Canadian and Japanese studies (Argonne National Laboratory 2015, Mizuho Information and Research Institute 2018). At the end of this chapter, a simplified comparison to the Japanese situation is outlined.

The JRC (2014) study contains energy and GHG balances for a variety of energy sources, as well as for different transformation, transport, storage and distribution processes. The study divides the hydrogen supply chain into five stages:

- **Production and conditioning at source**, i.e. extraction and any form of treatment and conditioning of the energy source, before transformation and/or transportation to the point of consumption;
- **Transformation at source**, e.g. power plants operation, the processes of gasification, reforming or electrolysis, liquefaction outside of the EU in case of LNG;
- **Transportation to market**, i.e. transport of the energy carrier (e.g. hydrogen, natural gas, coal) from the point of production or extraction to hubs in the country of consumption in the EU) via shipping, pipelines;
- **Transformation near market,** i.e. the same as “transformation at source”, in case it happens in the country of consumption;
- **Hydrogen conditioning and distribution**, i.e. compression and transport of hydrogen to from the hubs or points of transformation to the individual refuelling points.

3.2.2 Results

Figure 21 shows the GHG intensities for various hydrogen supply chains. Two of the main natural gas (NG) import sources for Europe have been modelled for processes based on natural gas reforming: Western Siberia (at the distance of 7000 km) and South-West Asia (at the distance of 4000 km). For coal, domestic production and gasification near the point of extraction is assumed. On-site production means that hydrogen production takes place near to end-consumers; central production implies transportation from the production plant to the end-consumer is necessary. Average road distance necessary for the distribution for centrally produced, compressed hydrogen is assumed to be 50 km; for cryogenic hydrogen, it is assumed to be 300 km. For hydrogen entering Europe in cryogenic form by sea, road transport over the distance of 500 km from the port of entry hub to the point of consumption is assumed. For both gas reforming and electrolysis plants, the JRC (2014) assumes central plants with a capacity of 200 MW on the output side. The small-scale, distributed hydrogen plants with a capacity up to 10 MW are used to serve hydrogen refuelling stations.

According to this modelling, the GHG emissions along the hydrogen supply chain vary considerably, depending on various factors. Generally, the hydrogen production process is the most energy intensive stage, while transport, distribution and others require much less energy. Accordingly, for fossil-based hydrogen production without CCS, all stages other than production typically account for 10 to 20 percent of the overall emissions.

Processes based on natural gas reforming without CCS, liquefaction or cryo-compression (bars 1 – 4) have GHG intensities between 100 and 130 g CO_2eq/MJ, regardless of the transport distance and transport mode or whether reforming has taken place in a central plant or on-site. With liquefaction, the energy demand rises slightly (bar 5). If the source was LNG, or if hydrogen has been cryo-compressed (bars 6 - 8), the GHG intensities are slightly higher again at 125 to 140 g CO_2eq/MJ. The use of CCS reduces the GHG intensity by between 60% and 70% for natural gas-based processes (bar 9).

Coal gasification without CCS is the most GHG-intensive supply chain modelled with 237 g CO_2eq/MJ (bar 10). With CCS, the overall GHG intensity drops by more than three quarters to about 56 g CO_2eq/MJ (bar 11).

Electrolysis based on electricity generated from fossil fuels without CCS generally has higher GHG than direct transformation via reforming or gasification, due to the higher efficiency losses. The three bars (12 – 14) depicting the processes based on combined cycle gas turbine (CCGT) or EU power mix all have GHG intensities above 200 g CO_2eq/MJ.

The last five processes depicted in the chart are based on renewable energy. Farmer wood, whether directly transformed via gasification or used in a thermal power plant, results in GHG emissions between 17 and 25 g CO_2eq/MJ (bars 15 – 17). Hydrogen produced by wind power-based electrolysis achieves even lower GHG emissions at 13 g CO_2eq/MJ (bar 18).[26]

The estimated CO_2 intensity of hydrogen production via natural gas reforming is in line with data obtained by the authors of this study from Japanese sources (around 150 g CO_2eq/MJ for the entire supply chain for compressed hydrogen and around 170 g CO_2eq/MJ for liquefied hydrogen) (Mizuho Information and Research Institute 2018). For other production processes, it was not possible to obtain information about the assumptions underlying the Japanese debate. Thus, a more in-depth comparative evaluation is not possible. For the case of green hydrogen from electrolysis, Mizuho Information and Research Institute (2018) assumes wind and PV as primary sources of electricity. The estimated CO_2 intensity of transport, storage and filling at 50 – 73 g CO_2eq/MJ is somewhat higher than in JRC (2014). Here too, no further information regarding the assumptions for production processes is available.

[26] JRC (2014) altogether analyses 64 different hydrogen supply chains. In this chapter, only the most relevant ones for this study have been selected.

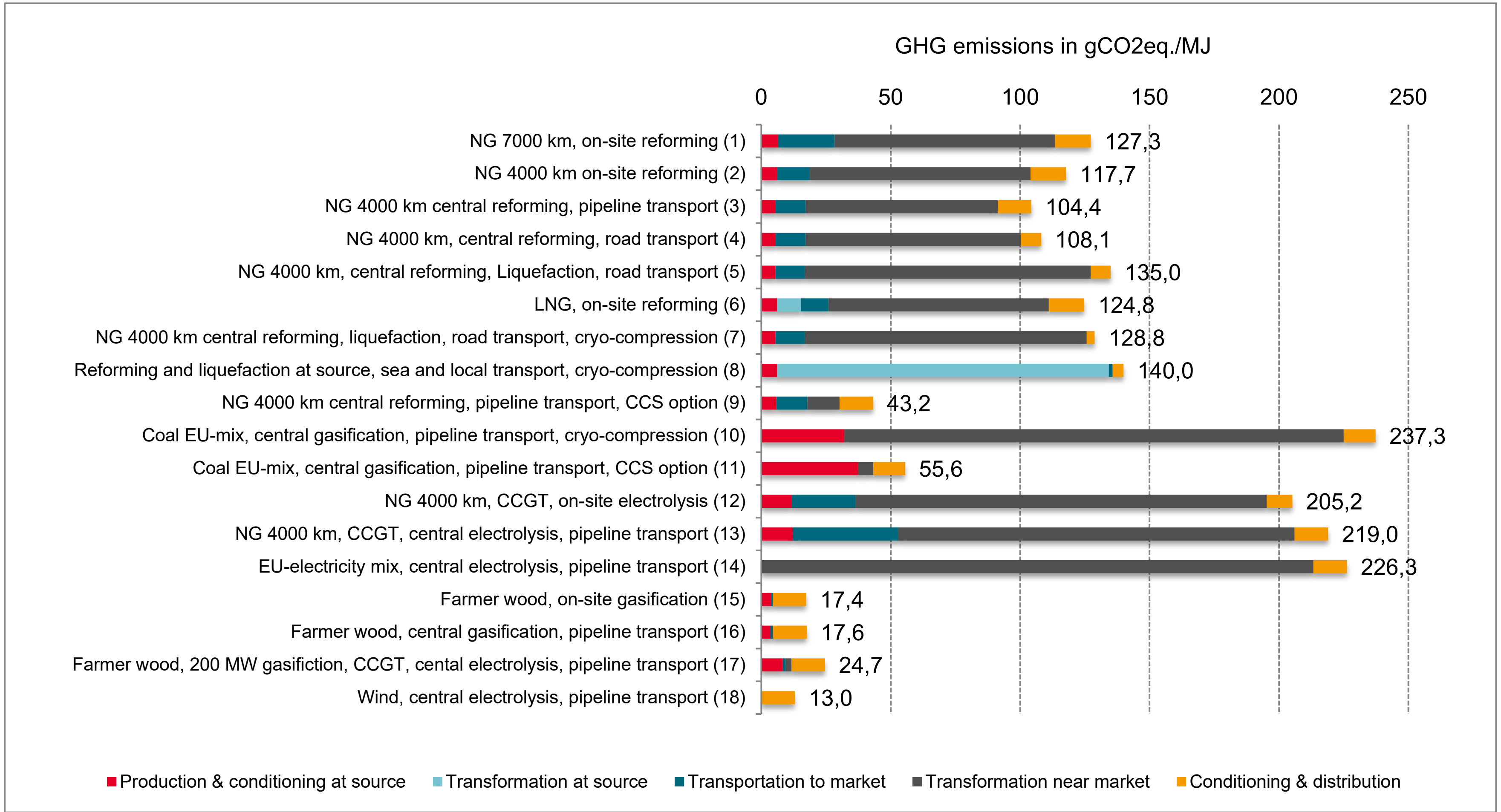

Figure 21: GHG intensities of hydrogen supply chains

Source: Own depiction based on input parameters from JRC (2014)

3.2.2.1 Hydrogen produced from fossil energy sources

Hydrogen produced from fossil fuels such as natural gas and coal without the use of CCS has roughly an order of magnitude higher overall GHG emission than hydrogen produced by electrolysis from renewable electricity or by gasification from biomass. Nevertheless, considerable differences in GHG intensities exist between different fossil energy sources if CCS is not used: hydrogen production from natural gas is about half as GHG intensive as that from coal.

For fossil fuels-based hydrogen, transforming the fossil primary energy source such as natural gas or coal is more efficient when carried out in a centralized manner in larger plants, due to better heat recovery. However, this is roughly compensated for by the lower distribution efficiency associated with central production. For the supply chains modelled by JRC (2014), central transformation is only slightly more efficient than decentralized hydrogen production. For fossil fuels-based hydrogen, production of hydrogen near the point of fossil fuels extraction and subsequent transport by sea to Europe results in slightly higher overall GHG intensity than transport of natural gas to Europe and production of hydrogen closer to the point of consumption.

For fossil fuels-based hydrogen, use of CCS can be an important factor for reducing emissions. In the supply chains modelled by the JRC (2014), it reduces the overall emissions by 60% to 70% for hydrogen produced from natural gas, and by about three quarters for hydrogen produced from coal.

Using fossil fuels to generate electricity, which in turn is used for producing grey hydrogen via electrolysis, leads to high efficiency losses along the conversion chain and to some of the highest overall GHG intensities among the modelled processes. This holds true not only for coal but also for natural gas, as well as for power mixes primarily based on fossil fuels such as those of Germany and Japan. Production of grey hydrogen (without the use of CCS on the power production process) thus cannot be considered a viable option for GHG emissions reductions.

Regardless of the energy source for hydrogen production, liquefaction is an energy intensive process, generally leading to slightly higher overall GHG intensities.

3.2.2.2 Hydrogen produced from renewable energy sources

When hydrogen is derived from biomass via gasification, the resulting life cycle emissions remain below one fifth of those resulting from natural gas transforming. Central and decentralized production has roughly the same emissions for biomass gasification.

Production of hydrogen via electrolysis based on renewable power (in this case, wind) exhibits the lowest GHG intensities among the modelled processes. Green hydrogen from renewable-based electrolysis has about a third of GHG intensity of hydrogen produced from natural gas or coal even with the use of CCS, and slightly below that of hydrogen derived from biomass.

3.3 Identification of potential hydrogen supplier countries

This chapter provides an analysis of potential clean hydrogen supplying countries, differentiating between green hydrogen (based on renewables) and blue hydrogen (based on fossil fuels with CCS).

3.3.1 Methodology

Of all the countries in the world, the following have been omitted from the analysis: sovereign states with less than 300.000 inhabitants, city-states and territories. Next, countries in the bottom decile of the distribution (including missing values) for political stability according to (World Bank 2018a) have been excluded, as they are unlikely to offer favourable conditions for capital intensive investments in new technology. After applying these filters 127 countries remain in the dataset.

As a next step, the green and blue hydrogen production potentials of each country have been assessed. The approaches are described in detail in the corresponding chapters. The results, in absolute terms of these potential assessments, have then been normalised to the value of the first-ranking country on a scale from 0 to 1, where 0 indicates the weakest and 1 the strongest value, in terms of clean hydrogen production potential. In other words, the first-ranked country for each indicator always has a value of 1, the others are presented in relation to it. The charts show the 20 countries with the highest indicators.

Finally, the countries with the highest indicators have been clustered under consideration of the country-specific contexts, based on existing literature[27] and own research. However, there still remains a need for a more detailed consideration of the country-specific context, as many relevant restrictions have not been considered in this approach. The outcome of this chapter should therefore be used for orientation and not as a definitive list of the most likely clean hydrogen producers and/or exporters.

3.3.1.1 Suppliers of green hydrogen: The prodigies

This section identifies countries with favourable conditions for the production of green, renewables-based hydrogen, named the prodigies. As shown in previous analyses such as those from Fasihi et al. (2017) and dena (2017), PV-wind hybrid plants generally represent the best option to provide green hydrogen and/or synthetic fuels at competitive costs. Previous analyses such as Pfennig et al. (2017) and Frontier Economics (2018) have already identified regions that offer favourable conditions for green hydrogen production.

The present document identifies the most favourable regions for green hydrogen production on the basis of extensive modelling carried out by the Lappeenranta University of Technology (LUT). The LUT modelled the costs of baseload green hydrogen supply for each chapter of the earth's surface at a resolution of 0.45° latitude by 0.45° longitude, roughly corresponding to an area of 50 km by 50 km on equator. The modelled hydrogen production system consists of a hybrid wind/PV power supply, an electric battery and an electrolyser. To reduce complexity, the model only considers island systems not connected to the power grid. The model assumes hydrogen storage in salt caverns. However, their availability at the exact locations with the best hydrogen production potentials has however not been verified. The

[27] E.g. Frontier Economics (2018), Singh et al. (2005) and Drennen et al. (2014).

capacities of all components are optimised for lowest hydrogen production cost at the specific site under these conditions. The assumed capex and opex levels for all system components take into account the effect of learning rates between now and 2030, a time when most scenarios for Germany and Japan assume hydrogen demand starts increasing considerably (chapter 2). The model assumes a weighted average cost of capital (WACC) of 7% all over the world. The model does not consider costs and restrictions related to land use, nor the costs for transporting the green hydrogen for the production site to the final users. Further information on the input parameters can also be found in Ram et al. 2018).[28]

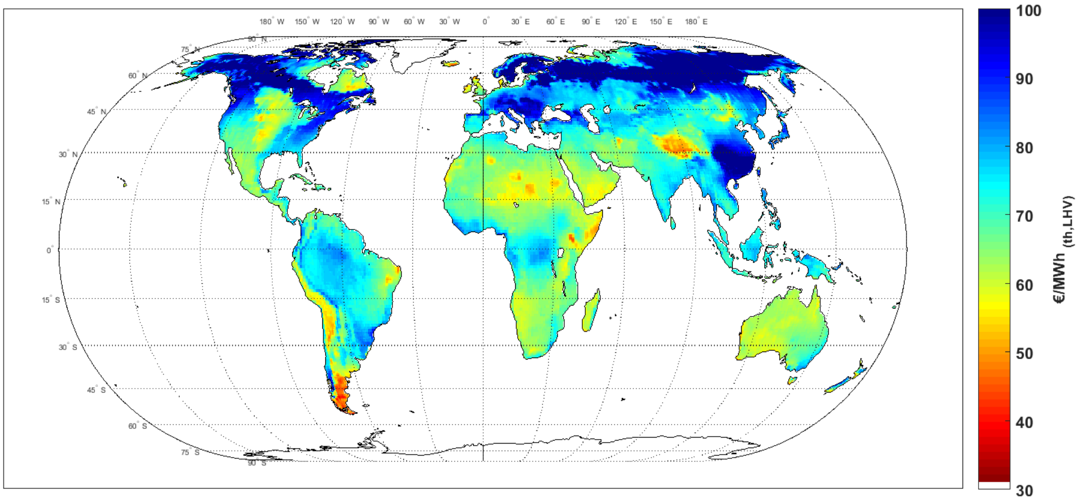

Figure 22: Levelised cost of on-site green hydrogen production
Source: LUT modelling done for this study

The outcomes of the LUT-model can help identify regions and countries with the most favourable conditions for green hydrogen production (Figure 22). In a medium term perspective (until 2030), it can be assumed that the global green hydrogen market will have a relatively modest volume. Therefore, hydrogen production cost, rather than the total production potential, will play a central role. Figure 23 visualises the ranking of the 20 countries (except those excluded, see above) with the lowest levelised cost of green hydrogen production. The data refers respectively to the region (see above) with the lowest cost level in each country. The lowest cost is modelled in Chile (3.04 EUR cent/kWh), followed by Argentina (3.21 EUR cent/kWh); Egypt, ranking 20th, features a production cost of 4.43 EUR cent/kWh.

[28] Geothermal and hydropower have not been considered. Further, factors such as distance of hydrogen production sites from the existing transport infrastructure, feasibility and costs of building the necessary transport infrastructure where none exists, population density, (desalinated) water availability, terrain topography, ground composition, vegetation, land use, land prices, public acceptance for renewable energy infrastructure and own demand for renewable power or clean hydrogen have not been considered at this step.

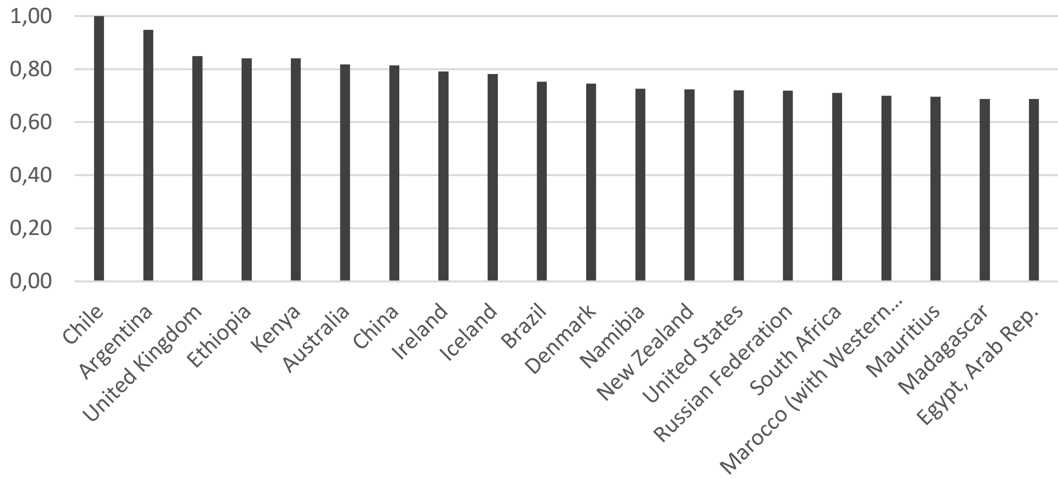

Figure 23: Countries with lowest levelised cost of green hydrogen production
Source: Own depiction based on LUT modelling

In a longer term perspective (until 2050), energy importers such as Germany and Japan will probably require large amounts of green hydrogen (and/or other synthetic fuels) in order to decarbonise their energy systems. In this timeframe, the volume of a country's green hydrogen production potential at an acceptable cost level becomes relevant. What cost level is deemed acceptable depends on many factors, including the cost of the energy carriers that green hydrogen can replace, and the implicit or explicit, politically determined cost of greenhouse gas emissions.

Currently, the US Department of Energy's cost target for distributed hydrogen production is \$2.30/kg (~ 2.1 EUR/kg) in 2020 (DOE 2019), while METI targets \$3/kg (~ 2.7 EUR/kg) in 2030 (METI 2017). The more ambitious of the two, the DoE target, corresponds to around 6 EUR cent/kWh at lower heating value. Below, the land area which offers the technical potential for green hydrogen production at 6 EUR cent/kWh or lower is used as a proxy to determine a country's production potential at this cost level.

Figure 24 shows the 20 countries with the largest land area fulfilling this criterion. Among the 104 countries able to produce green hydrogen at this cost level, the area itself varies considerably. Australia, ranking 1st, can technically produce green hydrogen at this cost level on just over 7 Mio. square kilometres, or around 90% of its entire surface; the United States with its vast wind potential on great plains ranks second with over 3.8 Mio square kilometres. Nigeria on place 20 technically has over 700,000 square kilometres with a hydrogen production potential at 6 EUR cent/kWh.

Of course, the area that any given country will realistically dedicate to green hydrogen production is further strongly limited by factors such as distance of hydrogen production sites from the existing transport infrastructure, feasibility and costs of building the necessary transport infrastructure where none exists, population density, (desalinated) water availability, terrain topography, ground composition, vegetation, land use, land prices, public acceptance for renewable energy infrastructure and own demand for renewable power or clean hydrogen. Considering these factors would require in-depth analysis of local conditions, which was not possible within the constraints of this analysis. However, it seems reasonable to assume that a positive correlation exists between the size of the land area where green hydrogen can be produced at competitive cost and the actual production potential.

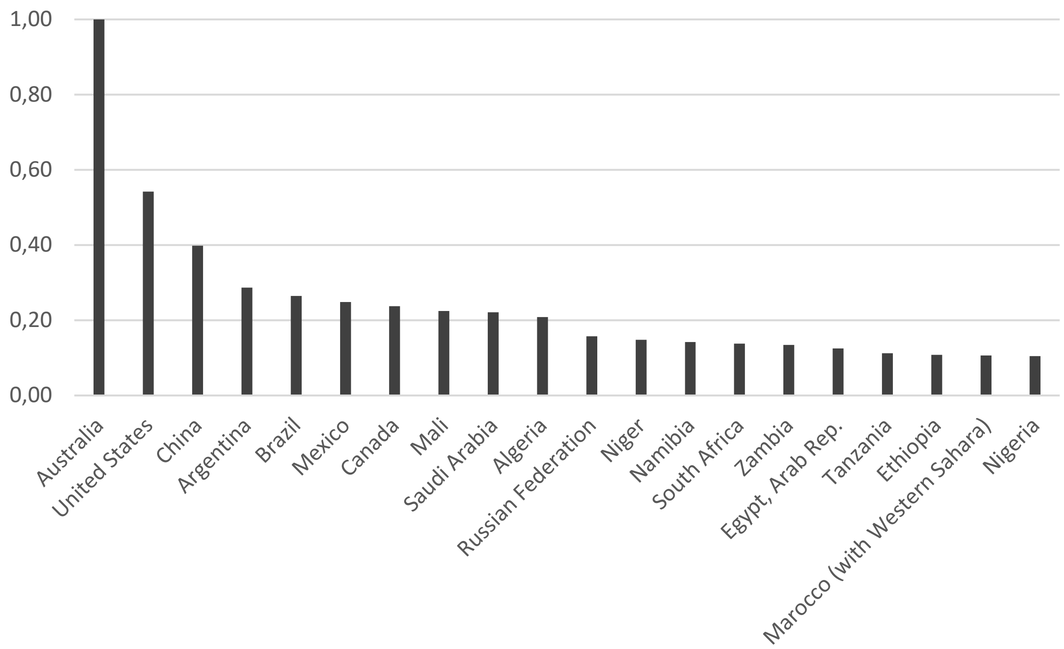

Figure 24: Countries by land area technically allowing green hydrogen production at 0.06 EUR/kWh

Source: Own depiction based on LUT modelling

Figure 25 merges the two sets of countries shown in the two previous figures – the top 20 with the regions with lowest production costs and the top 20 with the largest cost competitive production potential. 10 countries have been identified which belong to the top 20 for *both* criteria: Argentina, Australia, Brazil, China, Egypt, Morocco, Namibia, Russia, South Africa and the United States.[29]

[29] Morocco and Western Sahara were modelled both as separate entities and as one. Separately, only Western Sahara appears among the top 20 in terms of lowest cost while Morocco without the disputed area does not, and none of the entities separately appears in the top 20 by area where hydrogen production under 6 EUR cent/kWh is possible. By choosing this modelling approach, the study authors intended to avoid the impression of assuming a political position on this territorial dispute, either on their own behalf or on the behalf of the commissioning institutions.

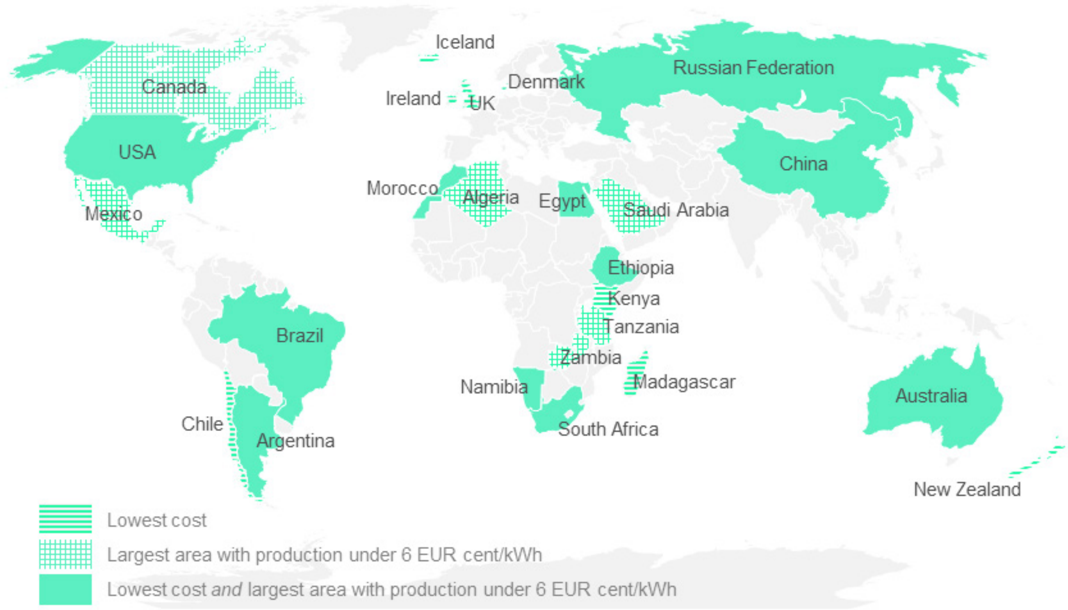

Figure 25: Potential green hydrogen producers
Source: Own depiction based on LUT modelling

By and large, the result is a selection similar to that already identified by previous studies. For example, all but six of the 23 countries identified in Frontier Economics (2018) as high potential PtX producers also show up in the current analysis. However, some discrepancies exist. Our selection of the top 20 countries for green hydrogen production does not include Oman (ranking 30th in lowest cost and 35th in area where production under 6 EUR cent/kWh is technically possible), Qatar (49th and 68th), United Arab Emirates (47th and 40th), Spain (48th and 65th), Kazakhstan (90th and 41st) and Norway (22nd and 56th). One reason for the discrepancies is that the model used in the present study only looks at wind and solar resources, and does not consider hydropower and geothermal energy as an additional basis for green hydrogen electrolysis. This lowers the ranking of countries such as Canada, Iceland and Norway. Further factors pertaining to each country's specific context are likely to further influence the outcomes. The absence of a country in our list of the top 20 producers does not automatically imply that it should not be considered as a potential green hydrogen supplier.

The LUT-model used in this study also identifies some countries in addition to those mentioned in Frontier Economics (2018). Among the top 20 countries in terms of lowest cost, a few Northern European countries rank very high, mainly due to good wind potential, with the UK ranking 3rd, Ireland ranking 8th, Denmark ranking 11th and New Zealand ranking 13th. However, at least for onshore wind, although the land use restrictions in these countries are likely to be substantial, all are assumed to have a substantial future domestic demand for green hydrogen and renewable power. Among the top 20 countries by area, Tanzania and Ethiopia rank 17th and 18th, respectively and exhibit good technical green hydrogen production potentials. Besides the parameters considered in the model, they also are relatively stable countries with relatively low population densities. Tanzania has access to sea, while Ethiopia is landlocked, which complicates both access to fresh water and the export route. Another interesting candidate is Zambia, ranking 15th, with relative political stability and comparatively low population density, but also a landlocked country.

On the other hand, the model also identifies some countries which seem like less viable candidates when context is taken into account. For example, Mauritius ranks 17th in terms of lowest cost thanks to its good wind and solar potential, but is a very small and densely populated country. In Mali, ranking 8th by land area available for production under 6 EUR cent/kWh, most of the favourable green hydrogen production locations are located on sand dunes – as Frontier Economics (2018) already notes, such terrain is not suitable for the necessary infrastructure. The same also partly holds for Niger in 12th place. Apart from that, both countries are landlocked and suffer from water scarcity and relatively low political stability. Political stability and high population density might also be problematic for Nigeria, which otherwise has relatively favourable conditions in terms of wind and solar resources and access to sea.

Of course, not all countries identified as having the potential to produce green hydrogen at competitive cost will necessarily be able and willing to export it. For one, they might not possess the necessary infrastructure or they may lie at prohibitively long distance from hydrogen demand. Another likely constraint is the countries' own demand for affordable carbon-neutral fuels. The model used in this study does not take into account domestic and international energy markets. In principle, however, it is presumably safe to assume that countries with large, sparsely populated areas and outstanding renewable resources, such as Australia, Saudi Arabia, Argentina, Morocco or Namibia are much more likely to produce green hydrogen quantities exceeding their own demand than some of the largest energy consumers such as United States, the UK, China or Mexico. Countries such as Canada, Norway, Iceland, Brazil, Morocco, South Africa and Egypt fall somewhere in between as their economic situations and climate policy ambitions might dictate the use of the green hydrogen they produce.

In lower income countries, the revenues from green hydrogen exports might help in financing domestic climate mitigation investments. However, there also is a risk that green hydrogen production sites are created only for export purposes, while the domestic energy supply remains highly GHG intensive. If the renewable generation resources are limited, the production of green hydrogen for export might de facto limit the exporting country capacity of decarbonising its own energy consumption. In this case, the overall climate benefit of the green hydrogen exports would be doubtful.

3.3.1.2 Suppliers of blue hydrogen: The shifters

This chapter identifies the shifters, i.e. countries with large fossil resources which could be used to produce low-carbon blue hydrogen by applying CCS. In this way, these countries would adapt to the growing demand for low carbon fuels.

As discussed more in detail in chapter 1.4.1, in the foreseeable future CCS deployment on German soil is unlikely, due to strong political opposition. However, the acceptance level in other countries might be sufficiently high and Germany might be open to imports of blue hydrogen, so long as it replaces more carbon intensive fossil fuels.

This chapter estimates the technical potential for blue hydrogen production. The analysis compares the volume of grey hydrogen that a country would be able to produce, based on data on proven reserves of natural gas, coal and oil as the source of flaring gas (BP 2018). This data is then compared to the country's carbon storage potential according to the Global CCS Institute (Global CCS Institute 2018). On this basis, Figure 26 below shows the 20 countries with the highest technical blue hydrogen production potential. The United States ranks first with its massive CCS resources, estimated at upwards of 2.300 Gt. Combined with its proven fossil fuels reserves, this gives it a total technical potential of upwards of 14 billion tonnes of blue hydrogen. The other countries are presented in relation to the US. China which ranks on the second place has a potential of just below 8 billion tonnes of blue hydrogen.

It must be noted that the absolute figures are rough estimates, based on the lower end of the range of the Global CCS Institute's country CCS potential estimations. First, the estimates of CO_2 quantities that have to be injected via CCS are based on simplified models for the various fossil energy sources (coal, natural gas and flaring gas). Second, there can be a number of restrictions to the full usage of a country's the carbon storage potential for the purpose of blue hydrogen production. Among others, the limiting factors can be public acceptance, environmental protection (due to potential impact on the chemical composition of the soil), as well as competing uses for the limited reservoir sites. Third, the carbon storage potential estimated by the CCS institute includes a significant share of enhanced oil and gas recovery (EOGR) sites, where the CO_2 injection is used to extract more oil or gas out of partly depleted oil and gas reservoirs. In a decarbonisation perspective, oil and natural gas extraction should be reduced as rapidly and strongly as possible (and partly replaced by clean hydrogen). It is therefore doubtful whether CO_2 injection for EOGR purposes is compatible with scenarios with high demand for clean hydrogen

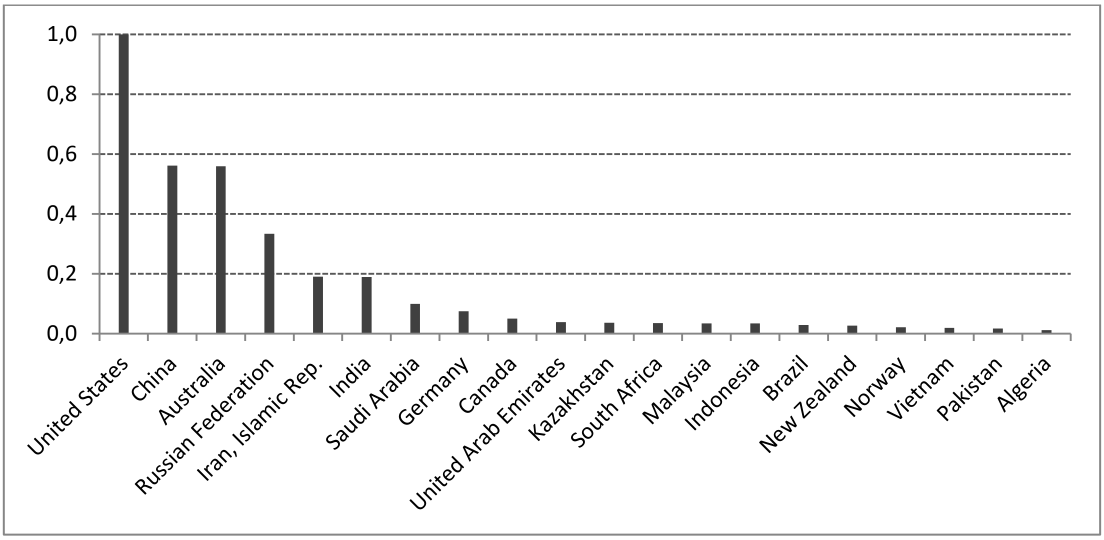

Figure 26: Countries by blue hydrogen potential
Source: Own depiction

The Global CCS Institute provides an indicator which also takes into account the maturity of carbon storage potential assessment as well as the progress with deployment of CO_2 injection sites (Figure 27) (Global CCS Institute 2019a). Canada, ranking first, was awarded 71 points out of the maximum of 100. Figure 27 shows the other countries in relation to Canada; the United States ranks 2 with 70 points. The selection of countries with the highest indicator roughly corresponds to the countries with large CCS projects already in operation or under construction; all of the top 10 countries except Germany, Denmark and Japan have at least one such project. USA, Canada and Norway are also the countries which have so far injected and stored the largest quantities of CO_2 in absolute terms (Global CCS Institute 2017).

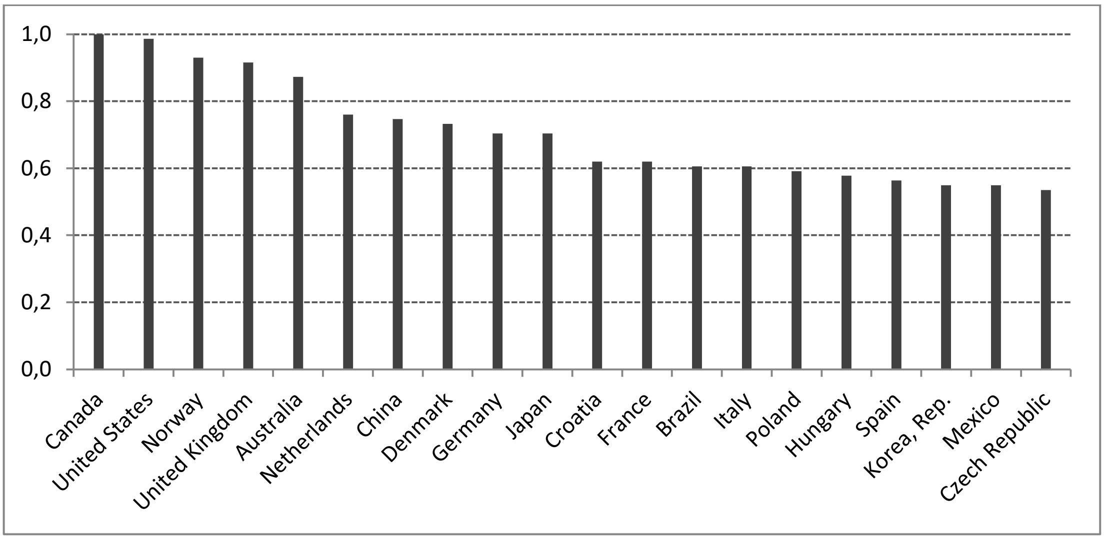

Figure 27: Countries by CCS readiness indicator
Source: Own depiction

Among these countries, seven appear in the top 20 for *both*, the absolute blue hydrogen potential and the CCS readiness indicator: Australia, Brazil, Canada, China, Germany, Norway and United States. 13 countries have a large CCS potential but a lower readiness factor: Algeria, India, Indonesia, Iran, Kazakhstan, Malaysia, New Zealand, Pakistan, Russia, Saudi Arabia, South Africa, UAE and Vietnam. Another 13 countries have a high readiness factor but their CCS potential is too low to be included in the top 20: Croatia, the Czech Republic, Denmark, France, Hungary, Italy, Japan, Mexico, Netherlands, Poland, South Korea, Spain and United Kingdom. Figure 28 depicts the potential blue hydrogen producing countries.

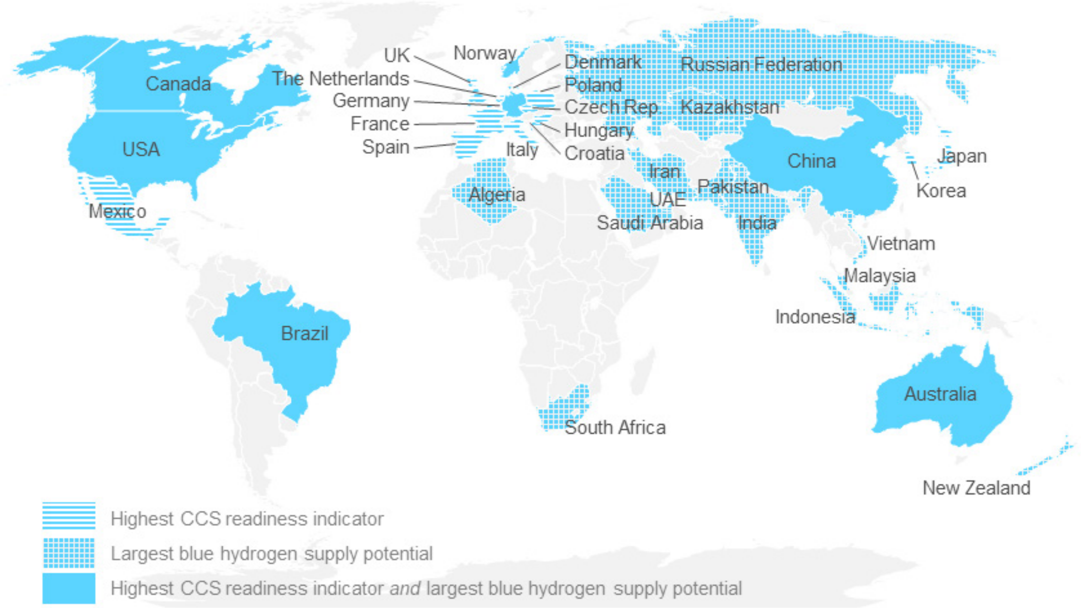

Figure 28: Potential blue hydrogen producers
Source: Own depiction

Not surprisingly, the 20 countries with the largest blue hydrogen potential also belong to the group of largest producers of fossil fuels. Together, they accounted for more than 55% of global oil production, more than 65% of natural gas and more than 90% of coal in 2017 (BP 2018). However, most of them have so far not gathered substantial experience with CCS. Nevertheless, those that did – Australia, Brazil, Canada, China, Germany, Norway and United States – still account for the production of more than 15% of the world's oil, more than 35% of natural gas, and more than 65% of coal in 2017. If these countries scale up blue hydrogen production, they could produce significant quantities.

Many European countries have a high CCS readiness indicator, but a low blue hydrogen supply potential, due to their limited reserves of fossil energy sources. Nearly all of them are also heavily reliant on energy imports. Depending on climate ambitions and domestic acceptance for CCS, it cannot be excluded that at least some European countries will store the CO_2 captured from imported energy carriers.

Further factors that might influence which countries become blue hydrogen producers and perhaps exporters include: the development of domestic demand and of technology costs; for example, the relative costs of blue hydrogen production via the natural gas SMR vs. coal gasification might favour blue hydrogen production in countries with strong gas or oil resources.

3.3.2 Results

Potential green and blue hydrogen producers were already analysed separately in chapters 3.3.1.1 and 3.3.1.2, respectively. Some distinct patterns emerge when they are compared to one another, as well as with countries with potential demand for clean hydrogen.

Table 17: Potential green and blue hydrogen producers

	Green hydrogen		*Blue hydrogen*	
	Lowest cost	*Volume*	*Readiness*	*Volume*
Algeria		X		X
Argentina	X	X		
Australia	X	X	X	X
Brazil	X	X	X	X
Canada		X	X	X
Chile	X			
China	X	X	X	X
Croatia			X	
Czech Republic			X	
Denmark	X		X	
Egypt	X	X		
Ethiopia	X	X		
France			X	
Germany			X	X
Hungary			X	
Iceland	X			
India				X
Indonesia				X
Iran, Islamic Rep.				X
Ireland	X			
Italy			X	
Japan			X	
Kazakhstan				X
Kenya	X			
Korea, Rep.			X	
Madagascar	X			
Malaysia				X
Morocco (with Western Sahara)	X	X		
Mexico		X	X	
Namibia	X	X		
Netherlands			X	
New Zealand	X			X
Norway			X	X
Pakistan				X
Poland			X	
Russian Federation	X	X		X
Saudi Arabia		X		X
South Africa	X	X		X

Spain			X	
Tanzania		X		
United Arab Emirates				X
United Kingdom	X		X	
United States	X	X	X	X
Vietnam				X
Zambia		X		

Source: Own compilation

Australia, Brazil, China and USA belong to the top 20 for both green and blue hydrogen, in *all four* supply-side indicators analysed in this study (Table 17). These four countries have exceptional wind and solar potentials across large land areas, and already are deploying substantial capacities of wind and solar power generation. They are potential early producers for *both* green hydrogen (due to low production costs) and blue hydrogen (due to high CCS readiness).[30] They are additionally incentivised to develop production capacities since they are in position to eventually produce large quantities of both green and blue hydrogen, should the demand materialise, and are upper middle to high income economies able to afford the necessary investments. This line of argumentation holds true regardless of whether these countries would consume the hydrogen themselves or export it.

Canada, Mexico, and Norway might also strive for a similar transition based on their high CCS readiness and good green hydrogen potential. Algeria, Egypt, the Russian Federation and Saudi Arabia, despite not being in pole positions in terms of CCS readiness, also have the wind and/or solar potentials necessary to provide large quantities of green hydrogen in the future, are established energy suppliers and are strongly incentivised to secure future financial flows from energy exports.

The crucial difference among the seven countries from the above paragraph might be the willingness and ability to take on the additional costs and risks associated with transitioning from conventional energy exports to clean hydrogen. As already mentioned in chapter 3.3.1.1, the importing countries might not provide the necessary economic incentive if they decide to continue to import energy in the same form as today and conduct CCS on the domestic soil (this argument holds especially true for countries exporting natural gas to Europe, such as Norway, Algeria and Russian Federation). This would on the one hand enable the exporting countries to keep to their existing business model, but it would also preclude them from gaining valuable experience with hydrogen transport and storage technologies. Of course, the current exporters with good green hydrogen potential might also decide to pursue both paths simultaneously where they continue with their fossil fuels-based business models, and simultaneously start investing in the green hydrogen production (assuming they are in the position to afford it).

The second cluster is comprised of countries with large CCS potential (and perhaps even a good CCS readiness indicator) but without the top prospects of becoming leading green hydrogen producers, based on data for green hydrogen production cost and quantities. The data suggests that such countries are India, Indonesia, Kazakhstan, Iran, Malaysia, Vietnam and United Arab Emirates. It has to be noted that further factors might nevertheless justify for a country to consider investing in green hydrogen. UAE, ranking 47th in the world in terms of lowest green hydrogen production costs and 40th in terms of area where it can be produced

[30] Australia seems to be following this strategy, as it is currently developing both lignite-based blue hydrogen (HySTRA project, chapter 1.5.3) as well as electrolysis (e.g. Port Lincoln 15 MW electrolyser plant).

at under 6 EUR cent/kWh according to the modelling, might see their competitive advantage in their established energy market position, access to large investment capital, building of competencies along the entire hydrogen value chain, and first-mover advantage. This may very well prove enough for it to establish itself as a green hydrogen leader, and also stresses the necessity of extensively considering each country's specific context before passing the judgement.

A third group of countries are those with limited or no CCS potential but exceptional green hydrogen production potential: Argentina, Chile, Ethiopia, Denmark, Iceland, Kenya, Madagascar, Morocco, Namibia, South Africa, Tanzania, UK and Zambia. These countries are however, very diverse in terms of size, population density,[31] climate ambition, as well as in terms of income per capita[32], making it hard to find a universal characterisation. Three nations stand out in *both*, lowest green hydrogen production cost and the area for green hydrogen production under 6 EUR cent/kWh, and have been the proverbial frontrunners for becoming green hydrogen champions: Argentina, Namibia and South Africa. These are all large countries with low to moderate population densities and higher middle to high income per capita, making them exceptionally well suited for deploying the massive infrastructure needed for producing large quantities of green hydrogen which could potentially exceed their domestic demand. Another country often mentioned as a potential green hydrogen powerhouse is Morocco, a lower middle income country with population density closer to that of the European countries, but with geographical closeness and strong economic ties to Europe, as already noted in Frontier Economics (2018).

Further candidates include the northern European countries Iceland, UK, Ireland and Denmark which all turn up among the top 20 countries in terms of lowest green hydrogen production costs in our model. However, their production quantities are limited – combined, the area where they can produce green hydrogen below 6 EUR cent/kWh is smaller than that of Morocco alone. Iceland, Ireland and Denmark also have ambitious climate protections targets which might additionally incentivise domestic green hydrogen production and consumption.

Among the African countries, Ethiopia stands out in both lowest cost and potential volume of green hydrogen production, but doesn't have an exceptionally low population density and is landlocked. Kenya and Madagascar are able to achieve very low green hydrogen production costs, and Tanzania and Zambia have large production potentials. These are, however, all low to lower middle income countries which are more likely to experience difficulties financing the necessary infrastructure. They also lie at greater geographical distances from the potential early consumption centres in Europe or Eastern Asia.

Aside from these three groups, there are countries which are hard to characterise based on their green and blue hydrogen potentials and other parameters; the roles they assume in the international clean hydrogen trade (if any) will likely depend on the specific priorities set by their individual energy strategies.

[31] Argentina, Chile, Namibia, Iceland and Zambia have low population densities (< 25 /km^2); Ireland, Morocco, South Africa, Ethiopia, Kenya, Madagascar and Tanzania have moderate population densities (< 100 /km^2); Denmark and UK have population densities exceeding 100 /km^2. Data from The World Bank (2019a)

[32] Argentina, Chile, Iceland, Ireland, Denmark and UK are high income countries; Namibia and South Africa are higher middle income countries; Kenya, Morocco and Zambia are lower middle income countries; Ethiopia, Madagascar and Tanzania are low income countries. Data from The World Bank (2019b)

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