DECHEMA

German Australian Business Council

Trans4ReaL

H2FORUM

H2 – Beyond the Hype

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Executive Summary

Green hydrogen, defined as hydrogen generated with water electrolysis powered entirely by renewable electricity, is expected to play a pivotal role in transforming the conventional energy and feedstock base in Europe, in line with the European Union's Net-Zero targets by 2050. Accordingly, from 2020, the EU launched a series of measures aimed at accelerating technical development of hydrogen technologies and their implementation at industrial scale. At the same time, Australia launched its »shipping the sunshine« strategy. In combination with very optimistic assumptions on cost degradation, industry experienced a significant hype. As reality sinks in and the true costs become apparent, it is time to take stock on progress made and challenges encountered on the pathway to green hydrogen. A diverse group of experts from the fields of technology, project development and execution, and financing and legal convened in a workshop entitled »Green H_2 – Beyond the Hype« to discuss these issues under the Chatham House Rule. This report is the summary of the outcomes of proceedings that took place at the DECHEMA premises on 20th of February 2025.

Green hydrogen has the potential to not only displace fossil derived energy and hydrogen for industrial users. It also enables renewable energy to be made accessible beyond spatial and temporal constraints, strengthening energy security in a low-carbon world based on renewable energies. It plays a vital role in transforming the steel and chemicals sectors which remain crucial industries. However, the envisaged timeline for change is very ambitious especially for strongly industrialized countries. This transformation to a low carbon economy must simultaneously keep the industries globally competitive. Since abundant and cheap green hydrogen will not exist widely for 10 – 20 years on its own merits in contrast to conventionally produced hydrogen, ongoing government intervention will be required to stimulate the development.

There are two main challenges: Firstly, how to close the gap between the high green hydrogen price and ROI required to make an electrolyser project viable? This can only be addressed by a deeper understanding of the electrolyser technology, project EPC and the true costs behind the economics of green hydrogen plants. Secondly, how to win over potential offtakers of green hydrogen without the need for massive and ongoing government subsidies but preserving industries' ability to compete globally. Since low-carbon hydrogen will remain more expensive, the free market alone won't be able to solve this issue.

Electrolyser technology cannot hope to demonstrate the same cost reduction curves as seen in wind and PV development, due to it being fundamentally limited to an improvement of a factor of 2. Nor is a comparable economy of scale of conventional gas/oil-based plants expected, due to it being a surface technology scaled-up by module multiplication. While development of stacks continues at the same time as scaling-up production facilities, field experience and reliable records of extended operation are lacking. This represents a significant project risk for a potential offtaker and may partly explain slow project progression. Some OEMs will likely not survive commercially and this disconnect poses an ongoing economic risk for proposed and built plants at scale. Finally, distribution costs of both power and hydrogen are rarely factored into the overall delivered cost of hydrogen to the offtaker, leading to unrealistic expectations that have materialised in high-cost projects and resulting low FID progression. Greater transparency of the green hydrogen delivered cost is required.

Green hydrogen prices can only reduce through higher efficiency technology (under development) or access to lower REN power costs. When considering the risks still present with the large-scale EPC of these plants as of today, and the unknown operational performance of large electrolyser plants, it is strongly suggested that future subsidies should be limited to either OPEX (power price subsidies) or hydrogen production itself (tax credits, subsidy for hydrogen produced). This insulates the tax payer from poor EPC execution or technology risk that should lie with the project owner. From a project development perspective, the lack of experienced and trained labour in key parts of the project chain (engineering, electrical tradespeople, permitting) is an issue that can continue to slow the potential roll out of green hydrogen projects in years to come. Governments are in a strong

position to ensure this skill and experience gap can be filled over the next 5 years. Also identified as barriers were the large variation in regulations. Regulation must be harmonised and fit for purpose across states and preferably nations within the EU.

There is no shortage of financing available in general, provided the business case is sound and risks are mitigated. Financing conditions reflect the greater unknown risk of the electrolyser projects. While financing is available, its cost will impact the overall business case as much as other factors. Acknowledging the reality of green hydrogen pricing relative to grey hydrogen within Germany, more government engagement to move the green hydrogen market whilst preserving industries' ability to compete globally is encouraged. Targeted subsidies are requested for the key objective: to drive offtakers for green hydrogen in sectors and applications where it is most appropriate (like for replacement of fossil hydrogen or imported green chemical product).

Two key elements of market knowledge are required: Firstly, a detailed understanding of the breakdown of costs of hydrogen supply at the different scales and purities for each key end user of hydrogen in each industry sector as an input to their production cost. This should be part of a review of the National Energy Strategy used to chart the path to a lower carbon future and the role green hydrogen has in the foreseen applications. It should review in detail the scale of supply and demand for, and the integration of, power, natural gas and green hydrogen products into the economy of today.

Secondly, detailed knowledge of the destination of the products (steel, chemicals etc.) into the consumer system is required. This information, in collaboration with industry input, enables projects to be prioritised on cost effectiveness, managed risk and societal needs and delivers higher certainty to project developers.

There is a need to align the National Energy Strategy and the National Industry Strategy to ensure that the transformation incorporates the goals and conditions of both strategies like net zero emissions and keeping a competitive industry during the transition. This also allows for greater alignment of measures and regulation in line with industry's needs and business investment cycles. This enables the government to design regulations and tax incentives to drive industry in a sustainable manner to the Net Zero target at minimum cost and lowest risk.

Industry would benefit from a clear roadmap for all industry sectors with incremental quotas and incentives, such as tax credits for those companies that commit to the target. This can be done through a revised mix of regulation and subsidies for OPEX (subsidized power), tax incentives (REDII, tax credits). Enforceable CBAM regulation to maintain EU competitiveness is a must. Next to hydrogen, the potential import of derivatives (methanol, ammonia) to the German market must also be part of the strategy. Such a strategy, starting from today's position, must:

1. be realistically achievable,
2. be aligned with constraints of all market aspects including both production, logistics demands and market end users,
3. be aligned with large industry investment cycles and,
4. withstand public scrutiny.

The speed and scale of the transformation over merely 25 years is breathtaking and requires a closer collaboration between government and industry to manage this change. More transparency is required to enable project developers to match the demand to supply. Social acceptance requires transparent and reliable information towards the public about the unprecedented social and technical change in the world. The true impact of green hydrogen in its many applications is manageable in the context of the overall life cycle of products.

Detailed recommendations made in and derived from the workshop appear from page 40 onwards.

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Abbreviations

ARENA	The Australian Renewable Energy Agency
BESS	Battery Energy Storage System
Btu	British thermal unit
CAPEX	Capital Expenditure
CBAM	Carbon Border Adjustment Mechanism, an EU policy to promote fair competition in the global trade of carbon-intensive products
CH_4	Methane, a major part of natural gas
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CO_2-eq	Greenhouse gas emissions, measured in CO_2 equivalents
CCS	Carbon Capture and Storage
DRI	Direct Reduce Iron
EPC	Engineering, Procurement and Construction, to define key elements of project builds
EU	European Union
FEED	Front End Engineering and Design, establishes plant design for FID
FID	Financial Investment Decision, usually taken after FEED completion
FIFO	Fly-in/Fly-out
FOIK	First of its Kind, refers to technology status in the field
GHG	Green House Gas
GHGeq	Green House Gas equivalents, relative to CO_2
GW	GigaWatt
H_2	Hydrogen, described using colour references where green is hydrogen from renewable sources, grey is from steam methane reforming
IEA	International Energy Agency
LCOH	Levelised Cost of Hydrogen
MM	Million
MWe	MegaWatt (electrical)
NG	Natural Gas
Nm^3/h	Normal cubic metres per hour, kNm^3/h is 1000's Nm^3/h
OEM	Original Equipment Manufacturer
OPEX	Operating Expenditure
PV	Photo Voltaic
PEM	Proton Exchange Membrane, referring to a type of electrolyser
PFAS	per- and polyfluoroalkyl substances, a large group of synthetic chemicals.
PFOS	PFOS is a specific type of PFAS, known as perfluorooctane sulfonic acid
PPA	Power Purchase Agreement
REN	Renewable Energy
RFNBO	Renewable Fuel of Non-Biological Origin
ROI	Return on Investment
SMR	Steam Methane Reformer
TCI	Total Cost of Installation, sometimes written as TIC, Total installed Cost
tpd	Tons per Day

Introduction

Green hydrogen is part of the drive to shift to a low carbon economy. In this report, green hydrogen refers to hydrogen derived from water electrolysis using Renewable Energy (REN). The conventional pathway to make hydrogen uses steam reforming of natural gas (SMR) and is labelled grey hydrogen. Hydrogen can also be low-carbon if it is produced for example from natural gas via SMR, but using carbon capture, from methane cracking, or from water electrolysis with low carbon power, such as nuclear power. Reliable access to cheap energy is a core component of economic and political stability in all countries. Green hydrogen is a medium for transporting renewable electrical energy globally, and also key to displacing fossil derived hydrogen for some large industrial users. Those large industrial users remain important to nations for economic wellbeing and industrial security. The transition being asked in a short period of time to a low-carbon economy is extreme and is a balancing act. Like all high wire acts, balance is maintained through constant re-adjustment for disturbances, and this balance is driven by government policy, since there is no abundant affordable green hydrogen today.

Background to the proponents

The concept of a forum of professionals involved in the green hydrogen industry arose from side discussions between members at the 2024 Ambassadors Dinner of the German Australian Business Council e.V. in Frankfurt. The honest and frank assessment from two different perspectives which involved free discussion outside of corporate core messaging suggested that this was a perspective missing potentially in advice to government.

So, together with DECHEMA who is very active in German hydrogen programs, specifically Trans4ReaL monitoring the implementation of industrial scale hydrogen technology, from the requisite technology requirements through project development and the market, a forum was organised. The restricted number of invitees enabled attendees to provide view points on key issues, assess their criticality, and more importantly, consider solutions in the short time that was available.The objective of the exercise was to provide an informed, unbiased industry perspective to respective governments for consideration in any review of their policy.

DECHEMA

DECHEMA Gesellschaft für Chemische Technik und Biotechnologie e.V. (Society for Chemical Engineering and Biotechnology) brings together experts from a wide range of disciplines, institutions and generations to stimulate scientific exchange in chemical engineering, process engineering and biotechnology. DECHEMA identify and evaluate emerging technological trends and facilitate the transfer of research results into industrial applications.

DECHEMA has over 5,500 members – individuals, institutions and companies. Together with DECHEMA Ausstellungs-GmbH DECHEMA are the organizers of ACHEMA, the world forum for the process industry. DECHEMA is based in Frankfurt am Main, Germany. Further information is available from www.dechema.de.

Trans4ReaL

Trans4Real is an overarching project funded by the German federal ministry of economic affairs and energy to support the hydrogen regulatory sandbox projects, aiming for industrial implementation of hydrogen technologies. Trans4ReaL offers advice, support and interaction to the projects as well as scientific analysis of framework conditions and advises the ministry on measures to improve the uptake of those technologies. The consortium is lead by Forschungsstelle der Energiewirtschaft with DECHEMA, Zentrum für Brennstoffzellentechnik, Ruhr-Universität Bochum, Technische Universität München, Agora Energiewende and Stiftung Umwelt- und Energierecht as project partners. Additional information is available (in German): www.energieforschung.de/de/vernetzen/begleitforschung/trans4real

German Australian Business Council

The German Australian Business Council is the premier network supporting business relations and engaging with government on both sides of the globe. Aimed at advancing both company and individual pursuits, the German Australian Business Council strives to develop and nurture opportunities through business, cultural and educational activities. The German Australian Business Council is headquartered in Frankfurt am Main, Germany, and has local chapters in Berlin and Munich as well as members in other parts of Germany, Australia and the world. Further information is available from www.gabc.eu.

The German Australian Business Council is part of the Australian Business in Europe (ABIE) network, a network of approx. 15 bilateral business organisations fostering business ties between Europe and Australia (www.abie.eu).

Background of Green Hydrogen within the Net Zero Industry Objective

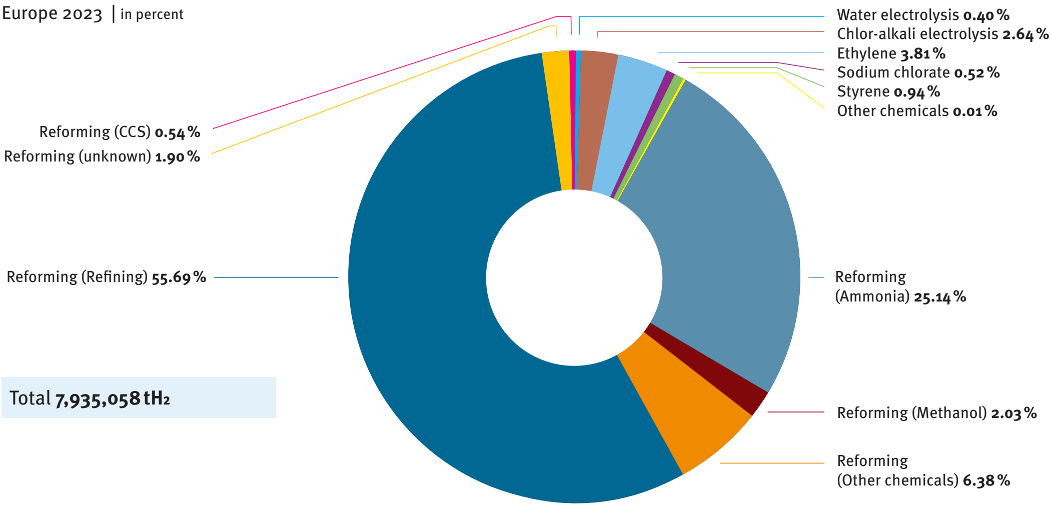
The water electrolysis industry is over 100 years old and the industrialisation of the technology was developed mainly in Germany and Norway. The main focus was then the production[1] of hydrogen for chemical and especially, fertilizer production, although at a much smaller scale of implementation at that time than the one required today. The industry waned in the late 1990's with the advent of natural gas which together with steam methane reforming (SMR) provided hydrogen at its cheapest price and at scale. Water electrolysis continued to play a role in niche applications[2] (eg. rotor cooling of turbines, hydrotreating of edible oils, metal working, electronics, atomic hydrogen welding) at small scales of typically 0,1 – 2 MW up to 5 MW, with a few exceptions, such as the 150 MW installation at the Aswan dam to produce ammonia from 1960 until the 2000's. The breakdown of technologies for hydrogen production in Europe today is shown in **FIGURE 1.** With a view to addressing the need for reducing the CO_2 footprint of hydrogen, there was the progressive development from 2017, leading to the first new plants of significant scale (~20 MW) in two decades of both alkaline and PEM technology.

Electrolysis derived hydrogen has also existed at large scale since the second half of the 20th century from the chlor-alkali electrolysis industry, which produces stoichiometrically in a fixed ratio chlorine, hydrogen and caustic soda. Chlor-alkali electrolysis typically runs on electricity from the grid, so that the hydrogen produced as a co-product will see its carbon footprint go down as electricity generation becomes more and more renewable. The agreed basis for assigning a CO_2-eq footprint to this hydrogen is contentious though, which is one of the reasons, together with the lack of hydrogen transport options, why much of this hydrogen is just burnt today.

Hydrogen production technologies

On-demand and indirect

Europe 2023 | in percent



Total 7,935,058 tH_2

FIGURE 1

Hydrogen production technologies (on demand and indirect) in Europe in 2023[3].

The resurgence of the industry accelerated from the end of 2019 when the European Union (EU) launched the EU Green Deal. This brought an immediate surge of interest and indeed, hype, together with a view that economic opportunities would arise supported by significant subsidies. More than five years on, the hype bubble has burst. A different reality was forming by the end of 2023, and more recently, global events have changed which will have significant influence on German, EU and global directions. Therefore, reality demands a reconsideration of the path of green hydrogen for all parties.

The post-COVID world is not the same as the pre-COVID world. Supply chains remain stretched, geo-political tensions have manifested in numerous wars globally with knock on effects on said supply chains, the labour pool is not the same, and large investment today is tuned more towards digitalisation than traditional industry. Prospective returns of the hydrogen economy are in competition with other investment options and are facing an uphill battle.

Status of Water Electrolysis Plants Today

Plants in Operation in Germany and Australia

Since the initial significant announcements made in 2021, the low numbers of actually realised plants over the last 4 years are indicative of the challenges for the industry. The table below lists the known plants in Germany and Australia that have reached FID phase or have commenced operation. It does not include the chlor-alkali plants in operation in Germany that co-produce hydrogen in quantities equivalent to that of circa 1 GW of installed water electrolysis capacity.

The table demonstrates the faster deployment of electrolysis plants in Germany as a direct result of government subsidies and a keen push towards green hydrogen. Compared to that, there is a relative lag in both deployment and scale in Australia, although the domestic demand for hydrogen is considerably less with a smaller manufacturing industry. Both countries have proposals for 1 GW plants. The realisation of 1 GW plants will be delayed in both locations at least until sufficient low-cost REN is available to attract off takers.

	Australia		Germany	
Electrolyser Plants	Number	Capacity Range	Number	Capacity Range
in Operation	16	Up to 1.4 MW Most ‹ 1 MW	76	Up to 55 MW
in Construction	14	0.16 to 10 MW	20	Up to 55 MW
in Proposal	61	Small to 1 GW	132	Up to 1 GW

References: Hydrogen Map – CSIRO and Green Hydrogen and Electrolysers in Australia – The Cleantech Showcase; German number from a version of the Elektrolyse Monitor (dated 12/06/2025) [4, 5].

TABLE 1
A short summary of Water Electrolysis Plants in Operation, Construction or Proposal.

Current Technology Development of Green Hydrogen Technology

The investment cost (CAPEX) of the electrolysis technology has been at times misunderstood, particularly in relation to the wider context of building a plant around the core technology. The economy of scale - electrolysers being a surface-based technology – is not as big a factor as in traditional, volume-based chemical/gas plants. The technology development of the stacks has focused in recent years on scaling up in size to meet large scale plant needs, rather than improving efficiency. The development path still requires improvements from lab through to scale and improved manufacturing to be implemented which does take 3 – 5 years.

There are new technical developments in the field of Anion Exchange Membrane (AEM) technology, and an altogether different stack design and scale up philosophy developed by other players such as Hysata in Australia. If delivered at industrial scale, these technologies promise much higher cell efficiencies of 90 – 98 % at commercial current densities (circa 1 A/cm^2) cf. ~72 – 80 % efficiency of today, which would reduce the overall LCOH by € 1 – 2/kg, if achieved at commercial scale.

Other than electrolysis, there are routes to producing hydrogen with much reduced CO_2 emissions that are also in development. It is not inconceivable that these prove more practical and cost efficient for delivering low carbon hydrogen to where it is needed particularly for large hydrogen demand applications. One of the uses of green hydrogen is to provide a low carbon vector for transporting and storing energy, and the overall cost of production, transport, storage and use cannot be ignored in a market economy that will compete with the global low cost of natural gas in the transition period over the next 20 – 30 years.

Outcomes from the Forum

The forum focused on 5 key areas that were thought to be influenced by national government policy:

1. Financing & ROI
2. Electrolyser Technology
3. Manufacturing & EPC
4. End Use Market
5. Ecosystem, including Regulation

Participants were given the opportunity to share their views on issues of concern, and potential ideas for mitigation. During the forum itself, two groups were assembled to address at least 2 of the 5 topics in some detail. The issues flagged were reviewed and potential risks, conclusions, and mitigations were discussed and captured. The Appendix provides some background numbers that assist in understanding the green hydrogen ecosystem.

Financing & ROI

The common agreement was that there is no shortage of finance available, but viable and bankable business cases are lacking, leading to low progress to Final Investment Decision (FID). Financing costs for green hydrogen projects will match the risk, and in the absence of strong risk mitigants, higher financing costs will impact the business case. In addition, there are insufficient offtakers willing to commit to the significantly higher prices that green hydrogen induces and to the period of time required to provide the minimum ROI that project developers need. Offtakers are prepared to wait for greater technology maturity and lower cost technologies. The low maturity of the technology places a higher risk premium on financing, and banks can readily meet their green funding commitments by investing in other types of projects with proven REN technologies and known ROI at minimal commercial risk, such as solar and wind.

Therefore, the two questions that must be asked are:

1. How can electrolyser projects progress to close the gap between the high green hydrogen price and ROI required?
2. How to move potential customers to take up green hydrogen, without the need for massive and ongoing government subsidies, whilst preserving industries' ability to compete in a global market?

To answer this requires an understanding of electrolyser plant limitations and risks, the impact of green hydrogen on market demands and therefore, where subsidies can be provided to encourage the building up of both the local production capacity and the development of offshore capacity for import. It is helpful to consider at a high level some successfully developed, large scale, green hydrogen projects to date.

The NEOM Green Hydrogen Company (NGHC), an equal production joint venture of ACWA Power, Air Products and NEOM will target 600 tpd of green hydrogen in the form of ammonia using low pressure alkaline technology of ThyssenKrupp Nucera (TKN). TKN has decades of experience in chlor-alkali electrolysis which translated well to meeting the scale of production for the NEOM water electrolysis project. Air Products will provide the means to convert green ammonia back to hydrogen or meet green NH_3 demand in Europe. ACWA secured very low-cost PV power at a scale of 4 GW. In short, the project is typified by an experienced electrolysis technology manufacturer teaming with a multi-national offtaker and access to cheap REN, all of this with a focus on the EU market.

Air Liquide and TotalEnergies are another two players that are forging ahead in the production and marketing of green hydrogen in Europe. Through a joint venture with Siemens Energy, a large manufacturer of atmospheric pressure PEM technologies, Air Liquide can deliver a number of plants in locations synergistic with their existing pipeline network to distribute green hydrogen to TotalEnergies and other customers. Buffering in the dedicated hydrogen pipeline network can also be achieved. In short, the project is typified by an experienced electrolysis technology manufacturer with a multi-national offtaker and an experienced industrial gas producer with a pipe network and a focus on the EU market.

A third example project announced in 2024 was that of the 100 MW REFHNYE II, based at Shell's refinery in Wesseling, Germany. It also features an international electrolyser player ITM with over 20 years of experience in PEM electrolysis, together with Linde, an international EPC industrial gas player, and an end customer in the form of Shell a large multi-national energy player.

Common to all projects are:
1. Large multi-national companies with large project experience and large balance sheets
2. Large electrolyser OEM experienced in technology manufacture at scale
3. Experienced gas plant operators
4. Offtakers either as partners or accessible through existing business

Therefore, **to improve the success rate of projects, it would appear key for the initial market ramp-up that project developers should team up with large multi-national players for large scale projects to share the risk, capitalise on their existing experience and access synergies that already exist in the market.** Government funding should recognise and encourage this if the wish is to diversify the base of hydrogen suppliers and achieve greater green hydrogen deployment. This is particularly important when targeting the smaller users of green hydrogen at the scale of 5,000 – 20,000 Nm^3/h H_2 with the aim of pulling through second tier electrolyser players.

Financiers are assessing projects using the same methodology as for other large-scale energy projects, and the contractual framework for developing and financing a green hydrogen project generally follows the same structure as for other large-scale energy projects. The only query raised is **whether First of its Kind (FOIK) has ever been applied to such a wholesale transition of both technology and ecosystem in such a short period of time without the industrial technology fully developed?** Whilst this may be noted as first mover risk, the large quantities of public funding being made available to facilitate this does lend itself to the potential for greater scale of failure due to the lack of time to fully derisk technology before deploying at large scale. The potential for this risk is discussed in the next section. Multiple failures may delay the increased take up of green hydrogen production.

The evolution of the electrolyser technology cannot be compared with that of wind and solar PV technologies. It is noted that wind and PV development has achieved orders of magnitude in cost reduction. However, these technologies were complementary to the electrical eco-system, and relatively simple, compared to the complexity of electrically driven, surface-based chemical processes. As **FIGURE 2** shows, the cost per unit has declined by a factor 10 for wind and 200 for PV over the last 30 – 40 years, with accompanying cumulative growth as costs came down below fossil fuel derived power costs. On the contrary, the cost for installed green hydrogen technology can only realistically be further reduced by a potential factor of 2 with efficiency gains, which means the cost of green hydrogen will not see significant further reductions over coming decades and thus will remain constrained. **The green hydrogen growth trend can therefore not follow that of renewable power development without regulatory pull through of end markets. Therefore, it is pragmatic to reconsider the projections of installed green hydrogen production capacity for Germany and Europe.**

Australia is in a more fortunate position in that there is a strong political focus on delivering lower cost power, which can be done by excessive build out of REN. This will result in excess power and grid constraints which will inherently provide low cost REN power for green hydrogen. This will provide an excellent outlet for alternate fuels. For some green hydrogen projects that can avoid significant grid connection costs, a high REN availability and low REN cost will be established. Finally, Australia can afford to wait for the technology improvements and the learnings from the first wave of international projects to be established, before accelerating its own green hydrogen market.

It is acknowledged that significant government funding is required to rapidly develop the industry to meet its objectives in the next 25 years. Each national government must compete with other nations to attract the necessary private capital of € 100’s of billions [4 5 6]. In an ongoing »cost of living crisis« that affects a large part of the voting public, government must counter arguments against the investment.

Renewable Energy Sources and Green H_2

Comparison of technological development

1975 – 2023

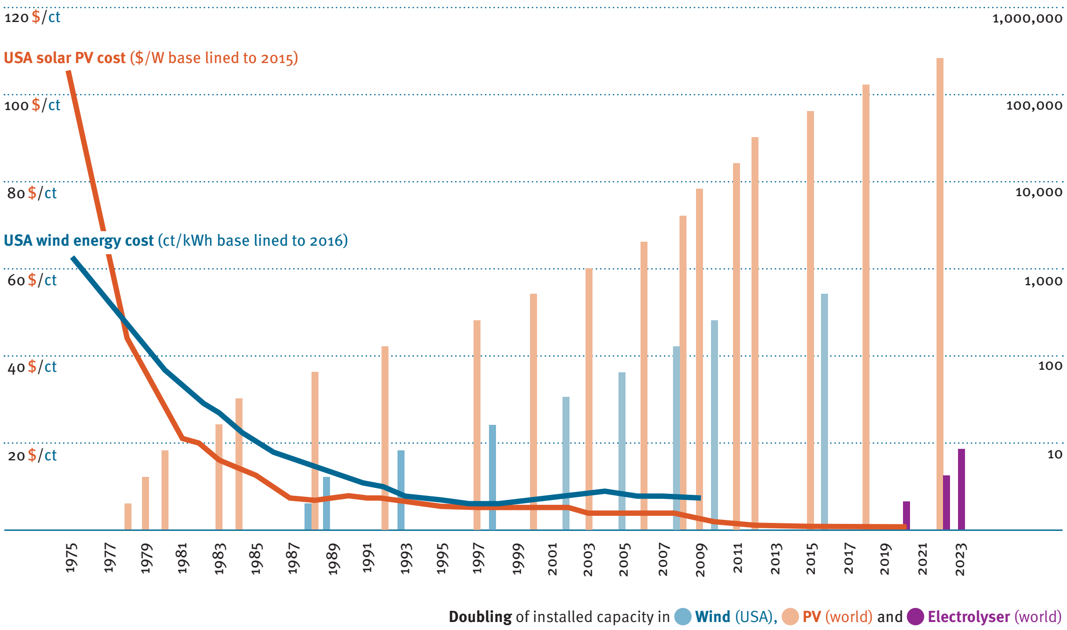


FIGURE 2

The mapping of wind energy and solar PV technology costs in the USA relative to the respective markets growth in USA (wind) and globally (solar PV) as shown by the doubling of the respective installed markets. The doubling of the electrolyser market is shown to indicate the low base [6, 7].

There is significant misquoted confusion of the extent that CO_2 tax on natural gas is required for green hydrogen to compete at different scales. The structure of the grid power market that defaults electricity price to the highest of that being produced invariably means the CO_2 tax on fossil fuels is incorporated into electricity price and consequently, electrolysis hydrogen costs. Decoupled REN prices are required to counter that effect.

Some ideas generated in the exercise to improve the project economics were:

a. Offer green bonds annually to the national residents to encourage people to invest in the future, literally to buy into the change, and to overcome the argument that the money does not come back to the public. Consider a lower tax on the bond yield for the individual, capped at a certain amount. A current example is Kiwi Bonds.
b. Using said retail bonds, the government to buy and operate some REN facilities under a national energy vehicle, with objective to deliver a return only after 15 years (at lower ROI) and pass on the lower cost of power to support minimum loads of electrolyser plants.
c. A government to mandate with legislation a minimum REN takeoff for »state« purposes as part of any new auction for REN production, which is then sold at cost of production to electrolyser hydrogen operators to maintain the minimum load or to meet hydrogen supplementation into natural gas pipelines. Note that the Western Australian government reserved 15 % of the NW Shelf gas for use in WA state in the original investments in the 1970’s, which has insulated the state from the high gas prices seen on the Australian East coast in recent decades.

The concepts above and further within this report that depend upon challenging existing government regulation are made with the acknowledgement of the complexity of EU, federal and state legal frameworks. The magnitude of the challenge offers an opportunity to develop fresh regulatory approaches to incorporate aspects of concepts contained within this report.

Electrolyser Technology

The initial tranche of EU subsidies has initiated large scale projects in Europe, from which EPC learnings are now cemented, and has also established a technology manufacturing base which today is at overcapacity in many cases. Some larger established companies within Germany may have a better position relative to other players. However, all OEMs with today’s technology are facing the same issues. Green hydrogen production is a high CAPEX and high OPEX operation, of which the latter is outside the control of the electrolyser vendor.

The high CAPEX stems from electrolysis technology inherently lacking the economy of scale of traditional gas and chemical plants. **A large-scale electrolysis plant is in fact nothing but a series of small-scale electrolyser units connected together,** and then to common headers for gas conditioning (purification and compression) and with significant utility installations. There are also **electrical limitations that will hinder scalability.** This stems from grid capacity limitations as well as the size of connectors, transformers and rectifiers. Grid limitations can be partly removed by direct connection to the REN facility, although grid connection, large batteries or onsite auxiliary power generation remains necessary for sustaining the »no production« plant operating status. Finally, **competing electrolysis Original Equipment Manufacturers (OEM) do not have a common electrical infrastructure,** and therefore it is not possible today to simply replace one OEM’s transformer/rectifier technology with another in the event of unresolvable technical problems, contrary to what may be done (e.g. with catalyst) in the conventional gas industry.

A significant risk to existing electrolysis plants is expected in the market in 5 years’ time, coming from higher efficiency and/or lower cost of new production systems. This may make first movers uncompetitive after subsidies finish or push current electrolyser stack supplier out of business. Electrolysis technologies are today not subject to any uniform standard such as for electrical charging stations, so simple substitution of one stack provider for another does not work. **This may result in expensive immature assets being stranded, unless the industry considers development of an ISO/CEN standard.** Today, most electrolyser players with electrolyser stacks of the scale of 0,5 – 2 MW will struggle to provide a reliable record of operating units with more than 2 – 3 years sustained operation, whilst plant economics are largely made on 8 years life of stacks. **This discrepancy between proven and expected performance presents an economic risk which may realise itself in 2029 – 2032 to projects initiated today.**

The success of the many vendors boils down to their offerings and the financial stability of the company behind the technology to ensure long-term support, and it is fair to say not all vendors will survive. Early feedback is that many OEM vendors have had numerous technical problems on early plants. This is due to the immaturity of the OEM scaled-up products and the rapid development of technology and companies. Operational feedback is still to come from projects starting and operating from 2024 through to 2028. **The impact of this operational feedback, in combination with potential step changes in the technology, will see vendors disappear from the market, jeopardising long term support to installed electrolyser plants. This risk will be realised in the period from 2025 – 2030 and must be managed by industry and government alike.** There is also the environmental and health risk that PEM technology has in relation to degradation of Nafion membranes and release of PFAS to the environment. EU regulations regarding the use and management of PFAS in PEM electrolysis remain under discussion.

In the context of government subsidies, it might be **considered prudent to limit CAPEX subsidies to avoid stranded assets post 2030 from foreseen potential failures.** Government can leave the capital risk to the project developers and their technology due diligence. However, to support the industry as a whole and ensure competition, CAPEX subsidies might be applied to new entrants at an appropriate demonstration scale and/or for perhaps the first installation, to manage first mover risk. Local content requirements in funding is still a favoured means to ensure technology development in Germany. Australia (ARENA program) has adopted an approach linked more to subsidising production, which places the technical risk on the private sector side, and reduces risk exposure on the public side. This does mitigate the public risk.

It was noted that there is **currently a lack of design and operational data from OEMs at (pre) Front End Engineering Design (FEED) stage. This manifests in large contingencies being applied on both Electrolyser and Electrical CAPEX in projects and extra financing is required to cover potential shortfalls in electrolyser stack lifetimes which contributes to projects not progressing to FID.** It presents a challenge to new entrant project owners/operators outside of traditional oil & gas or industrial gas players to select the right technology and satisfy financing requirements. This has been observed in a recent report from TNO (TNO 2024 R10766), whereby contingency accounted for a minimum 12 %, an average 17 % and up to 30 % of project costs which, in combination with the initial high CAPEX, is significant. OEMs do not currently provide lifetime data as they often do not have it, or it is inconsistent, or products (stacks) are changing constantly. Their stack performance is key in a competitive world and OEMs protect this information. However, this information is important for overall project economics and its relevance must be at an appropriate scale of application. E.g. 100 kW stack performance may scale to 1 MW but not further without increasing the risk of performance issues.

In the end, technical due diligence must be done by project developers with people of sufficient knowledge and experience, or the learning must come from executing at the smaller scale first to balance risk. Alternatively, an independent organisation, such as DECHEMA, could provide an independent assessment and risk rating of the different technologies on the market based on the level of information provided, to be used in German/EU CAPEX funded projects (if funds are only for operating, the techno-risk is purely with project owner and not government).

The requirement to operate electrolysis plants using REN necessitates higher priced power contracts to secure a higher amount of 100% equivalent operating hours to ultimately deliver sufficient hydrogen for optimal plant operation. The power contracts are not based on predictable supplies of natural gas that produces grey hydrogen, but from variable, weather influenced REN production. **With power and natural gas prices interlinked in Germany and the EU,** and the relatively low impact that CO_2 tax at 100 €/t has on the price of hydrogen from natural gas, green hydrogen generated in Germany (and the EU) will always be quite expensive compared to natural gas and hence grey hydrogen. **This requires the government to acknowledge the need to secure low-cost renewable power for meeting minimum green hydrogen needs for local production, particularly with increasing power demand from the electrification in the transport and building sectors.**

Although electrolyser technology can be switched on and off, this is not desirable for achieving extended lifetimes of the stacks, electrical components and downstream compression equipment. **Suggested mitigations by governments over the next 4 years to improve economics for newly installed plants and to pull through smaller installations include various options** such as:

a. Providing subsidies for renewable power to deliver an effective base price of 20 – 30 €/MWh to sustain minimum plant load operation (10 – 20 %) and so, improve overall economics, plant operability and availability, improve the ability to respond to spot market prices, and improve electrolyser longevity. Whilst acknowledging existing regulatory constraints, some possible approaches to deliver € 20/MWh power could be achieved through:
    i. a government owned power company that invests in part in projects, selling on some power at a loss and the rest at market rates to break even on their project.
    ii. a government mandate to all new wind and PV projects that 5 – 10 % of initial offtake must be supplied to the green hydrogen industry. This is important to enable electrolyser plants to deliver grid service.
    iii. Procuring power from existing REN projects as a subsidised quota of power for which operators bid based on the hydrogen price.
b. Linking this with the partial supplementing of natural gas in the gas network pipelines with guarantees on gas composition will achieve both enhanced domestic energy security, some reduced CO_2 emissions, reduced reliance on LNG from sources that are driving foreign conflicts, and require only management of hydrogen input into existing facilities to meet hydrogen in natural gas regulations in existing infrastructure.

This may be worth exploring further whether this can be done under powers granted under the recent € 500 billion German Climate and Infrastructure Fund.

In summary, the capacity for electrolyser manufacture has been established through the initial swathe of funding in Europe supporting giga factories by all players in EU (ITM, Cummins, SE, NEL, TK and a number of other smaller players such as Sunfire, JCL, McPhy, HydrogenPRO). Not all OEM vendors will survive, even fewer will survive the development of any new step change in electrolysis or alternate low-carbon technologies. The state therefore should not be subsidising more factories, unless they deliver step change technology and even then, the market will most likely support its development. Some consideration of funding for new technology development could be considered, however CAPEX gains will deliver competitive advantages to the OEM and thus sell the technology itself. Ergo, the state should focus more on how to pull through green hydrogen production with offtakers, leaving the technology market free to innovate and compete with e.g. Chinese offerings. Some measure of protection for the local market can still be achieved by tying government funding to a minimum of inclusion of local players in the project. For operators with installations starting up from 2024 – 2030 in Germany, government subsidies to secure low-cost REN power to maintain minimum loads will benefit the industry.

Manufacturing & EPC

The push for green hydrogen amongst other low carbon initiatives was accelerated during COVID and had to contend with

- Post COVID inflation in the chemical plant construction sector with price increases of about 20-30% during the past 3 years (see **FIGURE 3**)
- Global supply chain restoration and re-alignment
- Rapid scale up demands on electrolyser players and EPC players with (limited) availability of experienced people
- Education of the market in this sector with the majority of players managing a steep learning curve.

There have been numerous companies starting up with the aim of developing green hydrogen projects. These players will share a view that there is insufficient information available to make key decisions regarding the longevity and operating costs of the electrolysis units. This is a fair point and for most players, it is a high risk to take on board for 100's of MW projects. **It is unsurprising that the largest proposed projects that have progressed to FID and construction are backed by major industrial gas and oil players who have the necessary experience and balance sheets to support such risk, and the capabilities, experience and resources to deliver € 100 – 400 MM EPC projects.**

Inflationary effects in the chemical process sector

2015 – 2025

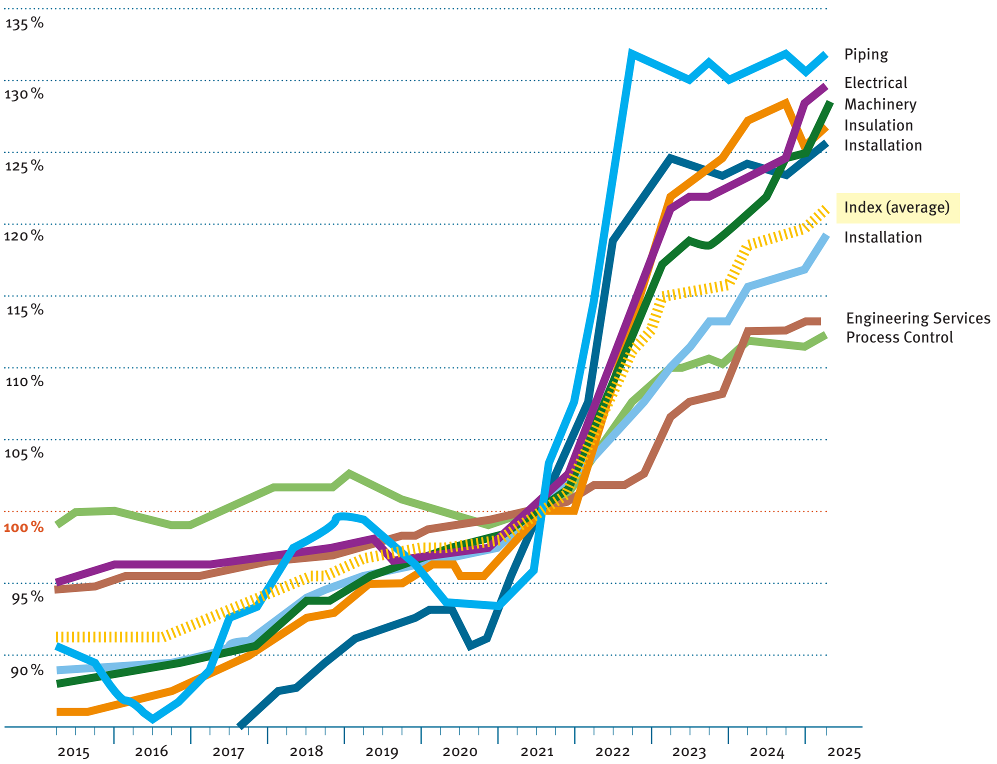


FIGURE 3
Inflationary effects for the past 10 years in the chemical process sector[8].

It was noted in the discussion that banks require technical due diligence to be performed by independent consultants and not the project developers themselves. Project developers do not get all the detail from vendors in the FEED phase, as all detail only arises during Detailed Engineering (after FID). This is the risk gap that must be managed. Closing this risk gap is key to enabling other project developers into the market. However, this is not likely to occur before circa 2030, when sufficient feedback from operations is available. For smaller projects and project developers, the duration of financing (being time limited for smaller developers) may also present a challenge to project viability. Banks do require mitigations within the business plan for those OEMs that do not have sufficient lifetime operating experience to remove the risk around stack life. This also adds a premium on the project financing costs. **A mitigation for the current risk gap was suggested for the German government to consider a state sponsored investment insurance such as the Euler Hermes Guarantees** to cover the risk of a failed investment for a German company abroad.

With respect to the cost of green hydrogen, there is significant discrepancy in reported literature and in modelling in the true cost of electrolysis plants. Often missing are full project EPC costs, and balance of stack and balance of plant equipment, which can easily double or triple the overall CAPEX cost.

1. a vendor can quote €/kW costs for stacks, with and without balance of stack, with and without major electrical equipment, but **many published studies have not captured the full cost of electrolyser gas plants, missing it by factors of 100 – 300 %.**
   a. A recent TNO report [9] based on project feedback in the Netherlands was considered more accurate representations by the authors.
   b. a report by ISPT [10] projected – using stack performance that is not yet delivered to the market – the total installed costs (TIC) of a 1 GW green hydrogen plant to be 1,400 €/kW for a plant using alkaline technology, and 1,800 €/kW for a plant using PEM technology. Note that there is an economy of scale of 1 GW electrolyser plants operating at 4,000 hours of 100 % equivalent full load.
2. **CAPEX is significant but the REN power price and available equivalent hours at 100 % plant load are much bigger factors in terms of annualised (or levelized) hydrogen production costs,** as indicated in **FIGURE 4** below, based on a study by Rosenstiel et. al.[11].
   a. The trends were replotted with a nominal increase of CAPEX added to the hydrogen price to account for optimistic numbers used by Rosenstiel et. al.[11] and with power prices directly converted to EU from US $.
   b. The availability of combined Wind and PV can reach the equivalent 100 % load hours of 4,000 – 5,000 hrs p.a. in Europe.
   c. The REN power pricing in Germany is not realistically attainable for quotas of at least 5,000 hrs at anything less than 60 – 80 €/MWh.
   d. The same chart if applied to more favourable REN markets such as the potential in the Australian market could realise 20 – 30 €/MWh, however an additional cost of 1 €/kg H_2 equivalent would be needed to ship finished product to EU market.

As a result of the lack of operating experience at scale under variable REN load, it will also be unsurprising to observe a lull in the project sector from 2025 – 2028 whilst the operating experience from these initial plants is assessed. It also provides a period for which the afore mentioned technical developments have time to reach TRL of 8 which will permit an accelerated roll out of more efficient plants. In addition to more recent turmoil in global geo-politics adding a degree of uncertainty to the future, **we are of the view that the development of large-scale projects may be delayed in the near term, although smaller plants meeting well-defined small-scale customer needs will progress. This expectation should prompt a reassessment of the market reality of the hydrogen economy, including scaling it back in some sectors.** The potential for a further accelerated period of growth post 2030 with the same project demands of today is unlikely without the raised issues being resolved.

The impact of the price of REN power and electrolyser full load hours on the nominal price of H_2

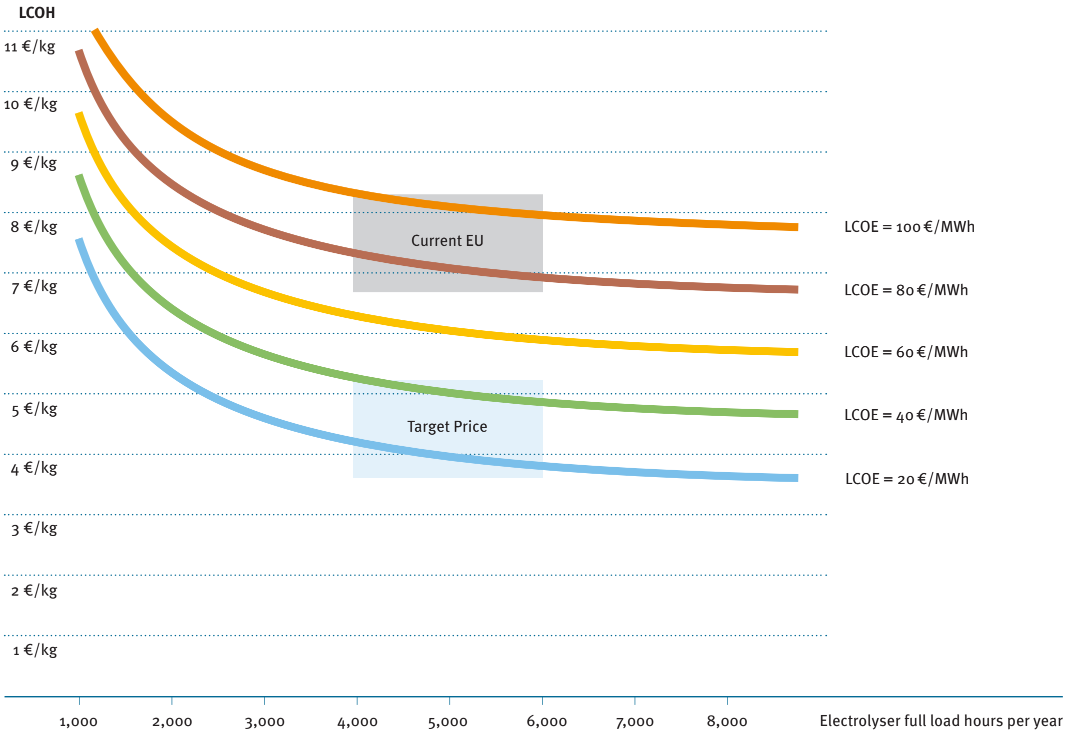


FIGURE 4
A plot indicating the impact of the price of REN power and Electrolyser full load hours per year on the nominal price of H_2, adapted for EU and with the TCI cost increased (Source: Adapted from data of Rosenstiel et. al.[11])

Project developers also have observed a significant cost difference between Western and Chinese alkaline electrolysers of up to 4 times. One factor is that Chinese electrolyser manufacturers are subsidised by the government, are state owned, or have different business drivers due to not being listed companies. The Chinese designs are also different to western installations, with less automation, possibly lower levels of process safety, and without the need to meet regulation of multiple bodies (CE, TUEV, PED, Machine directive, functional safety etc). Another factor is that pricing in publications have also given a false sense of project costs, unrealistic power costs and stated electrolyser costs relating to stacks only, or stack with balance-of-stack but without the main electrical and downstream plant units. Finally, Western electrolyser manufacturers have been investing in development to rapidly scale-up and in building factories in the past 5 years. Therefore, Western manufacturers costs should come down in time providing they survive.

Of note, in terms of levelized cost of hydrogen plants in the EU, the capital cost of electrolyser units (stacks and balance-of-stacks) in EU large green hydrogen plants are not the main part of the annualised cost but rather it is the power (unless capacity is underutilised). **EU manufacturing is still globalised and must find ways to compete – via build quality, automation, reliability and service – but it is acknowledged not at the expense of government subsidising inefficient technology.**

Identifying a path forward for greater transparency of electrolyser performance data, even if assessed and rated by an independent body will still not change pricing but help project developers better assess the best technology for their specific project (e.g. A tool by *Clean Hydrogen Observatory Europe* [12]). **To counter the lack of operating performance data, and to ensure new technologies have a chance at succeeding, public funding provided to smaller projects of ≤5 MW for capital subsidy of European sourced green hydrogen (electrolyser) technologies should be granted with the condition to share data/return of experience.** This would limit risk of both public and private monies, ensure no new technologies would be disadvantaged by the dominance of early large players, and help project developers bridge the risk gap on future projects at larger scales. There is a general acceptance in the industry that the speed of transition results in many learnings and constant improvements, but learnings should be completed on appropriate demo scales and not on large-scale plants. Of course, this is limited to the first few installations of a vendor before all subsidies of established technology are limited to operational subsidies, which lowers the public risk. This would assist in small scale developments and pull through of technology, but ultimately phasing out the subsidies.

It has to be acknowledged that **large-scale projects** are technically challenging endeavours with significant risk of failure or underperformance. The know-how to implement and manage such facilities currently rests with large international industrial actors (e.g. oil and gas, chemicals, steel industry, who are significantly responsible for historical Western CO_2 emissions). Governments need to balance the need of competition with the project implementation risk. One idea to accelerate project success is for the **government to encourage Joint Ventures between experienced operators with other new operators to harness expertise more widely, ensure competition and spread balance sheet risk.**

Due to the lower economies of scale for electrolysis plant, there is a higher labour component in construction of large scale projects. **In remote areas of Australia, labour is often regulated and at a relatively high cost especially when compared to Europe. This could impact project bankability and consequently, FID, which presents a key risk to project execution.** Government funding for the capital of the plant should note this.

Some considerations for mitigating the construction costs and ensuring project success, nominally in Australia, include:

a. Break up large projects into phased smaller projects, spread over years, with rebidding for subsidies based on past construction performance to encourage innovation and collaboration between all parties to reduce costs.
b. Subsidies to favour projects where construction companies have their own shares in the project itself.

Overall, the view with respect to the current strategy supporting electrolysis EPC was that:

1. The setup of electrolysis manufacturing and the first projects from 10 – 20 MW scale have been fully supported.
2. Future government subsidies should not be on CAPEX, but on OPEX or green hydrogen products produced.
3. Auctions for either operational subsidies on a basis of hydrogen produced such as that of the EU hydrogen bank or tax credits are viewed more favourably. Said auctions should be available for a number of German projects at small (< 20 MW), medium (≤ 100 MW) and large scale (> 100 MW), and also include imported hydrogen based on the use of German technology.
4. **The long-term strategy over 25 years was not clear to participants across sectors;** in particular to
   i. the application of and phasing out of subsidies,
   ii. the prioritisation of industry sectors and
   iii. the hydrogen pipeline network.

   A long-term pathway is key to avoid what happened to the collapse of the German solar PV industry with the sudden loss of subsidies. The strategy should be clearly aligned with the hydrogen pipeline installations.
5. The discussion in the sector does tend to focus on domestic production. Missing from the discourse are import subsidies for green hydrogen products, be it hydrogen, ammonia or methanol, which will be key to reducing the cost of transition for German industry. As shown in this section, conditions to reach lowest cost green hydrogen products to meet German industry needs cannot be fulfilled inside Germany.

Comparison of characteristics between Germany and Australia in the REN and green hydrogen space

	ENERGY	MANUFACTURING
	› High User Cost › REN Power transition › Insufficient Local REN Production › High demand for Imports: Low C Energy & Chemicals › Require Security of Supply › Sceptical Electorate	› Existing strength in REN (Wind, PV, Elec) › Existing strength Electrical & Electrolysis › High End Manufacture › Auto › Chemicals › Pharma › Power › Defense
	› High User Cost › REN Power transition › Very High REN (& GH_2) Production Potential › Stability › Sceptical Electorate	› Increased Onshore Manufacturing › Automated Manufacturing › Low Manufacture base › Defense

FIGURE 5
Comparison of characteristics between Germany and Australia in the REN and green hydrogen space

Finally, there is an international element to decarbonising not only individual nations' economies but the global economy. Low carbon transition benefits the world and should take place globally – it does not all have to be delivered in Germany. **It was noted that Australia and Germany have complementary needs in the space of green hydrogen.** FIGURE 5 indicates the characteristics of the two nations in their respective Energy and Manufacturing sectors. It is clear that Germany has strength in the REN technology manufacturing sector and has the needs in their industrial sector for fuel and chemicals that could be met by Australia. Australia also seeks to migrate to a low carbon economy and, as an exporting geopolitically stable nation with huge REN potential, is well placed to capitalise on the technology and manufacturing capabilities of Germany. **With a need to onshore manufacturing in both countries and yet diversify geographical locations for reliable and secure energy sourcing, there would appear to be common interests. Participants were very interested to understand better the views of respective governments for promoting increased business between the two countries.**

Secondly, in seeking lower cost locations to support REN, green hydrogen and chemical production plants to deliver the mix of energy and base chemicals to Germany and EU, there is a wider opportunity available. **Germany and Australia can increase support to developing nations in the form of mutual project development in the green space, instead of direct funding.** Fostering development and training in EPC delivery and plant operations in developing nations, and at the same time, delivering low-cost REN to the local population and cheaper green chemicals to Germany and the EU has the long-term advantage of:

a. Better local living standard
b. Avoiding corruption
c. Reduced reliance on imported fossil fuels for local economy as they transition to REN
d. Better local balance of trade (reduce fossil fuel reliance, increased export of products)
e. Lower risk to geopolitical upheaval by diversified sourcing
f. More independence of the local nation to US dollar fluctuations and/or tariffs
g. Meet part of climate change fund to assist developing nations with impact of climate change

In summary, the electrolysis industry covering OEMs and EPC players within Germany and indeed Europe have had a steep learning curve over the past 5 years. This has been managed best by the larger industrial gas and energy players. Part of the difficulty to bring projects to FID has been the costs, both inflationary but also the unknowns around the new technology prompting higher EPC contingencies. Going forward, manufacturing must improve to compete globally. Certain risks for Australia were noted for its future development in the sector. Learnings from first project costs in the EU are entering the public domain, but this will not lead to significant reductions in future costs, as for Germany it is shown that power still dominates the levelized cost of hydrogen and hence project economics. However, government engagement with the first adopters of large-scale plants to understand the project EPC and subsequent operations will help develop better policy and incentives to remove barriers. Taking an outward view and given the potential for synergy between Australian and German markets, together with the German government's new Climate and Infrastructure Fund, the two governments should consider how they can better drive the transition for mutual benefit.

End Use Market

In 2020, green hydrogen was seen more as a replacement for all fossil fuel combustion for domestic and commercial heat and power, for chemical conversions requiring hydrogen, and also for transport. Significant market developments have now occurred that require a reassessment of the real market. **Both domestic heating and light transport using hydrogen are not competitive in the current market and absence of hydrogen infrastructure. Any phased funding for both sectors should be reconsidered** relative to market developments over the next 25 years. Since the power price on the grid is coupled to natural gas, then green hydrogen from grid electricity for extended operating hours will always cost more than grey from natural gas. **Leaving it to the market to take-up green hydrogen will not result in the net zero objective being achieved since** the free market will always find the most optimised cost path to maximise profit of the day. An alternative approach is proposed herein.

To drive offtake of green hydrogen whilst preserving local industry requires two key elements of market knowledge. The first element is a detailed understanding of the breakdown of costs of hydrogen supply at the different scales and purities for each key sector customer as an input to their product cost. The market volumes for industrial sectors are known and the large hydrogen users are identified as shown in **FIGURE 6** below with the distribution of hydrogen usage indicated for European production. The same may not be currently available for smaller users. The next level of definition required is to know the hydrogen consumption almost by site for each industrial player and their requirements for continuous supply (e.g. chemical plants). It is suggested that this knowledge is already with state governments. Then, in conjunction with industry, a quota driven process to incrementally increase green hydrogen integration can be designed at minimum cost for governments. The quota system will not necessarily demand production to be in Germany. If delivering government assistance to private industry, it is both fair and reasonable to expect the recipients to be willing to work constructively and compromise to meet both parties' objectives. Small scale applications might get targeted funding for small OEMs over larger ones to ensure a sustained diversity of OEM supply is maintained.

Hydrogen Demand

Europe 2023 | in Percent

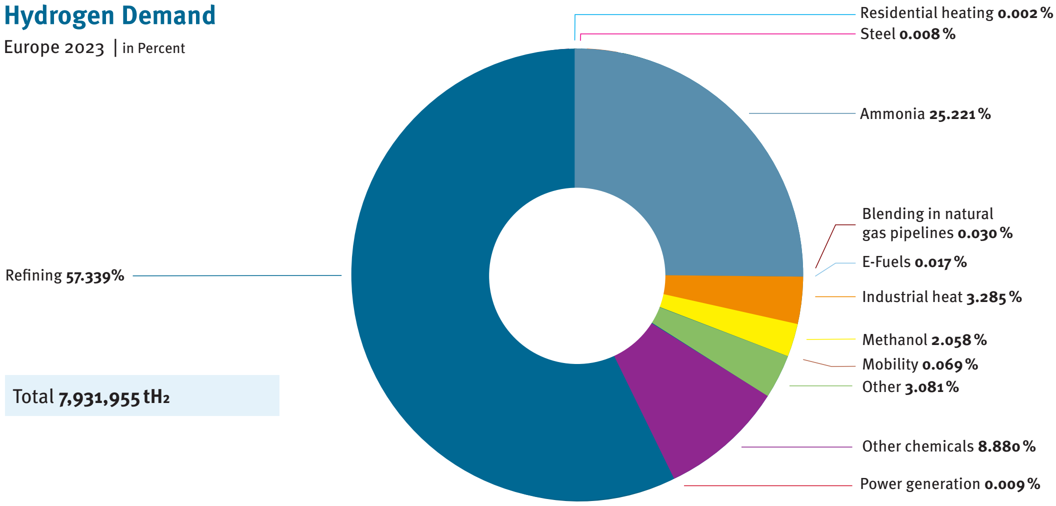


FIGURE 6
Nominal use of hydrogen in the European industry today[13].

For example, it is accepted that the ammonia and methanol market is generally best met by imported green hydrogen in the form of ammonia and methanol respectively from countries with the best REN conditions. Preferably from EU owned plants so that the cost of integrating low-carbon ammonia and methanol into the economy is significantly less that trying to meet the demand within Germany. Those key industries that are a national security necessity such as steel production should be considered to offset CO_2 emissions where it can be done most economically; direct reduction of iron (DRI) should be sourced both internally and outside the EU (Germany), and work done to further abate blast furnace emissions of CO_2 by other means. The potential loss of all virgin steel making capability in the UK offers a salutary lesson in what happens in absence of an industry sector plan. Two examples are provided to illustrate how government regulation could be prioritising the effort to decarbonise, whilst improving energy efficiency within the whole economy.

The first example notes that refineries are the largest users of hydrogen, and RWE noted in a recent press release[14] for a German project that: »Using 30,000 metric tons of green hydrogen in a refinery saves 300,000 metric tons of CO_2 per year. That's how much 140,000 cars emit on average per year.« Given that a typical BEV might use 100 kWh per week, or 5 MWh p.a, and that 30,000 tonnes H_2 totals a REN production of 1,500,000 MWh p.a. at 50 kWh/kg H_2, the equivalent of 300,000 BEV cars could be powered with the electricity used to produce the green hydrogen. This means the emissions of twice as many ICE cars could be avoided with the same amount of power. Therefore, it would make more sense to put the valuable REN into the grid for BEV use rather than into green hydrogen for refineries. However, the integrated benefit of refineries to the downstream chemical sector are not to be ignored, especially in Germany. Those integrated refineries taking in green hydrogen are not in any way noted as being a wrong move for reducing CO_2 output whilst sustaining the greater value to the community. However, the refineries that serve only to meet fuel purposes would not meet the secondary value added in light of an overall shift to BEV technology by 2035 and green hydrogen would not be the right investment for these entities in the long term. It demonstrates that within an industry sector, one rule will not apply to all facilities and the optimum global solution should consider cross-sector applications.

The second example notes that the German steel industry is reported to be responsible for approximately 50 million tonnes CO_2 p.a.[15] in 2022. Germany CO_2 emissions were estimated at 650 million tonnes

CO_2 in 2024 of which approximately 143 million tonnes are from transport[16]*. Therefore, the more facile step to decarbonise the German economy today is to move its automotive sector to BEV based on REN power, which should be achieved with considerably less costs than by reconfiguring the German steel industry in the next 5 – 10 years to be hydrogen based. There should be a stronger focus on transport conversion to BEV which is further progressed and cheaper than hydrogen can ever be (BEV is almost at parity with ICE and will remain cheaper than FCEV). In between, a 25 yr glide path for steel industry to produce an incremental quota of steel with a given low carbon footprint, by whatever method and not all with green hydrogen (as it is not practical). The green steel will find a market as long as the government ensures that other sectors such as housing, commercial buildings and automotive get quotas to incorporate green steel.*

The second element of market knowledge required is the destination of the green hydrogen based products (steel, chemicals etc.) into the consumer system. This is required to know the net impact on the higher costs in different sectors so that other pull through government regulation and/or targeted support or tax relief can be applied to different sectors. **FIGURE 7** shows the high-level flows of green hydrogen into the transport and large industry user network, together with competing demands of REN on the power grid. Because local green hydrogen production is integrated fully with the greater use of electricity in transport and heating, the green hydrogen system cannot be looked at in isolation. A National Energy Strategy over the next 20 – 25 years is thus required and needs to be managed by the national government. China's successful transition to a high-tech manufacturing industry over the past 10 years has been initiated and managed by their government.

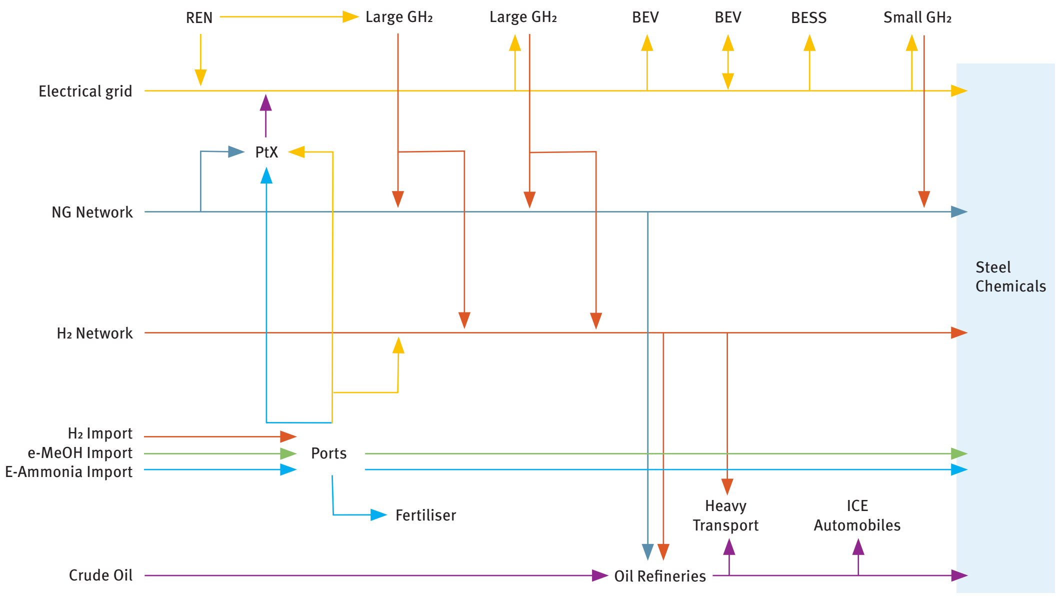


FIGURE 7
A simple sketch of key energy flows indicting the integration of hydrogen into the energy network shared by both transport and heavy industry sectors today

With such information, together with the primary information of end-user costs resulting from using green hydrogen along the value-chains in each sector, it is then possible to consider an appropriate timeline for incremental quotas of green hydrogen derived products to be applied to different industries. Together with what would be considered a National Energy Strategy incorporating net zero objectives, an effective National Industry Strategy can therefore be developed aligned with industry's needs and business investment cycles. An indicative example is shown in the **FIGURE 8**, which although based on USD, could equally equate to corresponding € cost by a fixed multiple. **FIGURE 8** would suggest that commercial mobility applications should be delayed until market conditions allow hydrogen to compete with ICE or BEV automotive applications.

To go further, the objective of ranking users relative to demand volume and price as depicted in **FIGURE 8** is to develop a better transition picture by looking at the inflationary impact of incorporating greener products. With allowance for macro factors around annual targets, a more transparent path can be constructed. With reference to **FIGURE 9**, and without changing end point objectives for decarbonisation, targeted regulation and financial support could be applied to:

EU, US, East Asia hydrogen demand and value-in-use split by end-use segment

2030 | US $/kg H_2e

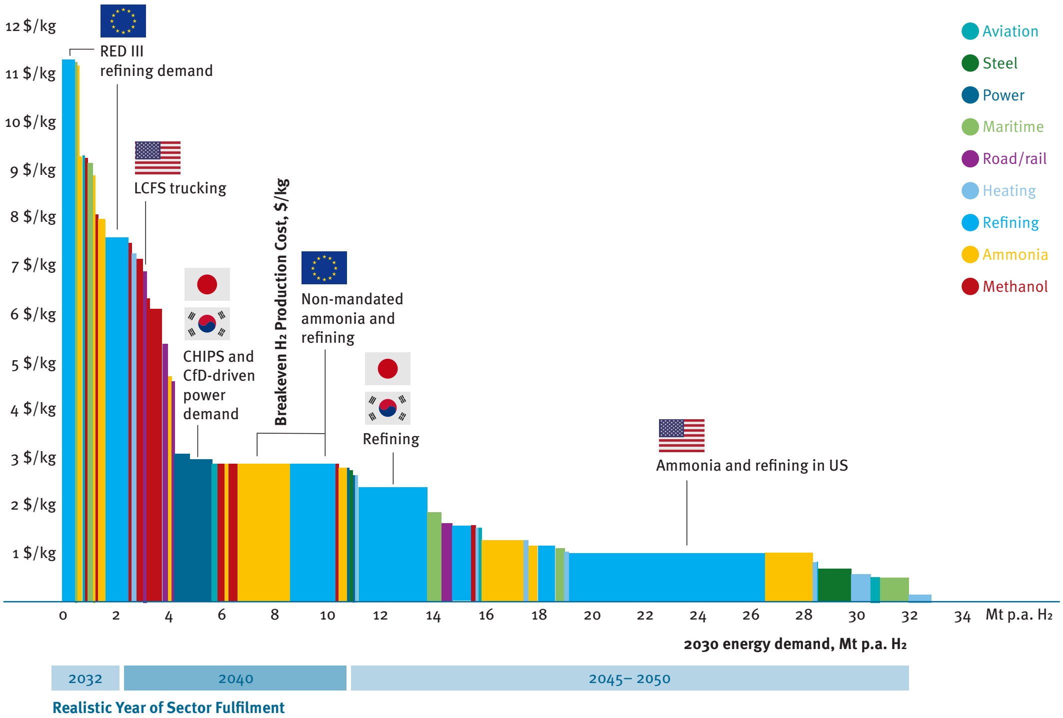


FIGURE 8

A modified plot[17] that demonstrates industry sector potential volumes of hydrogen use and the market price that can be supported. Suggested years of achieving such transition for key sectors have been marked underneath the X-axis by authors to align with Figure 9.

1. high value small hydrogen users (‹ 2,000 Nm³/h H_2 or ‹ 10 MWe) to be converted first under a program of quotas and deadlines. For the small-scale applications where green hydrogen can actually compete with bottled or trailer supply, the market should be considered capable to transition with little subsidy.
2. Medium users requiring up to circa 20 kNm³/h or 100 MWe electrolysis plants have a larger window to achieve a transfer to green hydrogen products, and they can opt for a linear system, or delay in intervening years to await improved green hydrogen economics but must then implement a faster transition (orange in **FIGURE 9**)
3. For large potential industrial operators such as ammonia, methanol, oil refining, steel; some of them being nationally critical, the companies should be on an incremental quota system. Hydrogen pipeline infrastructure must be in place as part of the solution. Imported green products can be advantageous. Agreement between government and industry sectors will nominate either:

   a. A linear compliance path from today (red in **FIGURE 9**), but with variance permitted within a rolling 3-year period but fixed end point with increasing penalties as that time nears,
   b. a delay in intervening years to await improved green hydrogen economics but must implement a faster transition through imports of cheaper green products and/or delayed local roll out (light green in **FIGURE 9**),
   c. and specifically for the steel industry (yellow in **FIGURE 9**) mainly, delay awaiting better costs and perhaps new technology, but clearly this means other sectors, such as transport, must decarbonise faster with the long-term commitment to hydrogen uptake by large industry players to define the demand for hydrogen pipelines.

For countries such as Germany, facilitating financing for projects in emerging economies that can deliver low cost REN and export green hydrogen products to meet European demand may be a win-win for all parties.

Share of green hydrogen in total hydrogen production

Indicative Trend

2025–2045 | in Percent

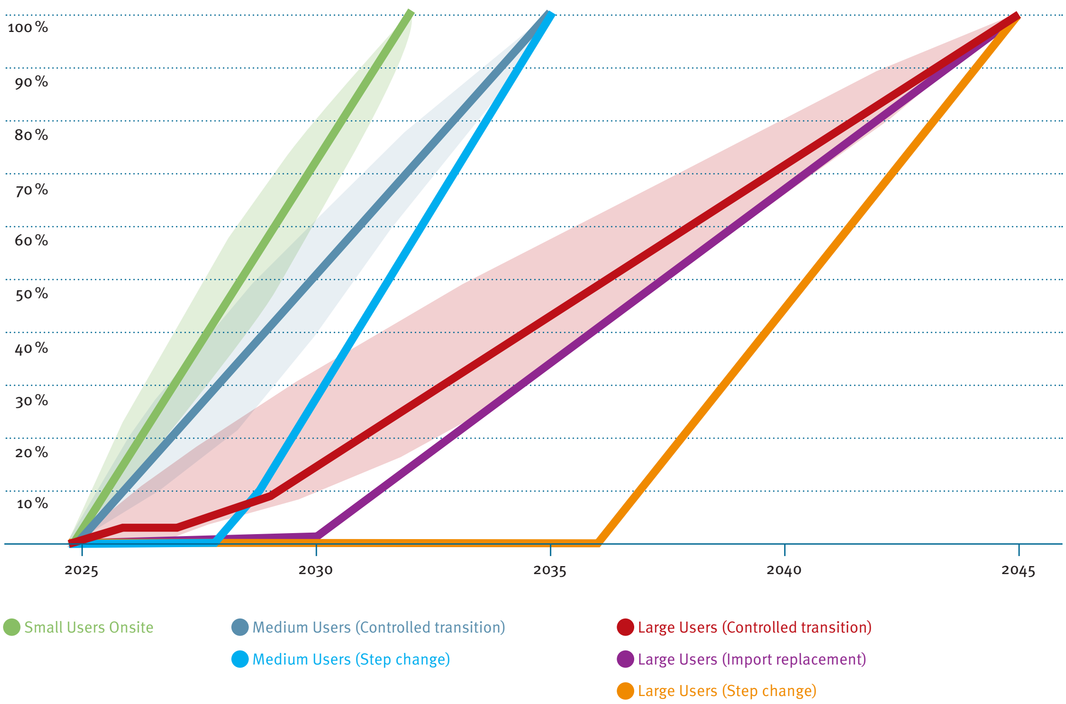


FIGURE 9
An indicative trend for more precisely targeted government funding to support transition in industry based on hydrogen usage, factoring in the different delays and permissible annual variations in shaded areas.

The proposals described above are based on a simple assessment using Fermi calculations, which determines that for many end-user products, the change in cost is likely to be bearable by consumer when incrementally introduced and when considered in a final application. This assumes that the green hydrogen contribution to the higher cost end products is not compounded by every part of the distribution and retail supply chain applying their current mark up. By example, for a nominal rise in a specific products cost of 110 % using green hydrogen in production, to apply a 130 % logistics margin and 200 % retail margin on the higher price is too expensive and not justified. EU regulation is sufficiently capable to separate out green components which makes it easier to apply a CBAM tax to extra-EU products for equality. If hotels can apply both city tax and VAT separately, a green premium tax and VAT, or lower VAT on green hydrogen products within EU is also achievable.

Two simple cases are provided to demonstrate the benefit of understanding end use. The first considers steel use in Germany. If a typical German house takes 15 tonnes of steel[18], people can understand that if DRI with green hydrogen is used, then steel price might increase by 50 %[19] to € 1,500/tonne, resulting in an increase of € 7,500 or 1.9 % on the house price of € 400,000. A VAT reduction might make such a case more palatable. One quarter of steel goes to automotive steel in Germany, an average car has 1 tonne of steel, so if steel price rises by 50 %, the price rises by € 500, which is < 2 % on an average car price. In both of these simple examples, it demonstrates that there is a cost but it is not so significant compared to the conventional price and over the lifetime of the product.

The second example is taken from the chemical industry to understand the impact of green hydrogen pricing on a key industrial chemical, methanol. The consumption and production of methanol is nominally 10 % of the total chemical sector and approximately two thirds goes into chemicals. Formaldehyde is one of the most significant chemicals made from methanol globally since it is a necessary raw ingredient for many products, including polymers, resins, paints and adhesives. In a house, the total might be 1 tonne of these methanol-based chemicals. The additional cost of using green methanol as a base to this chemical sector will increase the cost of a house by € 1,000[20], or < 0.25% increase for the same € 400,000 house. This can be absorbed, not-withstanding other net zero transition factors that might drive house prices upwards.

These two examples demonstrate that the nominal increase in the final product should not be significant if the incremental cost remains in absolute financial terms the same. However, what is observed in the market is that relative margins along the value chains are maintained, leading to excessive price increases for the end users. Measures preventing such effects are necessary to ensure the market system does not distort the cost of transition and to better chart a path between quotas (and fines for not meeting them) and funding matched to a timetable.

In summary, the lack of offtakers was the main issue identified that was holding back the green hydrogen industrial development and therefore extra consideration was taken post meeting to review paths forward. With respect to finding the offtakers, there is a need for identifying and prioritising the right hydrogen applications according to not only the potential to reduce CO_2 but also the market ability to absorb the higher costs of hydrogen and end-user products. The expensive error of moving first on hydrogen car refilling stations in Germany for a market that will not emerge for decades cannot be repeated. **It is timely for the national government to review the timeline and scope of the original plans for target industries, i.e. those deemed critical and/or offer synergies to existing infrastructure, as well as those large CO_2 emitters that can more readily absorb the cost incrementally over 25 years.** Achievable green product quotas or CO_2 caps could be applied in many sectors such as maritime and air transport, steel in automotive industry, building and construction. Crucially, other sectors where hydrogen is shown to be unsafe, grossly inefficient or not competitive must be ruled out in the midterm, such as the replacement of natural gas with hydrogen in domestic heating, or the use of hydrogen in fuel cell passenger cars. **Such a review should yield a long term (25 year) National Industrial Strategy developed by the national government and to be fully aligned with their Energy Transition Strategy.** The revised plans must be

1. realistically achievable,
2. aligned with constraints of all market aspects including both production, logistics demands and market end users,
3. critically aligned with large industry investment cycles and, withstand public scrutiny.

Ecosystem, including Regulation

The ecosystem under which the net zero change is to be enacted includes all of society and will touch upon all aspects of daily life. It also includes the hydrogen infrastructure to enable such change. The government's primary role is to provide the regulatory framework to enable such an orderly transition. Therefore, this section touches on a range of topics relating to various aspects that were raised but is by no means an exhaustive list.

The socio-technical impact and the level of information available to the public in the transition to a higher base cost of living is a key area to be addressed by government. **It was acknowledged in group discussion the power of negative media in shaping public perception and the lack of adherence to factual accuracy of the new non-traditional media.** This presents a real risk to public policy as witnessed in international events today where major efforts are being made to unwind an industrial policy agreed 2 years ago in the USA. **Therefore, a transparency is required from the whole green hydrogen industry: technology vendors, operators and also downstream customers, and overseen by reputable public bodies, to educate the public in simple numbers of how such perceived expensive change might impact on their daily lives.** This, to both demonstrate the path forward in greater clarity to relieve wider fears of the population and to ensure the public can see when corporations may be seeking an unfair advantage. This would also ensure a clear sense of how the market evolution for hydrogen can be best matched to levels and costs of production, with appropriate levers for government to intervene at timely intervals. **The message should encompass the need for greater energy security and autonomy for EU nations,** as revealed with the war in Ukraine.

On the project development side, there was identified a lack of **qualified and experienced tradespeople and engineers to meet the need for not only plant design but also construction and commissioning.** This was **especially remarked on in the area of permitting.** This is due to:

a. the inexperience of some project developers that are new to the hydrogen gas sector in Germany, as well as some government agencies in regions that had only very few gas or chemical installations until now,
b. the technical knowledge of a new (to market) and fast developing technology is not present at all levels of government, and especially in state and local governments with some exceptions,
c. both Europe and Australia have not had to deal with significant new chemical/industrial gas plants of a variety of scales in decades (gas plant development mainly limited to WA and Qld in Australia) with loss in competency,
d. some new electrolysis plants are proposed in locations outside of traditional controlled environments such as oil refineries and chemical parks, which introduces new considerations and demands.

This leads to delays in project execution. In Australia, it was remarked that the speed of approvals is linked to the state government that may be in power. This is not ideal for projects that must compete globally for limited manufacturing slots and, having secured end use customers and funding, may be then delayed. Harmonised national guidelines would also be advantageous in Australia to provide greater confidence in project timelines and execution.

The upskilling of the work force to meet demand presents a clear opportunity for governments to act if there is a desire to move forward faster in this sector. In the area of permitting, the steep learning curve requires more experienced people employed in administrations, especially in those regions with potential for new electrolysis plants, but little historical experience with chemical plant permitting. Education in regulatory and ongoing learnings based on industry feedback is important to ensure safeguarding of the public but enabling change to be made. **National governments are in a strong position to help facilitate improvements in both education and training of key disciplines through collaborative action between local, state and national governments,**

and in promoting the reskilling of the workforce to meet future industry needs. This is critical if a surge post 2030 in electrolysis development is to be expected.

The Australian government must consider not only the lack of expertise specific to the sector, but also the workforce demands for gas and chemical plants based on the new technology. Australia is accustomed to managing remote workforces on mine and oil & gas sites with FIFO operations. However, to fully capitalise on the potential for green hydrogen export markets, large electrolysis plants will be located in remote areas and often near REN sources (to reduce grid and hence input costs). **The new gas and chemical plants (e.g. ammonia, methanol) require permanent well-trained people to monitor both electrical and chemical process operations, and to complete regular maintenance activities.** Achieving this in Australia may need some innovative thinking such as lower tax zones for such plants, and the necessary infrastructure and support services that are required. Equally, for Germany to capitalise on the technology and manufacturing capacity for wind turbines, PV cells and electrolysis and process technology, **both the Australian and German governments might consider working more closely together to foster long term incentives to promote the exchange of people to facilitate project development and operation.**

From the perspective of liquidity in the hydrogen market, **the lack of a listed hydrogen trading market is** attributable to a current lack of scale and to the logistical challenges for moving large quantities of hydrogen around. Efforts are being made to address this and the free market will find a way to grow business by matching customers and producers. The government can support the market liquidity by providing transparent data on the current market consumers to reduce offtake risk.

Given the fast changing and volatile nature of the times, and noting green hydrogen supply contracts are usually signed for 10 – 15 year take-offs, the lack of liquidity and single offtaker risk hinders successful financing of projects. **Increased government interaction in the overall industrial planning can act to mitigate the risk of single customer dependence for project FID. In the event of the original customer closing operations, there is thus a strong likelihood through a regional plan for other hydrogen users to be found (eg. hydrogen or natural gas pipeline, clustering of hydrogen users).** It does means funding criteria will support clusters and those with existing hydrogen networks and account for reducing the overall project portfolio risk rather than just individual projects.

The issue of adding green hydrogen into the existing natural gas grid to pull through local green hydrogen production was contentious between participants. On one side, the advantage is that the transport and storage infrastructure is present, and even at only small levels of hydrogen content (eg. 2.5 %vol, nominally dictated by CNG automobiles), the scale of Germany's natural gas consumption means that this could easily account for 1 GW of local green hydrogen production. In terms of burning characteristics, the Wobbe Index is negligibly affected at 2.5 % (even up to $<$10 % hydrogen) although concerns were raised for special burning demands. As a means to drive the local electrolyser market, it appears simple to implement in high natural gas use locations with oversupply of REN power. An argument can be made that the premium that green hydrogen demands today is justifiable if it reduces reliance on LNG imported from specific regions especially at a price of circa € 14/MMBtu.

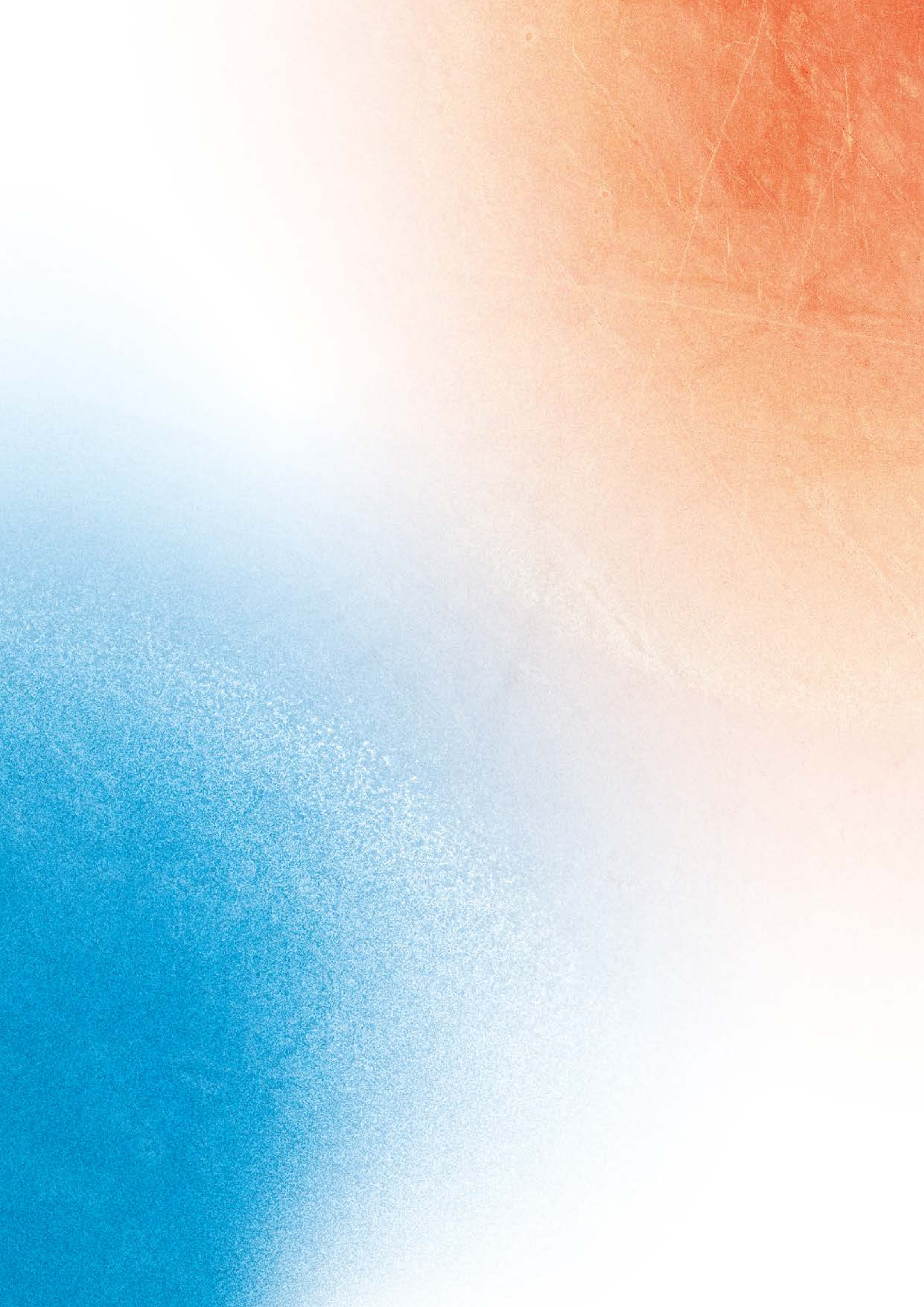
However, the other view was that making changes to a stable (gas) supply system today would not justify the addition of a relatively small amount of hydrogen that could make subtle changes to the natural gas a problem in industrial processes where natural gas is a feedstock. This hydrogen will mainly be used for heating which is a poor use of the valuable hydrogen. In this case, it is considered better to focus on delivering hydrogen by pipeline (new hydrogen or repurposed NG pipelines) to key users. In the end, as noted previously under End Market, knowing in finite detail all potential hydrogen users and their volumes is a key part to optimising the implementation of hydrogen delivery at the required scales and in the required form. Further insight into the government's strategy would be appreciated by those in the green hydrogen project space.

There is an ongoing discussion on virtues of different pathways to produce hydrogen, usually identified by colours. The main goal however is to ensure a low level of GHG emissions, independent of a specific technology. Using a lifecycle approach helps to identify strengths and weaknesses along the respective process chain. Next to green hydrogen discussed in this paper, blue hydrogen, a combination of using natural gas via SMR technology with CCS for the resulting CO_2, is a feasible and cost-effective process route to produce hydrogen. Provided all technologies are subject to a rigorous assessment (currently by EU as defined within the Delegated Act on Low-Carbon Hydrogen, achieving ≥ 70 % GHG savings) they should be able to contribute to the provision of hydrogen.

Finally, some suggestions were made to relax temporal and geographical components behind green hydrogen certification. These elements are present for good reason and part of it is to drive REN development across the EU. Recent adjustments [21] have been made in RED III for relaxing temporal requirements for REN to supply green hydrogen. Consideration of relaxing geographical requirements for sourcing of power should only be made for specific (large) user cases, considered integral to European industry, and could include REN power being purchased in one country and used in another only if the grid was contiguous and maybe only for a period of time whilst a lag from REN buildout in the country would be gradually removed over 10 years. However, geographical limits are applied to ensure national grid reliability can be maintained, so lifting this constraint should only be considered in exceptional cases. **Enabling the maximum conversion of REN to hydrogen at times of peak load must be a priority.**

Regulation underpins the market development in the drive to net zero. Revising policies and regulations is a must to address identified issues in the net zero strategy. It was acknowledged that EU regulation takes a long time to change and achieve common agreements between its many members. Therefore, some creative thinking is required to initiate change sooner. In an interim period of 5 years, national regulations must be adjusted to avoid further lost time to meet objectives. It is noted that:

1. Any changes decided by the German government to amend the direction of subsidies must still comply with existing EU regulations.
2. Government subsidies on investment are possible but are also subject to EU wide state aid rules, thereby limiting the maximum amount.
3. A degree of pragmatism is required for OPEX subsidies to be applied within EU state aid rules.
4. Flexibility must be built into regulations to allow for macro-economic factors and to enable entry of more players.
5. More can be done for reducing global emissions outside of Germany at lower cost than necessarily targeting complete reductions domestically.
6. Regulations that define product characteristics for subsidies (e.g. Certifiable Green Hydrogen) must be established earlier in future regulation to reduce barriers to market take-up.
7. Some sectors are better able to pass on to the end customer the increased costs from using green hydrogen. A clear example is the Sustainable Aviation Fuel (SAF) sector with quotas from the ReFuelEU Aviation, where the customer base can absorb the increased costs. However, the chemical industry does not have quotas and it is unclear if the customer base will absorb the cost. This leads to delay and distorted market development for green hydrogen in this sector.
8. Regulation must be developed with industry players and be transparent to those seeking to deliver green hydrogen to the end-user.



Conclusions

The purpose of the »H_2 – Beyond the Hype« workshop was not to provide definitive answers to all aspects of the transition from fossil fuels to a net zero economy. It was primarily focused on green hydrogen and its roll out in the wider energy transition picture. It served to highlight the more practical concerns of people within the green hydrogen industry and suggest mitigations that government agencies can consider in their regulations and long-term strategies. It is noted that Germany's larger industrial base, population and strong technology positions in energy and gas poses different questions and solutions to that of Australia, for which competitive low carbon solutions can drive new export markets and sustain future growth in local manufacture and production.

The wholesale transition of both new (electrolyser) technologies that are not fully developed and the energy ecosystem in such a short period of time is unprecedented in modern history. More recent events highlight the vastly changed global political and business environment of 2025 versus 2020. It is fair to state that:

- The 1.5 °C GHG driven temperature rise will be exceeded, which does place a greater importance on transitioning to low carbon economies sooner than later
- Geopolitical forces have and will continue to change global dynamics in near term forcing government and business to refocus on stabilising economies, rather than meeting green targets
- Energy security has more recently become more critical and green hydrogen can play a part in securing this
- Low-carbon objectives for 2050 may remain, however the path to their fulfilment must be reviewed

It was made clear that debt finance for electrolysis projects is readily available, provided that the business case is sound and risks are mitigated. Large industrial gas and energy players have been able to complete projects supported by their balance sheets. However, for many projects, the offtakers for the green hydrogen are not willing to pay current prices to enable projects to progress (with a viable ROI). The report then sought to answer two key questions that arose from this realisation.

The first question was how to close the gap between the high green hydrogen cost and ROI required to make an electrolyser project viable. To answer this required a deeper understanding of the electrolyser technology, project EPC and the true costs behind the economics of green hydrogen plants. It is made clear in the report that green hydrogen growth trend cannot follow that of renewable (wind and PV) power development without regulatory pull through of end markets due to the limited cost reduction that will be achieved. From an overview of the initial projects in Germany and Europe, it appears that improved project execution and financing might be realised if project developers team up with large multi-national players for large-scale projects to spread the risk, capitalise on their existing experience and access synergies that already exist in the market. However, the higher installed costs of green hydrogen plants in Germany and Europe prompts the need to reconsider the projections of local installed capacity.

Crucial to improving the short term pull through of installed electrolysis plants and to increasing the number of projects in Germany successfully passing FID would be to secure significantly lower REN prices. Some ideas generated in the exercise that could improve project economics and so the likelihood of progressing beyond FID were:

a. Providing subsidies for renewable power to deliver an effective base price of 20 – 30 €/MWh to sustain minimum plant load operation (10 – 20 %) and so improve overall economics, plant operability and availability, the ability to respond to spot market prices, and improve electrolyser stack longevity
   i. This could be achieved through a government owned power company that invests in part in projects, selling on some power at a loss and the rest at market rates to break even on their project.
   ii. This could be achieved through a government mandate to all new wind and PV projects that 10 % of initial offtake must be supplied to the green hydrogen industry.
   iii. Procuring power from existing REN projects as a subsidised quota of power for which operators bid based on the hydrogen price

b. Linking this with the partial supplementing of natural gas with green hydrogen into the gas network pipelines with guarantees on gas quality, to establish baseline operation of OEMs.

The above could be done under powers granted under the recent € 500 billion German Climate and Infrastructure Fund.

Electrolysis technology inherently lacks the economy of scale of traditional gas and chemical plants and it was shown that any reduction in the technology cost over the coming decade will not on its own bridge the price gap to grey hydrogen. Much of the electrolysis technology today lacks operational experience, and its absence incurs a larger risk component to projects. Indeed, OEM failure in the next 5 – 10 years can be expected as a result of field performance failure or the inability to compete against a step change technology, either within or outside the green hydrogen space. These risks favour a policy placing further subsidies only on either OPEX or produced hydrogen to reduce taxpayer risk exposure. Reducing the cost of electrolysis projects means reducing these risks.

Manufacturing capacity for electrolysis stacks in Europe has been secured via subsidies since 2020. Supply lines for the manufacture and assembly of other parts of the electrolyser units and the balance of plant units has met current project demand with some delay. The ability of supply chains to meet a potential rapid upsurge in demand may still be tested post-2030. The remaining forward risk for EPC and plant operation is linked to the availability of suitably trained personnel in key sectors. The lack of qualified and experienced engineers and tradespeople to meet the need for not only plant design but also construction and commissioning was noted. The lack of experienced and knowledgeable personnel was especially remarked on in the field of permitting within government agencies for several reasons. This adds significantly to delays in projects which adds cost and can also affect the ability to meet production deadlines. The unique job market in Australia for remote work may not match the different requirements that green hydrogen and associated chemical plants demand and this should be understood to ensure project costs are not prohibitive. National governments are in a strong position to facilitate improvements in both education and training of key disciplines through collaborative action between local, state and national government, and in promoting the reskilling of the workforce to meet future industry needs.

Future subsidies for projects that favour either OPEX (power prices) or hydrogen production itself insulates the taxpayer from poor EPC execution or technology risk that should lie with the project owner. In the German market, it was felt that there was missing a long term, 25yr strategy for the transition to green hydrogen products and how subsidies would be applied. More so, subsidies for imported green hydrogen products would allow for sustaining the German industrial base with low-cost green chemicals whilst meeting net zero objectives. Also missing from public discourse was the engagement between countries such as Germany and Australia, who share many synergistic characteristics in the energy transition sector. If supported, this could benefit the wider economies of both countries towards meeting their decarbonisation goals whilst growing their industrial and manufacturing base.

The second question was how to move potential customers to take up green hydrogen without the need for massive and ongoing government subsidies but preserving industries' ability to compete globally. The key point is that the change to low carbon technology for hydrogen cannot be left to the market since in most cases, it is more expensive than grey hydrogen. Government must act with two key elements of market knowledge in mind. The first element is a detailed understanding of the breakdown of costs of hydrogen supply at the different scales and purities for each end user of hydrogen for each industry sector as an input to their production cost. The second element of market knowledge is a detailed knowledge of the destination of the products (steel, chemicals etc.) into the consumer system. This information, in collaboration with industry input, enables projects to be prioritised on cost effectiveness, managed risk and societal needs and delivers higher certainty to project developers. Together with a National Energy Strategy incorporating net zero objectives, this National Industry Strategy can therefore be developed in alignment with industry's needs and business investment cycles.

A clear roadmap should be made available to all industry sectors and include quotas and inducements, such as tax credits for those companies that commit to the target. The key objective must be to drive offtakers for green hydrogen in sectors and applications where it is most appropriate and efficient. This can be done through a revised mix of regulation and subsidies for OPEX (subsidised power), tax incentives (REDII, tax credits) and achievable targets based on a clearly stated glide path together with enforceable CBAM regulation to maintain EU competitiveness. The roadmap, starting from today's position, must be:

1. realistically achievable,
2. aligned with constraints of all market aspects including production, logistics and end users,
3. aligned with large industry investment cycles and,
4. withstand public scrutiny.

Therefore, for a sustained competitive industry in Germany and whilst preserving critical industries, national governments and industry players must work closer together to manage what is a very fast change over the 25 year period. A greater degree of transparency is required to enable project developers to match the demand to supply.

That transparency should extend to the public arena. The social and technical change forecast in the next 25 years is enormous and quite naturally brings concerns to the population when it is not well understood. It was noted that public perception today is shaped increasingly by non-traditional media forms which may not adhere to factual accuracy as much as traditional forms. Therefore, a transparency is required from the whole green hydrogen industry – technology vendors, operators and also downstream customers – and should be overseen by reputable public bodies, to educate the public in simple numbers of how such an expensive change might impact on their daily lives. The message should encompass the need for greater energy security and autonomy for EU nations.

Recommendations

Australia and Germany share many commonalities in the low carbon sector but do have different requirements and timelines. The recommendations are divided per country, although the focus should be on finding common understandings to improve business and trade. Any actions should be progressed over the next 1 – 2 years to be prepared for an expected accelerated surge post 2030.

In light of the need to spur the end user market forward for green hydrogen products within Germany and for Germany to sustain its national industrial base, the following suggestions were made for consideration.

1. Development and/or refinement of the National Industry strategy for the next 25 years that aims at decarbonising the industry and sustaining its value to the economy.
   a. Draw upon technical and experienced people assessing numbers and technology, from both industry and independent bodies, to ensure the practicalities are addressed.
   b. Those national industries that are truly critical to defense and economic (job and energy) security can be granted a delay or are prioritized funding.
   c. Identify those industries of high margin, low volume products (pharmaceutical, electronics, electrical, defense) or with low hydrogen demands and push their transition to green hydrogen sooner (within the next 5 – 8 years) as the economics are more favorable.
   d. Focus on progressive quotas over a longer period (10 – 25 years) for bulk chemical, steel and cement players to achieve their change, noting that:
      i. Developments may require expensive new process changes (in the case of steel particularly) and should be aligned with investment cycles.
      ii. New technology development that may eventuate in 5 – 10 years will deliver a more cost-effective path to decarbonization and such changes should be aligned with national interest, justifying some delay.
      iii. The scale of the change requires long term planning over 10 – 20 years to manage cost inputs and/or associated process changes and/or changes in supply chains.
   e. Provide more flexibility in the early stages of the glide path.
   f. Tax credits (eg. from REDII) and regulations (EU ETS) are an effective carrot and stick solution.
   g. Favour synergistic solutions between sectors to preserve local industry as a key driver (eg. combining Cement & Chemicals).
   h. Supplementing local production of green bulk chemicals with imports from locations with higher REN potentials and better economics based on cheaper REN power (20 – 30 €/MWh) is a very sensible approach that should attract government support.
   i. Re-consider if existing nuclear power is acceptable for electrolysis through the EU to meet German chemical needs.
   j. Consider where the blending of locally produced green hydrogen into the existing NG grid can be effectively managed as a means of providing pull through of OEMs, increasing returns from REN installations, providing grid stability and improving national energy security.
   k. Ensure new technologies in the low carbon space are actively incorporated into the Energy and Industry strategies, noting it takes 5 – 7 years to develop and bring step change industrial technology to market, and that new technology will impact the demand for green hydrogen.
2. Refinement of a National Energy strategy for the next 25 years to ensure alignment with the National Industry Strategy and it should ensure that:
   a. Decarbonising the grid electricity should be the priority in terms of achieving CO_2 reductions in addition to making reductions in other sectors that are currently more cost competitive.
   b. The feasibility and means for securing REN power in Germany for local production at € 20 – 30/MWh for current and future electrolysis plants to maintain a minimum load operation is investigated as a matter of priority.
   c. The impact of competing demands from other power users on the ability to deliver (REN) grid power to electrolysis plants in Germany over the next 25 year time span is accounted for.

   d. That excess REN power that could be produced but is curtailed due to low demand is directed in part to green hydrogen production.
   e. Imports of energy in non-fossil forms is included, to ensure infrastructure is built or repurposed well in advance.
3. Comprehensive and transparent messaging to the wider population to be improved in simple economic terms and with the pathway defined to manage expectations and indicate how inflationary effects and technical changes from the transition are to be spread over 15 – 25 years:
   a. Ensure it is a published bi-partisan plan, achievable via coalition.
   b. Tracked metrics are reported and published in traditional media as well as online annually
   c. Active push of information to demonstrate changes at local level.
   d. Transparent calculations of the impact of higher cost material for the average person in their normal life over the transition period is made clear.
4. Especially in light of current geo-politics, recognise that the drive to net zero can be delivered by working more closely with other nations to ensure reliable and lowest cost solutions are found:
   a. Support developing nations in form of mutual project development in the green space and less in direct funding, with the added local social benefits.
   b. Actively work with nations with common aspirations in the energy and manufacturing sectors to deliver mutually beneficial solutions built on long term engagement.
5. The government has a key role in ensuring the right workforce and regulatory structures are available when demand arises:
   a. Ensure that the people are available and sufficiently skilled and trained to deliver on the requirements of the new industry across the spectrum from industry professionals, trades people and those in government charged with vetting and regulating the new industries.
   b. Harmonise regulations across state boundaries.
   c. Educate those in government and regulatory bodies tasked with approving project applications on a continual basis.

Australia's position relative to Germany reveals different priorities and schedules. Australia should not pass up the opportunity that green hydrogen products for export markets represent in driving a new era in base chemical production plants locally. The increasing rate of build out of REN capacity on the east coast should be encouraged since once capacity exceeds BESS and needs, Australia will find itself in a very good position to deliver the low-cost REN that competitive green hydrogen demands.

Therefore, the areas that the Australian government can be active in to capitalise on the opportunity are:

1. Ensure REN build out is aligned with a National Energy Strategy that aligns with a local Industrial strategy that targets new export orientated green chemical and DRI production to deliver lowest total cost REN power to electrolyser plants in the region of € 20 – 30/MWh (AU$ 35 – 50/MWh).
2. Ensure that the people are available and sufficiently skilled and trained to deliver on the requirements of the new industry across the spectrum from industry professionals, trades people and those in government charged with vetting and regulating the new industries:
   a. Harmonise regulations where possible across state borders,
   b. Regarding permitting, more help should be provided to companies to be aware of the requirements and how to address them.
   c. Educate those in government and regulatory bodies tasked with approving project applications on a continual basis.
   d. Training of technical people to meet the demand in rural areas is supported.
3. Ensure that the infrastructure necessary to support the new plants in (most likely) rural or isolated areas is delivered in a timely manner that aligns with projects and global demands.
4. Seek to capitalise on the opportunities for onshoring manufacturing through engaging more with both local and over-seas companies in this fast-moving high tech new energy sector. Manufacturing may also include service centres to meet expected increase in chemical plant technology that is at a very low base as of today.
5. Ensure the population can see the economic benefit of becoming a leading exporter in new green products and that it is the driver for future generations.

Appendix
Useful Comparative numbers for Green Hydrogen

Readers are encouraged to always challenge numbers and to dig deeper into the assumptions that may be presented. As an output from the Workshop, some practical insight is provided on the basis of industry experience to assist in understanding the electrolyser ecosystem.

Basic System costs

Electrolyser systems at large scale can cost from approximately € 500/kW to € 1,500/kW, for atmospheric to pressurised systems at large scale, more at smaller scale.

- Ensure for the scale and application that comparisons are directly comparable for the same H_2 flow at the same flow, pressure, temperature and composition.
- Ensure the supplied system is meeting all regulatory requirements for the location to be installed, noting some global locations may have a different acceptance level of operational risk and regulatory requirements, which does impact on the final price.
- Understand the impact of stop/start operation on hydrogen recovery and likely losses.
- Time onstream data is the only sure means of confirming stack longevity.
- Electrolyser manufacturers are always seeking improvements, which brings risk of technical operational issues, and these risks should be managed.
- With current electrolyser technology, a simple rule of thumb is that 5 MWe of electrolysis produces the equivalent of approximately 1,000 Nm³/h or 90 kg/h of hydrogen on average.

Power and power price

In Germany, the power price is coupled to the natural gas price so green hydrogen using grid power can never meet the cost of hydrogen from natural gas in an SMR.

Explanation: The electricity market design in Germany follows the merit-order principle, which defines the electricity price by the marginal cost of the last power plant contributing to satisfy the demand. For most hours of the year in Germany, this last power plant contributing will be a gas-fired power plant *(Fraunhofer ISE Energy-Charts,* Marginal Power Plant Data, 2024 and Bundesnetzagentur, SMARD Platform Dispatch Data). Since a gas fired power plant has an efficiency of electricity generation of about 50 % and an electrolyser an electrical efficiency of 70 % that is to be compared with an SMR that produces hydrogen also with an efficiency of 70 %. Notwithstanding other cost contributions (grid fees, pipe fees), electrolytic hydrogen is expected to be twice as expensive as hydrogen produced by SMR on a purely marginal cost basis.

The Delegated Act[21] for hydrogen used for RFNBOs requires to fulfil three criteria:

1. Spatial correlation (same or under certain conditions adjacent electricity bidding zone, REN-PPA or direct connection).
2. Temporal correlation (prove that the plant is running on REN, first on monthly, later on hourly basis).
3. Additionality (ensure that additional REN is used, but also decouples users from the electricity market).

Together these criteria significantly reduce the full-load hours for an electrolyser plant to produce using low-carbon electricity. It is fair to say that the power price

- will remain a primary component of LCOH of production.
- Electrolysis plants need a no load power to maintain the plant in operational state.
- Power price is linked to the total hours p.a. of REN at a nominal 100 % capacity which influences the price, and clearly the hydrogen production to meet end needs.
- Unlike traditional SMR plants, electrolysis plants can respond an order of magnitude faster to power inputs which is an advantage in certain demand cases.

There would be few situations that an entity can achieve low REN power cost unless there is an abundance of power and no alternative market for it, outside government subsidised power.

Emission calculations

- Losses of hydrogen to the upper atmosphere remain to be fully assessed in terms of its secondary role in associative contributions to GHG emissions, but estimates suggest global warming potential of hydrogen is 11 x CO_2-eq [22 23].
- The argument for generating hydrogen onsite on demand is supported by the potential impact of hydrogen in the upper atmosphere.

It has a significant impact on the development of the green hydrogen economy and where key chemicals such as methanol and ammonia should be produced.

Transport and storage of hydrogen

- is a significant (cost) factor to be taken into account for delivered green hydrogen product
- studies have been done, of which two are referenced for interest

Transport option for hydrogen

	Distribution		Transmission		
	0 – 50 km	51 – 100 km	101 – 500 km	>1,000 km	>5,000 km
Pipelines* Retrofitted	City Grid	Regional distribution pipelines	Onshore transmission pipelines	Onshore/Subsea transmission pipelines	N/A
New	City Grid	Regional distribution pipelines	Onshore transmission pipelines	Onshore/Subsea transmission pipelines	N/A
Shipping LH_2	N/A	N/A	N/A	LH_2 ship	LH_2 ship
NH_3**	N/A	N/A	N/A	NH_3 ship	NH_3 ship
Trucking LOHC**	N/A	N/A	N/A	LOHC ship	LOHC ship
LH_2 trucking	Distribution truck LH_2	Distribution truck LH_2	Distribution truck LH_2	N/A	N/A
Gaseous trucking	Distribution truck CH_2***	Distribution truck CH_2***	Distribution truck CH_2***	N/A	N/A

Costs <0.1 $/kg 0.1 –1 $/kg 1 –2 $/kg >2 $/kg

* assuming high utilization
** Including reconversion to H_2; LOHC cost dependent on benefits for last mile distribution and storage
*** Compressed gaseous hydrogen

FIGURE 10 The report Hydrogen-Insights-2021[24] issued by the Hydrogen Council indicating the modes for shipping green hydrogen products. Current projections might differ from this graph.

Total Shipping Cost – Clean Fuel + Carbon Tax Analysis

$ per kg/H_2

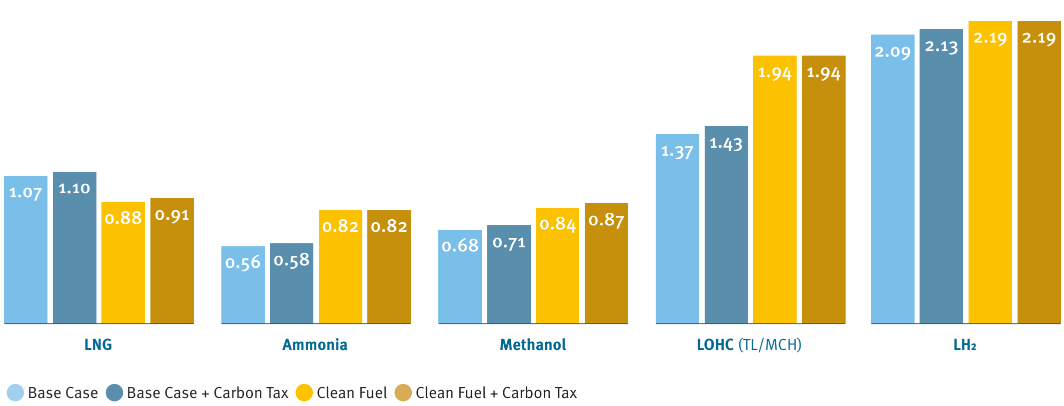


FIGURE 11 A comparison of the transport cost of green hydrogen products from Australia to Rotterdam. Adapted from C. Johnston et al.[25]

Comparing hydrogen price with hydrogen from natural gas with the Impact of CO_2 tax

A very simple analysis is completed considering only feedstock cost and simple stoichiometry. It ignores the capital cost and operations of an SMR, but consider adding a uniform € 2 – 3/kg to account for this. In the table below, the nominal prices for natural gas in USA (yellow) and recent EU and Japan (blue) are shown. Simple conclusions are that:

1. The CO_2 tax is incremental, not a major contributor to the overall hydrogen price relative to feedstock
2. By 2030, with EU CO_2 tax at € 100/t CO_2, the cost of REN green hydrogen in the best global locations may only just be competitive to EU natural gas today, although this is without considering logistics
3. This drives the EU to consider European owned plants in foreign countries to obtain the desired end result for large scale chemicals, which demands increased diplomacy
4. An effective CBAM is required to protect EU industry for those that choose the higher cost path.

	CO_2 tax €/t CO_2					
Natural gas € / MMBtu	**10**	**50**	**100**	**200**	**400**	**800**
USA **2**	0.61	1.05	1.60	2.70	4.90	9.30
USA **3**	0.86	1.30	1.85	2.95	5.15	9.55
4	1.11	1.55	2.10	3.20	5.40	9.80
6	1.61	2.05	2.60	3.70	5.90	10.30
8	2.11	2.55	3.10	4.20	6.40	10.80
10	2.61	3.05	3.60	4.70	6.90	11.30
EU, Japan **12**	3.11	3.55	4.10	5.20	7.40	11.80
EU, Japan **14**	3.61	4.05	4.60	5.70	7.90	12.30
16	4.11	4.55	5.10	6.20	8.40	12.80
18	4.61	5.05	5.60	6.70	8.90	13.30
20	5.11	5.55	6.10	7.20	9.40	13.80
30	7.61	8.05	8.60	9.70	11.90	16.30

TABLE 2
Indicative price of hydrogen (€/kg H_2) when incorporating only CO_2 tax and natural gas (methane) supply

When will green hydrogen be competitive with that from fossil sources (natural gas)?

A comparison on $/MMBtu enables a reasonable comparison with the equivalence of natural gas (although this simplification ignores the differences in logistics and end use that the two products have and the incumbency of infrastructure that natural gas enjoys over hydrogen).

From below, and the studies by IRENA and IEA, the sensitivity to power price and capacity factor are clearly shown, with the take home message that

- over the next 10 years, natural gas is likely to remain cheaper, excluding CO_2 tax, and more so with REN build out.
- The requirement for cheaper green hydrogen is to have lowest cost (oversupply) of REN
- Higher efficiency of electrolysers are also key to bringing the price down

Any further downstream conversion of green hydrogen to e-fuels such as Methanol or long chain hydrocarbons reduces the overall exergy and raises the costs further per $/MMBtu of recovered energy. However, transport costs may be cheaper and the final product most likely cheaper to the end customer.

Hydrogen production cost projection

$ / MM Btu

Capacity factor	Renewable solar costs ($/kW)	Electrolyser efficiency	Similar to	
<42 %	0.04 (20 %)	65 %	IRENA	**Arup** Green H_2 Price range
<50 %	0.02 (60 %)	65 %	IEA	**Hydrogen Council** Green H_2 range
				Arup Blue H_2 central estimate
<90 %	0.012 (75 %)	80 %	IEA	**Hydrogen Council** Blue H_2 range
65 %	0.03	65 %		**Gas** Price range

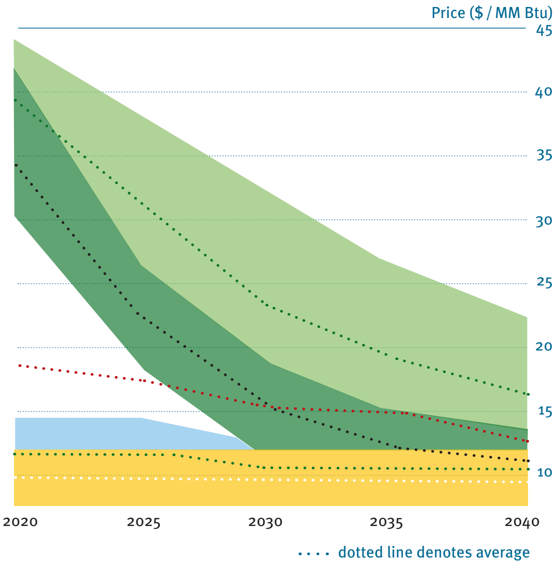


FIGURE 12
Hydrogen production cost projection by ARUP made in 2021[26]
Current projections might differ from this graph.

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