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WORKING PAPER

HySupply

A Meta-Analysis towards a German-Australian Supply-Chain for Renewable Hydrogen

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Disclaimer

This analysis is not an official publication of acatech and BDI. It presents preliminary results of the first phase of the German HySupply project group in the form of a working paper.

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About HySupply

Germany and Australia have intended to jointly fund a feasibility study to investigate the Australian-German supply chain involving the production, storage, transport and use of hydrogen and hydrogen-based energy carriers, produced from renewables. The study will identify ways to determine and overcome barriers and foster the development of an Australian-German renewable hydrogen supply chain.

For Germany the project is run by acatech – the National Academy of Science and Engineering – in cooperation with the Federation of German Industries (BDI) and funded by the Federal Ministry of Education and Research (BMBF). The Australian partners are a university–industry consortium led by the University of New South Wales (UNSW), with funding from the Department of Foreign Affairs and Trade (DFAT) and the Department of Industry, Science, Energy and Resources (DISER).

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Executive Summary

Delivering on the promise of renewable hydrogen requires strong alliances between academia and industry as well as international partnerships between countries. Together, Australia and Germany are well positioned to enable critical innovation, mobilise substantial human and financial capital, and leverage years of mutually beneficial trade and cooperation. HySupply unites leading partners from academia and industry to investigate the feasibility of importing renewable hydrogen and hydrogen-based energy carriers from Australia to Germany. Through this analysis the German project group takes a first step towards the German-Australian supply chain for renewable hydrogen. A state-of-play of Australia's hydrogen capability by the Australian project group complements this analysis.

The window of opportunity and time for action on renewable hydrogen is now. Germany's recently implemented target of climate neutrality by 2045 requires deep emission reductions in all sectors. Considering the short time frame for the transition, significant reductions are already necessary by 2030. Green molecules in the form of hydrogen and hydrogen-based energy carriers will play a key role in achieving these targets. They complement the ongoing expansion of renewable electricity, providing opportunities to defossilise the hard-to-abate sectors such as steel making, parts of the chemical industry, and refineries. However, due to Germany's limited potential for renewable energy generation, imports from regions with more favourable conditions will be vital.

These imports could in part be provided by Australia with its high average annual solar radiation and thousands of kilometres of windy coastline. Furthermore, Australia's technical renewable energy generation potential is considerably higher than its current total primary energy consumption. As one of the world's largest fossil fuel and raw material exporters, the country is also well positioned for future renewable energy exports. Due to a combination of existing bilateral trade relations and shared values, Australia is a cooperation partner of choice for Germany. However, the distance between Australia and Germany is significant, especially compared to other potential exporters of renewable hydrogen. Therefore, this analysis addresses the missing link between the two countries: transporting hydrogen and hydrogen-based energy carriers.

Liquid hydrogen (LH_2), liquid organic hydrogen carriers (LOHC), ammonia (NH_3), and methanol (MeOH) are examined as potential import options, focusing on the necessary elements for the seaborne transport of hydrogen, including conversion, storage, shipping, and reconversion. To understand the transport options and their potential to be available at scale in 2030, quantitative key performance indicators as well as qualitative indicators are considered individually for the necessary elements and each energy carrier respectively. The results show that the transport options come with different advantages and disadvantages, and especially different technological readiness levels. However, all have in common that the distance will not be a showstopper since the provision of cost competitive feedstocks is decisive. Moreover, a range of cross-cutting challenges are identified, including the intermittency of renewable electricity, infrastructure integration, shipping emissions, regulatory uncertainties as well as the uncertainties regarding the future of industrial value chains. Overcoming these challenges can kick-start the Australia-Germany hydrogen bridge.

To secure a strong and long-term partnership between the two countries, the future hydrogen partnership should be based on reliable framework conditions, equal opportunities, and shared responsibilities to fully realise the potential of both partners. Moving forward, the second phase of HySupply will address the identified key challenges, provide deeper analysis of the transport options, and formulate a roadmap to 2030

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1 Aim of the analysis

Green molecules in the form of renewable hydrogen and hydrogen-based energy carriers[1] will play a key role in realising the energy transition and achieving climate neutrality by 2045. They complement the ongoing expansion of renewable electricity, providing opportunities to defossilise the hard-to-abate sectors such as steel making, parts of the chemical industry, and refineries. International partnerships and supply chains that can facilitate large volumes at competitive costs are critical, now more than ever.

Importing Australia's abundant renewable energy potential by 'shipping the sunshine' is a promising opportunity to meet parts of the future demand for renewable molecules in Germany. However, since this has never been done before at scale and on a global level, a wide range of uncertainties, barriers, and unknowns remain that need to be identified and addressed.

The aim of this preliminary analysis is to take a first step towards a German-Australian supply chain for renewable hydrogen by:

- Screening the respective potential of both countries to become a future partner on hydrogen,
- Understanding the state-of-play of transport options for the import of renewable molecules,
- Identifying cross-cutting gaps and barriers of the transport options, and
- Envisioning the future German-Australian hydrogen partnership.

In accordance with the overall aim of HySupply, the premise of this preliminary analysis is to address transport options that are potentially available at scale by 2030.

The results of this analysis are based on literature reviews as well as expert discussions within the German project group. They are indicative and merit for further analysis.

[1] Hydrogen-based energy carriers are downstream products that can be produced from renewable hydrogen. These processes are referred to as Power-to-X (PtX) in this analysis. Electrical energy (power) is converted into a hydrogen-based energy carrier "X" (e.g. ammonia and methanol).

2 Germany's Emerging Hydrogen Economy

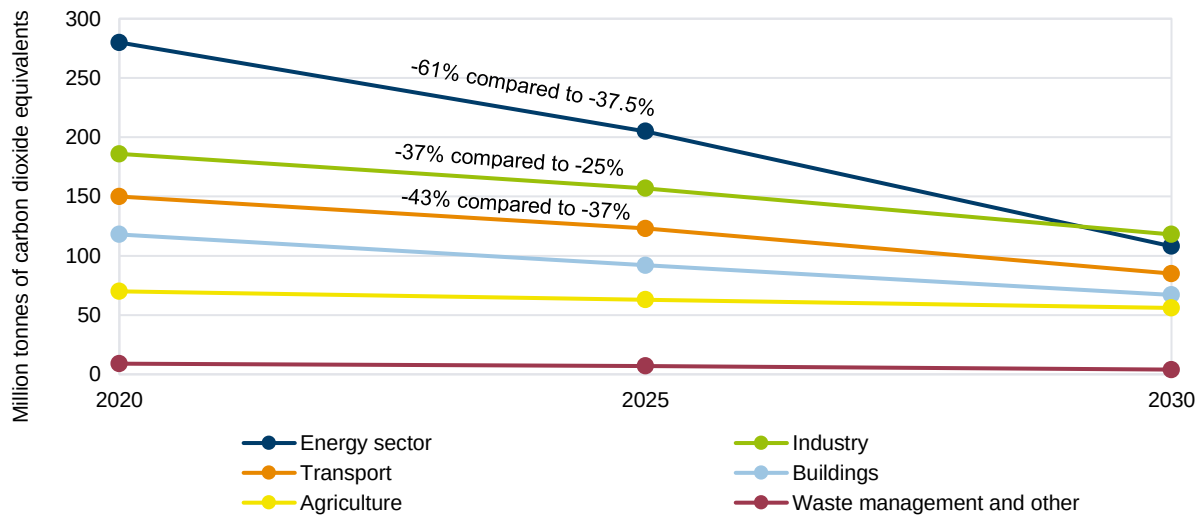
In 2020, hydrogen gained momentum as a key topic related to the defossilisation of the energy system when the European Union as well as several national governments, including Germany, published their own hydrogen strategies. Achieving deep emission reductions has been a major driver of the emergence of Germany's hydrogen economy. Future demand for hydrogen and other Power-to-X (PtX) products produced from renewables will be significant and domestic production potential in Germany is limited. Therefore, Germany will depend on imports of renewable molecules. At the same time, Germany is in a good position to establish itself as a leading provider of hydrogen technologies as well as further synthesis processes such as ammonia or methanol production.

2.1 The need for drastic emission reductions

Germany submitted its long-term low greenhouse gas (GHG) emission development strategy in accordance with the Paris Agreement in November 2016, known as the *Klimaschutzplan* (climate action plan) 2050. This strategy formulated targets for GHG emission reductions of 55% by 2030, including specific sectoral targets, and of 80 to 95% by 2050. The Climate Change Act which came into force at the end of 2019 then legislated the previously formulated climate target for 2030 and made the sectoral targets legally binding.

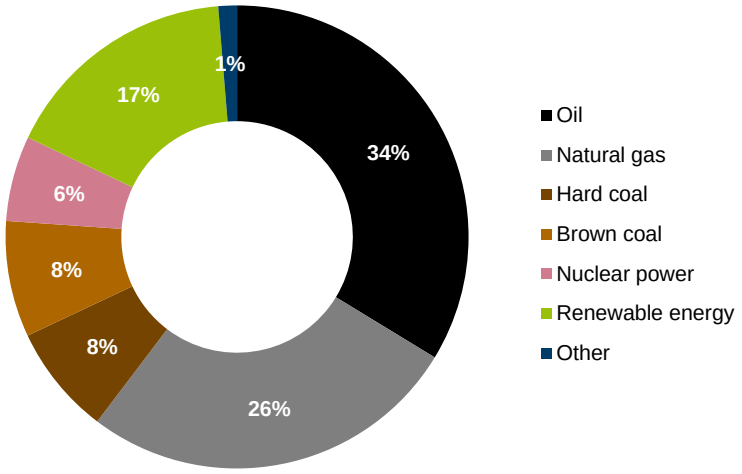
At the beginning of 2020, the European Commission proposed to legislate the target of climate neutrality by 2050 as part of the European Green Deal, which considerably tightened Germany's previous ambitions. Yet, in June 2021, the German Government passed an amendment of its Climate Change Act as an "intergenerational contract for the climate" which enshrined in law the target of achieving climate neutrality already by 2045. More specially, the amendment requires a reduction of GHG emissions of 65% by 2030 (compared to the previous 55%) and of 88% by 2040 compared to the 1990 levels respectively. Thereby, it also significantly narrowed the annual reduction targets per sector for 2030, creating additional pressure to transform Germany's energy system, especially for the energy sector and the transport and industry sectors (see Figure 1).

Figure 1: Sectoral emission reduction targets for 2030 as required by the amended Climate Change Act [1].



Until recently, Germany's energy transition has primarily focused on the deployment of renewables in the electricity sector driven by the Renewable Energy Sources Act (EEG), which aims to promote renewable electricity. As a result, the share of renewable electricity increased to over 45% in 2020 [2]. However, the share in the heating and transport sector is currently only 15.2% and 7.3%, respectively [2]. Renewable energy covers about 17% of Germany's primary energy consumption (see Figure 2). Similarly, concerning Germany's final energy consumption, the share of renewable energy is only around 19% [3]. This is because electricity represents just 20% of the German energy system whereas the remaining 80% is provided by molecules that mainly stem from coal, oil, and natural gas.

Figure 2: Germany's primary energy consumption by resource in 2020 [4].

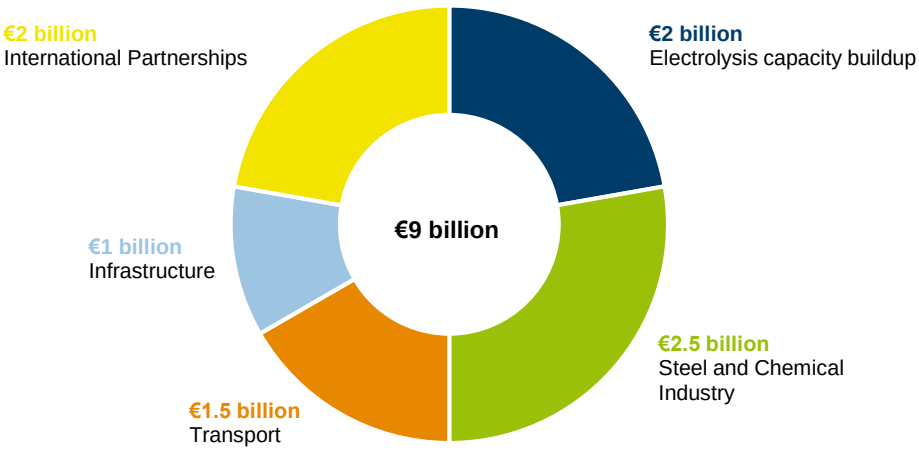


In order to be able to achieve the required drastic emission reductions, renewable electricity needs to be integrated in all sectors to fully substitute fossil fuels. PtX processes offer true sustainable alternatives for applications where direct electrification is not technically or economically suitable. The basis for all currently discussed PtX-technologies is molecular hydrogen, which is thus key to the defossilisation of the energy system.

2.2 Germany's national hydrogen approach

Germany released its National Hydrogen Strategy [5] (*Nationale Wasserstoffstrategie*, NWS) in June 2020, which emphasises hydrogen and PtX-products as necessary to meet emission reduction targets and become GHG-neutral. The strategy aims to build up 5 GW electrolysis capacity domestically by 2030, which corresponds to 14 TWh of hydrogen production and another 5 GW by 2040 at the latest. In order to achieve these aims and to kick-start the hydrogen economy, the strategy allocates €9 billion in total, €7 billion for the market ramp-up of the domestic market and €2 billion to the international hydrogen market (Figure 3).

Figure 3: Distribution of the allocated funds in the NWS in billion Euro [6].



Overall, the strategy encompasses 38 measures that constitute the required steps for the phase of the market ramp-up by 2023 (Figure 4). The second phase, which is due to begin in 2024, is meant to focus on the European and international dimension of hydrogen.

Figure 4: Mid-term vision of Germany's National Hydrogen Strategy and measures for international cooperation [5].

In general, the NWS only acknowledges hydrogen produced from renewables (green hydrogen) as sustainable in the long term, but stresses the importance of temporarily using “carbon-free hydrogen”, meaning blue and turquoise hydrogen for the market ramp-up (Box 1).

The fields of application for hydrogen are defined as "[where] the use of hydrogen is close to being economically viable in the short or medium term, [where] no major path dependency is being created, or [where] there are no alternative options for decarbonisation”. This means that the NWS does not exactly prescribe which processes or industries hydrogen should primarily be applied in. Yet, the NWS formulates different numbers of measures for the sectors (nine in transport, four in industry, and two in the heating sector). In

addition, the strategy has a strong focus on research, education, and innovation (measures 23-29). Regarding cooperation, the NWS sees a need for action on the European level (measures 30-33) as well as on the international hydrogen market (measures 34-38).

Box 1: Definitions of hydrogen according to the NWS [5]

Green hydrogen means "produced via the electrolysis of water; the electricity used for the electrolysis must derive from renewable sources. Irrespective of the electrolysis technology used, the production of the hydrogen is zero-carbon since all the electricity used derives from renewable sources and is thus zero-carbon".

Turquoise hydrogen refers to "hydrogen produced via the thermal splitting of methane (methane pyrolysis). This produces solid carbon rather than CO_2. The preconditions for carbon neutrality of the process are that the heat for the high-temperature reactor is produced from renewable or carbon neutral energy sources, and the permanent binding of the carbon".

Blue hydrogen means "hydrogen which is produced using a carbon capture and storage (CCS) system. This means that the CO_2 produced in the process of making hydrogen does not enter the atmosphere, and so the hydrogen production can be regarded on balance as carbon-neutral".

Grey hydrogen refers to "hydrogen produced via the thermal splitting of methane (methane pyrolysis). This produces solid carbon rather than CO_2. The preconditions for the carbon neutrality of the process are that the heat for the high-temperature reactor is produced from renewable or carbon-neutral energy sources, and the permanent binding of the carbon".

The definitions are not legally binding and do not reflect any current or proposed certification scheme.

According to the strategy, imports of renewable hydrogen and PtX-products beyond the European market are needed to achieve the national climate targets. Especially countries with an existing energy partnership with Germany and those that are part of the German Development Cooperation or the International Climate Initiative are described as potential partners on hydrogen. In addition, further cooperation may arise, such as with traditional energy exporters or other developing countries.

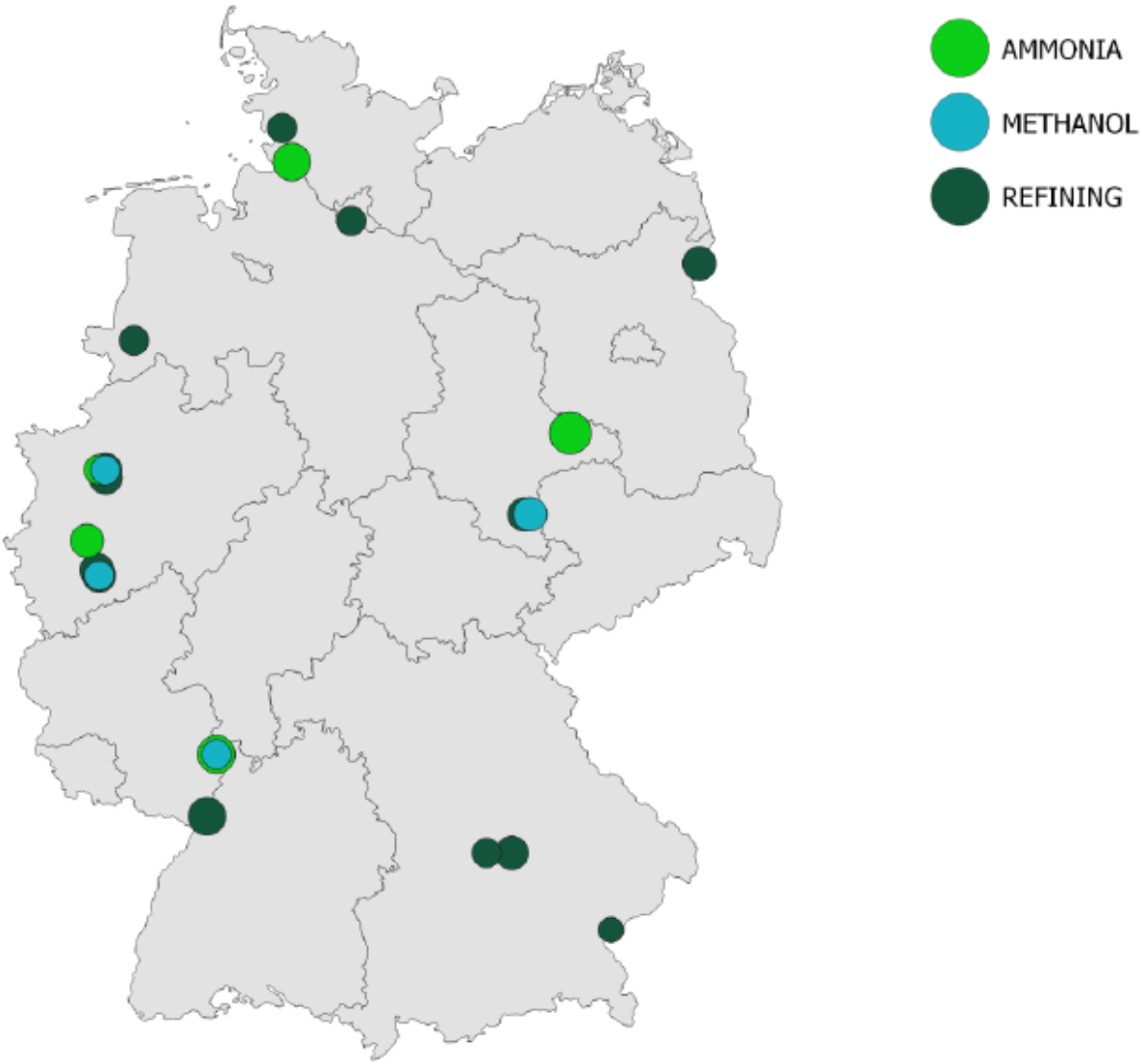
The first major initiative to trigger imports at scale is H2Global, which officially started in May 2021. The concept joins supply and demand with a double auction mechanism. The auctions will be handled by an intermediary: HINT.CO. Via the intermediary, it will be possible to conclude long-term purchase contracts on the supply side and short-term resale contracts on the demand side. The intermediary will compensate for the existing difference between supply and demand prices via a support mechanism based on the "Contracts for Difference" (CfD) approach. The aim is to create incentives for investment in green hydrogen and PtX production capacities abroad. The German Government has allocated €900 million to H2Global for 10 years.

2.3 Future demand and the need for imports

Estimating future demands for hydrogen and other PtX-products is associated with many uncertainties, including the role of hydrogen and PtX-products in the defossilisation strategy of the involved industries and individual companies. Understanding the landscape of current off-takers is only one of many indicators. Germany's current annual hydrogen demand is estimated at 55 TWh, primarily deriving from the desulphurisation of conventional fuels in refining (21.3 TWh), ammonia production plants (20.6 TWh) and methanol production plants (4.7 TWh), where hydrogen is produced via steam methane reforming (SMR) [7]. At

present, about fifty Power-to-Gas projects are in place that total some 1 GW, which would be insufficient to cover the current hydrogen demand.[2]

Figure 5: Current hydrogen consumption in Germany [7].

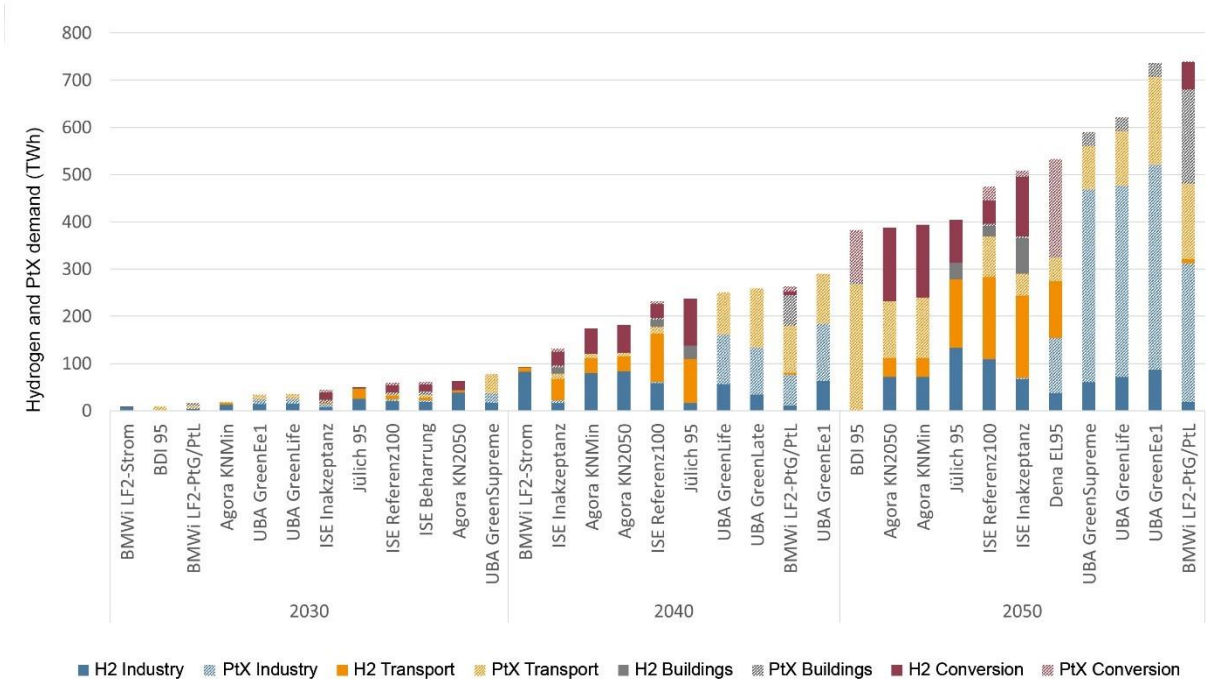


Several studies have modelled Germany's future energy system and the demand for hydrogen and PtX-products. On behalf of the National Hydrogen Council, the Fraunhofer Gesellschaft compiled a meta-study [8] based on eight of the most notable studies since 2018. Their overview includes demand scenarios with at least 95% emissions reduction in Germany by 2050.[3]

[2] For instance, assuming an electrolysis efficiency of 70% and 4,000 full-load hours, a total capacity of 20 GW would be needed to replace the 55 TWh production of grey hydrogen.

[3] Germany only introduced its new climate target of climate neutrality by 2045 in June 2021, which explains why all the studies analysed consider the year 2050 as the benchmark for the climate target.

Figure 6: Overview of the demand for hydrogen and PtX-products in the different sectors in 2030, 2040 and 2050 (without scenarios that deviate significantly) [8].



As highlighted in Figure 6, the projected total demand for hydrogen and PtX in the analysed scenarios is below 80 TWh in 2030. By 2040 and 2050, demand is projected to be in the range of 100 to 400 TWh and 400 to 800 TWh respectively. Future demand of up to 500 TWh (including biofuels) is largely created in **industry**, especially for green steel, renewable ammonia, and ethylene (provided by methanol-to-olefin) production. According to the studies, **transport** will be the second major sector, with projected demand between 150 to 300 TWh mainly for liquid fuels in international aviation and shipping. Additional hydrogen demand is projected to come from heavy duty vehicles around 2030 and passenger cars beyond 2030. Potential demand could also come from **buildings**, but likely only after 2040, since other electricity-based solutions for providing low-temperature heat are currently more viable. The **conversion** of hydrogen to power and heat is seen to complement the future demand, estimated at 50 to 150 TWh in 2050.

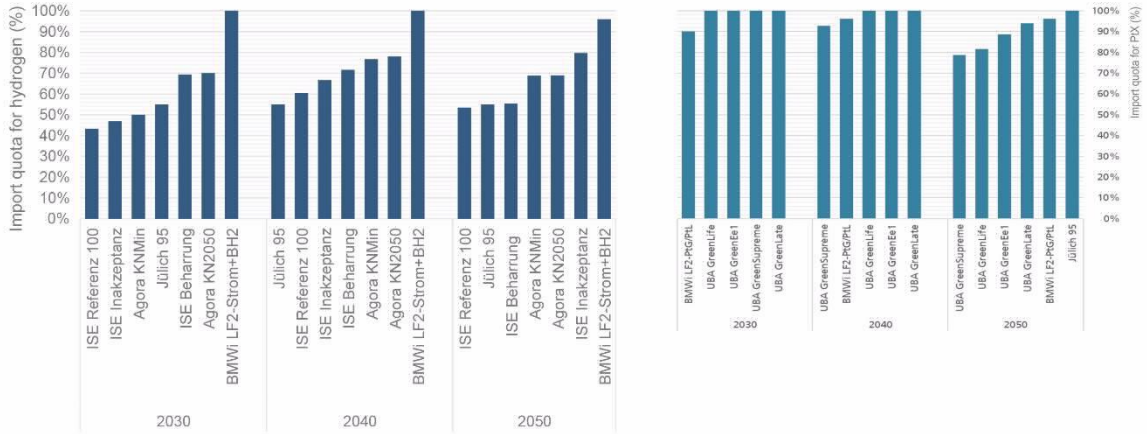
Besides identifying the ranges for future demands, the meta-study also identified several key factors that influence the ranges for future demand, including:

- Higher ambition levels for emissions reduction generally result in increased demand.
- Carbon Capture and Storage (CCS) can significantly reduce demand.
- The application of sustainable biomass can also reduce demand to some extent.
- Varying boundaries for scenarios result in large variations. Some scenarios do not or only partially consider non-energetic usage in industry and international aviation and shipping. Both will potentially increase demand substantially.
- Some models are not economically optimised but rather make specifications on design parameters such as allowed technologies, energy efficiency, and sufficiency. Assumptions on cost for different technologies and energy prices also vary greatly.
- Most scenarios do not assess the role of refineries as potential future off-takers for hydrogen but expect their capacities to decrease substantially due to a shift in value chains towards more favourable locations.

- Other possible relocations of industrial value chains such as for green steel or ethylene are mostly not considered in the scenarios.

According to the scenarios considered, electrolyser capacities in Germany are projected below 5 GW in 2030, expanding to 10 to 35 GW by 2040, and totalling up to 63 GW in 2050. Depending on the assumed domestic hydrogen production capacities, the share of imports for hydrogen varies accordingly. In 2030, the share ranges from 43 to 100%, in 2040 from 60 to 100%, and in 2050 from 53 to almost 100%. All scenarios have in common that the import quotas peak in 2040 and decrease by 2050 (Figure 7). Whereas the import quotas for PtX-products are very high throughout 2030 and 2040, ranging from 90 to 100%, they drop to below 90% in some scenarios.

Figure 7: Import quotas for hydrogen (left) and PtX (right) in 2030, 2040, and 2050 [8].



2.4 Germany's potential as a leading technology and knowledge provider

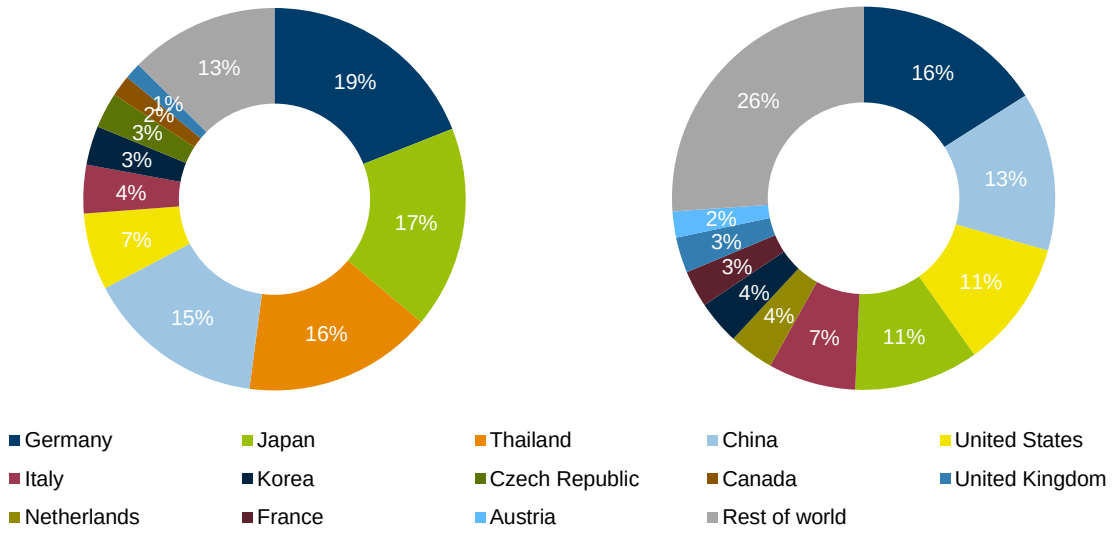
The electrolysis of water with renewable electricity is a key technology for producing renewable hydrogen. Currently, there are three main technologies for producing hydrogen from water[4] that are applied in Germany. The most advanced technology is alkaline electrolysis, which has been used in industrial processes since the 20th century. However, during the last decade, Proton Exchange Membrane (PEM) electrolysis has experienced substantial further development since it allows for dynamic operation with intermittent renewable energy sources. The third most common technology is Solid Oxid Electrolysis (SOEL), which operates at high temperature levels and is therefore well suited for the coupling of industrial processes. However, SOEL currently has a Technology Readiness Level (TRL)[5] of just 5-6 (see Box 2, p. 16).

German and European manufacturers are well positioned to benefit from the growing market of electrolysis since they offer all these three technologies as well as the special components needed for electrolysers. More specifically, three of the eight European providers for alkaline electrolysis are from Germany, namely

[4] Chlor-alkali electrolysis is a well-established technology where hydrogen is however only produced as a by-product. Therefore, it is not considered here as a key technology for producing renewable hydrogen.

thyssenkrupp Industrial Engineering, McPhy, and Sunfire as well as four of the six PEM-electrolyser providers: Siemens Energy, Greenerity, iGasEnergy, and h-tec Systems [9]. With Sunfire, Germany is one of only two technology providers for SOEL in Europe. As a result, Germany led the market shares for electrolysis in 2016 (Figure 8). The economic potential of the German electrolyser industry is expected to increase to €5.5 billion annually given the global capacity of electrolysers increases by 20 GW between 2020-2030 and by 200 GW annually thereafter [10].

Figure 8: Global market shares of electrolysis technologies (left) and plant engineering based on export revenues (right) in 2016 [11].



Germany has also been leading the market for plant engineering (Figure 8). This is largely the result of Germany's long and successful history in chemical energy conversion, including the invention of ammonia synthesis (the Haber-Bosch process) by German companies at the beginning of the 20th century as well as the Fischer-Tropsch process in 1925. Similarly, German chemists were the first to produce methanol at industrial scale with high temperatures and with a zinc/chromium oxide catalyst.

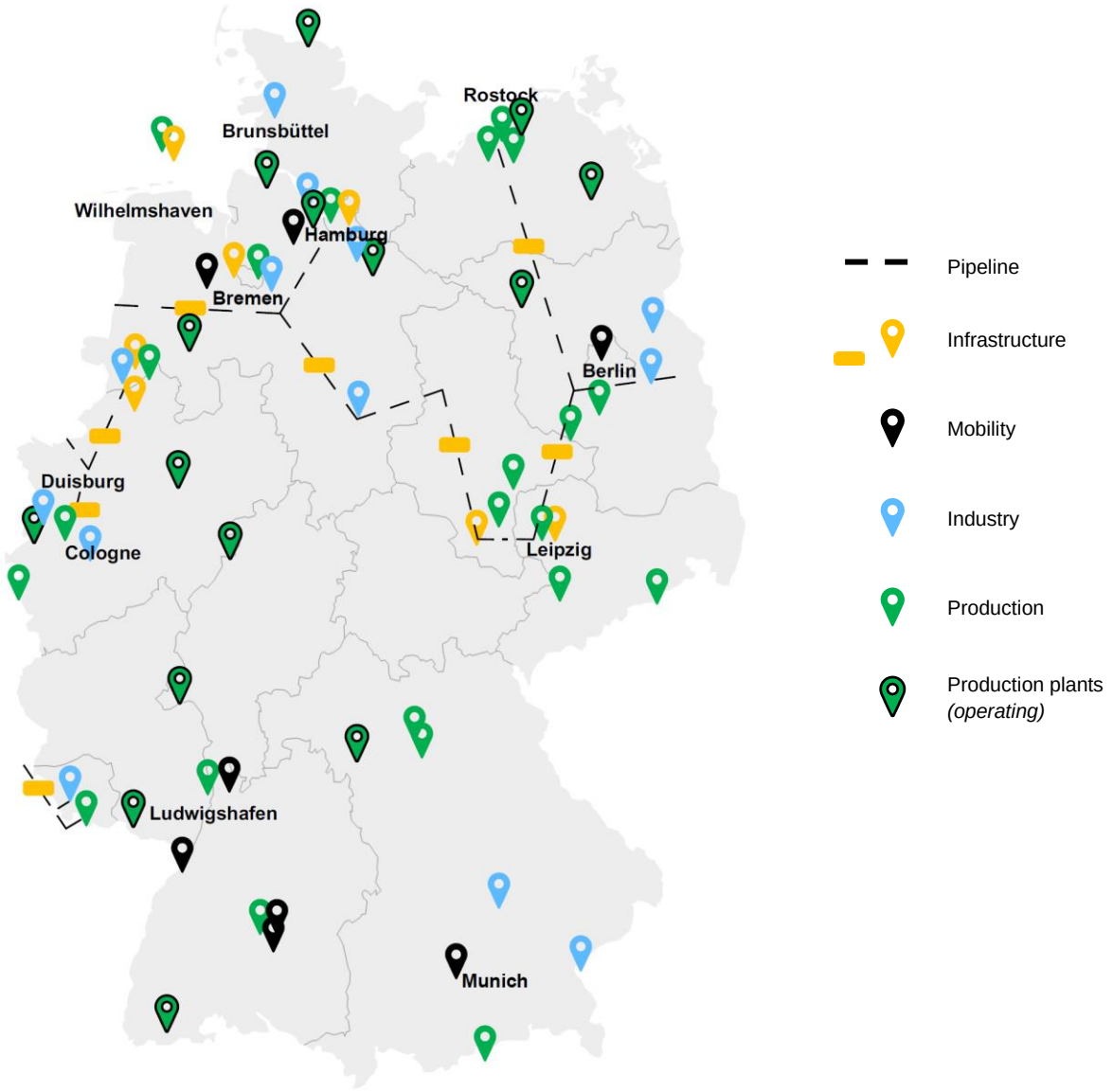
In order to maintain technological leadership, the expansion of the domestic hydrogen economy is essential. Therefore, the German Government has invested heavily in the development of hydrogen projects across the whole value chain. The most significant funding towards the domestic market for hydrogen has been jointly initiated by the BMWi and the Federal Ministry of Transport and Digital Infrastructure (BMVI). In May 2021 they announced the selection of 62 large-scale hydrogen projects which will receive a total of €8 billion[6] in funding as part of the joint European funding programme Important Projects of Common European Interest (IPCEI) (Figure 9).

Together, the selected projects will comprise more than 2 GW of electrolysis capacity, which adds to the existing PtG-projects' capacity of almost 1 GW. Fifteen of the 62 projects are dedicated to the industry sector, and especially to reducing CO_2 emissions from steel production. Twelve projects are planned that

[6] The funding is made up of federal as well as state funds with around €4.4 billion coming from the BMWi and up to €1.4 billion coming from the BMVI. The remaining funding will be provided by the federal states. In total, investments of €33 billion are to be triggered, of which more than €20 billion will come from private investors.

will promote the development and production of fuel cell systems and vehicles as well as the establishment of a hydrogen refuelling infrastructure. In addition, there are several projects aiming to advance the general hydrogen infrastructure with a total proposed length of 1,700 km of hydrogen pipelines.

Figure 9: Locations of the 62 selected hydrogen projects under IPCEI and of currently operating production plants. Adjusted from [12].



Besides pipelines, other transport options will be required for imports. Therefore, the guiding project “TransHyDE” will develop, test and scale up relevant transport options, including the transport of gaseous hydrogen in existing and new gas pipelines as well as via high pressure vessels, the transport of liquid hydrogen, and the transport of hydrogen in the form of ammonia. Another relevant initiative for the future import infrastructure is the “Green Wilhelmshaven” initiative, which was announced in April 2021. With the project, Uniper intends to establish an import terminal for green ammonia at the port of Wilhelmshaven on the North Sea coast, including an ammonia cracker. In addition, the project aims to install an electrolyser with a capacity of 410 MW.

3 Australia as a cooperation partner of choice

One major success factor for the development of a global hydrogen market is the availability of renewable hydrogen at the lowest possible cost. Therefore, countries with vast renewable energy resources are of particular interest as potential cooperation partners. However, besides techno-economic factors there are various other assessment criteria that determine a country's potential as a cooperation partner. The following reasoning represents a snapshot of why Australia has the potential to be Germany's cooperation partner of choice. Most of the information presented below can be obtained in detail from the state-of-play of the Australian partners.

Renewable and hydrogen generation potential

Australia has some of the highest annual solar radiation as well as thousands of kilometres of windy coastline and is massive in size. In 2020, Australia generated 62,917 GWh of renewable electricity, which made up more than 27% of total electricity generation. About two-thirds of the renewable generation was provided by solar PV and wind [13]. However, the current carbon intensity of the Australian grid is still very high at 656.4 g-CO_2/kWh since coal supplies some 75% of Australia's electricity.[7]

While not all of Australia's land area can be used for renewable energy generation, about 2.7 million km² are estimated to be usable for solar PV and around 4.5 million km² for wind energy, excluding coast areas suitable for offshore wind [HySupply]. It comes as no surprise that the country has a massive technical renewable generation potential of almost 117,000 TWh, which is more than 1,000 times the total primary energy consumption [14]. Just 4.5% of that renewable energy potential converted into hydrogen would be enough to supply Germany's current total primary energy consumption.[8] Therefore, Australia has very attractive conditions for the development of a domestic hydrogen economy. At the same time, their generation potential is more than enough for Australia to become a leading global exporter of renewable hydrogen.

While Australia is not producing renewable hydrogen at scale yet, it has listed 35 projects and hubs as "committed or under development" that particularly explore the value chain of renewable hydrogen for export market opportunities. Highlights include the Asian Renewable Energy Hub[9] project, which aims to build 26 GW of renewable energy plants to produce hydrogen and ammonia for the domestic and export markets, and the H2-HubTM Gladstone project, which aims to build up to 3 GW electrolyser capacity for the production of ammonia, with first production expected for 2025 (further detail can be found in the Australian state-of-play).

[7] For reference, the German carbon intensity was 408 g-CO_2/kWh in 2019.

[8] Assuming an electrolyser efficiency of 70%, the technical electricity generation potential can supply 81,900 TWh of hydrogen. Germany's current annual primary energy consumption is 3,753 TWh or about 4.5% of the maximum technical hydrogen supply.

[9] The expansion of the Hub to 26 GW is currently on hold by the Federal Government due to environmental concerns. The initially proposed 9 GW are not affected and are projected to commence.

Government support

Australia was one of the first countries to release its national hydrogen strategy in November 2019, which sets the foundations for the country to become a major hydrogen exporter. Both federal and state governments have rolled out policies and funding programs to develop a renewable export supply chain. At the federal level, Australia has most notably supported the creation of regional hydrogen export hubs by dedicating AUD$ 70.2 million for the first hub and AUD$ 177.5 million for four additional hubs as well as for further feasibility studies and legal reforms to facilitate trade [15]. The potential of a hydrogen economy has led all states and territories to develop their own hydrogen strategies or initiatives, with the majority being focused exclusively on renewable hydrogen.

Feedstock availability

To produce renewable hydrogen, water needs to be decomposed into hydrogen and oxygen. Australia has numerous regions that have rich freshwater resources. Although the water stress indicator is overall medium (2.67)[10] [16], it is not guaranteed that this is the case for the hydrogen production areas. Nonetheless, Australia also has existing desalination and water recovery infrastructure that can be used to produce hydrogen. This is especially favourable when hydrogen production is combined with further synthesis processes so that the waste heat can be used for the desalination processes, which in turn is an opportunity to supply arid areas with fresh water.

The production of synthetic fuels such as methanol and kerosene require a carbon source. As long as direct air capture (DAC) is not commercially available at scale, Australia could technically use the unavoidable emissions from its cement industry (some 6 million tonnes of CO_{2e} annually) [17] or biomass. Capturing nitrogen to produce ammonia is state of the art and consumes significantly less energy than electrolysis.

Existing bilateral trade relations

As one of the largest energy exporters of liquified natural gas (LNG), iron ore and coal, Australia is well positioned for future energy exports. At the same time, Australia ranks 16th on the Global Competitiveness Index [18] and has one of the highest scores on the ease of doing business index [19]. Australia and Germany have several bilateral agreements in place and an established economic relationship. Germany is Australia's 9th largest trade partner and together both countries had a total merchandise trade of over €11 billion in 2020 [20].

One of the first bilateral cooperation agreements on hydrogen was the Memorandum of Understanding (MoU) between RWE Supply & Trading and Woodside Energy Ltd. (Australia's biggest oil and gas company), signed at the end of 2020 to explore the options for producing hydrogen at export scale and marketing it to RWE's customer base in Europe and Asia [21]. Another cooperation of RWE Supply & Trading is the 2021 signed MoU with the Hydrogen Utility Pty Ltd (H2U). Together, they aim to bring hydrogen from South Australia to the planned LNG terminal in Brunsbüttel. In addition, both countries are also working closely together on a public-private level. For instance, the Sub-Working Group Hydrogen of the German-Australian Energy Partnership is chaired by the Australia Hydrogen Council (AHC) together with the Ger-

[10] In comparison, Germany has a score of 2.14 with two federal states even having a high water stress score.

man-Australian Chamber of Industry & Commerce (AHK) as well as through the German-Australian Hydrogen Alliance. Most recently, both countries strengthened their cooperation on a national level with the Hydrogen Accord, which was signed in June 2021.

Renewable energy and climate ambitions

At the federal level, the Renewable Energy Target (RET) was Australia's main national policy which aimed to promote the deployment of renewable electricity by 2020. Due to the strong increase in renewables, their share in the electricity mix rose to over 21%, which means that the RET was overachieved one year before it formally ended. While the federal government did not extend the RET, the states and territories are continuing their ambitions to promote the deployment of renewable electricity, with some jurisdictions setting renewable energy targets of 200%, as in Tasmania, or even 500%, as in South Australia. Similarly, while Australia has not yet committed to climate neutrality at the federal level, all state jurisdictions have their own climate targets aiming at net zero emissions by 2050 at the latest (Table 1).

Table 1: Overview of the Australian state-level climate targets.

Jurisdiction	Climate target*	Type of commitment
Australian Capital Territory	Net zero emissions by 2045	Legislated [22]
New South Wales	Net zero emissions by 2050	Aspirational in vision statement [23]
Tasmania	-60% by 2050 Net zero emissions by 2050	Legislated Aspirational in policy [24]
South Australia	-50% by 2030, net zero emissions by 2050	Aspirational in policy [25]
Victoria	-28 to 33% for 2025, -45 to 50% by 2030** Net zero emissions by 2050	Aspirational in policy Legislated [26]
Queensland	-30% by 2030** Net zero emissions by 2050	Aspirational in policy [27]
Northern Territory	Net zero emissions by 2050	Aspirational in policy [28]
Western Australia	Net zero emissions by 2050	Aspirational in policy [29]

* If not otherwise indicated, GHG emissions reductions compared to 1990 levels.
** GHG emissions reductions below 2005 levels.

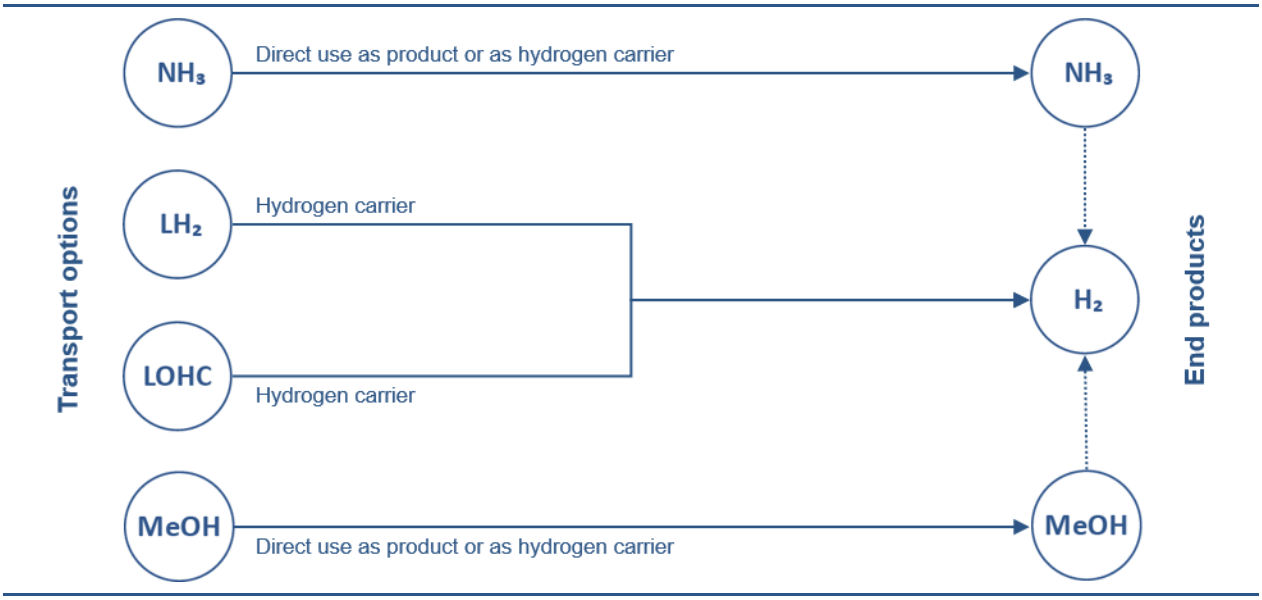
Shared values

As a representative democracy, Australia highly values democratic freedom as well as rule of law and therefore ranks 9th on the Global Democracy Index (compared to Germany at 14th) [30]. This is underlined by good scores for freedom of the press, judicial independence, and incidence of corruption. Together with a like-minded culture, Germany has a "warm and significant bilateral relationship" [31] with Australia, which provides the foundation for a strong, reliable, and long-term future hydrogen partnership between the two countries.

4 Transporting hydrogen: the missing link between Australia and Germany

Importing Australia's abundant sunshine and wind resources is a promising opportunity to meet parts of the projected demand for renewable hydrogen and PtX-products in Germany. There are two options for long-distance hydrogen transport: pipelines and marine vessels. Although pipelines allow for the transport of gaseous hydrogen without any additional steps, they are not feasible due to the distance between Australia and Germany. Thus, gaseous hydrogen needs to be converted into shippable carriers that have higher volumetric density and are easier to handle on marine vessels. While hydrogen is the priority to a majority of the off-takers involved, renewable ammonia and renewable methanol can also be applied to defossilise industrial processes. From the variety of different transport options that exist or are being researched, the following four were chosen to be analysed: liquid hydrogen (LH_2), liquid organic hydrogen carriers (LOHC), ammonia (NH_3), and methanol (MeOH) (see Figure 10).

Figure 10: Schematic illustration of transport options for the desired end products.



This chapter looks at these four transport options on the basis of a typical supply chain, focusing on the missing link between Australia and Germany: the elements needed for the seaborne transport of hydrogen, including conversion, storage, shipping, and reconversion (Table 2). Terminal infrastructure is not considered as storage is the main contributor to the costs and remaining infrastructure needs such as jetties are independent from the hydrogen carriers and are most likely to be shared with other energy carriers. Potential import terminals could be Bremerhaven, Brunsbüttel, Hamburg, Rostock, and Wilhelmshaven as well as Antwerp and Rotterdam. The production of renewable electricity and hydrogen is not considered here but is dealt with by the state-of-play of the Australian partners of HySupply. Neither distribution nor end use is examined, which however will be addressed during later stages of HySupply. For some use cases the reconversion of the carrier might not be necessary, however, the necessary technologies are included in this analysis to provide a clear picture.

Table 2: Definitions of supply chain elements covered in this analysis.

Conversion	After the production from renewables via electrolysis, the gaseous hydrogen needs to be converted into shippable carriers. This element illustrates all the necessary steps for the conversion after the electrolysis. The provision of the various carriers such as the LOHC components, carbon dioxide, and nitrogen is also considered. Hydrogen production costs are not included.
Storage	Before and after shipping, the hydrogen carriers need to be stored for a certain amount of time. This element describes the storage in tank systems. Specific parameters are highly dependent on annual throughput and the value chain design, as, for instance, higher throughput results in reduced specific costs and energy demand.
Shipping	Shipping is realised via marine vessels at an assumed one-way distance of 20,000 km with an empty return trip. No fees (e.g. for passing the Suez Canal) are included, as they depend on vessel and supply chain design. Since current marine vessels operate on fossil fuels, direct CO_2 emissions for the status quo with heavy fuel oil (HFO) are considered. At later stages, the hydrogen carriers will potentially cover the fuel demand. All quantitative indicator values are specific to the distance of the Australia-Germany supply chain.
Reconversion	After arriving at the port of destination, the gaseous hydrogen can be retrieved from the hydrogen carrier. This element describes the necessary processes involved, excluding potential aftertreatment of the carrier component. Although in some cases it might be more beneficial to use the carriers directly, the necessary technologies for reconversion are still considered.

To understand the transport options and their potential to be available at scale in 2030, quantitative key performance indicators as well as qualitative indicators are considered individually for each covered element of the supply chain (Table 3). These indicators are based on literature reviews and the expert opinions of German HySupply members. Sources marked with "[HySupply]" reflect opinions and internal data from members within the German project group.

Table 3: Quantitative key performance indicators for 2030 and qualitative indicators for the analysis of the transport options.

Key performance indicators for 2030	
Capacity (t-product and t-H_{2e})	Available capacities for the respective technologies expressed per tonne of product and contained hydrogen equivalent. Conversion and reconversion are expressed in production capacity per day.
CAPEX (€/t-product and €/t-H_{2e})	Capital expenditure per produced amount of product and per extractable hydrogen equivalent over the lifetime of the technology. Values present the lower boundary of capital expenditure since weighted average capital expenditure is assumed at 0% and availability at 100%. Values for storage reflect CAPEX per total storage capacity, as specific CAPEX are dependent on annual throughput.
OPEX (% of CAPEX)	Operational expenditure per year in relation to CAPEX, i.e. maintenance and utilities, excluding energy and feedstocks.
Energy demand (MWh/t-product and €/t-H_{2e})	All electricity and heat necessary to run the supply chain element.

Energy efficiency (%)	Based on lower heating values[11] (LHV). Potential use of excess heat which would increase efficiency is not included.
CO_2 emissions (t-CO_2/t-product and t-CO_2/t-H_{2e})	It is assumed that all considered technologies run fully on renewable electricity resulting in zero direct CO_2 emissions. However, since shipping fuels are currently fossil fuel based, the status quo is given with direct CO_2 emissions from HFO. Other GHG or particulate matter emissions are not included.
Qualitative indicators	
Current status	The current status provides an estimation of today's status quo, including the Technology Readiness Level (TRL) (Box 2) and typical capacities. The manufacturing process is given where possible.
Expected development	Based on the current status, this indicator refers to the expected development within the next decade, in particular for TRL, cost, and potential upscaling.
System integration	Two aspects are considered here. First, the integration of heat flows with other processes and the energy system. Secondly, the integration into existing infrastructures.
Research needs	This indicator describes the opportunities to improve the technology through research and development (R&D) activities.

Box 2: Technology Readiness Level (TRL) [32]

The TRL definitions are adapted from the annex of the Horizon 2020 Work Programme and evaluated for each technology by the HySupply project group. They provide a benchmark for tracking the technological development on a scale from TRL 1 to TRL 9. The following definitions apply:

TRL 1 – basic principles observed

TRL 2 – technology concept formulated

TRL 3 – experimental proof of concept

TRL 4 – technology validated in lab

TRL 5 – technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies)

TRL 6 – technology demonstrated in relevant environment (industrially relevant environment in the case of key enabling technologies)

TRL 7 – system prototype demonstration in operational environment

TRL 8 – system complete and qualified

TRL 9 – actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies; or in space).

Commercial applications are influenced by factors such as scale, funding, market, and system integration in addition to technological readiness. Hence, the TRL does not conclusively reflect the commercial readiness and availability for the supply chain at a given time.

[11] The choice of LHV leads to lower efficiency numbers, while the usage of higher heating values would result in higher efficiency numbers. The difference, however, is purely theoretical and usage of either can be viewed more as a question of personal preferences or habit than of mathematical correctness.

4.1 Liquid Hydrogen

Liquefaction of hydrogen increases the volumetric density by a factor of 800 compared to gaseous hydrogen, enabling seaborne transport in marine vessels over long distances. Today, LH_2 is mainly used in aerospace applications as rocket fuel. Therefore, NASA is currently one of the largest operators of LH_2 tanks. Nonetheless, LH_2-fueled passenger car prototypes, such as the “BMW hydrogen 7” have demonstrated the wide applicability of LH_2 in transport as well.

An advantage of LH_2 is that no additional elements are required for conversion and reconversion, which means that hydrogen is kept in its pure molecular form. Furthermore, its ”cold energy” could be integrated with the cooling infrastructure in the country of destination and thereby could allow for additional energy savings.

Carrier properties of LH_2	
Aggregate	Liquid at -253 °C and 1 bar
Chem. formula	H_2
Hydrogen content (%)	100
Volumetric density (t/m³)	0.071
LHV (MWh/t)	33.33
Boiling point (°C)	-251.6
Melting point (°C)	-259.1

The main disadvantage of LH_2 stems from the low boiling temperature at normal pressure, which makes cooling to -253 °C necessary and requires significant energy input. Consequently, all infrastructures must be fitted for handling cryogenic materials and to minimise boil-off losses caused by heat entry. The boil-off gas (BOG) and other potential leakages need thorough treatment to reduce the risk of explosions, which stems from the wide ignition limits of hydrogen/air mixtures and the low ignition energy of hydrogen.

Conversion

The huge energy demand for hydrogen liquefaction stems from the various compression steps for hydrogen and the refrigerants, which are required for the cooling process. Current liquefaction plants require up to 15 kWh of electricity to liquefy 1 kg of hydrogen, which results in an efficiency of 55%. The theoretical efficiency limit is estimated at 92%. It should be noted that current H_2-liquefaction plants are comparatively small, for example for aerospace applications, which is why the current plants are optimised towards CAPEX rather than towards efficiency. Consequently, future liquefaction plants are expected to have more complex cooling cycles that allow higher efficiencies. The single largest hydrogen liquefaction plant is currently being built in South Korea by Linde and Hyosung and completion is planned for 2022. Its estimated annual liquefaction capacity is 13,000 t-LH_2.

Key performance indicators 2030 [33] [34] [35] [36]		
Capacity	t-H_2/d	120-700
CAPEX	€/t-H_2	160-203
OPEX	% of CAPEX	2-4
Energy demand	MWh/t-H_2	6-8
Energy efficiency	%	76-82

Two spin isomers of molecular hydrogen exist, ortho- and parahydrogen. At room temperature roughly 25% of the hydrogen molecules are in the para-form and 75% are in the ortho-form, while at cryogenic temperatures, the para-form is dominant. The natural transformation is slow, especially compared to the liquefaction process. Furthermore, the ortho-para isomerization is an exothermic process, which makes it undesirable to occur in already liquefied hydrogen. Therefore, the process is accelerated via catalysts at the beginning of the liquefaction process so that the obtained LH_2 does not require further spin isomerisation.

Qualitative Indicators [HySupply]

Current status	TRL 9 with plants available at capacities below 30 t-H_2 per day.
Expected development	Scale-up to capacities of 100 t-H_2 per day without significant changes is possible. In general, high potential for improvements exists, especially for energy efficiency, becoming more likely with higher plant capacity. More efficient technologies come with higher investment costs, but economies of scale will help to reduce specific investment costs.
System integration	The high energy demand of current plant designs could require additional installed power generation for the supply chain system.
Research needs	Various concepts e.g. mixed refrigerants, high pressure liquefaction, Brayton cycles, alternative compression technology need R&D.

Storage

For storage of LH_2, spherical, double-walled tanks are suitable, which are available technologies and, for instance, are operated by NASA. Heat entry leads to evaporation of up to 0.1% per day of the hydrogen, which is the so-called boil-off gas. The boil-off gas is either released via flares or if possible, sent back to the liquefaction plant, which increases the energy demand for storage but prevents any physical loss of hydrogen. Modern concepts, such as Integrated Refrigeration and Storage (IRaS), apply a heat exchanger with a cryogenic refrigeration system to the storage tank directly, which counteracts the heat entry and completely prevents the formation of boil-off gas. Thereby, long-term storage of LH_2 becomes feasible.

Key performance indicators 2030 [34] [35] [36]		
Capacity	t-H_2	3,550-7,000
CAPEX	€/t-$H_{2\text{-capacity}}$	12,800-80,225
OPEX	% of CAPEX	4
Energy demand	MWh/t-H_2	Depends on storage length
Boil-off	%/d	0.03-0.1
Energy efficiency is dependent on storage length and reliquefaction strategy.		

Qualitative indicators [HySupply]

Current status	TRL 9 for capacities of up to 5,000 m³ (355 t-LH_2) in double-walled spheres.
Expected development	No design change is required for scaling-up spheres to larger sizes, but size limit is expected to be between 20,000-50,000 m³ (1,420-3,550 t-LH_2). Larger sizes must be realised in non-spherical forms.
System integration	Boil-off can be sent back to the liquefaction plant for reliquefaction to eliminate any losses or IRaS strategies could be applied. Refitting of LNG tanks could be possible.
Research needs	Alternative tank concepts for enabling very large storage capacities (> 50,000m³), e.g. flat bottom type tanks as known from LNG business with specific changes required by LH_2.

Shipping

Shipping of LH_2 requires highly specialised vessels with highly insulated tanks. Currently, only one prototype, the Suiso Frontier, from the Japanese company Kawasaki Heavy Industries exists with a volume of 1,250 m³ (89 t-LH_2). The first large-scale LH_2 vessels with capacities of 160,000 m³ (11,360 t-H2) have been announced for 2030 and would allow for commercial operation.

Key performance indicators 2030 [33] [35] [36] [37] [38] [39]		
Capacity	t-H_2	11,360
CAPEX	€/t-H_2	108-451
OPEX	% of CAPEX	0.02-4
Energy demand	MWh/t-H_2	1.7-11.5[12]
Boil-off	%/d	0.2
Energy efficiency	%	89-90 (boil-off used) 59-84 (boil-off unused)
CO_2 emissions	t-CO_2/t-H_2	0.5-3.3 (HFO)

The technology is similar to LNG and experiences and lessons learned from LNG vessel development can speed up the development of LH_2 vessels. Nonetheless, increasing the transport volume of LH_2 carriers by a factor of 128 in less than 10 years seems ambitious and assuming additional time for further commercialisation seems reasonable. Furthermore, direct retrofitting of existing LNG carriers should be investigated but seems challenging considering that the temperature of LH_2 is almost 90 °C colder than that of LNG. Moreover, in the next decades there will not be many stranded LNG assets available.

The optimal fuel for LH_2 vessels is renewable hydrogen itself, so that the vessels are fuelled by their load. This would avoid almost all CO_2 and particle emissions. Interestingly, many LNG vessels are nowadays fuelled by LNG as well. Depending on the shipping characteristics, such as distance and speed, the boil-off gas can either be used in hydrogen engines, which would increase the efficiency of shipping, or could be released via a flare into the surrounding environment. Alternatively, an onboard reliquefaction system could be installed.

On the return to Australia, a small amount of the LH_2 (up to 4% [36]) would be kept in the tanks (so-called heel) to keep the tanks at cryogenic temperatures and to avoid entry of air. This heel reduces the net capacity of the vessels and results in boil-off, which then also takes place during the return to Australia. From LNG vessels it is known that the boil-off of an “empty” vessel, where only heel remains, is roughly 80% of the full vessel’s boil-off, which can be used as the initial assumption for LH_2 vessels.

[12] The energy demand mentioned in [35], which results in 11.5 MWh/t-H_2 for the Australia-Germany supply chain, is considered as a very pessimistic assumption.

Qualitative Indicators [HySupply]	
Current status	TRL 6 with the only existing prototype by Kawasaki Heavy Industries at a capacity of 1,250 m^3 (89 t-LH_2), which has yet to carry out its first shipment. Some uncertainties remain regarding the real current status.
Expected development	TRL in 2030 uncertain and dependent on the development of the proposed vessel by Kawasaki Heavy Industries with a capacity of 160,000 m^3 (11,360 t-LH_2). Investment costs are expected to decrease but since vessel designs are highly specialised, will likely remain very high.
System integration	Boil-off could be completely prevented by on board reliquefaction. The minimum energy demand would be the heat of vaporisation of hydrogen, which is given as H_{vap}=898.3 J/mol (=0.123 kWh/kg) for normal boiling conditions [40]. For a boil-off of 0.2% per day, reliquefying requires an energy level that corresponds to only 0.00074% per day of the loaded hydrogen. Even if reliquefying engines are one order of magnitude worse than the optimum, the required energy for reliquefying could be almost neglected. If boil-off is used for the ship's engine, onboard reliquefaction may not be required, but the ship's speed could be optimised based on the boil-off. At long distances, ships could return "warm", which would completely reduce the boil-off on the return. The energy required for re-cooling a "warm" LNG tanker corresponds roughly to 1% of its load. If this is similar for a LH_2 tanker, it could be worth considering for the distance between Australia and Germany. However, thermal stress on the vessel structure needs to be addressed and further investigated.
Research needs	Possible retrofitting of LNG carriers could be investigated.

Reconversion

In general, regasification of LH_2 is cost and energy efficient because ambient heat can be used. The simplest regasification method is based on direct expansion, while other methods exploit more sophisticated thermodynamic cycles (e.g. Brayton and Stirling) [41] and sea water is often used as an "ambient heat source". The CAPEX costs of LH2 regasification plants are estimated to be one order of magnitude smaller compared to liquefaction plants and have an almost negligible energy demand [42]. Moreover, the large temperature difference between the LH2 and the environment can be utilised, which is often referred to as the so-called "cold energy". This cold energy could be used for cooling purposes, to produce electricity, or to improve the efficiency or capacity of thermal power plants, which has previously been realised, for example for LNG regasification [43].

Considering the large energy demand required for liquefaction of hydrogen, on the one hand, LH2 should ideally be employed in sectors where LH2 can be applied without regasification. On the other hand, however, if the downstream supply chain is cheaper for gaseous hydrogen, centralised LH2 regasification could be employed. Therefore, regasification of LH2 is rather a question of system design than a technical necessity and consequently not further discussed in this study.

4.2 Liquid Organic Hydrogen Carriers

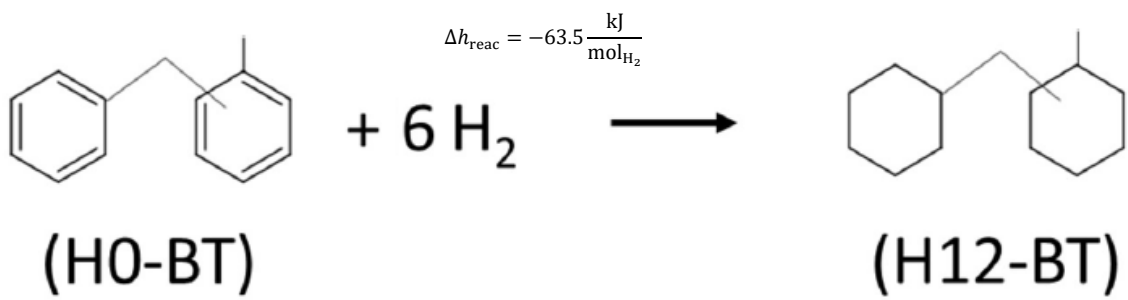
LOHCs are fuel-like chemical substances that can chemically bind and release hydrogen, which makes them a promising option for storing and transporting hydrogen. This means that there is a dehydrated form of LOHC (often aromatic compounds) to which the hydrogen can be bound via a hydrogenation reaction, and a hydrogenated form of LOHC, which needs to be dehydrated to release the hydrogen. The usage of LOHCs as a hydrogen carrier is still a rather young application. Currently, LOHCs have high costs and are produced from fossil fuels in the petrochemical industry only in smaller quantities. The building blocks, however, are available on a large scale. Possibilities to defossilise the production of LOHC molecules are for instance green methanol to aromatics, biomethane to aromatics or lignin to LOHC, all of which are currently more expensive than the fossil production routes.

Carrier properties of LOHC	
Aggregate	Liquid at ambient conditions
Chem. Formula	$C_{14}H_{26}$ / $C_{14}H_{14}$
Hydrogen content (%)	6.18
Volumetric density (t/m³)	0.876/0.996
LHV (MWh/t)	-
Boiling point (°C)	265/280
Melting point (°C)	-30

Due to their similarities with fossil fuels, the LOHC pathway can reuse existing crude oil and diesel infrastructure, e.g. for storage and shipping, which can potentially decrease costs and increase the speed of transformation. However, hydrogen and dehydration plants for the uptake and release of hydrogen need to be newly installed. In addition, after the release of hydrogen at the point of destination, the LOHC component must be returned to the point of origin, which increases the logistical effort.[13]

There are a variety of different molecules and mixtures that have been identified as potential LOHCs [44]. Especially toluene and dibenzyl toluene have been widely studied. Recently, the interest has shifted towards benzyl toluene (H0-BT), which is examined in this analysis. When loaded with hydrogen, H0-BT becomes perhydro benzyl toluene (H12-BT) (Figure 11). Advantages of H12-BT include a low melting point and low viscosity, which allows for pumping in cold regions without heating. It also has a comparatively low reaction enthalpy, which reduces the effort required for dehydrogenation, offers fast reaction kinetics, and has a high selectivity during conversion. Moreover, it has a good ecotoxicological profile.

Figure 11: Schematic reaction of benzyl toluene, reaction enthalpy at reference conditions [45].



[13] The extra logistic effort compared to other hydrogen shipping scenarios could in fact be small as in all shipping options empty ships have to return to Australia to bring another load of hydrogen in chemical bound or elemental form.

Conversion

The hydrogenation of the H0-BT LOHC component is an exothermic reaction, so that up to 9 MWh_{th}/t-H_2 is released during the process. The conversion rate is above 99% at pressures of 30 bar and temperatures of 250 °C. Due to these favourable thermodynamics and the gas-liquid-mode of the storage reaction, the hydrogenation is suitable with intermittent hydrogen input and requires no buffer storage.

Key performance indicators 2030 [HySupply]		
Capacity	t-H_2/d	60
CAPEX	€/t-H_2	51
OPEX	% of CAPEX	3
Energy demand	MWh/t-H_2	0.43
Energy efficiency	%	99

Today, the LOHC components are only produced on a small scale due to a lack of demand. However, the basic materials for their production are manufactured and used at scale in the chemical industry. About 15.2 tonnes of the unloaded H0-BT are required for the uptake of 1 tonne of H_2 under ideal conditions. Current costs are estimated at €3,500/t-H0-BT with projected cost reductions to €2,000/t-H0-BT in 2030. Consequently, providing the LOHC component with a capacity of loading 1 tonne of H_2 in 2030 is estimated to cost €30,400. Thus, setting up a large-scale LOHC-based supply chain requires investments at the beginning of the project for acquiring the initial LOHC load.

The supply of the LOHC component is challenging regarding cost and emission calculations because it largely depends on the assumed lifetime of the LOHCs. Experts estimate a lifetime of up to 200 cycles for LOHCs. With up to five round trips of LOHC vessels between Australia and Germany per year, some 40 years of continuous operation would be possible with the same LOHC load. After 200 cycles, the LOHCs can be repurified so that only a small percentage of the LOHCs need replacement. While the costs of repurification are unclear today, the impact of the cycles on cost for the LOHC component is significant: if 100% is replaced after 200 cycles, the cost for the LOHC component would be €152/t-H_2 over its lifetime. If only 10% needs replacement, the cost decreases to €15.2/t-H_2.

Similar considerations apply for potential CO_2 emissions, which can be problematic, if the H0-BT is produced from fossil feedstocks. Thermally utilising unusable LOHC molecules after the repurification process, for instance, results in 3.38 t-CO_2/t-H0-BT. In turn, if 100% of the LOHC components are replaced after 200 cycles, emissions would be 0.26 t-CO_2/t-H_2 and 0.026 t-CO_2/t-H_2 if 10% are replaced. Alternatively, non-energetic usage of the replaced LOHC components could be an option, which would result in fewer CO_2 emissions.

Qualitative Indicators [HySupply]

Current status	TRL 6 today at capacities below 5 t-H_2 per day.
Expected development	TRL 7 in 2023 when 80 t-LOHC per day plant is operational. Additional developments are expected, but uncertainties remain regarding actual LOHC production capacity, supply of LOHC components, and speed up.
System integration	Released heat can be integrated with other processes such as desalination plants or direct air capture, increasing energy efficiency to 126%. Steam produced in hydrogenation reactors can be used to drive hydrogen compression (if required) or for electricity generation to reduce overall electricity demand.

	Dedicated large-scale production of LOHC components might require additional infrastructure.
Research needs	Precious metals are used today for hydrogenation and their potential for base metals use should be explored further. Other research needs relate to the toxicity and long-term environmental impacts. The development of LOHC systems with higher gravimetric and volumetric hydrogen capacity is an active field of research. Values of up to 7.2% hydrogen content are likely within reach [46].

Storage

LOHCs are chemically stable and can be stored at ambient conditions, which makes them also eligible for the long-term storage of hydrogen. Crude oil and diesel storage tanks can be employed for LOHC storage and no technical difficulties are expected. Moreover, storage tanks, which are likely to become redundant due to the expected decrease in demand for crude oil and diesel, could be reused for LOHC storage and are a cost-efficient option.

Key performance indicators 2030 [36] [38] [14]		
Capacity	t-H_2	2,700-6,000
CAPEX	€/t-$H_{2\text{-capacity}}$	4,603-6,076
OPEX	% of CAPEX	0-2.5
Energy demand	MWh/t-H_2	~ 0
Energy efficiency	%	> 99

Qualitative Indicators [HySupply]

Current status	TRL 9 of diesel and crude oil storage infrastructure.
Expected development	Regulatory procedures for large-scale storage are not yet established, but straightforward adoption is expected, considering the more favourable ignition limits and the well-defined substance.
System integration	Reuse of diesel and crude oil tanks.
Research needs	None.

[14] The references apply dibenzyl toluene (DBT) as the LOHC component. The values presented here are adjusted to BT according to the density differences.

Shipping

The BT LOHC system has similar physiochemical properties to diesel and crude oil components and can consequently be shipped in similar vessels. These kinds of vessels are already available, consist of proven technology, and are comparatively cheap. Moreover, oil tank vessels, which will likely become redundant due to the expected decrease in crude oil and diesel demand, could be reused for LOHC shipping and are a cost-efficient option. The first LOHC-based supply chain was established in 2020 between Brunei and Kawasaki City in Japan, albeit with toluene [47].

Key performance indicators 2030 [HySupply] [35] [36][15]		
Capacity	t-H_2	4,700-12,000
CAPEX	€/t-H_2	43-82
OPEX	% of CAPEX	5
Energy demand	MWh/t-H_2	3.5-7.8
Energy efficiency	%	76-90
CO_2-emissions	t-CO_2/t-H_2	1.0-2.3 (HFO)

The LOHC pathway requires that the hydrogen-lean LOHC component is shipped back to the point of origin, which constitutes a unique feature. Consequently, vessels are also fully loaded on the return and almost no fuel savings from reduced return-weight can be realised. Note, that empty vessels are filled with ballast water to allow for proper manoeuvrability, so the extra fuel compared to an empty ship return is small.

Strategies for defossilising LOHC shipping include the usage of hydrogen from onboard dehydrogenation of H12-BT, preferably in full heat integration with the hydrogen use on board for the vessel's propulsion system e.g. using HT-PEM, solid oxide fuel cells (SOFC), or using hydrogen combustion engines. An alternative is the bunkering of additional green fuels such as green ammonia. The development of ship propulsion systems based on LOHC-bound hydrogen is an active field of development. Burning H12-BT as ship fuel directly seems not practicable due to the high costs of providing the LOHC component and the related CO_2 emissions from burning the fossil-based LOHC carrier.

Qualitative Indicators [HySupply]

Current status	TRL 9 for diesel and crude oil vessels at Suez-Canal-compatible capacities at some 180,000 m³ (about 12,000 t-H_2).
Expected development	No major developments for vessels themselves are expected. Similar to storage, regulatory procedures for large-scale transport are not yet established, but straightforward adaption from diesel and crude oil vessels is expected, considering the more favourable ignition limits and the well-defined substance. Low-emission engines utilising hydrogen or ammonia and methanol will likely be available in 2030.
System integration	Reuse of existing diesel and crude oil vessels.
Research needs	Onboard dehydrogenation coupled with SOFC for renewable fuel supply.

[15] The references apply dibenzyl toluene (DBT) as the LOHC component. The values presented here are adjusted to BT according to the density differences.

Reconversion

The dehydrogenation of H12-BT takes place at conditions above 200 °C and at pressures below 5 bar. For thermodynamic reasons higher output hydrogen pressure requires higher temperatures. The hydrogen release step requires the same heat input (63.5 kJ/mol H_2) that was liberated in the hydrogen storage process. It is highly desirable to provide this heat from the waste heat of the subsequent energetic utilisation of the released hydrogen. Additional energy is required if hydrogen purification is needed.

Key performance indicators 2030 [HySupply]		
Capacity	t-H_2/d	60
CAPEX	€/t-H_2	96
OPEX	% of CAPEX	3
Energy demand	MWh/t-H_2	12.2
Energy efficiency	%	64

The speed and the extent of dehydrogenation of the LOHC component are dependent on the design choices. High dehydrogenation speed in harsh temperature conditions contributes to faster aging of the LOHC component, while reaching dehydrogenation extents of almost 100% requires longer residence times in the reactor, i.e. higher capital investment into the reactor equipment. Therefore, dehydrogenation extents of slightly below 100%, typically 95%, are chosen for practical reasons for hydrogen logistics applications, which in turn reduces the effective hydrogen transport capacity. Nonetheless, no loss of hydrogen occurs.

Qualitative Indicators [HySupply]	
Current status	TRL 6 today at very small capacities.
Expected development	TRL 7 in 2023 when the 20 t-LOHC/day plant is operational. However, much larger capacities are required for an intercontinental supply chain.
System integration	Ideally heat integration with waste heat. For example, the waste heat of a glass factory that utilises the LOHC-shipped hydrogen for heating the glass melter can be used to drive the dehydrogenation process. Another example is the use of the waste heat of a solid oxide fuel cell that operates with the LOHC-released hydrogen. For the LOHC technology for the Australian-German supply chain it is perhaps not always necessary to release hydrogen in a large central unit. It could potentially be more suitable to transport the hydrogen-charged LOHC to the location of application (filling stations, production sites, on-board applications in trains, ships, trucks etc.) where heat integration with the waste heat from the utilisation is often possible. In central units for reconversion of loaded LOHC to hydrogen, in contrast, the dehydrogenation heat must be provided at these locations. In Germany and Rotterdam, the heat demand for such central reconversion units might be difficult to meet completely with renewables.
Research needs	Decentralised dehydrogenation for heat integration with waste heat near the end user, e.g. waste heat from engines. Current R&D has identified new routes for autothermal hydrogen release via reversible partial oxidation of the LOHC component. This autothermal release technology would reduce or eliminate the energy demand at the destination at the cost of increased energy demand in Australia. The autothermal hydrogen release from LOHC systems is currently TRL 2/3 and requires further research for technical implementation.

4.3 Ammonia

Ammonia (NH_3) has a long history of large-scale, cost-optimised industrial production and serves as a building block for the chemical industry. Over 80% of ammonia production is used for fertiliser production. Other use cases include the production of nitric acid and acrylonitrile as well as applications as refrigerants [48] [49]. Global annual production is estimated at 180 million tonnes and current prices for ammonia are some €210-220 per tonne [50]. New applications for ammonia as a renewable energy vector in ship engines, fuel cells, and power plants will likely increase future demand. Major demand could be created by co-firing ammonia in coal-fired power plants, especially in Asia [51].

Carrier properties of NH_3	
Aggregate	Liquid at -33 °C and 1 bar
Chem. formula	NH_3
Hydrogen content (%)	17.8
Volumetric density (t/m³)	0.6835
LHV (MWh/t)	5.18
Boiling point (°C)	-33.3
Melting point (°C)	-77.7

Ammonia provides the opportunity to use some of the existing LPG (liquified petroleum gas) infrastructures. Most importantly, ammonia contains no carbon, thus, no recovery or recycling is needed after a potential dehydrogenation [52]. However, ammonia is a highly toxic and irritating gas with a sharp suffocating odour. It dissolves easily in water to form ammonium hydroxide solution, which can cause irritation and burns. Any spills are likely to have severe effects on biodiversity and human health. Ammonia is not highly flammable, but containers may explode when exposed to high heat.

Since renewable ammonia is potentially both a hydrogen carrier and a renewable product, values given for capacities, CAPEX, energy demand, and shipping emissions are displayed in t-NH_3 and t-H_{2e}.

Conversion

Ammonia is conventionally produced from nitrogen and hydrogen over iron-based catalysts at pressures above 150 bar and temperatures above 400 °C through the Haber-Bosch (HB) process. Existing conventional plants have capacities of more than 3,000 t-NH_3 per day and natural gas is predominantly used as feedstock. It is necessary to remove CO_2 in the process, which can subsequently be used to produce urea or carbonic acid [48]. Remaining emissions are still comparably high at some 1.8 t-CO_2/t-NH_3 if natural gas is used as feedstock [49]. Technology suppliers and integrators are among others Air Liquide, thyssenkrupp Industrial Solutions, and Linde Engineering.

Key performance indicators 2030[16] [HySupply] [34] [38] [49] [53] [54]		
Capacity	t-NH_3/d t-H_{2e}/d	600-3,000 107-533
CAPEX	€/t-NH_3 €/t-H_{2e}	22-33 124-183
OPEX	% of CAPEX	1.5-4
Energy demand	MWh/t-NH_3 MWh/t-H_{2e}	0.4-0.7 2.3-3.9
Energy efficiency	%	77-81

[16] The air separation unit (ASU) for nitrogen production is included in the key performance indicators.

Renewable ammonia requires a modified HB process where renewable hydrogen replaces natural gas as both feedstock and fuel. Nitrogen is derived from an air separation unit (ASU) at -196 °C, replacing the reformer, converter, and gas removal of the conventional process [33] [53]. Both hydrogen and nitrogen are compressed to the required 100-250 bar for the HB synthesis loop and later refrigeration. Low equilibrium single-pass conversion necessitates multiple recycling loops to increase efficiency. The ammonia product stream is liquified via expansion cooling for storage and transport. The largest plant using the modified HB process is operated by YARA and BASF in Texas with a capacity of 2,000 t-NH_3 per day, albeit with conventional pipeline hydrogen.

Qualitative Indicators [HySupply]	
Current status	TRL 9 for conventional synthesis gas process with industrial production. TRL 7 for modified HB synthesis based on renewable electricity with single plants operating at capacities of up to 2,000 t-NH_3 per day.
Expected development	Mature technology with no major developments expected for HB process itself. TRL 9 for modified HB process in 2030 with minor cost reductions.
System integration	Steam produced in HB reactors can be used to drive synthesis gas compression or for electricity generation to reduce overall electricity demand. Since individual technologies for renewable routes are known, system integration should be straightforward. Renewable methods lose a certain level of heat integration. Existing NH_3 loops can be revamped for electricity-based production, including the ASU.
Research needs	Although HB is very mature, research can be done on catalysts that operate at lower pressures and temperatures, thus reducing OPEX. Research needs also exist for integration with renewable generation, where flexible operation will be required together with optimal integration of buffering concepts.

Storage

Liquid ammonia can be stored in carbon steel pressure vessels at ambient temperatures of 20 °C and pressures above 8.6 bar. This system does not lose any of the stored ammonia and requires no energy to maintain the pressure. Typically, these vessels operate at pressures of 17 bar to keep the ammonia in a liquid state even if temperatures increase. However, due to material mechanics, storage systems cannot be larger than 300 t-NH_3 and steel demand is significant [53] [56].

Key performance indicators 2030 [33] [34] [38] [55] [56] [HySupply]		
Capacity	t-NH_3 t-H_{2e}	40,920-114,576 7,263-20,337
CAPEX	€/t-NH_3 €/t-H_{2e}	350-2,200 2,000-12,400
OPEX	% of CAPEX	2-4
Energy demand	MWh/t-NH_3 MWh/t-H_{2e}	0.01-0.03 0.06-0.2
Boil-off	%/d	0.03-0.10

At large scales, liquid ammonia is typically stored in stainless steel flat bottom tanks at -33 °C and atmospheric pressure. Low temperature storage allows for larger units compared to pressurised gas storage and

15 times less steel demand. During storage heat enters the tanks and a portion of the ammonia continuously evaporates, creating boil-off gas. To reduce losses over the supply chain the boil-off is reliquefied when possible [53] [56]. Storing large quantities of ammonia raises environmental, health, and safety concerns due to its inherent carrier properties, especially its high toxicity. However, ammonia storage has been established on a large scale for decades and is readily available.

Qualitative Indicators [HySupply]

Current status	TRL 9 with units available at capacities of up to 45,000 t-NH_3.
Expected development	Mature technology with no major expected developments.
System integration	Existing infrastructure for ammonia as well as some existing LPG infrastructure can be used and excess energy from other processes can power the necessary cooling and reliquification. However, due to projected increase in demand new storage units are likely necessary.
Research needs	Almost none since this is an established technology.

Shipping

Ammonia is a globally traded commodity with vessels widely available for order and charter. Maritime trade in 2019 was estimated at 17.5 million tonnes with 71 liquefied gas carriers at typical capacities of 2,500-40,000 t [58]. Some 120 ports worldwide are equipped with import or export infrastructure [59]. Long distance shipping is realised at low but non-cryogenic temperatures (-33 °C), enabling transport at liquid state in steel tanks where boil-off gas can be reliquefied or partly used for propulsion [33]. Existing LPG infrastructure for storage, loading and unloading, as well as bunkering, could be retrofitted for ammonia.

Key performance indicators 2030 [33] [34] [38] [55] [57]		
Capacity	t-NH_3 t-H_{2e}	15,841-95,480 2,812-16,948
CAPEX	€/t-NH_3 €/t-H_{2e}	7-21 40-119
OPEX	% of CAPEX	3.5-5.0
Energy demand	MWh/t-NH_3 MWh/t-H_{2e}	0.5-0.9 3.0-5.2
Boil-off	%/d	0.0-0.2
Energy efficiency	%	82-91
CO_2-emissions	t-CO_2/t-NH_3 t-CO_2/t-H_{2e}	0.1-0.3 (HFO) 0.7-1.5 (HFO)

Ammonia can potentially be used in current diesel combustion engines with modifications. Renewable ammonia is being discussed as one of the most promising low-emission marine fuels which has no direct CO_2-emissions. Combustion engines, dual-fuel engines, and fuel cells can likely use ammonia for propulsion in the future. Some emissions would remain since ammonia engines require an ignition fuel such as marine diesel oil. MAN Energy Solutions and Samsung Heavy Industries announced the development of an ammonia-fuelled ultra-large container ship and an Afromax tanker by 2024 [59]. In addition, by 2024, Eidesvik and Equinor plan to retrofit a vessel with an ammonia fuel cell [59].

However, the IMO prohibits the use of cargos identified as toxic products as fuel for shipping. Bunkering and engines standards are also missing. Furthermore, uncertainties remain regarding the sustainability of

ammonia as a shipping fuel since significant amounts of ignition fuel are needed and environmental concerns regarding NOx, CO and N_2O have not been resolved yet [60].

Qualitative Indicators [HySupply]	
Current status	TRL 9 for large-scale vessels with conventional engines. TRL 6 for carriers with ammonia combustion and dual-fuel engines. TRL 3-4 for ammonia fuel cell engines.
Expected development	No major developments for vessels themselves. TRL 9 for ammonia combustion engines in 2030 with medium cost reductions. TRL 6-7 for ammonia fuel cells on smaller vessels. Uncertainties remain regarding regulations on ammonia as a shipping fuel and thus the future development of engines.
System integration	Existing ammonia infrastructure can be used and LPG as well as LEG infrastructure can potentially be retrofitted. Retrofitting LNG infrastructure might also be an option. Increased NOx emissions from ammonia engines will likely require aftertreatment on board.
Research needs	Reducing NOx and N_2O emissions, both potent greenhouse gases, as well as reducing ignition fuel demand for ammonia combustion engines will be key. Development of ship designs where boil-off ammonia can be utilised.

Reconversion

Today, there are no large-scale cracking units available for decomposing ammonia into hydrogen and nitrogen. Current commercial solutions use an electricity-based furnace at production capacities of less than 2 t-H_2 per day. These units produce a mixture of hydrogen and nitrogen for industrial applications where hydrogen purification is not required [49].

Key performance indicators 2030 [34] [39] [HySupply]		
Capacity	t-H_2/d	240-729
CAPEX	€/t-H_2	50-115
OPEX	% of CAPEX	4
Energy demand	MWh/t-H_2	11.2-13.1
Energy efficiency	%	65-73

There are several concepts for high purity ammonia cracking on larger scales. Catalytic cracking is currently being investigated at lab-scale with Nickel- and Ruthenium-based catalysts and temperatures between 400-700 °C [61]. A modelled design by [49] for high purity hydrogen production uses a gas-fired reformer design at a capacity of 200 t-H_2 per day which outputs a forming gas composed of hydrogen, nitrogen, and ammonia. Uncracked ammonia is fed back to the reformer via absorption/desorption. To reach a fuel cell-compatible ammonia content well below 0.1 ppm and to eliminate nitrogen from the syngas, final purification is based on a cryogenic cycle. The forming gas is cooled to -230 °C, nearly completely liquefying the nitrogen. Hydrogen purity is estimated at 99.97% [49]. Alternatively, pressure swing adsorption technology can be used to purify hydrogen.

Qualitative indicators [HySupply]	
Current status	TRL 4 at very small scales of less than 2 t-H_2 per day, with low purity and very high CAPEX. Currently not commercially viable.
Expected development	Significant cost reductions are expected due to economies of scale [49] [39] and technological advancements. TRL in 2030 is uncertain and highly depends on the future of renewable ammonia.
System integration	Heat integration from other sources could be an option but is challenging due to the high temperatures required.
Research needs	Catalyst optimisation and heat integration concepts for reducing external cooling needs. Material selection to prevent corrosion/embrittlement.

4.4 Methanol

Methanol (MeOH) is one of the largest volume chemicals in the world and serves as a foundation for various other products such as formaldehyde, methyl-tert-butyl ether, and acetic acid. It is currently predominantly produced from natural gas or coal. Global annual production doubled over the last decade to over 98 million tonnes [62] due to increased coal-to-methanol conversion for fuel production in China. Some 1.4 million tonnes were produced in Germany in 2019 [63]. Prices are volatile and currently at around €410 per tonne in Europe [64]. Methanol has the potential to substitute crude oil and natural gas as the major feedstock for organic chemicals, providing platform chemicals such as methyl formate and dimethyl ether as well as methanol-to-gasoline, methanol-to-olefins, and methanol-to-aromatics pathways.

Carrier properties of MeOH	
Aggregate	Liquid at standard conditions
Chem. formula	CH_3OH
Hydrogen content (%)	12.6
Volumetric density (t/m³)	0.792
LHV (MWh/t)	5.54
Boiling point (°C)	67.4
Melting point (°C)	-97.6

Converting hydrogen to methanol for storage and transport is attractive due to its high energy density, hydrogen content, and its wide range of direct applications. Furthermore, it is liquid at ambient temperatures, miscible in water and degradable. However, methanol is also toxic, easily flammable with no visible flame in daylight but extinguishable with water. It also requires a carbon source for synthesis. The combustion of one tonne of methanol emits 1.37 t-CO_2.

Since renewable methanol is potentially both a hydrogen carrier and renewable product, values given for capacities, CAPEX, energy demand, and shipping emissions are displayed in t-MeOH and t-H_{2e}.

Conversion

Methanol is conventionally produced via a copper, zinc oxide, and aluminium oxide ($Cu/ZnO/Al_2O_3$) catalyst from synthesis gas derived by reforming natural gas. The resulting process emissions are 0.3-0.4 t-CO_2/t-MeOH. Technology integrators and suppliers are among others Linde Engineering and Air Liquide. Production based on renewable energies can be done with CO_2 and H_2 provided via water electrolysis in two ways:

Key performance indicators 2030 [38] [33] [65] [66] [67] [35]		
Capacity	t-MeOH/d t-H_{2e}/d	0.72-3,000 0.09-378
CAPEX	€/t-MeOH €/t-H_{2e}	1-55 10-433
OPEX	% of CAPEX	2-4
Energy demand	MWh/t-MeOH MWh/t-H_{2e}	0.2-0.5 +2.0-2.8 for DAC 1.7-4.3 +15.8-22.8 for DAC
Energy efficiency	%	78-81 56-62 with DAC

CO_2 can be reduced to CO with the endothermic reverse water-gas shift reaction (RWGS) followed by the conventional synthesis loop [68]. The exothermic synthesis then takes place at pressures between 50-100 bar and 200-300 °C [69]. Alternatively, methanol can be produced by direct hydrogenation of CO_2 in an integrated process where hydrogenation of CO, RWGS, and synthesis of methanol run simultaneously in the loop reactor. This process offers advantages such as reduced by-product formation, higher

efficiency, and lower heat development. However, increased water formation [69] and lower equilibrium conversion necessitate improved catalyst and reactor designs [70]. Producing one ton of methanol requires 1.4 t-CO_2 and 0.2 t-H_2 as feedstock [69] [33]. The theoretical achievable maximum energy efficiency based on the LHV is estimated to be 89% [65].

Qualitative Indicators [HySupply]	
Current status	TRL 9 for conventional synthesis with giga plants available. TRL 7 for direct hydrogenation of CO_2 with first pilot projects at capacities of 4,000 t-MeOH per year, e.g. Carbon Recycling International in Iceland. TRL 4-6 for DAC and TRL for CCU depends on point source: SMR pre-combustion (9), ATR syngas capture (9), cement plant (3-4), biomass combustion plant (3-4).
Expected development	All production routes will be TRL 9 in 2030 with medium cost degression for direct hydrogenation of CO_2. High uncertainties remain for the TRL and cost development of DAC. Potential cost reductions and overall competitiveness of the synthesis are highly dependent on the price of feedstocks.
System integration	Existing conventional methanol loops can be revamped to the renewable process. Excess heat can cover some of the energy requirements of DAC. Intermittency of renewable energy production requires concepts for buffer storage.
Research needs	Catalyst improvements for longer service, higher selectivity, higher activity, resulting in fewer by-products and smaller reactors; better system integration with renewables; H_2 recovery concepts.

Box 3: Carbon sources for methanol production [67] [70] [73]

The necessary carbon feed for the synthesis of methanol based on renewable energies can be captured from industrial point sources, biogenic sources, and from ambient air by direct air capture (DAC). Capture costs vary greatly, depending on the type of source, available CO_2 quantity, as well as on flue gas conditions such as temperature, CO_2 partial pressure and contaminants in the flue gases. Estimated costs for capturing carbon from diluted industrial and biogenic flue gases range from €50-100/t. CO_2 from highly concentrated sources such as bioethanol, conventional ammonia, and hydrogen plants can be captured for much less. Due to the lower TRL of DAC and lower CO_2 concentration in ambient air, current costs for DAC are at least €250/t [67] [70], with some projections going as high as €1,000/t [73]. Progressive scenarios assume cost reductions to around €120/t by 2030 [67]. Climeworks, a Swiss company specialising in DAC, has claimed long-term price targets of less than €75/t. However, in 2017 their self-estimated cost was still around €500/t. Other factors such as scalability, long-term availability, sustainability, and creditability of the carbon sources must be considered as well.

There is currently no comprehensive regulation on eligible carbon sources for methanol in Germany. In line with RED II, a major EU legislation regulating renewable fuels in the transport sector, the electricity used for carbon capture would be required to comply with four, not yet specified criteria, if methanol is to be counted as renewable: renewability, geographical correlation, temporal correlation, and additionality. While the RED II does not exclude any carbon source per se, it is very likely that industrial point sources must be “unavoidable”. However, the legislation does not make any further specifications. The RED II is scheduled to be adopted into German law in late 2021. The competitiveness of carbon sources will also be influenced by the carbon border adjustment mechanism, which is currently being developed by the EU.

Storage

Methanol is stored at ambient conditions in carbon steel or stainless-steel chemical tanks with capacities of up to 50,000 m³ (39,600 t-MeOH) per unit. Storage is easy without any boil-off and requires only very little energy input. Due to methanol's inherent properties, vapour treatment and firefighting measures are needed at storage sites. Since methanol is already globally traded, re-using existing storage units can reduce necessary investments.

Key performance indicators 2030 [33] [38]		
Capacity	t-MeOH t-H_{2e}	39,600-132,000 4,990-16,632
CAPEX	€/t-MeOH €/t-H_{2e}	75-379 595-3,006
OPEX	% of CAPEX	1.0-2.5
Energy demand	MWh/t-MeOH MWh/t-H_{2e}	0-0.0015 0-0.01
Efficiency	%	> 99

Qualitative Indicators [HySupply]

Current status	TRL 9 with large units available.
Expected development	Mature technology used at large scale with no major developments expected.
System integration	Due to existing regulations on biofuels, conventional MeOH must be stored separately from bio MeOH. If renewable methanol is not substituting conventional methanol, it is very likely that new units will be required for any potential supply chain.
Research needs	None.

Shipping

Methanol is the highest volume chemical commodity shipped globally with chemical vessels of various scales being readily available for order and charter. Double-walled pipes are required for loading and unloading due to safety concerns. On board, methanol can be stored at ambient conditions in zinc-coated steel ballast tanks. Methanol cargos require inert atmospheres to prevent the formation of explosive atmospheres. This can be done by displacing air (oxygen content should be less than 8%) and moisture prior to loading with nitrogen or other inert gases. Methanol is already handled as a cargo product in compliance with international shipping regulations and guidelines.

Key performance indicators 2030 [33] [38] [57]		
Capacity	t-MeOH t-H_{2e}	17,048-110,880 2,148-13,971
CAPEX	€/t-MeOH €/t-H_{2e}	3-24 24-193
OPEX	% of CAPEX	3.0-6.5
Energy demand	MWh/t-MeOH MWh/t-H_{2e}	0.4-0.8 3.2-6.6
Energy efficiency	%	85-93
CO_2-emissions	t-CO_2/t-MeOH t-CO_2/t-H_{2e}	0.1-0.2 (HFO) 1.1-1.9 (HFO)

If the CO_2 for the methanol synthesis is provided from sustainable sources such as biomass and DAC, methanol is potentially a low-emission shipping fuel. Existing two-stroke dual-fuel engines can run on HFO and methanol. Furthermore, conventional combustion engines can be converted to methanol with minor modifications to the fuel injection system [33]. Ship-to-ship bunkering can also be carried out with the same barge types as HFO. Interim guidelines for methanol as fuel are in place with comprehensive regulations currently being drafted [59]. The first smaller engines running completely on methanol are already in operation [33], provided predominantly by MAN Energy Solutions. Maersk, the largest shipping company in the world, is aiming to operate the first commercial scale methanol-fuelled vessel by 2023, which will be provided by South Korean shipbuilder Hyundai [59].

Qualitative Indicators [HySupply]	
Current status	TRL 9 with conventional and dual-fuel engines with large-scale vessels. TRL 6-8 with alternative engine designs running on methanol.
Expected development	Mature technology used at large scale with no major expected developments. TRL 9 for methanol engine designs in 2030. Widespread application is expected due to IMO climate targets and methanol already being one of four supported fuels for international shipping. Cost reductions for methanol engines are expected.
System integration	Chemical vessels are flexible and can transport various chemical commodities after cleaning at destination port. An increasing amount of trade is performed using dedicated methanol vessels, eliminating some flexibility but also the need for cleaning.
Research needs	More efficient engine designs such as methanol fuel cells as well as larger vessels that comply with safety standards.

Reconversion

Retrieving hydrogen from methanol can be done by high temperature steam reforming and by low-temperature dehydrogenation. Methanol reforming is a known but energy-intensive, three-stage process, which operates at high temperatures above 400 °C over a heterogenous catalyst. The product stream consists of H_2, CO_2, and CO (syngas) and requires aftertreatment due to the high toxicity of CO. Low-temperature dehydrogenation is in the early stages of development and

Key performance indicators 2030[17] [HySupply] [38]		
Capacity	t-H_2/d	2,100-3,000
CAPEX	€/t-H_2	105-245
OPEX	% of CAPEX	3
Energy demand	MWh/t-H_2	10.5-15.3
Energy efficiency	%	56-61

[17] Indicator values depict the steam reforming route for methanol.

promises only very small amounts of CO in the product stream but also slower reaction speeds. After re-conversion, the hydrogen stream must be purified and compressed for transport and distribution. The outgoing CO_2 can either be captured and stored, reused, or released into the atmosphere [66] [71].

Other technologies that use hydrogen directly such as methanol-to-gasoline, methanol-to-olefines, as well as conversion to chemical commodities are likely much more promising. Methanol can also be used directly in fuel cells for energy production.

Qualitative Indicators [HySupply]

Current status	TRL 9 for small scales at capacities of less than 1 t-H_2 per day and TRL 5-6 for large scales. TRL 3 for low-temperature dehydrogenation at small scales.
Expected development	Uncertain development since it appears unlikely that methanol reforming will be a suitable solution for renewable hydrogen production. Significant scale up would be necessary.
System integration	Large energy demand at destination makes additional capacities of renewable energies necessary since reforming with grid electricity is almost at grey hydrogen emission intensity levels. Suitable only for remote locations.
Research needs	Reduction of reforming temperatures and further development of low-temperature dehydrogenation.

4.5 Overview of transport options

Liquid hydrogen

Liquid hydrogen is currently used in niche applications and is therefore not a globally traded commodity. There is limited experience in large-scale handling and operation and no comprehensive regulatory framework is in place. Potential retrofitting of LNG infrastructure is currently being explored. The pathway does not require additional chemical elements for conversion. Reconversion is cost and energy efficient, if required, and "cold energy" could be integrated for additional energy savings. Liquefaction and storage have a high TRL but at small capacities and are associated with high cost. The pathway requires highly specialised and expensive vessels, of which only one is built at a very small scale. All necessary technologies for the supply chain between Australia and Germany will likely be mature in 2030 while uncertainties remain regarding vessels, where future development is highly uncertain. The future market for molecular hydrogen is expected to grow, which makes liquid hydrogen very attractive.

	CAPEX €/t-H_2	OPEX % of CAPEX	Energy demand MWh/t-H_2	Efficiency %	TRL Today (2030)
	160-203	2-4	6-8	76-82	9
	12,800-80,225[18]	4	Depends on storage length and reliquefaction strategy.		9
	108-451	0.02-4.0	1.7-11.5	59-84 (BOG unused) 89-90 (BOG used)	6 (uncertain)
	Regasification of liquid to gaseous hydrogen is a question of system design.				

The biggest challenges

- Competitiveness of LH_2 pathway is highly dependent on the cost of energy and hydrogen.
- Current liquefaction plants are not optimised for efficiency and have high energy demands, which need to be addressed for commercial application.
- Liquefaction based on exclusively intermittent renewable electricity likely requires some form of additional hydrogen buffer storage capacities or battery storage.
- High uncertainty regarding LH_2 vessel data since only one small-scale demonstration vessel is in operation. Furthermore, there is currently only one technology provider and the availability of sufficient large-scale vessels by 2030 is uncertain.
- Comprehensive regulation on hydrogen as a shipping fuel, including handling and safety guidelines, is missing. Some uncertainties regarding widespread availability of hydrogen compatible engines.
- Infrastructure must be fitted for handling cryogenic materials and to minimise boil-off losses caused by heat entry. Furthermore, risk of explosions through BOG and other potential leakages, which stems from wide ignition limits of hydrogen/air mixtures and the low ignition energy of hydrogen.

[18] CAPEX of storage is highly dependent on annual throughput and supply chain design. Displayed values are €/t-capacity.

Liquid Organic Hydrogen Carriers

The BT-LOHC technology is comparatively young with no established global market. There is limited experience of large-scale handling and operation and no comprehensive regulatory framework is in place. However, petro-chemical products such as BT have been handled and shipped for almost a century. Typical crude oil and diesel infrastructures can be utilised, especially storage capacities and vessels, which are known and available supply chain elements. Hydrogenation and dehydrogenation are available but currently only in small scales with medium TRL. The LOHC pathway offers high potential for cost reductions through economies of scale and better system integration. All necessary technologies for the supply chain between Australia and Germany will likely be mature by 2030. The future market for LOHC as a hydrogen carrier depends on the development of hydrogen release technologies.

	CAPEX €/t-H_2	**OPEX** % of CAPEX	**Energy demand** MWh/t-H_2	**Efficiency** %	**TRL** Today (2030)
	51[19]	3	0.43	99	6 (7)
	4,603-6,076[20]	0-2.5	~ 0	> 99	9
	43-82	5	3.5-7.8	76-90	9
	96	3	12.2	64	6 (7)

The biggest challenges

- Competitiveness of LOHC pathway is highly dependent on the costs of energy, hydrogen, and the LOHC component. Initial investment in LOHC is required for the provision of H0-BT.[21]
- Global production of H0-BT is currently insufficient for large-scale LOHC systems and hydrogenation and dehydrogenation plants have not been realised at scale yet.
- Low-emission shipping of LOHC requires either on-board dehydrogenation or other fuels such as ammonia.
- Dehydrogenation currently requires large amounts of energy. Smart integration concepts are likely necessary, i.e. the usage of waste heat of high temperature fuel cells or coupling with waste heat from energetic hydrogen use.
- Missing regulation regarding the usage of fossil-fuel-based LOHC components for the creditability of “green” hydrogen in Europe.

[19] Provision of H0-BT carrier is not included. Additional specific CAPEX are highly dependent on possible cycles of the LOHC component.

[20] CAPEX of storage is highly dependent on annual throughput and supply chain design. Displayed values are in €/t-capacity.

[21] Current costs for H0-BT are estimated at €3,500/t and projected to decline to €2,000/t by 2030. Some 15.2 tonnes are required for the uptake of 1 tonne H_2, resulting in necessary initial investments of €30,400/t-H_2 in 2030.

Ammonia

Ammonia is a globally traded commodity with a long history in handling and processing as well as an existing regulatory framework for conventional production, storage, and transportation. Ammonia production is well established, and the conventional process can be revamped for renewable electricity-based synthesis. Storage capacities as well as ammonia vessels are widely available and known supply chain elements. All technologies necessary for the scale up of a renewable ammonia supply chain between Australia and Germany are mature with high TRL and moderate capital cost. Existing ammonia infrastructure can be used, and LPG and LNG infrastructure can likely be retrofitted. The future market is projected to grow, which makes direct use of ammonia without reconversion an attractive option.

	CAPEX €/t-NH_3 (t-H_{2e})	**OPEX** % of CAPEX	**Energy demand** MWh/t-NH_3 (t-H_{2e})	**Efficiency** %	**TRL** Today (2030)
	22-33[22] (124-183)	1.5-4.0	0.4-0.7 (2.3-3.9)	77-81	7 (9)
	350-2,220[23] (2,000-12,400)	2-4	0.01-0.03 (0.06-0.2)	> 95	9
	7-21 (40-119)	3.5-5.0	0.5-0.9 (3.0-5.2)	82-91	9
	50-115	4	11.2-13.1	65-73	4 (uncertain)

The biggest challenges

- Competitiveness of the ammonia pathway is highly dependent on the costs of energy and hydrogen.
- Ammonia's high toxicity and severe adverse effects on biodiversity and human health could potentially be barriers for social acceptance of imports. Handling of NO_x and N_2O emissions and minimising leakage risks is critical.
- Production based on exclusively intermittent renewable electricity likely requires some form of additional buffer storage capacities for hydrogen, nitrogen, and ammonia or additional battery storage.
- Conventional ammonia production in Germany is highly integrated and by-product CO_2 is a valuable raw material for urea and carbonic acid production. Substituting domestic production with renewable imports from Australia would necessitate the provision of alternative feedstock for these products.
- Ammonia is currently prohibited as a shipping fuel since toxic cargo cannot be used as fuel. Comprehensive regulation for ammonia, including handling and safety guidelines, is missing.
- Uncertainties regarding widespread availability of sufficient ammonia compatible engines remain.
- Reconversion of ammonia is currently not commercially viable, adds complexity, and a bottleneck due to its low TRL, high cost, and high energy demand. Future development is uncertain.

[22] Values for ammonia synthesis include the ASU for nitrogen production.

[23] CAPEX of storage is highly dependent on annual throughput and supply chain design. Displayed values are in €/t-capacity.

Methanol

Methanol is a globally traded commodity with a long history in handling and processing as well as an existing regulatory framework for conventional production, storage, and transportation. Methanol production is well established, and the conventional process can be revamped for renewable CO_2-based synthesis. Storage capacities and methanol vessels are widely available and are well known. All technologies necessary for the scale up of a renewable methanol supply chain between Australia and Germany are mature with high TRL and moderate capital cost. Existing methanol infrastructure can be used. The future market is projected to grow, which makes direct use of methanol without reconversion an attractive option.

	CAPEX €/t-MeOH; t-H_{2e}	**OPEX** % of CAPEX	**Energy demand** MWh/t-MeOH; t-H_{2e}	**Efficiency** %	**TRL** Today (2030)
	1-55 (10-433)	2-4	0.2-0.5 (1.7-4.3)	56-62	7 (9)
	75-379[24] (595-3,006)	1.0-2.5	< 0.0015 (< 0.01)	> 99	9
	3-24 (24-193)	3.0-6.5	0.4-0.8 (3.2-6.6)	85-93	9
	105-245	3	10.5-15.3	56-61	5-6 (uncertain)

The biggest challenges

- Competitiveness of the methanol pathway is highly dependent on the costs of hydrogen, energy, and CO_2. Especially CO_2 capture can add significant cost.[25]
- Eligible CO_2 sources for production are uncertain due to the missing regulations in Germany.
- Offsetting of emissions reduction from capturing CO_2 in Australia and potential release in Germany.
- Future development of DAC in terms of cost and availability is uncertain. Low TRL for other CO_2 capture technologies, i.e. biomass and cement plants.
- Carbon content of methanol could be a potential barrier to public acceptance.
- Synthesis based on exclusively intermittent renewable electricity likely requires some form of additional buffer storage for hydrogen, carbon dioxide, and methanol or additional battery storage.
- Timely transition from interim to comprehensive regulation for methanol as a shipping fuel, including handling and safety guidelines.
- Some uncertainties remain regarding the widespread availability of sufficient methanol engines.
- Large-scale reconversion of methanol adds complexity and presents a bottleneck due to its low TRL, high cost, and high energy demand. Future development is uncertain.

[24] CAPEX of storage is highly dependent on annual throughput and supply chain design. Displayed values are in €/t-capacity.

[25] CO_2 cost of €250/t would add €350/t-MeOH to the CAPEX of the methanol pathway, which almost equals the current market price for conventional methanol in Europe (€410/t). Furthermore, DAC would increase the energy demand by some 2.0-2.8 MWh/t-MeOH.

5 Cross-cutting gaps and barriers

The analysis of the transport options and expert discussions within the German project group revealed certain gaps and barriers that can mainly be attributed to the fact that trade relations on renewable hydrogen and PtX-products are still in their infancy. In order to be able to implement a supply chain for hydrogen and PtX-products between Germany and Australia, challenges arising from these gaps and barriers need to be addressed. Once identified and tackled, they can become opportunities for the hydrogen bridge between the two countries.

A	**Intermittent electricity generation**
Challenges	One of the greatest challenges for the supply chain is the availability of sufficient renewable electricity to fuel hydrogen production as well as all subsequent processes. Even when the needed capacity is built, the challenge of the natural intermittency of renewable energy sources remains. In general, most of the subsequent synthesis processes and plants should be operated constantly, either for economic (CAPEX) or performance reasons such as to operate near the predesigned efficiency optimum. Moderate adjustment of the capacity is often possible at the cost of some loss of efficiency, but complete stops and restarts of the plant should be avoided. Restarting of plants often requires substantial energy and leads to faster attrition, which is especially challenging for cryogenic temperatures (e.g. liquefaction of hydrogen) or high temperatures (e.g. ammonia production).
Opportunities	To combat the natural intermittency of renewable electricity generation, the postprocessing steps can be designed with a smaller capacity compared to the installed renewable energy capacity. Thereby, the electrolysis plant can run with full capacity, even at reduced electricity supply. However, this approach will result in electricity generation peaks that are above the capacity of the electrolysis. This surplus can be fed into the grid or supply other off-takers, which might be challenging at remote or standalone production sites without grid connection in Australia. Furthermore, it is only economically feasible as long as the CAPEX for electrolysis and downstream processes is higher than for the power supply. Another strategy to account for intermittency is to store the electricity or heat, e.g. through overnight storage, or by storing other products such as hydrogen. While storage is a straightforward method, capacity is often expensive and losses can occur, especially for heat and electricity. Therefore, this option is often chosen to account for short-term but not for seasonal fluctuations. For the latter, segmented plant strategies can be applied. For example, instead of one large electrolyser, two medium size electrolysers can be built so that one electrolyser can run all year long while the other one is just added during the summer months. Thereby, the full-load hours can be maximised.

B	**Infrastructure integration**
Challenges	New technologies usually require the build-up of new infrastructure, which can lead to high upfront investments and might require long planning and approval processes. There is also a high risk of stranded investments when more attractive technologies emerge and the initially chosen pathway loses competitiveness. This is particularly challenging when the technology is not suited to be integrated unlike its conventional counterpart. Moreover, regulations and standards are usually non-existent at present, which further complicates implementation. Thus, reusing infrastructures and assets will be essential to help facilitate a step-by-step approach.
Opportunities	The LH_2 pathway could potentially make use of the existing LNG terminal and storage infrastructure in Australia and Europe. Research is being conducted on modifying existing LNG tanks. While synergies with the cold integration of LH_2 exist, this has not yet been demonstrated. The LNG Terminal at the Port of Rotterdam is investigating this option, which has potential for this specific supply chain. LOHC could reuse widely available crude oil terminals with respective storage facilities in Australia and Europe. Due the projected decreasing demand for crude oil, these infrastructures are potentially abundant. Moreover, existing large crude oil vessels can carry LOHC without any modification. However, engines will likely have to run on other bunker fuels such as methanol since typical combustion engines cannot be retrofitted for LOHC. Methanol is currently not being produced in Australia and thus there is no existing infrastructure for exports. For shipping, however, chemical vessels are readily available on the global market, and their engines can be retrofitted for methanol as a bunker fuel. Furthermore, several chemical terminals with storage facilities are available in Europe. Ammonia technically has existing infrastructures in place for every step of the value chain since Australia is a large producer and exporter of conventional ammonia. Existing HB plants could be revamped. Marine vessels are also plentiful and retrofitting NH_3 engines should be possible once regulations are in place. There are multiple terminals available in Europe, including in the Port of Rotterdam and some German ports that have plans for new dedicated green ammonia terminals. Theoretically, LNG terminals could be revamped for NH_3.

C Shipping emissions

Challenges

In 2018, international shipping was responsible for 0.9 Gt/CO_{2e} (2% of total global emissions) [72]. The considered vessels in this analysis use heavy fuel oil for propulsion due to the limited availability of alternative low-emission engine designs. As a result, today, all transport options would have some direct CO_2-emissions from shipping: LH_2 and LOHC vessels in the range of 0.5-3.3 t-CO_2/t-H_2, ammonia and methanol in the range of 0.1-0.3 t-CO_2/t-product (0.7-1.9 t-CO_2/t-H_{2e}). This could potentially be a dealbreaker regarding public acceptance and certification.

Neither hydrogen-fuelled engines nor ammonia-fuelled engines applicable to ships of larger size are fully commercial yet. Both ammonia and hydrogen are currently prohibited as shipping fuel and need thorough regulations on handling and safety.

Methanol is the only considered transport option that is currently in operation as fuel for international shipping. However, regulation is only interim and the share in total annual consumption is small at less than 0.01%.

Opportunities

From a technical standpoint, ammonia, hydrogen, and methanol are all suitable low-emission shipping fuels. Retrofitting of existing combustion engines is very likely possible and fuel cells are in development with moderate TRLs. All three fuels also have reduced sulphur emissions, which are typically a huge problem for international shipping. For low-emission LOHC shipping, either these fuels or alternatively, on-board dehydrogenation to hydrogen with integrated SOFC heat management can potentially be applied.

While methanol combustion has direct emissions of 1.37 t-CO_2/t, shipping can be climate-neutral if the CO_2 for production is supplied by sustainable sources. Ammonia and hydrogen do not emit CO_2 by combustion, but NOx emissions are likely to be an issue as well as minor emissions that occur from ignition fuels such as marine diesel oil. At later stages bio or renewable synthetic fuels can be used for ignition to reduce total emissions to zero. The demand for alternative low-carbon fuels will be immense: if 30% of current marine fuel consumption were to be covered by ammonia, an additional 150 million tonnes of ammonia per year would be required, almost doubling current global production [58].

D	**Regulatory framework**
Challenges	Since no global market for hydrogen and other renewable energy carriers has been established yet, numerous unsolved questions and challenges stem from regulatory uncertainties. When there are no clear regulatory framework conditions in place, private investors will withhold their investments, which impedes the development of international trade for renewable energy carriers. Major uncertainties include the lack of a clear definition for “renewable energy carrier”, corresponding certifications as well as recognition of avoided emissions. Alignment with WTO regulations puts additional pressure on the uncertainties to be resolved.
Opportunities	In order to apply renewable hydrogen as well as PtX-products and account it towards achieving emissions reductions, a clear harmonised definition of what constitutes renewable features is central. The implementation of the Delegated Act of the European Renewable Energy Directive (RED II) is crucial to define the sustainability criteria for electricity used for the hydrogen production[26] as well as the GHG calculation and the eligibility of carbon sources for synthetic fuels. The ongoing development of a trade agreement between Australia and the EU is another major vehicle for the future trade of renewable energy as this would also enable the acknowledgement of guarantees of origin. Once the renewable energy carriers are defined, there is a need for a mechanism or agreement to determine where the avoided emissions from producing and using renewable energy carriers will be accounted – only in the country of destination or partly in the country of origin – to avoid double counting. To overcome uncertainties and barriers possibly imposed by WTO regulations, models such as “book and claim” might facilitate the trade of renewable energy carriers. However, it needs to be investigated whether this is favourable for a bilateral supply chain.

[26] There are four criteria categories that are, however, currently only applicable to the transport sector, i.e. “renewability”, “temporal correlation”, “regional correlation”, and “additionality”.

E Shifts of industrial value chains

Challenges

Due to Germany's limited capacity to produce sufficient renewable hydrogen at competitive prices, imports constitute a great opportunity to harness the world's best locations with low production cost. If renewable energy carriers such as ammonia and methanol or, alternatively, further processed products such as reduced iron can be delivered cost-effectively and at scale, implications for the value chains of today's industries might arise. This might especially be the case where the whole value chain operates in Germany and no raw materials are imported.

When it comes to conventional ammonia and methanol in Germany, natural gas is imported as a feedstock. However, the downstream processes of then producing ammonia from hydrogen and nitrogen as well as using the by-product CO_2 to produce urea and carbonic acid production are highly integrated. This means that if renewable ammonia was supplied by imports, no value would be added to produce ammonia in Germany anymore. Furthermore, the CO_2 would need to be supplied by other carbon sources, adding costs. Similarly, the processing steps to produce steel take place in Germany whereas the raw materials used for the conventional blast furnace route are provided by imports. Compared to ammonia, however, the production technology needs to be changed in order to be able to use renewable hydrogen. Although the German steel industry is engaging in the development of DRI-based processes, countries like Australia that can export both hydrogen and iron ore at scale might be able to supply the "new" raw material for these processes.

Opportunities

The growing global hydrogen economy and potential shifts in existing industrial value chains can also offer opportunities for German companies. When future hydrogen exporters increasingly engage in further synthesis processes such as for ammonia and methanol, Germany could be a leading technology provider. Individual companies might already have foreign branches in those countries or can potentially create Joint Ventures. European companies could also establish a consortium on raw materials which would collectively ensure the export of European technologies while securing the supply of renewable energy carriers or products from foreign countries. Since shifts in industrial value chains impact domestic employment, a public debate is needed to discuss how much certain value chains are valued as well as what makes the most sense from an economic and environmental perspective.

6 Envisioning the German-Australian Hydrogen Partnership

In June 2021, Germany and Australia signed a Declaration of Intent (DoI) on the Australia-Germany Hydrogen Accord[27] "to enhance collaborative activities in technological innovation, research, development and deployment, to build a global hydrogen industry with deep and robust supply chains, and accelerate pathways to achieve net zero emissions as soon as possible". The Accord will focus on three initiatives: 1) the German-Australian Hydrogen Innovation and Technology Incubator (HyGATE) which promotes renewable hydrogen projects along the whole supply chain, 2) the support of German-Australian demonstration projects in Australian hydrogen hubs as well as 3) exploring the opportunities to best make use of Germany's H2Global initiative for the trade with Australia.

Together with HySupply, the Accord and the three proposed initiatives can lay the foundation for a future hydrogen partnership. From the perspective of the German project group, a strong and long-term partnership between the two countries is ideally based on three pillars: reliable framework conditions, equal opportunities, and shared responsibilities.

Reliable conditions

Partnerships are based on trust and reliability. Establishing that trust requires reliable framework conditions as well as mutual agreement on a shared vision. A DoI on the national level that underlines the long-term commitment of both parties was found to be a cornerstone for a German-Australian hydrogen partnership and has been achieved by the DoI on the Hydrogen Accord. It also included matching governmental funds, which was determined as another element required to build up confidence among industries and investors and provide a sustainable environment for long-term investments.

While clarity is needed on what each party is guaranteeing to bring into the partnership, it was agreed that one of the most important vehicles to kick-start any hydrogen supply chain is to ensure the reliable off-take from Germany. Therefore, instruments are needed to bridge the gap for economic viability, such as through the funding of capital costs, contracts for differences or quotas for renewable energy in sectors like transport, and additional R&D funding. Only once reliable off-take is established, will Australia be able to provide long-term guarantees for supply at scale.

Equal opportunities

We believe that Australia and Germany see eye to eye as equals. Therefore, providing equal opportunities with mutual benefits is crucial for the long-term success of the partnership. Institutionalised and continuous knowledge exchange will be key to realising win-win-situations. Joint research and development should be intensified and bilateral projects such as HySupply can serve as a role model. For Germany in particular, the partnership provides the opportunity to import renewable hydrogen and hydrogen-based energy carriers at scale to meet the projected demand and achieve climate neutrality well before 2050. In addition, exporting German hydrogen technologies can provide sustainable jobs in Germany and secure the leading role

[27] The text of the Accord as well as the press statement of the BMWi can be found on their website: BMWi - Federal Ministry for Economic Affairs and Energy - Declaration of Intent signed to establish German-Australian hydrogen alliance.

of German industry in a competitive global environment for low-carbon technologies. With joint ventures along the supply chain and German technologies, the partnership can strengthen Australia's future as a renewable energy giant, creating jobs and providing added value in local communities. Together, both parties are in a great position to shape the future hydrogen economy.

Shared responsibilities

If the intended partnership of equals is to be successful, responsibilities must be shared equally between the two countries. As highly industrialised nations, both Germany and Australia share the responsibility of reducing emissions and tackling climate change. A strong commitment to climate neutrality by both parties on the national level can be the anchor for the hydrogen partnership. Providing additional renewable capacities for hydrogen production will be critical in underlining the ambitions for sustainability. To achieve this transformation, the necessary investments in infrastructures and technologies should be shouldered by the public and private sectors. When the responsibilities within the partnership are shared across countries and sectors, the relationship grows stronger and risks can be minimised. Ultimately, the partnership should systematically lead to a transformation of the respective national energy and economic systems towards climate neutrality.

7 Conclusion and next steps

The aim of this meta-analysis was to take a first step towards a German-Australian supply chain for renewable hydrogen. It was shown that both countries are ideally suited for a bilateral hydrogen partnership: Germany's substantial demands for green molecules meet Australia's promising potential to produce renewable hydrogen at scale. Furthermore, Germany's technology leadership and know-how can fuel Australia's ambition to become a future energy giant and major exporter of renewable energies. To harness the full potential of the promise of hydrogen, a future partnership should be based on reliable conditions, equal opportunities, and shared responsibilities.

The missing link for 'shipping the sunshine' and realising a future supply chain is the intercontinental transport of renewable energies and green molecules. This analysis has considered liquid hydrogen (LH_2), liquid organic hydrogen carriers (LOHC), ammonia (NH_3), and methanol (MeOH) as suitable transport options for providing green molecules from Australia. Given the premise of realisation by 2030, each option comes with different advantages and disadvantages, but all have in common that shipping will likely be a small cost factor for the supply chain. Nonetheless, a range of cross-cutting challenges have been identified that need to be fully understood and successfully tackled so that they can become opportunities for the implementation of the hydrogen supply chain. These include dealing with the intermittency of renewable energy, identifying possible infrastructure integration, dealing with emissions from shipping, addressing the lack of clear regulatory framework conditions, and discussing the future of industrial value chains.

Key messages of this analysis

1. Germany's demand for hydrogen and PtX will be significant and imports are necessary
2. Australia is willing and able to become a future hydrogen and PtX exporter to Germany
3. Long distance transport between the two countries is technically feasible
4. The future partnership should be built on reliable conditions, equal opportunities, and shared responsibilities
5. The window of opportunity and time for action is now

Since the analysis was based on literature reviews and expert discussions within the German project group, the results presented are not exhaustive and merit further analysis. More specifically, the following aspects are planned to be addressed as next steps:

- Diving deeper into the quantitative assessment of the different transport options.
- Merging the results from both preliminary analyses and developing a common understanding of the supply chain by providing a comprehensive model that includes all relevant elements, from production in Australia to application in Germany.

- Discussing the possible shift of value chains for certain industries and products such as green steel and green ammonia as well as their impact on the industrial policy of Germany.
- Identifying and evaluating funding schemes and mechanisms for hydrogen imports and including stakeholders such as insurance companies and financiers.
- Diving into the regulatory framework for the seaborne transport of hydrogen and PtX-products as well as working on contract design and logistics for trading hydrogen internationally.
- Discussing the CO_2 footprint of renewable hydrogen and PtX-products from Australia and potential ways to credit them towards obligations in Germany.

The next phase of HySupply will also focus on identifying the needs and interests of relevant German stakeholders from industry and academia for a future hydrogen cooperation with Australia. Based on this, options for actions for German industry and academia but most importantly for German policy makers will be identified and outlined in a clear roadmap.

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