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THE ROLE OF HYDROGEN IN THE ENERGY TRANSITION

INTRODUCTION

Martin Lambert

The last two years (2019 and 2020) have seen growing momentum behind the global recognition of the urgency of the ‘climate emergency’, with more and more countries committing to achieve net zero emissions, typically by 2050 (e.g. UK, European Union, Japan, and South Korea) and by 2060 in the hugely significant case of China. The same two years have also seen a growing conviction that hydrogen will play a significant role in the decarbonisation of the energy system. Electrification will certainly play a much enlarged role in future, with many commentators suggesting that the share of electricity in final consumption is likely to rise from typically around 20 per cent today to around 50 per cent by 2050. Even if that proves to be an underestimate, it will still leave considerable demand for low-carbon molecules, and, with current technologies, the most likely low-carbon (or preferably zero-carbon) molecule is hydrogen. A growing number of countries have now published national hydrogen strategies, and more such strategies are under development. These strategies set bold ambitions for development of hydrogen but are relatively unclear on the pathways and steps to reach those ambitions.

The scale of transformation of the energy system from one based largely on fossil fuels to one where fossil fuels play a very minor role is enormous, and to complete such a transformation within 30 years requires unprecedented speed. Low-carbon hydrogen is starting from a small base, and current costs do not support a commercial business case. For hydrogen to achieve the ambitious targets which have been set for it in various strategies will require many players across the energy industry (private sector, government, regulators, and consumer groups) to work together to drive the required policies and behaviours. The structures to enable that collaboration will need to be developed as a matter of urgency in the next year or two. Against that background, it is very timely that this edition of the *Oxford Energy Forum* is dedicated to exploring the role of hydrogen in the energy transition.

Adam Hawkes from the Sustainable Gas Institute at Imperial College, London sets the scene well, looking at the potential role of hydrogen in the context of an overall decarbonized energy system. He explains that while decarbonisation involves electrification of as many energy end-uses as economically and technically practical, something else will be required to cover periods of low renewable power generation and for those sectors (like aviation and parts of heavy industry) not suited to electrification. That ‘something else’ could potentially be low-carbon hydrogen. He also provides a valuable insight into the oft-stated ‘blue’ vs ‘green’ hydrogen debate, arguing that for blue hydrogen to become a major player in the energy system will require far-reaching success with carbon capture and storage (CCS), as well as dealing with supply chain methane emissions. He concludes with the key message that the priority for now is to support innovation, demonstration, and deployment of hydrogen supply chains while also supporting a range of other technology options to achieve climate change mitigation.

After that general overview, we go on to look at the potential role of hydrogen in some specific applications. My colleagues, Aliaksei Patonia and Rahmat Poudineh of OIES, consider the potential role of hydrogen, and more specifically ammonia produced using low-carbon hydrogen, to provide the required flexibility to the changing structure of the electricity grid. They argue that in principle, power-to-ammonia could provide grid services such as seasonal storage, emergency backup, and energy transmission. This could reduce the need for significant excess capacity in the electricity system and minimize the need to expand electricity grid capacity. They also point out a number of challenges which need to be overcome, in addition to the usual suspects like increasing scale, decreasing cost and obtaining required government support. Significantly, the ammonia synthesis process generally requires continuous operation to avoid damaging the catalysts, which limits its ability to provide higher-value grid-balancing services with intermittent renewable power generation. In addition, the toxicity of ammonia leads to limited social acceptability and stringent storage and handling requirements.

Continuing the ammonia theme, Bruce Moore of Howe Robinson Partners contributes a very interesting article on the options for decarbonisation of the shipping industry, to meet the ambitious targets set by the International Maritime Organization. There has been considerable focus recently on the potential use of ammonia from low-carbon hydrogen. This does indeed seem to be a promising option, but the article puts it in the context of other alternatives like direct electrification and use of biofuels. The author also makes the encouraging observation that while the cost of decarbonized fuels is higher than that of the fuel oil used currently, this generally only results in a small percentage increase in the cost of delivered goods.

Blending low-carbon hydrogen into the natural gas grid is sometimes considered a logical initial step in the energy transition. Andy Lewis from Cadent and Tommy Isaac from Progressive Energy contribute a fascinating article explaining some of the detailed technical and safety work which was carried out in preparation for the initial trials of blending 20 per cent hydrogen into parts of the natural gas distribution grid in the UK. This illustrates well the level of detail which is necessary before making even that limited change, and gives an indication that a similar approach will be necessary before conversion of existing natural gas infrastructure to carry 100 per cent hydrogen. Several such projects are already under way; for example, Gasunie in the Netherlands has already converted a short section of transmission pipeline to carry hydrogen, and National Grid in the UK is building a test site to assess components of the National Transmission System when used to carry hydrogen.

Markus Schöffel from thyssenkrupp Steel points out that the iron and steel industry globally is currently responsible for around 7 per cent of global CO_2 emissions with the dominance of coal-based blast furnace technology. He explains clearly how switching to a direct-reduction process using low-carbon hydrogen could eliminate around 95 per cent of these emissions, and encouragingly highlights the ambition of thyssenkrupp Steel to convert around one-third of its capacity to direct reduction by 2030. He also points out the challenge of securing sufficient low-carbon hydrogen supply, particularly given Germany's current policy focus on green hydrogen. He makes the case for parallel development of blue hydrogen, and points out some of the key regulatory changes which will be required to accelerate the transition to the direct-reduction process.

Picking up the regulatory theme more generally, Alex Barnes of OIES provides a good overview of the complex topics around regulation of hydrogen markets, with a particular focus on potential concerns about 'locking in' technologies with relatively high emissions. He argues that the risk of such lock-in is low, and that government policy and regulation can adjust over time as technology develops. He stresses that the higher priority should be for regulation to enable an early start to stimulating the required investments in hydrogen infrastructure, pointing out that there is a greater risk of delaying the switch from unabated fossil fuels.

Linked to the topic of regulation and market development, Patrick Heather of OIES then looks further ahead and considers how a traded hydrogen market might develop, drawing particularly on lessons from the historic development of trading in the natural gas industry. He points out that the process of natural gas market liberalisation in the UK took nearly 15 years, and it took a further five years for the British NBP to become a liquid trading hub, with slightly longer overall time frames in other European countries. He assesses that the situation of European hydrogen infrastructure today is less mature than the gas market was in the 1960s, so there is a long journey ahead to establish a traded hydrogen market. Depending on the speed of the energy transition, he projects that it is feasible there could be a traded market by 2040.

Just two or three years ago, it appeared that most of the focus on decarbonisation was in Europe (and probably even more concentrated in relatively affluent north-west Europe), while interest in climate change was muted elsewhere in the world. The articles thus far have largely reflected that focus. That Eurocentric focus of decarbonisation has changed dramatically in the last year, however, with 'net zero' declarations from countries such as China, Japan, and South Korea and the change of administration in the United States. Similarly, interest in hydrogen as a low-carbon energy vector has also grown substantially. Reflecting that growing global interest, we have included articles from a selection of countries which are developing serious plans for low-carbon hydrogen.

Ken Koyama from the Institute of Energy Economics in Japan provides a fascinating insight into the current deliberations in Japan following Prime Minister Suga's declaration in October 2020 of the country's carbon-neutrality target for 2050. He explains the current ideas which may become incorporated into the release of the next Strategic Energy Plan later this year, which is likely to include low-carbon hydrogen/ammonia in the intended 2050 power generation mix. However, he also highlights some of the key challenges which Japan faces to be able to develop low-carbon hydrogen at a reasonable cost. These include the cost of renewable power generation, which is higher in Japan than in many other countries, and the likely requirement for a large share of hydrogen (or derivatives like ammonia) to be imported into Japan.

To meet that potential demand for imports into Japan and elsewhere, Australia is positioning itself to become a significant exporter of hydrogen to Asia, as explained by Peter Grubnic and David Norman of the Australian Future Fuels Cooperative Research Centre. They explain how Australia plans to take advantage of its abundant natural resources, both wind and solar, as well as traditional hydrocarbons, which could be linked with carbon capture and storage technologies. Most export-oriented projects are focussing on renewables-based hydrogen and ammonia; and following a number of domestically focussed pilot and demonstration scale projects, some developers are now evaluating export-focussed projects up to GW-scale.

Saudi Arabia is also positioning itself as a very large potential low-carbon hydrogen exporter. Ahmad O. Al Khowaiter and Yasser M. Mufti of Saudi Aramco provide an excellent insight into their company's thinking around the opportunities and challenges for hydrogen. They explain the current initiatives in both blue and green hydrogen in Saudi Arabia, including the demonstration shipment of blue ammonia to Japan in September 2020. They highlight Saudi Aramco's significant existing experience in carbon capture, utilisation, and storage (CCUS), and the Kingdom's significant existing role in the global ammonia trade, but remind us of the very rapid scale-up required in CCUS technologies. The International Energy Agency's Sustainable Development Scenario envisages global CCUS capacity to grow to 5.6 billion tonnes per year by 2050 from just 40 million tonnes per year today. To meet such challenging ambitions, they remind us, there is a need for inclusive global policies and appropriate market mechanisms, perhaps drawing lessons from the early days of the LNG industry.

Staying in the Middle East, Robin Mills, CEO of Qamar Energy and OIES research associate, explains how hydrogen fits with the low-carbon energy ambitions in the United Arab Emirates (UAE), building on existing plans for renewable power generation and gas. With abundant low-cost solar resources (potentially the next solar power project could have a strike price below 1 US¢/kWh), manufacture of green hydrogen could become increasingly attractive. The country is also a leading exponent of carbon capture, and the new leadership of the Abu Dhabi National Oil Company sees hydrogen as an important part of its strategy. Robin also points out that there are several major challenges for the development of hydrogen as a business in UAE. He suggests that competitive economics may lie less in becoming a major exporter of low-carbon hydrogen and more in domestic use and investment in international projects.

Finally, we cover probably the two most important energy economies which as recently as a year ago may scarcely have featured in a discussion of decarbonisation. In the last 12 months that has changed dramatically, with China's pledge in September 2020 that the country would reach carbon neutrality by 2060, and with the new Biden administration setting the United States on a path to net-zero emissions by 2050. Kenneth Medlock of Rice University's Baker Institute provides a US perspective, highlighting that the potential of hydrogen rests in its diversity, particularly the range of alternatives for production of low-carbon hydrogen. He also emphasises the importance of infrastructure in the massive supply chains which comprise the energy system, and the importance of making use of such infrastructure as far as possible. He also makes clear that while there are some federal incentives which can benefit hydrogen, certain states, most notably California, also have incentives which make hydrogen more attractive.

Michal Meidan of OIES reminds us that China is a global leader in clean energy technologies and poses the question of whether China can replicate its success with low-carbon hydrogen. She points out that evolving geopolitics may make previous synergies between developing technologies in the West and scaling them up in China more challenging. Nevertheless, she argues that the 2060 carbon neutrality pledge bodes well for hydrogen. China already has significant production and industrial use of hydrogen, albeit much of it highly polluting, using coal as a feedstock, and has already been promoting use of hydrogen in transport, with nearly 7,000 fuel cell vehicles having been sold. She suggests that while hydrogen is now gaining momentum in China, there are several challenges to overcome. Notably, as in other countries, regulations will need to adapt, and cost competitiveness will need to improve. In an interesting parallel with the United States, she explains that in many cases provincial governments are taking the lead on hydrogen development, adapting to more local circumstances.

Reflecting on the diverse range of articles contributed to this edition of the *Oxford Energy Forum*, it is clear that huge momentum and expectations are building related to low-carbon hydrogen in many sectors and many countries, but significant challenges remain to be overcome. We hope that you enjoy reading this issue of the *Forum* and find it stimulating and informative. I would like to thank all of the contributors to this edition, Amanda Morgan for copy editing, and Kate Teasdale for her usual attention to detail in finalising the publication. If you would like to discuss or comment on any of the points raised, please feel free to contact me (martin.lambert@oxfordenergy.org) or the individual authors directly.

OPPORTUNITIES AND CHALLENGES FOR HYDROGEN IN A DECARBONIZED ENERGY SYSTEM

Adam Hawkes

It is now well established that the way in which we produce, transform, and consume energy must fundamentally change over the coming decades if the Paris Agreement target of limiting global warming to well below 2°C is to be met and if we are to avoid dangerous climate change.

Fortunately, there is now substantial evidence regarding the broad features of future energy systems that might meet this target; the cornerstones of the transition are improved energy efficiency, power sector decarbonization, and electrification of as many energy end-uses as economically and technically practical (e.g. substantial parts of building heating and transport). This vision is already making significant headway in the form of rapid renewables uptake in the power sector and movements towards the electrification of large parts of the transport sector, and to an extent in heat provision.

In the 1990s and early 2000s, hydrogen was seen as playing a key role in the future of energy.[1] It then lost favour as technological optimism was overcome by infrastructure, economic, and other concerns. But this is now changing, and hydrogen is back with renewed interest, helpful policy targets, and a range of credible companies offering products and services across the value chain.

Where does hydrogen fit in future energy systems?

Arguably the biggest success stories of decarbonization to date are those of solar photovoltaics (PV) and wind power. One does not need to look far in the literature or at on-the-ground uptake to see that this is true.

For example, in the case of solar PV, deployment has consistently exceeded expectations, and learning rates have been reducing capital cost by more than 20 per cent for each doubling of capacity.[2] Similarly, for wind power, the success of offshore auctions in the UK has been spectacular, with prices dropping from around £ 120/MWh to less than £ 40/MWh in less than a decade. With these trajectories it is no surprise that solar PV and wind power are expected to make up a large portion of global power system capacity by mid-to-late century. This, combined with upbeat projections of end-use electrification of transport, heat production, and parts of industry is central to conventional wisdom on how to combat climate change.

But how far can the world go with such a strategy? While a number of prominent studies involving 100 per cent renewable power systems exist, the question of intermittency of solar and wind sources, and therefore system operability, cannot be overlooked. On this point, most studies of global decarbonization limit solar and wind uptake to 50–70 per cent of electricity production. This issue is further compounded by potential large-scale electrification of end-uses, changing the timing of demands and increasing the magnitude of demand peaks.

A good example of this is the coincidence of low wind, low sun, and high heat demand in winter in the UK. Notable examples of this were in January 2010 and January 2021. In such periods, if space and water heating demand were served by ubiquitous air source heat pumps, as is often proposed (and especially since heat pump performance drops in cold weather), very large excess electricity supply capacity may be required. Moreover, end-use electrification is not economically and technically viable in all sectors. Often-cited examples of this are aviation, heavy goods transport, and important parts of heavy industry.

Given these issues, it seems likely that something else, in addition to the fundamentals of power sector decarbonization and end-use electrification, is needed if the world is to reach Paris Agreement targets while maintaining a workable, diverse, and economically sensible energy system. This is where hydrogen can potentially play a role in the future.

Hydrogen has several attractive features, beyond the obvious of being perfectly clean-burning and a very common element (though often tied up inconveniently with other elements such as oxygen or carbon). Of particular importance are its useful features of relative transportability (e.g. compared to heat) and long-term storability. The latter point is advantageous for not only the intermittency issue described above, but also broader energy security and system resilience. And hydrogen appears to have both the technical and economic advantage for long-term storage. One recent study pointed out that while lithium-ion batteries are increasingly dominant in many storage applications, they will likely not be able to compete with hydrogen in long-duration applications, even in the long term.[3]

Furthermore, hydrogen can be an important peak-shaving resource, providing very significant value to energy systems by avoiding the need for large amounts of backup, carbon-emitting peaking power-generation capacity. During cold snaps, for example, hydrogen could serve peak heat demand, or fill long-duration troughs in renewables supply, taking load off the power sector when capacity is stretched, thereby avoiding potentially enormous price spikes. The fact that such a role is of high value to the energy system (and thus to consumers) creates a conundrum for energy markets in that a per-kWh price for hydrogen may not make sense; rather, its value is measured in avoided cost of standby electricity generation capacity (i.e. electricity kW versus gas kWh).

[1] See for example 'Beyond carbon; the future is a gas', *The Economist*, 10 February 2001.
[2] Creuzig et al. (2017), 'The underestimated potential of solar energy to mitigate climate change', *Nature Energy* 2, 17140.
[3] Schmidt et al. (2019), 'Projecting the future levelized cost of electricity storage technologies', *Joule* 3(1), 81–100.

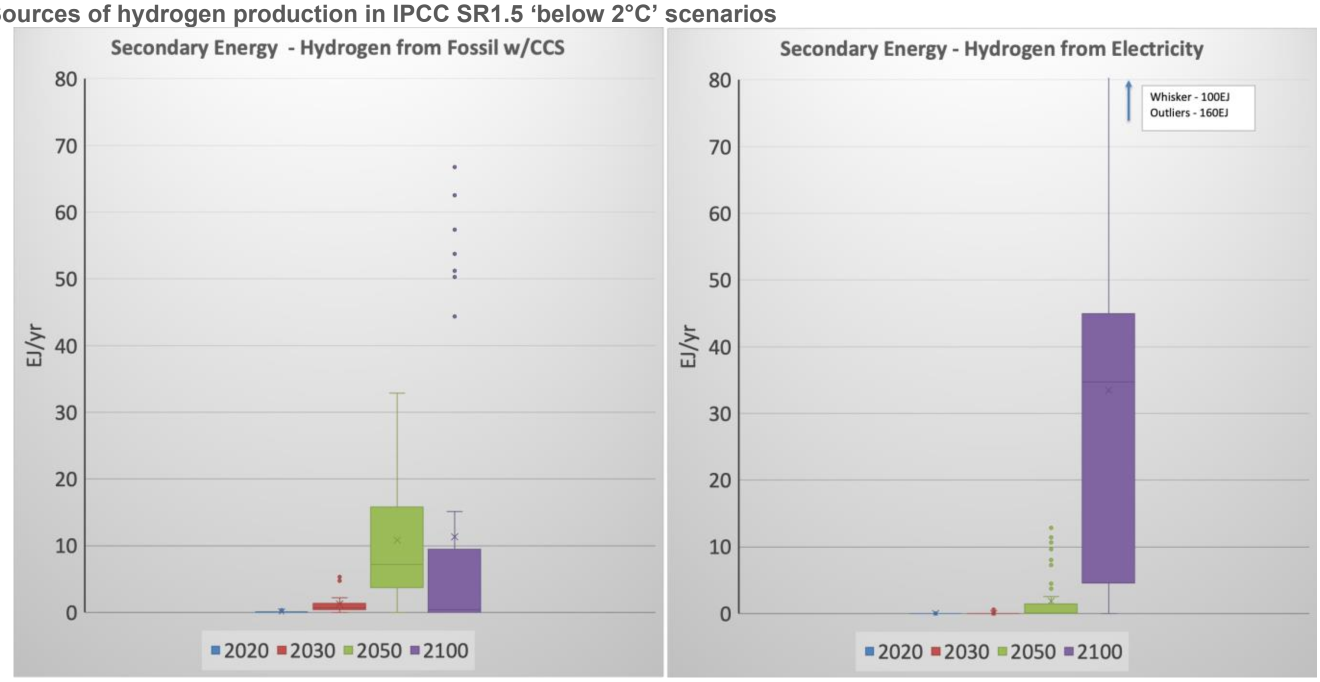
Finally, but certainly not least importantly, hydrogen can play a significant role in otherwise hard-to-decarbonize applications. Industry is probably the best example of this, where technologies such as direct reduction of iron can use hydrogen, as can any process requiring heat at greater than about 100°C, the range at which a heat pump is more challenged to operate. Industry is also the one sector where hydrogen is already routinely used, particularly in refining and chemicals production, and is often also present on site anyway, due to its use as a process feedstock.

How might hydrogen be produced?

The next important question is where the hydrogen to serve future energy needs might come from. A colourful array of terms has emerged to describe the technology options, based on which form of primary energy they are derived from—black for coal, grey for gas, blue for gas with carbon capture and storage (CCS), green for renewable electricity via electrolysis, turquoise for gas via less-proven pyrolysis technology, and more.

The figure below shows the range of production sources of hydrogen in the future scenarios as presented in the 2018 IPCC (Intergovernmental Panel on Climate Change) special report on global warming of 1.5°C (IPCC SR1.5). For context, this is against a background of 500–600 EJ world final energy consumption, as presented in the recent Shell scenarios. The figure shows a story of rising fossil-based hydrogen production with CCS, becoming the largest source of H_2 production by 2050. This is arguably mostly blue hydrogen, but the International Institute for Applied Systems Analysis database does not provide that detail, and the fossil source could vary from model to model. Green hydrogen (hydrogen from electricity) then takes over, dominating the market by 2100, though the outliers on both the fossil-based and green hydrogen sub-plots should be noted; there is substantial disagreement between some models at such long time frames.

Sources of hydrogen production in IPCC SR1.5 'below 2°C' scenarios



Note: The 'x' on each box-and-whisker entry represents the mean of all values, the horizontal line represents the median, the boxed area shows the inter-quartile range, the whiskers represent the largest/smallest values within 1.5 times the interquartile range, and all points outside this range are represented by individual outlier points.

Source: Huppmann, D., et al. (2019), *IAMC 1.5°C Scenario Explorer and Data Hosted by IIASA*.

From these scenarios we can conclude that both blue and green hydrogen could be important in the coming decades, and it is not a simple case of 'green versus blue'. In fact, the dominant form of production may well vary between locations according to natural endowments, proximity to demand, proximity to viable CO_2 geo-sequestration sites, and other factors such as policy and regulation.

Despite uncertainty about future production routes, and arguably similar environmental and long-term cost credentials of each, recent policy in the EU has focused on green hydrogen. The EU Hydrogen Strategy prioritized green hydrogen by setting ambitious electrolyser capacity targets of 6 GW and 40 GW in 2024 and 2030, respectively. This is a bold move, supporting a technology that is currently less mature and more expensive over the more proven technology of steam methane reforming. It may pay off, if the cost of electrolyser technology can follow a trajectory similar to that of solar PV and wind power, as described above. It is possible, though not guaranteed, that green hydrogen can become cost-competitive with any other option far sooner than expected.

What factors impact on the role for blue hydrogen?

While green hydrogen is at present well supported by EU policy, the future of blue hydrogen is less certain. What are the main conditions for blue hydrogen to play a role?

Given that hydrogen production from gas is relatively mature technology, it is the CCS part of the supply chain that requires the most attention. There are an increasing number of CCS projects worldwide. However, several key elements are still lacking: scale of activity, development of one-size-fits-all technology, and plug-and-play policy. Without such things, it is hard to imagine a future that might put CCS on a path equivalent to that taken by solar PV and wind power over the last 15 years. This is particularly true in the UK, where the first and second attempts at kick-starting CCS failed, with the cited reasons being cost concerns, difficulty in guaranteeing (in the insurance sense rather than the technical sense) that the CO_2 would stay underground, and ultimately well-founded concerns regarding continuity of government support.

Broadly speaking, if blue hydrogen is to become a major player in global energy systems, far-reaching success is also needed with CCS. This aligns blue hydrogen technology with other CCS-entwined technologies such as bioenergy with CCS and direct-air carbon capture and storage (DACCS). The former, and increasingly the latter, are seen as critical for achieving climate change mitigation ambitions, so it is a wonder that more effort is not directed at the success of CCS, whilst variable renewable energies race ahead.

Methane emissions are the second key issue for blue hydrogen. Methane emissions related to the oil and gas supply chain are estimated by the International Energy Agency Methane Tracker at 70 $MtCH_4$/year, roughly equivalent to the entire energy-related emissions of the EU in terms of CO_2 equivalence. These methane emissions have become a key issue for the gas industry in recent years, and are now the subject of forthcoming regulation in the EU, with publication of an EU Methane Strategy in 2020. Like any technology related to fossil fuel supply chains, the embodied emissions in blue hydrogen may be significant, and may prove difficult to abate sufficiently despite concerted efforts by industry.

Finally, should methane emissions be dealt with, it is also clear that high-capture-rate CCS processes will be required to produce blue hydrogen. In this respect it is important to investigate technology beyond steam methane reforming with CCS, which requires capture from two streams (process and heat generation). Auto thermal reforming and methane pyrolysis are both interesting options in this regard, with the former relatively well established and the latter in development and early demonstration. Achieving a capture rate above 95 per cent, ideally close to 99 per cent, will be important for this technology in the future.

Conclusion

The weight of evidence suggests that hydrogen has a fighting chance at a role in future energy systems. This role may be bigger than long-term modelling under the auspices of the IPCC may suggest. Not all of the underlying integrated assessment models in such studies have full representation of hydrogen value chains, from supply through transformation and transition to the full range of end uses. Should this be consistently included, it is plausible that a much greater potential role for hydrogen would present itself.

The features of hydrogen, particularly its potential for long-duration storage and transportability, make it a solid zero-emissions partner to variable renewable energy. Hydrogen would likely have on-tap availability to serve peak demands, and the related supply chain can both consume and produce electricity, heat, motive power, and other services to complement zero and net-negative carbon electricity systems.

The thermal and energy density features of hydrogen also make it a good option for otherwise hard-to-decarbonize applications. Industry, heavy transport (and potentially aviation), and long-term storage applications are prime candidates.

Overall, hydrogen has similar inter-sectoral features as zero-carbon electricity; it can be used in multiple applications in multiple sectors with no end-use emissions, making it ripe for economies of scale across these sectors and benefitting from the lack of correlation of the demands between them. A decade ago, natural gas may have been the cost-effective partner to renewables;

but new developments, not least the Paris Agreement, mean that hydrogen should be considered as an alternative. Time will tell. The priorities for now are to support innovation, demonstration, and deployment of hydrogen supply chains while also supporting a range of other technology options to achieve climate change mitigation.

CAN POWER-TO-AMMONIA PROVIDE GRID FLEXIBILITY?

Aliaksei Patonia and Rahmat Poudineh

As energy production accounts for around 70 per cent of all global greenhouse gas emissions,[4] moving towards climate neutrality requires transforming existing carbon-intensive energy systems. This means, among other things, shifting from extensive reliance on fossil fuels to greater dependence on low- and zero-carbon energy sources such as solar photovoltaic and wind power. An energy transition of this kind, however, poses significant challenges to the power system, as these resources do not have the key characteristics of traditional flexible generation.

Specifically, while seasonal fluctuations in energy consumption owing to winter heating and summer cooling are significant in most countries, renewable energy production cannot be substantially increased on request to meet peak demand. Additionally, unpredictable disturbances and periods of challenging weather conditions—such as snow cover and high pressure, which minimize the potential for solar or wind generation—create further barriers to grid balancing in renewables-dominated energy systems. Although one option in both cases is to maintain significant excess capacity in the electricity system, it is certainly not efficient. Finally, the cheapest and/or cleanest energy resources are not always close to demand centres, and connecting low-carbon energy resources to users via grid lines may be neither easy nor cheap.

One possible solution to this set of challenges is power-to-X, technologies allowing for the conversion of renewable electricity into carbon-neutral fuels that could later be stored and transported or converted back to electricity.

Whilst 'green' hydrogen has traditionally been envisioned as the ultimate product of the power-to-X process, increased attention has recently been paid to 'green' ammonia (NH_3) as a potentially more attractive alternative. This article focuses on the power-to-ammonia (P2A) systems that use renewable electricity to first generate hydrogen from water (via electrolysis) and nitrogen from air and then combine both in the Haber-Bosch process to synthesize ammonia.[5] It argues that, in principle, P2A could offer grid services such as periodic and seasonal storage as well as emergency backup. Also, by transferring energy across time and space, 'green' ammonia could facilitate utilization of stranded renewables and thus minimize the need to increase grid capacity.

Nonetheless, development of P2A faces several challenges, including the relatively low flexibility of the ammonia production process. Since this makes ammonia not particularly suitable for providing fast-response services, it prevents it from participation in high-value markets which require fast response, such as ancillary services. To compete with alternative grid service providers, P2A capital and operating costs also need to decline, and regulatory and policy barriers need to be overcome.

Power-to-ammonia and its services to the power grid

Key threats to the stability of power systems include fluctuations in frequency, voltage, power demand and supply, as well as overall system failure. Although these could be addressed by various resources, energy storage can play a unique role. In fact, most of these challenges could be resolved by storing power for a short time (seconds or minutes), while others require medium-term (hours or days) or long-term (weeks or months) energy storage.

Four major types of energy preservation technologies are currently available: electrical, mechanical, electrochemical, and chemical.[6] Of these four categories, the future of long-term energy storage is more often associated with the electrochemical (batteries) and chemical (e.g. natural gas, hydrogen, and ammonia) options. Unlike other options, these can store large volumes of energy for a long time in a transportable form, so that power can be transferred across both time and space. Of these, only hydrogen and ammonia—two substances that can be generated carbon-free—are able to preserve the same amounts of energy as fossil fuels, potentially cost-efficiently, while not emitting any CO_2 when combusted.[7] Of these two, ammonia can deliver more energy within the same volume, and it has an established infrastructure and lower handling costs.[8]

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[4] C2ES (2019), *Global Emissions*, Arlington, VA: Center for Climate and Energy Solutions.
[5] N_2 (gas) + $3H_2$ (gas) $\leftrightarrow$ $2NH_3$ (gas).
[6] Although direct storage of heat is also possible, the paper does not discuss that and focuses on main methods of energy preservation with application in electricity sector.
[7] Hydrogen: $2H_2 + O_2 = 2H_2O$; ammonia: $4NH_3 + 3O_2 = 2N_2 + 6H_2O$; Electricity Advisory Committee (2018), *A Review of Emerging Energy Storage Technologies*, Washington, DC: US Department of Energy.
[8] Kraemer, S. (2018), 'Missing link for a solar hydrogen is … ammonia?', *PhysOrg*, 9 January, p. 4.

Electric power systems: characteristics and energy storage needs

Power system		Electricity storage services		Description	Storage duration needed
Challenge	**Characteristics**				
Potential system failure	**n/a**	Emergency backup		Providing power during outages (long-term)	Hours-days Weeks-months
		Ancillary services	Black start capability	Providing power during system restoration (short-term)	Seconds-minutes Hours-days
Fluctuations	**Frequency**		Frequency control	Management of frequency fluctuations	Seconds-minutes
			Spinning reserve	Extra generating capacity (through increased power output) that is on-line	
			Standing (non-spinning) reserve	Extra generating capacity that is not on-line	Hours-days
	Voltage		Voltage control	Management of voltage fluctuations	Seconds-minutes
	Power demand	Peak shaving		Reduction of peak load	
		Load levelling		Shifting load towards off-peak periods	Hours-days
	Power supply	Periodic and seasonal storage		Storing electricity for off-peak production periods	Week-months

Source: Adapted from Fuchs, J., et al (2012), Technology Overview on Electricity Storage: Overview on the Potential and on the Deployment Perspectives of Electricity Storage Technologies, Aachen: Institut für Stromrichtertechnik und Elektrische Antriebe.

In principle, P2A could offer several services to the power system:

- By transforming surplus electricity from intermittent renewables such as solar and wind into 'green' ammonia, it could provide periodic and seasonal storage, which would enable adjusting the output of generation facilities to the demand of grid operators and ultimate consumers. For renewable energy sources connected to the transmission network, P2A can potentially balance the grid by minimizing the need to curtail excess generation that would normally result in an overloaded and unstable grid. Instead, surplus power could be transformed into ammonia and stored until it could be used or converted back to electricity when the transmission system is available.[9]
- P2A could facilitate grid integration of stranded renewables. Indeed, when the extension of the power grid is not possible for technical and/or economic reasons, the electricity produced by stranded renewables could be converted into 'green' ammonia and delivered to the end user through the normal transportation modes.
- Due to ammonia's capacity to preserve large volumes of energy for a long time, P2A systems could be used for emergency backup. Synthesized by solar and wind electricity during favourable conditions, 'green' ammonia could later be reconverted to electric energy when generation incidents and failures cause outages.[10]

However, in practice, P2A faces constraints to its ability to provide grid balancing services. This is specifically relevant to high-value products such as frequency response which require a fast response. This is because there are specific technical requirements for production of ammonia, such as the need for continuous operation at a constant pressure and temperature. A dynamic operation can damage ammonia synthesis catalysts and result in loss of containment due to hydrogen embrittlement. Also, an intermittent operation weakens the economics of 'green' ammonia plants.

The flexible production of hydrogen through electrolysers is possible, but not at a large scale. The whole ammonia plant is,

[9] Bennani, Y., et al. (2016), *Power-to-Ammonia: Rethinking the Role of Ammonia from a Value Product to a Flexible Energy Carrier (FlexNH$_3$)*, Schiedam, Netherlands: Proton Ventures.
[10] Lipman, T., and Shah, N. (2007), Ammonia as an Alternative Energy Storage Medium for Hydrogen Fuel Cells: Scientific and Technical Review for Near-Term Stationary Power Demonstration Projects, Berkeley, CA: University of California, Berkeley.

however, limited in flexibility by the NH_3 synthesis section. Therefore, in order for P2A to be used effectively and reliably for grid balancing, the whole production process needs to become more flexible. This would require investment in further research and development.

Using existing technologies, it is possible to modify the configuration of an ammonia plant to improve its flexibility to some extent, albeit at a cost. For example, more flexible electrolysis (such as polymer electrolyte membrane units) can be used, which follows the profile of generated renewable electricity. The first stage can also use a combined electrolyser and battery, but of course, this would increase the cost significantly. The ammonia plant, including air separation section, can be operated in a base load pattern if the excess hydrogen can be stored for later utilization when electricity supply drops. If underground hydrogen storage is available, the cost of variability can be reduced significantly compared with using a pressurized tank.

Overall, P2A requires technological improvement in order to address the technical constraints of fast ramp-up and turn-down. In the presence of such constraints, the cost of operating P2A in a flexible manner can be an impediment for its participation in high-value markets such as fast response ancillary services.

Decentralized power-to-ammonia: drivers of capital and operational costs

Scale efficiency has traditionally been a key investment determinant for ammonia generation based on natural gas as a feedstock. Investors favour large-scale industrial production in order to take advantage of economies of scale and minimize costs. However, this is not the case when electricity is used as a feedstock.

With natural gas as the feedstock, reducing the size of an operation from large (2,000 tonnes NH_3/day) to medium (545 tonnes NH_3/day) (i.e. shrinking it by a factor of 3.6) will result in a 42 per cent increase in the cost of production. The corresponding increase when the feedstock is electricity is only 6.7 per cent. Thus, with the rapid growth of decentralized renewables generation technologies in the future, electricity-based NH_3 production is likely to be organized and expanded in the form of a small- or medium-scale operations, as there is no significant cost advantage in increasing the scale.

Small-scale ammonia production is organized in a modular way, which can be better adjusted to the needs of renewable energy sources that are not necessarily connected to the grid. A typical 1.5-megawatt P2A unit running on renewable power is able to produce around 3 tonnes of ‘green’ ammonia per day.[11] Although this may not look impressive compared to the output of methane-powered ammonia plants, with the current average capacity of most onshore wind turbines being around 2 megawatts,[12] small-scale modular P2A systems seem to be particularly suitable for intermittent renewable energy sources.

Moreover, with the nexus of offshore wind and P2A technologies, greater volumes of ‘green’ NH_3 could be produced. This could be done either onshore, if the electrolysers are connected to the turbines through cables, or offshore, if P2A facilities are placed next to the power generators. The latter option even offers potential cost reduction opportunities for remote wind turbines given the high costs of submarine cables (around EUR 1 million per km).[13]

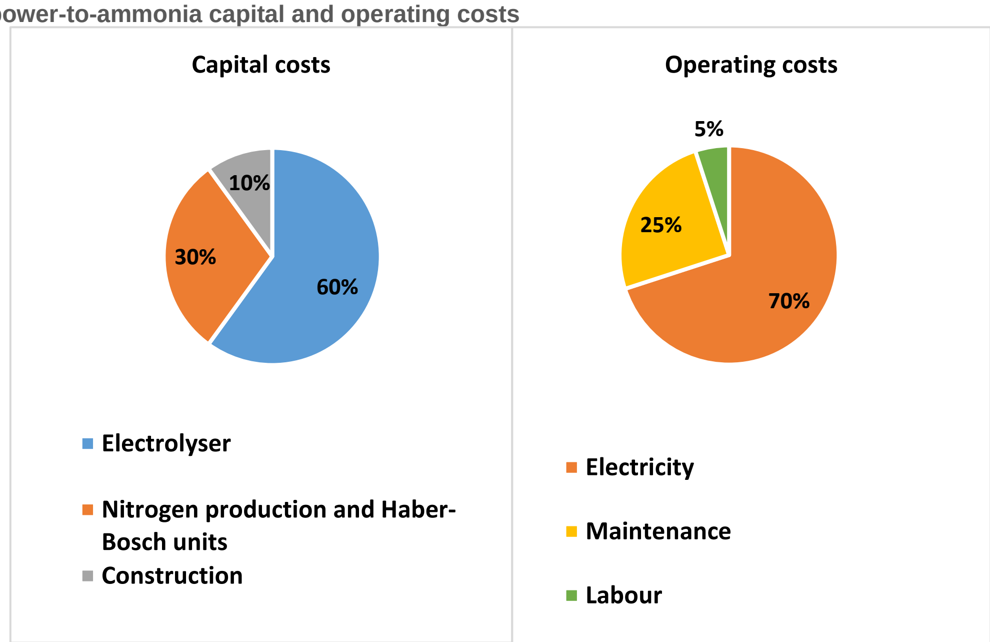
At the same time, in order for ‘green’ ammonia to successfully compete with conventional ammonia, its key capital-cost drivers need to be significantly reduced. With electrolysers currently constituting at least 60 per cent of capital costs, and nitrogen production and Haber-Bosch components jointly responsible for up to 30 per cent, construction costs are only around 10 per cent.[14] Expenditures on construction can be further lowered, since each of the key modules of such P2A facilities (electrolysers, nitrogen generators, and ammonia loops) represents a separate component that can be supplied off-shelf, easily transported to the production site and then integrated into the joint system with no loss to economic efficiency.[15] On the other hand, due to the technology’s maturity, the costs of nitrogen generation and ammonia synthesis are unlikely to decline further.[16] Hence, the costs of electrolysers have the biggest potential for a significant drop and are expected to be almost cut in half by 2030, from around $ 700 /kW to around $ 344 /kW.[17]

[11] ‘Sustainable ammonia for food and power’, *Nitrogen+Syngas*, 354:1 (2018), pp. 1–10.
[12] International Renewable Energy Agency (2019), *Renewable Capacity Statistics 2019*, Abu Dhabi, UAE: IRENA.
[13] Crolius, S. (2018), *The Offshore-Wind/Ammonia Nexus*. Brooklyn, NY: Ammonia Industry Association.
[14] Institute for Sustainable Process Technology (2017), *Power to Ammonia*, Amersfoort, Netherlands: ISPT.
[15] J. Vrijenhoef, J. (2017), *Opportunities for Small Scale Ammonia Production*, London, UK: International Fertiliser Society.
[16] Fernandez, C.A., and Hatzell, M.C. (2020), ‘Economic considerations for low-temperature electrochemical ammonia production: achieving Haber-Bosch parity’, *Journal of the Electrochemical Society*, 167:1, pp. 1–9.
[17] Nayak-Luke, R., and Bañares-Alcántara, R. (2020), ‘Techno-economic viability of islanded green ammonia as a carbon-free energy vector and as a substitute for conventional production’, *Energy & Environmental Science*, 9:13, pp. 2957–2966.

Nevertheless, even with such a dramatic fall in the main capital-expenditure item, in order for P2A to compete economically in the electricity market, operating costs should also be substantially reduced. Apart from the cost associated with improving the flexibility of P2A, the costs of electricity generation as well as maintenance and labour are the main expenditures. Electricity appears to make up more than 70 per cent of operating costs, leaving around 25 per cent for maintenance and 5 per cent for labour.[18]

Although electricity cost could be minimized if primarily surplus power is used, constant operation on excess electricity may not be possible if the first and second stages of ammonia production are not redesigned to improve their flexibility. Additionally, the intermittency of solar and wind used for P2A lowers the capacity factor and further increases the costs.[19] Similarly, since maintenance costs often strongly depend on the quality and costs of electrolysers, they may not be easily lowered. Last but not least, labour is likely to represent one of the most rigid operating costs.

Key drivers of power-to-ammonia capital and operating costs



Source: Adapted from Institute for Sustainable Process Technology (2017), *Power to Ammonia*, Amersfoort, Netherlands: ISPT; Boulamanti, A. and Moya, J. (2017), 'Production costs of the chemical industry in the EU and other countries: ammonia, methanol and light olefins', *Renewable and Sustainable Energy Reviews*, 68:2, 1205–1212.

Decentralized power-to-ammonia: barriers

Apart from the costs challenges of decentralized P2A, there are a number of regulatory, market, and policy barriers hindering development. In particular, because ammonia is highly toxic and potentially a significant threat to public health and the environment, the construction and operation of all 'green' ammonia installations are regulated in ways that may limit the conditions (e.g. scale and location) under which ammonia is produced, stored, and transported. These conditions, in turn, must align with the requirements of the specific renewable generating facilities used for production, which creates additional complexity.[20] That is why it may be administratively burdensome for investors in P2A to provide the scale and capacity necessary for efficient contribution to grid balancing, while each small-scale facility will have to comply with strict regulations.

At the moment, high global demand for ammonia as well as low prices of natural gas (as the main feedstock for conventional ammonia) appear to be the key market barriers for the promotion of P2A, as they give competitive advantage to conventional large-scale ammonia generation based on methane. In this context, state policies on subsidizing production of fossil fuels and fertilizers further undermine the competitiveness of 'green' ammonia, which, in turn, has to overcome the adversity of higher

[18] Institute for Sustainable Process Technology (2017), *Power to Ammonia*, Amersfoort, Netherlands: ISPT; Boulamanti, A., and Moya, J. (2017), 'Production costs of the chemical industry in the EU and other countries: ammonia, methanol and light olefins', *Renewable and Sustainable Energy Reviews*, 68:2, pp. 1205–1212.
[19] MacFarlane, D., et al. (2020), 'A roadmap to the ammonia economy', *Joule*, 4, pp. 1186–1205.
[20] Bennani, Y., et al., 2016, Power-to-Ammonia: Rethinking the Role of Ammonia from a Value Product to a Flexible Energy Carrier (FlexNH$_3$), Schiedam, Netherlands: Proton Ventures.

marginal capital and operating costs. Furthermore, the absence of policies aimed at improving the generally low social acceptance of ammonia will make it hard for new P2A facilities to compete with the already established ones.[21]

Conclusion

P2A could offer important services as periodic and seasonal storage as well as emergency backup. In addition, by transferring energy across time and space, 'green' ammonia could facilitate grid integration of stranded renewables. Technically, this could be done due to the possibility to organize P2A production in a decentralized way using a modular approach.

However, development of P2A faces a number of challenges. Technologically, slow progress in the improvement of electrolysers along with intermittency of wind and solar energy production are major hurdles which need to be overcome. Currently the flexibility of P2A is low, and this prevents it from participating in high-value markets which require fast response. Furthermore, the high cost of electrolysers—along with issues regarding ammonia's toxicity, its lack of social acceptance, and the use of low-cost fossil fuels as the main feedstock for conventionally generated ammonia are barriers to the development of P2A. On top of that, state subsidies to the producers of hydrocarbons and fertilizers are likely to further discourage investors in 'green' ammonia, as they will make their decarbonized product even less competitive.

THE ROLE OF AMMONIA AND HYDROGEN IN MEETING INTERNATIONAL MARITIME ORGANIZATION TARGETS FOR DECARBONIZING SHIPPING

Bruce Moore

Decarbonizing shipping

The world's shipping fleet is responsible for approximately 0.9 Gt of CO_2 emissions annually, around 2.9 per cent of the world's man-made emissions total. Under a 'business as usual' scenario, this is forecast by the International Energy Agency to grow to almost 1.7 Gt per year by 2050.[22] The industry's principal regulatory body is the International Maritime Organization (IMO). The IMO aims to reduce world shipping's greenhouse gas (GHG) emissions in line with the 2015 Paris Agreement. In practice, moving a heavy ship over long distances results in a combination of a high power requirement and severe constraints on weight and space. As such, shipping, along with aviation, remains one of the most stubbornly difficult sectors to decarbonize.

Shipping's commercial environment also makes rapid decarbonization difficult. Margins are thin, and capital-intensive assets have long investment life cycles. The industry is fragmented, geographically and across multiple trade sectors, with a myriad of regulatory bodies as well as the IMO. Nevertheless, to stand a chance of meeting the IMO's targets, change is required now.

Regulators hope to make material gains in decarbonization through both operational measures (e.g. speed reduction and port logistics) and advances in vessel design (e.g. hull form, wind assistance, and engine technology). The targeted GHG reductions will not be achieved, however, without the introduction of lower-carbon and decarbonized fuels, such as hydrogen, ammonia, and battery power, as well as biofuels and synthetically manufactured low-carbon fuels. This article focuses on the relative merits of the lower-carbon fuel alternatives.

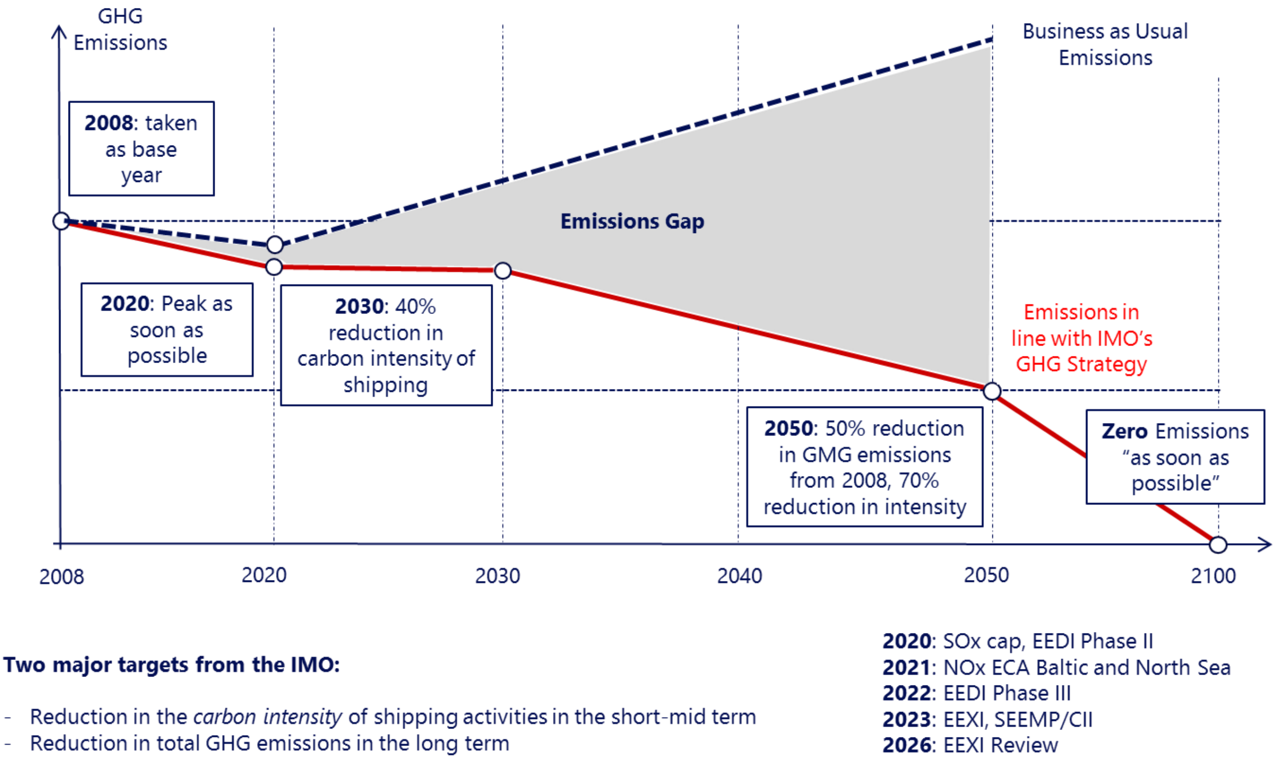
Environmental targets, the IMO, and the European Union

The IMO targets a reduction in GHG emissions from shipping of at least 50 per cent, compared with 2008 levels, by 2050. Lloyd's Register estimates the 50 per cent cut in absolute emissions is 'equivalent to a real-world reduction of about 85% in operational CO_2 intensity'[23]—that is, vessels will have to cut their CO_2 emissions by 85 per cent per nautical mile to take account of increasing numbers of ships and activity over the coming years.

The pace of change at the IMO has often been criticized. For example, the European Union (EU) arguably is seeking a faster pace of change through the inclusion from 2022 of shipping within the EU Emissions Trading Scheme. There are also many advocates for a universal carbon tax or levy on shipping fuels.

[21] MacFarlane, D.R., et al. (2020), 'A roadmap to the ammonia economy', Joule, 4:1, pp. 1186–1205.
[22] International Energy Agency (2017), Energy Technology Perspectives.
[23] Techno-economic assessment of zero-carbon fuels, *Lloyd's Register*, March 2020.

IMO regulatory timeline—a road map for GHG reductions



Source: Howe Robinson Partners / DNV GL

Hydrogen

Of all liquid or compressed-gas marine fuels, the use of hydrogen, generated from renewable electricity, potentially results in the lowest GHG emissions. However, its direct inclusion in marine propulsion systems faces arguably the greatest technical challenges.

In the volumes that would be required for marine propulsion, hydrogen would be stored either as a compressed gas or cryogenically as a liquid at −240°C and 13 bar pressure. As a liquid, its energy density is approximately five times less than that of heavy fuel oil (HFO), and including the cryogenic containment required, the volume of tank space needed is considerably higher. Such containment systems are very expensive and are in the early stages of development. Hydrogen-driven internal combustion engines are less efficient than those for diesel; the further development of fuel cells is considered critical for any material marine take-up.

Synthetic low-carbon fuels—ammonia, LNG, methanol, and diesel

The energy of renewably generated hydrogen may well be more pragmatically utilized via the generation of what have been dubbed synthetic fuels or e-fuels. A range of such fuels—such as diesel, ammonia, methanol, and methane—can be produced by chemically combining hydrogen with carbon (commonly CO_2) and nitrogen.

The overall energy efficiency of these processes can be seen in the table below. Production of each of the fuels listed starts with hydrogen production by renewable-power-generated electrolysis. The differences in efficiency and forecast cost ranges between fuels are relatively narrow, with likely adoption being driven more by technical and logistical considerations (e.g. energy density) than by pure fuel price or overall energy efficiency.

Energy efficiency and forecast cost ranges for synthetically produced fuels

	Hydrogen	Synthetic methane (LNG)	Synthetic diesel	Synthetic methanol	Ammonia
Energy efficiency (%)					
Electrolysis	71	71	71	71	71
Power-to-gas process	–	75	–	–	87
Liquefaction	83	96	–	–	–
Power-to-liquid process	–	–	75	75	–
Overall efficiency	59	51	53	53	62
Cost range ($/tonne oil equivalent)	1,000–2,000	1,500–2,500	1,700–2,700	1,700–2,500	1,800–2,300

Source: DNV (2019), 'Maritime Forecast to 2050', *Energy Transition Outlook 2020*.

Biofuels

Biofuels (fuels derived from biomass feedstock) provide a promising solution for GHG reduction, as they can with some exceptions be treated as 'drop in' fuels (fuels that can be used with existing bunkering infrastructure). The GHG emissions from their combustion as fuel are considered balanced by the CO_2 consumed in the growth of the biological source material.

Currently the most promising biofuels for marine use are biodiesel (e.g. hydrotreated vegetable oil and fatty acid methyl ester), straight vegetable oil (which can replace HFO), bio-methanol, and liquid biogas (primarily methane). Bio-methanol is becoming available,[24] and further technologies (e.g. based on algae) are in development.

Biofuels are more expensive than their fossil counterparts, although it is likely that prices will fall as production gains economies of scale. Within the aviation sector, biofuels are already available at a price two to three times above fossil-based jet fuel.[25] However, for biofuels to be produced sustainably, they must not compete with food production, and in practice be based primarily on waste streams (mostly agricultural, forestry, or municipal). Scalability in biofuel use will therefore be a significant issue. Global biofuel production was 154 million mt in 2018[26] (including sugar and starch-based ethanol), the bulk of this being used on land rather than at sea. For comparison, the world marine sector consumed ~ 314 million mt in 2020.

Ammonia

When generated from green hydrogen, ammonia can act as a carrier for renewable electricity. Much interest has been shown recently in the potential for ammonia as a marine fuel.

Ammonia is commonly stored in liquid form at either −33°C or pressurized at 7 bar; a feedstock for fertilizer production, it is widely shipped through most major ports. It has a low flammability and slow flame speed; this means that when used in an internal combustion engine it must be blended with another combustion medium, such as LNG, hydrogen, or diesel. The technical challenges, particularly with regard to large marine two-stroke engines, are considerable. The engine manufacturer MAN aims to have an ammonia-fuelled two-stroke engine available 'as early as 2024'[27]. Ammonia is nitrogen-rich, so its use will result in considerable generation of nitrogen oxides, which must be mitigated via selective catalytic reduction.

Ammonia also presents particular safety hazards, being highly toxic. For its widespread adoption as a marine fuel, a whole new bunkering infrastructure chain would need to be developed. Liquid ammonia has an energy density greater than that of liquid hydrogen but less than that of LNG.

Several commentators have expressed the view that ammonia is likely to gain more widespread use in the medium to long term. Jacopo Tattini, a transport and energy analyst at the International Energy Agency, has predicted, 'Ammonia as a shipping fuel will not be big in the next five years, but in the next 10–15 years it will definitely take off.'[28]

[24] European Technology and Innovation Platform (2021), *Use of Biofuels in Shipping,* https://www.etipbioenergy.eu/value-chains/products-end-use/end-use/water.
[25] Energy Transitions Commission (2019, January), *Mission Possible.*
[26] Blue Insight (2020), *Low Carbon Shipping Fuels & Energy Guide 2020.*
[27] https://www.man-es.com/discover/two-stroke-ammonia-engine
[28] Gas Strategies (2020, December), *Ammonia: Shipping Fuel of the Future or Hyped Fantasy?*

Methanol

Methanol as a marine fuel has its champions among some industry leaders, although the barriers to its widespread adoption are more commercial than technological.

Methanol is a common feedstock, produced mainly from natural gas. It has lower energy density than HFO, with required tank volumes around 2.5 times those for HFO. The use of conventionally produced methanol for marine propulsion offers the opportunity to reduce GHG emissions by up to 10 per cent versus HFO. However, for methanol to contribute materially to decarbonization, it would need to be produced as described previously, from either hydrogen or bio- generation.

A.P. Moller – Maersk have championed methanol as part of their decarbonization ambitions, although in a recent interview Berit Hinnemann, the company's senior innovation project manager, said, 'In pioneering this technology, it will be a significant challenge to source an adequate supply of carbon-neutral methanol within the timeline we have set ourselves. We have a lot of work ahead of us to find the projects which are truly scalable and carbon-neutral.'[29]

LNG

LNG is widely viewed as an important lower-carbon fuel on the overall decarbonization pathway. LNG as a fuel results, depending on supply chain and engine configuration, in 10 to 25 per cent lower GHG emissions than HFO. The release of any uncombusted methane ('methane slip') reduces the effectiveness of LNG in reducing GHG emissions, as methane has 25–30 times greater GHG effect than CO_2. LNG's lower energy density requires fuel tanks roughly twice the volume of HFO tanks; the insulation and space requirements of the tanks increases this to three or four times the volume.

Ultimately, as a hydrocarbon, LNG by itself will not enable the industry's overall aim of full decarbonization. But for long-haul shipping right now, LNG is arguably the only investable fuel option that brings about material GHG gains. LNG has widely been dubbed a transition fuel; in the IMO's current strategy, there is still room for some GHG emissions in 2050. Whether those investments pay off will depend on how long that transition lasts.

LPG

Like LNG, LPG offers the prospect of lower GHG emissions than HFO (up to approximately 15 per cent). In general, the incremental capital cost of LPG propulsion is less than that for LNG, although LNG is for the most part a cheaper fuel. Hence, for the moment, LPG power is confined to LPG carriers themselves, taking advantage of the cargo on board. There are prospects that some bio-LPG may become available as a by-product of biodiesel production.

One intriguing development is the emergence of new designs (e.g. from Daewoo Shipbuilding & Marine Engineering in Korea) for LPG marine power plants that can be made 'ammonia ready'—easy to convert once large two-stroke ammonia engines have been marketed.

Batteries

Where they can be applied for marine operations, the use of batteries promises to be transformational. Electrical systems are highly controllable, with low maintenance costs and prospectively high safety levels. However, considerable technical challenges remain.

Lithium-ion batteries, widely adopted in car designs, are likely to provide the leading technology for the foreseeable future. They have proven competitive for some ferry and cruise ships, particularly as part of hybrid battery/conventional solutions. Battery prices are decreasing rapidly, the cost of lithium-ion battery cells dropping by more than 50 per cent since 2016. However, compared to liquid fuels, marine batteries have poor energy density; the best performing commercial battery in 2018 had an energy density of 2,434 kJ/l, as compared to marine diesel oil at 39,970 kJ/l.[30] The size and weight of such batteries right now precludes their adoption for deep-sea trading ships.

Fuel cells

Fuel cells are devices that convert hydrogen-rich fuels into electrical power by electrochemical oxidation. Hydrogen is the most common fuel, although other fuels such as ammonia, methane, methanol, or even diesel can be used. Whilst fuel cells have been in use for military submarines for some time, for widespread civilian maritime use they will need to be developed with greatly increased scale and power output.

[29] *Offshore Energy*, March 25, 2021.
[30] Blue Insight (2020), Low Carbon Shipping Fuels & Energy Guide 2020.

Nuclear

Concerns regarding both safety and proliferation have to date excluded nuclear power from civilian maritime use. However, new technologies such as the 'atomic battery' proposed by CORE-POWER show great promise in the longer term; CORE-POWER aims to have a demonstration model reactor running by 2027. As with nuclear power ashore, the use of this technology onboard civilian marine vessels will most probably be determined as much by public and governmental perception of risk as by the basic science and engineering.

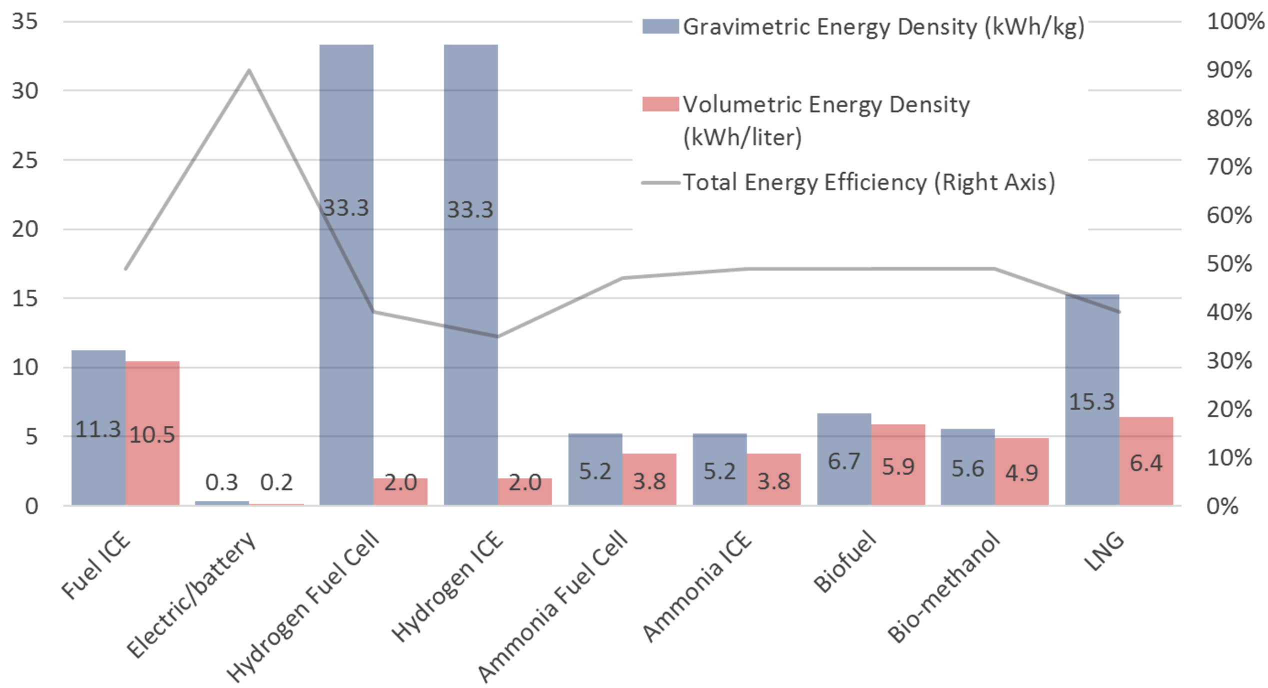
Short-sea shipping vs deep-sea shipping

Short-sea shipping (e.g. ferries and coastal trade) involves relatively low energy demand. Lower-density fuels such as hydrogen and battery power will become more feasible; indeed, battery power has gained a foothold in the Norwegian ferry sector. Deep-sea shipping, however, involves larger vessels travelling over longer distances, often at higher speeds; higher propulsive power and energy density are required to make long voyages possible. Furthermore, for vessels trading with no set route or schedule (common in the oil and bulk trades), fuels must be globally available. The introduction of new fuels will involve the construction of whole new bunkering supply chains as well as new vessel designs.

Fuel comparisons

The figure below compares the overall energy efficiency and energy density of current technologies. Energy efficiency is most relevant in its influence on overall cost. From a practical point of view, energy density is a key driver; batteries are particularly disadvantaged due to their size and weight. Hydrogen-based systems are light but highly demanding in terms of tank space. Biofuels currently have a slight edge over ammonia-driven systems.

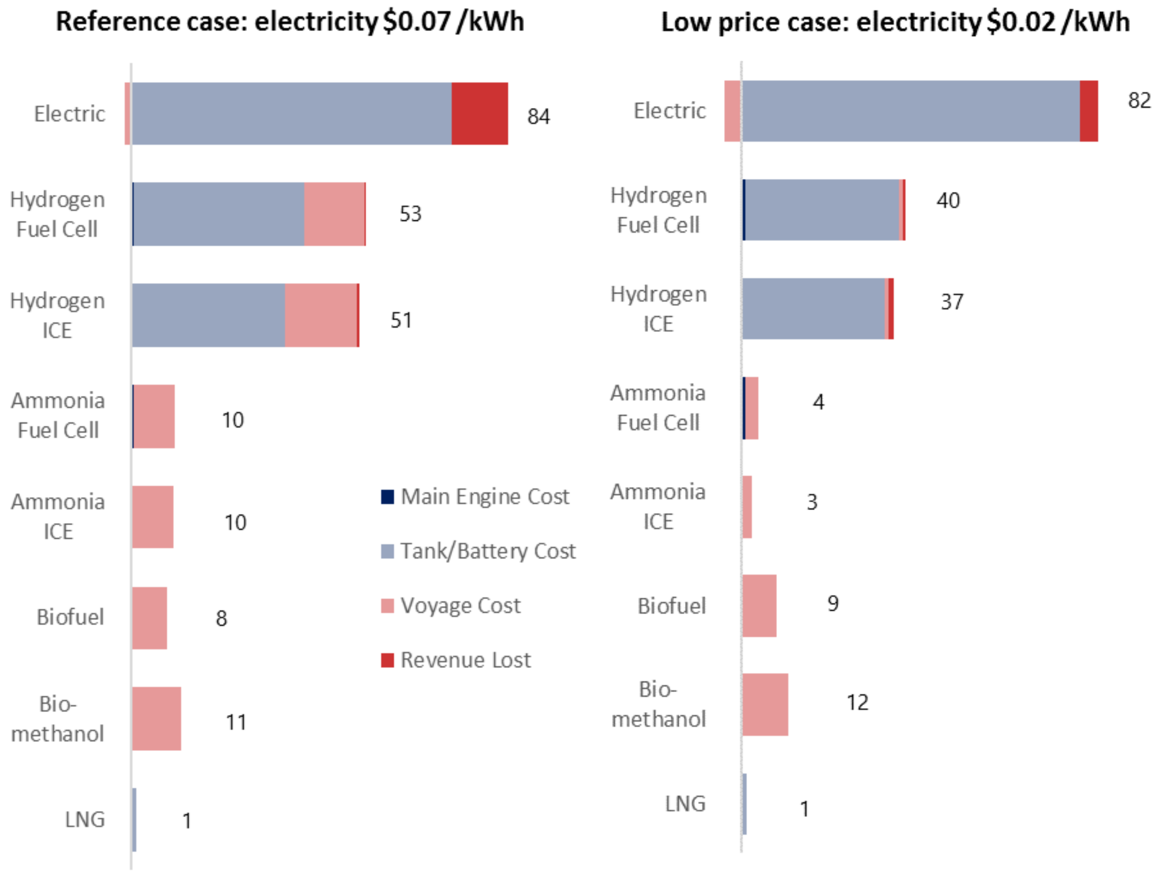
Energy efficiency and energy density of alternative fuels



Source: Energy Transitions Commission (2019, January), *Mission Possible*.

The next figure compares the cost of various fuels for a deep-sea tanker, assuming two different renewable electricity prices. Whilst capital costs are those known currently, renewable electricity prices have been tested with a conservative reference case and a low case (assuming forecast power generation cost reduction by 2030/2035). The price disadvantage of battery and hydrogen systems is clear. In the reference case, ammonia is broadly competitive with biofuels, although in the low electricity scenario, ammonia provides the cheapest decarbonized fuel source.

Annual incremental cost ($ million) of alternative fuels for a tanker compared with HFO (HFO cost is $ 4.9 million per year)



Source: Energy Transitions Commission (2019, January), *Mission Possible*.

Regarding pace of change, two recent studies assessed how the fuel mix may change going forward. The Getting to Zero Coalition estimated that to attain Paris agreement decarbonization goals by 2050, zero-emission fuels need to represent 5 per cent of the international shipping mix by 2030.[31] Thereafter, with a more ambitious goal of full decarbonization by 2050, 27 per cent by 2036, and 93 per cent by 2046 would be required. By contrast, DNV estimated that to comply with the IMO's current emissions strategy, the fuels mix shown in the next table would be sufficient.[32]

Sector by sector—cargoes and customers

When considering how decarbonization is likely to change ship propulsion, we should not lose sight of the fact that decarbonization will radically change the cargoes carried. Ultimately the world will have less use for coal, then oil, then gas. Likewise, radically fewer large tankers will be required as the oil trade declines, followed ultimately by fewer LNG ships. The cruise sector is forecast to remain the fastest-growing segment of the industry.

Total costs

The total cost of maritime decarbonization to IMO targets has been estimated at $ 0.8–1.2 trillion by 2050, or on average $ 40–60 billion annually for 20 years.[33] It should not be forgotten, however, that the cost of shipping is a relatively small contributor to end-user raw material or product prices. A 110 per cent increase in freight voyage costs would, for example, add only about $ 0.3 or 1 per cent to the cost of a pair of jeans priced at $ 60.[34]

[31] Getting to Zero Coalition (2021, March), *Insight Brief.*
[32] DNV (2019, June), *Assessment of Selected Alternative Fuels and Technologies*.
[33] Getting to Zero Coalition (2020, January), The Scale of Investment Needed to Decarbonize International Shipping.
[34] Energy Transitions Commission (2019, January), Mission Possible.

Fuel mix to comply with IMO emissions strategy by 2050

Projected overall fuel mix by 2050	Energy requirement (EJ/year)	Fuel mix (million t oil equivalent)
Carbon-neutral fuels[a]	4.3	102
LNG	2.5	60
Electricity	0.6	13
HFO / marine gas oil	3.7	89
Total	11.1	264

[a] These include biofuels and carbon-free fuels (H_2, NH_3).Source: DNV (2019, June), *Assessment of Selected Alternative Fuels and Technologies*

Conclusion

The best technological pathways to achieving decarbonization of shipping are right now highly uncertain. It is likely that in the near term the greatest potential for GHG reduction will be in operational efficiencies, most obviously in slow speeds and port congestion management. In the short to medium term, batteries, and later on hydrogen-based electrification, will become more common, at least for short-sea shipping. The use of biofuels will significantly expand, limited ultimately by the sustainability of their production and the relative price of alternatives. LNG and to a lesser extent LPG will play a significant, but ultimately time-limited role, as they offer significant GHG reductions now but not the prospect of full decarbonization.

In the much longer term, ammonia currently looks like the most likely route to total decarbonization in deep-sea shipping, although a whole new world fleet and bunkering infrastructure would need to be developed, which will take time. Much depends on future pricing of renewably generated electricity. Carbon capture and nuclear power could well remain enticing but undelivered silver bullets.

The cost of decarbonization may seem high; but in the long run, it will have only a modest effect on the cost of goods transported. If the pace of regulatory change in the shipping industry going forward is slow, then regulators may well be overtaken by the pace of markets, as all stakeholders demand further change. Investors and businesses, and increasingly governments, are making commitments and starting to act. The shipping industry is fragmented geographically and between sectors; its immediate priorities must be on ways to more quickly bring about a mix of commercial incentives and regulatory change that results in tangible emissions reductions.

HYDROGEN BLENDING—LESSONS FROM HYDEPLOY

Tommy Isaac and Andy Lewis

The HyDeploy project[35] is the first programme in the UK to supply hydrogen, in the form of a blend, to a live gas network since the conversion from towns gas in the mid-1970s. The project is delivered by Cadent, Northern Gas Networks, Progressive Energy, the Health and Safety Executive (HSE) Science and Research Centre, Keele University, and ITM Power. The programme is funded via the Ofgem Network Innovation Competition and commenced in 2017.

The objective of the HyDeploy programme is to demonstrate that a blend of hydrogen, up to 20 per cent by volume (vol%), can be safely distributed and utilized within the Great Britain (GB) gas distribution network. The current limit for hydrogen distribution is 0.1 per cent by moles (mol%) as per Schedule 3 of the Gas Safety (Management) Regulations (GS(M)R), 1996.[36] Derogation, or exemption, to elements within the regulations can be applied for via Schedule 11 of GS(M)R. Such exemption cases must be presented to the regulator, the HSE. The exemption cases must demonstrate that 'those affected by the proposed change are not prejudiced in consequence of it'. To achieve this, a safety case must be presented that evidences that a blend of 20 vol% hydrogen is 'as safe as' natural gas. The purpose of the HyDeploy programme is therefore to generate and demonstrate this evidence base on a GB scale to facilitate the deployment of hydrogen blending across the GB gas distribution network.

[35] Isaac, T. (2019), 'HyDeploy: The UK's first hydrogen blending deployment project', Clean Energy Journal, 3:2, 114–125.
[36] UK Gas Safety (Management) Regulations 1996, UK Statutory Instruments 1996, No. 551.

The overall HyDeploy project is structured into two separately funded programmes, HyDeploy and HyDeploy$_2$. The first HyDeploy programme has delivered the first private trial of hydrogen blends at Keele University; it started in 2017 and will end in 2021. The HyDeploy$_2$ programme continues on, to deliver the first public trial of hydrogen blends in Winlaton, Gateshead, and will seek to deliver a final exemption to act as a template for national hydrogen blending. HyDeploy$_2$ started in 2019 and will continue to 2023.

The purpose of this article is to detail the lessons learnt from the core technical programmes of the overall project to date and from the operation of the first trial at Keele University. The evidence base in support of the Keele University trial exemption has been assessed and approved by the HSE. At the time of writing, the evidence base for the Winlaton safety case is still under review by the HSE.

Technical programmes

The technical programmes of the overall HyDeploy programme are the basis on which the safety case is developed to apply for exemption to the hydrogen limit within GS(M)R. Each technical area seeks to investigate any marginal impacts that relate to the introduction of a hydrogen blend, relative to business-as-usual operations with natural gas. Any impacts are then quantified and assessed though an overarching quantitative risk assessment (QRA) to understand the total risk profile and structure of the hydrogen blend relative to natural gas.

Gas characteristics

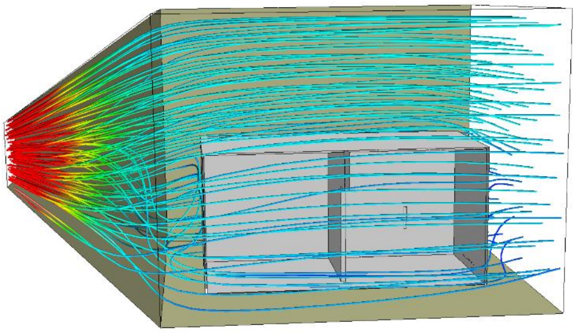
Gas characteristics research is central to the understanding of any marginal differences between a hydrogen blend and natural gas. For the purposes of the research undertaken, natural gas has been explored via a proxy of 100 per cent methane, as is standard practice in gas research. The gas characteristics work streams have primarily explored the chain of causality that leads to fire/explosion, to understand at each stage whether a hydrogen blend affects the current elements. For clarity, the chain of independent events of concern is as follows: a gas leak occurs; the gas leak accumulates to a flammable concentration; an ignition source of sufficient energy is present and activated within the flammable cloud; and a fire or explosion occurs, leading to building impacts and injury.

Gas leakage characteristics are determined by the flow regime of the moving fluid; lower velocity and therefore lower volumetric leaks are laminar, and larger leaks are turbulent. In the laminar flow regime, viscosity is the dominant gas characteristic. In turbulent flow, density is the dominant factor. The viscosity of a hydrogen blend is 99 per cent that of methane; therefore, no practical difference in leak rate occurs for smaller leaks. For larger leaks, an increase of up to 10 vol% would be expected due to the reduced density of the hydrogen blend relative to natural gas.

Extensive experimental and modelling analysis has been undertaken to explore if any changes in leak dynamics result in a greater propensity to generate flammable environments. Both the experimental and analytical results have shown that no meaningful changes in gas concentration result from the potential increase in volumetric leak rate for turbulent leaks. This is due to the self-correcting nature of the induced ventilation flow. Following a leak of a buoyant gas, the fluid will naturally accumulate at the highest point of a room, and from there the gas will start to escape the room through windows, doors, ceilings, or cracks. The outflow of gas from the room induces ventilation into the room. Over time, the flow of air into the room equilibrates with the outflow of the gas, and a steady-state concentration is established. Given that both the volumetric leak rate and induced ventilation flow are driven by the buoyancy of the gas, both increase with reducing gas density. The net effect created is a self-correcting mechanism where the ultimate gas concentration is not affected. This conclusion was analytically predicted and then experimentally confirmed.

The potential risk of a fire or explosion primarily relates to the impact on the building structure in which the incident occurs. The direct impact of a pressure wave on a human is a secondary factor given the order of magnitude difference between the impact pressure required to cause structural damage, such as window or wall blowing out, relative to the impact pressure required to cause direct damage to humans. The impact of pressure waves on building structures is nuanced, with complex stoichiometric and geometric factors heavily influencing the resulting pressure–time curve. Peak pressure and impulse are the two characteristics that determine structural damage, where the impulse accounts for the time duration of the pressure wave as well the magnitude of the pressure wave itself. As pressure waves relate to structural damage, the impulse metric is a more appropriate parameter, as it accounts for a greater number of characteristic variables than just the peak overpressure.

Gas leakage research facility



Ignition research facility

These dynamics have been extensively studied, both using established theoretical models and through dedicated experimentation where nearly 60 gas-air-geometries were studied. In general, peak pressures change with laminar burning velocities, where a hydrogen blend has an approximately 20 per cent increase in laminar burning velocity. However, due to the higher laminar burning velocity, the duration of the pressure wave was found to reduce, and hence changes to the impulse metric were significantly less.

Appliances

Demonstrating the safe operation of appliances without the need for disruption or change is a fundamental objective of the HyDeploy programme. Extensive experimentation and field testing have taken place to study the impact of a hydrogen blend on the operation of both well-operating and malfunctioning appliances. Since 1993 all domestic gas appliances sold into the UK have been tested for operability with 23 vol% hydrogen, which has been part of the certification testing required to achieve their CE marking (designating compliance with European standards).

The laboratory analysis was supported by a review of appliance design and certification standards from the present back to 1976, when the first natural gas standards came into effect following the conversion from towns gas. A carefully defined sample set of 13 appliances, primarily determined by their burner and flue design, were selected to provide a GB-representative test set. Safety and performance testing was then undertaken to evaluate the impact of a hydrogen blend on operational parameters such as flue gas emissions, nitrogen oxides production, combustion efficiency, delayed ignition, component temperatures, and appliance commissioning and set-up. The evidence generated showed that UK appliances are capable of operating with a 20 vol% hydrogen blend safely and with good performance and without the need for adjustment.

Methane flame (left); methane and 28.4 vol% hydrogen flame (right)

The work demonstrated an important beneficial safety impact of operating malfunctioning appliances on a hydrogen blend. When the appliances were put into fault conditions to generate high levels of carbon monoxide (CO), changing the gas supply to a hydrogen blend reduced CO production by around 70 per cent; in many cases the level of CO reduced back to acceptable limits.

Materials and assets

Materials and assets research has assessed a wide array of materials to understand whether exposure to a hydrogen blend could be expected to have any potential impact. The programme has encompassed many common materials, including stainless steels, brass, copper, rubbers, polyethene, and aluminium. A rigorous asset register was developed for the whole network and downstream equipment that would be exposed to the hydrogen blend; then the components and materials of construction were identified. A literature review was then undertaken to inform the physical testing programme. Samples of materials were produced and then exposed to hydrogen blends for varying durations, followed by tensile and mechanical testing.

Materials soaking facility

This process of materials testing has enabled a body of evidence to be generated on the expected impacts on material properties following exposure to a 20 vol% hydrogen blend. Testing to date has focused on that which is required to justify the safety cases in support of the trials, and therefore has been bounded to representative conditions of the low- and medium-pressure distribution tiers. These tiers are up to 2 barg. Further testing is under way at higher pressures which are representative of the full pressure boundary of the gas distribution network. The results of these tests will allow a complete picture of material suitability to be established.

Procedures and gas detection

Procedures, both upstream (gas network) and downstream (within premises), and their supporting gas detection equipment, are critical to ensuring the safe use of gas within the UK. Using the outputs of the scientific programmes, an understanding was reached of whether procedures would need to change to accommodate the impacts of a hydrogen blend. Much like the materials work streams, the network procedures were bounded to the low- and medium-pressure procedures. Higher-pressure tier procedures will be reviewed in due course by the project.

Gas detection instruments—survey detectors (A) and fixed detectors (B)

Almost all low- and medium-pressure tier procedures were demonstrated to be adequate in their current form. Importantly, the emergency response procedures used by network engineers to respond to public reports of gas escapes were demonstrated to be suitable, provided they were paired with the appropriate gas detection equipment. Only a handful of procedures, such as network purging, required a minor update, such as specifying a slightly higher minimum purge velocity.

The review of the downstream procedures took the form of assessing all procedures that a Gas Safe certified engineer could use to install, commission, repair, and maintain appliances and their supporting installation such as the pipework and ventilation. A process of review and challenge was undertaken and the findings shared with the standard-setting bodies, the British Standard Institution and the Institute of Gas Engineers and Managers. It was concluded, and agreed to by the standard-setting bodies, that no domestic procedure would require modification to accommodate the impacts of a hydrogen blend.

Quantitative risk assessment

A QRA was developed to understand the causality of risk that results from the use of natural gas within the GB gas distribution network. The QRA encompassed both the gas network and appliance operations, assessing the risk to life due to both CO exposure and fire/explosion. The QRA was 'baselined' by first assessing the whole of the GB network, for which independent historical figures were available to calibrate and validate the model. From this a regional model of risk was developed using characteristic values of the regions under consideration. This allowed a baseline of the regional risk with natural gas to be understood. Finally, the outputs of the scientific programmes were converted to inputs into the QRA to understand the risk profile that resulted from introducing the hydrogen blend. Through this step-wise approach, a comparative analysis could be presented to numerically demonstrate that the total impact of a hydrogen blend did not result in an increase in risk.

Keele University trial

The evidence base generated in support of the Keele University trial set the expectations of the trial. Over the course of the trial, a continuous monitoring programme was enacted to collate evidence to confirm the pretrial expectations. As the purpose of the HyDeploy programme is to demonstrate the safe transportation and utilization of a 20 vol% hydrogen blend, the lessons learnt from the trial are structured in that order.

Network findings

The findings from the network surveys and monitoring confirmed the pretrial expectation of the impacts on the network:

- Gas composition: A consistent composition of gas was observed throughout the trial, utilizing a permanently installed gas chromatograph as well as six sample points for manual samples.
- Network pressures: The pressure profile of the network remained within the normal operating bounds. At the six sample points, permanent remote pressure indication was installed to gather data.
- Odour intensity: No perceivable dilution in odour intensity was observed; therefore, no impacts on the ability of the public to detect and report gas escapes would be expected. The six sample points contained test stations to assess the odour intensity (rhinology testing).
- Network leakage: No increase in leakage frequency was identified, relative to historical trends.

Overall, the network findings have provided strong confirmatory evidence that the introduction of a hydrogen blend does not result in the generation of operational constraints or risks that would require separate processes to mitigate and manage.

Appliance findings

The trial findings as they relate to appliances were generated by active monitoring and testing. A dedicated facility was constructed to operate typical appliances in an accelerated fashion (continuous operation), where half were supplied with natural gas and the other half with a hydrogen blend; this allowed a direct comparison of the two fuels. Alongside this facility monitoring of the existing customer and University appliances was undertaken as well as annual services and Gas Safe checks. The findings were as follows:

- Safe operation: The appliances continued to operate safely and within the recommended limits of typical operation.
- Failure frequency: No increase in failure frequency was observed, relative to historical trends.
- Installation tightness: Nearly 100 installations were tested for their tightness with both natural gas and a hydrogen blend, all installations found to be acceptably tight on natural gas were also compliant with the hydrogen blend.

Conclusion

The scientific programmes developed through the HyDeploy project and the evidence they have produced have helped to develop a robust understanding of the risk profile of a 20 vol% hydrogen blend relative to natural gas, within the context of the proposed trials. The technical evidence base collected so far, as well as the supporting field evidence, have shown that for the purpose of the trials a hydrogen blend is as safe as natural gas. The remainder of the programme will be focused on making this case beyond the constraints of individual trials to underpin and facilitate national blending.

HYDROGEN AND THE DECARBONIZATION OF STEELMAKING

Markus Schöffel

Traditional blast furnace steelmaking

Global crude steel (CS) production totalled about 1.88 billion metric tonnes in 2019, of which 72 per cent or 1.34 billion metric tonnes were primary steel produced via the blast furnace and basic oxygen furnace (BF-BOF) route.[37] This carbon-based pathway, as implemented in integrated steel mills, comprises coking plant, sinter plant, and BF-BOF plant. First, coking coal is transformed into coke in the coking plant, and iron ore fines are agglomerated to lumps in the sinter plant, generating emissions of about 300 kg CO_2/t coke and about 270 kg CO_2/t sinter.[38]

In a second step, coke is fed in alternating layers together with sinter and lump ore as well as pellets into the blast furnace. During descent of the burden in the BF, iron ore gets reduced to metallic iron by coke as well as by pulverized coal being injected together with the hot blast as reducing agents. As temperature rises above the melting point in the lower part of the BF, liquid hot metal, a eutectic iron carbon phase, containing about 4.5 per cent carbon by mass, is formed and leaves the tap hole.

The third step consists in refining of hot metal to CS in the BOF, where dissolved carbon is oxidized and removed. Based on

[37] *Steel Statistical Yearbook 2020*, concise version, Brussels: World Steel Association, https://www.worldsteel.org/steel-by-topic/statistics/steel-statistical-yearbook.html.
[38] Climate Change Committee, Eurofer (2020), *Benchmarking Study among 20 European Sites*.

average BF-BOF emissions of 1,470 kg CO_2/t CS and coke and sinter demands of 375 kg coke/t CS and 880 kg sinter/t CS,[39] the integrated steelmaking process is linked to emissions of about 1,800 kg CO_2/t CS. Considering the world CS production in 2019, this industrial sector emitted 2.6 Gt CO_2,[40] corresponding to about 7 per cent of the global emissions of 38.0 Gt CO_2.[41]

Even in a circular economy, primary steelmaking will constitute a main pillar of steel supply, as many steel products, for example in building and infrastructure applications, have decades-long life. Of all the steel ever produced, 70 per cent is still in use today and therefore not available for recycling.[42] Electric arc furnace (EAF)-based secondary steelmaking will play a role in CO_2-lean production but cannot cover total demand on its own.

Natural gas direct reduction as a first step in CO_2 reduction

Direct reduction plants (DRP) yielded another 0.11 billion metric tonnes or 6 per cent of the global CS supply in 2019, with increasing share in recent years.[43] This technology differs from the BF route in two main ways: first, the iron ore in the furnace is reduced by syngas produced from natural gas (NG) instead of carbon, and second, the direct reduced iron (DRI) leaves the furnace as a solid, which must be melted to produce liquid hot metal. The thermal energy consumption of a DRP operated with NG is 9.6 GJ/t DRI for DRI containing 3.5 per cent carbon by mass.[44] The input of 175 kg methane (55.5 MJ/kg HHV[45]) will finally generate 480 kg CO_2/t DRI from reduction cycle flue gases as well as from decarburization during steelmaking corresponding to 510 kg CO_2/t CS, considering a DRI metallization of 94 per cent by mass. Electrode burn-off and foaming coal addition during melting of DRI in an EAF will generate about 30 kg CO_2/t CS,[46] resulting in 540 kg CO_2/t CS from the DRP-EAF production route, provided that all electricity used is renewable. Comparing this value to emissions from the BF-BOF route shows that even using NG, a reduction of CO_2 emission to about one-third is feasible. Switching the German steel industry to the bridging technology NG-DRP will boost demand for NG and support the economic viability of current expansion measures on import pipelines as Nord Stream 2.

Use of other types of electric melters (EMs), like submerged arc furnaces instead of EAF is also feasible. An additional refining treatment in BOF allows adjusting the concentration of carbon and accompanying elements so that all steel grades produced today with the BF-BOF route can be manufactured from DRI.

With hydrogen direct reduction to net zero

Operating a DRP on climate-neutral hydrogen makes it possible to bring down emissions from the reduction step to almost zero. However, in order to carburize the DRI, small quantities of coal will have to be added in the EM. Assuming carburization at a lower limit of 2 per cent by mass, remaining emissions from the BOF refining step amount to about 70 kg CO_2/t CS, and overall emission from the H_2-DRP-EM route to about 100 kg CO_2/t CS. The future use of biogenic carbon sources for carburization and as electrode material, or coupling with a carbon capture and utilization technique like Carbon2Chem,[47] would make the overall process climate-neutral.

Comparison with the emissions of the BF-BOF route shows that H_2-DRP-EM steelmaking has a potential of at least 1,700 kg CO_2/t CS emission abatement and can make a huge contribution to global emission reduction in the order of 5–6 per cent. In the steel industry, significant emissions reduction through a small number of major investment decisions is equivalent to savings requiring millions of small decisions in other sectors, for example in passenger cars or buildings.[48]

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[39] Song, J., et al. (2019), 'Comparison of energy consumption and CO2 emission for three steel production routes—integrated steel plant equipped with blast furnace, oxygen blast furnace or COREX', Metals, 9, 364, https://www.mdpi.com/2075-4701/9/3/364/htm.

[40] International Energy Agency (2020), Direct CO2 Emissions in the Iron and Steel Sector by Scenario, 2019–2050, https://www.iea.org/data-and-statistics/charts/direct-co2-emissions-in-the-iron-and-steel-sector-by-scenario-2019-2050.

[41] Crippa, M., et al. (2020), Fossil CO2 Emissions of All World Countries—2020 Report, EUR 30358 EN, Luxembourg, Publications Office of the European Union, Luxembourg, https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/fossil-co2-emissions-all-world-countries-2020-report.

[42] EuRIC (2020), Metal Recycling Factsheet, Brussel: EuRIC, https://circulareconomy.europa.eu/platform/en/knowledge/metal-recycling-factsheet-euric.

[43] Midrex Technologies (2020), World Direct Reduction Statistics 2019, https://www.midrex.com/wp-content/uploads/Midrex-STATSbook2019Final.pdf.

[44] Duarte, P., Scarnati, T., and Becerra, J., (2008), ENERGIRON Direct Reduction Technology—Economical, Flexible, Environmentally Friendly, Castellanza, Italy: Tenova, https://www.energiron.com/wp-content/uploads/2019/05/2008-Environmental-Emissions-Compliance-And-Reduction-Of-Greenhouse-Gases-In-A-DR-EAF-Steel-Plant-2.pdf.

[45] Hahne, E. (2010), Technische Thermodynamik: Einführung und Anwendung, Oldenbourg.

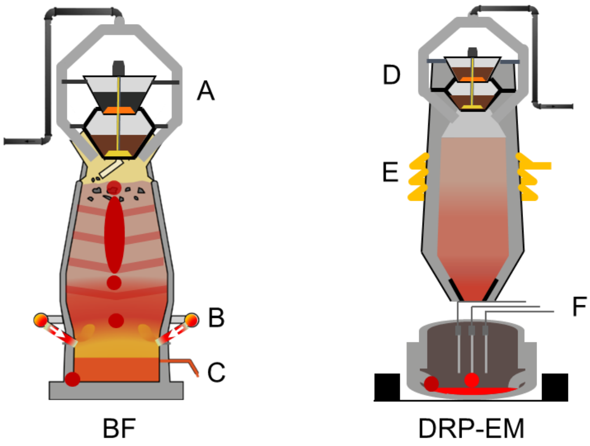
[46] Hölling, M., Weng, M., and Gellert, S., (2017), 'Bewertung der Herstellung von Eisenschwamm unter Verwendung von Wasserstoff', ArcelorMittal, https://germany.arcelormittal.com/icc/arcelor/med/b8e/b8e0c15a-102c-d51d-b2a9-147d7b2f25d3,11111111-1111-1111-1111-111111111111.pdf.

[47] ThyssenKrupp (n.d.), *Carbon2Chem,* https://www.thyssenkrupp.com/carbon2chem/de/carbon2chem.

[48] Wirtschaftsvereinigung Stahl (2020), *Fakten zur Stahlindustrie in Deutschland 2020*, https://issuu.com/stahlonline/docs/wv-stahl_fakten-

Although the potential is huge, today no commercial-scale DRP is operated on hydrogen, as low-carbon and affordable hydrogen sources are lacking. Assuming an identical thermal energy demand on hydrogen as on NG, about 65 kg (HHV) or 750 Nm^3 hydrogen per t DRI are required.

Comparison of blast furnace *and* direct reduction plant/electric melter technology—A: feedstock inlet for burden (iron ore) and coke; B: hot blast tuyères and pulverized coal inlet; C: tap hole for hot metal; D: feedstock inlet for iron ore pellets; E: reducing gas inlet; F: smelting electricity connection



Hydrogen supply as challenge

The German National Hydrogen Strategy released in June 2020 foresees a build-up of green hydrogen production in Germany with a capacity of 5 GW and 14 TWh hydrogen output by 2030, and another 5 GW capacity and 14 TWh output by 2035, at the latest by 2040.[49] On the demand side, thyssenkrupp Steel Europe, which operates the largest integrated steel production site in Europe (at Duisburg), envisages, within their tkH2steel strategy, consuming 8 TWh hydrogen in 2030, through conversion of around one-third of total production capacity. A recent benchmarking study by the German steel association predicted that the hydrogen demand of the entire German steel industry will be 22 TWh in 2030 and rise to 67 TWh in 2050.[50]

The comparison of these values shows that more than the intended domestic green hydrogen production will be necessary for a single industrial sector, and that therefore other climate-neutral hydrogen production techniques as well as imports of hydrogen or derivatives have to be considered. One large-scale commercially available technology is NG reforming that can be equipped with CO_2 sequestration. Assuming permanent storage of CO_2 in offshore geological sites, and taking into account upstream methane emissions from NG production and transport, this process will easily lead to a CO_2 abatement of 95 per cent or more. In the coming years, NG pyrolysis technology should also be able to contribute to large-scale climate-neutral hydrogen supply.

A feasibility study within the H2morrow steel project[51] concluded that blue hydrogen production at large scale up to 2.7 GW is practicable using an autothermal reforming unit with CO_2 separation located at the North Sea coast, CO_2 ship transport and storage in an offshore carbon capture and storage project like Northern Lights, and hydrogen delivered by pipeline to Duisburg at costs of € 2.1/kg, assuming a future NG price of € 23/MWh. This project on its own could close the hydrogen gap of 1.9 GW in 2030 between supply and demand as determined in the German gas grid development plan for 2020–2030,[52] and accelerate the ramp-up of a hydrogen economy.

2020_rz_web.

[49] German Federal Ministry for Economic Affairs and Energy (2020, 10 June), *The National Hydrogen Strategy*, https://www.bmwi.de/Redaktion/EN/Publikationen/Energie/the-national-hydrogen-strategy.html.

[50] Wirtschaftsvereinigung Stahl (2020), *Fakten zur Stahlindustrie in Deutschland 2020*, https://issuu.com/stahlonline/docs/wv-stahl_fakten-2020_rz_web .

[51] ThyssenKrupp (2021, 12 January), *H2morrow steel Schließt Machbarkeitsstudie ab, Projektpartner arbeiten weiter zusammen*, https://www.thyssenkrupp.com/de/newsroom/pressemeldungen/pressedetailseite/h2morrow-steel-schliesst-machbarkeitsstudie-ab--projektpartner-arbeiten-weiter-zusammen--versorgung-des-duisburger-stahlwerks-mit-blauem-wasserstoff-technisch-moglich--klarung-der-.

[52] *Netzentwicklungsplan 2020* (2020, 1 July), Berlin: FNB Gas, https://www.fnb-gas.de/netzentwicklungsplan/netzentwicklungsplaene/netzentwicklungsplan-2020/.

Hydrogen transport infrastructure

The means of hydrogen transport is of central importance for cost and availability at the point of consumption. Liquid hydrogen, ammonia, or synthetic NG might be solutions for long-range transport when importing hydrogen from elsewhere in the world. Due to large investments in the conversion plants and associated high fixed costs, this will not be the solution of choice for transport of hydrogen over short to medium distances within the EU or from its neighbouring countries. Small demand centres with capacity needs in the range of 100 MW can be supplied by decentralized electrolysers; the electricity grid enhancement linked to the expansion of renewable energy generation should be able to absorb this demand. Capacity needs in the GW range, as necessary to supply H_2-DRP in the steel industry, would require the construction of dedicated high-voltage lines only for the purpose of captive hydrogen generation, unless well-connected former fossil-energy-generation sites can be repurposed.

The new natural gas pipeline ZEELINK, technically completed in February 2021, has a 1,000 mm diameter and a design pressure of 100 bar running over 216 km in the north-western part of Germany.[53] Construction costs were € 600 million for a transport capacity of 9.6 bcm/year or 12 GW of NG,[54] resulting in specific infrastructure costs of € 0.23 million per km per GW. This pipeline passes through industrial clusters and has multiple intersections with existing infrastructure, including crossing under the river Rhine, resulting in rather high specific costs. Construction at the lower cost bound due to routing in less densely populated areas was possible for the 1,400 mm-diameter pipeline OPAL,[55] ensuring the 473 km connection between Nord Stream and the border to the Czech Republic. Costs were about € 1 billion,[56] for a capacity of 36 bcm/year or 45 GW of NG, yielding specific infrastructure cost of € 0.05 million per km per GW.

Following a current study, the transport capacity of pipelines when switched from NG to hydrogen can reach 80–90 per cent of the NG capacity, so that the specific infrastructure costs are almost identical.[57] Capital costs for new-built hydrogen pipelines are largely determined by civil engineering expenses, so that cost parity to new-built NG pipelines can be assumed. Referring to operating costs, the European Hydrogen Backbone initiative estimates hydrogen transport costs to be as little as € 0.09–0.17 per 1,000 km per kg.[58]

On the electricity side, the German project for high-voltage direct current transmission SuedLink,[59] stretching from the North Sea coast to southern Germany, foresees an underground cable over 684 km, capable of transporting 4 GW of electricity for an estimated total cost of € 10 billion,[60] yielding specific capital cost of € 3.7 million per km per GW. The comparison shows that infrastructure costs for energy transport in the form of electricity are about 15 to 75 times higher than for hydrogen transport, leading to the conclusion that long-distance transport of electricity in the GW range is not reasonable from a macroeconomic point of view.

Regulatory framework required

To speed up the transformation from BF to DRP-EM and to implement climate-neutral hydrogen as a reducing agent in steelmaking, four central regulatory issues have to be addressed:

[53] 'Eine sichere Versorgung benötigt auch gute Verbindungen—Projektübersicht: ZEELINK Fernleitung' (2019), *Zeelink*, https://www.zeelink.de/wp-content/uploads/2019/09/ZEELINK_Fernleitung_Projektvorstellung_Brosch%C3%BCre_190919.pdf.
[54] Elliott, S. (2020), 'First testing on new German gas pipeline Zeelink set for November: developer', *S&P Global Platts*, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/100720-first-testing-on-new-german-gas-pipeline-zeelink-set-for-november-developer.
[55] 'OPAL—die grösste Erdgaspipeline Nordwest-Europas' (2021), *Opal*, https://www.opal-gastransport.de/netzinformationen/ostsee-pipeline-anbindungsleitung.
[56] 'Die Erdgasleitung Opal ist offiziell fertiggestellt' (2011, 13 July), *LR Online*, https://www.lr-online.de/lausitz/finsterwalde/die-erdgasleitung-opal-ist-offiziell-fertiggestellt-35284734.html.
[57] *Wasserstoffinfrastruktur—tragende Säule der Energiewende* (2020), Siemens Energy, Gascade Gastransport GmbH, Nowega GmbH, https://www.get-h2.de/wp-content/uploads/200915-whitepaper-h2-infrastruktur-DE.pdf.
[58] *European Hydrogen Backbone: How a Dedicated Hydrogen Infrastructure Can Be Created* (2020), Guidehouse, https://gasforclimate2050.eu/sdm_downloads/european-hydrogen-backbone/.
[59] *SuedLink Gleichstrom-Erdkabel: Für eine sichere und zuverlässige Stromversorgung* (2019), TenneT TSO, https://www.tennet.eu/fileadmin/user_upload/Our_Grid/Onshore_Germany/SuedLink/Technologie/Factsheet_Technik__Gleichstrom-Erdkabel_.pdf.
[60] Wetzel, D. (2016, 27 September), 'Deutsche Strom-Autobahn wird gigantisch groß—und teuer', *Welt*, https://www.welt.de/wirtschaft/article158407192/Deutsche-Strom-Autobahn-wird-gigantisch-gross-und-teuer.html.

1. *The European Emissions Trading System:* Regulation (EU) 2019/331[61] foresees the applicability of the hot metal benchmark only for liquid iron as a product of blast furnaces at the exit point of the blast furnace. This means that a liquefied DRP product is not covered by this benchmark, and only the lower emission factor of NG (56.1 kg CO_2/GJ[62]) would be applied, yielding free allowances of 540 kg/t CS. Contrary to the principle of the Emissions Trading System, this would discourage investment in CO_2 reduction technologies. To speed up transformation to CO_2-lean production, all primary steelmaking technologies have to be covered by the hot metal benchmark.
2. *The German Energy Industry Act (Energiewirtschaftsgesetz):* This law governs the pipeline transport of NG but not of pure hydrogen. A technology-neutral modification to cover hydrogen from all production methods was requested by numerous associations starting in 2019,[63] resulting in an amendment, which passed the cabinet on 11 February 2021. This amendment has now to be enacted as law to provide legal certainty, allow pipeline operators to invest in hydrogen infrastructure, and encourage future hydrogen customers to make firm bookings.
3. *Transport of liquefied CO_2 on ships:* According to Article 49 of the regulation (EU) 2018/2066,[64] only CO_2 emissions, which are transferred to a transport network aiming to convey them to a geological storage site, can be subtracted from the emission total that an installation has to report under the Emissions Trading System. Article 3 (22) of directive 2009/31/EC[65] defines a transport network as a network of pipelines, and therefore excludes the transport of CO_2 by ship to a storage site from exemption to submit Emissions Trading System certificates. As ship transport of liquefied CO_2 represents an easy-to-implement and cost-effective form of CO_2 mitigation, this means of transport has to be included.
4. *Funding:* Large government funding schemes to cover higher capital expenditures for new-built DRP-EM plants instead of BF relining will be necessary and have to be exempted from state aid regulations. Due to higher costs for hydrogen replacing coal as a reducing agent, support for operating expenditures through carbon contracts for difference will be vital for operation of the new technology.

Conclusion

Steelmaking by DRP-EM represents a commercially available technology that can deliver a two-thirds reduction in CO_2 emissions compared to the BF route, even if operated with NG. Deep decarbonization to about 5 per cent of remaining emissions can be reached by using climate-neutral hydrogen. Blue hydrogen can ramp up this technology as long as renewable hydrogen is not available in sufficient volumes. Additionally, the transport of hydrogen in pipelines has a cost advantage of one to two orders of magnitude compared to electricity transport, encouraging a fast build-up of a pure hydrogen pipeline grid. To kick-start the transformation, regulatory and financial issues remain to be clarified in the short term.

REGULATION OF HYDROGEN MARKETS—ARE CONCERNS ABOUT ‘LOCK-IN’ EFFECTS VALID?

Alex Barnes

In the days when the law required British pubs to close at 11 p.m., pub owners would sometimes enable favoured customers to continue drinking by closing the doors to other customers, while keeping the favoured customers ‘locked’ inside. ‘Lock-ins’ were seen by many as an enjoyable (albeit illegal) way of avoiding regulation. Today the issue of ‘lock-ins’ is being debated in the

[61] Commission delegated regulation (EU) 2019/331 of 19 December 2018 determining transitional Union-wide rules for harmonised free allocation of emission allowances pursuant to Article 10a of Directive 2003/87/EC of the European Parliament and of the Council, https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32019R0331&from=de.

[62] *Leitfaden Zuteilung 2021–2030 Teil 3 b* (2019), Umweltbundesamt and DEHSt, https://www.dehst.de/SharedDocs/downloads/DE/stationaere_anlagen/2021-2030/Leitfaden-3b.pdf?__blob=publicationFile&v=5.

[63] *Auf dem Weg zu einem wettbewerblichen Wasserstoffmarkt* (2020), FNB Gas, BDI, BDEW, VIK, DIHK, https://bdi.eu/publikation/news/auf-dem-weg-zu-einem-wettbewerblichen-wasserstoffmarkt/.

[64] Commission implementing regulation (EU) 2018/2066 of 19 December 2018 on the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council and amending Commission Regulation (EU) No 601, https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32018R2066&from=de.

[65] Directive 2009/31/EC of the European parliament and of the council of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/, https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=CELEX:32009L0031&from=EN.

context of the future regulation of European hydrogen markets. This has nothing to do with drinking, and much to do with perceptions of how the hydrogen market should develop. There is a risk that misunderstanding of how markets develop will lead to poorly designed regulation, and a delay to reducing greenhouse gas (GHG) emissions in Europe. This article explains what lock-in effects are, why some people are concerned about them in the context of developing hydrogen markets, and whether such concerns are valid.

The concern is that Europe will be stuck with energy technologies which will make it difficult or impossible to reduce GHG emissions over the next 30 years to meet the EU's 2050 net zero target. The idea is closely related to the idea of 'path dependence', namely that decisions taken today influence the way in which energy systems will develop in the future. Lock-in effects can arise because of the costs or difficulties of switching from current energy technologies to future ones. Lock-in mechanisms include economies of scale and scope; network externalities, including early de facto setting of standards in industrial networks; technology interrelatedness, which prevents technology which is incompatible with the dominant technology from being used; and institutional lock-in, which means that 'strong political actors can impose their rules on others.'[66]

'Renewable' vs 'low-carbon' hydrogen

Hydrogen is a potential means for the EU to reduce its GHG emissions by replacing existing fossil fuel consumption in sectors which cannot easily be electrified, such as industry and heavy transport, and in heating of buildings where heat pumps may be less cost-effective or impractical. Hydrogen can be produced via electrolysis of water using renewable electricity, which produces no CO_2 during the production process. The EU refers to this as 'renewable' or 'clean' hydrogen.[67] It can also be produced via steam methane or auto thermal reforming of natural gas. Carbon capture and storage (CCS) prevents the release of most of the accompanying CO_2 into the atmosphere, but capture rates are not 100 per cent. Pyrolysis of natural gas produces hydrogen and solid carbon so does not require CCS. However, the production and transportation of natural gas involves methane emissions, which are also a source of GHG.[68] The EU therefore refers to hydrogen produced in this way as 'low carbon.'

Given the ambitions for net zero by 2050, and the residual GHG emissions associated with low-carbon hydrogen, it would appear obvious that renewable hydrogen is the only way to go. However, there is currently insufficient renewable generation to meet all existing electricity demand, let alone the increase expected as large sections of the economy electrify. In 2018, renewables provided only 33 per cent of EU27 electricity generation, compared with 26 per cent nuclear and 41 per cent non-renewables.[69] Solid fuels such as coal accounted for 21 per cent of gross generation.

Using renewables to produce hydrogen instead of replacing fossil fuel electricity generation would be inefficient. Whilst one kWh of renewable electricity would replace one kWh of fossil-based electricity, it would replace only 0.8 kWh of natural gas if used to produce hydrogen, because of conversion losses.[70] Using grid-based electricity, which includes a share of fossil-fuel-generated electricity, to produce hydrogen would make no sense from a decarbonization point of view unless it was based on a high share of renewables. For example, German electricity generation produces 338 g of carbon dioxide equivalent (CO_2e) per kWh.[71] After conversion this would result in hydrogen with a carbon footprint of 423 g CO_2e/KWh.

[66] Klitkou, A., Bolwig, S., Hansen,T., and Wessberg, N. (2015), 'The role of lock-in mechanisms in transition processes: the case of energy for road transport', *Environmental and Innovation and Societal Transitions*, 16, 22–37, https://reader.elsevier.com/reader/sd/pii/S2210422415300071?token=60E22EB9878B6C9FDD4636D8368E1260E0E7A024AD08541B1C94528F17C93202D6F5BD2C499D7891FADC2A79A4ACD183&originRegion=eu-west-1&originCreation=20210402081925.

[67] EU Commission (2020), A hydrogen strategy for a climate-neutral Europe, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020DC0301.

[68] For more on methane emissions see Stern, J. (2020), *Methane Emissions from Natural Gas and LNG Imports: an Increasingly Urgent Issue for the Future of Gas in Europe*, Oxford: Oxford Institute for Energy Studies, https://www.oxfordenergy.org/publications/methane-emissions-from-natural-gas-and-lng-imports-an-increasingly-urgent-issue-for-the-future-of-gas-in-europe/.

[69] Directorate-General for Energy, European Commission (2020), *EU Energy in Figures: Statistical Pocket Book 2020*, Table 2.6.2, https://op.europa.eu/en/publication-detail/-/publication/87b16988-f740-11ea-991b-01aa75ed71a1/language-en?WT.mc_id=Searchresult&WT.ria_c=37085&WT.ria_f=3608&WT.ria_ev=search.

[70] Dickel, R. (2020). *Blue Hydrogen as an Enabler of Green Hydrogen: the Case of Germany*, Oxford: Oxford Institute for Energy Studies, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/06/Blue-hydrogen-as-an-enabler-of-green-hydrogen-the-case-of-Germany-NG-159.pdf.

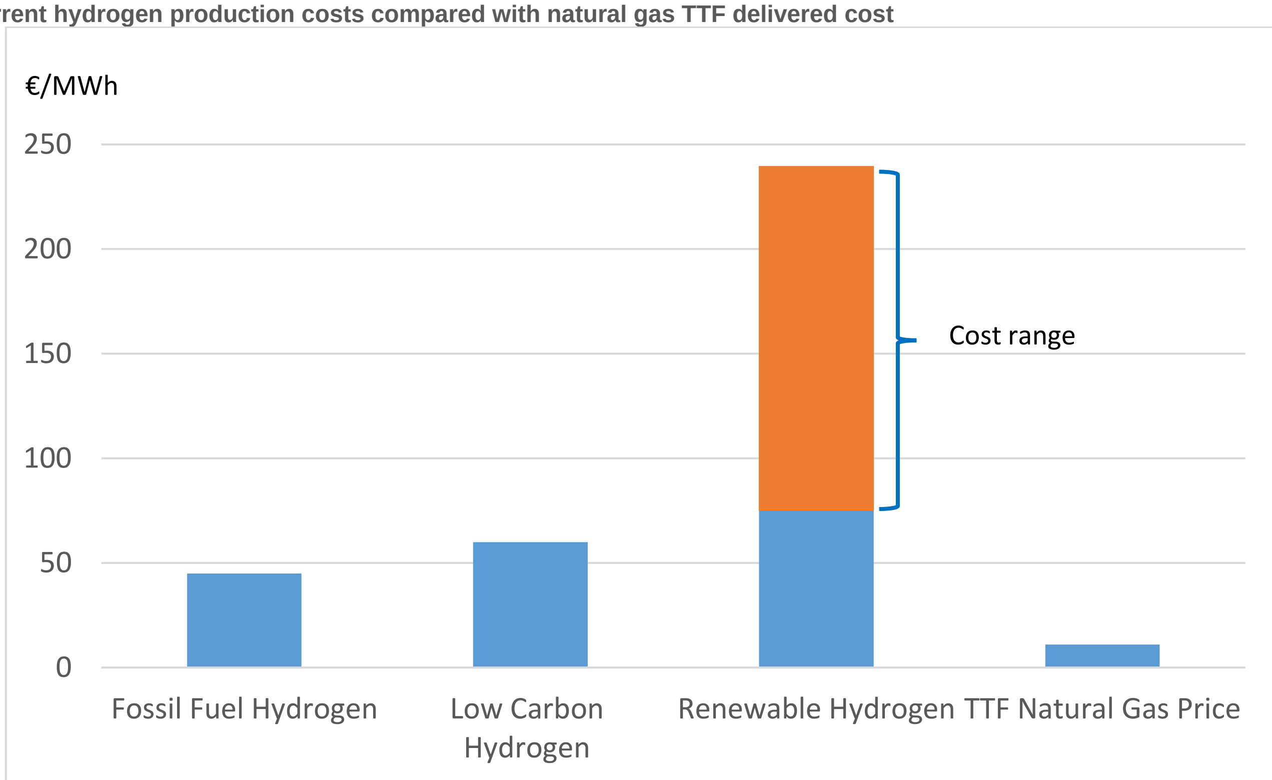
[71] European Environment Agency (2020): Greenhouse Gas Emission Intensity of Electricity Generation, https://www.eea.europa.eu/data-and-maps/indicators/overview-of-the-electricity-production-3/assessment.

The current CertifHy Guarantee of Origin criteria for low-carbon hydrogen,[72] based on reforming of natural gas with CCS, sets a minimum threshold of 131 g CO_2e/kWh (36.4 g CO_2e/MJ). This is based on a 60 per cent reduction from the benchmark of current hydrogen production without CCS of 328 g CO_2e/kWh (91 g CO_2e/MJ). Both of these are lower than hydrogen based on German grid electricity. However, this underestimates the capability of CCS with either steam methane or auto thermal reforming, which can achieve capture rates of 90 per cent.[73] With 90 per cent capture the carbon footprint of hydrogen from natural gas falls to 33 g CO_2e/kWh based on the CertifHy benchmark process.

The carbon content of German electricity would have to fall by over 90 per cent to achieve the same carbon footprint as reforming of natural gas with 90 per cent CCS. Between 2010 and 2019 the carbon content of German electricity fell by only 30 per cent from 483 g CO_2e/kWh, despite very large subsidies for renewables. (Note that both figures are based on the production of electricity and hydrogen alone and do not include GHG emissions from the production or transportation of fossil fuels used in electricity generation and hydrogen production.)

The other challenge is cost. It is self-evident that hydrogen would already be used if it was competitive with existing fossil fuels. However, this is a long way from being the case, as the EU Hydrogen Strategy acknowledges.

Current hydrogen production costs compared with natural gas TTF delivered cost



Source: EU Hydrogen Strategy, ICIS TTF Gas Year 20, 30 July 2020. Fossil fuel hydrogen is based on reforming of natural gas without CCS. Low-carbon hydrogen is based on reforming of natural gas with CCS.

Simply replacing current fossil-fuel-based hydrogen with low-carbon hydrogen could cost up to € 6.5 billion in subsidies via carbon contracts for difference.[74] Although costs for renewable hydrogen are expected to reduce in coming years, this will take time. During this period, uptake of renewable hydrogen will therefore either be limited or require extra subsidy. Such delay or costs can have knock-on effects on decarbonization efforts because of the lead times for industry to convert from fossil fuels to hydrogen, and the adverse impact on competitiveness leading to carbon leakage.

[72] CertifHy (2019), CertifHy Scheme Subsidiary Document: CertifHy-SD Hydrogen Criteria, https://www.certifhy.eu/images/media/files/CertifHy_2_deliverables/CertifHy_H2-criteria-definition_V1-1_2019-03-13_clean_endorsed.pdf.
[73] Van Cappellen, L., Croezen, H., and Rooijers, F. (2018), Feasibility Study into Blue Hydrogen, CE Delft , Table 1, https://www.cedelft.eu/en/publications/2149/feasibility-study-into-bleu-hydrogen.
[74] Barnes, A., and Yafimava, K. (2020), EU Hydrogen Vision: *Regulatory Opportunities* and *Challenges*, Oxford: Oxford Institute for Energy Studies, https://www.oxfordenergy.org/publications/eu-hydrogen-vision-regulatory-opportunities-and-challenges/.

In light of these factors, both the Commission and the EU Council have explicitly recognized the role of low-carbon hydrogen in contributing to decarbonization. The Council noted in its December 2020 'Conclusions "towards a hydrogen market for Europe"' that 'there are different safe and sustainable low-carbon technologies for the production of hydrogen that contribute to the rapid decarbonisation.'[75]

However, this has met with resistance from those who view low-carbon hydrogen as a means to enable the continued existence of fossil fuels. The debate comes down to whether low carbon hydrogen can contribute to the transition to net zero, or if the use of low carbon hydrogen will make it impossible to reach that goal. Opponents of low-carbon hydrogen have cited lock-in effects as a key concern.

Using low-carbon hydrogen: the 'lock-in' concern and its limitations

In January 2021, members of the European Parliament (MEPs) voted in favour of the use of low-carbon hydrogen from natural gas as a bridging solution until renewable hydrogen becomes commercially available.[76] However, Green MEP Jutta Paulus said, 'Unfortunately, a dirty majority formed that focused more on the future of the gas industry than on environmental issues.'[77] Barbara Mariani, a policy officer at the European Environmental Bureau, said, 'It's hard to avoid lock-in effects when billions of euros are invested in long-lasting and expensive technology needed to produce, transport and deploy climate-wrecking forms of hydrogen.'[78] Even the EU Council's December 2020 'Conclusions' called on the Commission to 'outline approaches to avoid sunk investment costs and ensure that the transition is not hampered by lock-in effects.'[79] Given these concerns, it is worth examining how real the threat of lock-in is.

Firstly, the hydrogen produced by electrolysis or from natural gas is substitutable, so it seems highly unlikely that the means of hydrogen production will determine which type of hydrogen, renewable or low-carbon, will be used. The EU has committed to competitive, traded hydrogen markets, and in such markets, consumers will prefer the lowest-cost hydrogen. Since transportation infrastructure and end-user appliances will be able to use either type equally easily, it is hard to see how technological lock-in can prevent consumers switching from low-carbon to renewable hydrogen. The clear parallel for this is the electricity market, where renewable electricity has replaced fossil fuel electricity once renewables have become cost competitive.

Even if renewable hydrogen never becomes cost competitive with low-carbon hydrogen, this does not mean that consumers will be locked in to low-carbon hydrogen once there is sufficient renewable hydrogen available. Those consumers who place a higher value on a low carbon footprint will be able to contract voluntarily to buy renewable hydrogen. Alternatively, governments can mandate that consumers use only renewable hydrogen, or that suppliers only supply renewable hydrogen, or ensure the cost of carbon is such that low-carbon hydrogen is more expensive.

The EU has committed to certification of hydrogen, so that consumers can differentiate between different forms, and this will in turn enable the use of carbon pricing (via the Emissions Trading System, for example), quotas under the Renewable Energy Directive to favour renewable hydrogen, and the use of Guarantees of Origin for consumers wishing to choose renewable hydrogen. Coupled with the EU Commission's 'Strategy to reduce methane emissions',[80] such certification should also ensure that the full carbon footprint of low-carbon hydrogen is taken into account.

Secondly, the prediction of lock-in effects rests on the assumption that companies will continue to produce low-carbon hydrogen to earn a return on their investments and thus avoid the problem of stranded assets. This is undeniable, but it ignores the impact of the competitive pressures and potential government actions described above. Companies will only keep producing low carbon hydrogen so long as customers buy their hydrogen and government regulations allow them to do so. The prediction also confuses the issue of stranded assets with that of lock-in effects.

[75] Council conclusions: 'towards a hydrogen market for Europe' (2020, 11 December), Brussels: Council of the European Union, https://www.consilium.europa.eu/media/47373/st13976-en20.pdf.
[76] Taylor, K. (2021, 27 January), 'MEPs back natural gas as a 'bridge' to 100% renewable hydrogen', *Euractiv*, https://www.euractiv.com/section/energy-environment/news/meps-back-natural-gas-as-a-bridge-to-100-renewable-hydrogen/.
[77] Ibid.
[78] Ibid.
[79] Council conclusions: towards a hydrogen market for Europe (2020, 11 December), Brussels: Council of the European Union, https://www.consilium.europa.eu/media/47373/st13976-en20.pdf.
[80] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on an EU strategy to reduce methane emissions (2020, 14 October), Brussels: European Commission, https://ec.europa.eu/energy/sites/ener/files/eu_methane_strategy.pdf.

Existence of an asset or product does not guarantee the product or company's future. As soon as a product that is better, cheaper, or government mandated comes along, consumers and companies switch to using it, even if other options were there first or are more plentiful. This is pithily expressed in the saying that the Stone Age did not end because of a shortage of stones. Or one can look at previous technological trends, for example where mainframes were superseded by personal computers, and Blackberries by other smartphones, despite significant investments by companies in the earlier technologies. In the case of energy, owners of both gas- and coal-fired electricity plants have seen their utilization fall depending on their relative profitability, and as renewable generation has become more competitive.

Where economics does not work, government regulation can. Both the Large Combustion Plant Directive and the Industrial Emissions Directive forced companies to choose between upgrading their plants to comply or closing them down.[81] Plants that had been profitable but were not worth upgrading were closed. From this we can conclude that companies have always faced the risk of stranded assets, whether as a result of competitive pressures or government action, and that the existence of assets alone is not sufficient to create a lock-in effect.

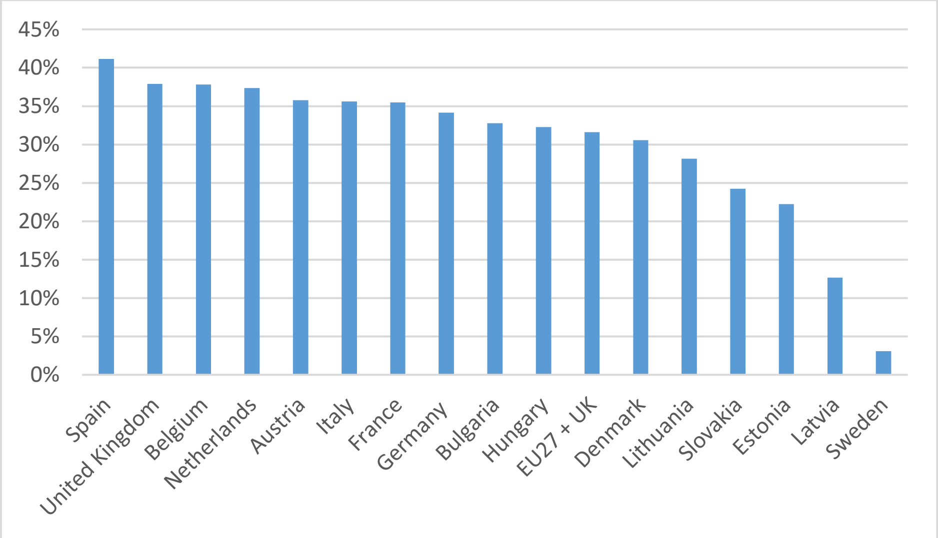
It could be argued, as suggested in the quotes above, that the existence of assets creates vested interests which will aim to influence government policy to protect their assets. It is true that the closure of coal-fired generation has been heavily influenced by political considerations in some countries, for example Germany. But such concerns are not unique to either hydrogen or the energy industry. The role of different actors in political decision-making is simply a reflection of the operation of a pluralistic, democratic system, where decision-makers have to make trade-offs. The success of any given interests will depend on their ability to win sufficient support, and will not happen because of their mere existence.

Given the EU's commitment to net zero by 2050 and the significant changes this will entail, it is hard to argue that vested interests have succeeded in maintaining the status quo, even if the route chosen is not as radical as some would like. There is nothing predetermined about the future of low-carbon hydrogen, since it is dependent on future government policy, which is dependent on the wider political consensus, not a particular hydrogen production technology. Talk of lock- in therefore seems overblown.

Waiting for renewable hydrogen: the cost of delay

In worrying about future lock-in, critics of low-carbon hydrogen are missing the bigger picture. The use of unabated natural gas is a significant contributor to the European economy, providing about a quarter of primary energy supply in the EU 27+UK. In particular it is a crucial source of energy for industry.

Natural gas share of industry final energy consumption, 2018



Source: Barnes, A. (2020), *Can the Current EU Regulatory Framework Deliver Decarbonisation of Gas?* Oxford: Oxford Institute for Energy Studies, Annex 1.

[81] European Commission. Environment. Industrial Emissions. https://ec.europa.eu/environment/industry/stationary/index.htm. Website accessed 6th May 2021.

Some of this consumption can be replaced with electricity; but for those companies which cannot easily electrify, there is currently no alternative. The real lock-in problem is therefore that such companies will not be able to decarbonize until either hydrogen or CCS is widely and commercially available. The longer the availability of hydrogen is delayed (for example waiting for the build-up of renewable electricity generation), or the higher the cost, the slower the decarbonization process will be. The same applies to the use of natural gas in domestic heating. In Germany, the natural gas share of residential final energy consumption is 40 per cent, and this rises to 51 per cent in Italy, 54 per cent in Slovakia, 63 per cent in the UK, and 71 per cent in the Netherlands. Converting houses to electric heat pumps will be costly and disruptive; until governments solve this problem, residential consumers are already locked in to natural gas. Hydrogen may make the switch to low-carbon energy easier for such households, assuming it is available at a reasonable cost.

Conclusion

The potential for Europe to become locked in to low-carbon hydrogen instead of renewable hydrogen is low to non-existent. Government policy is easily capable of ensuring that renewable hydrogen is preferred once there is sufficient supply—by increasing the cost of carbon, subsidizing renewable hydrogen more than low-carbon hydrogen, mandating the use of renewable hydrogen, or a combination of all three. The risk associated with stranded assets for low-carbon hydrogen is not that it will preclude the use of renewable hydrogen but that it will prevent companies from investing in low-carbon hydrogen at all, which means delaying the switch from unabated fossil fuels to lower-carbon energy, prior to a final switch to renewable hydrogen once it is sufficiently available.

By contrast, enabling the development of low-carbon hydrogen today will enable the development of hydrogen infrastructure and adaptation of consumer equipment, so that it will be ready for the time when there is sufficient renewable hydrogen available. It will also immediately reduce GHG emissions, thus slowing the build-up of GHG in the atmosphere and buying more time for decarbonization. Policymakers should therefore not be distracted by ill-thought-through concerns about lock-in effects.

HOW A TRADED HYDROGEN MARKET MIGHT DEVELOP—LESSONS FROM THE NATURAL GAS INDUSTRY

Patrick Heather

The appetite for a ‘hydrogen market’ has been growing in the past year or two and is often mentioned by the European Commission (EC), member state governments, the UK government, energy regulators, European TSOs (Transmission System Operators), energy industry bodies, oil and gas companies, and even the press.

All of this keen interest raises the question of what ‘hydrogen market’ they are referring to, as there is currently no such market established. This article looks at how a future traded hydrogen market might develop, what the prerequisites would be for the development of a wholesale market, and whether there are lessons to be learned from the traded natural gas market. Although many of the arguments expressed and examples given are based on the European gas and future hydrogen markets, they are equally applicable to other countries; indeed, there are strong reasons why North America and China might follow a route towards a traded hydrogen market in time.

The article also looks at several initial projects, in particular the European Hydrogen Backbone and its associated infrastructure. These projects appear to augur well for the development of a traded market, but how realistic are they, both in construct and time frame? Lessons learned from the establishment of the natural gas market can help inform projections for a potential time frame for the development of a traded hydrogen market. Finally, the article briefly assesses three basic energy transition scenarios that might help determine whether and how quickly a traded hydrogen market might develop in Europe.

Development of the natural gas market

Before assessing the likelihood of the development of a traded hydrogen market, it is important to review how the traded natural gas market developed. Possibly the most important point to note, and in total contrast to the emerging hydrogen market, is that when the vast reserves of natural gas were discovered in the northern part of the Netherlands in the 1950s, there already existed a town (or manufactured) gas market, albeit for a nationalized industry; there already was infrastructure in place to manufacture, transport, and distribute that gas to end users; and there was a pricing mechanism, with various tariff structures and decided by government.

Industry was primarily using coal, oil, and oil products, so natural gas producers had a dilemma as to how to bring their product to market and to displace the use of town gas and other fuels. This was done by indexing the price of their natural gas to that of their industrial customers' competing fuels, through a formula that would ensure that natural gas would always be cheaper, as well as by emphasizing the clean and efficient advantages of gas. They also over time repurposed, and added to, the town-gas transportation infrastructure and converted burner tips in appliances.

This created a very stable, profitable, and successful business model; the risks were generally low, and the result was a massive expansion of European gas demand and the physical infrastructure to meet that demand.

Liberalization of the gas market and a change in price formation came later, as a consequence of the increasing market share of gas, particularly in the industrial sector, and the increasing loss of switchability (being able to change back from natural gas to another fuel). The North American gas markets were the first to transition to gas-on-gas pricing in the 1980s, followed by the British market in the mid 1990s. More recently, the continental European (especially north-west European) markets have followed a similar pattern. It has typically taken from 10 to 20 years for these markets to truly liberalize and to, in some but not all cases, become liquid traded markets. The result as of 2020 is that there are only three liquid, mature, natural gas benchmarks in the world: the American Henry Hub, the British NBP, and the Dutch TTF.[82]

In addition to the development of the physical natural gas market, five main factors led to the successful trade in natural gas, and these should be taken into account when assessing the likelihood of a potential traded hydrogen market:

- *Liquidity* is a measure of how easy it is to trade volumes at any given price, without moving the market. This is a measure of market depth and is considered essential by traders when looking for a market in which to conduct their risk management strategies. Standardization of traded contract terms and conditions tends to concentrate liquidity.
- *Volatility* is a measure of price movement in relation to market activity. Energy markets are typically very volatile but may also be very liquid. Volatility is often decried by politicians and regulators; but in fact, volatility in a *liquid* market will attract more traders and therefore will create even more liquidity.
- *Anonymity* is the cornerstone of exchange trading, where the clearing-house is the counterparty to all trades, thereby allowing small and large participants to trade with each other. This also brings more traders to that market and will help increase liquidity.
- *Market transparency* is a very important element in the development of a successful traded market; having traded volumes and prices quickly disseminated in the public domain will give traders added confidence in that market.
- *Traded volumes* simply relate to the total actual volume traded, whether over the counter or exchange traded, whether spot or forward contracts.

First steps towards a hydrogen network infrastructure

A key difference between the natural gas and hydrogen markets is network infrastructure. Unlike the gas market in the 1960s, European hydrogen infrastructure today is virtually non-existent, and there is no underlying market (except for some specialized and localized needs in the industrial and medical sectors, plus very limited transportation uses). It is difficult to contemplate a traded hydrogen market if there is no underlying physical market servicing an established supply/demand infrastructure.

That said, a raft of projects has been announced, and many are already under way. These projects hinge primarily on repurposing or building new transportation pipelines, but some are looking at converting residential natural gas use to hydrogen and at various industrial uses.

A significant pipeline infrastructure project already under way is the European Hydrogen Backbone (EHB), set up by 11 European TSOs who published their first report in July 2020. The group has since expanded to comprise 23 TSOs from 21 countries, and it published an updated report in April 2021,[83] which details their vision and includes a much more ambitious network plan with a more detailed cost analysis.

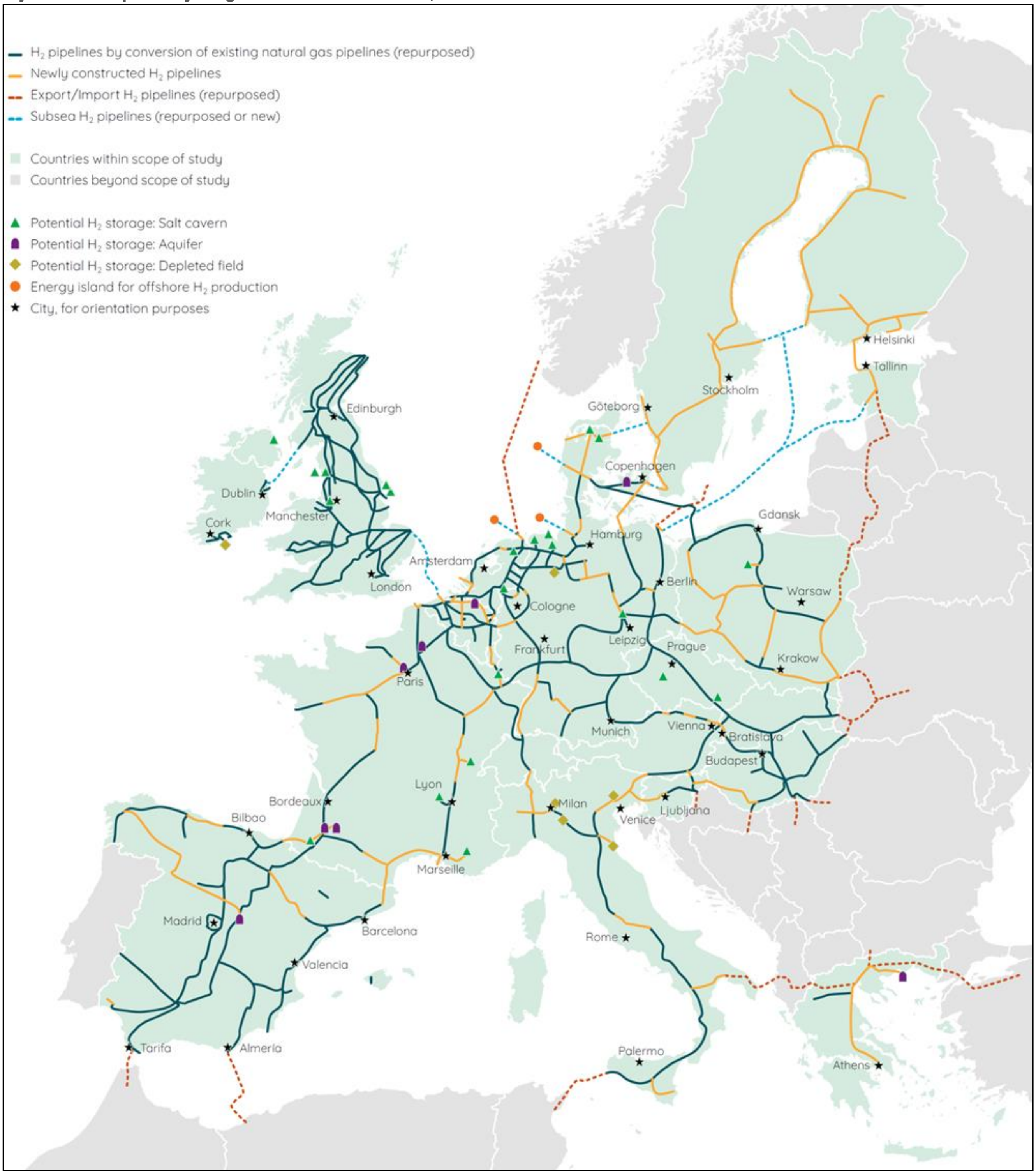
According to the report, by 2030, the EHB could consist of an initial 11,600 km pipeline network, connecting emerging hydrogen clusters. The hydrogen infrastructure could then grow to become a pan-European network, with a length of 39,700 km by 2040, made up of 69 per cent repurposed natural gas pipelines and 31 per cent new build. Further network development could be

[82] A full account of the process of change is given in Heather, P. (2015), *The Evolution of European Traded Gas Hubs*, Oxford: Oxford Institute for Energy Studies, https://www.oxfordenergy.org/publications/the-evolution-of-european-traded-gas-hubs/.

[83] *Extending the European Hydrogen Backbone: a European Hydrogen Infrastructure Vision Covering 21 Countries* (2021), Guidehouse, https://gasforclimate2050.eu/sdm_downloads/extending-the-european-hydrogen-backbone.

expected after 2040. The total investment cost of the envisaged 2040 EHB is estimated at € 43–81 billion, covering the full capital cost of building new hydrogen pipelines and repurposing natural gas pipelines. The range reflects differences in capital cost assumptions, with the greatest uncertainty stemming from compressor costs.

Projected European Hydrogen Backbone network, 2040



Source: European Hydrogen Backbone update, April 2021. https://gasforclimate2050.eu/?smd_process_download=1&download_id=669

Another significant project is H21 North of England.[84] This is a joint project between NGN (Northern Gas Networks), Cadent, and Equinor, evolved out of an initial study conducted in 2016 by NGN which had the aim of determining the technical and economic feasibility of converting the existing natural gas network in Leeds, one of the largest UK cities, to 100 per cent hydrogen.

The North of England project is a greatly expanded version of the Leeds one, also including the sequestration of CO_2, and envisages converting the natural gas networks across the north of England to hydrogen between 2028 and 2034. It plans to deliver a 125 gigawatt capacity hydrogen transmission system, delivering low-carbon heat to Newcastle, Gateshead, Teesside, York, Hull, Leeds, Bradford, Halifax, Huddersfield, Wakefield, Manchester, and Liverpool—an area containing about 17 per cent of total UK domestic meter connections.

A third project, led by Snam in Italy,[85] is focused on adapting the steelmaking process at the Dalmine plant in Bergamo, northern Italy, to use green hydrogen instead of natural gas by generating hydrogen and oxygen through a 20 megawatt electrolyser.

There are more hydrogen projects around Europe, many in the Netherlands, including several by Gasunie (the Dutch TSO),[86] and another led by the Port of Rotterdam,[87] each including a vision of a national and local hydrogen infrastructure backbone.

These and the many other local hydrogen projects do show that the gas industry in general, and the infrastructure companies in particular, are keen to participate in the transition from natural gas to hydrogen. Many of these projects have received initial financing for analysis and feasibility studies, but so far none has received financing for implementation.

Regulatory framework

One important element of analysing the prospect of a future traded hydrogen market is consideration of the political and regulatory framework that must support such a market and create the right environment to attract market participants.

The EC has been considering revising its Gas Directives and is expected to include hydrogen and other green gases in any new legislation. It published a *Combined Evaluation Roadmap/Inception Impact Assessment* in February 2021 as part of the Gas Networks—Revision of EU Rules on Market Access consultation process. The document states:

> ‘Hydrogen pipeline transportation is not properly addressed by the current regulatory framework, which risks creating non-regulated monopolies that hamper the entry of new players and competitive market outcomes. . . .
>
> The objectives of this initiative cannot be achieved on a national level. The initiative aims at modifying existing EU legislation and creating a new framework for an internal hydrogen market, which is key to achieve a cost efficient clean hydrogen economy’.[88]

Supply and demand

From a traded market viewpoint, all these (mainly infrastructure) projects and the EC’s focus on creating an hydrogen regulatory framework can be seen to be very positive for the creation of a traded market in the future, but there remains the question of supply and demand.

The supply of hydrogen will need to be increased substantially, and there is currently a debate as to the different types of hydrogen; colour-coded, depending on their environmental credentials: grey hydrogen, made from fossil fuel; blue hydrogen, which has had the CO_2 (carbon dioxide) extracted and stored; and green hydrogen, which is made from renewable sources. From a trading point of view, the important thing is to establish an hydrogen market regardless of origin, which can be dealt with through Guarantee of Origin certificates and similar mechanisms.

[84] *H21 North of England* (2018), https://www.h21.green/wp-content/uploads/2019/01/H21-NoE-PRINT-PDF-FINAL-1.pdf.
[85] Snam (2021, 11 January), Tenaris, Edison and Snam join together in a project to trial steelmaking with green hydrogen in the Dalmine mill in Italy, https://www.snam.it/en/Media/Press-releases/2021/Tenaris_Edison_Snam_trial_steelmaking_green_hydrogen_Dalmine_Italy.html.
[86] Gasunie (2021), *Hydrogen*, https://www.gasunie.nl/en/expertise/hydrogen.
[87] Port of Rotterdam (n.d.), *Hydrogen in Rotterdam*, https://www.portofrotterdam.com/en/doing-business/port-of-the-future/energy-transition/hydrogen-in-rotterdam.
[88] European Commission, Gas networks—revision of EU rules on market access, page 3, https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12911-Revision-of-EU-rules-on-Gas.

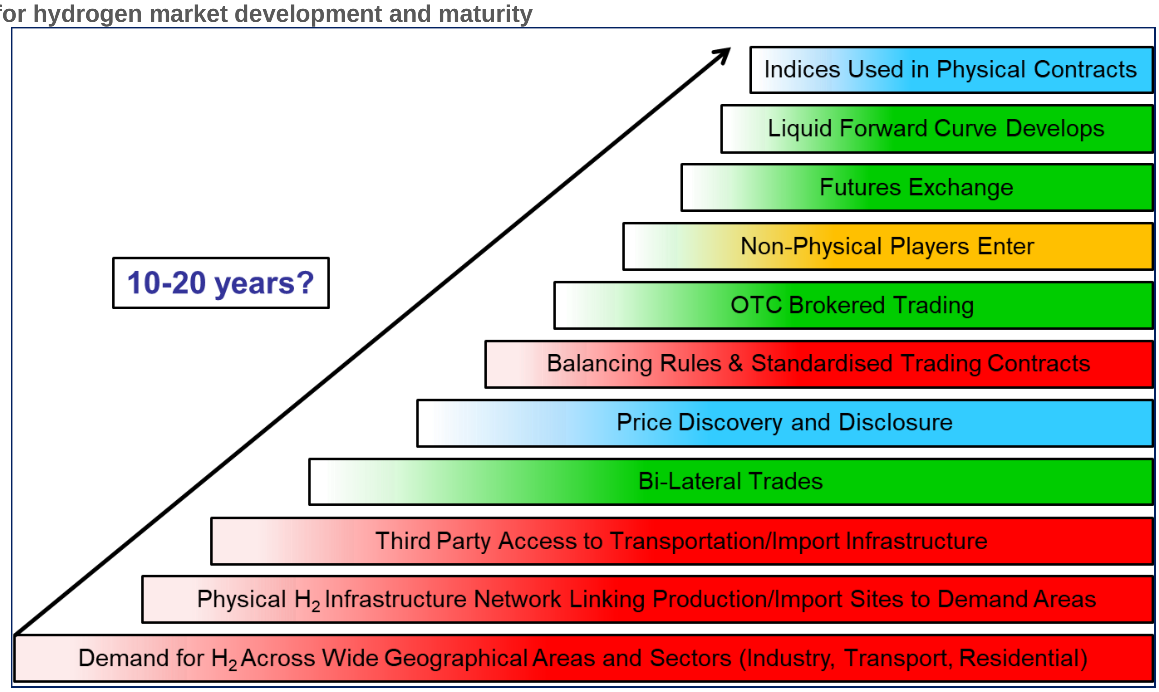
The demand for hydrogen needs to increase substantially for there to be any chance of a traded market being established. Industrial use may be able to expand quickly if it is given access to hydrogen at a competitive cost; and use in transportation, in both road vehicles and trains, is already developing, albeit slowly. The main stumbling block on the demand side appears to be the residential sector, although several projects, including the UK's H21 project mentioned above, are assessing the viability. What might still need to be achieved is the reassurance of the general public that the use of hydrogen is safe.

The overall demand for hydrogen, and its speed of introduction as a day-to-day source of energy, will largely depend on various energy transition scenarios.

- It is possible to envisage a 'failed transition', —especially after the Covid-19 pandemic, its huge cost to all economies, and the perceived poor management by the EU and national governments. Would Member States and other governments agree to and follow a financially and possibly socially difficult environmental path? In this scenario it would be hard to envisage the building of costly infrastructure for hydrogen and the development of a market.
- It is quite likely that there will be some form of 'slow/business-as-usual' transition, with further political promises of future environmental targets but without the real political push and financial support necessary to reach even the 2030 targets. In this scenario there will be development of further local hydrogen clusters and small networks linking supply sources to demand, but little progress on national or international transmission infrastructure.
- A 'fast transition' could also occur, especially after the United Nations Climate Change Conference (COP26) in November 2021, with a renewed political push towards meeting both the 2030 and 2050 targets. In this scenario, legislation and financing would enable a concerted push to develop hydrogen infrastructure, which in turn would lead to a developing and growing market.

Once there is a growing physical market, how could a traded market develop? The figure below shows a Path to Maturity for hydrogen, adapted from a similar path for natural gas, with the added essential criteria of demand and physical infrastructure placed as the first steps.

Criteria for hydrogen market development and maturity



Source: Adapted from Heather, P. (2015), *The Evolution of European Traded Gas Hubs*, Oxford: Oxford Institute for Energy Studies, NG104, Figure 1.

Although the steps listed are not necessarily sequential, there does need to be a large enough demand for hydrogen before a traded market can develop; and for that to happen, there needs to be the right physical infrastructure in place to manufacture and transport it to the customers. For there to be a competitive market, there need to be many suppliers and buyers and, in order to attract them to the market, there must be third-party access to infrastructure and structured trading rules, including standardized contracts. This in turn will lead to bilateral and over-the-counter trading, which in time will encourage exchanges to offer hydrogen spot and futures contracts, and eventually there might be a European hydrogen benchmark; is a hydrogen TTF equivalent possible? Gasunie state in the EHB document:

> 'The most ambitious project Gasunie worked on in 2020 concerns the development of a national transport network for hydrogen, the 'hydrogen backbone'. […] This backbone could be in place as early as 2026. Thanks to this hydrogen infrastructure, the Netherlands and northern Germany can be the market leaders in Europe for the global hydrogen market, just as they are now for natural gas'.[89]

Conclusion

The conversion from town gas to natural gas took 10 years in Britain; it took nearly 15 years to complete the process of liberalization and a further five years for the British NBP to become a liquid, mature trading hub. Slightly longer overall time frames were experienced in other European countries.

Taking into account the apparent keenness of the infrastructure operators to find a way to repurpose their natural gas pipelines, and the stated political desire to move away from natural gas to hydrogen, it is possible that the first stage of the process could be shortened slightly. The time for development of a traded market from that point could also be shortened, as it would in part be done in parallel and could follow existing legislative and regulatory frameworks and trading rules and practices. As long as the industry and the politicians focus on the end goal and don't get side-tracked by the issues of how the hydrogen was made or its purity, the overall time frame could be much shorter than that of natural gas.

There is no doubting the desire and vision of politicians and gas TSOs for a future hydrogen economy, but there is a still very long way to go before such an economy will be found, even in north-western Europe, let alone throughout all of Europe. Realistically, a traded hydrogen market is still some time off; but, depending on the speed of the energy transition, it is feasible that there will be a traded market by 2040. It may even be quite developed by then and well on the path to maturity!

THE ROLE OF HYDROGEN IN JAPAN'S ENERGY TRANSITION TOWARDS 2050 CARBON NEUTRALITY

Ken Koyama

Japan joined the global 'carbon-neutral club' in October 2020. That year may turn out to be a significant year for the development of world climate-change policy: one after another, major countries and regions with substantial greenhouse gas (GHG) emissions—such as the EU, China, Japan, Korea, and the US—announced targets of net zero GHG emissions (carbon neutrality) around the middle of this century. Japan's carbon-neutral target for 2050 was declared by Prime Minster Suga at a Diet session on 26 October 2020. The declaration is regarded as a milestone change in Japan's climate change and energy policy.

In the second half of 2019, the Japanese government started discussions in its advisory committee to revise the Strategic Energy Plan (SEP), which is Japan's most fundamental and comprehensive energy policy document. The existing SEP had been approved by the Cabinet in July 2018. As the SEP is revised about every three years, it is now expected that the next revision will be completed sometime this year. In this context, the declaration of the carbon-neutrality target for 2050 has a significant impact on the discussion about revising the SEP as well as to determine the targeted 'energy mix' between now and 2050. Clearly, CO_2-free energy options and technologies will be required to achieve carbon neutrality, as Japan (like the rest of the world) is still highly dependent on fossil fuels for its energy supply. Under the circumstances, CO_2-free hydrogen is increasingly regarded as a critically important option for Japan in working towards carbon neutrality.

Discussion on the revision of SEP and the role of hydrogen

Japan now needs to fully commit to implementing the following basic approach for achieving carbon neutrality:

[89] *Extending the European Hydrogen Backbone: a European Hydrogen Infrastructure Vision Covering 21 Countries* (2021), Guidehouse, page 29, https://gasforclimate2050.eu/sdm_downloads/extending-the-european-hydrogen-backbone/.

- Minimize energy consumption by promoting energy efficiency improvement/energy saving and maximize the use of non-fossil energy such as renewable energy and nuclear power.
- Maximize the degree of electrification (share of electricity consumption in total final energy consumption) and achieve zero emissions in the electricity sector.

In addition to the above basic approach, which can rely on the use or adaptation of existing technologies, Japan (and every country which pursues carbon neutrality) must depend on the contribution of innovative technologies such as CO_2-free hydrogen and direct air capture. In other words, it would be very difficult for any country to map a carbon-neutral future without substantial reliance on innovative energy technologies.

The current energy/power mix target was decided by the Ministry of Economy, Trade and Industry (METI) in July 2015 and reconfirmed in the existing SEP in July 2018, in which Japan aims to reduce its GHG emissions by 26 per cent in 2030 from the level in 2013. To achieve this emission reduction, Japan's power mix target for 2030 aims for renewable energy at 22–24 per cent, nuclear power at 20–22 per cent, LNG at 27 per cent, and coal at 26 per cent. There is no target for the share of hydrogen or any other innovative technologies for 2030. But now a serious discussion is being conducted in the advisory committee to determine the power mix and primary energy mix for 2050 which is compatible with carbon-neutral status.

For this purpose, METI officials submitted a preliminary 'idea' on power mix in 2050 to the advisory committee as a reference for the discussion. The idea relates to a zero-emission power mix which is composed of renewable energy at about 50–60 per cent, nuclear power and fossil fuel power generation with carbon capture and storage (CCS) at about 30–40 per cent, and CO_2-free hydrogen and ammonia at about 10 per cent. Thus, the dominant zero-emission power generation sources in this preliminary idea are renewable energy, nuclear power, and fossil fuel power generation with CCS. But CO_2-free hydrogen and ammonia are given a numerical targeted position in Japan's energy mix for the first time in Japan's energy policy history. Of course this remains just as a preliminary 'idea', subject to further discussion in the advisory committee.

In addition to large-scale utilization in the power sector, CO_2-free hydrogen and ammonia are expected to play a significant role in other sectors, such as transportation, industry, and household use, to contribute to achieving carbon-neutral status as an alternative to the traditional use of fossil fuels in these sectors. Examples of these initiatives include promotion of fuel cells in heavy-duty trucks and ammonia/hydrogen use in shipping. While battery electric vehicles are increasingly popular in Japan (and worldwide), Japan continues its serious efforts to promote fuel cell vehicles alongside its new emphasis on promoting battery electric vehicles.

Challenges for large-scale use of clean hydrogen and ammonia

The ongoing discussion in the advisory committee is expected to come up with some conclusions about the 2050 (and revised 2030) power mix and energy mix, in which a certain share of CO_2-free hydrogen will be officially included as a policy target. In this regard, CO_2-free hydrogen and ammonia are important innovative technologies and attract increasing attention in Japan's energy policy and industry circles. Expectations of a greater role for CO_2-free hydrogen and ammonia are getting higher and higher. But just as is the case for other innovative technologies expected to make great contribution to achieving carbon neutrality, CO_2-free hydrogen and ammonia have challenges and problems to be overcome if they are to be major energy supply options for Japan.

First and foremost is their economic feasibility. Very significant cost reduction is essential for CO_2-free hydrogen/ammonia to penetrate the energy market in Japan or anywhere else in the world. According to METI's hydrogen basic strategy, released in 2017, CO_2-free blue hydrogen supply costs should be reduced from the current 170 Japanese yen (JPY) per normal cubic metre (Nm^3) to about JPY 30/Nm^3 in 2030 and JPY 20/Nm^3 in 2050. The current cost of JPY 170/Nm^3 includes very high shipping/transportation costs for liquefied blue hydrogen and other costs, for which technology development and economy of scale are expected to contribute to substantial cost reduction in the future. The cost reduction target is based on the concept of parity with existing LNG-fired power generation cost, where the 2050 target of JPY 20/Nm^3 corresponds to JPY 12/kWh for power generation cost for hydrogen.

The hydrogen basic strategy highlighted that technology research, development, and diffusion should be further promoted as a means for cost reduction, while significant scale-up of supply capacity for CO_2-free hydrogen production is expected to provide important economies of scale. The strategy also calls for 5–10 million tons of hydrogen to be supplied to the power generation sector in 2050 so that economy-of-scale effects and other technology advancement factors can work well to realize the cost reduction target.

As the 2017 hydrogen basic strategy was made well before the carbon-neutrality target was announced in 2020, both the cost reduction and supply volume targets for CO_2-free hydrogen in 2050 are likely to be revised when the ongoing discussion on the SEP is concluded with a new power and primary energy mix target for 2050. It is possible that the supply volume target for CO_2-free hydrogen will be revised upward. At the same time, different discussions are being held at METI and other related ministries to examine the issues related to the value of carbon or carbon pricing so that the value of CO_2-free characteristics of clean hydrogen/ammonia can be appropriately reflected in the economic evaluation in the energy marketplace in Japan.

In relation to the issue of economic feasibility, infrastructure development for CO_2-free hydrogen/ammonia is also regarded as a key challenge. CO_2-free hydrogen tends to require brand-new infrastructure across its supply chain from upstream (production) to midstream (transportation) and downstream (utilization and consumption). One example is the ultra-low-temperature liquefaction facility needed to transport hydrogen by ship. The specialized infrastructure needed for hydrogen substantially increases supply cost and creates a classical ‘chicken and egg’ problem regarding cost reduction and market development for hydrogen.

The next challenge is related to the hydrogen production methodology and supply chain. Globally, green hydrogen, produced by electrolysis using renewable power generation, often costs more on average than blue hydrogen, produced from fossil fuels with the use of CCS. This is true despite the rapidly declining cost globally of power generation using renewable energy.

In Japan, the cost of renewable power generation is much higher than in many other countries, which further reduces the economic feasibility of green hydrogen. Key reasons for this include less favourable climate conditions in terms of sunshine and wind, the need for greater protection from earthquakes and other local environmental hazards, and the higher cost of construction due to Japan’s complicated supply chain. However, the cost of renewable power generation has been declining in Japan. For example, the feed-in tariff rate for solar photovoltaic (below 10kW capacity) in Japan declined from JPY 42/kWh in FY 2012 to JPY 19/kWh (about 17 US¢/kWh) in FY2021.

The high cost of renewable energy in Japan is an important reason why Japanese government and industry are keen to develop an international supply chain for blue hydrogen as a potentially more promising and economically competitive source of CO_2-free energy than green hydrogen. Of course Japanese stakeholders welcome all CO_2-free hydrogen options. Any colour of hydrogen—green, blue, yellow, or other—is acceptable if it contributes to carbon reduction. In terms of economic feasibility, blue hydrogen seems to be a step ahead of other hydrogen options given Japan’s energy market conditions.

Importance of an international supply chain of blue hydrogen/ammonia

Government and industry have made serious efforts to develop international blue hydrogen supply chains with major resource-rich countries, including Saudi Arabia, the United Arab Emirates, Brunei, Malaysia, Australia, and Russia. Japan recognizes the importance of mutually beneficial cooperation with resource-rich countries: Japan needs stable and affordable CO_2-free energy supplies, while resource-rich countries can continue to best utilize their abundant fossil fuel resources in a decarbonized world and avoid their resources becoming stranded assets.

In this regard, a unique and important initiative was made between Japan and Saudi Arabia to establish an international supply chain of blue ammonia. In September 2020, the Japanese and Saudi partners issued a joint press release on the world’s first shipment of blue ammonia from Saudi Arabia to Japan. The initiative was conducted with the common understanding between the two countries that the supply cost of blue ammonia can be much lower than that of blue hydrogen, as blue ammonia can best utilize the existing supply chain (both facilities and technology). While blue hydrogen may be the ultimate clean supply option, blue ammonia can be an important and feasible initial step that opens the way for clean use of decarbonized fossil fuels as a whole.

The blue ammonia initiative has just recorded its first success in terms of production, shipping, and utilization (co-firing with natural gas- and coal-fired power generation and ammonia-only firing power generation as pilot projects). It is necessary to further promote cost reduction in blue ammonia use for Japan and the world. As such, other innovative options, including blue and other CO_2-free forms of hydrogen, will require much stronger effort to reduce costs and develop the necessary infrastructure to overcome the ‘chicken and egg’ problem if they are to make a real contribution in Japan to achieving carbon neutrality by 2050.

Conclusion

Japan, as a major country with the Prime Minister's declaration to achieving carbon-neutral status by 2050, needs to accelerate its energy transition in order to achieve its energy and climate-change policy goals. To this end, METI and its advisory committee are in the process of revising Japan's Strategic Energy Plan. The Plan's energy mix target will indicate a certain share of CO_2-free hydrogen/ammonia for the first time in Japan's energy policy history. At this moment, it is hard to predict the share of hydrogen/ammonia in the targeted energy mix. But it is also clear that expectations are rising for an increasingly important role for CO_2-free hydrogen/ammonia. Government and industry are working hard to promote the use of clean-energy options, but there are many challenges, including issues related to economic feasibility, to establishing a 'hydrogen society' to contribute to achieving carbon neutrality. Success in overcoming these challenges will be a key to realizing Japan's declared target of carbon neutrality.

AUSTRALIA'S APPROACH TO HYDROGEN—DOMESTIC USE VS EXPORTS

David Norman and Peter Grubnic

Global hydrogen strategies, should they reach fruition, suggest a large market for internationally traded hydrogen emerging within the next decade. Fifteen countries that have released national hydrogen-specific vision, strategy, or road-map documents account for around 30 per cent of global GDP.[90] A strong domestic hydrogen industry will be an important early contributor underpinning Australia's export capabilities, enabling Australia to become a leading player in the global hydrogen energy market.

Australia is well placed with abundant renewable resources, open space, and advantageous geographic proximity to key Asian markets. As a large exporter of mineral and energy commodities, Australia has a long and credible track record as a supplier, as well as technical, commercial, and contractual experience in supplying global markets.[91]

Various reports have explored global hydrogen market potential, with several suggesting that global demand by 2050 could be multiples of today's demand of approximately 70 million tonnes per annum (Mtpa). In a demand study prepared in support of the development of Australia's National Hydrogen Strategy, four representative scenarios were examined, with the 'Hydrogen: targeted deployment' and 'Hydrogen: energy of the future' scenarios indicating global hydrogen demand of around 170 and 300 Mtpa, respectively, by 2050.[92]

Under these scenarios, taken in concert with published global hydrogen strategies, there is considerable potential for increased demand for Australian-produced hydrogen.

Australia's positioning

Australia has many of the prerequisites needed to support a large hydrogen production industry, with potential comparative advantages in both key production pathways for clean hydrogen.

Hydrogen production through renewable energy is dependent on a range of factors, including sufficient wind, solar, or hydro resources, water, and necessary distribution infrastructure, such as ports, roads, and pipelines. It is estimated that more than 250,000 square kilometres of Australia has high potential for the production of renewables-based hydrogen.[93]

In some markets, the use of low-emissions hydrogen from coal and natural gas in association with carbon capture and storage (CCS) technologies is viewed as part of a portfolio of measures to meet decarbonization goals.[94] In Australia, in the near term, the best opportunities for establishing CCS sites to support decarbonization goals in potential markets include (but are not limited to) areas offshore Victoria and offshore Western Australia.[95]

[90] Commonwealth Scientific and Industrial Research Organisation (2021), 'International hydrogen policies—key features', *HyResource*, https://research.csiro.au/hyresource/international-hydrogen-policies-key-features/.
[91] Office of the Chief Economist, Department of Industry, Science, Energy and Resources (2021, March), Resources and Energy Quarterly, Government of Australia, https://publications.industry.gov.au/publications/resourcesandenergyquarterlymarch2021/index.html.
[92] Deloitte (2019), Australian and Global Hydrogen Demand Growth Scenario Analysis, report prepared for the Council of Australian Governments Energy Council, National Hydrogen Strategy Taskforce, https://www2.deloitte.com/content/dam/Deloitte/au/Documents/future-of-cities/deloitte-au-australian-global-hydrogen-demand-growth-scenario-analysis-091219.pdf.
[93] Feitz, A.J., Tenthorey, E., and Coghlan, R. (2019), Prospective *Hydrogen Production Regions* of Australia, Record 2019/15, Geoscience Australia, https://ecat.ga.gov.au/geonetwork/srv/eng/catalog.search#/metadata/130930.
[94] See, for example, Government of Japan (2017), Basic Hydrogen Strategy, https://www.meti.go.jp/english/press/2017/pdf/1226_003b.pdf.
[95] Feitz, A.J., Tenthorey, E., and Coghlan, R. (2019), *Prospective Hydrogen Production Regions of Australia,* Record 2019/15, Geoscience Australia, https://ecat.ga.gov.au/geonetwork/srv/eng/catalog.search#/metadata/130930.

Not only does Australia have access to considerable environmental and natural resources and infrastructure to support a clean hydrogen industry, it is well positioned to supply large potential demand sources in the Asian region, which presently accounts for a significant proportion of the world's population and around 40 per cent of world energy consumption.[96] This positioning advantage is complemented by the trading relationships and supply chain management expertise built up by Australian energy exporters (with large energy-importing countries) in the region over the past half-century. Asian markets presently account for over 60 per cent of Australia's annual total energy exports.[97]

While emphasis of potential exports is on Asia, wider global export opportunities are being explored. A key example includes a feasibility study jointly funded by the Australian and German governments to investigate a supply chain involving the production, storage, transport, and use of hydrogen (including hydrogen-based energy carriers, such as ammonia) produced from renewables.[98]

Policy development with large-scale exports as 'the prize'

Policy momentum in support of hydrogen industry development is considerable in Australia.

Australia was one of the first countries to release a national hydrogen strategy, in November 2019.[99] Nearly all Australian states and territories have published hydrogen-specific strategies or road-maps; in New South Wales, Australia's most populous state, an overarching policy framework to support development of the hydrogen industry is currently under preparation, and hydrogen-specific announcements have been included in wider climate change mitigation programs.

In September 2020, Australia's first Low Emissions Technology Statement was released.[100] The Roadmap identifies economic stretch goals for five priority low-emissions technologies—clean hydrogen (hydrogen production under AUD 2 per kilogram), energy storage, low-carbon materials (steel and aluminium), CCS, and soil carbon.

Key Australian policy documents that directly focus on hydrogen industry development or can influence the uptake of hydrogen technologies are shown in the table below.

Australian policies affecting the hydrogen industry

Jurisdiction	Key documents	Release date
Commonwealth of Australia	Australia's National Hydrogen Strategy	November 2019
Australian Capital Territory	ACT Climate Change Strategy 2019–25	September 2019
New South Wales	Net Zero Plan Stage 1: 2020–2030	March 2020
Northern Territory	Northern Territory Renewable Hydrogen Strategy	July 2020
Queensland	Queensland Hydrogen Industry Strategy 2019–2024	May 2019
South Australia	South Australia's Hydrogen Action Plan	September 2019
Tasmania	Tasmanian Renewable Hydrogen Action Plan	March 2020
Victoria	Victorian Renewable Hydrogen Industry Development Plan	March 2021
Western Australia	Western Australian Renewable Hydrogen Strategy	July 2019

Source: Commonwealth Scientific and Industrial Research Organisation (n.d.), *HyResource*, https://research.csiro.au/hyresource/. This website also contains summaries of each key document and relevant funding initiatives.

[96] Enerdata, *Global Energy Statistical Yearbook 2020*, https://yearbook.enerdata.net/total-energy/world-consumption-statistics.html.
[97] Office of the Chief Economist, Department of Industry, Science, Energy and Resources (2021, March), *Resources and Energy Quarterly*, Government of Australia, https://publications.industry.gov.au/publications/resourcesandenergyquarterlymarch2021/index.html.
[98] See Matich, B. (2020, 20 November), UNSW to lead Australian-German green hydrogen trade feasibility consortium, *pv magazine Australia*, https://www.pv-magazine-australia.com/2020/11/20/unsw-to-lead-australian-german-green-hydrogen-trade-feasibility-consortium/.
[99] Council of Australian Governments Energy Council (2019), Australia's National Hydrogen Strategy, Commonwealth of Australia, https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf.
[100] Australian Government, Department of Industry, Science, Energy and Resources (2020), Technology Investment Roadmap: First Low Emissions Technology Statement 2020, https://www.industry.gov.au/data-and-publications/technology-investment-roadmap-first-low-emissions-technology-statement-2020.

Renewables-based hydrogen production is the main focus of the various plans. The Hydrogen Energy Supply Chain Pilot Project in Victoria[101] is a key component in the world's first intercontinental shipping of liquid hydrogen, such shipments to occur between Japan and Australia in 2021. The project is also an important step in evaluating the longer-term potential for development of an international fossil-fuel-based hydrogen export supply chain (employing CCS technologies).

All these plans, aside from that published by the landlocked Australian Capital Territory, contain targets, ambitions, or statements that look to large-scale export potential, usually by around 2030, as the 'prize' of Australian hydrogen industry development.

Specific examples of such goals or measures of success include the following:

- Australia's National Hydrogen Strategy: 2030 measures of success for being a major global player include that Australia is among the top three exporters of hydrogen to Asian markets.
- Western Australian Renewable Hydrogen Strategy: goals by 2030 (originally 2040, reset to 2030 on 17 August 2020 as per ministerial announcement) include that Western Australia's market share in global hydrogen exports is similar to its share in LNG at the time the strategy was released.
- Tasmanian Renewable Hydrogen Action Plan: establishes a goal for 2030 that Tasmania is a significant global producer and exporter of renewable hydrogen.

Hydrogen hubs—a key element in the strategic approach

The translation of potential export demand into actual export activity depends in large part on global cost competitiveness. A consistent theme in descriptions of hydrogen industry development in Australia is the creation of 'hydrogen hubs' – clusters of large-scale industrial activity.

The introduction of hydrogen hubs can reduce the cost of low-carbon hydrogen pathways through several mechanisms, including:

- promotion of synergies through sector coupling
- enabling economies of scale to be reached quickly as co-location of hydrogen production facilities allows efficiencies through utilization of existing infrastructure and skills
- fostering of innovation, for example by attracting hydrogen-based industry and academic institutions.

Several potential hydrogen hubs have been identified in various state plans and through a review of projects on the HyResource site.[102] Many of these potential hubs are located near existing resource-based industries with access to deep-water port facilities, including the following:

- In New South Wales, opportunities for hydrogen hubs in the Illawarra and Hunter regions are being explored, with the latter centred around Port Kembla.
- In South Australia, three hydrogen hub possibilities have been identified at Port Bonython, Port Adelaide, and Cape Hardy/Port Spencer.
- In Queensland, several large-scale export-oriented projects are clustering close to the port city of Gladstone.
- In Victoria, potential export activity is centred around the port of Hastings and the Port of Portland.
- In Western Australia, large-scale export-oriented projects are focused around the Pilbara region (home to many large mining, energy and Industrial operations) in the north-west of the state.
- In Tasmania, the Bell Bay Advanced Manufacturing Zone in particular is seen as an ideal site for large-scale renewable hydrogen industry development.

[101] Commonwealth Scientific and Industrial Research Organisation (2020), 'Hydrogen energy supply chain—pilot project, *HyResource*, https://research.csiro.au/hyresource/hydrogen-energy-supply-chain-pilot-project.
[102] See Commonwealth Scientific and Industrial Research Organisation (n.d.), 'Projects: Industry', *HyResource*, https://research.csiro.au/hyresource/projects/facilities/

Around one-third of the 60 Australian hydrogen projects listed in HyResource (as at 7 April 2021) were classified as having an end-use based on export demand or included export potential along with (often initial) domestic uses in their scale-up profiles.

The export-oriented projects tend to emphasize production of renewables-based hydrogen and ammonia, the latter as both a product and an energy carrier. Other projects are specifically evaluating liquid hydrogen production and export. All projects target Asian markets. Several export-oriented projects are adopting a phased approach to development, with export potential facilitated by initial (or concurrent) domestic supply.

Many export-oriented projects are at the earlier stages of development planning and limited information is publicly available (while feasibility studies are underway). It is very difficult to identify specific hydrogen production capacity devoted to export demand, and any estimate would carry a large ‘use with caution’ caveat; for the purposes of this paper, any such estimate is used primarily to compare *magnitude* of export potential vs domestic use projections.

Based on the HyResource Australian hydrogen project pipeline information, electrolyser production capacities geared to potential export demand could be estimated as being in the several GW range.

Several export-oriented projects under development have electrolyser capacities that are equal to or exceed 100 MW. Other hydrogen-related developmental projects have sought environmental approvals for wind and solar generation capacities of over 10 GW or have plans for combined generation capacities of up to 5 GW.[103]

Timelines for operations for many of these projects are under development, though few could realistically be operational (and meeting projected export demand) in the first half of this decade. Important considerations impacting the speed with which export projects can be delivered include the timing of tangible (bankable) market opportunities, availability of financing options for large-scale projects given the current emerging state of the clean hydrogen industry, full supply chain development timetables, and the existence of supporting regulatory and policy environments.

Domestic projects provide the early steps

While large-scale export potential is the prize, the various Australian strategies are consistent in that the pathway to this prize is complemented (and enhanced) by early steps to develop a range of domestic-oriented projects designed to demonstrate the use of hydrogen across a range of uses and establish a viable clean hydrogen industry.

Around 60 per cent of the 60 Australian projects listed on HyResource (as at 7 April 2021) are considered as having one or more domestic end uses. As a range marker, electrolyser capacities for these projects, where available, could be placed at around 500 MW (several projects are in concept stages and have limited information).

Among these domestically focused activities, those advancing most rapidly are projects that emphasize the injection of renewables-based hydrogen into gas distribution networks (initially at 5–10 per cent by volume, though higher rates are being investigated), the use of hydrogen for mobility (e.g. passenger vehicles, coaches/buses, and heavy transport), and the use of hydrogen technologies in developing local microgrid systems.

The New South Wales government has set an aspirational target of blending up to 10 per cent hydrogen in the gas network by 2030, while the Western Australian government has set a goal that its gas pipelines and networks contain up to 10 per cent renewable hydrogen blend by 2030. Victoria and South Australia are evaluating the possibility of partial conversion or longer-term full conversion to 100 per cent hydrogen into their gas networks.

Hydrogen in mobility applications is emphasized in global hydrogen strategies. While plans in the Asian region encompass a fuller range of mobility options (e.g. passenger vehicles, trucks, buses/commercial vehicles), those in Europe tend to be directed more to heavy transport uses. Increasingly, targets, goals, or aspirations for hydrogen mobility applications are being put in place in key overseas economies.[104]

[103] Commonwealth Scientific and Industrial Research Organisation (2020), ‘Asian renewable energy hub’, *HyResource*, https://research.csiro.au/hyresource/asian-renewable-energy-hub/; Commonwealth Scientific and Industrial Research Organisation (2020), ‘Murchison renewable hydrogen project’, *HyResource*, https://research.csiro.au/hyresource/murchison-renewable-hydrogen-project/.

[104] See, for example, Commonwealth Scientific and Industrial Research Organisation (2019), ‘Republic of Korea (South Korea)’, *HyResource*, https://research.csiro.au/hyresource/policy/international/republic-of-korea-south-korea/.

Of the 40 or so domestically focussed projects in Australia, 13 are operating or under construction, with a total electrolyser capacity of around 4 MW. The largest single electrolyser unit is the 1.25 MW plant at the Hydrogen Park South Australia project,[105] which (as at 7 April 2021) is in the final stages of commissioning prior to entering operations.

Another seven projects are considered to be at an advanced stage of development planning (close to a final investment decision). The Arrowsmith Hydrogen Project, Stage One, in Western Australia has a planned electrolyser capacity of 50 MW;[106] the other projects are much smaller (each less than 1 MW, where data is publicly available).

Looking beyond this first wave of projects, the next evolution of the Australian hydrogen industry will involve a scale-up of electrolyser capacities.

In April 2020, the Australian Renewable Energy Agency (ARENA) opened its (staged) AUD 70 million Renewable Hydrogen Deployment Funding Round; seven companies were shortlisted to submit full applications by January 2021, with selection of preferred projects expected by mid-2021.

The short-listed applicants all have plans to deploy 10 MW electrolysers, targeting various end uses, including mobility, injection into gas networks, renewable ammonia production, power, and industrial use. It is ARENA's intent to support two or more of the shortlisted projects.

All applicants to this ARENA round may also be considered for concessional financing from the Clean Energy Finance Corporation under its AUD 300 million Advancing Hydrogen Fund, provided they meet the Corporation's funding criteria.

The construction and operation of several electrolysers of this scale has considerable benefits in supporting wider deployment of clean hydrogen technologies in Australia:

- It would provide a much clearer picture of the real costs of producing renewables-based hydrogen at commercial scale.
- It would provide a catalogue of construction/operational lessons learnt with which to improve the performance of later projects at the same scale and for incorporating into the development of larger-scale facilities (including lessons on the efficacy of existing regulatory/permitting/skills availability for progressing projects at much larger scale).
- In combination, the above points would provide a robust indication to key stakeholders, including commercial financiers, of the opportunities and challenges associated with deployment of 10 MW or larger hydrogen projects in Australia.

This set of larger capacity projects can be expected to start becoming operational In 2023/2024.

Supporting the federal funding initiatives, all state and territory governments have announced project support and other programs to develop their local hydrogen industries.[107]

The first steps towards establishing a viable and growing domestic hydrogen industry can supply important confidence signals supporting longer-term growth. Amongst other things, it will provide real project-based information on industry production economics and scopes for improvement and on regulatory/policy opportunities or challenges that can be addressed early, and it will inform public understanding and acceptance of clean hydrogen technologies.

Domestic and international collaboration is a crucial enabler in the current phase of development. Domestically, this is occurring across industry, government, academia, and civil society; organizations such as the Commonwealth Scientific Industrial Research Organisation (CSIRO), Future Fuels Cooperative Research Centre, Australian Hydrogen Council (and other industry associations), National Energy Resources Australia (especially through its Hydrogen Clusters initiative[108]), and various government agencies are all collaborating to facilitate industry development. International collaboration and exchange is equally important to accelerate learning across borders as larger pilot and increasingly commercial scale projects, are developed.

[105] Commonwealth Scientific and Industrial Research Organisation (2020), 'Hydrogen park South Australia, *HyResource,* https://research.csiro.au/hyresource/hydrogen-park-south-australia/.
[106] Commonwealth Scientific and Industrial Research Organisation (2020), 'Arrowsmith hydrogen project—Stage 1', *HyResource*, https://research.csiro.au/hyresource/arrowsmith-hydrogen-project/.
[107] Commonwealth Scientific and Industrial Research Organisation (n.d.), 'Australia and New Zealand', *HyResource*, https://research.csiro.au/hyresource/policy/australia-and-new-zealand/.
[108] National Energy Resources Australia (n.d.), *Regional Hydrogen Technology Clusters*, https://www.nera.org.au/regional-hydrogen-technology-clusters.

These are all important steps to ensure Australia's hydrogen industry is able to scale up quickly and safely and gain maximum export advantage by 2030 and beyond.

Conclusion

The saying goes 'you have to walk before you can run'.

Global hydrogen strategies suggest a significant global trade in hydrogen as the decade progresses. Australia has access to the abundant environmental and natural resources, infrastructure, and global energy supply chain management expertise it needs to be a significant exporter of hydrogen.

The prize of long-term export potential has resulted in a hydrogen projects pipeline in Australia that includes a number of large-scale export-oriented projects—although, as would be anticipated for this stage of industry development, many of these projects are at the earlier stages of development planning.

While the prize is dangling, early steps supporting much wider deployment are being taken with domestic projects across a range of end-use applications. These projects, while smaller and less glamorous than those proposed for export, together with similar local efforts globally, will provide valuable information to investors, policymakers, and the community that can support future phases of industry development in the second half of the decade.

While emphasis of domestic use vs export leads to images of conflict or countervailing pressures, the evidence in Australia's approach to hydrogen industry development strongly suggests that the early-stage development of domestic projects complements and enhances the pathway to realizing the country's considerable potential in hydrogen exports.

SAUDI ARAMCO'S PERSPECTIVES ON HYDROGEN: OPPORTUNITIES AND CHALLENGES

Ahmad O. Al Khowaiter and Yasser M. Mufti

The Covid-19 pandemic has caused an unprecedented shock to the global economy. As the world came to a standstill, the energy sector continued to play a critical role in the global pandemic response, keeping hospitals running to provide necessary healthcare services, enabling smooth transport of food, goods, and personal protective equipment, and allowing millions of people to continue their work remotely (IEA Sustainable Recovery, 2020). Also, 2020 witnessed a renewed commitment by many countries to set their economies on a sustainable energy path. While the pace and nature of the energy transition will differ across regions, we reiterate the view expressed last year in this forum that any such transition must be inclusive, considering economic growth, energy access, and sustainability on an equal footing. To this end, the circular carbon economy (CCE)—which was endorsed by the G20 leaders under the Saudi Arabia 2020 Presidency—provides a comprehensive and practical framework to achieve the increasingly ambitious climate aspirations while ensuring wider sustainability goals are met (see Al Khowaiter and Mufti, 2020).

As the world's largest integrated energy and chemicals company, Saudi Aramco continues to invest in technologies and innovative business models to enable the sustainable use of hydrocarbon resources across the value chain. One such effort is our work on blue hydrogen, which is hydrogen produced from hydrocarbon feedstock, such as natural gas, while capturing the associated CO_2 emissions using carbon capture, utilization and storage (CCUS) technologies. In 2020, we successfully demonstrated the production and shipment of blue ammonia—an energy vector of hydrogen—from Saudi Arabia to Japan for use in zero-carbon power generation (Saudi Aramco, 2020). Blue hydrogen provides an exciting opportunity to leverage available hydrocarbon resources to provide clean, affordable, and reliable low-greenhouse gas (GHG) energy to meet the world's needs.

The potential role of hydrogen in the energy transition

While electrification can present technologically feasible and soon-to-be cost-effective means of lowering GHG emissions from parts of the energy mix, their deployment at scale in more energy-intensive sectors—such as long-haul transport, shipping, aviation, and industrial processes—is either infeasible or very costly. On the contrary, hydrogen is a versatile energy carrier with the potential to achieve significant low-emission options for hard-to-abate sectors (IEA World Energy Outlook, 2019, page 587).

Various consultants have estimated that hydrogen has the potential to address, either fully or partially, half of the annual energy-related GHG emissions, amounting to approximately 18 billion tonnes of CO_2 equivalent.

Hydrogen is already an established and growing global business, with about 70 million tonnes produced annually, corresponding to a production capacity of about 4 million barrels of oil equivalent per day. Currently, 99 per cent of this hydrogen is produced from natural gas, liquid hydrocarbons, and coal, while the remaining 1 per cent is produced from both renewable electricity and hydrocarbons coupled with CCUS (IEA The Future of Hydrogen, 2019, pages 31 and 32).

The role of hydrogen in a global sustainable energy system has gained significant traction and momentum in major economies around the world. Several nations, in recognition of the potential opportunities, are pursuing highly aspiring and dedicated hydrogen agendas as part of a suite of policies and incentives to establish a robust and commercially-viable hydrogen supply chain, in particular within the transport sector. According to the Hydrogen Council, there are over 30 countries with hydrogen roadmaps, 228 large-scale hydrogen projects announced with 85 per cent located in Europe, Asia, and Australia, and with more than $ 300 billion earmarked for spending through 2030 ("Hydrogen Insights," Hydrogen Council, 2021). This growing enthusiasm is particularly evident in China, the European Union, Japan, South Korea, and California, where government incentives are driving the private sector to develop and advance hydrogen infrastructure, technologies, and products. Also, Saudi Arabia announced the world's largest green hydrogen project in Neom. The $ 5 billion joint venture—between Neom, ACWA Power, and Air Products—will produce 650 tonnes per day of green hydrogen for export to global markets (ACWA Power, 2020). Put in energy terms, this translates into a hydrogen production capacity of about 5 million barrels of oil equivalent per year (see here).

While technology has reached a point where many hydrogen solutions are commercially viable, current barriers to widespread adoption are primarily due to a lack of infrastructure in the case of transport applications, and cost competitiveness in the case of power and industry. New efforts are undertaken globally to remove these barriers through targeted policy support and scaling up activities.

Blue hydrogen economics

Blue hydrogen refers to the production of hydrogen using hydrocarbon feedstock coupled with capture of associated CO_2 emissions using CCUS technologies. Today, the vast majority of hydrogen is produced by reforming natural gas via the steam-methane reforming (SMR) process without capturing in-process CO_2 emissions. This production route results in a hydrogen product referred to as "grey hydrogen".

The first step in the SMR process involves the high-pressure catalytic reaction of natural gas with high-temperature steam to produce hydrogen and carbon monoxide. Afterwards, carbon monoxide is further reacted with steam using the catalytic water-gas shift reaction to produce more hydrogen. Finally, impurities such as carbon dioxide and others are removed from the gas stream via separation processes, such as pressure-swing adsorption (PSA), to produce a high-purity hydrogen stream (The U.S. Department of Energy, 2020). The SMR process is a mature and well-understood technology. It provides an efficient way to extract CO_2 from the PSA tail gas for storage or utilization purposes, where retrofitting existing SMR plants with carbon capture technologies will be hugely advantageous from a cost standpoint.

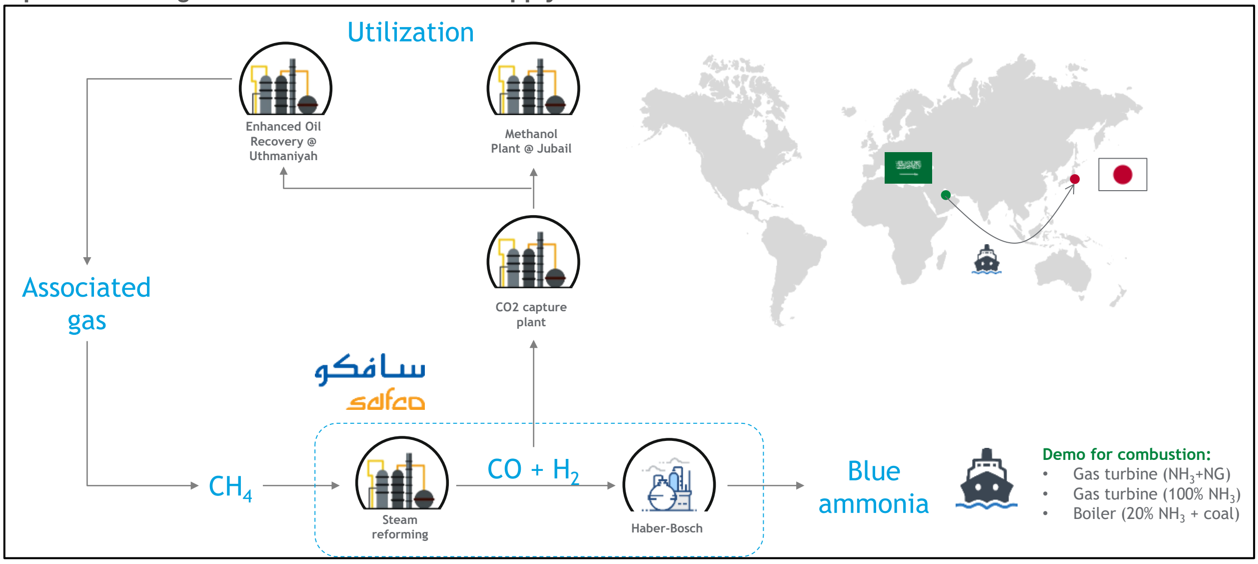
According to the International Energy Agency (IEA), there are 21 CCUS facilities in operation globally, capable of capturing and permanently storing 40 million tonnes of CO_2 emissions annually, equivalent to planting 80 million trees per year. The past few years have seen a positive rebound for CCUS, with more than 30 projects announced since 2017, set to double the existing capture capacity. These projects will cover wide sectors, such as cement, utilities, and hydrogen production (IEA Energy Technology Perspectives—Special Report on CCUS, 2020).

Other hydrogen production processes include coal and biomass gasification, and electrolysis of water into hydrogen and oxygen. If the electricity source is renewable, the resulting hydrogen product is called "green hydrogen". Amongst the low-carbon hydrogen routes (i.e., blue and green hydrogen), the Hydrogen Council estimates that the current costs of production range from $ 1.0–2.2/kg for blue hydrogen, compared with $ 3.7–6.1/kg for green hydrogen (Hydrogen Council, 2021, page 8), providing an order of magnitude cost advantage for blue hydrogen. The technology maturity, coupled with favourable economics, provide a readily available low emissions option to natural gas via blue hydrogen, with further potential cost reductions that can be achieved as CCUS deployment is scaled up.

Saudi Aramco's blue ammonia shipment to Japan

In September 2020, Saudi Aramco took a major step in pursuit of its low-GHG energy efforts by successfully demonstrating the production and shipment of 40 tonnes of high-grade blue ammonia from Saudi Arabia to Japan to be used for zero-carbon power generation. This was the result of a multiparty collaboration with the Institute of Energy Economics Japan (IEEJ) and Saudi Basic Industries Corporation (SABIC), with support from the Japanese Ministry of Economy, Trade and Industry (see here). The figure below shows a conceptual process flow diagram of the demonstration.

Conceptual flow diagram of the blue ammonia supply chain demonstration



Source: Saudi Aramco.

Not only was this demonstration a first-of-a-kind, it also spanned the full supply chain, including the conversion of natural gas to hydrogen through steam reforming and then to ammonia, as well as the capture and utilization of associated CO_2 emissions in methanol production at SABIC's Ibn-Sina methanol production facility, and enhanced oil recovery (EOR) in Saudi Aramco's 'Uthmaniyah CO_2-EOR plant. This demonstration reaffirms our view that existing and mature technology solutions (in this case, the extraction, processing, and conversion of natural gas into hydrogen and ammonia), coupled with life-cycle-based analysis, can provide cost-effective and scalable routes to low-GHG energy solutions.

Saudi Aramco prospects in the hydrogen economy

- **Upstream excellence**

  Saudi Aramco is the lowest-cost producer of crude oil and natural gas. This feedstock advantage is combined with our best-in-class reservoir management practices and subsurface operations, which are key sources of our cost leadership and industry-leading carbon intensity performance at 10.5 kg of CO_2 per barrel of oil equivalent (see here). Coupling Saudi Aramco's clean and cost-competitive upstream assets with hydrogen production routes will compound the climate gains and ensure the most sustainable pathway to providing blue hydrogen to the market.

  In addition, Saudi Aramco has gained significant know-how in the area of CCUS, especially since the 'Uthmaniyah CO_2-EOR plant came on stream in 2015. The plant is currently one of the largest in the world, capable of capturing and sequestering 800,000 tonnes of CO_2 per year. The stored CO_2 is used for EOR processes, as well as permanent storage in saline aquifers. It provided Saudi Aramco with hands-on experience in testing and optimizing various innovative CO_2 monitoring and surveillance techniques, in addition to mapping and measurement of injected CO_2 (Al-Meshari, Muhaish and Aleidan, 2014). The knowledge gained from this project—coupled with our advantageous geological formations and scale of operations—puts Saudi Aramco at an advantage to execute large-scale, integrated CCUS projects that will be essential for a blue hydrogen market at scale.

- **Integrated and complementary infrastructure at scale**

  In 2020, Saudi Aramco completed its share acquisition of a 70 per cent stake in SABIC from the Public Investment Fund (PIF), the sovereign wealth fund of Saudi Arabia. This acquisition combines strengths and interests of two global companies, to accelerate Saudi Aramco's downstream strategy and position the company for low-GHG energy opportunities. Specifically, significant synergies and infrastructure complementarity arising from the acquisition, as evident by the blue ammonia demonstration, will enable Saudi Aramco to establish a competitive hydrogen business at scale.

Today, Saudi Arabia is the third largest ammonia exporter through SABIC, capturing 1.6 million tonnes of the global ammonia trade (IHS Markit, 2020). The acquisition will provide Saudi Aramco with access to ammonia production know-how, and ammonia production/export capacity that is amongst the largest globally. In addition, SABIC has been operating a 500,000 tonnes of CO_2 per year carbon capture and utilization (CCU) plant at its affiliate "United", using proprietary technology to capture CO_2 for utilization in a range of industrial processes (see here). SABIC's experience with CO_2 utilization will complement Saudi Aramco's existing CCUS capabilities, opening up the spectrum of CO_2 use beyond storage and EOR.

The aspects above highlight Saudi Aramco's unique opportunity to utilize its oil and gas assets and infrastructure, SABIC's leading chemicals position and asset base, and the combined expertise in large-scale CCUS operations to establish a competitive presence in any emerging hydrogen market. They also set forth an example of the required integrated approach to make this happen.

The role of well-informed policies and conducive market environment

The proof of concept for the hydrogen supply chain is a critical step to unlock the potential of hydrogen. While technology has reached a point where many hydrogen solutions are technically viable, current barriers for widespread adoption are primarily due to a lack of infrastructure and cost competitiveness with alternatives. New efforts must be undertaken globally to remove these barriers through targeted policy support and scaling-up activities. To this end, we believe the following need to be considered:

- **Enact inclusive global policies.**
  The IEA forecasts that the share of oil and gas in primary energy demand will continue to be significant for decades to come. Under the Sustainable Development Scenario (SDS), which is aligned with the Paris Agreement, as well as wider sustainable development goals, oil and gas are forecasted to constitute approximately a 47 per cent share of global primary energy demand by 2040 (IEA World Energy Outlook, 2019, page 38). With this in mind, the world will need its policymakers to adopt an all-fuels, all-technologies lifecycle-based approach to their choices and implementation of policies. This will maximize the emissions reduction potential, ensure efforts are focused on emissions rather than fuel source, and minimize the social and economic costs of any form of energy transition.

- **Develop market mechanisms to de-risk investments.**
  Setting up low-carbon hydrogen production capacity at a commercial scale, whether blue or green, will entail large capital investments into long-life assets and infrastructure. Developers, investors, and project financiers will require predictable cash flow streams to finance hydrogen projects. At this early stage of market development, this can be achieved through long-term offtake contracts that establish acceptable terms to both sellers and buyers, similar to the early development of the LNG industry. Other mechanisms, such as Contracts for Differences (CfD), might be useful for hydrogen developments geared for domestic consumption. As the blue ammonia shipment demonstrated, the role of multinational alliances and public–private partnerships will be instrumental in the early stages of market development.

  Although hydrogen is not a new product or technology, the emerging business cases will be different from traditional off-takers. This provides room for involved parties to be more innovative in setting up creative market mechanisms to accelerate and de-risk developments.

- **Unify global standards for the hydrogen supply chain.**
  Market mechanisms also need to go hand-in-hand with clear global standards around mapping the lifecycle GHG emissions of each supply chain. Such a certification system can be organized through one of the worldwide standardization bodies and kept in the public domain, allowing for full transparency around the hydrogen entering each market. Creating such a vehicle early on in the process will further underscore the fundamental point of a transparent playing field, as players position themselves in the hydrogen market.

- **Enable CCUS at scale.**

  It is widely accepted that CCUS technologies will play a central role in achieving a low-emissions future. Specifically, CCUS is an integral piece in the blue hydrogen supply chain. This importance has not translated into a solid global action plan, where the past decade has seen a stagnation of investments and policy support for CCUS.

  The IEA estimates that meeting the SDS will require global CCUS capacity to grow to 5.6 billion tonnes per year by 2050, from 40 million tonnes per year today. This corresponds to annual capacity additions of almost 180 million tonnes per year up to 2050, further underscoring the scale of CCUS investments needed for meaningful climate action (IEA Energy Technology Perspectives – special report on CCUS, 2020, page 48). The gap between what is needed and the current momentum can be bridged when emphasis on policy support is prioritized, and only then can scaling up the hydrogen market be a more realistic prospect.

  The Global CCS Institute reported that 12 of the new project additions in 2020 came from the US, largely due to the 45Q tax credits, which address project revenue risk. To date, 45Q provides practical principles for a comprehensive CCUS policy incentive scheme that is fit for certain purposes and under certain jurisdictions. In addition, to unlock more investments, the interdependency of the CCUS value chain will need to be addressed. Governments can address this by providing capital support targeted at establishing a shared transportation and storage infrastructure, paving the way to developing hubs and clusters to lower costs through economies of scale and high infrastructure utilization rates. The adoption of similar or other mechanisms worldwide will be needed to accelerate CCUS deployment and the scale-up of other industries (The Global CCS Institute, 2020).

- **Foster an inclusive approach in formulating related policies.**

  The past few years have witnessed increasing investor appetite for sustainable energy technologies and solutions. Capital flows in sustainable funds (sometimes called environmental, social, and governance or ESG funds) continue to enjoy record-breaking numbers. Increasing investor demand has resulted in net flows of around $ 50 billion in 2020 in the US market, almost 10 times the 2018 numbers, and constituting 24 per cent of overall 2020 flows into US equities and bond funds (Morningstar, 2021). While this is a positive development, it is critical to bear in mind that truly sustainable solutions will emerge from the emissions-reduction potential of different energy sources, which must be factored into policymaking and investment decisions. The transition is a complicated process and will require a suite of technologies and energy sources.

Conclusion

In the future, for oil and gas companies to thrive, adopting new business models and continuous investments in technology will be necessary. In its history, the oil and gas industry has displayed, time and again, a strong ability to adapt to technological changes and continue to power the global economy. With this in mind, Saudi Aramco continues to invest for the future, leading an expansive research and development portfolio that focuses on breakthrough technologies, such as low-carbon fuels, clean transport systems, stationary and mobile carbon management solutions, and non-fuel uses of hydrocarbons. Our experience with the blue ammonia demonstration has taught us that combining lifecycle analysis with available and mature technologies can result in energy solutions with solid, measurable, and verifiable emission reductions. Blue hydrogen presents the world with a unique opportunity to establish a low-carbon hydrogen market at scale, paving the way to viably reducing GHG emissions from hard-to-abate sectors.

HYDROGEN IN THE UNITED ARAB EMIRATES

Robin Mills

The United Arab Emirates (UAE) has in recent months jumped boldly on hydrogen. The light molecule fits its new energy ambitions: low-carbon, innovative, and building on the country's plans for renewables and gas. The key issue is whether it can become a cost-competitive producer.

Dubai was arguably earlier to the party, but Abu Dhabi, the main oil-producing emirate, has been the main force behind the hydrogen push. Dubai has set a string of records for low-cost solar power. In February 2019, it carried out a pilot for solar-driven electrolytic production of hydrogen to power transport at the Expo 2020 site, in partnership with Siemens, and the Emirates National Oil Company will offer a futuristic service station with hydrogen provision at the event. The Roads and Transport

Authority included testing the hydrogen-powered Toyota Mirai and is looking into hydrogen-fuelled buses from Hyundai. But for now, it appears Dubai's clean transport plans focus mostly on electric vehicles.

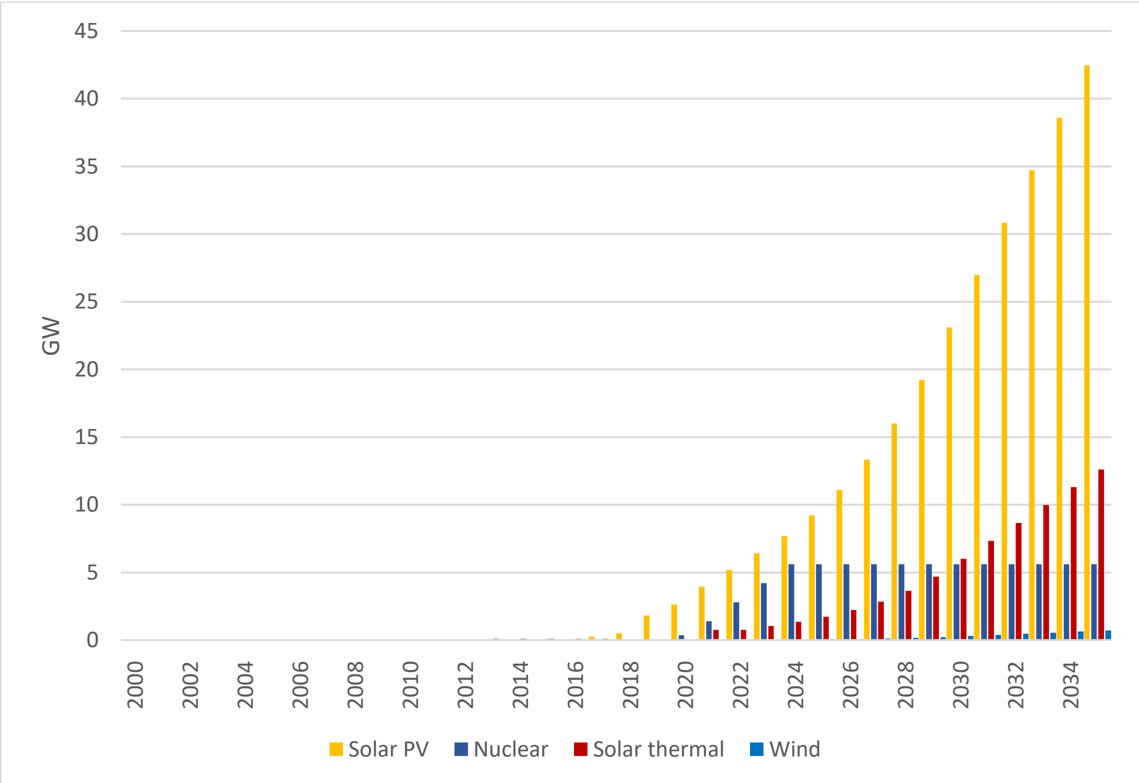
Abu Dhabi has moved more quickly recently, perhaps catalysed by the Neom announcement in neighbouring ally and rival Saudi Arabia. In January 2021, Abu Dhabi National Oil Company (ADNOC), state holding company ADQ, and government strategic investor Mubadala formed an alliance to explore both 'blue' (fossil fuels with carbon capture and storage) and 'green' (renewable electrolytic) hydrogen. Mubadala has an agreement with Italian energy infrastructure player Snam on hydrogen.

Meanwhile ADNOC announced it would also pursue blue hydrogen on its own. The national oil company has concluded partnerships with Petronas of Malaysia, South Korea's GS, and Japan, and is in discussions with others including German firms. Japan's Marubeni has signed a memorandum of understanding with Abu Dhabi's Department of Energy on a 'hydrogen-based society'.

The attractions of hydrogen for the UAE are clear. Levelized cost of electricity bids for its renewable energy tenders reached 1.69 US¢/kilowatt hour (kWh) in October 2019 for the 900 MW solar photovoltaic (PV) Phase V of the Mohammed bin Rashid solar park, 1.35 US¢/kWh for the 2 GW Al Dhafra PV project in April 2020, and given the latest announcement of 1.04 US¢/kWh from Saudi Arabia, it's likely the next UAE project could break the sub-1¢/kWh level. The 7.3 US¢/kWh bid in June 2017 for the Mohammed bin Rashid concentrated solar power (CSP) plant was also a record for that technology.

The UAE's National Energy Strategy (2016) foresaw that 'clean' generation, including nuclear power, should reach 50 per cent of capacity by 2050. The state media agency has reiterated a goal of 14 GW by 2030 (5.6 GW of which is nuclear), compared with current installed capacity of about 30.6 GW of natural gas-fired generation, 1.4 GW of nuclear, and about 6.15 GW of solar operational or approaching completion. Projections by Qamar Energy suggest the 2030 target can be substantially exceeded, with 23 GW of PV alone (see chart). The 2050 target implies about 41 GW of renewables, and it also includes 11 GW of 'clean coal', which is in practice likely to be mostly replaced by additional renewables. Again, given likely further improvements and cost reductions in renewable technology, grid and demand management, and electricity storage, the 2050 target looks readily achievable and probably conservative. Qamar's forecast suggests it could be reached as early as the mid-2030s.

Current and projected renewable-energy capacity in the United Arab Emirates



Source: Qamar Energy.

The success of solar alongside nuclear raises some challenges. Generation during the sunny but relatively cool spring days may quite soon begin to exceed demand, if nuclear is not to be curtailed. Electrification of desalination (via reverse osmosis), offshore oil facilities, and, perhaps, a growing share of transport is one part of the solution. The manufacture of electrolytic hydrogen is another option. Hamad Al Hammadi, ADQ investment director, recently referred to the use of nuclear power to produce hydrogen.

The country is also a leading exponent of carbon capture, use, and storage (CCUS), having started the world's first commercial-scale deployment on industry, the Emirates Steel direct reduced iron plant, in 2016. The carbon dioxide is used for enhanced oil recovery by ADNOC, whose overall capture levels are intended to reach 5 Mt/year by 2030. The already large quantities of 'grey' (non-CCUS fossil-fuelled hydrogen) in refineries and the FERTIL ammonia and urea plants at the industrial centre of Ruwais will grow further with a major set of new refining and petrochemical plans, which will boost petrochemical output from 4.5 to 11.4 million tonnes per year by around 2025. Replacement of domestic grey with blue or green hydrogen would be an initial step to develop a market and advance decarbonization.

Gas has been a key area of focus, with the UAE intending to reach self-sufficiency by 2030. Currently, it imports almost 20 bcm annually from Qatar, as well as 1.6 bcm of LNG into Dubai. The boycott of Doha by some of its Gulf neighbours ended in January 2021, but the UAE would still prefer to limit its dependence on what it sees as a troublesome neighbour. In order to boost production, ADNOC plans an ambitious campaign to produce from the gas caps of its oilfields, develop very large and costly offshore sour gas, and exploit unconventional gas. Gas production from the tight carbonate Diyab reservoir began in November 2020. In February 2020, the discovery of 80 Tcf of shallow unconventional gas was announced at Jebel Ali, on the Abu Dhabi–Dubai border. Exploration for further gas is ongoing.

The emirate has not yet defined its hydrogen use or export plans clearly. Its oil and LNG sales are overwhelmingly directed towards Asia, unlike Saudi Arabia and Qatar, which remain substantial suppliers to Europe. Its geography and partnership agreements so far suggest this would also apply to hydrogen, though Europe could be an accessible market too.

In the longer term, Fujairah on the country's Indian Ocean coast, the world's second- or third-largest marine bunkering port, may turn to hydrogen or a derived fuel such as ammonia as an offering for ships, as Germany's Uniper has advocated. Fujairah has to bear in mind the competitive threat from the ports of Sohar and Duqm in Oman, both of which are advancing green hydrogen plans in cooperation with European port operators. And the UAE, as a centre for aviation, is also aware it ultimately needs low-carbon flight options. Etihad, Abu Dhabi's national carrier, has trialled biofuels.

All this is in line with the overall ADNOC and Abu Dhabi strategy: to accelerate and maximize value realization from its hydrocarbons, while developing new industries and transitioning towards a lower-carbon economy. The innovative image of hydrogen also fits with the new, aggressive approach of Abu Dhabi and of ADNOC under the dynamic chief executive Sultan Al Jaber, a close aide of Crown Prince Mohammed bin Zayed's.

Despite all these good strategic reasons, however, the development of hydrogen as a major UAE business faces major challenges and even contradictions.

Some of the issues are common to hydrogen plans for many countries: the market is nascent, and it is still unclear what if any premium price consumers in Europe or Japan will pay for low-carbon hydrogen or products made from it. The preferred long-distance transport method has not been settled, whether liquid hydrogen, ammonia, a liquid organic hydrogen carrier, synthetic fuels, or decarbonized materials such as steel. Saudi Arabia has mentioned a hydrogen pipeline to Europe, a possibility from its north-western Neom site, but this is not an option for the UAE. The recent plan from Aramco, to sell LPG to South Korea for hydrogen production and then take back the carbon dioxide for reinjection, is a fascinating concept, and one that might work for the UAE too, also a big LPG exporter. It does provide a possible route to carbon-neutral hydrocarbons.

Other concerns are more specific to the UAE. Its gas strategy has embodied a tension from the start. The Dolphin pipeline contract from Qatar expires in 2032. Depending on relations between the two countries at that point, it could be renewed, and would probably still represent the lowest-cost supply to the UAE while providing superior netbacks to Doha than yet more LNG exports. The domestic sour gas projects, by contrast, are extremely expensive, with implied costs about $ 5 per million British thermal units (MMBtu) for the onshore Shah gas and $ 7–8 per MMBtu for the offshore, while the commerciality of the Jebel Ali gas remains to be confirmed.

Redesign and falling service industry rates may reduce these levels, but this still does not look like cheap gas. At the same time, the combination of nuclear, solar, and coal in Dubai, along with improved energy efficiency, will reduce national gas demand, as least in the medium term. So, given the ambition of being capable of self-sufficiency, Abu Dhabi would then face a choice between prioritizing domestic gas production over cheaper Qatari imports, exporting the surplus (if it can find markets), or developing new gas-using industries at home.

So far, Qatar has said very little on the topic of hydrogen. But it could be a very low-cost and potentially large-scale producer of blue hydrogen given its gas resources and CCUS experience and plans. Aramco has said it will focus on blue hydrogen rather than LNG exports; the sales price for its highest-priced new non-associated gas is set at $ 3.84 per MMBtu. US production costs are likely also low if Henry Hub prices remain at current levels (around $ 2.60 per MMBtu), especially given existing CCUS tax incentives. So Abu Dhabi has an imperative to make the most effective use of a likely gas surplus, but needs to define how to compete against rivals with lower-priced feedstock.

On the side of green hydrogen, the UAE has achieved, as noted, very low renewable bid prices, because of low-cost financing, readily available land, a clear bidding process, and giant scale. Its solar resource is excellent but not the world's best. On the other hand, its wind resource is very limited. To achieve good economics for an electrolyser, it should run at high load factors to make best use of the high capital cost. Solar PV in the Gulf, with a capacity factor of 20–24 per cent, is not sufficient on its own. Given the Gulf's dusty and hazy skies, its potential for CSP, which can generate at much higher annual capacity factors using thermal storage, is not as good as for PV, while parts of Saudi Arabia and North Africa have superior conditions. However, a recent German–Emirati joint government report is more optimistic that a mix of PV and CSP in the UAE could achieve a 50 per cent capacity factor and competitive green hydrogen costs in the longer term.[109]

Saudi Arabia received a very low price for its first utility-scale wind project, 1.99 ¢/kWh for Dumat Al Jandal in August 2019. Both the Neom site, in the Kingdom's north-west, and Oman's southern port of Duqm, where Deme Concessions of Belgium and Acme of India are planning projects, have the combination of excellent solar and wind, which could drive electrolyser utilization factors to around 80 per cent. Egypt and Morocco have similar good solar/wind combinations, and are closer to Europe, while Australia and Chile are potential green hydrogen competitors for Asian buyers.

Green hydrogen can be a storage medium of surplus renewable energy. But even as the UAE's renewable penetration grows, its demand—largely for air-conditioning in summer—matches well with solar generation. Retaining some gas-fired capacity along with batteries and solar thermal equipped with overnight storage is probably sufficient for most needs. Shedding a modest amount of very cheap solar PV is not a serious problem, and likely preferable to installing electrolysers which would run at low utilization factors.

Gradually transitioning the UAE's industrial facilities to low-carbon hydrogen appears a viable pathway, particularly as premium pricing or carbon tariffs provide incentives. Becoming a powerhouse in exporting blue or green hydrogen seems much more challenging. Its business-friendliness, existing infrastructure, openness to innovation, and speed to market are all advantages over most of its regional peers. The import demand for hydrogen from Europe, Japan, South Korea, and others will also be fast-growing and potentially large, as implied by national decarbonization strategies and the constraints on their domestic hydrogen output.

Still, the UAE will have to show that some clever combination of solar, low-wind-speed turbines, surplus nuclear power, and storage can provide viable economics for green hydrogen, or that it can bring down gas costs and leverage its CCUS advantages for blue hydrogen. Otherwise, the opportunities may come to lie more in domestic use and investment in international projects and technologies.

[109] Emirati-German Energy Partnership (2021), *The Role of Hydrogen for the Energy Transition in the UAE and Germany*, Berlin: Guidehouse, https://www.moei.gov.ae/assets/download/614c3e91/aa62e677.pdf.aspx.

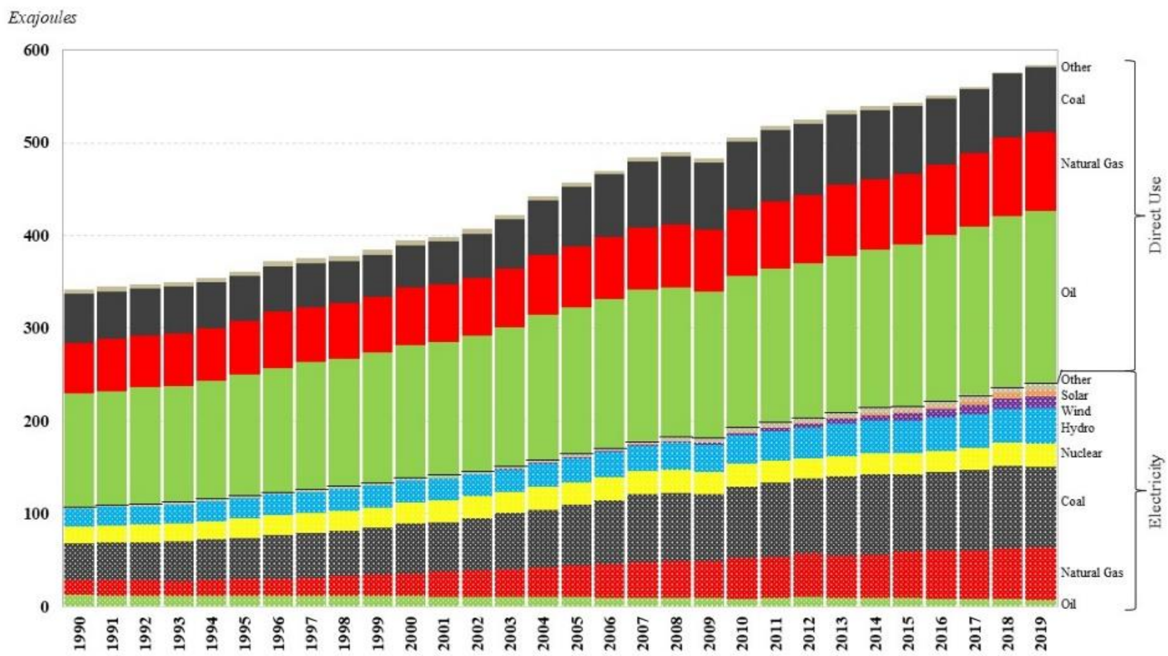
A US PERSPECTIVE: THE POTENTIAL OF HYDROGEN RESTS IN ITS DIVERSITY

Ken Medlock

Reducing the carbon footprint of energy is a driving force in energy transitions. But this is not without its challenges. Certainly, costs are declining for a number of new energy technologies, and this holds well-touted promise for delivering low-cost, low-carbon energy solutions. It is important to remember, however, that the cost of *generating* a unit of energy is not the same as the cost of *delivering* a unit of energy. While this may seem like a trivial statement, it is not.

The existing energy ecosystem that sustains economic activity around the world is 70 per cent larger today than it was 30 years ago, and it is heavily dependent on coal, oil, and natural gas. In fact, all fossil fuels combined accounted for over 84 per cent of total global energy use in 2019, which is little changed since 1990 when they accounted for 87 per cent of total energy use. Even as the share of electricity has increased from 31.1 per cent to 41.2 per cent since 1990, fossil fuels have remained a staple of total energy use. Moreover, global energy use today only serves about 6.5 billion of the 7.7 billion people on the planet, and a good portion of the 6.5 billion who are served are not served reliably. So, the scale of the energy problem demands a portfolio of innovative solutions. Hydrogen can play a major role in that portfolio.

Global energy use by source, 1990–2019



Data source: BP Statistical Review, 2020.

Energy is very infrastructure intensive. Using energy requires massive supply chains that connect production to consumption through a network that involves conversion, transmission, and distribution. As such, there is a massive legacy of infrastructure associated with each type of energy that is used. Ignoring this legacy inevitably leads to problems, because the full cost of adopting new energy technologies includes the cost of deploying the assets that are required to deliver them to consumers. In other words, the full cost of a new 'widget' is not just the cost of producing the widget; it is also the cost of developing the full supply chain to manage its delivery into the market. This is why new technologies that can leverage existing supply chains and their associated infrastructures have a distinct advantage: they can piggy-back on the sunk costs of legacy infrastructure. Technologies that require the development of completely new supply chains do not enjoy that luxury, which can render them too costly to adopt, even though they may be low-cost in terms of generating useful energy service. Indeed, the proverbial 'valley of death' for new energy technologies is littered with great, low-cost ideas that ignored economic hurdles such as deployment costs and the sunk costs of legacy assets.

Fossil fuels have been and still are a dominant source of energy globally, which means there is a large amount of infrastructure in place to support a value chain that produces, transports, and uses fossil fuels. Leveraging this hydrocarbon value chain could make for an excellent enabler of a low-carbon fuel such as hydrogen. Of course, there are ways to produce hydrogen that do not involve hydrocarbons, but those approaches may not be the least-cost means of production in some locations. Moreover, given the scale of energy demands for modern economic activity on a truly global scale, societies will need to use everything, and do so sustainably.

This is where hydrogen has a real opportunity to be a centrepiece of the low-carbon future of energy. Hydrogen can leverage legacy infrastructures related to production and transportation of fossil fuels, while also affording the potential to develop new infrastructures that are not related to fossil fuels. Notably, this means that hydrocarbons can remain an important source of primary energy, but the end-use of energy will take a very different, low-carbon shape.

Hydrogen's many uses: now and in the future

Hydrogen is the simplest and most abundant element. It already has a dominant place in our current energy system that is facilitated in combination with a prolific natural hydrogen carrier—carbon—in the form of molecules known generically as hydrocarbons. But the negative CO_2 externality associated with hydrocarbon combustion is driving greater interest in direct use of hydrogen as an energy source.

Direct use of hydrogen as an energy source has held intrigue for many years, but technical and commercial challenges have kept it from proliferating. Currently, hydrogen is used in refining (to remove sulphur from crude oils), fertilizer production, metallic ore reduction, and a number of industrial applications in chemicals, textiles, and electronics. Perhaps the most famous use of hydrogen is in liquid form for rocket fuel. Looking to the future, hydrogen has a number of potential applications that could be significantly expanded across a range of end-use sectors from transportation to electric power to industry. For example, hydrogen can be used in fuel cells to power passenger and commercial vehicles, heavy-duty trucks, buses, trains, and waterborne vessels.

Beyond transportation, hydrogen can be used in fuel cells to generate electricity for backup power and/or distributed energy applications, and it can be blended into natural gas for use in a gas turbine to generate electricity. Hydrogen can also be stored for use in power generation to manage load in power systems when intermittent renewables are not available. For hard-to-decarbonize applications, hydrogen can be used for steel, cement, chemical, and other manufacturing processes that aren't easily electrified.

The fact that hydrogen can be used in so many different applications across multiple sectors makes it a prime candidate for playing a substantial role in transitioning the energy system. But demand must be met with supply for such a transition to occur.

Hydrogen's many colours: an advantage for growth

Fortunately, hydrogen can be produced in many different ways, which allows many options for meeting demands in relatively low-cost ways. Indeed, the least-cost option for hydrogen production may be different across different regions. To the extent this is the case, the principle of comparative advantage will play an important role in shaping how regions adopt hydrogen as an energy source and what technologies are chosen for production.

The 'hydrogen rainbow' is a colour-coding of the various processes for producing hydrogen, where each colour is associated with a different means of production. Currently, 'grey' hydrogen is the overwhelmingly dominant means of production, but; it is primarily derived from natural gas using steam methane reforming, resulting in CO_2 emissions. But there are a number of other technologies that can be used to produce hydrogen, many of which eliminate CO_2 emissions.

Notably, the suite of technologies used to produce hydrogen includes the use of hydrocarbons as a feedstock, but in a low-carbon future it must also involve some carbon removal technology. 'Blue' hydrogen leverages existing production, transportation, and distribution infrastructures for hydrocarbons, but eliminates CO_2 emissions by installing carbon capture technologies alongside steam reformation. In this way, blue hydrogen has the potential to avoid stranded costs being imposed on existing assets, while also avoiding added fixed costs for new infrastructures that may be needed with other low-carbon energy options.

'Turquoise' hydrogen is similar to blue hydrogen in that it also can leverage existing hydrocarbon production, transmission, and distribution infrastructures. But it also introduces a carbon-to-value proposition that can dramatically alter the commercial prospects of the technology. For example, material science innovations in the use of solid carbon as a feedstock for carbon nanotechnologies and advanced carbon-based materials have potential to replace steel and other materials in construction and vehicle manufacturing. In the case of vehicles in particular, light-weighting vehicles can improve fuel efficiency and electric vehicle range, which reduces the energy requirement per unit distance travelled, thus carrying an added carbon reduction benefit.

The colours of hydrogen

Grey	Produced from natural gas using steam methane reforming. Most common form of hydrogen production currently in use. Results in CO_2 emissions.
Brown	Produced from gasification of fossil fuel feedstock, usually coal. Often discussed as a potential future use of coal. Results in CO_2 emissions.
White	Produced as a by-product of an industrial process. CO_2 emissions are dependent on the industrial process.
Yellow	Produced by electrolysis using electricity from solar power. No CO_2 emissions depending on the source of power generation. Can also leverage existing power grid. Can be CO_2 neutral if carbon capture is deployed at sources of fossil-generated power.
Blue	Grey or brown hydrogen with carbon capture. CO_2 emissions are substantially reduced. Modifies existing production methods, thus leveraging legacy, or existing, infrastructures.
Turquoise	Produced by methane pyrolysis with a solid carbon by-product. CO_2 emissions are substantially reduced. Leverages existing natural gas infrastructures. Opens 'carbon-to-value' propositions as solid carbon can be a replacement for carbon black and used as a feedstock in advanced carbon material applications.
Green	Produced by electrolysis using electricity from renewables. No CO_2 emissions.
Pink	Produced by electrolysis using nuclear power. No CO_2 emissions.

Source: Adapted from North American Council for Freight Efficiency (2020), 'Hydrogen color spectrum', *Making Sense of Heavy-Duty Hydrogen Fuel Cell Tractors*, https://nacfe.org/emerging-technology/electric-trucks-2/making-sense-of-heavy-duty-hydrogen-fuel-cell-tractors/.

Note: There are multiple derivatives of the colour palette for hydrogen technologies. For example, yellow is sometimes associated with solar power, brown with lignite, and black with coal.

Production technologies that use electrolysis to split hydrogen from water ('yellow', 'green', and 'pink') generate no CO_2 at the point of conversion. Moreover, the hydrogen that is produced is not distinguishable from other forms of hydrogen. So, a lot of emphasis has been placed on the use of electrolysis for hydrogen production, with a majority of attention given to green hydrogen to date.

The multitude of hydrogen production technologies has the potential to support more rapid scale-up and market evolution because each technology produces the same commodity—hydrogen—but the relative cost of each technology is not likely to be the same everywhere; green hydrogen costs are likely lower in regions with an abundance of wind and/or solar resources, just as blue and turquoise hydrogen costs are likely to be lower in regions with abundant natural gas resources and legacy natural gas infrastructure. Altogether, this supports regional arbitrage opportunities that can promote competition, liquidity, and cost reductions.

Hydrogen in the US: heterogeneity, infrastructure, and a role for policy

In the US, there are approximately 1,600 miles (2,575 kilometres) of hydrogen pipelines in operation.[110] For comparison, there are over 3 million miles (4.83 million kilometres) of natural gas pipelines in the US.[111] The fixed cost of expanding the hydrogen pipeline network is a barrier, which has motivated investigation of the use of natural gas pipelines for transporting hydrogen in the context of the commercial prospects of the various production technologies.[112] Of course, if natural gas is used as a

[110] US Department of Energy (n.d.), *Hydrogen Pipelines*, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines.
[111] US Energy Information Administration (n.d.), *Natural Gas Explained,* https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php#:~:text=The%20U.S.%20natural%20gas%20pipeline,and%20storage%20facilities%20with%20consumers.
[112] Melaina, M.W., Antonia, O., and Penev, M. (2013), *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*, Technical Report NREL/TP-5600-51995, National Renewable Energy Laboratory , https://www.nrel.gov/docs/fy13osti/51995.pdf; US

feedstock for blue and turquoise hydrogen production, which is co-located with end-use applications, then the need for significant expansion of hydrogen pipeline infrastructure is reduced. But even with blue and turquoise hydrogen, takeaway capacity for captured CO_2 and/or solid carbon must be built. Fortunately, there are efforts to significantly expand the use of carbon capture[113] in various US regions where the potentials for blue and turquoise hydrogen are greatest.

Expanding hydrogen use is taking different focus across regions of the US, largely reflecting the comparative advantages driven by existing energy infrastructures and policy support. To be clear, there are a number of federal incentives directed at hydrogen,[114] which include various tax credits and exemptions, loan programme support, and zero-emissions incentives, but certain states also have incentives that make hydrogen more attractive. For example, California's Low Carbon Fuel Standard provides a significant boost to hydrogen, so much so that it is often raised as a potential policy prescription in other regions, although the reception varies by state. In fact, California has more laws and incentives in place directed at hydrogen than any other state,[115] so it should not be surprising that it also leads the nation in hydrogen fuelling locations.

Toyota has been testing hydrogen in heavy-duty applications in the Port of Los Angeles since 2017, and is actively marketing its Mirai hydrogen fuel cell vehicle for personal transport. Companies such as Air Liquide have been actively developing hydrogen production with an aim to serve the California market. While efforts are also under way in other parts of the country, the significant policy support in California has accelerated non-traditional uses of hydrogen in the state relative to other regions.

In traditional oil- and gas-producing regions that also have large chemical and petrochemical sectors, hydrogen is gaining a significant amount of attention from regional port authorities, industrial energy consumers, local political leadership, and the oil and gas industry. For example, in Texas, which has long been associated with oil and gas, the sustainability of the regional economy is driving interest in hydrogen pathways, especially those involving hydrocarbon feedstocks while eliminating CO_2. Texas already has a large industrial complex with a sizeable hydrogen footprint, which is an enabler; and the number of studies, focus groups, and pilot programs is growing rapidly. Change is coming.

The role of hydrogen in the US energy system is on the precipice of significant growth, and it is likely that different states will leverage different technologies, policies, and commercial approaches in expanding the hydrogen market. However, it remains to be seen how firms will handle commercial and legal challenges related to hydrogen infrastructure expansion. This is important because, just as with natural gas, greater hydrogen infrastructure would allow regional trade and enable the development of an efficient national hydrogen market. Accordingly, this may foretell a future role for federal policy.

Last but not least . . .

In sum, hydrogen has significant potential to expand well beyond its current applications to meet the energy demands of sectors that require fuel supplies to be flexible and scalable while reducing the environmental impact of energy consumption. However, increasing hydrogen production to a magnitude suitable for use in the various potential applications will require further innovation and cost reduction.

This is where policy can play a formative role. Public funding (through direct subsidy or tax credit), mandates, and low-carbon fuel standards all can play a formative role. But perhaps the most transformative actions would be de-risking investments through pilot programs and/or support for infrastructure and hub development. Hubs are enablers because they reduce barriers to entry by mitigating the risk of offtake for investors upstream of the market hub as well as the risk of lack of access to supply downstream of the market hub. In turn, this promotes liquidity and, hence, greater investment.

Finally, although not often mentioned in the context of energy transitions and hydrogen, there are ancillary benefits associated with hydrogen. For one, hydrogen used in place of hydrocarbon energy sources will improve local air quality by eliminating particulates as well as sulphur- and nitrogen-based pollutants. In addition, the fact that there are many ways to produce hydrogen from different feedstocks using different technologies can substantially diversify sources of energy supply for transportation, thus carrying an energy security benefit. Altogether, hydrogen, because of its diversity, is multidimensional in terms of the externalities it addresses.

Department of Energy, Hydrogen Program (n.d.), *DOE H2A Analysis*, https://www.hydrogen.energy.gov/h2a_analysis.html.

[113] Medlock, K.B., and Miller, K. (2021), *Carbon Capture in Texas*, Baker Institute for Public Policy, Rice University, https://www.bakerinstitute.org/research/carbon-capture-texas/.

[114] US Department of Energy (n.d.), *Hydrogen Laws and Incentives in Federal*, https://afdc.energy.gov/fuels/laws/HY?state=US.

[115] US Department of Energy (n.d.), *Hydrogen Laws and Incentives by State*, https://afdc.energy.gov/data/10376.

CHINA'S EMERGING HYDROGEN STRATEGY AND THE 2060 NET ZERO COMMITMENT

Michal Meidan

China is widely recognized as a global leader in clean-energy technologies, controlling over 60 per cent of global manufacturing in every step of the solar supply chain and home to five of the world's top 10 wind turbine manufacturers. It leads the world in lithium-ion batteries, bio-power, hydropower, solar water heating, and geothermal heat output. China's abilities in long-term planning, supportive policies, and financial incentives have all been contributing factors to its emergence as a clean-tech leader, but it is the domestic scale of manufacturing which has been key in making clean technologies affordable, and increasingly competitive with fossil fuels, in every country. Indeed, as Barbara Finamore argued in a previous *Oxford Energy Forum*,[116] as a result of China's innovative manufacturing techniques, economies of scale, and integrated supply chains, solar photovoltaic (PV) module prices have dropped around 90 per cent in the last decade.

Given Chinese leaders' pledge in September 2020 that the country would reach carbon neutrality by 2060, and the importance hydrogen is set to play in fulfilling that goal, all eyes are on China to develop and scale hydrogen technologies. Can China now replicate its success in PV module cost reductions with electrolysers? If past is precedent, China can be expected to make considerable gains in developing hydrogen uses and technologies. But the external environment has changed markedly since earlier instances of clean-tech innovation, and China's diplomatic and commercial relations with Western countries and companies have become more fraught.

The synergies that helped the diffusion of clean technologies in the past—namely, developing technologies in the West and scaling them up in China—are looking increasingly challenging, suggesting that China's route to a hydrogen economy could be slower than expected. This article discusses how Chinese decision-makers have viewed hydrogen development to date, and to what extent the carbon neutrality pledge will accelerate China's efforts to lead the global hydrogen race, before assessing the potential and challenges that hydrogen development faces in China.

China's 2060 pledge is driven by climate and industrial policies, boding well for hydrogen

In September 2020, China's president, Xi Jinping, announced that the country would peak carbon emissions by 2030 and aim to reach carbon neutrality by 2060. The announcement came as a surprise to many in China and has generated a debate within the country about the pathways to achieving these goals. Ministries, provincial leaders, and state-owned companies are now preparing road maps for reaching these targets at or ahead of the date. So, even though carbon neutrality is now clearly recognized as the general goal, requiring a rapid electrification of end-uses and a massive increase in renewables, there is still considerable uncertainty about how to get there. The roles of different fuels and technologies are all open questions.[117]

That said, given China's efforts to develop its technological capabilities and remain a leading supplier of global clean tech, hydrogen will be key in China's path to carbon neutrality. Indeed, hydrogen was listed in the latest five-year plan (FYP)—the 14th, covering 2021–2025—under the emerging industries that decision-makers see as a priority. Given that these designations lead to state support in the form of capital and human resources, the focus on hydrogen bodes well for its development.

Shifting focus

To be sure, China is no newcomer to hydrogen development. In fact, the country's hydrogen production was estimated at 22 million tonnes (Mt) by the China Hydrogen Alliance in 2019,[118] making it the world's largest producer. But unlike many other countries where steam methane reforming (SMR) is the dominant production route, in China coal remains the most common feedstock for hydrogen, via a partial oxidation process. Roughly 14 Mt of hydrogen produced in 2019 was from coal gasification, with additional hydrogen derived from coking, and under 4 Mt was produced via SMR. An estimated 1 Mt of hydrogen in the chlor-alkali industry was produced via electrolysis.

In terms of demand, ammonia manufacturing is the biggest consumer, estimated at 10 Mt in 2019 by the China Nitrogen Fertilizer Industry Association, followed by 8 Mt in methanol production. Finally, around 3–4 Mt of hydrogen is used in petroleum refining, with at least 10 per cent of that hydrogen also derived from coal, and almost half produced from naphtha reforming.

[116] Finamore, B.A. (2021), 'Clean tech innovation in China and its impact on the geopolitics of the energy transition', *Oxford Energy Forum*, 126, 18–22, https://www.oxfordenergy.org/publications/oxford-energy-forum-the-geopolitics-of-energy-out-with-the-old-and-in-with-the-new-issue-126/.
[117] For a discussion on the carbon neutrality pledge, see Michal Meidan (2020, December), *Unpacking China's 2060 Carbon Neutrality Pledge*, Oxford Energy Comment, https://www.oxfordenergy.org/publications/unpacking-chinas-2060-carbon-neutrality-pledge/.
[118] http://www.h2cn.org/Uploads/File/2019/07/25/u5d396adeac15e.pdf.

Small volumes of hydrogen are used in metal smelting, electronics, pharmaceuticals, and other products.[119]

Policies to develop hydrogen date back to the 10th FYP (2001–2005) with a focus on the transport sector, as the growth of the Chinese car market and the related oil demand was deemed a source of strategic vulnerability. Efforts to replace oil in transport with hydrogen were seen as a means of limiting the country's heavy dependence on imported oil and curbing air pollution, although the sources of hydrogen were a secondary concern.

In 2015, the Chinese government published the Made in China 2025 initiative—a ten-year plan to upgrade China's manufacturing industry—citing hydrogen as a key technology to develop in the energy vehicle market. The following year, the first Hydrogen Fuel Cell Vehicle (FCV) Technology Roadmap was released, aiming for mass application of hydrogen in the transport sector by 2030.

The Roadmap included interim targets to have 5,000 FCVs in demonstration, alongside 100 hydrogen refuelling stations (HRS), by 2020, focusing on industrial clusters and demonstration-application areas in the Beijing-Tianjin-Hebei area, as well as the country's manufacturing and export powerhouses, the Yangtze River Delta, Pearl River Delta, and Shandong Peninsula, as well as the central region. By the first half of 2020, just under 7,000 FCVs had been sold in China and 72 HRS were in operation. The Roadmap also envisions having over 50,000 FCVs in operation and over 300 HRS in 2025, reaching over 1 million FCVs by 2030 and a somewhat modest target of over 1,000 stations by 2030. By then, 50 per cent of hydrogen production is expected to come from renewable sources.

The National Alliance of Hydrogen and Fuel Cell (or the China Hydrogen Alliance) was also launched in February 2018, with the aim of enhancing the development of China's hydrogen sector. In its inaugural report, the Alliance predicted that by 2050, hydrogen would account for 10 per cent of China's energy system, with demand tripling to 60 Mt. But given the emerging changes in China's climate and industrial policies, policies to develop hydrogen could prove more ambitious. In its 2020 report, released in April 2021, the Alliance projected that hydrogen production from renewable energy in China will reach 100 Mt by 2060, accounting for 20 per cent of China's final energy consumption.

Already since 2019, however, policy support for hydrogen in China started gaining renewed momentum. The Government Work Report included a national mandate to 'promote the construction of charging and hydrogen refuelling facilities'—the first time that hydrogen energy was included in a Government Work Report. In 2020, four ministries jointly introduced fiscal subsidy policies for FCVs and promised that the subsidies will not be phased out after 2020, when electric vehicle (EV) subsidies were set to be withdrawn. The country's credit system for rating new energy vehicles is increasingly rating FCV vehicles higher than EVs, encouraging automakers to add FCVs to their portfolios.

Beyond its application in transport, in March 2020, the National Development and Reform Commission and the Ministry of Justice issued Opinions on Accelerating the Establishment of Green Production and Consumption Laws and Policies,[120] stating that the promotion of clean energy development requires the study and formulation of standards and supporting policies for new technologies, such as hydrogen and ocean energy. In April 2020, in preparation for the 14th FYP, the National Energy Administration highlighted the need to combine new technologies, such as energy storage and hydrogen energy, in order to increase the proportion of renewable energy in regional energy supplies.

In that vein, a number of policy documents were released in 2020, outlining the technical requirements for hydrogen pipelines and storage systems and the content of liquid hydrogen to be used at refuelling stations; laying out a road map for universities and other educational institutions stressing the need to promote research on the hydrogen energy revolution in China; and emphasizing compressed-air energy storage, chemical energy storage, new types of batteries, fuel cells, and hydrogen storage.

Challenges on the road to becoming a hydrogen superpower

While hydrogen has been gaining momentum in China, increasingly with a view to expanding applications beyond the transport sector, the 14th FYP framework was light on detail beyond mentioning hydrogen as part of the strategic emerging industries. Industrial as well as provincial plans will offer further details, and while concerted state-led efforts will help the development and deployment of new technologies, there are a number of challenges that suggest the path to hydrogen development in China will be far from smooth.

[119] Tu, K.T. (2020), *Prospects of a Hydrogen Economy with Chinese Characteristics*, Etudes de l'Ifri, IFRI, https://www.ifri.org/en/publications/etudes-de-lifri/prospects-hydrogen-economy-chinese-characteristics.
[120] https://www.ndrc.gov.cn/xxgk/zcfb/tz/202003/t20200317_1223470_ext.html.

First, hydrogen is classified in China as a hazardous material, so its production, transportation, refuelling, and storage are strictly regulated. For example, production is restricted to chemical industry zones, hindering the development of on-site HRS; in road transport, the working pressure of tube trailers for hydrogen transportation is limited to 20 megapascals, resulting in low transportation efficiency and high costs. And since China does not have a standardized approval process for the construction of HRS, construction times tend to be long.

Second, while hydrogen has been designated a key technology to develop in the energy vehicle market, the government has promoted EVs more aggressively, offering generous subsidies for both production and sales. Compared to 7,000 FCVs sold in China by mid-2020, the cumulative stock of EVs exceeded 4 million units.

Third, China currently lacks the key technologies to enable renewables-based hydrogen production, and lags behind advanced economies in hydrogen storage and transport technologies as well as in manufacturing capacity for key materials including membrane humidifiers, bipolar plates, and hydrogen circulation pumps. Even for FCVs, China still relies on imports of key materials including catalysts, proton exchange membranes, and carbon papers. Indeed, in the development of PV panels and wind technologies, China's clean-energy entrepreneurs relied on partnerships with foreign firms to access new technologies, rather than their own research and development. They then focused on shaving production costs in order to stay competitive against domestic and international rivals, which generated cost-cutting innovations in the manufacturing process. Growing international concerns about China's business practices and the race for technological dominance could constrain flows of these materials to China and limit Western investments in the country. Even though China's 14th FYP, in recognition of these trends, stresses technological self-sufficiency and efforts to develop break-through technologies, this could take time.

Finally, for green hydrogen to be competitive with coal-gasification, electricity costs will need to fall sharply. In Sichuan province, regulators have capped end-user electricity prices at RMB 0.3/kWh (€ 0.04/kWh), capitalizing on low hydropower costs, but these prices are still estimated to be three times higher than coal-based hydrogen.[121] Similarly, the current cost of PV power generation is estimated at RMB 0.59/kWh, and the cost of wind power is about RMB 0.37/kWh, requiring further reductions in order to enable green hydrogen production.[122]

In light of China's 2060 pledge, and the expected increase in renewables, water electrolysis powered by electricity sourced from renewables is likely to become the major source of China's hydrogen supply. Similarly, renewable electricity used in green hydrogen will rise, driving renewables growth and helping solve some of China's curtailment issues. Nonetheless, if green hydrogen rises to 15 per cent of total hydrogen demand by 2030 and 75 per cent by 2050, as estimated by the China Hydrogen Alliance, electrolyser capacity will also need to grow substantially. Domestic alkaline electrolysers are already globally competitive, but they are less suitable than PEM (polymer electrolyte membrane) electrolysers for power-to-gas from the intermittent power generation of renewables. PEM electrolysers will increasingly become a focal area for the Chinese market, as they are still very costly and the technology gap between domestic and international products is also still large.

Different strokes for different provinces

With guidance from the central government still rather vague, provincial governments are taking the lead on hydrogen development. This allows provinces to set out strategies that are best suited to their industrial make-up and resource endowment, and gives the central government the ability to experiment with different applications. Some provinces are likely to stick to traditional hydrogen production methods, as the market for transportation or for blending hydrogen in natural gas networks for urban heating can be developed rather quickly, switching only later to more sustainable production methods. Other renewables-rich provinces, however, will seek to capitalize on the abundance of renewables and focus on green hydrogen.

By April 2021, 23 of China's provinces and municipalities had listed hydrogen as a key economic priority or formulated hydrogen development plans. In Zhejiang Province, the emerging focus is on hydrogen in combined power and heating, FCVs in public transportation and harbour logistics transportation, as well as combining hydrogen production with offshore wind installations. Hebei Province in central China is looking to showcase hydrogen in the 2022 Winter Olympics, focused on Zhangjiakoug city, which has abundant wind power. The province is looking to develop FCV transportation in time for the Winter Olympics and gradually introduce green hydrogen in the iron, steel, and petrochemical industries. But other provinces, such as Shandong, are more cautious on green hydrogen and are instead looking to promote blue hydrogen. The peninsular province is hoping to become a hydrogen transportation corridor by 2025, blending hydrogen into its gas infrastructure.

[121] Yu, Y. (2020), 'Why not hydro-to-hydrogen? Green hydrogen economics based on China's hydropower', *Energy Iceberg*.
[122] (2019, November), *Hydrogen Production from Water Electrolysis: Development Status and Bottlenecks* [in Chinese], https://www.chinaautoms.com/a/new/2019/1112/12186.html.

Regional blueprints will be released over the next few months, and a national development strategy could also be issued as part of the 14th FYP development agenda. It is clear that there is growing momentum behind hydrogen applications in China and a gradual shift from grey hydrogen to blue and green hydrogen. And while the power of the state in China can be formidable and will help develop hydrogen technologies and applications, there are also challenges. As such, it is too soon to assume that China has won the hydrogen race.

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