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WHEN TRUST MATTERS

HYDROGEN FORECAST TO 2050

Energy Transition Outlook 2022

CONTENTS

FOREWORD

Welcome to DNV's first standalone forecast of hydrogen in the energy transition through to 2050.

While there are ambitious statements about the prominent role that hydrogen could play in the energy transition, the amount of low-carbon and renewable hydrogen currently being produced is negligible.

That, of course, will change. But the key questions are, when and by how much? We find that hydrogen is likely to satisfy just 5% of global energy demand by 2050 – two thirds less than it should be in a net zero pathway. Clearly, much stronger policies are needed globally to push hydrogen to levels required to meet the Paris Agreement. Here it is instructive to look at the enabling policies in Europe where hydrogen will likely be 11% of the energy mix by 2050.

Five percent globally translates into more than 200 million tonnes of hydrogen as an energy carrier, which is still a significant number. One fifth of this amount is ammonia, a further fifth comprises e-fuels like e-methanol and clean aviation fuel, with the remainder pure hydrogen.

Hydrogen is the most abundant element in the universe, but only available to us locked up in compounds like fossil fuels, gasses and water. It takes a great deal of energy to liberate those hydrogen molecules – either in 'blue' form via steam methane reforming of natural gas with CCS, or as 'green' hydrogen from water and renewable electricity via electrolysis.

By 2050, more than 70% of hydrogen will be green. Owing to the energy losses involved in making green hydrogen, renewables should ideally first be used to chase coal and, to some extent, natural gas, out of the electricity mix. In practice, there will be some overlap, because hydrogen is an important form of storage for variable renewables. But it is inescapable that wind and solar PV are prerequisites for green hydrogen; the higher our ambitions, the greater the build-out of those sources must be.

Hydrogen is expensive and inefficient compared with direct electrification. In many ways, it should be thought of as the low-carbon energy source of last resort. However, it is desperately needed. Hydrogen is especially needed in those sectors which are difficult or impossible to electrify, like aviation, shipping, and high-heat industrial processes. In certain countries, like the UK, hydrogen can to some extent be delivered to end users by existing gas distribution networks at lower costs than a wholesale switch to electricity.

Because hydrogen is crucial for decarbonization, safety must not become its Achilles heel. DNV is leading critical work in this regard: hydrogen facilities can be engineered to be as safe or better than widely-accepted natural gas facilities. That means safety measures must be designed into hydrogen production and distribution systems, which must be properly operated and maintained throughout their life cycles. The same approach must extend to the hydrogen carrier, ammonia, which will be heavily used to decarbonize shipping. There, toxicity is a key concern, and must be managed accordingly.

It is no easy task to analyse the technologies and policies that will kick-start and scale hydrogen and then model how hydrogen will compete with other energy carriers. As we explain in this report, there will be many hydrogen value chains, competing not just on cost, but on timing, geography, emission intensity, risk acceptance criteria, purity, and adaptability to end-use. I commend the work my colleagues have done in bringing this important forecast to you, and, as always, look forward to your feedback.

Remi Eriksen

Group president and CEO

DNV

HIGHLIGHTS

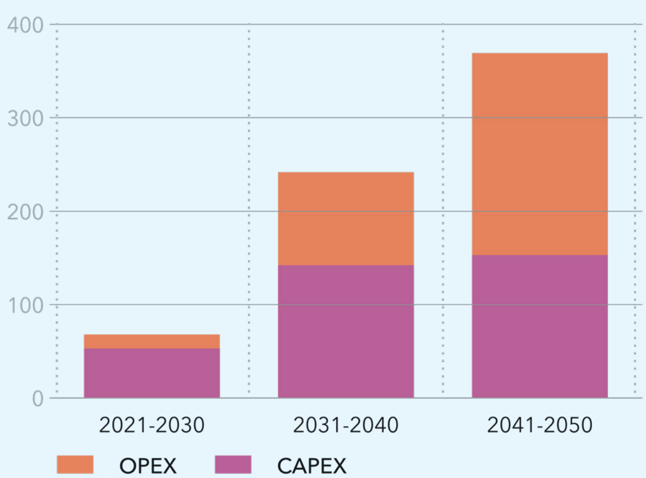
Forecast

- Renewable and low-carbon hydrogen is crucial for meeting the Paris Agreement goals to decarbonize hard-to-abate sectors. To meet the targets, hydrogen would need to meet around 15% of world energy demand by mid-century.
- **We forecast that global hydrogen uptake** is very low and late relative to Paris Agreement requirements – **reaching 0.5% of global final energy mix in 2030 and 5% in 2050**, although the share of hydrogen in the energy mix of some world regions will be double these percentages.
- **Global spend on producing hydrogen for energy purposes from now until 2050 will be USD 6.8trn**, with an additional USD 180bn spent on hydrogen pipelines and USD 530bn on building and operating ammonia terminals.

FIGURE 1

Global annual average expenditure for production of hydrogen and its derivatives for energy purposes

Units: Bn USD/yr

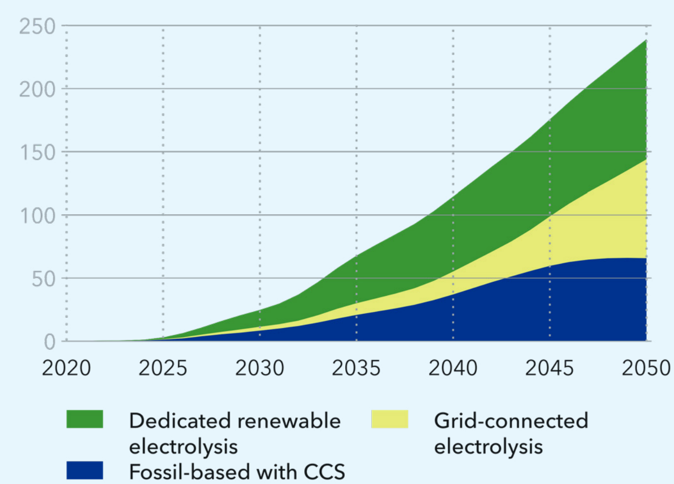


Does not include expenditures related to non-energy feedstock use.

FIGURE 2

Global production of hydrogen and its derivatives for energy purposes by production route

Units: MtH_2/yr



- **Grid-based electrolysis costs will decrease significantly towards 2050** averaging around 1.5 USD/kg by then, a level that in certain regions also will be matched by green hydrogen from dedicated renewable electrolysis, and by blue hydrogen. **The global average for blue hydrogen will fall** from USD 2.5 in 2030 to USD 2.2/kg in 2050. In regions like the US with access to cheap gas, costs are already USD 2/kg. **Globally, green hydrogen will reach cost parity with blue within the next decade.**

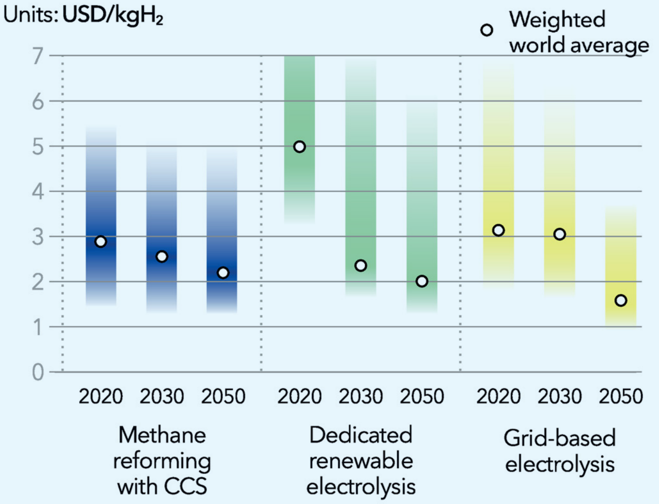
- **Green hydrogen will increasingly be the cheapest form of production in most regions.** By 2050, 72% of hydrogen and derivatives used as energy carriers will be electricity based, and 28% blue hydrogen from fossil fuels with CCS, down from 34% in 2030. Some regions with cheap natural gas will have a higher blue hydrogen share.

- Cost considerations will lead to more than **50% of hydrogen pipelines globally** being **repurposed from natural gas pipelines**, rising to as high as 80% in some regions, as the cost to repurpose pipelines is expected to be just 10-35% of new construction costs.

FIGURE 3

Levelized cost of hydrogen

Units: USD/kgH_2

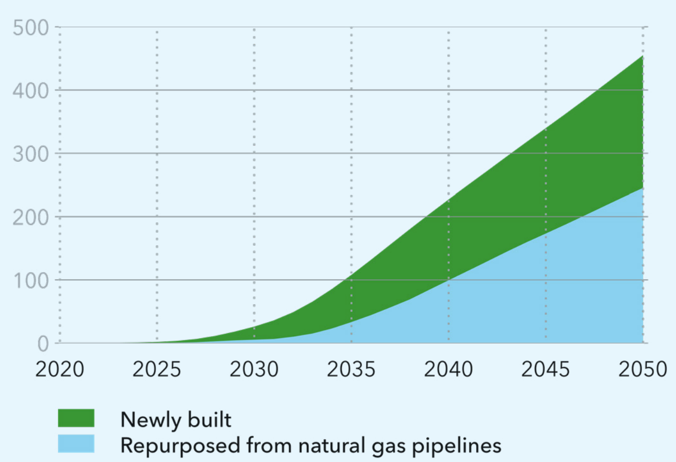


Levelized cost of production after support.

FIGURE 4

Global hydrogen pipeline capacity

Units: TW-km



Includes transmission, distribution and trade pipelines. Capacity in terawatt-kilometres; a composite measure of peak flow multiplied with length of pipelines.

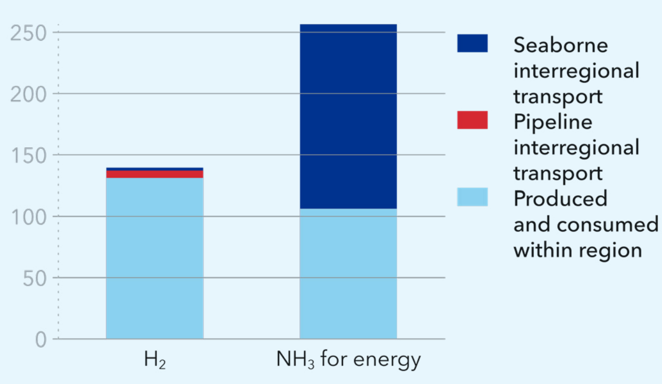
HIGHLIGHTS

- **Hydrogen will be transported by pipelines** up to medium distances within and between countries, but almost never between continents. **Ammonia** is safer and more convenient to transport, e.g. **by ship**, and 59% of energy-related ammonia will be traded between regions by 2050.
- **Direct use of hydrogen will be dominated by the manufacturing sector**, where it replaces coal and gas in high-temperature processes. These industries, such as iron and steel, are also where the uptake starts first, in the late 2020s.
- **Hydrogen derivatives** like ammonia, methanol and e-kerosene **will play a key role in decarbonizing the heavy transport sector** (aviation, maritime, and parts of trucking), but uptake only scales in the late 2030s.
- **We do not foresee hydrogen uptake in passenger vehicles**, and only limited uptake in power generation. Hydrogen for heating of buildings, typically blended with natural gas, has an early uptake in some regions, but will not scale globally.

FIGURE 5

Transport of hydrogen and ammonia in 2050

Units: Mt/yr

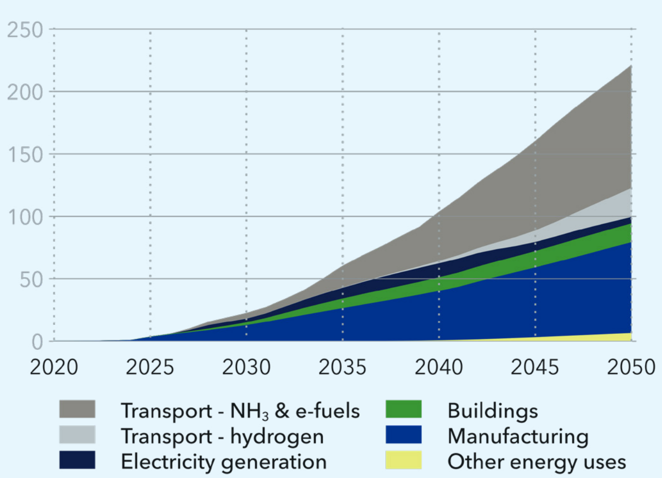


Interregional transport only covers transport between 10 regions defined in this report. All numbers displayed in mass terms: Mt of H_2 or Mt of NH_3. The mass of ammonia converted from H_2 is 5.6 times the mass of H_2.

FIGURE 6

Global demand for hydrogen and its derivatives as energy carrier by sector

Units: MtH_2/yr



All non-transport uses are pure hydrogen.

Insights

- **Hydrogen** requires large amounts of either precious renewable energy or extensive carbon capture and storage and **should be prioritized for hard-to-abate sectors**. Elsewhere, it is inefficient and expensive compared with the direct use of electricity.

- **Unabated fossil-based hydrogen** used as an industrial feedstock (non-energy) in fertilizer and refineries **can be replaced by green and blue hydrogen immediately** – an important existing source of demand before fuel switching scales across energy sectors.

- **Safety (hydrogen) and toxicity (ammonia) are key risks.** Public perception risk and financial risk are also important to manage to ensure increased hydrogen uptake.

- The low and late uptake of hydrogen we foresee suggests that **for hydrogen to play its optimal role in the race for net zero, much stronger policies are needed** to scale beyond the present forecast, in the form of stronger mandates, demand-side measures giving confidence in offtake to producers, and higher carbon prices.

1 INTRODUCTION

Hydrogen has been used in large quantities for well over 100 years as a chemical feedstock, in fertilizer production, and in refineries. However, the present use of hydrogen as an *energy carrier* is negligible. That is because the production of hydrogen itself must be decarbonized – currently at high cost – before it can play a prominent role in the drive to decarbonize the energy system. That formidable cost barrier is not deterring the energy industry's interest in hydrogen, although the number of projects with investment decisions and in a construction phase is still at a modest level. Further up the innovation pipeline, there are many feasibility studies from both existing technology suppliers, and start-ups are developing more efficient and larger-scale concepts.

Hydrogen normally has significant cost, complexity, efficiency, and often safety disadvantages compared with the direct use of electricity. However, for many energy sectors, the direct use of electricity is not viable, and hydrogen and its derivatives such as ammonia, methanol and e-kerosene are the prime low-carbon contenders – sometimes competing with biofuel.

There is an emerging consensus that low-carbon and renewable hydrogen will play an important role in a future decarbonized energy system. How prominent a role remains uncertain, but various estimates point to hydrogen being anything from 10 to 20% of global energy use in a future low-carbon energy system. DNV's own *Pathway to Net Zero* has hydrogen at 13% of a net zero energy mix by 2050 and gaining share rapidly by then.

Our present task, with this forecast, is not to state what share hydrogen *should* take in the 2050 energy mix, but what share it is *likely* to take. We find that hydrogen is not on track to fulfil its full net zero role by mid-century – in fact far from it. Our forecast shows that hydrogen is likely to satisfy just 5% of energy demand by 2050.

Scaling global hydrogen use is beset by a range of challenges: availability, costs, acceptability, safety, efficiency, and purity. While it is widely understood that urgent upscaling of global hydrogen use is needed to reach the Paris Agreement, the present pace of development is far too slow and nowhere near the acceleration we see in renewables, power grid, and battery storage installations. Nevertheless, there is a great deal of interest among a range of stakeholders and the media in the promise of hydrogen. Yet very few commentators are taking a careful, dispassionate look at the details behind hydrogen's likely global growth pathway.

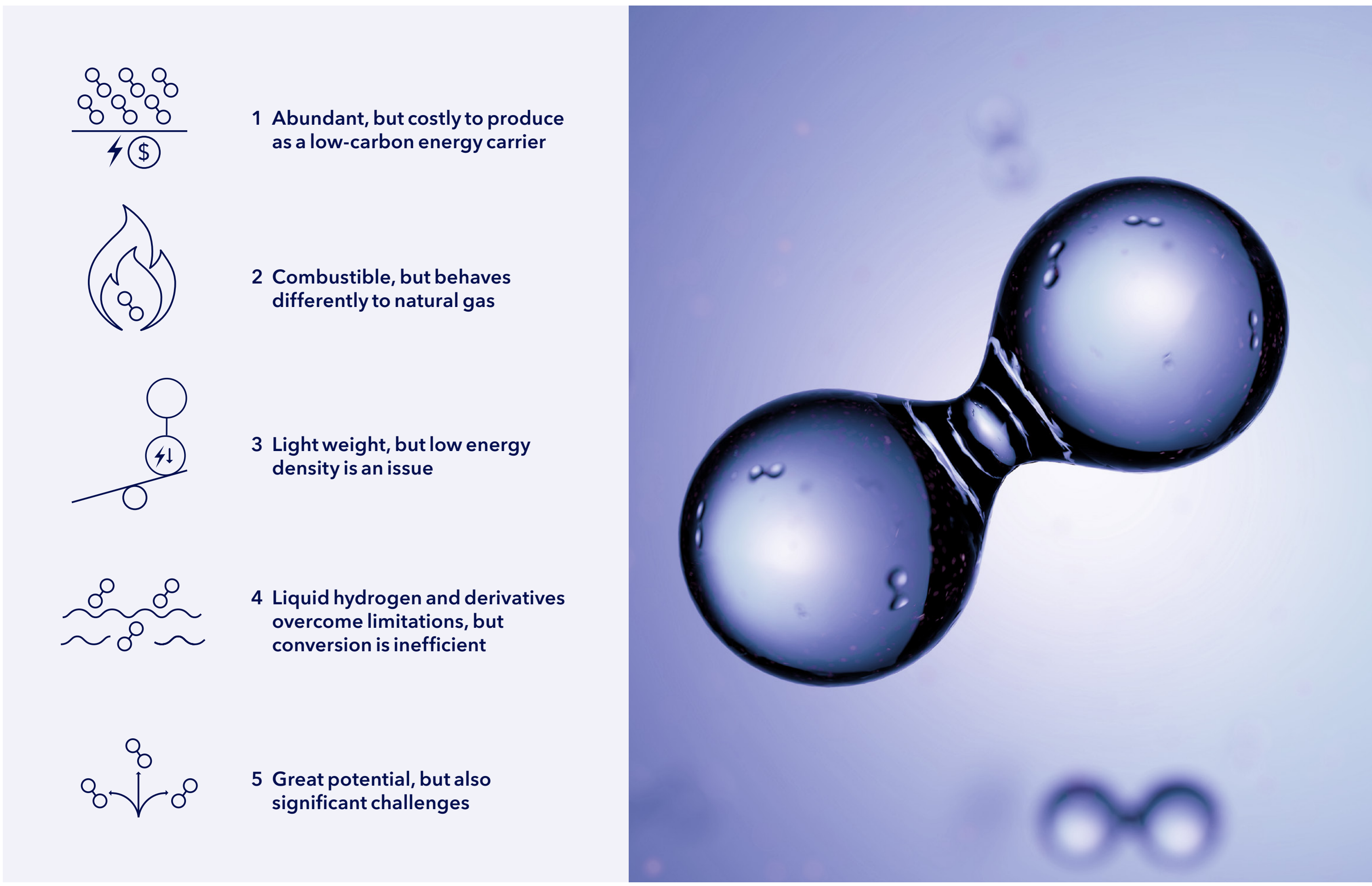
This report is a part of DNV's annual Energy Transition Outlook (ETO) suite of reports. The results presented here will be part of the 2022 version of the main ETO report to be released in October 2022. Our insights and conclusions in this hydrogen forecast are based on more detailed hydrogen modelling in DNV's ETO model, including new modules for hydrogen trade and transport and a much closer study of new production methods and hydrogen derivatives.

Our aim with this forecast is not to state what share hydrogen *should* take in the 2050 energy mix, but what share it is *likely* to take.

The report starts by explaining the properties and present use of hydrogen, as well as safety and investment risks, and continues by describing present and likely future hydrogen policies and strategies. Chapters 3 and 4 go into the details of hydrogen technologies for production, storage and transport. The results from DNV's modelling of hydrogen uptake are presented in Chapter 5, looking at hydrogen production and use in the different energy sectors. Chapter 6 covers the trade of hydrogen. The final chapter dives into examples and a comparison of different hydrogen supply chains.

FIGURE 1.1

Hydrogen properties



1.1 Properties of hydrogen

Hydrogen is both familiar and different from anything else in the energy system. As with electricity, hydrogen is an energy carrier that can be produced via renewable energy, and like electric power, it can be used to 'charge' batteries (comprised of fuel cells). Like a fossil fuel, hydrogen is explosive and produces heat when combusted; it can be extracted from hydrocarbons, held in tanks, moved through pipelines, and stored long term; it can be transformed between gaseous and liquid states and converted into derivatives.

These properties make hydrogen a fascinating prospect in the energy transition, but also create barriers to its adoption in terms of safety, infrastructure, production, use cases, and commercial viability.

Abundant, but costly to produce as a low-carbon and renewable energy carrier

Hydrogen is the most abundant element in the universe, but on Earth it is found only as part of a compound, most commonly together with oxygen in the form of water but also in hydrocarbons.

For use as an energy carrier or zero-emission fuel, hydrogen must temporarily be released from its bond with oxygen or extracted from hydrocarbons. Hydrogen is the simplest of all elements, but processes to produce it in its pure form are not so simple: they are energy intensive and involve large energy losses, have significant costs, and can produce their own carbon emissions. The main driver of widescale hydrogen use is to decarbonize the energy system, and more specifically those parts of it that are hard-to-abate (i.e., cannot be directly electrified). This makes it essential to produce and transport low or zero emission hydrogen, with efficient use of water and byproducts such as waste heat and oxygen.

Hydrogen is the simplest of all elements, but processes to produce it in its pure form are not so simple: they are energy intensive and involve large energy losses, have significant costs, and can produce their own carbon emissions.

Combustible, but behaves differently to natural gas

Hydrogen is combustible and gaseous at normal atmospheric pressure and temperature, but it behaves differently to natural gas, requiring adaption or development of infrastructure, appliances, and safety standards.

Relative to familiar alternatives such as natural gas or petrol vapours, hydrogen ignites with very low energy and has a wide flammability range. The dispersion behaviour is different to other gases due to the small size of hydrogen atoms. Hydrogen is colourless, tasteless, and odourless, meaning that specific sensors or odorization are required to detect it, and additives are needed to produce the familiarity of a visible colour flame when burning hydrogen.

Light weight, but low energy density is an issue

Hydrogen is the lightest element and has high energy density compared to weight, offering some advantages for applications where weight can be an issue, such as in heavy road transport. Overall, it is more relevant to consider hydrogen's energy density compared with volume, which is very low compared to other fuels. This makes hydrogen more difficult to store and transport. Low energy density also reduces the feasibility of hydrogen – at least in its gaseous form – for use cases not connected directly or regularly to the grid, such as shipping and aviation. The solution is to condense hydrogen to a liquid – which only partly solves the challenge – or convert it to derivatives such as ammonia, methanol, or synthetic fuels.

Liquid hydrogen and derivatives can overcome limitations, but conversion is inefficient and can be costly

Compressed hydrogen is in general the most cost-effective way of transporting large volumes over long distances, but this requires pipelines and presents technical challenges. Hydrogen may need to be operated at different pressures (or velocity) than natural gas/biomethane and could have an adverse effect on materials (e.g., in pipes and valves).

To match some of the density and flexibility benefits of liquid fuels, such as gasoline and diesel, hydrogen can be condensed into a liquid, but the temperature point for hydrogen liquefaction is extremely low at -253°C, requiring significant energy. Even in its liquid state hydrogen is not as energy dense as comparable fossil fuels. Liquid hydrogen also has different safety characteristics than compressed gaseous hydrogen – for example, becoming a heavy gas when released that may accumulate, rather than rising and dissipating as with compressed hydrogen gas.

Hydrogen can be converted to derivatives such as ammonia, which has a higher energy density per volume than liquid hydrogen and can be stored and transported as a liquid at low pressures or in cryogenic tanks at around -33°C at 1 bar. Ammonia can be transported at low cost by pipelines, ships, trucks, and other bulk modes. The caveat is that the ammonia synthesis, and its subsequent dehydrogenation to release hydrogen, requires significant energy.

Great potential, but also significant challenges

The properties of hydrogen give it great potential in the energy transition, and there are solutions to the challenges presented by hydrogen properties. The trade-off is often the energy required to implement these solutions. The separation or extraction process for hydrogen production requires energy, and the energy content of the output hydrogen is always less than the energy content of the input fuel, plus the energy required for the hydrogen process. In other words, producing and converting hydrogen is inefficient and involves large losses. Hydrogen is also generally more energy intensive to store and transport than other conventional fuels. The value of hydrogen in pure form to users or to society at large must be sufficient to justify the energy losses in its production, distribution, and use.

The properties of hydrogen require consideration across the hydrogen value chain based on application and context, to determine the best source, state, and derivative, and associated infrastructure and appliance, to maximize the benefits of hydrogen properties and minimize negative impacts. A successful hydrogen value chain will balance the pros and cons, physical and safety/risks, costs and benefits, and decarbonization potential of hydrogen against other energy carriers and fuels.

One major consideration is the relationship between greater electrification and widescale hydrogen use. Where decarbonization through direct electrification of a sector is feasible, this is the first priority due to the inefficiencies of converting electricity to hydrogen. Where electrification is not an option – or a very poor one – then hydrogen is the best alternative, as is the case in many so-called hard-to-abate sectors. The energy industry is clear on where hydrogen and electrification can play a role: some 80% of energy professionals we surveyed believe that hydrogen and electrification will work in synergy, helping both to scale up; just 16% believe hydrogen and electrification will be in competition for the same share of the energy mix[1].

1.2 Today's industrial use and ambitions

Hydrogen and its derivatives are produced in large quantities today, but as an energy carrier, its use is negligible. To meet the targets of the Paris Agreement, however, the existing industrial production of hydrogen must be decarbonized. More crucially, an additional very large quantity of low-carbon hydrogen and its derivatives is needed as an energy carrier – including heating in industry, shipping and aviation, and energy storage.

Hydrogen production is already a thriving industry

Hydrogen production is already a large and thriving industry. Except it is not low-carbon hydrogen production that is thriving today. The hydrogen produced today is predominately used in fertilizer or for chemical feedstock and is produced from coal or natural gas without carbon capture. The associated emissions are significant: around 900 million tonnes of CO_2 in 2020, or greater than the CO_2 emissions of France and Germany combined.

Global demand for hydrogen and its derivatives as an industrial feedstock (i.e., non-energy hydrogen) is around 90 million tonnes per year (2020)[2]. In energy terms, this is equivalent to around 12 EJ or roughly 2% of world energy demand. To put this in perspective, DNV forecasts that demand for hydrogen as an *energy carrier* will not reach this level until the early 2040s. Non-energy hydrogen has a role to play in the energy transition, however. Tackling its emissions will help to scale and accelerate carbon capture and abatement technologies.

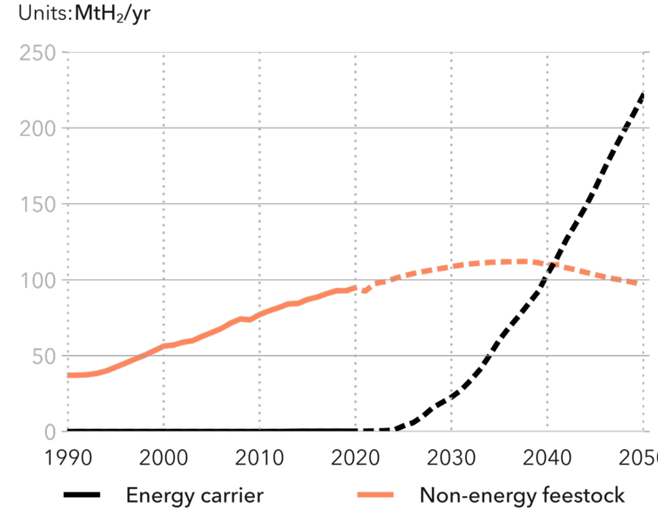
Hydrogen today is used in oil refining, fertilizer, and industrial processes

Today's hydrogen demand is split between pure

FIGURE 1.2

Global demand for hydrogen and its derivatives by purpose

Units: MtH_2/yr



Historical source: IEA Future of Hydrogen (2019) hydrogen use in oil refining and demand for hydrogen from chemical production to produce derivatives such as ammonia and methanol. Of hydrogen used in chemical production, roughly three-quarters is used for ammonia production and one-quarter for methanol. A relatively small proportion of hydrogen demand is also consumed directly in steel production.

- Petroleum refining – Oil refineries are the largest consumer of hydrogen (around 37 Mt in 2020) using it to reduce the sulfur content of diesel oil and upgrade heavy residual oils into higher-value oil products. This demand is set to continue in the coming years as global oil demand remains around its current level, before declining from around 2030 with a fall in oil demand.
- Ammonia – Around 33 Mt/yr of hydrogen is used annually to produce ammonia (NH_3), with 70% of this used as an essential precursor in producing fertilizers[3]. Accordingly, ammonia demand is correlated with global agricultural production, which continues to grow. Ammonia is traded around the world, with global exports equating to about 10% of total production – showing the feasibility of ammonia shipping and global ammonia trade, which will be an important enabler of the future hydrogen ecosystem.
- Methanol – Around 13 Mt/yr of hydrogen is used each year for methanol production, which is used in industrial processes to produce the chemical formaldehyde and in plastics and coatings.
- Steel – Close to 5 Mt/yr of hydrogen annually is used directly in steel production for direct reduction of iron (DRI). Fossil fuels are currently used throughout the steelmaking process, in the form of coke, as a reducing agent, and as for various heat-intensive stages of the iron- and steelmaking process – all of which could be replaced by low-carbon hydrogen.

The hydrogen produced today is almost exclusively produced from fossil fuels (grey, black and brown hydrogen, from natural gas and coal respectively). However, carbon prices are rising, particularly in Europe, and all industries are under mounting pressure to decarbonize – particularly the oil and gas industry. From one perspective, the transition from grey/black/brown hydrogen to blue and green (produced from fossil fuels with carbon capture, or by renewable energy) in oil refining, ammonia production, and other industrial uses could ensure early demand for low-carbon hydrogen, helping the hydrogen 'ecosystem' – i.e., value chains supporting hydrogen as an energy carrier – to scale. From another perspective, these are large industries that will later compete with energy users for low-carbon hydrogen.

Growing ambitions for hydrogen as an energy carrier

Hydrogen has a new status as an important, viable, and rapidly-developing pillar of the energy transition. More than six in ten senior energy professionals surveyed by DNV in 2022 say that hydrogen will be a significant part of the energy mix by 2030[4], and close to half say their organization is actively entering the hydrogen market. More than this, the hydrogen pledges, plans, and pilots of recent years are now beginning to evolve into concrete commitments, investments and full-scale projects.

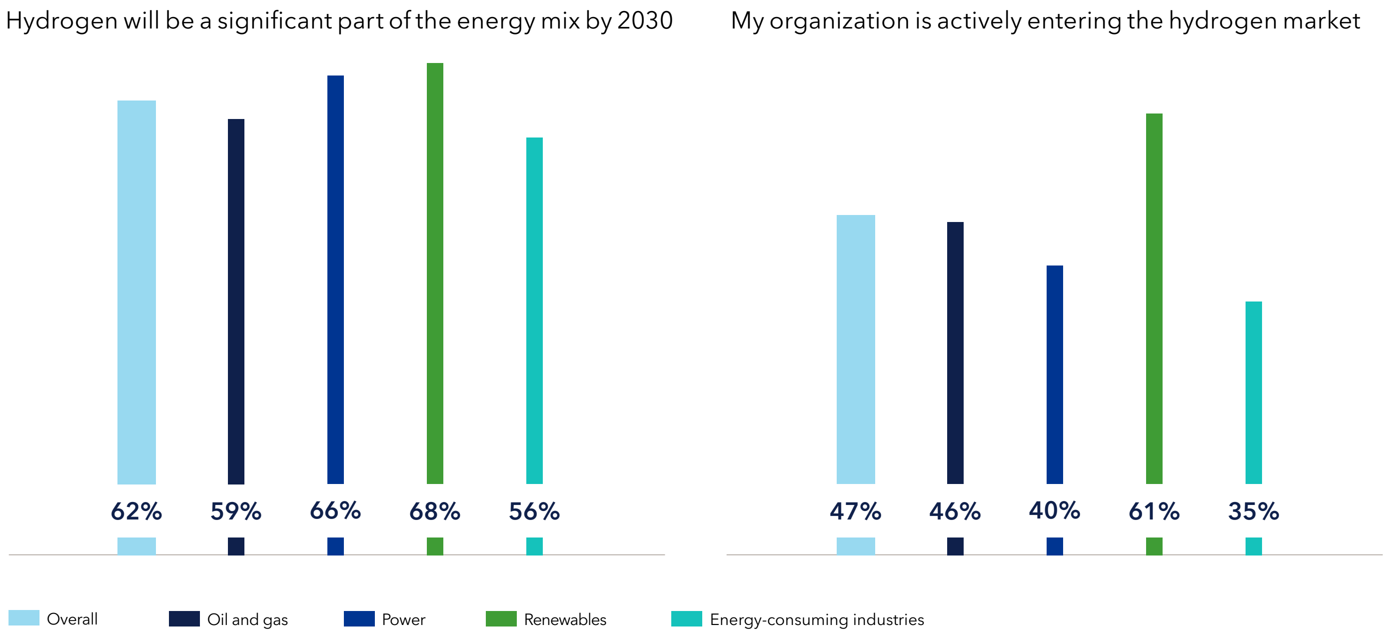
To pursue their ambitions to increase their production of green and blue hydrogen in the coming years, producers will need greater certainty to have the confidence for large-scale investments and projects. This will require ambitious policies and government strategies, several industries simultaneously building the demand-side of the hydrogen value chain, and realization of the expected huge growth in renewable generation. That growth has to accelerate beyond the demand for renewably-generated electricity to create clean, low-cost energy for green hydrogen production, and greater demand for hydrogen for energy storage.

In line with climate and net zero goals, many industries have a pressing need to replace carbon-intensive processes by reconfiguring their plants, machines, models, and practices to switch to hydrogen – which can be a substitute for either fossil-fuel-based energy or feedstock needs in these industries. For example, long-haul trucking fleets can replace diesel with hydrogen fuel cells; heat processes in cement, aluminium and steelmaking can be fuelled by hydrogen; and chemical companies that produce ammonia can swap grey/brown hydrogen feedstock for blue/green equivalents.

We present the forecast demand and supply in Chapter 5.

FIGURE 1.3

Energy industry ambitions for hydrogen



Source: DNV Energy Industry Insights 2022, based on a survey concluding in January 2022.

Low-carbon derivatives key to a widespread use of hydrogen as an energy carrier

Just as hydrogen today is converted to ammonia and methanol for some industrial applications, widespread use of hydrogen as an energy carrier will also rely on hydrogen derivatives and hydrogen-based synthetic fuels, where the properties of these energy carriers make more sense for the application than pure hydrogen. These derivatives will need to be produced in a low-carbon way.

Aviation and shipping stand out as the two sectors that will make the most significant use of low-carbon hydrogen derivatives. What they have in common is that they are disconnected from the grid and require large amounts of energy, meaning electrification or pure hydrogen are not feasible alternatives to the fossil-based fuels they currently rely on. The energy density of both pure hydrogen and batteries are too low to be used widely in these industries. Where these sectors differ from one another is the weight and space available for fuel storage, with weight particularly critical in aviation.

- Aviation – Hydrogen-based synthetic fuels – synthetic kerosene or similar – are likely to be used in aviation, and we expect pure hydrogen to see some use for medium-haul flights, but we don't forecast significant uptake before the 2040s.
- Shipping – There is no relevant battery electric option for decarbonizing the deep-sea shipping sector, with synthetic fuels, ammonia, hydrogen and biofuels being the most realistic low-carbon alternatives. These high-cost fuels, which can be implemented in hybrid configurations with diesel- and gas-fuelled propulsion, will see significant uptake, providing slightly over 42% of the maritime fuel mix by 2050, according to DNV's latest forecast.

Hydrogen derivatives will also be used in the transport and storage of hydrogen, as we explore further in Chapter 5.

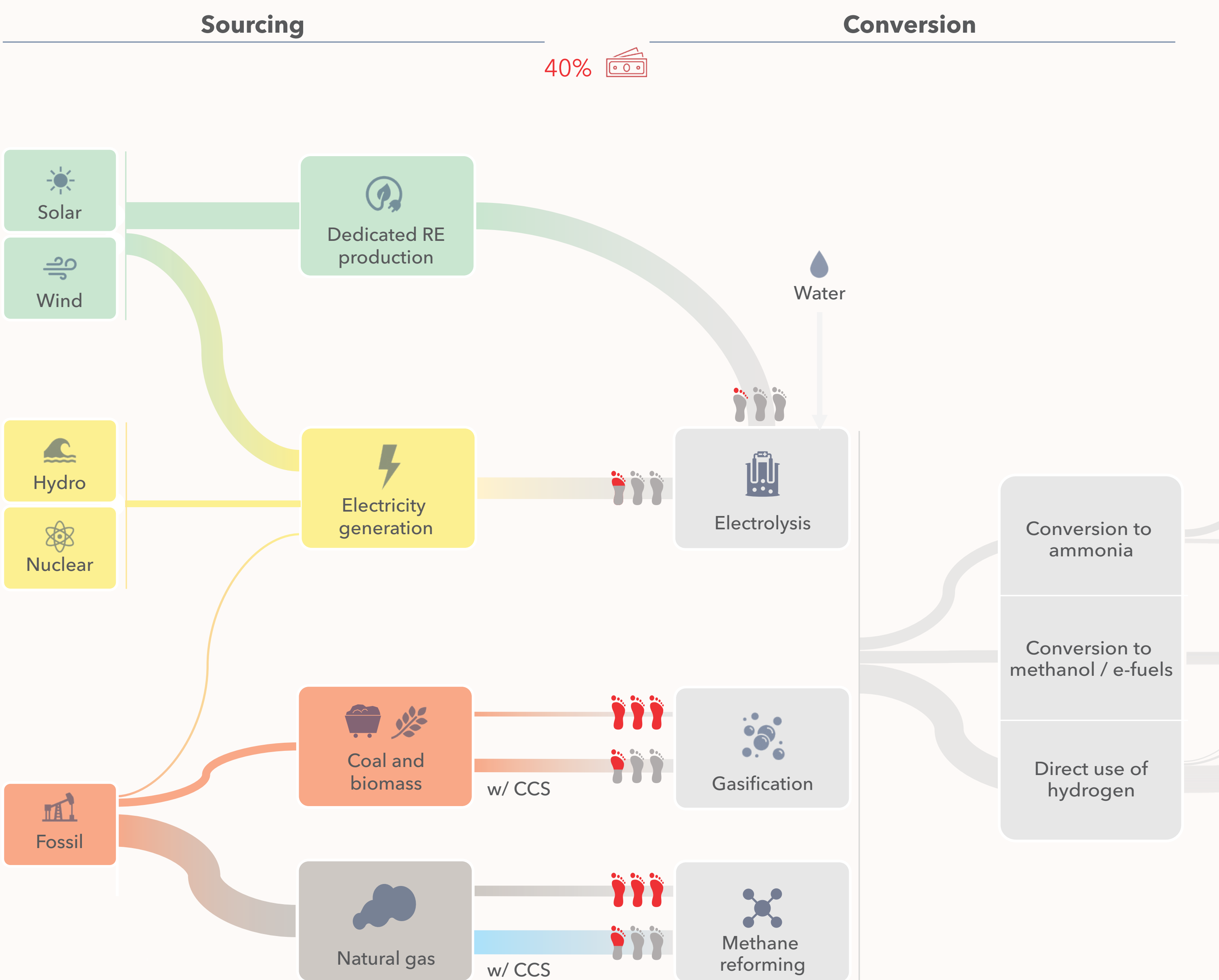
1.3 Hydrogen value chains

The market and value chains for hydrogen as an energy carrier are in their infancy – even as the potential has been debated for decades. Hydrogen markets today are mainly captive, with production taking place at or close to key industrial consumers. There are little to no open commodity markets for hydrogen, with the exception of markets for hydrogen derivatives such as ammonia and methanol. Hydrogen is currently almost exclusively produced from natural gas and coal without CCS. In many if not most cases, an intermediate step to a fully decarbonized hydrogen value chain is through the production of blue hydrogen (i.e. CCS-based hydrogen production from fossil fuels) before surplus or dedicated renewable energy is available in sufficient quantities for the large-scale production of green hydrogen.

For hydrogen to play a meaningful role as a strategic decarbonized energy carrier, new value chains and the development of hydrogen markets are required.

Many different hydrogen value chains will develop towards 2050. This is partly due to the versatility of hydrogen: it can be produced from coal, natural gas, grid electricity, or dedicated renewables; it can be stored, transported, and used in its pure form, blended with natural gas, or converted to derivatives; and it will be consumed across a range of industries and applications, including maritime shipping, heat production, road transport, and aviation.

HYDROGEN PRODUCTION AND USE IN 2050



= size of CO_2 footprint, including lifecycle emissions.

This figure presents hydrogen production and use flows in 2050. The thickness of the flow lines approximates the volume of each flow indicating major production routes and end uses in 2050. However, in contrast to the Sankey diagram shown on page 68, no losses are displayed here. By 2050, the vast majority of hydrogen produced is low-carbon hydrogen either from renewable sources or CCS based fossil production.

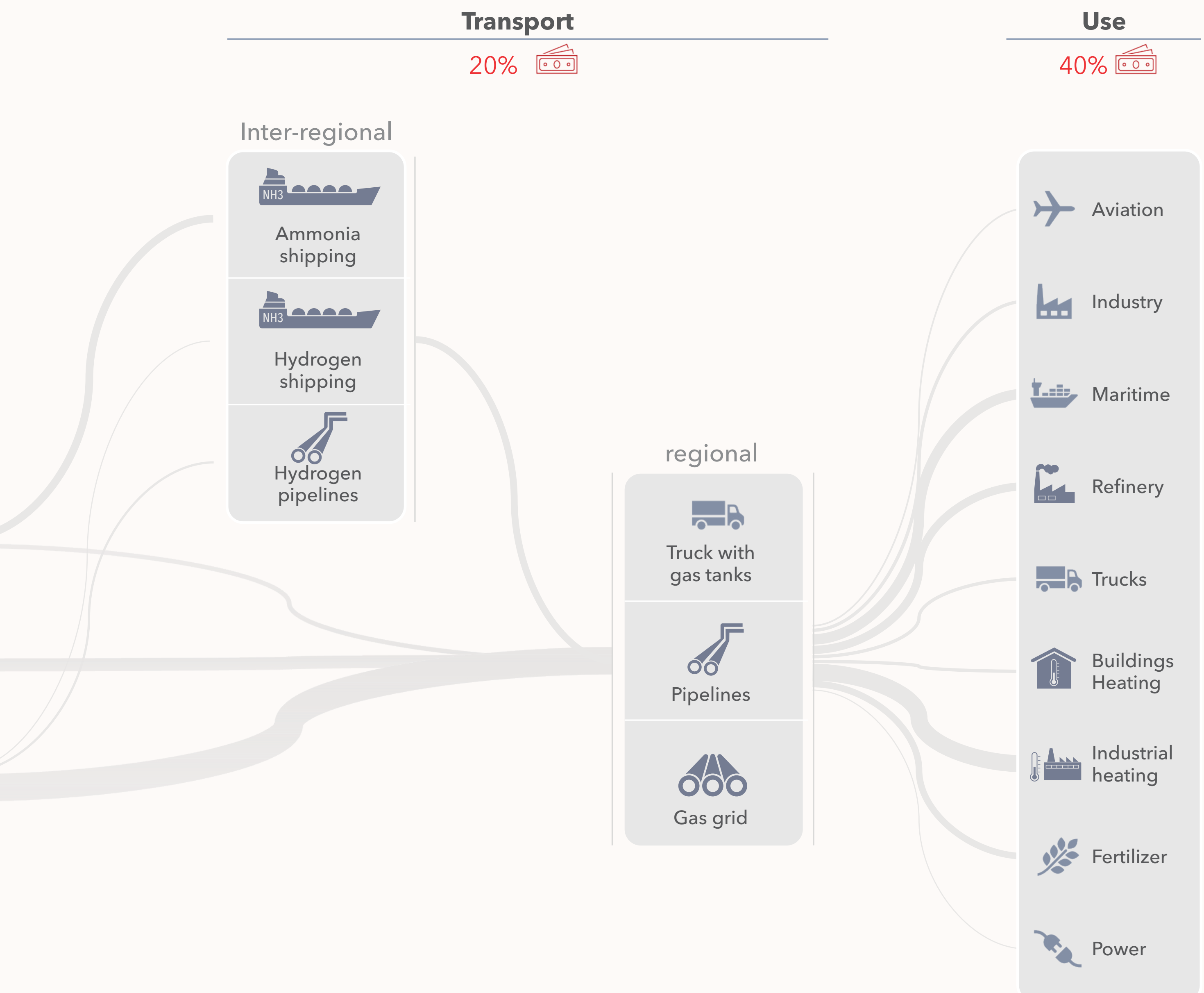
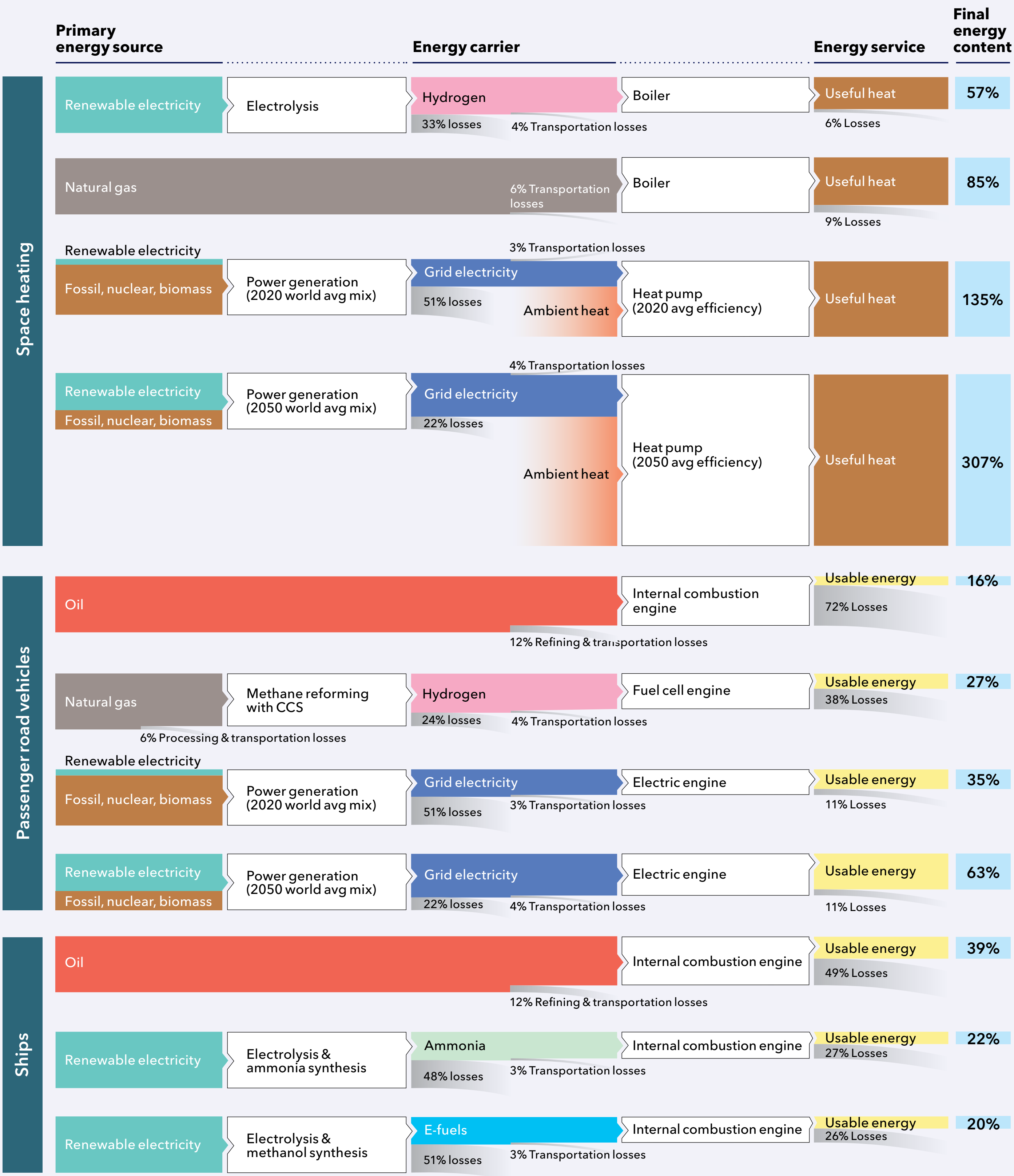


FIGURE 1.4

Comparison of selected hydrogen value chains and their competitors



Efficiencies, economics, emissions, and geography key to determining viable value chains

Determining viable hydrogen value chains is not just about linking production to consumption. It is considering energy efficiencies and losses, economics, greenhouse gas emissions, and geography – in terms of both location for transport, and resources such as natural gas and renewable energy for production. Issues of public acceptance and safety – addressed in Section 1.4 – are also pivotal.

Figure 1.4 shows alternative hydrogen value chains and their associated energy losses. Energy loss is important when it comes to deciding a value chain, as it also determines the economic situation. However, the overall economic situation is usually the main determinant for the setup and design of a hydrogen value chain. The production of hydrogen is associated with significant losses in each value chain, but when the source of hydrogen production, like renewable electricity in the coming decades, is abundantly available, energy losses will be less important in the long term.

Value chain greenhouse gas emissions will be a decisive factor in establishing specific hydrogen value chains. Takers of hydrogen, such as countries or end-use sectors, will have preferences on the value chain greenhouse gas emissions and thus incentivize their implementation. Transport of hydrogen is another decisive factor influencing a hydrogen value chain. Some world regions might not be able to supply their regional needs of hydrogen and thus have to import hydrogen via pipelines or maritime shipping. Related to this is the factor of geographies. Whereas some regions in the world can use abundant resources from wind and solar to produce green hydrogen, other regions might need to rely on hydrogen from natural gas. All of the above is of course surrounded by economic assessments as hydrogen is expensive to produce and needs to be used sensibly. As illustrated in Figure 1.4, there are plenty hydrogen value-chain permutations, impacted by, amongst others, the aforementioned factors. The specific details combining in each of these chains, such as sources, conversion, transport, end use, etc. are presented in more detail in the coming chapters.

Skills and standards key to successful implementation of new value chains

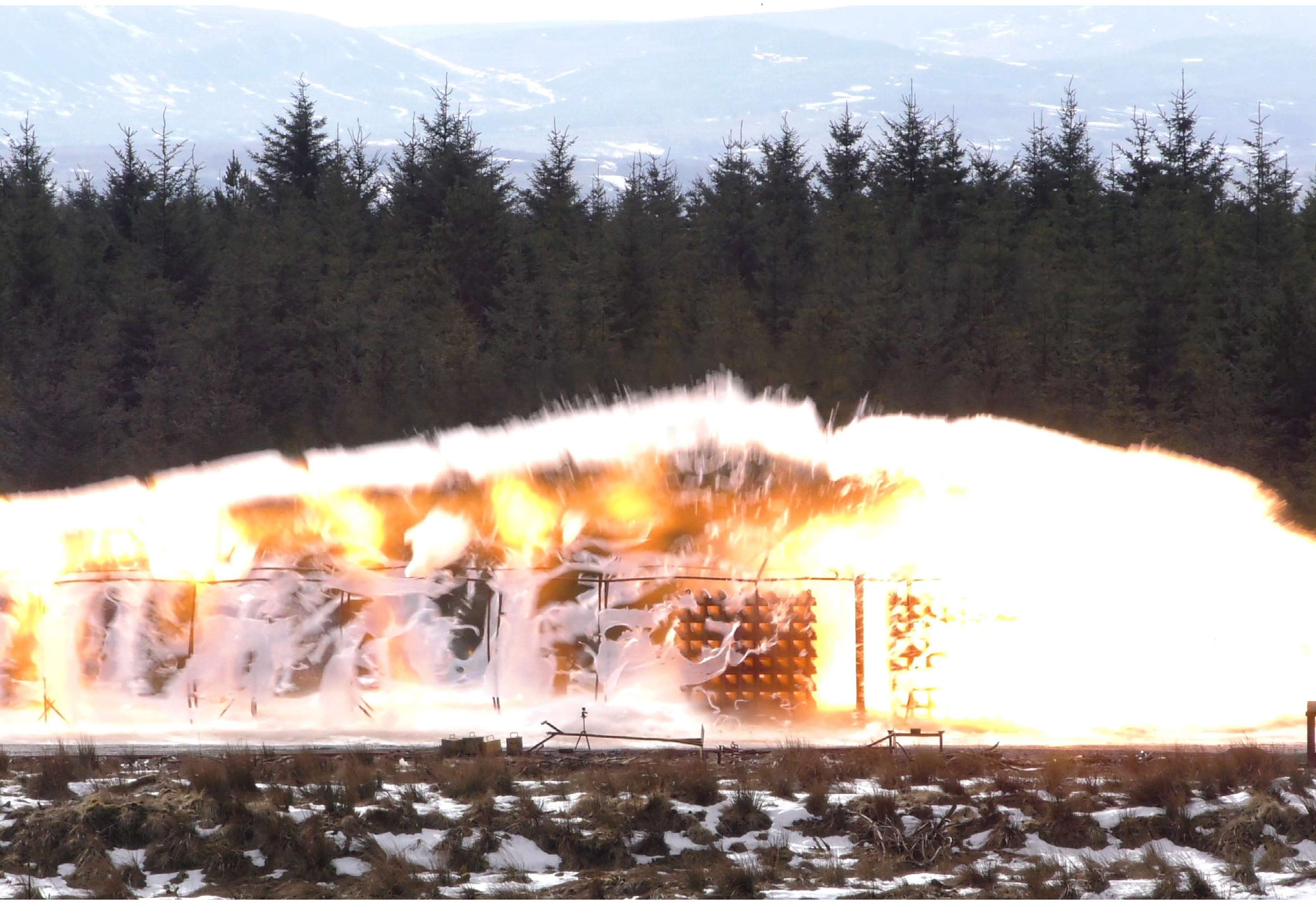
The implementation of hydrogen in the energy system will re-use existing energy industry skills and services across the whole supply chain. These will be transferred from the oil and gas sector to support both blue and green hydrogen. Connected to blue hydrogen, oil and gas skills will have to be retained to produce natural gas for refineries to reform into blue hydrogen.

Value chain greenhouse gas emissions will be a decisive factor in establishing specific hydrogen value chains.

Standards and procedures for existing offshore operations will help ensure the safety and success of the new hydrogen industry. For example, connected to green hydrogen, offshore wind will involve the installation of ever larger wind turbines requiring knowledge of floating and fixed structures in deep water and operation in challenging weather conditions.

The hydrogen supply chain will also include ports and logistics, pipeline design and manufacture, transmission and distribution infrastructure, safety assessments, above ground storage tanks and below ground geological hydrogen storage. Each of these will require skilled labour.

Chapter 7 dives more deeply into value-chain evolution, with examples and details of their economics and possible growth paths.



Detonation of hydrogen is entirely credible at scales representative of many scenarios where it is not for traditional hydrocarbons. This image shows a still image from a 15 m^3 hydrogen detonation conducted as a demonstration at DNV's Spadeadam Research Centre in the UK

1.4 Safety, risks and hazards

Hydrogen is not new to society; it has been produced and used in large quantities for over a century. However, this has mostly been in industrial environments where there is a good degree of control, and where facilities are managed by people who have a clear understanding of the potential hazards. The forecast significant growth in the market for hydrogen as an energy carrier will introduce many new hydrogen facilities that are very different from those we have had in the past. Moreover, some of the facilities will be in much closer proximity to the public and will be built and operated by new entrants who may not have relevant experience in hydrogen safety. Our previous experience of hydrogen safety is thus an imperfect guide, at best, as to what might happen in the future.

Risk perception will be an important factor in acceptance of hydrogen use. Accidents involving hydrogen are likely to receive more media attention than comparable events with conventional fuels (at least initially) and this could excite public resistance and prompt a more restrictive regulatory environment. The sensitivities to risk and risk perception will likely vary among sectors but will be highest where the public is near the actual use of hydrogen, such as in aviation and domestic heating, and less so in more industrial-type applications such as hydrogen storage.

Safety represents a significant business risk to investors and developers. There have already been examples where incidents at hydrogen refuelling stations have halted hydrogen use in vehicles for significant periods.

The industry has tried-and-tested methods for managing the safety of flammable gases that have been used for decades and these come with some very important, hard won, lessons. Firstly, safety must be based on an understanding of how the particular properties of hydrogen and hydrogen derivatives affect the potential hazards. Secondly, it is by far most effective (in terms of both safety and cost) if appropriate risk-reduction measures are added early in the design stage. In many instances, if addressed early, these measures can be incorporated at little (and at times no) extra cost and can result in designs that are inherently safer. Finally, the design intent needs to be maintained through the full life cycle: safety measures should not degrade.

Achieving all this requires an understanding of the key properties of hydrogen (and its derivatives) that affect the hazards. As hydrogen is very different to its derivatives, we need to consider those separately.

Hydrogen hazards

Hydrogen is a flammable non-toxic gas in ambient conditions. The effect of its properties on hazards and hazard management are probably best understood by reference to another flammable non-toxic gas that is widely accepted by society: natural gas (or its primary component, methane).

So how do the properties of hydrogen change the potential hazards? For hydrogen, as with natural gas, ignition of accidental releases can result in fires and explosions. Research is very active in these areas and DNV is engaged in large-scale experimental research at our Research & Testing site at Spadeadam, Cumbria, UK[5]. Although our understanding is still developing, we know enough to understand where to concentrate efforts with hydrogen. Table 1.1 summarizes the differences between hydrogen and natural gas/methane, in both gaseous and liquid form.

Ignition of a flammable gas cloud does not always result in an explosion. Pressure is generated when either the gas cloud is confined within an enclosure, or the flame accelerates to high speed (or both). This could occur in a wide range of possible scenarios, from low-pressure leaks in domestic properties, medium-pressure leaks in hydrogen production facilities or marine applications, to high-pressure leaks from storage facilities.

Our previous experience of hydrogen safety is an imperfect guide, at best, as to what might happen in the future.

The severity of an explosion will depend on many factors, but in general, the more 'reactive' the fuel the worse the explosion. Reactivity in this sense relates to how fast a flame moves through a flammable cloud. At its worst, hydrogen flames can burn about an order of magnitude faster than natural gas and much faster than most commonly-used hydrocarbons.

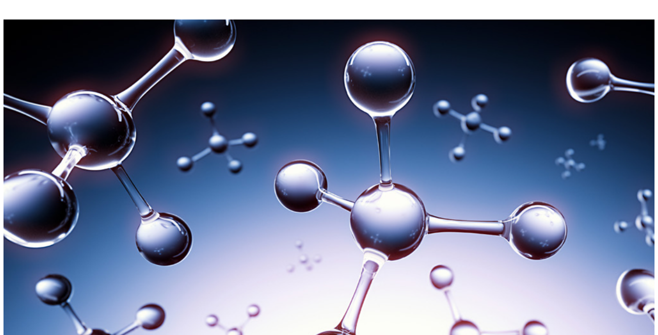
To add to this, when a flame travels very fast, going supersonic, the explosion can transition to a detonation. A detonation is a self-sustaining explosion process with a leading shock of 20 bar that compresses the gas to a point of autoignition. The subsequent combustion provides the energy to maintain the shockwave.

DNV's HyStreet Facility sits at the end of the most complete onshore 'beach to burner' demonstration of hydrogen use anywhere in the world. DNV's HyStreet provides the domestic end-use with 100% hydrogen boilers providing heating, Northern Gas Network's H21 project demonstrates distribution in the below 7 barg regime and National Grid's currently-under-construction FutureGrid facility will demonstrate transmission in large diameter, high pressure systems (up to 70 barg).

TABLE 1.1

Comparison of hydrogen and natural gas/methane properties and hazardous outcome

Hydrogen property		
Gaseous (compressed) hydrogen		
Density	Release rate	Being one eighth of the density of methane, in equivalent conditions the volumetric flow rate of hydrogen is 2.8 times that of methane; conversely, the mass flow of methane is 2.8 times that of hydrogen. Isolated hydrogen pressure systems will depressurise faster than for methane, but larger flammable clouds may result. The higher energy density per unit mass of hydrogen means the energy flow (like for like) is similar.
	Dispersion and gas build-up	Hydrogen is more buoyant than methane and will have a strong tendency to move upwards, an aspect that can be used to minimise the potential for hazardous concentrations to develop.
Ignitability	Ignition energy	The minimum spark energy required to ignite a hydrogen-air mixture is less than a tenth of that required for methane or natural gas. However, this does not necessarily significantly increase the chance of ignition. Testing by DNV has shown that many potential ignition sources either ignite both hydrogen and natural gas mixtures or neither. Only a small proportion will ignite hydrogen but not natural gas. Additionally, equipment approved for use in hydrogen systems is readily available.
	Flammability	Concentrations of hydrogen in air between 4% and 75% are flammable, which is a much wider range than for natural gas (5-15%). This will increase the likelihood of ignition.
Combustion	Fire	Released compressed hydrogen gas will burn as a jet fire. Flame lengths correlate well the energy flow rate and as this is similar for hydrogen and methane, in like for like conditions, the jet fire hazards are similar.
	Explosion	The explosion potential for hydrogen is much greater compared to methane as at higher concentrations in air (>20%) the speed of the flame is much more than for methane. In addition, hydrogen-air mixtures can undergo transition to detonation in realistic conditions, which would not occur with methane.
Liquid hydrogen (additional to compressed gas hazards)		
Temperature	Liquefaction	In many ways, liquid hydrogen is a cryogenic liquid like liquefied natural gas (LNG). But due to the lower temperature, spillages can liquefy and solidify air from the atmosphere. The resulting mix of liquid hydrogen and liquid/solid air has exploded in small scale field experiments. This does not occur with LNG.
Density	Buoyancy and dispersion	As liquid hydrogen vapourizes and mixes with air, it cools the air, increasing its density. Consequently, a hydrogen air cloud produced from a liquid hydrogen release will not be as strongly buoyant as in a gaseous hydrogen case. This also occurs with LNG but in this case the LNG-air mixture will be denser than air.



Methane molecule

Hydrogen molecule

Detonability varies from fuel to fuel and detonations would not occur in any realistic situation with natural gas but are entirely credible for hydrogen. It is also notable that current explosion simulation methods used by industry are not able to model the transition to detonation, but only indicate when it might occur, though there is still considerable uncertainty in this area.

This sounds like bad news for hydrogen facilities yet we know that these properties depend on the concentration of the fuel in air. If concentrations are kept below about 15% hydrogen in air, it is no worse than methane at similar concentrations. The implication is that a key element of managing hydrogen safety is the control of gas dispersion and build-up to prevent the concentration of hydrogen in air exceeding 15% as far as is practicable. This is a particular challenge where dispersal space is constrained – for example onboard ships. Gas detection and rapid isolation of hydrogen inventories will be key measures. Consideration of ventilation rates and ventilation patterns is also critical. Importantly, current simulation methods can model gas dispersion and build-up with reasonable confidence.

In summary, although hydrogen's high explosion reactivity is justifiably concerning, by being aware of this issue and designing to avoid high hydrogen concentrations in the atmosphere, it is reasonable to expect we can engineer facilities that are as safe or better than widely-accepted natural gas facilities. If based on a sound technical understanding and addressed in early design, the cost implications of such engineering solutions may not be significant.

Feasibility of ammonia for shipping has been described in the DNV white paper from 2020: *Ammonia as a marine fuel*. The additional DNV class notation "Gas fueled ammonia" was released in July 2021.

Hydrogen derivatives

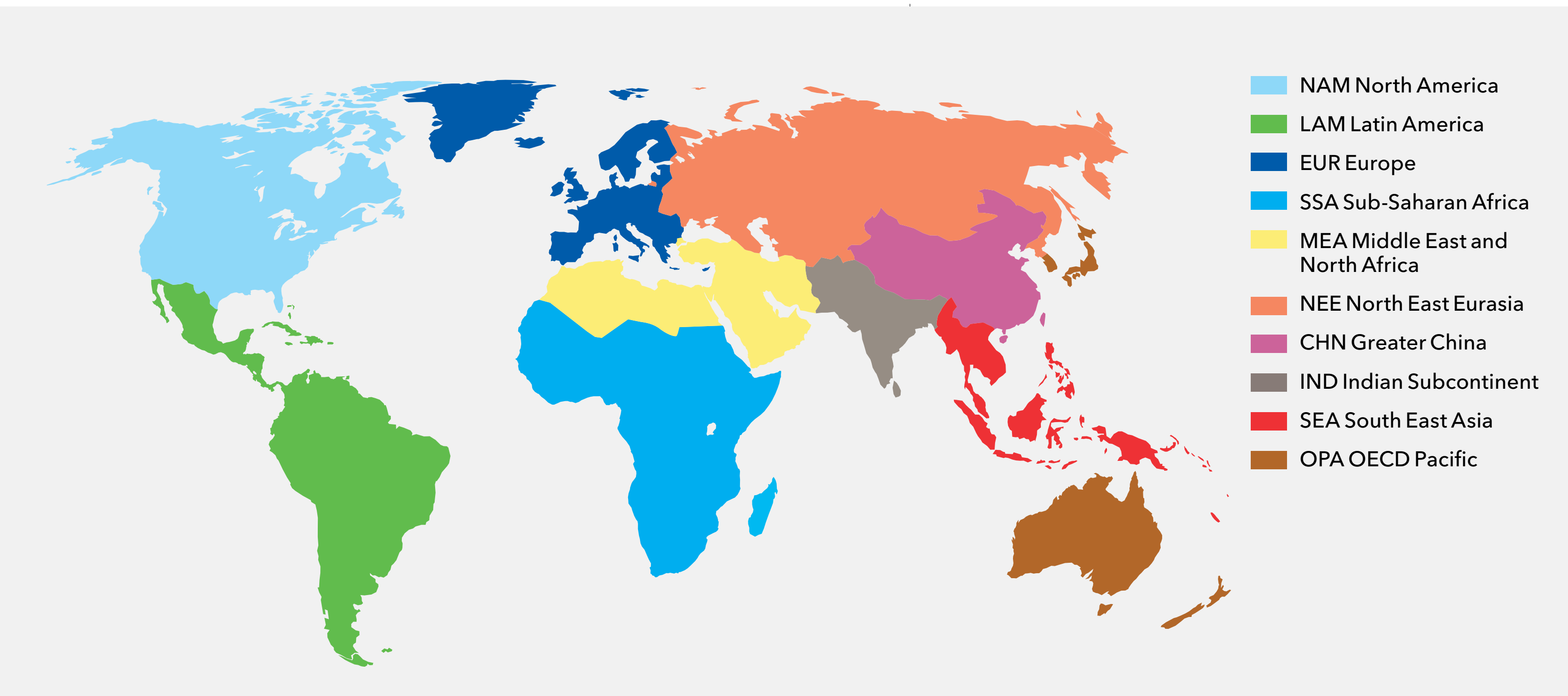
Arguably, the most important hydrogen derivative in relation to hazard management is ammonia. Ammonia is flammable but it is relatively difficult to ignite and as its burning velocity is well below that of methane, the explosion risk is small. The key hazard with ammonia is its toxicity; it is harmful to personnel at concentrations well below its lower flammability limit of 15% in air. For example, UK HSE indicates a concentration of 0.36% could cause 1% fatalities given 30 minutes of exposure. Concentrations of 5.5% could cause 50% fatalities following 5 minutes of exposure.

While ammonia has been widely manufactured for over 100 years and is used in considerable amounts in the manufacture of fertilizers, its potential hazards need now to be understood in the context of new energy transition applications, as is the case with hydrogen. A very relevant example is the likely use of ammonia as a fuel in the maritime sector. An ammonia release within the hull of a ship has the potential to develop potentially fatal concentrations in confined spaces. Unlike hydrogen, this hazard cannot be reduced by measures that reduce the chance of ignition; ammonia has a direct effect if released and comes into contact with personnel. There is therefore no guarantee that the risks are lower than for hydrogen, even though it has no real explosion potential. Risk assessment would involve application of standard hazard management methods and would need to consider aspects such as the types of release that could occur, the potential concentrations that could be generated, and the likelihood of personnel being exposed to harmful levels. Mitigation methods would include ammonia release detection and emergency shutdown of ammonia systems and ventilation, but could also require the availability of emergency breather units and very well defined escape routes.

A key element of managing hydrogen safety is the control of gas dispersion and build-up to prevent the concentration of hydrogen in air exceeding 15% as far as is practicable.

Liquid organic hydrogen carriers (LOHCs) have the lowest safety risks as their properties are close to those of liquid hydrocarbons already handled in large quantities.

Safety management should be straightforward, though it should be noted that hydrogen will be required during production and will be produced at the point of utilization (as may also be the case for ammonia).

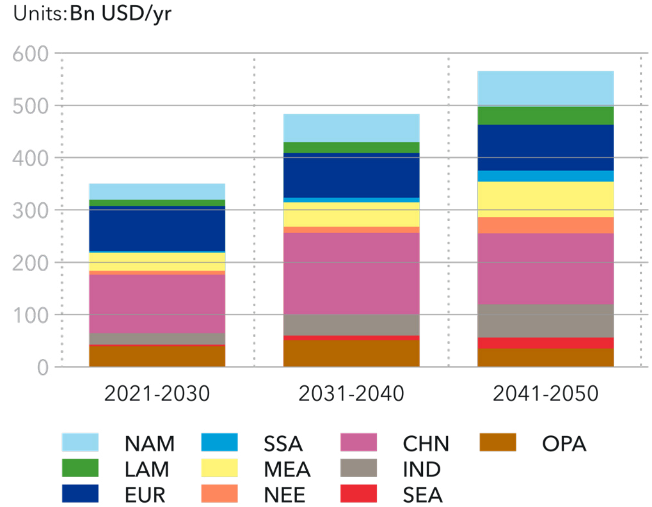


1.5 Hydrogen investments risks

FIGURE 1.5

Global expenditures for production of hydrogen and its derivatives by region

Units: Bn USD/yr



Includes both capital and operating expenditures.

There is currently unprecedented interest in renewable and low-carbon hydrogen as an energy carrier, fuel, and clean molecule. However, there is still a long way to go: first for investment to flow beyond research and pilot projects, and second to realize many large-scale hydrogen projects and develop or retrofit infrastructure.

Huge investments required for large-scale value chains for energy purposes

In 2021, USD 12bn was invested globally in hydrogen as energy carrier. Annual investment in hydrogen and its derivatives by 2030 will stand at USD 129bn and by 2050 at USD 440bn – with hydrogen as an energy carrier growing rapidly by then and well into the second half of this century. As impressive as these figures are, much more investment will be needed in hydrogen, and sooner, to ensure a Paris-compliant energy transition. Our *Pathway to Net Zero Emissions* sees hydrogen accounting for around 13% of global energy demand, more than double the most likely future we forecast for hydrogen.

The question arises whether a faster, bigger future for hydrogen is affordable. Within the context of world expenditure on energy, the answer is yes. We forecast that the percentage of world gross domestic product (GDP) that will be spent on energy is set to fall from 3.2% in 2019 to 1.6% in 2050 owing to rising efficiencies associated mainly with electrification. If the current fraction of GDP devoted to energy expenditures were to remain constant, the surplus funds to spend on clean energy would grow by around USD 2trn each year, reaching close to USD 63trn by 2050 – enough to finance a transition compliant with the Paris Agreement, including the required scaling of decarbonized hydrogen.

Hydrogen investment intrinsically linked to wider energy investment trends

As the energy transition accelerates, energy companies are making critical, long-term strategic decisions on their futures, with much of the industry making transformational green investments. Financiers, meanwhile, are reassessing and bringing forward the future risk in fossil fuels – fearing stranded assets, and driven by developments in areas such as ESG, taxonomies, carbon pricing, and pressure from shareholders and the public.

Significant capital is looking for a new home in the energy transition, but it is not necessarily the case that this capital will flow into hydrogen. Oil and gas projects have been struggling to secure financing, with 38% of senior oil and gas professionals saying that their organization is finding it difficult to access reasonably priced finance for oil and gas projects[6]. This response is based on DNV's January 2022 survey undertaken before Russia's invasion of Ukraine. Nevertheless, our research shows that the drivers away from fossil fuels – decarbonization and the energy transition – are resilient, long-term trends that have been largely unaffected by the cyclical nature of the industry.

In contrast, renewable energy projects, at least in developed markets, are receiving significant interest and there is abundant capital available to these projects – the bottleneck for renewables is instead permitting and available projects[7]. However, financing is not as readily available for projects employing technologies with less-mature value chains. For hydrogen, while interest and investment expectations are increasing, the capital is not flowing as readily into projects as it is into renewables.

Reducing risk and increasing the appeal of hydrogen investments

Capital will only flow into projects that are bankable. Energy companies and investors need to ensure hydrogen projects offer a balance between risk and return. This requires long-term stability, certainty, and line-of-sight, which can be strengthened by business models and long-term agreements, the regulatory environment, government support, partnerships, and technological innovation.

The market's maturity is also essential, with investment risk reduced by greater certainty of demand, now and in the future. An ever-present worry for companies investing in hydrogen production is where the demand will come from, at what level, and crucially, when.

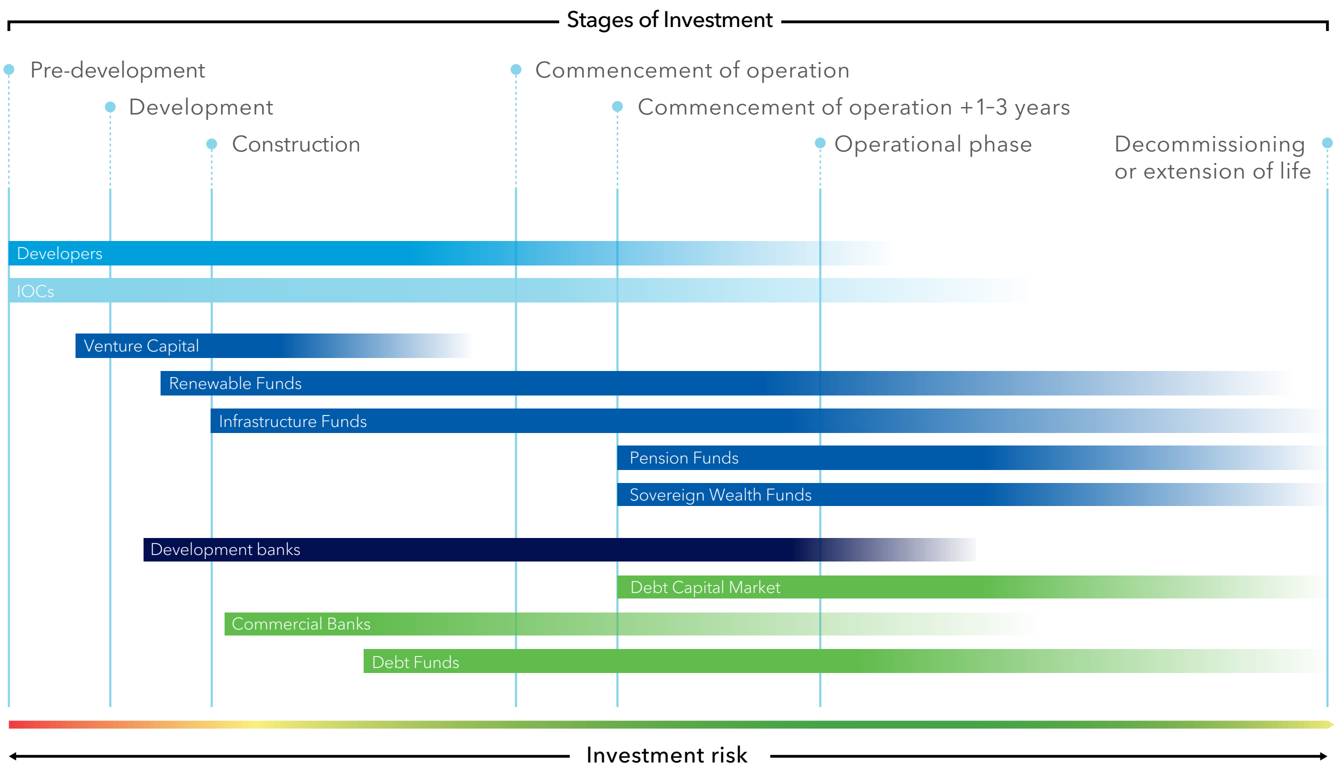
The core issue is that from a financing perspective, hydrogen opportunities are currently long-term, low-return, and seemingly high-risk. Financiers are unlikely to accept such risk without significant government support in terms of creating certainty and providing more direct support through subsidies – and this is what we see in the markets.

In the early stages of rolling out technologies, the costs are often high, and enterprises have to follow long-term strategies and implement plans that may lack profits in the short term. But they do so to gain market share in the industry, in the expectation that once hydrogen supply and demand increase, costs will fall, and profits will improve.

Early-stage investment can be a challenge. Initial support and industry involvement is needed to fast-track projects to the stage where they have lower risk and fit the profile for widely-used financial mechanisms. It is a question of achieving safe, large-scale production of low-carbon hydrogen at a lower price. The ambition is to develop the maturity of markets and investors within them, so that different financiers have the business models and risk appetites to come in at each stage of a project, from concept to completion. For hydrogen, most projects – beyond pilots and R&D – are in the pre-development phase. Risk is high at this stage, and it is developers and IOCs (international oil companies) that are active.

FIGURE 1.6

Investor appetite



Source: Financing the Energy Transition, DNV 2021

Certainty of demand and supply

Greater certainty on the demand for technologies and innovations can reduce risk and increase investment. But as debates continue on blue vs green hydrogen, hydrogen vs electrification, and green hydrogen vs batteries for energy storage, demand for hydrogen is far from certain.

This report, providing DNV's independent forecast of hydrogen supply and demand to 2050, may help by providing a best estimate for a likely energy future that companies and governments may consider when forming their hydrogen strategies. Beyond that, there are other ways to ensure certainty of demand, such as agreements between producers and consumers, whether in the form of a green hydrogen power purchase agreements (PPAs) or joint investment in industrial clusters for hydrogen. Announcements from major companies, such as a switch to hydrogen by a major industrial user in steel production, or for ammonia use in shipping, can help to create certainty. Governments can also lead the way as major investors and consumers of hydrogen, for example by building early demand for hydrogen use in public transport. Another option for governments is to introduce quantity-based policies to stimulate the demand-side (see discussion in Chapter 2).

National hydrogen strategies and policies will play a crucial role. Policymakers will need to plan at the level of energy systems, simultaneously pursuing policies to enable significant scaling of renewable power generation and the build out of CCS value chains. Currently, from the supply side, hydrogen producers face uncertainty in the supply of resources to produce low-carbon hydrogen, whether it's available and affordable natural gas with sufficiently low supply-chain emissions for low-carbon blue hydrogen production, or grid surplus or dedicated renewable energy (or potential) for green hydrogen production. Further along the value chain, consumers in hard-to-abate industries – reliant on fossil fuels for fuel and feedstock – are looking for solutions such as hydrogen and derivatives to decarbonize but need certainty that they will be able to access a secure and affordable supply of the low carbon alternative to which they transition.

Standards, taxonomy and carbon price

Standards and taxonomies classify activities that are sustainable and aligned with climate targets, and those which are not, providing clear direction for energy investment and the basis for incentives, standards, and regulations. Taxonomies, such as the EU taxonomy, can help to ensure capital flows into clean energy projects and technologies, and away from unabated or emissions-intense fossil fuels. Such taxonomies and standards, and certification that hydrogen projects and products comply with them, can significantly de-risk investment. The flip side is that before taxonomies are agreed and finalized, there is uncertainty and risk. Companies are unlikely to invest in blue hydrogen for example, until there is clarity on whether this will be eligible for "low-carbon" investment.

DNV's research *Blue Hydrogen in a Low-Carbon Energy Future* (2021) addresses the issue of whether blue hydrogen can be considered low carbon[8]. We find that blue hydrogen can be delivered with a lower greenhouse gas (GHG) footprint than the thresholds in the taxonomy as defined by the EU and World Business Council for Sustainable Development. However, this requires a combination of hydrogen production technology and carbon capture that focuses on high conversion rates and high CO_2 capture rates, resulting in low process-related CO_2 and methane emissions. In addition, the natural gas supply-chain emissions of CO_2 and methane must be kept low. Our data show that this can be delivered with current natural gas supply in some regions, but far from all.

Certification of hydrogen could play a major role in this regard, directing capital to low-carbon projects, and giving both producers and consumers the confidence – and data – that a switch to hydrogen will support their decarbonization efforts.

An effective carbon price – or clarity on when such a price will be implemented – would also incentivize clean energy and disincentivize unabated fossil fuels. By effective, we mean properly pricing the damage caused by emissions, but also pricing at a level that makes low-carbon technologies commercially viable. Such a carbon price would significantly de-risk hydrogen investment.

Financial instruments

To de-risk and improve the profitability of clean-energy opportunities governments and markets worldwide have developed business models and financial instruments. These mainly reduce risk and create certainty (such as hydrogen power purchase agreements or contracts for difference) or subsidise and incentivize (such as via feed-in-tariffs or tax equity financing) in order to develop projects and technologies to a stage where more traditional forms of financing are available – such as debt and equity financing.

As mentioned, hydrogen has a unique mix of attributes that give it similarities to electricity and to a fossil fuel. The question then from a finance perspective is: how will hydrogen be priced once the market matures? The view from the industry is split roughly 50/50 on this question[9]. How hydrogen is priced has implications for what types of financial mechanisms would be best to employ. Electricity prices are often governed by regulatory bodies, which serve to protect consumers and guarantee a stable rate of return for providers. Fossil-fuel prices are more driven by free-market forces, which makes them more volatile, yet potentially more profitable.

More specific policies and mechanisms will need to be adapted for regions, countries, and sectors to be effective. It is visibility of the implementation, of what regulations and support for these technologies will look like, that will give the certainty required. We explore hydrogen policies and strategies in more detail in Chapter 2.

2 HYDROGEN POLICIES AND STRATEGIES

2.1 Policy and the hydrogen transition

Hydrogen's role in the energy transition has become clearer in recent years, and more urgent just in recent months. The decarbonization pathways of a select few sectors largely rely on hydrogen's environmental credentials, while ensuring affordability, availability, and safety. Renewable and low-carbon hydrogen will increasingly play a part as strategic energy carriers for an energy-secure future.

However, realizing any innovation journey depends on regulatory frameworks prompting stakeholder cooperation and aligning decisions and collective competencies. There is a need to co-evolve the hydrogen value chains and 'ecosystems' from production, distribution, and use. At the same time, policy must unleash additional renewable power capacities and CCS deployment, as both are prerequisites for renewable (green) and low-carbon (blue) hydrogen, e-fuels and hydrogen carriers.

Here we delve into policy and regulations that are already in play to accelerate the evolution. In Section 2.4, we describe the policy considerations directly factored into our forecast. We also summarize key considerations for policymakers (see opposite).

Revamping regulatory frameworks to advance hydrogen energy

The hydrogen innovation trajectory, and overcoming its barriers, are shaped by the emerging and harmonizing regulatory frameworks, displaying a broad spectrum from government policy to industry regulation that incentivize coordination through codes of practice and standards. For any nascent energy carrier and market, a comprehensive regulatory framework needs development, and hydrogen is no different. Policymakers and regulators face added complexity from the fragmented set of players and different energy subsectors, traditionally operating and regulated within their own silos. With more sector coupling, these players and sectors are increasingly intertwined, requiring harmonized regulatory frameworks that view electricity and gas sectors cohesively.

Regulatory frameworks will have to address several hydrogen production and use areas simultaneously, such as:

- Decarbonizing existing hydrogen production and use
- Fuel switching (e.g. from natural gas to hydrogen), which means retrofitting or modifying infrastructure mostly in established industry
- New uses, which means establishing new infrastructure for conversion of energy carriers (e.g. from diesel trucks to hydrogen electric fuel cell versions) that are largely 'outside the fence' of industry-regulated areas.

Key considerations for policymakers

1. **Policies must target multiple sectors as renewable/low-carbon hydrogen can be a sustainable energy carrier, fuel, and chemical feedstock.** Hydrogen can assist decarbonization where electrification is difficult and will be used in making sustainable end products (e.g., ammonia/fertilizers), green materials (e.g., steel and aluminium), and low-carbon chemicals (e.g., methanol and plastics).

2. **Decarbonization policies/regulation must address safety gaps.** There are gaps in guidelines and operational procedures for hydrogen, especially large-scale production, storage, transport, and new end-uses. For a safe transition, new/retrofitted infrastructure will need updated guidelines and standards alongside policies and regulation.

3. **Regulation is complex but can be tailored to required transitions.** Regulation is needed for decarbonizing current hydrogen production/use; retrofitting or modifying infrastructure for fuel switching; new uses; and production with new infrastructure. Existing, updated, and new policies can be overarching or sector-specific.

4. **Policies/regulation must spur ramp-up of technologies to support hydrogen use.** Policies must unleash renewable/low-carbon hydrogen production by vastly boosting renewable power capacity, CCS, new/retrofitted gas and power grids, and scale production of electrolysers. CCS is also needed at huge scale for direct air capture of CO_2 to meet climate targets.

5. **Hydrogen needs policies that accelerate production *and* offtake.** Direct funding is the main tool supporting scaling of low-carbon hydrogen production by lowering CAPEX costs. Demand-side policy must stimulate offtake. Fiscal policies (e.g. carbon pricing, taxes reflecting carbon efficiency/pollutants) are needed for low-carbon hydrogen to compete with unabated fossil-based hydrogen. Market-based instruments such as contracts for difference (CfDs) can cut OPEX costs and offer predictable terms for producers and end users.

6. **Decarbonized hydrogen can benefit humanity but needs infrastructure plans and investment.** Hydrogen can be part of existing gas systems, or a decarbonized energy carrier for medium- to long-term storage, providing energy security. As a feedstock for ammonia/fertilizers, it supports food security. Maximizing these benefits hinges on planning and new public infrastructure investments (e.g. salt caverns to store hydrogen, and new/retrofitted gas pipelines to transport it), and on continued use of existing practices and infrastructure for ammonia while decarbonizing its production.

7. **Easy wins include decarbonizing existing hydrogen production and use.** Use renewable hydrogen from electrolysers co-located with industries and capture carbon from fossil-based hydrogen production. This requires support to reduce investment costs and incentivize early retirement of fossil-based capacity in a policy package to increase competitiveness of low carbon-intensity hydrogen.

8. **A comprehensive regulatory toolbox is needed to encourage fuel switching, retrofitted/newbuild infrastructure, and multiple decarbonization options.** Hard-to-abate industries need more support for retrofitting/replacing equipment and/or modifying infrastructure. New infrastructure must often be built alongside existing assets before old infrastructure is retrofitted. Higher OPEX and lower margins are seldom options for commodity producers, unless markets offer green premiums. Sectors will often choose hybrid decarbonization pathways (electrification, hydrogen, CCS) requiring a policy mix. Regulation of integrated energy systems is key if harmonization between sectors and across borders is needed.

9. **New production and offtake require new regulatory frameworks, standards, and guidelines.** This is relevant, for example, for offshore hydrogen production, new direct hydrogen offtake, or hydrogen carrier use in shipping or aviation. Innovation and full-scale testing and developments are needed. Moving beyond pilots to large-scale testing and implementation often requires new regulations, standards, and guidelines.

10. **Readiness for scaling is high, but key factors block investment.** Policy should aim to remove barriers to large-scale investments. Key barriers include: having no framework for guaranteeing the origin/traceability of hydrogen; renewable power and CCS capacity must scale while reducing CAPEX/OPEX costs; support mechanisms (e.g. CfDs or higher carbon pricing on fossil hydrogen) are crucial for low-carbon hydrogen.

Governments are steering the trajectory by incorporating hydrogen into planning and requirements. Their targets and dedicated hydrogen budgets aim to catalyse projects and advance scaling timeously and safely towards 2030 and 2050 climate objectives. Synchronously, government strategies and policies are geared towards industrial positioning, competitive advantages and, increasingly, towards energy security. However, our analysis of regions (highlights presented in Section 2.3) shows that not all regions and governments are stimulating hydrogen development comprehensively across the full chain from production to use.

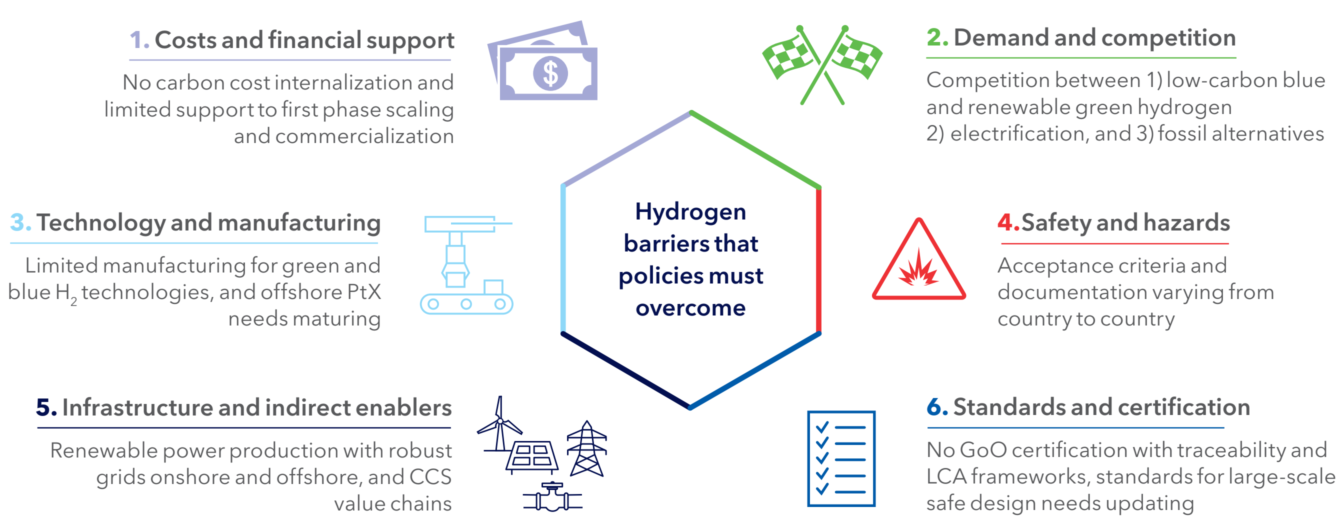
Policy measures amongst pioneer countries kick-start technology cost-learning dynamics. We saw this with solar and wind power cost reductions in their early-stage development. The same will be the case for specific hydrogen technologies. Front-runner countries play a big role in kick-starting learning and cost reductions. For example, Germany is speeding up its hydrogen transition, with EUR 7bn made available to drive the market rollout towards 2030, while the US is dedicating USD 8bn to hydrogen hubs and aims for clean hydrogen produced at USD 1 per kilogram of hydrogen (/kgH_2) within the decade.

Businesses are the key agents in all development phases from demonstration and deployment to hydrogen infrastructure and transportation. Some hydrogen technologies are well-established (e.g. grey hydrogen used directly in refineries and ammonia production), while others are not (e.g. infrastructure for new end use, large-scale electrolysers and offshore production). An industrialized or commercialized scale-up with safe and cost-effective production, transportation, and use of hydrogen needs carefully crafted policy frameworks to succeed. Towards this end, policymakers are shaping the business innovation agenda as seen recently in the government-led Glasgow Breakthroughs, the global Mission Innovation initiative, and the public-private partnership First Movers Coalition.

International collaboration is pulling government and industry players together to progress hydrogen. This is exemplified by the Partnership Agreement between the International Renewable Energy Agency (IRENA) and the Hydrogen Council; the IRENA and World Economic Forum (WEF) Hydrogen Toolbox; and the World Business Council for Sustainable Development (WBCSD) SMI hydrogen industry pledges initiative (H_2Zero), also with proposed policies[1]. These collaborative initiatives are instrumental in facilitating harmonization and exchange of best practices.

FIGURE 2.1

Breakdown of barriers for policies to overcome



2.1.1 What policies and regulatory frameworks must target to overcome barriers

Regulatory frameworks and policies need tailoring to overcome administrative, technical, and economic barriers to hydrogen scale-up, and with safety as a cross-cutting priority. Figure 2.1 is inspired by the work of IRENA & WEF 2022[2] and recaps the current state of play. These potential showstoppers need to be overcome to facilitate a safe and accelerated scaling of hydrogen production, enabling infrastructure, and supporting new offtake. The figure shows the main barrier categories the policies must address. This is not an exhaustive checklist. While some barriers are overarching, global and regional, most must be dealt with on a country-by-country basis.

1. Costs and financial support
- No carbon cost internalization
- Lack of upstream support
- Lack of downstream support
- Unfit market design
- Unclear frameworks for Contracts for Differences until fossil hydrogen, and alternatives become more costly
- A higher cost level for the future (> 1.5–2 EUR/kg), not possible for any kind of hydrogen (except turquoise/ pyrolysis and purple/nuclear?)

2. Demand and competition
- Global competitiveness between H_2 production and trade
- Global competition between alternatives to hydrogen use (batteries, electrification and existing fossil alternatives)
- Availability and security of supply (where storage is minimized due to high costs)

3. Technology and manufacturing
- Materials use in equipment
- De-risking new industrial applications
- Electrolyser and fuel cells performance
- Assessing compatibility of the existing gas grid
- De-risking integrated Power-to-X (PtX) pathways
- Slow electrolyser manufacturing expansion
- Fuel cell manufacturing capacity
- Industrial assets lifetime delaying renewal

4. Safety and hazards
- Acceptance criteria and documentation, varying from country to country, some do not have established criteria
- No experience with large-scale green hydrogen production (> 200 MW), and unclear safety philosophies and inherently safe design
- Little experience with hydrogen use for certain sectors (fuel switching and new use)
- Unclear national and local procedures for approving new installations, especially outside industry areas

5. Infrastructure and indirect enablers
- Slow renewable capacity deployment and unclear additionality
- Carbon capture and storage (CCS) value chains
- Power grid capacity – power grid for distributed green hydrogen production
- Gas grid retrofit or newbuild – for buffering/storage of early production, connecting large-scale production (in new areas) and offtake (in existing clusters)
- Lack of infrastructure support and development Infrastructure uncertainty

6. Standards and certification
- No Guarantee of Origin (GoO) certification of hydrogen
- No GoO certification of hydrogen derivatives
- Incompatibility across borders
- Unclear methodology for estimates in lifecycle assessment (LCA) of greenhouse gas (GHG) emissions
- Lack of clarity on environmental impact beyond GHGs
- Standardization for design and safety

2.2 Details on the policy and regulatory landscape

Several hydrogen-related guides for policy makers have been published recently (e.g., IEA 2021, IRENA 2021[3]). To progress the hydrogen transition, there is a policy toolbox of known and proven measures available (e.g. DNV Energy Transition Outlook 2021, Section 6.5[4]), which leans heavily on approaches and experience from advancing renewable electricity over decades. However, new policy measures tailored to specific needs along the value chain are needed and are evolving.

In this section, we elaborate five policy categories that affect the most likely hydrogen future to 2050. Four of them are national strategies, technology-push, demand-pull, and fiscal policies. A fifth, standards and certification, gets its main impetus from public and private partnerships.

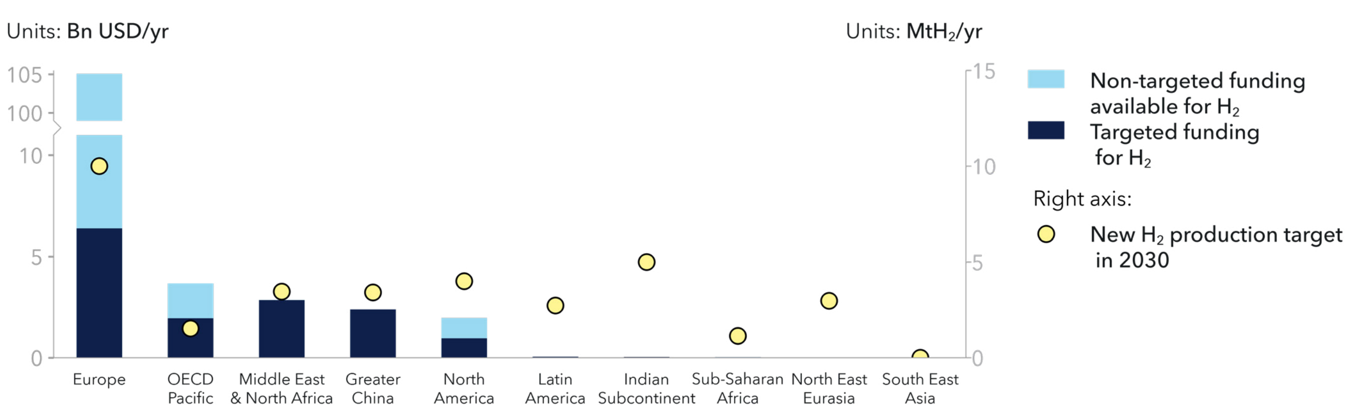
National strategies with timelines and targets are the first step to creating a stable planning horizon and certainty for stakeholders. The second step is to establish more costly fossil-energy carriers (see elaboration under fiscal policies page 34) until the hydrogen value-chain becomes economically viable.

National hydrogen strategies and roadmaps have been multiplying in DNV's Energy Transition Outlook (ETO) regions. Not surprisingly, this is predominantly in regions with net-zero mid-century ambitions, such as Europe, North America, and OECD Pacific. However, we see great variation in terms of comprehensiveness and real policies on 'how to deliver' under these strategies.

As part of green hydrogen strategies, renewable electricity development needs significant attention and upscaling, where additionality – meaning renewable-based electricity consumed by electrolysers *is additional* to renewables meeting renewable electricity consumption targets – is also expected to be a requirement. The buildout also needs a speedier process. A data insight from Energymonitor.ai (2022 based on GlobalData[5]) showed that Top 20 EU countries have four-times more wind capacity in permitting than under construction, and that the 'standstill' is not a uniquely European challenge: while 81% of the EU's wind pipeline is stuck in permitting, the US (79%), China (74%), and India (64%) are also facing logjams. Renewable power buildout is a prerequisite for green hydrogen production, and the scale required is enormous: DNV's *Pathway to Net Zero* study (2021[6]) projects electricity demand growth of more than 180% by 2050, with the largest (400-fold) increase in power demand coming from hydrogen production via electrolysis.

FIGURE 2.2

Available public funding and production target for hydrogen by region



Sources: DNV analysis; IRENA (2022)

Note on funding: The figure provides an overview of the funding support potentially available for hydrogen projects in the 10 regions as of April 2022. More funds might be available.
Note on production targets: The production targets represent outspoken targets on new (renewable or low-carbon) hydrogen production per year in 2030. Where targets are based on installed electrolyser capacity from dedicated renewables, such as for some countries in LAM, NEE, CHN and SSA, yearly production is calculated using an efficiency of 65% and 5000 full load hours per year.

Real policy and support measures are needed to catalyse implementation of national hydrogen strategies.

Technology-push policies are at play to advance technologies along the entrepreneurial and technology development cycle from R&D and piloting to scale-up.

We find that government funding programmes with investment grants/loans to capital expenditures (CAPEX) are the dominant early-stage form of support.
Programmes are focusing on promoting renewable and low-carbon hydrogen production. Funding is available to decarbonize existing hydrogen production, new merchant production, and for transformation projects for switching to hydrogen-based fuels (i.e., e-fuels, ammonia).

In Figure 2.2, the average annual government funding (targeted for hydrogen, and non-targeted but for which hydrogen projects qualify) available for different regions is mapped against national production targets in 2030. Some regions – e.g. Europe, Middle East and North Africa, and OECD Pacific – show a clear connection between ambitions on scaling hydrogen production and available funding. In addition to local production, Europe has targets of 10 Mt/yr renewable hydrogen imports. Other regions have ambitious targets but are lacking in funding, which is likely to make it more difficult to reach their targets. However, with several of these regions (e.g. Latin America and Sub-Saharan Africa) mainly targeting production for exports, funding might be available from international partnerships with importing regions. As an example, the German Federal Ministry of Economic Cooperation and Development (BMZ) is promoting green hydrogen production in South Africa (see Section 2.3.4).

To date, only a few countries have production support mechanisms supporting operational expenditures (OPEX) over a fixed timeframe.
One example is the US, where a 10-year tax credit per kilogram of hydrogen (see Section 2.3.1), is proposed with tax-credit rates tailored to emissions, the highest to renewable hydrogen. Another example is Denmark's planned feed-in tariff scheme with a fixed-price subsidy, also for 10 years.

We expect to see more schemes supporting OPEX costs and a guaranteed price to producers in the future to enhance the business case for both producers and users. In this regard, Contracts for Difference (CfDs) are a plausible mechanism. As CAPEX support is likely to dwindle over time after initial government-supported plants have been built — and grey hydrogen remains less expensive because of, for example, insufficient carbon pricing — a long-term arrangement is needed to close the economic gap and incentivize continued investments. CfDs support operational costs with a strike price guaranteed to producers over a fixed period. Such contracts can provide stable and predictable terms for producers, and for end users because, through continued investments and reduction in hydrogen costs, they have spillover effects for hydrogen price and demand in end uses.

Demand-pull policies are in play to create demand for renewable and low-carbon hydrogen in new applications as well as among established industry to switch from unabated fossil-based hydrogen. We find that government funding programmes are equally available to hydrogen consumers to cover CAPEX such as that linked to conversion of process technology and equipment upgrades (e.g. to use hydrogen for heating in manufacturing, buildings, and heavy transport).

It is uncommon to find quota-based or quantity-based policies to stimulate consumption and create demand among end-use sectors.
Future policy packages are likely to involve mechanisms such as binding targets and obligations on demand sectors (e.g. industrial consumers requiring a fixed amount/share of energy/fuels to come from hydrogen). The EU is proposing to mandate green hydrogen in the EU energy mix by 2030 (e.g. with a transport sector sub-target of 2.6% from green hydrogen and e-fuels) with use of RFNBOs (renewable fuels of non-biological origin) to meet targets. In road transport, California as part of the North America region, South Korea, Japan and China have targets and support for fuel-cell powered vehicles (FCEVs) and infrastructure development.

We expect to see hydrogen blend mandates applied in maritime and aviation to trigger uptake in the future. Grid blending of a certain percentage into the gas grid is another option that could provide long-term volume offtake certainty and confidence to new investments.

Overall, we find that policy measures to spark offtake and demand creation across end-use segments are rather limited.

Fiscal policies include economy-wide economic signals, such as carbon pricing to pass on carbon costs to emitters, hence encouraging the use of low-carbon or renewable hydrogen.

Although the number of schemes is increasing, carbon pricing is not at sufficient levels across ETO regions. In combination with fossil-fuel subsidies, this limits decarbonization, CCS uptake, and hydrogen competitiveness overall. Robust carbon prices stimulate innovation and are needed to close the cost gap between conventional unabated fossil-fuel-based technologies and new hydrogen-based technologies.

Operating alongside carbon pricing are energy taxation, and often high grid-connection costs and taxes on grid-connected power consumption. Reform efforts are expected, as exemplified by the revision of the EU Energy Taxation Directive, for increasing alignment of taxation with environmental performance and climate objectives. Reforms will unfold at an uneven pace with high-income regions (with net-zero targets by 2050) being first movers in the refinement of tax schemes to promote electrification and hydrogen use.

Implementing safety standards and certification schemes are key in scaling hydrogen as an energy carrier and fostering international trade.

To pave the way for global trade of hydrogen and other hydrogen-derivatives (see Chapter 6), standards and certifications need to be in place as they ensure clarity on the quality and origin of a product. A key aspect here is establishing the carbon intensity of the hydrogen produced, to guarantee that it really is contributing to meeting decarbonization targets.

Although these standards and guidelines need further development, we see several promising initiatives from both industry and public-private partnerships. Some examples are the Hydrogen Production Analysis Task Force (IPHE) on GHG estimation methodology, and the WBCSD initiative on low-carbon hydrogen pledges from industry and supporting methodology for calculating emission levels. Other initiatives include new national and EU legislation on certification of hydrogen, such as enabled by the voluntary CertifHy™ certification scheme providing guarantees of origin and transparent information about environmental attributes of hydrogen. These will be essential to support harmonization and, in so doing, establishing the global hydrogen value chain.

In addition to product certification schemes, clarity, standardization and harmonization on the technical and safety aspects of hydrogen are needed to ensure secure and reliable supply. It can be a challenge to scale hydrogen as an energy carrier at the pace required to meet decarbonization targets while also achieving satisfactory hydrogen safety. Nevertheless, safety requirements need to be the foundation of all projects, as unwanted incidents can slow down or halt developments. Although safety guidelines and regulation for hydrogen and other carriers such as ammonia are well known in established industries, this is not the case for several new use-cases, such as for large-scale storage or hydrogen blending in pipelines. Industry is now paving the way in establishing new, global standards on hydrogen-related activities. Although several countries might have to adopt their own standards, having global and harmonized standards across regions and sectors can help de-risk hydrogen projects and provide clarity for all parties involved.

As part of green hydrogen strategies, renewable electricity development needs significant attention and upscaling.

2.3 Regional hydrogen policy developments

The field of regional policy analysis is a moving target with frequent new policy announcements. Nevertheless, we have assessed the current 'state of play', focusing on the extent to which plans and targets are backed by comprehensive policy packages to ensure their execution. In other words, policy packages that address the hydrogen value chain from production to usage, and so instil a level of believability in implementation.

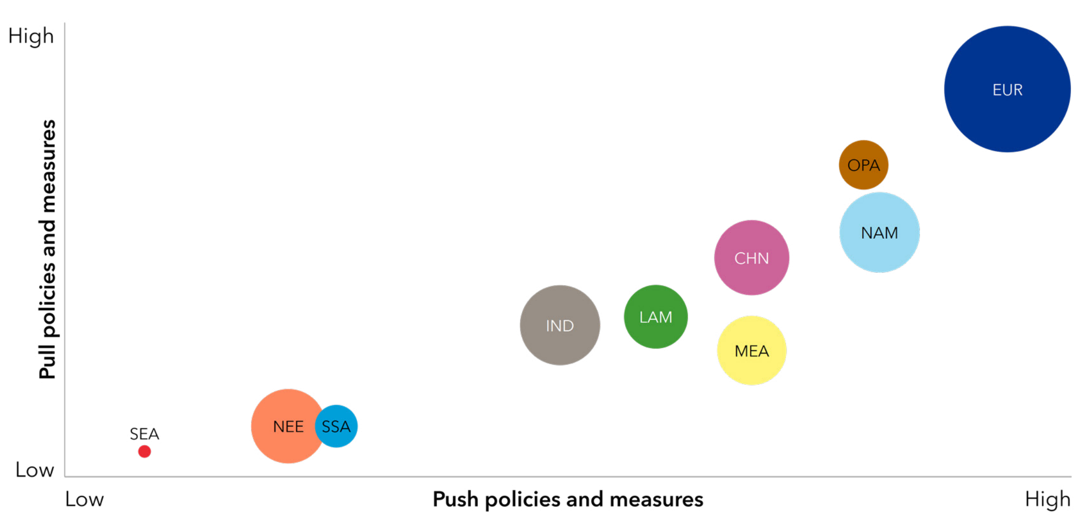
Our analysis of the policy landscape of national strategies, targets, funding levels and policy measures suggests that not all regions have comprehensive policy frameworks in place to implement hydrogen ambitions. Some regions are clearly at the forefront of advancing hydrogen. Others look less mature despite encompassing individual countries that have taken steps to position themselves as front-runners on the global hydrogen stage.

Figure 2.3 provides an overview of the 10 world regions and their targeted *new* renewable or low-carbon hydrogen production in 2030. Note that this does not include targets on imported hydrogen. The placement of region bubbles is determined by the comprehensiveness of present policy packages in terms of their combination of technology-push, demand-pull, and fiscal policies. We have *not* attempted to score the content of individual policies. Rather the intent is to pinpoint how regions are positioned with regards to putting in place a holistic set of policy measures to achieve their announced ambitions and to advance their hydrogen development trajectories.

- Europe is in the lead. The policy package provides substantial funding to kick-start the scaling of hydrogen production and cluster development. In parallel, offtake and utilization in end-use sectors are stimulated; for example, proposed legally binding targets and obligations on fuel suppliers. Cost competitiveness against conventional fossil-fuelled technologies is advanced through tightening carbon pricing (inclusion of more sectors and removal of exemptions), and the carbon-border adjustment mechanism aims to create a level playing field between EU and non-EU suppliers.

FIGURE 2.3

Regional production targets and policy comprehensiveness



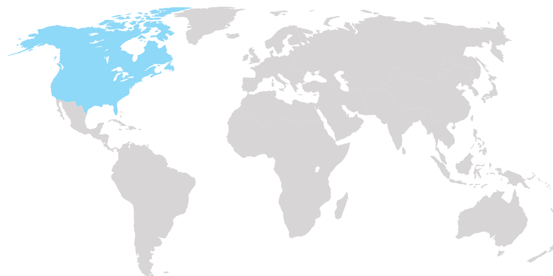
From left to right:

SEA: South East Asia
NEE: North East Eurasia
SSA: Sub-Saharan Africa
IND: Indian Subcontinent
LAM: Latin America
MEA: Middle East & North Africa
CHN: Greater China
OPA: OECD Pacific
NAM: North America
EUR: Europe

Bubble area is proportional to new H_2 production target in 2030.

- The OECD Pacific and North America regions trail Europe. They also have strategies, targets and funding pushing the supply-side, but with lower carbon-price levels and fewer or no carbon-pricing schemes at all (some US states, Australia). Carbon pricing is not central to the US climate change programme, for example. The North America region also has less-concrete targets/policies, and hence less predictability, on the future end-use uptake trajectory.
- Greater China follows on, recently providing more clarity on funding and hydrogen prospects towards 2035 coupled with an expanding national emissions trading scheme. But beyond the road transport sector, real policy frameworks are not yet concrete.
- Latin America and the Middle East and North Africa each include a select few countries where the hydrogen policy agenda is firmly established with strategies and funding, particularly targeting hydrogen production for exports. While Latin America has a key focus on renewable-based green hydrogen production, the Middle East and North Africa focus on hydrogen from renewables, nuclear, and natural gas with CCS.
- Indian Subcontinent, with India being the dominant economy, has an announced hydrogen mission and funding programme also emphasizing domestic industrial consumption, replacing present unabated fossil-fuel based hydrogen. However, the region has yet to establish comprehensive policy and regulatory frameworks, including on carbon pricing.
- North East Eurasia and Sub-Saharan Africa have some country strategies and targets for becoming blue and green suppliers, respectively, with the latter depending on foreign investments. South East Asia has no policy in place yet.

Key policy developments in our forecast regions are highlighted overleaf.



2.3.1 North America

National strategies: Canada and the US are targeting net zero GHGs by 2050, with hydrogen use pivotal to success. The US's National Clean Hydrogen Strategy and Roadmap, and the Hydrogen Energy Earthshot (June 2021), target cost reduction for clean hydrogen by 80% to USD 1/kgH_2 by 2030. Canada's Hydrogen Strategy (December 2020) aims for global leadership in clean supply and for a 30% share of hydrogen in end-use energy by 2050. No specific production targets are mentioned, though the Canadian strategy states a potential for 4 Mt/yr clean hydrogen production by 2030.

The region's focus is on advancing production hubs in low-carbon (blue) hydrogen and electrolysis based on renewables or nuclear. End-use plans include switching of existing grey hydrogen, industrial processes, road transport, and grid balancing.

Carbon-free power sector targets (US by 2035, Canada 90% by 2030) facilitate hydrogen efforts, as do strong CCS policy with R&D funding, requirements, and economic instruments (e.g. the US Section 45Q tax credit and grants).

Technology-push: Several US and Canadian federal governmental funding programmes are available for CAPEX support and scale-up. For example, the US has a USD 8bn Hydrogen Hub Plan, USD 1bn for R&D, and the USD 500mn hydrogen supply-chain initiative. Canada has a federal Low-Carbon and Zero-emissions Fuels Fund of CAD 1.5bn (USD 1.1bn) including funding for hydrogen, and the CAD 2.75bn (USD 2.1bn) Zero Emission Transit Fund for vehicles and refuelling stations. The US tax credit proposal to producers also aims to incentivize hydrogen uptake through a maximum tax credit rate of USD 3/kgH_2 for 10 years for hydrogen produced with a carbon intensity below 0.45 kgCO_2e/kgH_2 (for projects beginning construction before 2029). The tax credit rate decreases with increasing carbon intensity; for example, production with a carbon intensity between 1.5 and 2.5 kgCO_2e/kgH_2 receives 25% of the full tax credit. Facilities with 4–6 kgCO_2/kgH_2 must be placed into service before 2027.

Demand-pull: States and provinces have individual road-maps and policies. For example, California is already leading hydrogen mobility/infrastructure globally because of its Zero Emission Vehicle policy and incentives. Canadian provinces are also developing programmes supporting hydrogen storage and grid-integration pilots, industry phase-in and hydrogen-ready equipment (e.g. in Ontario). A regulatory framework for blending hydrogen in gas and propane systems, encouraging use in heavy transport, exists in British Columbia.

Carbon pricing: We see this rising in Canada from CAD 15/tCO_2 to CAD 170/tCO_2 in 2030. There are US state schemes, but no federal policy. Our projection for the regional average carbon-price level is USD 25/tCO_2 in 2030 and 70/tCO_2 by 2050.

2.3.2 Latin America

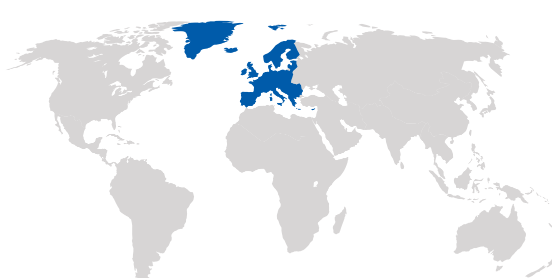
National strategies and targets: Several countries are developing hydrogen strategies (e.g. Uruguay in 2021 and Paraguay in 2022). Chile's National Green Hydrogen Strategy (2020) and Colombia's Hydrogen Roadmap (2021) are the most concrete to date. Both target clean hydrogen production to become global hydrogen export hubs. Among others, Chile aims to have 5 GW of electrolyser capacity under development by 2025, and 25 GW with committed funding by 2030. Colombia aims for 1–3 GW electrolysis capacity installed and 50 kt/yr of blue hydrogen produced by 2030. There is no concrete CCS policy, but the region has diversified its electricity mix with high renewable shares/targets with government capacity tenders/competitive bidding.

Local industry (e.g. mining, Chile's largest industry) and heavy-duty transport are key focus areas for hydrogen use; for example, Colombia plans for 40% of industry hydrogen consumption to be low-carbon hydrogen by 2030. However, the principal focus is on exporting hydrogen.

Technology-push: There is limited public funding for scaling hydrogen. The Chilean government's Production Development Corporation (CORFO) has funding of USD 50mn, with a cap of USD 30mn per company, to finance electrolyser investments.

Demand-pull: There are limited policy frameworks in road transport; for example, vehicle tax exemptions for light EVs (likely transferrable to FCEVs) and CAPEX support including for refuelling infrastructure, such as for public buses.

Carbon pricing: There are schemes, but pricing is low. Our projection for the regional average carbon-price level is USD 25/tCO_2 in 2030, and 50/tCO_2 by 2050.



2.3.3 Europe

National strategies and targets: Europe is a front-runner in the energy transition with its Green Deal to deliver a transformation to a sustainable, low-carbon economy and a climate-neutral EU by 2050. The European Union (EU) hydrogen strategy (2020) aims for at least 40 GW electrolyser capacity installed in 2030 (6 GW by 2024). REPower EU (2022) boosts ambitions, aiming for 10 Mt of domestic renewable hydrogen and 10 Mt of renewable imports, by 2030. Some countries in the region (e.g. Germany) are expected to develop into large-scale importers of hydrogen, with others becoming exporters or transit hubs. Several countries in the region have their own strategies and targets for installed hydrogen production capacity by 2030 to support the EU goals: for example, Denmark (4–6 GW), France (6.5 GW), Italy (5 GW), Germany (5 GW), and Spain (4 GW).

In REPowerEU, the EU's revision of the Renewable Energy Directive proposes a 45% renewable share of European energy use by 2030, bringing renewable generation capacities to 1,236 GW compared with 1,067 GW envisaged under Fit for 55. Hence there is strong focus on scaling renewable hydrogen production in the EU, though low-carbon hydrogen is recognized in a transitional phase. The key focuses towards 2030 are scaling electrolyser capacity, decarbonizing existing hydrogen use in industry, promoting hydrogen for new use-cases, and buildout of distribution infrastructure including storage facilitates.

Technology-push: Hydrogen projects can apply to several EU funding programmes supporting the Green Deal. The EU also recently established the public-private Clean Hydrogen Partnership to accelerate development and improvement of clean hydrogen applications. The total funding available is EUR 1bn in grants from public funding, and EUR 1bn from industry. The first call for proposals this year saw a total of EUR 600mn available for 41 topics across the hydrogen value chain. Several countries also have their own funding programmes targeted for hydrogen, most notably the German 'Packet for the Future' with EUR 7bn for hydrogen market rollout plus EUR 2bn for fostering international partnerships.

CCS policy is an enabler of hydrogen. The EU Innovation Fund finances up to 60% of the additional investment and operational costs of large-scale projects. The focus is on Projects of Common Interest (PCIs) and supporting chains to benefit several industrial installations – for example, the Northern Lights and Porthos projects in

Norway and the Netherlands, respectively. Several EU and non-EU countries (e.g. Denmark, Germany, the Netherlands, the UK) have CCS policies to help achieve net-zero ambitions.

Demand-pull: Although governmental funding is mainly based on grants as a percentage of CAPEX support (up to 50%) for hydrogen production, the funding is also available for other parts of the hydrogen value chain, stimulating demand offtake. Moreover, the European Commission is to propose Carbon Contracts for Difference (CCfDs) for green hydrogen as part of its REPowerEU scheme. CfDs for hydrogen proposed by the UK are set to be finalized by the end of 2022.

Carbon pricing: There are established schemes with clear upward pricing trends. Our projection for the regional average carbon-price level is USD 95/tCO_2 in 2030 and 135/tCO_2 by 2050.

2.3.4 Sub-Saharan Africa

National strategies and targets: Some countries within ETO regions are taking steps to becoming hydrogen exporters to Europe. South Africa's Hydrogen Society Roadmap (February 2021) aims for renewable hydrogen exports, targeting a 4% global market share by 2050 with the following timetabled production capacity targets:1 MW electrolyser production piloted to 2024; expansion to 10 GW (2025–2030); and 15 GW capacity installed (2030–2040).

Technology-push: There are low funding levels and no dedicated support programmes for hydrogen. South Africa has a ZAR 800mn (~ USD 49mn) green fund to support green initiatives including renewable energy and hydrogen. Renewable power is targeted with shares around 40% of the energy mix by 2030 (e.g. in South Africa, Kenya, Nigeria). No country in the region has concrete CCS policy.

Hydrogen development is likely to advance only if supported through international funding and bilateral government offtake agreements. Indication of movement in this direction is seen in Germany's energy links with the region. It is providing EUR 12.5mn to promote green hydrogen production in South Africa; intends to form a green hydrogen partnership with Namibia, and developed the H_2Atlas-Africa project with Sub-Saharan partner nations. Development finance institutions will also be primary financiers if green hydrogen projects are to advance.

Demand-pull: No relevant policy frameworks are available in the region.

Carbon pricing: Low/absent carbon pricing and slow adoption are expected. Our projection for the regional average carbon-price level is USD 5/tCO_2 in 2030 and 25/tCO_2 by 2050.

Note: Africa faces energy poverty and lacks stable energy supply infrastructure, hampering economic development. Making affordable power available for Sub-Saharan Africa's underserved population, and for economic development, should be prime objectives. Decarbonizing the region's power sectors should be another objective before pivoting into renewa-ble-based hydrogen for exports.

> Hydrogen development is likely to advance only if supported through international funding and bilateral government offtake agreements.

2.3.5 Middle East and North Africa

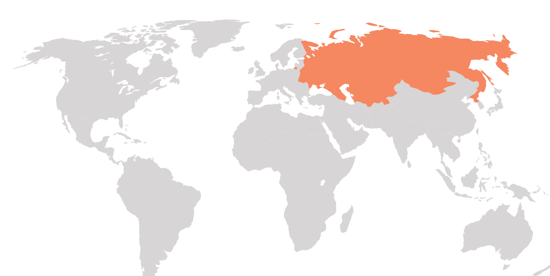
National strategies and targets: The region is a hydrogen export contender with countries seeking to become top global suppliers of hydrogen and its derivatives. Hydrogen production capacity is building on existing fossil-fuel capacities; large natural gas resources available for conversion; excellent conditions for low-cost renewables; and nuclear-powered electrolysis as in Saudi Arabia and the United Arab Emirates (UAE). Morocco, Oman and the UAE have published their hydrogen strategies, and Saudi Arabia, Algeria, Egypt and Turkey are developing theirs.

- Morocco's Green Hydrogen Roadmap (2021) targets a 4% share of global demand by 2030, prioritizing export to Europe. Domestic use plans include as raw material (feedstock) in fertilizer production, fuel for transport (freight, public transit, aviation), and green hydrogen for energy storage. The hydrogen ambitions are complemented by a 52% renewable power target (2030).
- Oman's National Hydrogen Strategy (2021) pursues blue and green hydrogen with capacity targets of 10 GW by 2030 and 30 GW by 2040. The country focuses on hydrogen for domestic use for heating in industrial processes (iron, aluminium, chemicals production), as a raw material (feedstock), and for road transport.
- The UAE's Hydrogen Leadership Roadmap (2021) targets a 25% share of the global low-carbon hydrogen/derivatives market by 2030. It is home to the region's first solar PV / green hydrogen facility. Targets include domestic use in manufacturing (e.g. steelmaking, kerosene) and public transit. Examples of export focus include bilateral agreements with Japan, South Korea, and memoranda of understanding (MoUs) with several European countries (Austria, Germany, Netherlands).
- Saudi Arabia is preparing its roadmap. It is demonstrating a blue ammonia value chain with shipment to Japan, and is planning a large-scale project for renewable hydrogen-based ammonia (NEOM). It aims for large market shares in blue hydrogen and blue ammonia in alignment with its strategy on a circular carbon economy (carbon capture, storage and utilization, CCUS). The country targets domestic hydrogen use in transport applications (FCEVs, public transit, aviation, and sustainable jet fuel production).

Technology-push: State funding and state-owned companies (e.g. in oil and petrochemicals) are involved in hydrogen projects. The UAE and Saudi Arabian governments pursue joint funding in hydrogen industrial partnerships. Morocco expects cumulative hydrogen investments of USD 8bn by 2030 and USD 75bn by 2050. Oman targets USD 34bn in renewable-hydrogen investments by 2040. Funding and support to Egypt is expected from the European Bank for Reconstruction and Development.

Demand-pull: No relevant policy/regulatory frameworks are available.

Carbon pricing: Presently low/negative. Our projection for the regional average carbon-price level is USD 10/tCO_2 in 2030 and 30/tCO_2 by 2050.



2.3.6 North East Eurasia

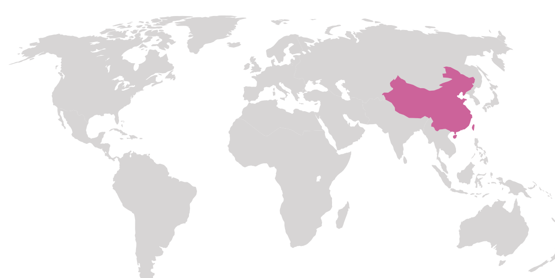
National strategies and targets: Russia's Roadmap for Hydrogen Development (2020) for the period 2021–2024 aims to preserve the country's leading role as a global energy exporter with targets of 0.2 Mt/yr by 2024 and 2 Mt/yr low-carbon hydrogen by 2030.

Ukraine featured prominently in the EU's hydrogen import plans before the Russian invasion. Ukraine's draft Hydrogen Strategy (December 2021) aims at renewable hydrogen exports, building on its extensive existing natural-gas infrastructure. The draft document includes targets of up to 10 GW of renewable hydrogen production capacity by 2030, with 7.5 GW of this dedicated to exports to the EU.

Technology-push: There is no relevant policy/regulatory framework, and no firm CCS policy/support.

Demand-pull: No relevant policy/regulatory frameworks exist.

Carbon pricing: Presently low/negative. Our projection for the regional average carbon-price level is USD 6/tCO_2 in 2030 and 20/tCO_2 by 2050.



2.3.7 Greater China

National strategies and targets: China's 14th Five-Year Plan (2021–2025) sees hydrogen as a 'frontier' industry area of the future and as support towards the goal of peak carbon emissions before 2030 and carbon neutrality by 2060. Hydrogen is expected to have a 10% share of final energy consumption by 2050 (5% by 2030). China's Hydrogen Development Roadmap targets 10 GW installed electrolyser capacity by 2025, at least 35 GW by 2030, and more than 500 GW by 2050.

In the newly released Medium and Long-term Plan for the Development of Hydrogen Energy Industry from 2021–2035 (NDRC & NEA 2022[7]), China's government targets a long-term transit to renewable hydrogen supply with a rise in renewable electricity, aiming for 100–200 kt/yr of renewable hydrogen production in 2025. The key development focus towards 2025 is within hydrogen technology manufacturing, industrial systems, and the policy environment. By 2035, the goal is a hydrogen energy industry formation with diversified applications in transportation, energy storage, industry and other fields. Industry is expected to be the dominant hydrogen demand segment.

Technology-push: Chinese government funding of USD 20bn, half of it targeting transport applications, is available to hydrogen projects.

Demand-pull: Policy/regulatory frameworks are under development. Purchase subsidies are replaced by city cluster demonstration support (2020) for FCEVs, including infrastructure.

Carbon pricing: China's national emissions trading scheme (ETS) is expanding coverage. Our projection for the regional average carbon-price level is USD 22/tCO_2 in 2030 and USD 90/tCO_2 by 2050.

2.3.8 Indian Subcontinent

National strategies and targets: India's National Hydrogen Mission (August 2021) aims to make the country a global hub for hydrogen technology manufacturing. It is progressing policy after the COP26 2070 net zero announcement. India's first phase green hydrogen policy (February 2022) aims to produce 5 Mt/yr of renewable hydrogen by 2030, and for 75% of hydrogen to come from renewable sources by 2050. The country is targeting 500 GW of renewables by 2030 (70–100 GW from hydro and 450 GW from wind and solar combined).

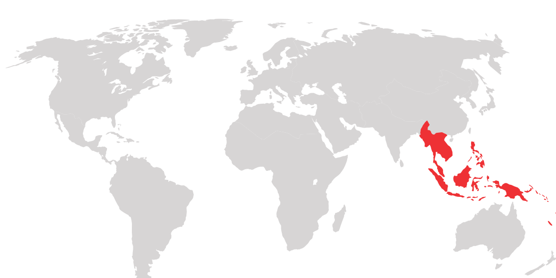
The previous targets of 100 GW of solar and 60 GW of wind by 2022 were unmet. India has no firm CCS policy. Hydrogen deployment is planned in major consumption centres, including the fertilizer industry (ammonia production) and desulphurization of fuel in refineries, uses which together account for around 80% of hydrogen consumption.

Technology-push: India's National Hydrogen Mission has identified several hydrogen activities for investment with a proposed financial outlay of Rs 800 crores (EUR 95mn) towards 2025 for R&D, pilot projects, infrastructure, and supply chain.

India's largest company, Reliance, is investing USD 75bn in renewable energy infrastructure, including solar and electrolyser capacity targeting green hydrogen production costs below USD 1/kg.

Demand-pull: India is developing a policy/regulatory framework.

Carbon pricing: There is currently no explicit carbon pricing. India has announced a planned carbon-trading scheme (April 2022). Our projection for the regional average carbon-price level is USD 10/tCO_2 in 2030 and 25/tCO_2 by 2050.



2.3.9 South East Asia

National strategies: Hydrogen has yet to formally enter policy agendas in the region. No clear strategies are developed.

The ASEAN Centre for Energy has conducted hydrogen studies such as 'Hydrogen in ASEAN –Economic Prospects, Development and Applications' (2021). Singapore's long-term low-emission strategy (2020) sees hydrogen as a low-carbon alternative, and the government is looking at the country becoming a hydrogen hub for the Asia region.

ASEAN member states are targeting 35% renewables in installed power capacity by 2025.

Technology-push: No policy/regulatory frameworks are available.

Demand-pull: No relevant policy/regulatory frameworks are available.

Carbon pricing: There is currently no explicit carbon pricing. Our projection for the regional average carbon-price level is USD 25/tCO_2 in 2030 and 50/tCO_2 by 2050.

2.3.10 OECD Pacific

National strategies and targets: There are net zero 2050 targets in Japan, South Korea, and New Zealand. For Japan and South Korea, pivoting to hydrogen is key to decarbonization, diversification of energy supply, and green growth.

South Korea's Hydrogen Economy Roadmap (2019) and Hydrogen Law (effective 2021) target a mix of grey, blue, and green hydrogen towards 2030 with a total of 3.9 Mt/yr (of which around 2 Mt/yr will be renewable hydrogen imported from overseas). For 2050, the aim is to produce 5 Mt/yr (3 Mt/yr renewable hydrogen, 2 Mt/yr low-carbon hydrogen) while importing 23 Mt/yr renewable hydrogen.

Japan's Strategic Roadmap for Hydrogen and Fuel Cells (2019) sees hydrogen and ammonia supplying 1% of its energy demand by 2030, with hydrogen already generating electricity by then. Japan aims to import renewable or low-carbon hydrogen from overseas (e.g. with ammonia shipments from the UAE). A key part of its strategy is to build a comprehensive international supply chain in the manufacture, storage, transport and use of hydrogen.

Australia's National Hydrogen Strategy (2019) targets clean hydrogen (blue and green) production and becoming an export hub in renewable and low-carbon hydrogen and ammonia. Australia's different regions also have regional targets for hydrogen use (e.g. 10% hydrogen blending in the gas network by 2030) and production. New Zealand is preparing its roadmap.

Technology-push: Japan has funding supporting its Green Growth Strategy – for example, USD 2.8bn to develop international supply chains and USD 3.1bn for applications in aviation, shipping, steelmaking and ammonia production.

South Korea has targeted annual funds to hydrogen projects. Recovery package with USD 2.4bn (KRW 2.6trn). Its Hydrogen Law stipulates support to hydrogen-focused companies (R&D, loans, tax exemptions). CCS is one of Korea's nine National Strategic Projects, but policy support is needed (e.g. applications to coal-fired power plants). Australia's government is investing around USD 320mn in Clean Hydrogen Industrial Hubs. Its Renewable Energy Agency is channelling about USD 40mn in support for R&D in green hydrogen and ammonia projects, and Australia's regions also have funding programmes for hydrogen.

Demand-pull: Japan and South Korea support domestic uptake of hydrogen. Japan has industrialization and capacity targets for hydrogen-based power plants. It also has road vehicle targets (800,000 FCEVs and 900 refuelling stations by 2030) driven by a goal of reducing automotive emissions by 80%. South Korea has pilot cities testing application of hydrogen in transportation, industry, and buildings space heating, and aims to become a leading hydrogen economy by 2040. Both countries are enabling the transition with investment support.

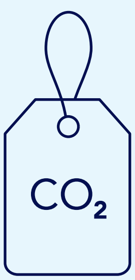
Carbon pricing: Schemes are established, except in Australia. Our projection for the regional average carbon-price level is USD 35/tCO_2 in 2030 and USD 90/tCO_2 by 2050.

2.4 Policy factors in our hydrogen forecast

The present forecast factors in policy measures that exert influence in three main areas:

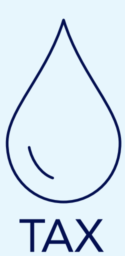
a) Supporting technology development and activating markets that close the profitability gap for low-carbon technologies competing with existing technologies;
b) Applying technology requirements or standards to restrict use of inefficient or polluting products/technologies; or
c) Providing economic signals (e.g. a price incentive) to reduce carbon-intensive behaviour.

We translate country-level data into expected policy impacts, then weigh and aggregate to produce regional figures for inclusion in our analysis. Here, we present a snapshot of policy measures that we consider.



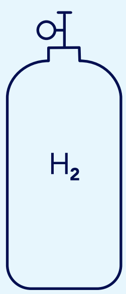
Carbon-pricing schemes

- Region carbon-price trajectories to 2050 consider hybrid pricing (cap-and-trade schemes and carbon taxation). They are reflected as costs for fossil fuels in manufacturing and buildings, and in power, hydrogen, ammonia and methanol production, and as participating progressively in the same regional and/or sectoral carbon-pricing schemes. Europe, North America, OECD Pacific, Greater China regions are projected to reach carbon-price levels in the range of USD 22–95/tCO_2 by 2030 and USD 70–135/tCO_2 by 2050. Carbon pricing across all 10 regions in mid-century is projected to range between USD 20/tCO_2 in North East Eurasia and USD 135/tCO_2 in Europe.
- Cost of capital reduces the attractiveness of fossil-based equipment, a trend driven by governments incorporating GHG thresholds in taxonomies (see discussion in Section 1.5) stipulating what can be described as 'green', 'low-carbon', 'zero-carbon', and so on. Cost of capital rates are differentiated to reflect region-specific risk, and further reflect technological maturity with declining rates as low-carbon technologies gradually reach maturity.



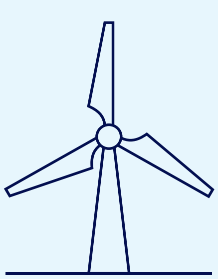
Taxation of fuel, energy, carbon and grid connections

- Fossil fuels used in road transport are taxed at the consumer level, labelled as fuel or carbon taxes.
- Effective fossil-carbon rates are incorporated into fuel prices for road transport, with taxation highest in Europe.
- We assume that these taxes will increase in line with a region's carbon-price regime, growing at a quarter of the carbon-price growth rate.
- Energy tax rates incorporated for other demand sectors (buildings, manufacturing) encourage switching from fossil fuels to electricity and hydrogen use. Electricity taxation declines in high-tax regions to enable electrification of end-use sectors. Hydrogen is expected to be exempt from energy taxation through to 2035 to favour its uptake. In regions prioritizing domestic use of hydrogen, the tax exemption has a phase-out profile, and hydrogen increasingly faces tax levels equal to those applied to the region's future industrial electricity, to assure a harmonized energy taxation system.
- Taxes and grid tariffs for grid-connected electrolysers are assumed to be a 25% surcharge over the wholesale electricity price.



Hydrogen support

- Support for the build-up of hydrogen infrastructure, and for the supply-side in terms of hydrogen production, is estimated based on total annual government funding available for hydrogen R&D and deployment (pilot projects, support for large-scale infrastructure, and industry projects) and reflected as a percentage subsidy for the capital cost of low-carbon hydrogen production routes. This also has spillover effects for hydrogen demand in end-uses through reduction in hydrogen price.
- For the demand-side, a hydrogen-policy factor reflects CAPEX support to manufacturing and buildings but varies by region in terms of policy focus and percentage level of CAPEX, as specified in government funding programmes. The full subsidy is kept until 2030 and gradually halved to 2050.
- For road transport/vehicles, the speed of hydrogen uptake is determined by a hydrogen-policy factor reflecting, among other parameters, FCEV CAPEX support including refuelling infrastructure, such as incentives driven by municipality-based CAPEX reduction policies for hydrogen-fuelled public buses.
- For shipping and aviation, fuel-mix shifts are driven by fuel blending mandates and carbon pricing
- CCS for blue hydrogen is mainly driven by regional carbon prices. Carbon prices higher than the cost of CCS will become the main trigger for CCS uptake. Beyond the carbon price, regional policies providing specific support for CCS are reflected to enable the initial uptake and reduce costs. This additional policy support will be reduced when carbon prices become high enough to sustain the growth.



Renewable power support

- Renewable electricity buildout is advanced by governments in all regions, based on the profitability of renewable electricity, and through market-led approaches such as capacity quotas, competitive bidding/auctions, investment support to storage capacity coupled with renewable generation, and evolving market design. Carbon pricing and cost of capital increases reduce the attractiveness of fossil-based generation.

3 PRODUCING HYDROGEN

3.1 Ways of producing hydrogen

Hydrogen can be produced using a number of different methods with varying efficiencies and environmental impacts, and is typically classified into colours depending on the method and feedstock used. A summary of the different colours of hydrogen, including feedstock, production technology and emission levels, is given in Table 3.1, with a fuller discussion of the technologies following further on in this chapter.

As seen in the table, the greenhouse gas (GHG) emissions can vary greatly even within a specific colour due to differences in efficiencies, capture rates, supply chain emissions and grid mix. As such, using colours to define and discuss emission levels of hydrogen can be misleading. DNV now sees a shift towards defining hydrogen in terms of carbon intensity (expressed in unit of CO_2 equivalents per unit of hydrogen produced) rather than colours, making it possible to compare technologies, production routes and resulting emission levels on a level playing field.

A final key aspect when looking at different production methods of hydrogen is the resulting purity level, with hydrogen produced by electrolysis having the highest level of purity. Different end-user segments have different requirements for hydrogen purity. For example, hydrogen for use in fuel cells has a high purity requirement. Consequently when producing hydrogen from fossil fuels, a purifier is often needed.

TABLE 3.1

The colours of hydrogen and resulting GHG emissions

	Colour of hydrogen	Feedstock	Production technology	Direct GHG emissions[a] kg CO_2e/kg H_2	Indirect GHG emissions[b] kg CO_2e/kg H_2
Produced using electricity	Green	Renewable electricity, water and/or steam by thermolysis	Electrolysis	–	>0[c]
	Yellow	Grid electricity, water		–	<1 – 30 *Depends on the carbon intensity of the grid mix*
	Pink	Nuclear electricity, water		–	>0[c]
Produced using fossil fuels	Grey	Natural gas	Methane reforming	9 – 11	0.5 – 4
	Brown	Lignite	Gasification	18 – 20	1 – 7
	Black	Black coal	Gasification	18 – 20	1 – 7
	Blue	Natural gas or coal	Methane reforming with CCS Gasification with CCS	0.5 – 4	0.5 – 7
	Turquoise	Natural gas	Pyrolysis	Solid carbon (by-product)	0.5 – 5
	Green	Biogas or biomass	Reforming with or without CCS Gasification with or without CCS	Possibility of negative emissions with CCS	1 – 3
Other	Red	Nuclear heat, water	Thermolysis	–	>0[c]
	Purple	Nuclear electricity and heat, water	Thermolysis and electrolysis	–	>0[c]
	Orange	Solar irradiance, water	Photolysis	–	>0[c]
	Green	Waste wood, plastic, municipal solid waste	Thermochemical	Possibility of negative emissions with CCS	Not assessed as variabilities in the value chains are too great to accurately represent the GHG equivalent emissions

[a] Direct emissions account for the hydrogen production process emissions.

[b] Indirect emissions account for the feedstock supply-chain emissions as well as the energy generation supply-chain emissions. Other indirect emissions, such as capex-related emissions, are also important but are not included here.

[c] Comparable to renewable power production infrastructure (1-20 gCO_2/kWh). The emissions related to the hydrogen infrastructure and hydrogen leakage will also contribute to indirect GHG emissions, where the exact quantities have to be identified.

The table is inspired by: Global Energy Infrastructure (GEI), 2021.

3.2 Hydrogen from fossil fuels: methane reforming and coal gasification

Black/brown hydrogen

Black/brown hydrogen, produced from coal, is generally produced through gasification. Coal gasification is based on partial oxidation (POX), where a portion of coal (or other carbonaceous materials) is burnt with a selected amount of oxygen under pressure in a gasifier. The output of this gasification step is a syngas containing a mixture of hydrogen, carbon monoxide, carbon dioxide and other gases.

In a second step, the addition of steam enables the water gas shift reaction with carbon monoxide, producing additional hydrogen. Most of today's coal gasification plants are in China, which has a market share of about 85%[1].

Grey hydrogen

Grey hydrogen produced from natural gas can be produced by methane reforming, which includes steam methane reforming (SMR) and autothermal reforming (ATR).

Simply explained, the SMR process works by introducing natural gas, mainly methane, and steam into a reactor supplied by heat from a surrounding furnace. The furnace combusts natural gas and excess air. Natural gas is converted to hydrogen and carbon monoxide, which is then sent through a water gas shift reactor and a pressure swing adsorber to convert carbon monoxide to carbon dioxide and then separate the hydrogen out from the syngas.

ATR is less commercially advanced than SMR, however, the process is based on a combination of SMR and POX technology[2]. In an ATR, pure oxygen is used instead of air. The primary reformer in ATR differs from the SMR in that the heat is supplied in the process itself, eliminating the need for a furnace. Otherwise, the process is similar. A gas heated reformer can also be included for pre-heating purposes and reforming some of the initial hydrocarbons.

Blue hydrogen

Adding CCS to any of the before-mentioned technologies will create blue hydrogen, and 1% of hydrogen today is produced as blue hydrogen[3].

For SMR, there are different options for the placement of a carbon capture plant that affect the overall capture rate and the efficiency of the plant. For the ATR, the capture plant will typically follow the water gas shift reactor. In coal gasification, the carbon and hydrogen can be separated with pressure swing adsorption. Another interesting option is to use palladium membranes with a high H_2-selectivity[4,5].

It should be stressed that capture plants do not capture 100% of the CO_2 and there are also concerns regarding upstream emissions, which include both carbon dioxide and methane. A study by DNV[6] has shown that these emissions can be significant, as listed in Table 3.2, albeit with regional variations[7].

Cost-wise, SMR is currently the most economic production method, although there is less research on the costs of ATR compared with SMR. However, the overall cost of SMR with CCS is expected to increase towards 2050, despite a decrease in the CAPEX, because fuel and carbon costs are likely to increase[8]. The same applies to ATR, however the cost of ATR is less dependent on carbon costs and more dependent on the cost of electricity.

Regarding emissions from blue hydrogen technologies, ATR is the technology with the possibility for the lowest emissions; it is also has fairly high efficiency and is hence a promising option for blue hydrogen.

Capture plants do not capture 100% of the CO_2 and there are also concerns regarding upstream emissions, which include both carbon dioxide and methane.

TABLE 3.2

Comparison of efficiency, emissions and levelized cost of hydrogen (LCOH) across production methods

		SMR	SMR with CCS	ATR	ATR with CCS	Coal gasification	Coal gasification with CCS
Efficiency	%	66–76	69–79	67–85	74-80	60-66	58
Emissions	kg CO_2/kg H_2	8.9–9.4	0.5–2	7.4–9.8	0.3-1.3	16.5-20.2	1.8-2.1
LCOH	USD/kg H_2	0.8–2.7	1.8–4.1	0.8–2.7	1.3 - 3.0	2.2 - 4.1	3.7 - 5.2

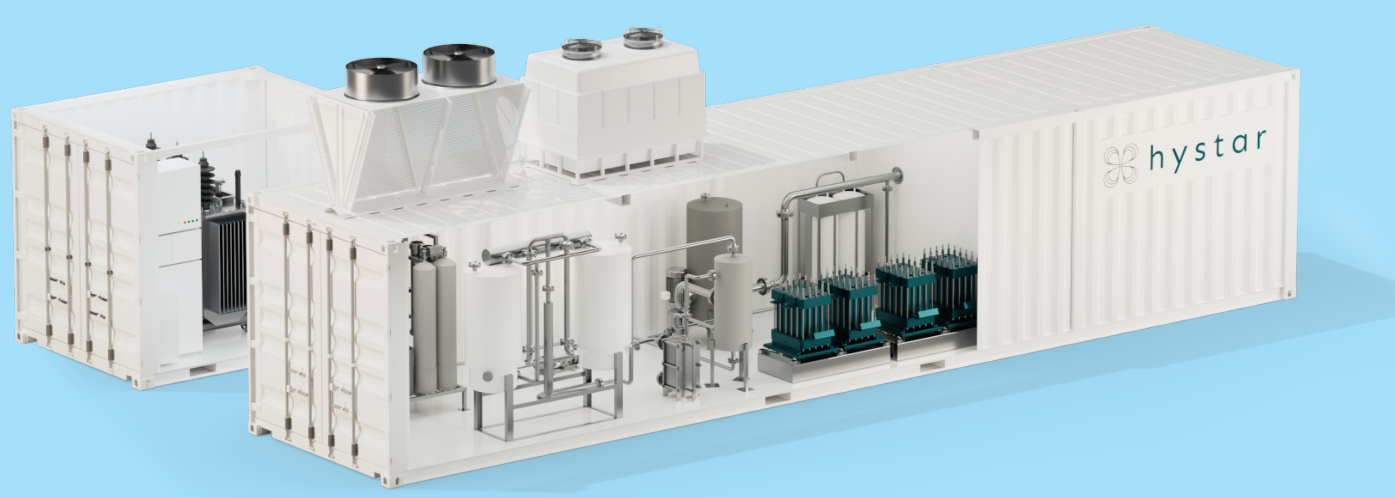
3.3 Hydrogen from electricity: electrolysis

At a basic level, electrolysis splits water (H_2O) into hydrogen (H_2) and oxygen (O_2) by applying an electric current. As simple as it sounds, researchers and developers have optimized this process and currently there are four main technologies; Alkaline, Proton Exchange Membrane (PEM), Solid Oxide Electrolysis (SOE) and Anion Exchange Membrane (AEM).

Alkaline is most developed but growing interest in green hydrogen boosting further development. Manufacturers are focused on performance improvement, cost reduction and upscaling. Where the established alkaline technology was mainly atmospheric, pressurized systems have also entered the market. Pressurized systems require less compression which is generally needed for most applications. Pressurized systems are also better equipped to respond to changes in power input (e.g., from renewable energy). This gives pressurized alkaline the advantage to still compete with other technologies such as PEM when combined with renewable energy.

PEM has seen much development over the last decade and has an established position in the electrolyser market. PEM is known for its ability to ramp up and down very quickly, making it a suitable technology to follow changes in power input from renewable energy. The focus areas for development are very similar to alkaline but are expected to follow a steeper learning curve to catch up to costs of alkaline. Additional development with PEM goes to the reduction and recycling of iridium and platinum, rare materials which could limit very large-scale expansion of PEM.

SOE has reached commercialization and recent investments have led to competitiveness in the market and upscaling of production capacity. The technology is mainly recognized for high operating temperatures (500-900°C), high efficiencies, and the use of steam instead of liquid water. The technology is commercially available but is still far behind alkaline and PEM in terms of scale and maturity. The current focus for development, is commercialization, upscaling, lifetime improvement and cost reduction. The latter two still need much development to compete with Alkaline and PEM. A unique advantage of SOE is its capability to directly form syngas using co-electrolysis of steam and CO_2,



Containerized PEM electrolyser. Image courtesy Hystar.

TABLE 3.3
Main electrolyser characteristics

	Current | 2030 [A]	Alkaline	Pressurized Alkaline	PEM	SOE	AEM
Efficiency	kWh/Nm³	4.7 | 4.3	4.7 | 4.3	4.8 | 4.5	3.6 | 3.3 [B]	4.8 (stack only)
Stack lifetime	hours	80,000 | 100,000	80,000 | 100,000	50,000 | >80,000	20,000 | >20,000	5,000
Flexibility	Time to reach nominal capacity	Minutes	<10s	<1s	<1s [C]	<1s
Pressure	bar	Atm.	<40 | <70	<40 | <70	atm. | <20	<35
Commercial status		Available	Available	Available	Available 2022-2024	Under development

[A] Predictions based on manufacturer indications, literature or FCH JU targets.
[B] Efficiency of SOE assumes external heat is provided.
[C] Hot system in laboratory, unknown for commercial systems. Cold systems require start up times of hours if not more.

and to produce a mixture of hydrogen and nitrogen with co-electrolysis of steam and air. The latter is advantageous combined with ammonia production, saving costs on air separation units to produce nitrogen and the possibility to use waste heat for steam production. SOE is also capable of operating in reverse, acting as a fuel cell[9].

AEM is the latest developed technology and has not yet commercialized at relevant scale. It shares many similarities with PEM in terms of design but uses cheaper materials. The main focus of development is lifetime improvement before it will enter commercialization, cost reduction and further improvements.

A suitable match

DNV believes there will be a future for each technology, although for different applications. Atmospheric alkaline might be the preferred option for large scale and more base-load hydrogen production as this is most developed and has lower costs. Pressurized alkaline and PEM will likely also be applied in this area once these technologies have achieved further costs reductions. Both pressurized alkaline and PEM are suitable in combination with renewable energy and will likely see their application there, both onshore and offshore. When AEM is further developed, it will follow these technologies. SOE requires heat as an input and will therefore likely be applied at locations where this is available. An example would be a combination of SOE and an ammonia plant or nuclear plant where waste heat can be used. Here the advantage of producing both hydrogen and nitrogen will also be relevant.

Electrolysis will see massive upscaling and costs reduction

Electrolysis is developing rapidly but requires massive upscaling of manufacturing to meet industry and government targets. The pressure is on electrolyser manufacturers to further develop their technologies, standardize their systems for large-scale application, and increase their manufacturing capacity. The most established manufacturers have already started this process and are getting ready to supply electrolysers at large scale in the coming decade and beyond. Although upscaling brings opportunities for manufacturers, it is very challenging. The clearest risk is the uncertainty of the market itself, making for an unsteady foundation for the kind of rapid-fire decisions and large-scale investments that manufacturers need to make.

Other challenges are the growth of supply chain, the use of precious materials (especially for PEM) and finding experienced and qualified personnel. Additional challenges are the readiness of large-scale electrolysis design and to develop inherently safe design for ever-larger concepts, for instance regarding cross-over of oxygen internally, safe blow-down with venting/flaring, and reducing leaks by improving the "weak links" such as valves, seals etc.

While DNV does not see these challenges as show-stoppers, they do require urgent resolution or mitigation. This requires early identification of challenges and the involvement of industry and government to assure the right direction of development, certainty for offtake, and the right policy measures to de-risk the overall hydrogen value-chain.

Electrolysis is developing rapidly but requires massive upscaling of manufacturing to meet industry and government targets.

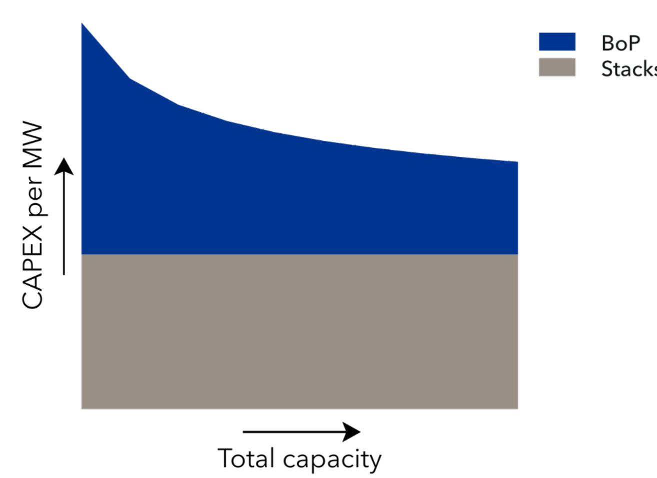
In addition to upscaling of manufacturing and system capacity, electrolysis will see significant cost reductions. Electricity consumption and system investments are the main cost drivers. Costs for renewable electricity are not influenced by electrolyser manufacturers; they can only improve system efficiencies which have a direct, and large bearing, on CAPEX. Options for cost reduction include:

- Standardization of system design – to act as building blocks for scaling up the capacity. This allows for a switch from tailor-made solutions to a standardized solution that can facilitate multiple clients and scales.
- Improved and automated manufacturing – Most electrolysers and stacks are currently assembled by hand which can be partially automated with the standardized design.
- Economies of scale – apply especially to the balance of plant (BoP) and can reduce system costs significantly. Figure 3.1 illustrates the effect of capacity on the system costs.
- Performance improvement – Improving performance such as efficiency and stack lifetime will decrease costs during the overall operational lifetime.
- Cost optimization – Other means to cut costs are improving agreements and pricing from sub-suppliers by reducing or replacing expensive materials, and optimization of design.

We already see some effects of these cost reduction methods in the new generation electrolysers which are offered in upcoming large-scale projects. Although there is currently a wide range of electrolyser costs, we expect a 25% drop in average costs by 2030 and 50% by 2050 based on current market insights. Figure 3.2 is an approximation of the cost reduction per technology based on various literature sources (recalculated to 1 MW). All technologies will see cost reductions. PEM and alkaline costs are likely to overlap considerably from the early 2030s onwards. Technologies like SOE and AEM are still very early stage, and it is difficult to estimate their cost development. While SOE will likely be

FIGURE 3.1

Effect of system capacity on capital expenditure



applied in industrial areas with available waste heat, and in combination with other conversion processes such as ammonia or syngas, AEM could have a disruptive effect on costs if the technology is developed successfully. Application will likely be similar to Alkaline and PEM while material costs can be lower.

Electrolysers in China

Chinese manufacturers hold significant advantages in terms of low labour and material costs and have the potential to disrupt the electrolyser market. However, currently, we do not yet see a significant export of Chinese systems. The domestic Chinese electrolyser market is still large enough to absorb Chinese production and manufacturers have not yet scaled up at the rate Western manufacturers have. In addition, most Chinese manufacturers have not yet internationalized with the correct certification and have not adapted their business to an international language. Furthermore, there are quality concerns with the performance and reliability of Chinese electrolysers. Over the course of a project lifetime, lower yield and higher maintenance costs continue to render Chinese systems less competitive than Western electrolysers, despite the lower costs[10].

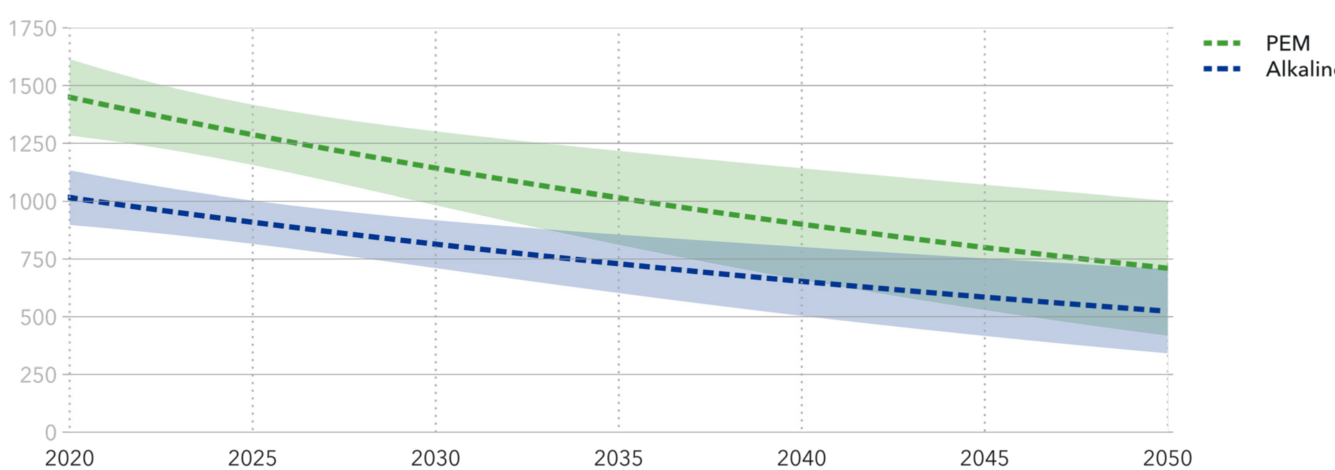
From a project development perspective, there is also a lower risk when choosing a local supplier with regard to agreements and guarantees, service and maintenance, and shipping of equipment. Especially regarding service and maintenance, many project developers rely on the manufacturer to perform or assist with maintenance and operations.

When Chinese electrolyser manufacturers scale up, improve product quality and internationalize we can expect an export increase. How disruptive this proves to be to the electrolyser market in the West will depend on global market growth – electrolyser demand is currently larger than supply – and policy on import and trade. Western countries might move to protect their own markets from Chinese competition. Some Western manufacturers have already taken action regarding the Chinese market. Cummins recently announced they will open a GW factory in Southern China in a joint venture with Sinopec[11] and John Cockerill has also started a joint venture with Jingli[12] to produce electrolysers in both China and Europe.

FIGURE 3.2

Electrolyser CAPEX by technology

Units: USD/kWe



Values are for a 1 MW reference system.

4 STORAGE AND TRANSPORT

4.1 Ways of transporting and storing hydrogen

The future of the hydrogen value chain will rely on developing infrastructure for low-cost distribution and delivery. Compared with other gases and liquids, hydrogen as energy carrier is challenged by low energy density, embrittlement, and safety concerns. These unique properties present special cost and safety obstacles at every distribution step, from manufacturing to end-use.

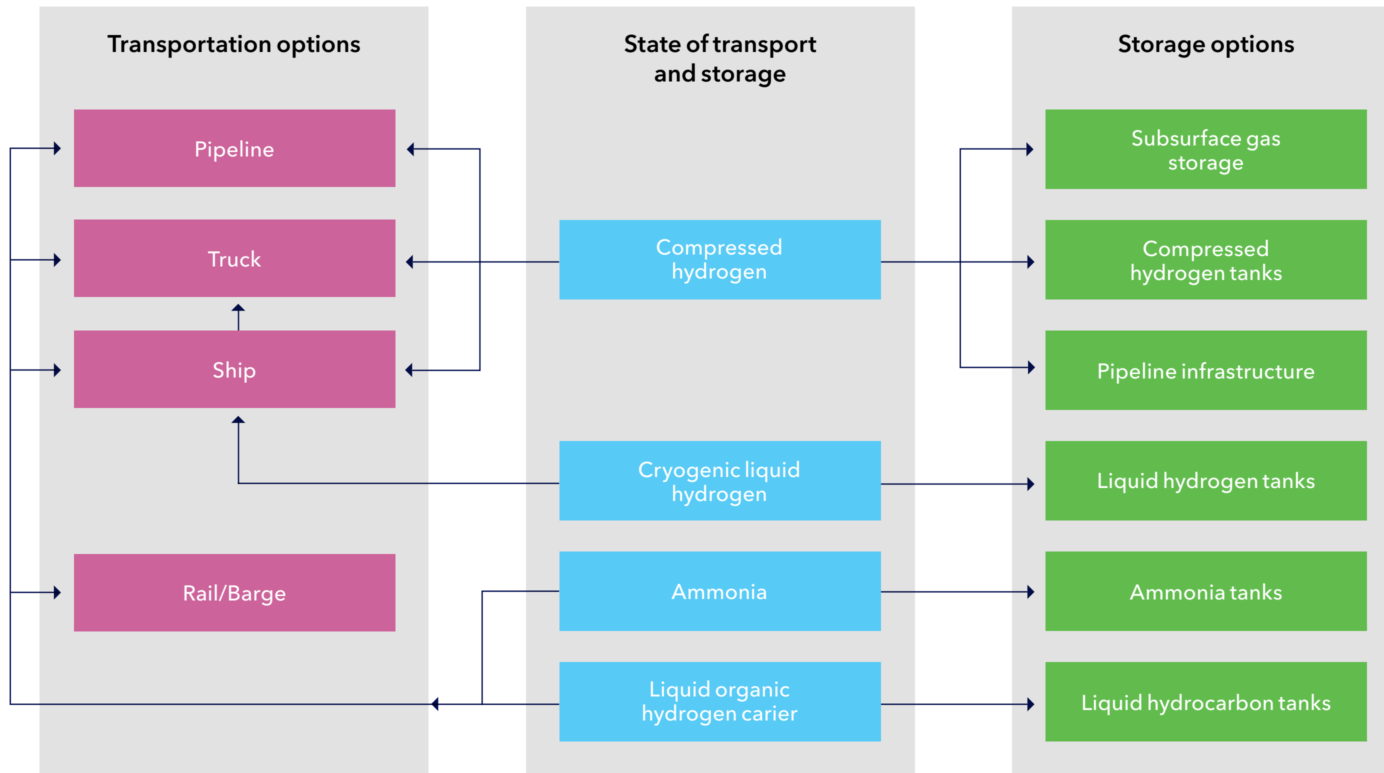
Also critical is the form of hydrogen being transported and stored. Hydrogen can be transported as pure hydrogen – either pressurized or liquified – or by using a liquid hydrogen carrier such as ammonia or liquid organic hydrogen carriers (LOHC). An overview of options for transport and storage of hydrogen is shown in Figure 4.1. Each selected option requires different state-conversions such as compression, liquefaction or chemical reactions as indicated in the figure. These state conversions induce losses (energy use) and costs. The preferred or lowest-cost option for transport and storage will depend on the state, distance over which hydrogen is transported, and on scale and end use.

Compressed hydrogen

Pipeline transport of compressed gaseous hydrogen is in general the most cost-effective way of transporting large volumes over long distances. This can be done in pure form, or blended into natural gas in gas pipelines, up to limits prescribed by the relevant regulations or imposed by contract or other restrictions such as purity require-ments for end-use. Small volumes, such as those required today at hydrogen refuelling stations, would usually be most cost-effectively transported in bulk by truck.

FIGURE 4.1

Overview of main options for transport and storage of hydrogen



Liquid hydrogen

While liquid hydrogen has a higher energy density than compressed hydrogen, more energy is required to liquefy hydrogen than for compressing it to relevant pressures. Furthermore, liquid hydrogen has different safety characteristics than compressed gaseous hydrogen. For example, a leak into open air from compressed hydrogen tanks will rise due to buoyancy and will generally dissipate quickly. In contrast, a leak of liquid hydrogen into open air will freeze the surrounding air, become a heavy gas, and may accumulate on the ground for some time. This is relevant when, for instance, transporting hydrogen either by ship or truck, or when storing it in tanks.

Ammonia and liquid organic hydrogen carrier (LOHC)

Ammonia has a higher energy density per volume than liquid hydrogen and can be transported and stored as a liquid at low pressures or in cryogenic tanks at around -33°C at 1 bar. This implies that ammonia can be transported at low cost by pipelines, ships, trucks, and other bulk modes. The drawbacks are that the ammonia synthesis and its subsequent dehydrogenation to release hydrogen require significant energy and it is toxic if an accidental release occurs. Hydrogenation and dehydrogenation of LOHCs, such as toluene, requires less energy, but the gravimetric density of the hydrogen that can be extracted from the hydrogenated liquid (methylcyclohexane for the LOHC toluene) is 50%–70% lower than the gravimetric hydrogen density of ammonia[1].

These considerations show that the lowest cost or preferred value chain depends on the application and context.

4.2 Storage

Any effective energy system must be able to provide security of supply and resilience for customers. The energy system must be designed and operated to ensure sufficient security of physical assets, diversity of energy supply, market control, and resilience to geopolitical events. One of the primary challenges for the energy transition is increased reliance on variable renewable energy for hydrogen production and this means that storage will become increasingly necessary to match supply and demand. Hydrogen can be stored in two ways – either as pure hydrogen or integrated into a carrier which makes it easier to transport and store.

Hydrogen can be stored as a gas at high pressures or as a liquid at very low temperatures. When required, hydrogen can be withdrawn from the storage and the pressure or temperature carefully adjusted to suit end use without any further significant chemical processing.

Liquid hydrogen carriers are molecules that have significant hydrogen content, and are liquid at conditions close to ambient temperatures and pressures – this makes them easier for shipping or above-ground storage without specialist containment. There are several examples of organic molecules that are hydrogen rich such as toluene and di-benzyl toluene – these are known as liquid organic hydrogen carriers (LOHC). The drawback of LOHCs is that there is an energy penalty in synthesising them in the first place and in subsequent regeneration of hydrogen at the point of use. If the energy used in the hydrogen carrier process is not renewable, then there will be a carbon penalty too. Ammonia, which has the formula NH_3, is a well-established liquid hydrogen carrier and contains one atom of nitrogen and three atoms of hydrogen. Ammonia may be combusted directly in some applications rather than cracking to release hydrogen.

Energy demand and supply

Most industrial economies have a varying demand for energy, often increasing at certain times of day with more extreme seasonal variations, especially in countries with cold winters. These variations are therefore both short term (intraday) and long term. Where renewable power is used to generate energy, the variations in electrical supply need to be overlaid on the varying demand and this creates a very complex operating regime. To ensure security of supply, energy storage is required to fill those gaps when demand is greater than supply or when supply is greater than demand. Storing electrical energy in batteries is possible but challenging at large scale and for long periods of time. Storing molecular energy in the form of hydrogen is a stable and reliable form of energy storage and the hydrogen can either be used directly or converted to electricity as required.

Hydrogen is a stable and reliable form of energy storage; it can either be used directly or converted to electricity as required.

If hydrogen is required only for road transport, shipping, manufacturing, and power generation, then the demand profile for hydrogen is relatively flat with slight variations caused by the power sector – the need for hydrogen storage in this case is driven by the variation in generation from renewable power. If hydrogen is additionally used for space heating, then the demand profile is dominated by the cold weather months which, coupled with variations in renewable power production, leads to a significantly increased mismatch between supply and demand across the year. Countries and regions aiming to replace natural gas for heating with hydrogen will need greater volumes of storage than they have now. Additionally, where natural gas linepack may have provided some resilience previously, hydrogen linepack depletes much more rapidly and quicker access to storage withdrawal will be necessary to maintain pipeline pressures.

During the energy transition, the introduction of hydrogen blends into gas networks and filling new hydrogen storage facilities will be a necessary first step; this will stimulate the build out of hydrogen production and the hydrogen ecosystem. For domestic heat appliances, variation in hydrogen blends up to 20 mol% can be tolerated but large industrial consumers, gas turbines, gas engines and gas-fired power generation will not be as tolerant to varying hydrogen concentrations. Other mechanisms for balancing hydrogen supply and demand, such as demand-side flexibility and supply flexibility, could be important but these fail to capitalize on periods of excess renewable power production which would leave curtailment as the last option.

Understanding storage needs and options

It is likely that a mix of hydrogen storage options will be needed, and projects centred on industrial clusters will be important to understand storage needs and timings. Energy system modellers will need to carry out whole-system balancing analyses to determine storage needs in detail. Overall, hydrogen storage may need to be more distributed than that of natural gas as there will be less linepack in gas pipelines. We must also not forget that hydrogen has a much lower volumetric energy density than natural gas (3 to 4 times less dense) which increases the complexity of the solution. Where hydrogen is to be used for transport applications it is about 2,700 times less dense than gasoline which means that it needs to be compressed, liquefied or chemically combined before storage.

An overall framework for comparing hydrogen storage options is likely to be necessary and assessments for each region or country should include:

- Capacity
- Deliverability
- Injectability
- Discharge duration
- Response time
- Energy intensity
- Cost per unit stored
- Safety
- Location
- Time to market

A mix of storage options is likely to include:

- Long discharge duration storage for gas networks
- Salt caverns that can manage multiple fill/discharge cycles, and that can deliver and inject very quickly
- Seasonal storage in porous rocks, although this is not good for deliverability and injectability

A summary of options is shown in Table 4.1.

Looking back at historical mechanisms and solutions for natural gas storage will not help solve the issues around hydrogen storage. Natural gas production can be ramped up and down as required but low-carbon hydrogen needs to be made by the electrolysis of water or by reforming hydrocarbons and CCS. Intermittent (renewable energy) or flat production processes (reforming of methane or electrolysis using nuclear power) each create a different storage challenge and will need a different storage solution.

TABLE 4.1

Hydrogen storage options and associated considerations

Energy storage type	Hydrogen storage option	Storage capacity (TWh)	Response / turnaround time	Duration	Technology readiness level	Deployment timeframe	Demand side applications	Centralised or de-centralised solution	Hazard / toxicity
Geological	Repurposed salt cavern	–	Fast response (1 hour)	Multiple annual cycles	Medium	Medium	Multiple users across power, industry, and heat	Centralised	Low
	New salt cavern	1.5[a]			High	High			
	Repurposed hydrocarbon reservoir	9[b]	Slow response (12 - 24 hours)	Single seasonal cycle	Low	High	Large scale seasonal heat demand		Medium
	New offshore fields	–			Low	High			
Surface	Compressed	0.00004[c]	Fast response (minutes)	Multiple annual cycles	High	Low	Limited due to size	Both	Medium
	Liquid hydrogen	1[d]	Fast response (1 hour)		Low	High	Multiple users across power, industry, and heat		High
	Ammonia		Medium response (> 4 hours)[f]		Medium	High			High
	LOHC				Low	High			Low
Network	Line pack	1.2[e]	Fast response (instant)	Within day cycle	High	–			Low
Import	Hydrogen pipeline	–	Fast response (instant)	–	High	Medium		Centralised	Medium
	Ammonia	–	Slow response (days dependent on shipping)	–	Medium	High	Limited due to response time, target large predictable swings in demand such as heat		High
	LOHC	–		–	Low	High			Low
	Methanol	–		–	Low	High			High
	Liquid hydrogen	–		–	Low	High			High
Supply flexibility	Flexible production (Blue Hydrogen)	-	Medium response (> 4 hours)	-	Medium	Medium	Industry and heat	Both	-
	Flexible production (Grid-connected electrolysis)	-	Fast response (1 hour)	-	Medium	Medium	Multiple users		-
Demand flexibility	Interruptible contracts	-	-	-	High	Low	-		-
	Smart heating systems	-	-	-	Low	High	-		-

[a] Salt cavern storage volume based on H21 project estimations
[b] Energy based on estimated storage of a re-purposed Rough reservoir
[c] Based on largest standard size metal cylinder (50 m^3)
[d] Based on H21 estimations, footprint requirements major impact
[e] Based on conversion of existing natural gas network linepack to hydrogen
[f] Dependent on complexity and future technology developments

4.3 Transmission transport system

A hydrogen transmission system transports large amounts of hydrogen over long distances, with the hydrogen typically in compressed gas or in liquid form. Transmission of hydrogen can be done by ships, trucks, rail, or transmission pipelines.

Transmission transport of hydrogen by truck is a mature option, where hydrogen can be transported in gaseous or liquid form or via a carrier, such as ammonia or LOHC. Despite the maturity of this option, for longer distances it is often not the cheapest route. For compressed gas, a truck typically carries 20 ft or 40 ft containers made from a glass fibre composite or carbon fibre composite, and in theory one truck can hold 1,100 kg of hydrogen compressed to 500 bar[2]. Another approach, transporting liquefied hydrogen by truck, is more common for longer distances. The truck can carry 4,000 kg of hydrogen over 4,000 km; any further distance might cause the hydrogen to overheat resulting in a rise in pressure due to the Joule-Thompson effect[3]. By converting the hydrogen to ammonia prior to transport, a truck can carry around 5,000 kg of hydrogen.

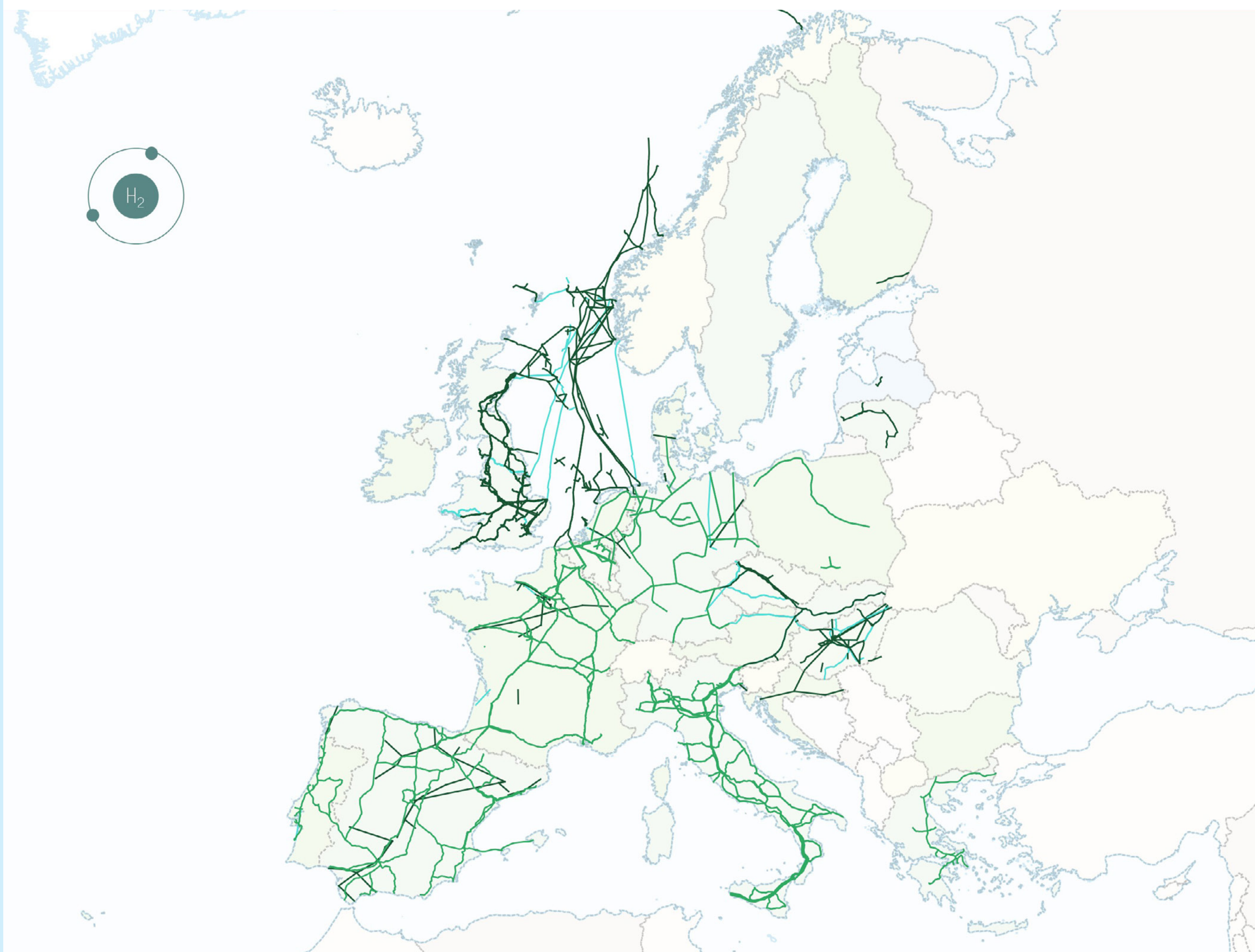
Transporting hydrogen through pipelines is an inexpensive and robust method for distances up to 2,000 km dependent on several factors, like the volume of hydrogen transported. In the US there are over 2,500 km of hydrogen pipelines already in place. Within Europe, the longest pipelines are in Belgium and Germany, at 600 km and 400 km respectively. In total there are roughly 5,000 km of hydrogen pipelines worldwide, compared with 3 million km of natural gas pipelines[4]. Hence, it is natural to investigate the extent to which hydrogen can make use of an existing natural gas infrastructure. A project completed by DNV and Carbon Limits (2021), called Re-Stream, concluded that most offshore pipelines can be reused for pure hydrogen based on the current state of knowledge and standards. For onshore pipelines, about 70% of the total pipeline length could be reused, based on pipelines in Europe. The remaining 30% could conceivably be reused, although more testing and/or updated standards are required. From the Re-Stream project, the following map was made (Figure 4.2), illustrating the pipelines that can be reused in Europe[5].

For offshore pipelines in Europe, the median maximum allowable operating pressure (MAOP) is around 160 bar for offshore gas pipelines, and 70 bar for onshore pipelines.

FIGURE 4.2

Assessment of reuse of the current pipeline network in Europe for hydrogen

Category A: pipelines reusable considering the current state of knowledge/standards (assessed by Re-Stream team)
Category B: Pipelines that would require more testing and/or update of standards to be reusable (assessed by Re-stream team
Category A: pipelines reusable (assessed by TSOs)



Source: Carbon Limits AS and DNV (2021), Re-Stream – Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe.

TABLE 4.2

Typical values for onshore and offshore gas pipelines[6]

	Onshore gas pipeline	Offshore gas pipelines
Typical main material	45% made of API 5L X60 steel grade, rest range from X52 – X80	API 5L steel grade X65
Median MAOP	70 bar (40 – 100 bar range)	160 bar
Typical external diameter	12-36 inches	> 24 inches

The flow characteristics of hydrogen differ from natural gas, and a pipeline design with a lower flow speed avoids recompression[7]. This is necessary as the low molar mass and high-volume flow of hydrogen mean that its compression requires more energy compared with the compression of natural gas. Transporting hydrogen through a natural gas pipeline may require that the hydrogen is operated at a lower pressure or that a layer of internal coating is added[8].

There are some limitations for hydrogen transmission transport in pipelines, such as the embrittlement of steel. The current standard ASME B31.12-2019 is applicable for hydrogen transport in pipelines. The standard limits the allowable pressure when using higher-grade steel to transport hydrogen. There is agreement amongst material experts that the criteria on hydrogen in high-grade steel pipelines in the ASME B31.12-2019 standard are too conservative. There is research investigating the use of higher-grade steel, X65, X70, and above, for transporting hydrogen. DNV experts believe that in the future most hydrogen will be transported by X70 steel.

Hydrogen can also be transported as a blend into natural gas, which might be seen as a solution during the transition from natural gas to hydrogen. Blending hydrogen in a gas network can be a cost-effective solution and provide learnings towards a pure hydrogen grid. There are different limits to the amount of hydrogen that can be blended into the gas network in different regions and countries, where the limits typically range between 2- 8%. The differences in the limits among countries pose a challenge for transporting the blends across borders, and standardization work is ongoing, with a particular focus on regulatory harmonization. A 20% blend is technically possible, although there are uncertainties about the long-term effects on the pipelines[9]. Blending hydrogen into the natural gas network will also incur an additional cost due to injection stations as well as a higher OPEX[10].

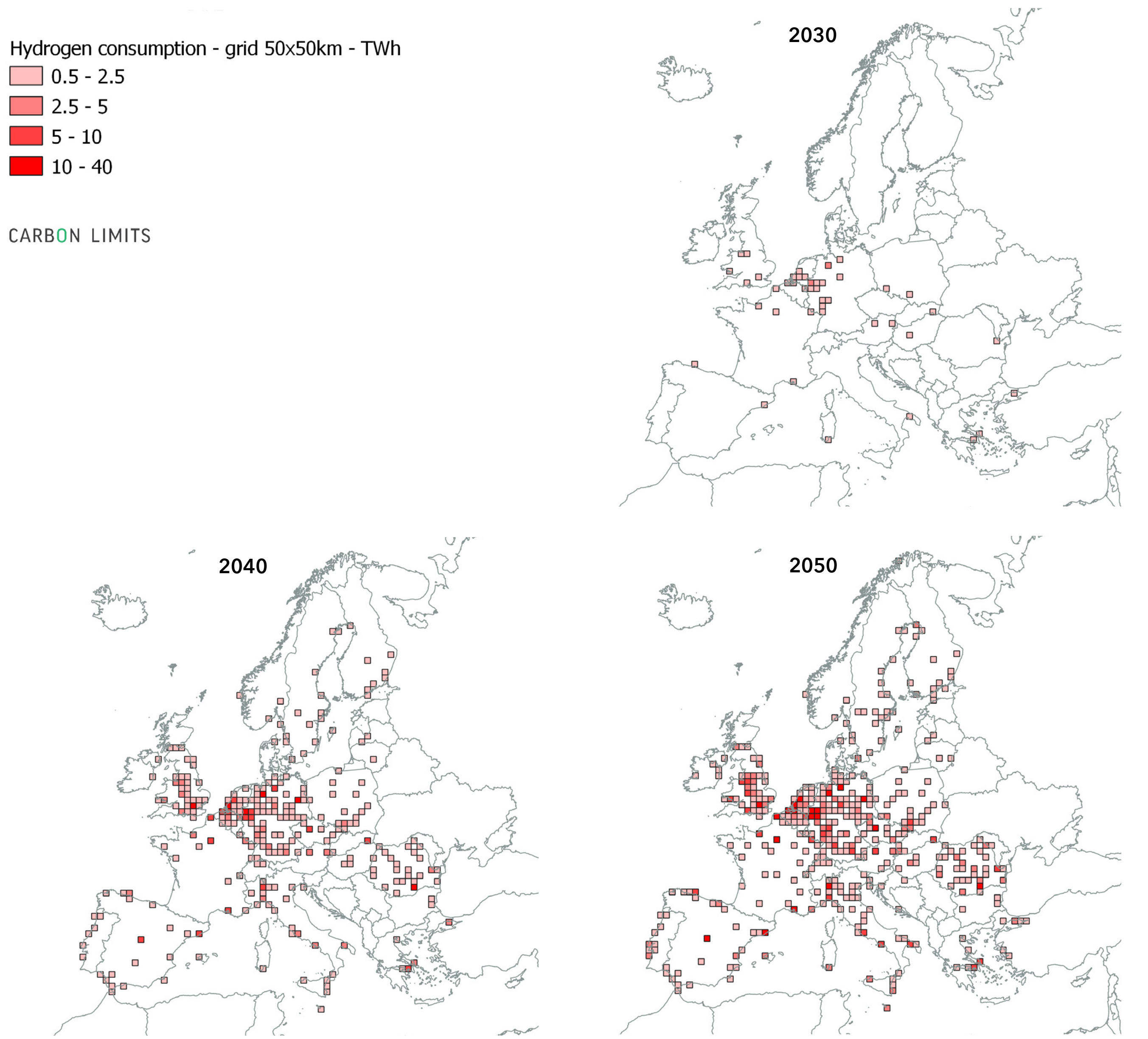
As explained in the previous section, it is also possible to transport hydrogen via a liquid hydrogen carrier in a pipeline. Ammonia is easier to transport compared with hydrogen and can be a good alternative, although the cost of converting the ammonia back to hydrogen needs to be considered. For distances shorter than 1,500 km, it is cheaper to transport hydrogen in pipelines as pure gas, while for longer distances, transporting the hydrogen as ammonia or via a LOHC by ship seems to be more cost-effective. Converting ammonia or LOHC back to hydrogen for the end user adds costs of about 1 USD/kg H_2 or 0.4 USD/kg H_2 respectively[11]. Reconversion of ammonia to hydrogen also requires about 7-18 % of the energy content of the hydrogen, while for LOHC it requires about 35-40%.

As the momentum grows worldwide around hydrogen as an energy carrier, there are several ongoing projects and sizeable initiatives to further develop hydrogen infrastructure[12]. The existing infrastructure for natural gas is a good starting point but there are hurdles to be overcome before a hydrogen transmission network can be realized. Several initiatives involve coastal industrial hubs, connecting to offshore wind and to demand from the surrounding industrial base. Areas of interest for such hubs are Europe, Japan, Latin America, U.S., and China.

An example, as demonstrated in both the Re-Stream analysis and the European Hydrogen Backbone report[13] (2020) is that the expected hydrogen hubs in Europe will develop outwards, mainly south-east, from the Netherlands, as seen in Figure 4.3[14]. The lack of investment in infrastructure is generally seen as one of the more important barriers to the development of the hydrogen 'ecosystem'. With several projects covering hydrogen pipelines, work is ongoing at DNV to create guidelines for transmission system operators (TSOs) to introduce hydrogen into existing infrastructure reliably and safely.

FIGURE 4.3

The development of hydrogen consumption in Europe in 2030 – 2050 within a 50x50 km grid cell



Source: Carbon Limits AS and DNV (2021), Re-Stream – Study on the reuse of oil and gas infrastructure for hydrogen and CCS in Europe.

4.4 Distribution pipelines

For decades, local gas distribution networks have delivered gas to millions of homes, businesses and industries cost-effectively, reliably and safely. We foresee that, in some regions, the decarbonization of the built environment will involve a competition between electrification and decarbonized gases. As with other end-user segments where hydrogen is used for heating, hydrogen could initially be blended up to 20-30% with natural gas to form a transition path towards a fully renewable decarbonized gas supply.

In some regions, a dense natural gas distribution infrastructure is already in place to connect individual homes and small business to the high-pressure transmission networks. Up to millions of individual end users could be connected to these distribution systems differentiating them from the transmission systems. Typically, in these networks the gas pressure is reduced in a number of steps from 16 bar in the transmission network down to 0.1 to 0.03 bar overpressure at individual end-user connections.

The pipelines are mainly made of plastic (polyethylene, PVC), yet some can be made of steel or cast iron. A gas distribution network is a complex system comprising a number of installations, including: pressure reducing stations, metering stations, valve stations, main lines, service lines, injection stations and blending stations for decarbonized gases.

The conversion of distribution systems to transport (blends of) hydrogen is being considered by a number of distribution system operators (DSOs). In several countries across Europe and North America, DSOs have issued feasibility studies and set up pilot and demonstration projects. One of the main boundary conditions is to operate the distribution system safely with no additional risk compared with existing natural gas systems. This safety case has to take into account the properties of hydrogen that differ from natural gas, notably the larger combustion speed that could influence the impact of explosions. The H21 project is a frontrunner in this respect, where a large part of the distribution grid in the northern part of the UK will be converted to pure hydrogen distribution. The project's safety assessment concludes that this is possible without an increased risk profile for the distribution grid when additional parts of the pipeline network are replaced by PE pipelines. Pilot and demonstration projects are currently being set up to further increase the experience with hydrogen in the built environment.

Cost considerations will lead to more than 50% of hydrogen pipelines globally being repurposed from natural gas pipelines over the next decades, with the share as high as 80% in some regions, as shown in Figure 4.4. The cost to repurpose pipelines is expected to be just 10-35% of new construction costs[15], so new pipelines still make up the majority of expenditure, particularly in the 2020s, as show in Figure 4.5.

FIGURE 4.4

Percentage of hydrogen transmission pipelines repurposed from natural gas pipelines in 2050

Units: Percentages

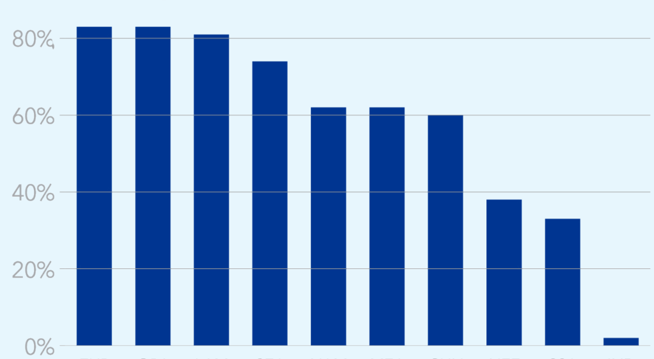
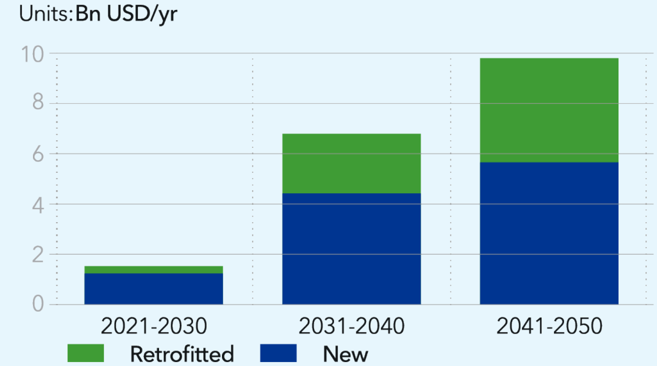


FIGURE 4.5

Global expenditure for hydrogen pipelines

Units: Bn USD/yr



Includes both capital and operating expenditures.

4.5 Shipping hydrogen

Hydrogen can be transported in ships in several ways. For shorter distances, compressed hydrogen may be feasible, but for longer distances and larger volumes liquified hydrogen, ammonia and liquid organic hydrogen carriers (LOHC) appear to be the best solutions.

Ammonia is produced today via the Haber-Bosch process that turns a mixture of hydrogen and nitrogen into ammonia. Upon delivery ammonia can be cracked into hydrogen and nitrogen with limited loss of energy.

As noted in Section 4.3, an LOHC is an organic compound that can reversibly store hydrogen[16]. Its benefits include improved safety (loaded and unloaded LOHC typically do not easily ignite), compatibility for distribution and storage with existing infrastructure, no storage loss, likely lower cost of storage, and a volumetric density between compressed and liquid hydrogen. However, LOHC is released by heat and the amount of heat required depends on the chemistry. Typically, it will take more than 30% of the energy content of the transported hydrogen to release the hydrogen with temperatures between 300-350°C. In one example, a 37% energy loss was estimated[17] – a distinct drawback. The release of hydrogen from LOHC may also involve slow kinetics.

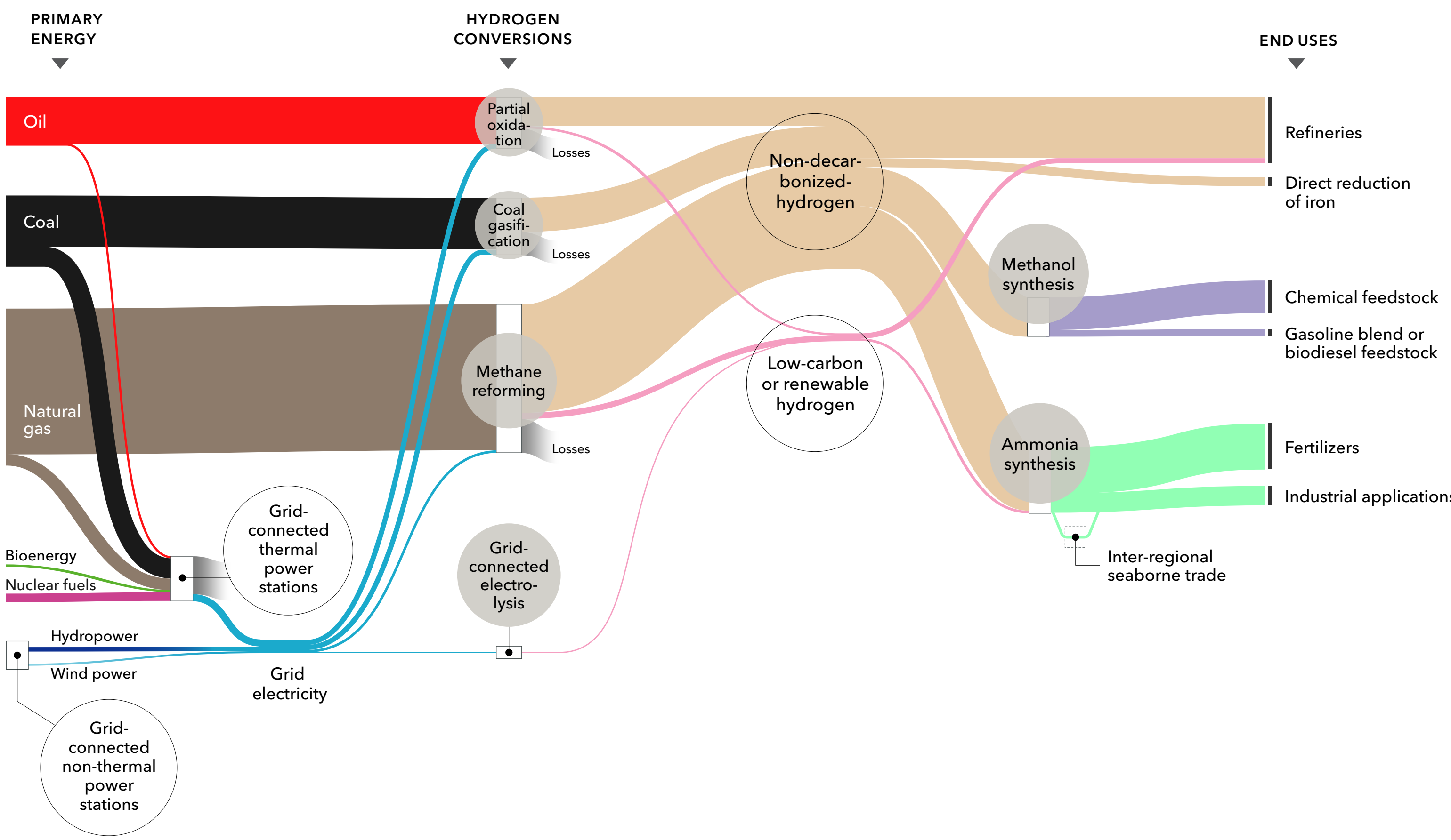
Liquid hydrogen at a low temperature of 20 K is a possibility for transporting hydrogen. A carrier for liquid hydrogen was recently finalized that can transport 2,500 m^3 of liquid hydrogen from Australia to Japan[18]. A Norwegian

concept study of a 9,000 m^3 bunkering vessel for liquid hydrogen has also been carried out[19]. It should be noted however, that it takes between 30-40% of the energy to liquify hydrogen and, furthermore, some hydrogen may be lost during transport owing to boil off.

Due to these limitations, it is currently only possible to transport a relatively small amount of liquid hydrogen by ships (2,500 m^3 corresponds to about 175 tonnes hydrogen), although larger carriers have been envisaged. By contrast, ammonia is already traded on a large scale, with approximately 18.5 million tonnes per year transported, mainly from key natural gas producing countries to fertilizer producers[20]. Ammonia is transported in gas carriers designed for ammonia transportation. These are similar to LPG carriers, that may have sizes of up to 80,000 m^3. Ammonia shipments are typically smaller than LPG parcels and therefore shipments of ammonia are done by a selection of carriers up to LGC (Large Gas Carrier) size of 60,000 m^3. This corresponds to about 40,000 tonnes ammonia or more than 6 000 tonnes of hydrogen. Larger ships are usually refrigerated to -50°C and close to ambient pressure. See Chapter 6.1 for forecast amounts of shipped hydrogen and ammonia.

It is currently only possible to transport relatively small amount of liquid hydrogen by ships.

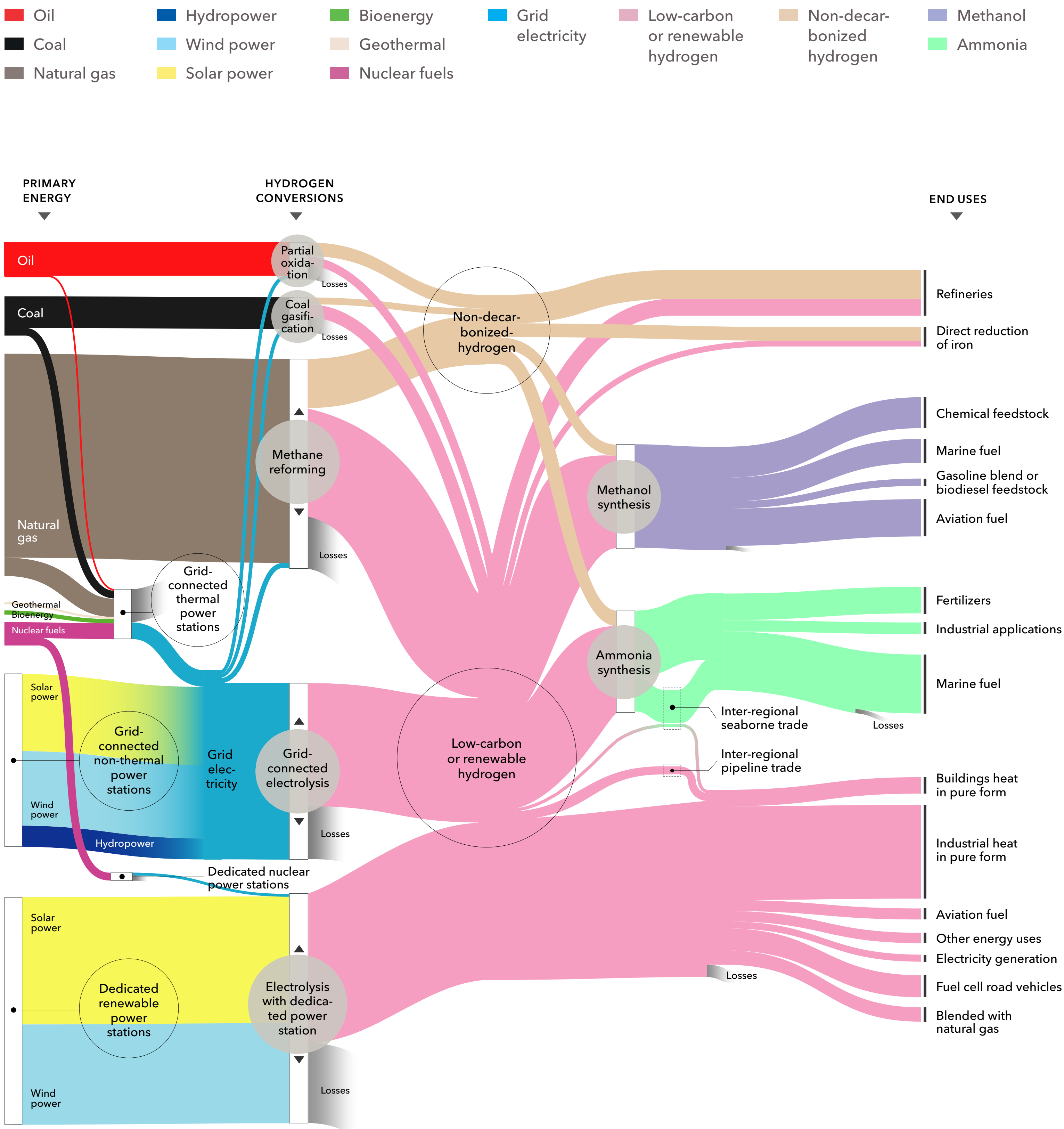
HYDROGEN FLOWS: 2020 AND 2050



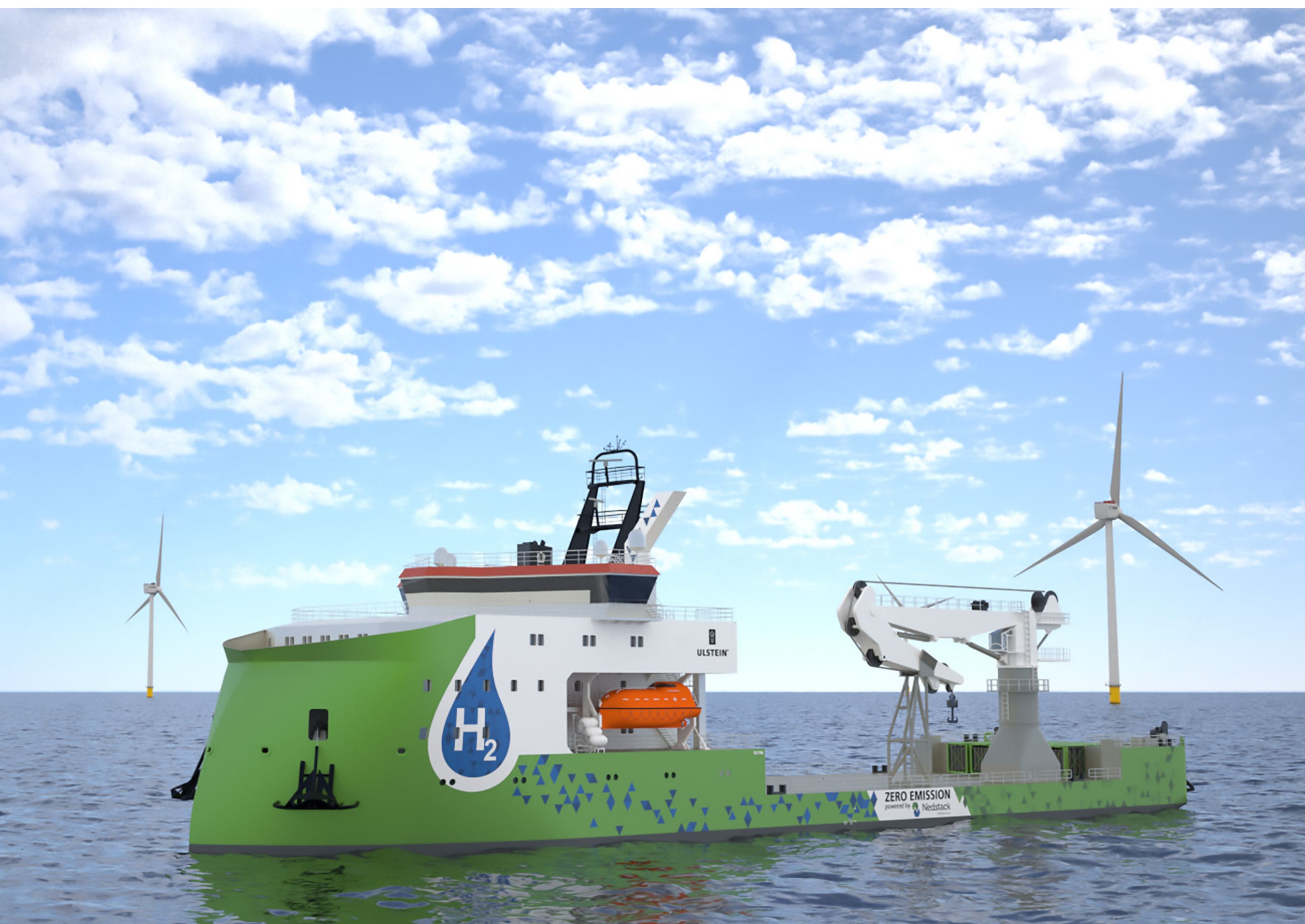
These Sankey diagrams show the flows of energy for the global hydrogen supply chain from their sources to their final uses. The width of each stream is proportional to the energy content of the energy source/carrier flow. Significant losses in conversion and transportation are indicated by fading flows.

The hydrogen system in 2020 predominantly uses fossil-fuels for feedstock and energy. Only a small amount of electricity is used to power pumps, motors, heat-exchangers, and other electrical equipment. Less than 1% of all hydrogen produced is low carbon, and that is mainly in a few refineries using CCS. In addition to being used in refineries, hydrogen is used to produce ammonia and methanol. Although the diagram shows hydrogen production and ammonia/methanol syntheses as separate processes, in most cases, they are only two steps of one continuous process happening inside a facility.

The 2050 hydrogen system is much more diverse in terms of sources and end-uses. Non-fossil primary energy sources, particularly solar and wind power, becomes the main source of hydrogen, either directly in dedicated electrolysers, or indirectly through providing power to the electricity grid, which in turn is used by grid-based electrolysers. Renewable or low-carbon hydrogen becomes the main type of hydrogen to be used either directly as an energy carrier, or in ammonia and methanol production.


Oil
Coal
Natural gas
Hydropower
Wind power
Solar power
Bioenergy
Geothermal
Nuclear fuels
Grid electricity
Low-carbon or renewable hydrogen
Non-decarbonized hydrogen
Methanol
Ammonia
PRIMARY ENERGY
HYDROGEN CONVERSIONS
END USES
Oil
Coal
Natural gas
Geothermal
Bioenergy
Nuclear fuels
Partial oxidation
Losses
Coal gasification
Losses
Methane reforming
Losses
Grid-connected thermal power stations
Solar power
Wind power
Hydropower
Grid-connected non-thermal power stations
Grid electricity
Grid-connected electrolysis
Losses
Dedicated nuclear power stations
Solar power
Wind power
Dedicated renewable power stations
Electrolysis with dedicated power station
Losses
Non-decarbonized hydrogen
Low-carbon or renewable hydrogen
Methanol synthesis
Ammonia synthesis
Inter-regional seaborne trade
Inter-regional pipeline trade
Losses
Losses
Refineries
Direct reduction of iron
Chemical feedstock
Marine fuel
Gasoline blend or biodiesel feedstock
Aviation fuel
Fertilizers
Industrial applications
Marine fuel
Buildings heat in pure form
Industrial heat in pure form
Aviation fuel
Other energy uses
Electricity generation
Fuel cell road vehicles
Blended with natural gas

5 HYDROGEN: FORECAST DEMAND AND SUPPLY



ULSTEIN SX190 concept H_2 vessel design for zero-emission operations in offshore construction market.
Image courtesy: Ulstein Design & Solutions B.V.

Almost all of the world's current 90 Mt/yr[1] annual hydrogen production is produced and used for non-energy purposes. These mainly involve the removal of sulfur from refined products and heavy oil upgrading in refineries, the use of ammonia as feedstock in ammonia and methanol production, and hydrogen for the direct reduction of iron. IEA[1] estimates another 30 Mt/yr hydrogen use in residual form from industrial processes, which is not considered as hydrogen demand in this report.

The world's total future hydrogen demand is broadly divided into the three categories

1. Decarbonizing existing use of hydrogen – replacing unabated fossil fuels with lower-emission alternatives

2. Fuel switching to hydrogen and its derivatives – retrofitting and modification of infrastructure

3. New use of hydrogen – where new infrastructure has to be established

The non-energy uses of hydrogen will continue to grow slowly until the mid-2030s, declining thereafter to current levels by the mid-century, with falling demand mainly associated with the decline in demand for oil products and the associated use of hydrogen in refineries.

Substantial growth in hydrogen demand will come from its use for energy purposes either directly, or in the form of ammonia and e-fuels derived from hydrogen. In 2030, 22 out of the 131 Mt hydrogen produced globally will be used for energy purposes. By 2040, hydrogen demand for energy will catch up with non-energy use of hydrogen. In 2050, only 30% of global hydrogen supply will be used for non-energy purposes. 39% will be direct use of hydrogen as energy while 31% will be converted to ammonia or e-fuel for energy end users.

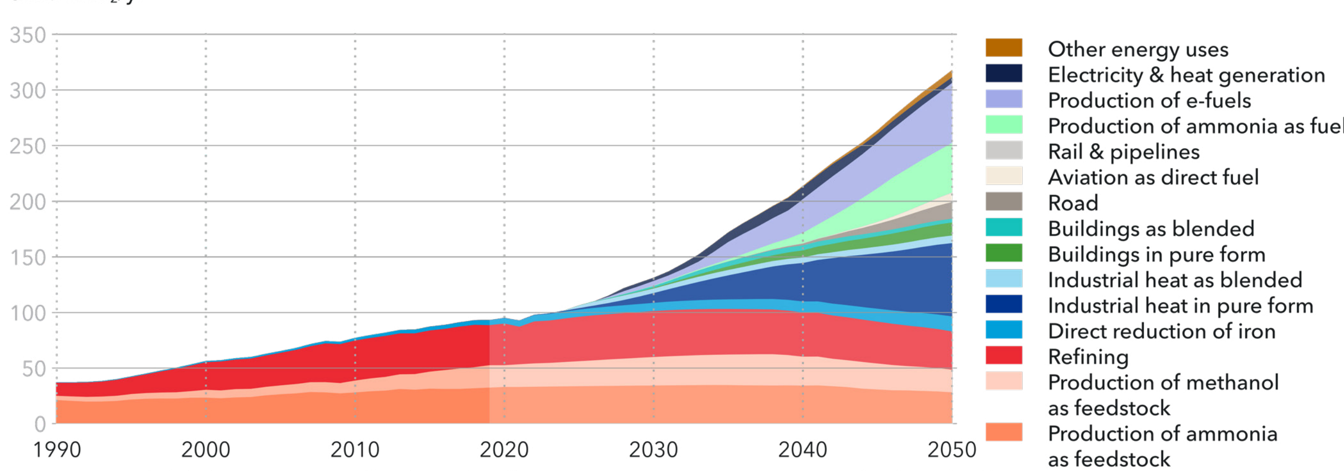
The next three decades of hydrogen demand

In **present decade**, hydrogen will remain too expensive to be widely used and the demand will instead be created through policy support and incentives from governments mainly in Europe, OECD Pacific, North America and China. This first decade is shaped by a desire to kick-start production and related infrastructure and to enable cost learning. Blending hydrogen into natural gas transmission networks is one of the ways we will see hydrogen being pushed to consumers, especially in industry. Subsidizing the price difference between

FIGURE 5.1

Global hydrogen demand by sector

Units: MtH_2/yr



Does not include hydrogen use in residual form from industrial processes. Historical data sources: IEA Future of Hydrogen (2019), IEA Global Hydrogen Review (2021), USGS Mineral Commodity Summaries (1990-2022), IFA (2022) natural gas and hydrogen will facilitate acceptance and offtake. We will see the start of the application of pure hydrogen use in industries using high heat, such as iron and steel production, where hydrogen's role as feedstock in direct reduction of iron is also increasing.

In the **2030s**, the average price of hydrogen will reduce by half compared with the early 2020s and hydrogen's role in industrial heating will become more widespread, with its use in global industrial heat supply exceeding 5%. This second decade will also see wider use of hydrogen in buildings for heating, as a fuel blend in gas-fired power stations, and in transport. Despite growth in these markets the global use of hydrogen as an energy carrier will remain smaller than its non-energy use.

The **2040s** will be the decade of demand diversification as more hard-to-abate sectors will be forced to use hydrogen or its derivatives to decarbonize. Although the cost of hydrogen will continue to fall and approach the USD 1-2/kg range, uptake will mostly still be driven by the increased cost of the alternative because of carbon pricing, or by decarbonization mandates. In this decade, we project a more widespread uptake of fuel-cell vehicles in long-distance heavy trucking and uptake of ammonia and e-fuels as maritime fuels.

Leaders and laggards

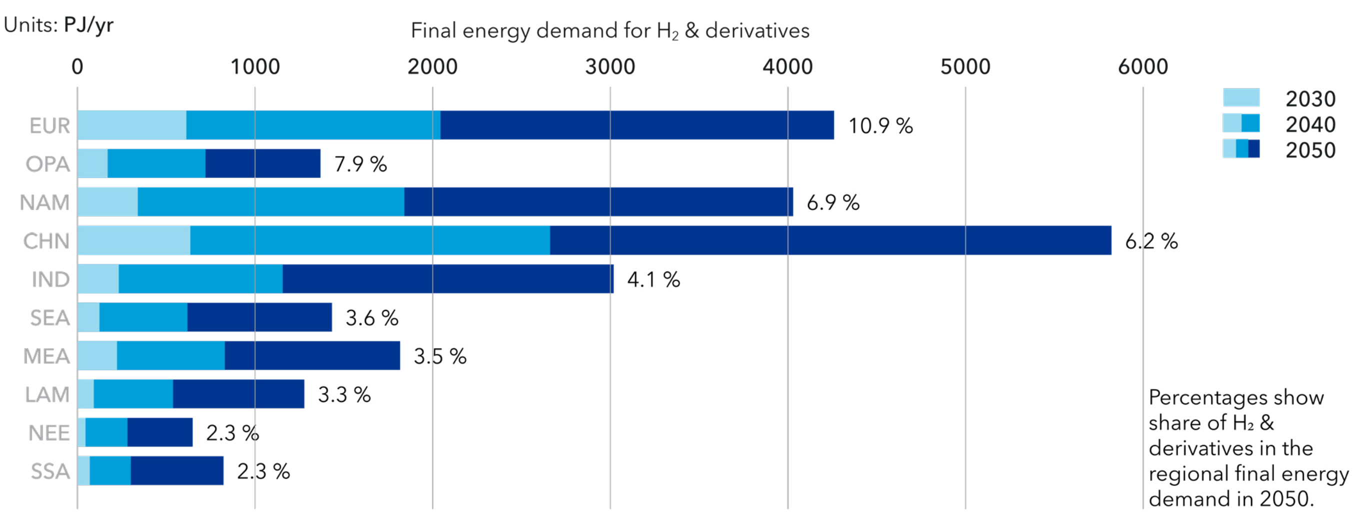
Across our world regions, there is a wide range of national plans and policies on the role of hydrogen in the decarbonization of energy systems, as explained in Chapter 2. These differences will lead to different paths, as shown in Figure 5.2. Europe, with its strong hydrogen support policies will lead the pack with 11% hydrogen and its derivatives in its 2050 final energy mix. OECD Pacific, North America and Greater China follow Europe with shares above the world average of 5.1%. These four leading regions will together consume two-thirds of the global hydrogen demand for energy purposes, a figure that also reflects regions' shares in international maritime and aviation energy consumption in line with the size of their economies.

In present decade, hydrogen will remain too expensive to be widely used and the demand will instead be created through policy support and incentives from governments.

FIGURE 5.2

Regional comparison of hydrogen uptake

Units: PJ/yr



For region definitions, see map page 26.

5.1 Hydrogen production

As of 2022, almost all of world's 90 Mt/yr hydrogen production is fossil-fuel-based and unabated, i.e., without CCS[1]. This includes about a quarter of ammonia plants that capture their process emissions (only around half their carbon emissions) and provide the recovered CO_2 to be used in urea production (carbon capture and utilization – CCU), accounting for some 8 MtH_2/yr. Only a few refineries, methanol and fertilizer production facilities use CCS (carbon capture and storage) to capture emissions from the dilute flue gas stream (usually up to 85-90% of the total CO_2 emissions) and store long-term, with a combined capture capacity of less than 10 $MtCO_2$/yr [2]. Most of these facilities are in the US and Canada.

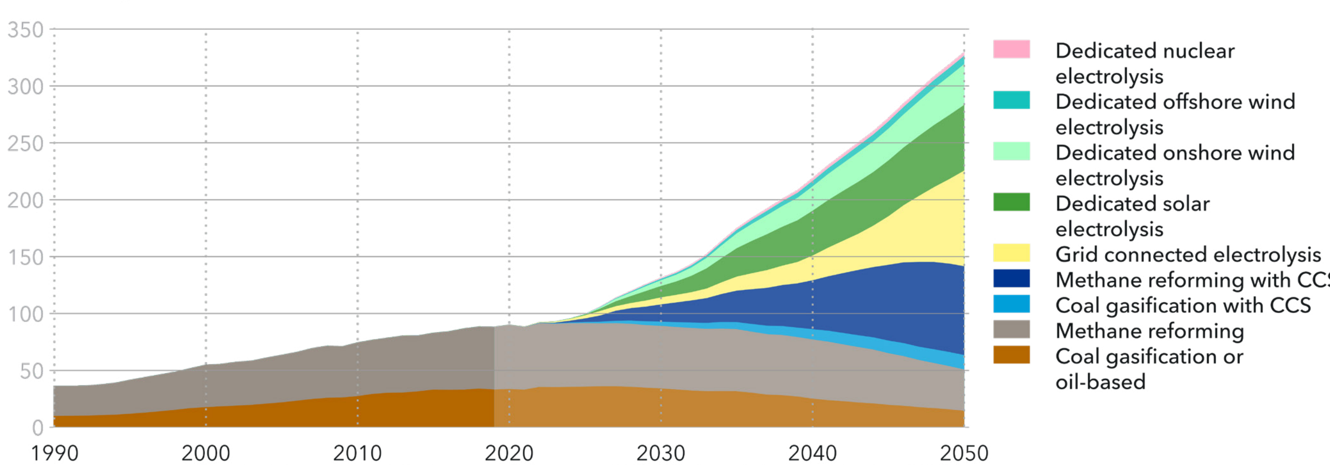
Figure 5.3 shows the breakdown of global hydrogen supply by production route. Methane reforming, almost all of which is steam methane reforming (SMR), is the most common way of producing hydrogen for ammonia and methanol production. Coal gasification is the principal route used in China, but has limited use elsewhere. In oil refineries, about half of the hydrogen is produced as a by-product of other processes in the refinery or from other petrochemical processes integrated into certain refineries[1]. The other half is produced primarily from methane reforming, or coal gasification in the case of China.

The future hydrogen supply mix will be shaped by two related trends: firstly, the use of hydrogen as an energy carrier will increase, and secondly, there will be a gradual replacement of existing production capacity with lower-emission alternatives. As the main motivation for hydrogen use in energy systems is to decarbonize sectors that cannot be electrified, only low-carbon production routes are future contenders. With energy use of hydrogen and its derivaties dominating hydrogen demand after 2040, the supply mix will be increasingly low-carbon. In 2030, we forecast that a third of global supply will be low-carbon and renewable, with fossil fuels with CCS taking a 14% share of the global total and hydrogen from electrolysis 18%. In 2050, 85% of world's hydrogen supply will be from low-carbon routes, broken down as follows: 27.5% from fossils with CCS, 25.5% from grid-connected electrolysis, 17.5% from dedicated solar-based electrolysis, 13% from dedicated wind-based electrolysis and 1% from dedicated nuclear-based electrolysis.

FIGURE 5.3

World hydrogen production by production route

Units: MtH_2/yr



Historical data source: IEA Future of Hydrogen (2019), IEA Global Hydrogen Review (2021).
Does not include hydrogen use in residual form from industrial processes.

Cost and the speed of build-up are the main factors determining the shares of production routes in the supply mix. Currently, on the global average, the cheapest low-carbon hydrogen production route is methane reforming with CCS, commonly referred to as blue hydrogen, with an average cost just below USD 3/kgH_2 in 2020 (see Figure 5.4). This global weighted average is more representative of regions like North America and North East Eurasia with access to cheap natural gas, and does not reflect the increase in the gas prices since 2020. Reflecting recent increased gas prices, our estimate is that the levelized cost of methane reforming with CCS has increased from 2020 to 2022 by 20-30% in gas producing regions, and 60-400% in gas importing regions.

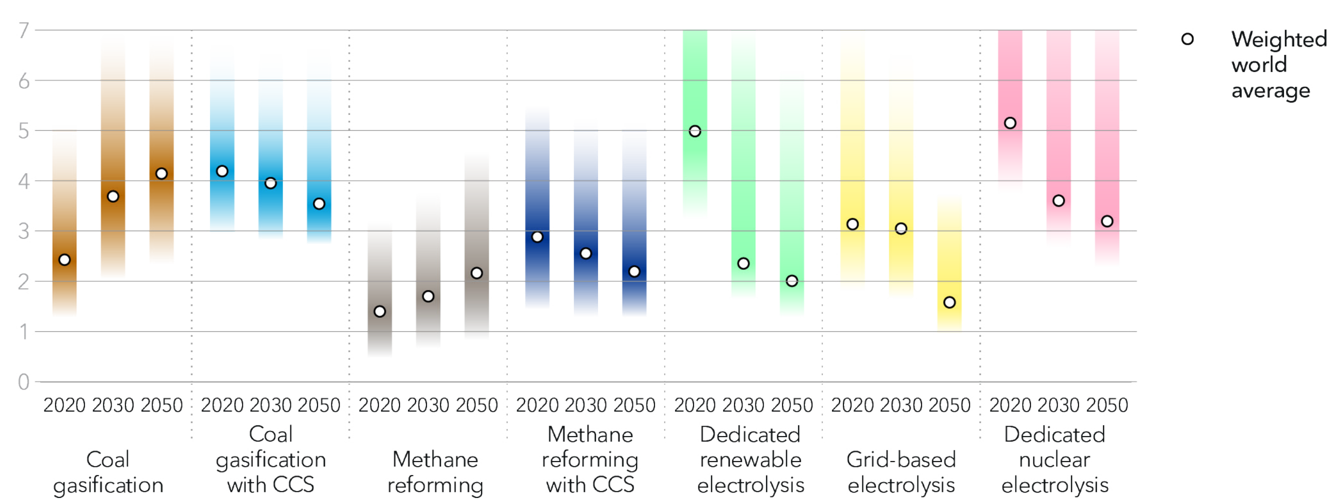
Although we foresee gas prices falling from the current high levels by 2030s, there are additional challenges for blue hydrogen. CCS is still a developing technology and concerns about long-term storage sites, uncertainties on future costs, and only marginal benefits from economies of scale are limiting the speed of deployment. Moreover, CO_2 capture rates beyond 90% will remain uneconomical, and the remaining direct CO_2 emissions throughout the supply chains associated with blue hydrogen is a disadvantage, which will be echoed by policymakers and result in a weaker support for blue hydrogen compared with other low-carbon, renewable alternatives. Nonetheless, with the continued reduction in CAPEX for methane reforming (particularly ATR technology) and carbon capture, and with reducing risk premiums for hydrogen investments, and increasing carbon prices, blue hydrogen will gain significant market share, especially in ammonia and methanol production. The cost of carbon capture for ammonia production is lower than the cost of carbon capture for merchant hydrogen. Of the 78 MtH_2/yr produced globally from methane reforming with CCS in 2050 (which will constitute 24% of the global hydrogen supply), 68 MtH_2/yr will be captive hydrogen. Captive means that it is produced in the same facility in which it is consumed in ammonia and methanol production or in refineries or in the direct reduction of iron.

The cost of dedicated renewables-based electrolysis is presently prohibitively expensive, with a global weighted average of USD 5/kgH_2 in 2020. But, in the decade to 2030, we will see a sharp reduction in the cost of electrolysis with dedicated solar or wind capacity reducing on average towards USD 2/kgH_2. The main driver of this trend will be a 40% reduction in solar panel costs and a 27% reduction in turbine costs. With continued improvements in turbine sizes and solar panel technologies, the annual operating hours will simultaneously increase by

FIGURE 5.4

Levelized cost of hydrogen after support by production route

Units: USD/kgH_2



10-30%, varying between technologies and regions. Moreover, the cost of capital for electrolysers of any kind will see 25-30% reduction as the perceived financial risk keeps coming down.

Electrolysers coupled with a dedicated nuclear power station will benefit from unconstrained running hours, providing continuous supply of electricity with essentially no variable cost for the production of hydrogen. However, electricity costs are high. Despite a 35% reduction in the average nuclear CAPEX by 2050, influenced by the expected uptake of small modular reactors, dedicated nuclear electrolysers will only account for 1% of the world's hydrogen supply in 2050, almost all of which is in China, where nuclear costs are relatively lower.

This percentage share of hydrogen supply from nuclear power does not include any grid-connected nuclear power plants that may see their annual operating hours (capacity factor) drop owing to a high renewables penetration in the power system, and which then choose to use that excess capacity to produce hydrogen. We would account for such nuclear capacity (or indeed spare capacity from any other kind of power station) under the category of "grid-connected electrolysis", as the operation of these electrolysers will be dictated by power market dynamics. Technically, these power stations, as 'auto producers', will not be buying electricity from the grid, and thus avoid paying grid connection charges and other taxes and levies at the same rate as electricity end-users. However, other grid-connected electrolysers which are 'buyers' of electricity will mainly be purchasing electricity when there is a surplus of renewable power. Owing to their flexibility and market-stabilizing role – preventing electricity prices from going to zero or even into negative territory – these grid-connected power purchases are likely to be incentivized with lower tax and grid charges. We assume they will typically pay only 25% above the wholesale electricity price. Hence the two categories of grid connected electrolysers – auto producers and buyers – operate under fairly similar costs of power. Moreover, it is not easy to estimate the fraction of auto-producers versus buyers. From a modelling perspective, it is therefore expedient to treat them as one category of hydrogen production.

For grid-connected electrolysers, the largest cost component is the cost of electricity (see Figure 5.5), specifically, the availability of cheap electricity. In the longer term, the share of variable renewable energy sources (VRES) in the power systems will be the main factor in determining the future electricity price distribution; more VRES means more hours with very cheap (or even free) electricity. However, before 2030, the penetration of VRES in the power systems will not be sufficient to exert large impacts on the electricity price distribution. Hence, any reduction we see in the cost of grid-connected electrolysers in the remaining years of this decade is due to a decline in CAPEX along with any support governments provide. As there are no well-established supply chains and markets for hydrogen, existing electrolysers do not compete with each other. This means that their operating hours are mainly determined by their own levelized cost. In many regions, the optimum capacity factor is well above 90%, which helps to spread initial CAPEX across many hours.

Towards 2050, we will see two main trends that affect annual operating hours: increased competition from alternative hydrogen production routes and more hours with cheap electricity. The main competitor for grid-connected electrolysis will be blue hydrogen from methane reforming with CCS. In a fully competitive market, the variable cost of hydrogen produced from grid-connected electrolysis (i.e., the cost of electricity) cannot be higher than variable cost of hydrogen from methane reforming with CCS (i.e., the corresponding cost of gas). This means, in regions with cheap gas like North America, at current electricity prices, the competitive annual operating hours would be less than 2000 out of 8760 hours in a year. This may be insignificant today as competition is limited. But over the next 30 years, most hydrogen consumers will have access to hydrogen from various production routes and competition will be a major issue. Fortunately, with increased VRES in the system, the number of hours where hydrogen from electricity will be cheaper than blue hydrogen increase towards 2050. Consequently, although we see a tight range of annual operating hours in 2030s of between 2000-4000 hours, this expands to 4000-7000 in many regions towards 2050.

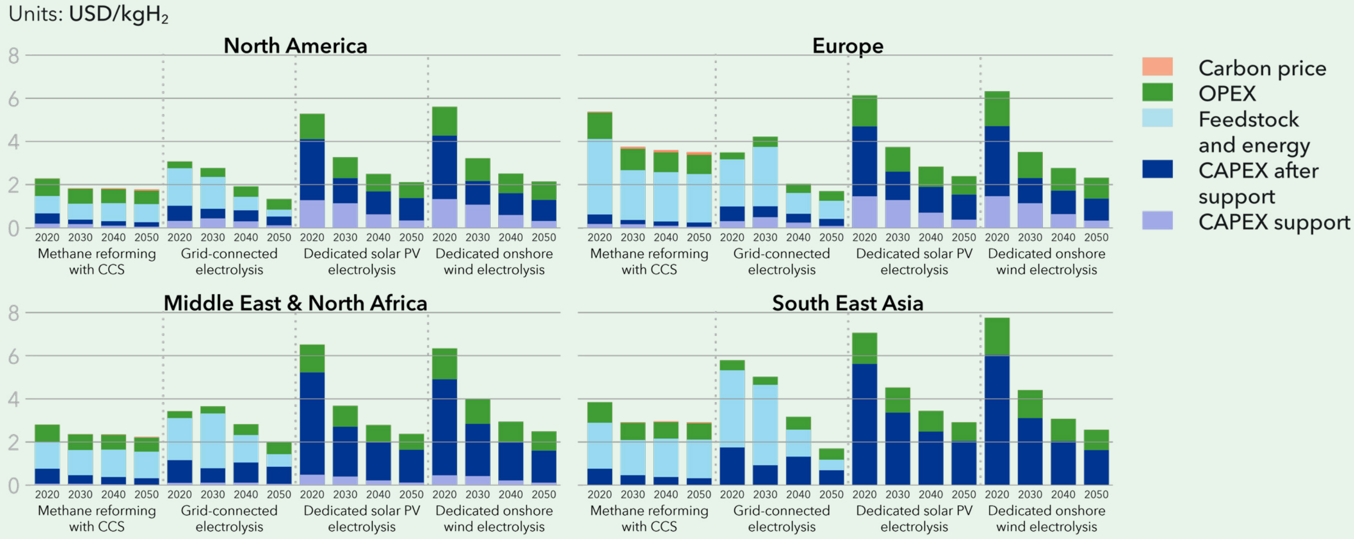
Figure 5.5 shows levelized cost and its components in four selected regions, which illustrate the trends explained in the preceding paragraphs. The wide spread in costs between regions is due to factors such as differences in local conditions, fuel prices, availability of support, and cost of capital. The differences in regional costs influence regional production mixes as shown in Figure 5.6.

Table 5.1 summarizes the capacity of all electrolysers, dedicated or grid-connected, merchant or captive, in 10 world regions. Greater China, with its high hydrogen

FIGURE 5.5

Average levelized cost of hydrogen production by component in selected regions

Units: USD/kgH_2



Inputs to the levelized cost calculations are as follows. Natural gas price (all in USD/MMBTU): 3.14.7 (2020), 4.3 (2030), 5 (2050) in NAM; 10.522 (2020), 132.4 (2030), 13.5 (2050) in EUR; 7.65 (2020), 6.67 (2030), 7.6 (2050) in MEA; 13.48.8 (2020), 109.4 (2030), 11.4 (2050) in SEA. Electricity price is determined using the hours at which electrolysers operate, assuming 25% surcharge over wholesale price to cover grid charges and other TSO expenses. Resulting electricity prices (all in USD/MWh): 33.8 (2020), 29.8 (2030), 6.5 (2050) in NAM; 42.4 (2020), 54.5 (2030), 16.9 (2050) in EUR; 38 (2020), 51.5 (2030), 12 (2050) in MEA; 69.3 (2020), 75.7 (2030), 10 (2050) in SEA. Grid-electrolysis operating hours determined as a weighted average of operating hours minimizing total levelized cost (dominant factor in 2020) and hours where electricity price makes electrolysis cheaper than methane reforming with CCS (dominant factor in 2050). Resulting annual operating hours: 8753 (2020), 5718 (2030), 5856 (2050) in NAM; 8452 (2020), 4632 (2030), 7803 (2050) in EUR; 8505 (2020), 8682 (2030), 4034 (2050) in MEA; 5058 (2020), 6764 (2030), 5194 (2050) in SEA. Methane reforming annual operating hours: 8332. Annual operating hours for dedicated renewables increase with improved solar technology (tracking, bifacial panels) and turbine size. Ratio of power output to electrolyser capacity is assumed 0.7 for solar, 1.0 for onshore wind. Annual operating hours for solar (2020-2050): 2300-2600 in NAM; 1600-2000 in EUR; 1800-2600 in MEA; 1700-1900 in SEA. Annual operating hours for onshore wind (2020-2050): 3500-4300 in NAM; 3050-3950 in EUR; 3400-4150 in MEA; 2550-3750 in SEA. Lifetime for hydrogen production capacity 25 years. Lifetime for solar PV: 30 years. Lifetime for onshore wind: 30-35 years. Electrolyser stack lifetime: 72000 hours in 2020, 80500 hours in 2050. CAPEX for methane reforming with CCS 1440 USD/(kgH_2/day) in 2020. CAPEX for electrolysis including stack: 880 USD/kW in 2020. CAPEX for solar PV (in USD/kW) in 2020; 994 in NAM, 833 in EUR, 823 in MEA, 760 in SEA. CAPEX for onshore wind (in USD/kW) in 2020: 1500 in NAM, 1610 in EUR, 1380 in MEA, 1220 in SEA. Additional engineering & procurement cost is assumed as 35% for all technologies. Learning rate for methane reforming: 11%, for CCS CAPEX: 13%, for electrolysers: 15% in 2020 reducing to 12% in 2050, for solar panels: 26% in 2020 reducing to 16% in 2050; for wind turbines: 16%. Discount rate: 11%/yr (2020), 7.5%/yr (2030), 5.5%/yr (2050) in NAM; 10%/yr (2020), 7%/yr (2030), 5%/yr (2050) in EUR; 13%/yr (2020), 10%/yr (2030), 8%/yr (2050) in MEA and SEA. High discount rates in 2020 reflect the risk premium of hydrogen production. Annual H_2 production OPEX: 3.3%/yr of H_2 production CAPEX for methane reforming with CCS; 3% for electrolysers. Short term H_2 storage and transport cost: 0.15-0.11 USD/kgH_2 for methane reforming, 0.1-0.3 USD/kgH_2 for grid-connected electrolysis, 0.4-0.3 USD/kgH_2 for solar electrolysis, 0.5-0.4 USD/kgH_2 for onshore wind electrolysis. Specific feedstock intensity for methane reforming: 145.3 MJ/kgH_2. Specific fuel intensity for methane reforming: 11.5 MJ/kgH_2. Specific electricity intensity for methane reforming: 5.18 MJ/kgH_2, for electrolysers: reducing from 185.5 MJ/kgH_2 in 2020 to 173 MJ/kgH_2 in 2050. Emission intensity of methane reforming: 57.3 kgCO_2/GJ of natural gas. Cost of carbon capture and storage (all in USD/tCO_2): 58 (2020), 51 (2030), 49 (2050) in NAM; 109 (2020), 85 (2030), 81 (2050) in EUR; 60 (2020), 56 (2030), 52 (2050) in MEA; 76 (2020), 65 (2030), 65 (2050) in SEA. Carbon price (all in USD/tCO_2): 10 (2020), 25 (2030), 70 (2050) for NAM; 30 (2020), 95 (2030), 135 (2050) for EUR; 0 (2020), 10 (2030), 30 (2050) for MEA; 1 (2020), 25 (2030), 50 (2050) for SEA. CAPEX subsidy: 25% (2020), 50% (2030), 25% (2050) in NAM, EUR; 13% (2020), 10% (2030), 8% (2050) in MEA; 0 in SEA. All numbers are for merchant hydrogen, reflecting the average conditions in the region.

demand and relatively high gas prices, leads the way in electrolysis capacity. As explained in Chapter 3, the current cost of electrolysers in China is significantly cheaper than elsewhere in the world. BNEF's recent estimates[3] for alkaline electrolysers are as low as USD 300/kW. However, they are also known to be less efficient and have shorter lifetimes[4]. We expect some improvements in these disadvantages, which will help China to build the largest electrolyser capacity in the world.

However, technology diffusion from China to other regions will be limited as shown in Chapter 3. Europe, with its ambitious targets from the EU and the UK, will be also ahead of the other regions, especially until 2030. In Europe, we forecast 111 GW of electrolyser capacity in 2030, producing 6.6 Mt hydrogen at the regional operating hours average of 3,000 hours/yr, falling short of the 10 Mt ambition by 2030 in its REPower EU plan.

TABLE 5.1

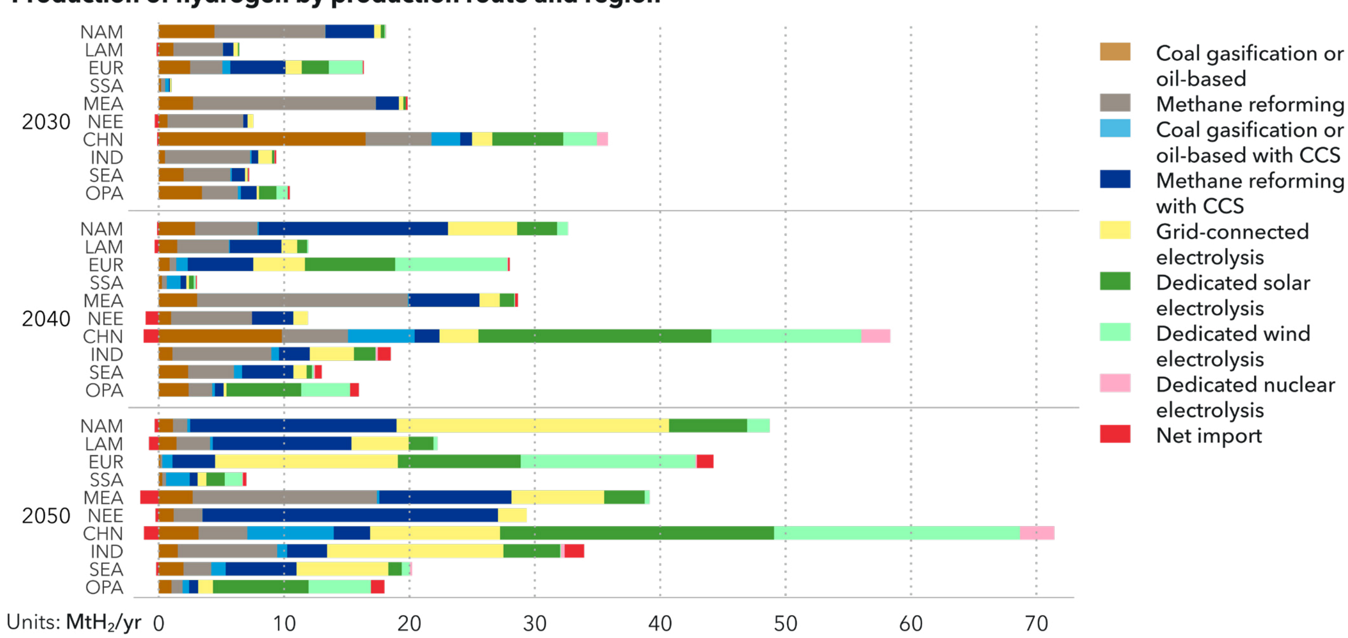
Electrolyser capacity by region

Units: GW

		2030	2040	2050
NAM	North America	10	120	305
LAM	Latin America	4	27	83
EUR	Europe	111	351	574
SSA	Sub-Saharan Africa	4	16	66
MEA	Middle East & North Africa	8	35	147
NEE	North East Eurasia	3	13	22
CHN	Greater China	258	899	1248
IND	Indian Subcontinent	18	80	263
SEA	South East Asia	3	27	123
OPA	OECD Pacific	45	180	244
World		**465**	**1748**	**3075**

FIGURE 5.6

Production of hydrogen by production route and region



5.2 Hydrogen as feedstock

As shown in Figure 5.7, in the next few years, decarbonization of non-energy hydrogen overshadows hydrogen for energy and provides valuable learning and catalysation for uptake of green and blue hydrogen for energy use from the late 2020s. Hydrogen will, however, also increasingly be used as a feedstock to produce products like ammonia and e-fuels which will then be used for energy purposes.

This section considers how much hydrogen is used as feedstock to industrial processes and to other products, which may then be used for *either* energy *or* non-energy purposes.

Hydrogen as a feedstock is used in six major categories: in oil refineries for desulfurizing diesel and fuel oil, production of ammonia, production of methanol and other chemicals, production of direct reduced iron, production of ammonia as fuel, and production of e-fuels such as e-methanol and e-kerosene.

The last two demand categories do not yet exist as such. Despite this, we foresee that hydrogen derivatives used as energy carriers will be critical in satisfying the energy demand in hard-to-abate sectors such as aviation and maritime in the future.

In total, 195 MtH_2/year is needed as feedstock for both non-energy and energy uses in 2050; in other words, a more than doubling of demand from 2020.

Currently, two major needs for feedstock hydrogen are for oil refineries, and for producing ammonia for fertilizers. Our forecast shows that while in absolute quantities the demand for hydrogen in these segments sees a slight decrease, there will be a burgeoning need for derivatives to be used for energy purposes. In fact, by 2050, the hydrogen demand for producing e-fuels and ammonia fuel will be more than that of the combined demand for hydrogen for oil refineries and fertilizer production.

Figure 5.8 shows the evolution of the feedstock hydrogen production routes.

At present, almost all hydrogen to be used for industrial processes is produced either through coal gasification,

FIGURE 5.7

Share of global green and blue hydrogen production used for energy purposes

Units: percentages

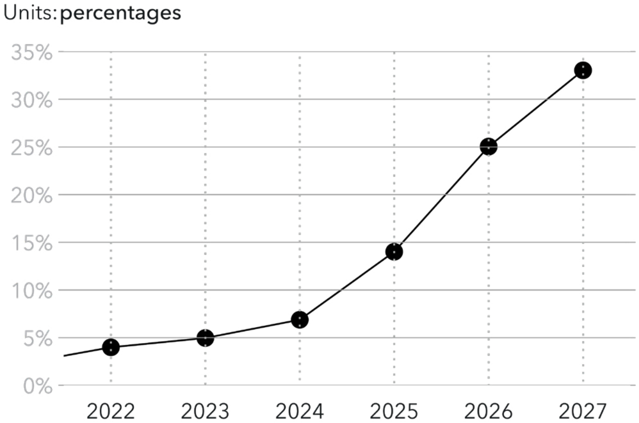
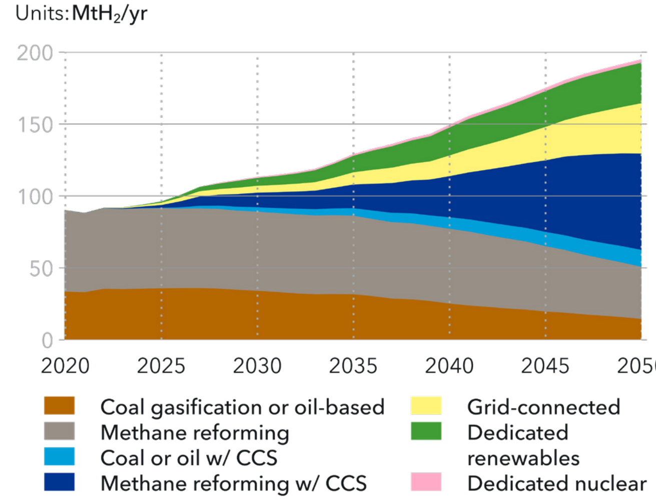


FIGURE 5.8

Global production of hydrogen as feedstock by production route

Units: MtH_2/yr



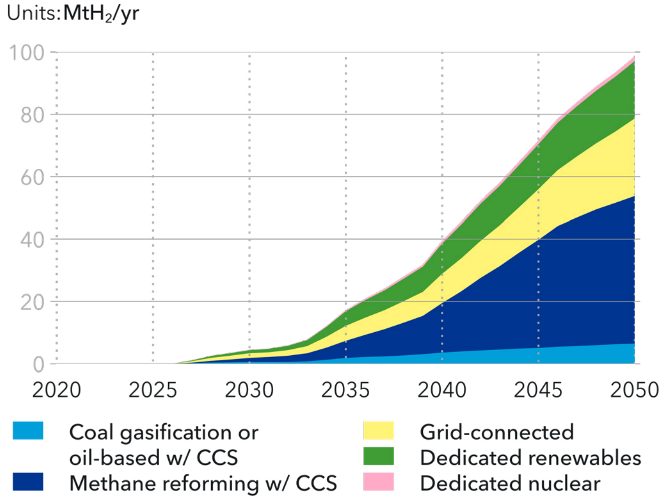
oil-based steam cracking or methane reforming. A miniscule amount (less than 1%) of feedstock hydrogen is produced by grid-connected electrolysis. We predict that the current production routes for hydrogen as feedstock will undergo a dramatic transition by 2050 (Figure 5.8). CO_2-intensive production routes, such as methane reforming and coal gasification will lose their dominant positions, replaced by methane reforming coupled with CCS, grid-connected electrolysis and electrolysis coupled to dedicated renewables. Rising carbon prices in regions such as Europe, will trigger faster hydrogen uptake and will kick-start the transition from carbon-intensive production routes to low-carbon production routes.

There is regional differentiation on the production routes of hydrogen. For example, in Middle East & North Africa, methane reforming is the dominant production route even in 2050, with a 52% production route share. This is tied to the relatively lower carbon price-level in the region coupled with lower cost of production of natural gas. On the other hand, in OECD Pacific (36%) and Europe (42%), the renewables-based electrolysis production route will have the major share, due to higher natural gas prices and carbon prices.

FIGURE 5.9

Global production of hydrogen derivatives as energy carrier by production route

Units: MtH_2/yr



In addition to regional differentiation, we also forecast differentiation of production routes across the different feedstock hydrogen categories. We analyse this under two broad categories: hydrogen for derivatives, and for oil refineries and production of direct reduced iron (DRI).

Hydrogen demand for derivatives

Total hydrogen demand for the production of derivatives will be 147 Mt in 2050. Of this, two-thirds will be for hydrogen derivatives used as energy carriers in the transport sector and the rest will be for production of ammonia and other chemicals (e.g. methanol).

For the transport sector, we do not foresee brown and grey hydrogen-based e-fuels and ammonia (Figure 5.9). Instead, our forecast shows that blue hydrogen will come to dominate this demand segment, especially with its prevalence in regions such as North East Eurasia and North America, which have access to relatively cheaper, domestically produced, natural gas. Higher natural gas prices and the earlier uptake of dedicated renewables for hydrogen lead to half of Europe's hydrogen for this demand segment coming from dedicated renewables in 2050.

Total hydrogen demand for the production of derivatives will be 147 Mt in 2050. Of this, two-thirds will be for hydrogen derivatives used as energy carriers.

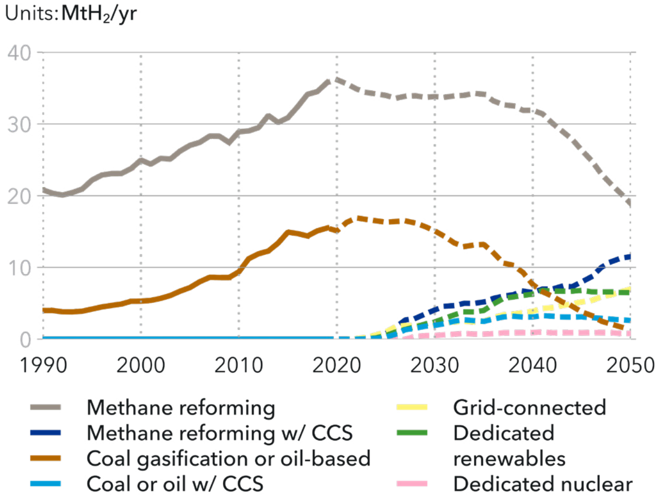
Unlike in hydrogen derivatives used for energy, we forecast methane reforming persisting to a large extent (39%) in the production of ammonia, methanol and other chemicals, especially in fossil-fuel rich regions such as Middle East & North Africa and North East Eurasia, even in 2050 (Figure 5.10). Higher carbon prices in regions such as Europe and North America, and relatively cheaper CCS costs for ammonia production also ensure a 24% share of blue hydrogen in the production of ammonia and other chemicals.

Coal gasification is likely to lose its competitiveness as a result of higher carbon prices, in the production of ammonia and other chemicals. Its share in production reduces from 32% in 2020 to 8% in 2050. Coal gasification technology is primarily used in China, which will still be the case in 2050. Coal gasification coupled with CCS will have a 5% share in 2050, primarily located in Greater China.

Contrarily, electrolysers running on dedicated renewable electricity increase their competitiveness starting from late 2030s and by 2050 achieve a 13% share of production. The cost-learning-rate effects reduce the levelized cost of H_2 produced via electrolysis coupled to dedicated renewable power generation, which in turn spur the growing share in H_2 production for ammonia and other chemicals.

FIGURE 5.10

Global hydrogen use in production of feedstock ammonia and other chemicals, by production route
Units: MtH_2/yr



Hydrogen for oil refineries and direct reduced iron (DRI)

The total demand for hydrogen in oil refineries and DRI had a share of 43% of total hydrogen demand in industrial processes in 2020. This reduces to 25% in 2050, largely due to the burgeoning demand for hydrogen derivatives.

Nevertheless, in absolute numbers, hydrogen demand in oil refineries increases from 37 Mt to 41 Mt in 2030 and then shows a slight decline to 34 Mt by 2050. Hydrogen is used for desulfurizing diesel and fuel oil. Despite the world's oil demand reducing from present days to 2050, more stringent air-quality standards on fuels, across all regions, lead to the demand for hydrogen being maintained.

Historically, most of the hydrogen demand in oil refineries has been satisfied by hydrogen produced within the refineries (captive production), during steam cracking processes or by dedicated on-site production. We foresee this trend continuing, with 47% of hydrogen for oil refineries being produced through the oil-based production route in 2050. Out of this 47%, 8% will be coupled with CCS. Another 39% will be from methane reforming and methane reforming coupled with CCS. Less than 15% is through electrolysis, both grid-connected and dedicated renewables-based.

The historical demand for hydrogen in the steel making process has been very little, and in 2020, the demand was 5 Mt. This is because hydrogen is mostly needed as a reducing agent to make sponge iron via the electric arc furnace (EAF) route, whose share is low when compared to the conventional steelmaking process. Nevertheless, we foresee the DRI+EAF steelmaking route being favoured in the future, as a way to decarbonize steel production, which in turn almost triples the demand for hydrogen in this demand segment.

At present, the majority of the H_2 for DRI is produced through methane reforming. We foresee this trend continuing, with 72% of the demand of 13.5 Mt being produced via methane reforming in 2050. Nevertheless, we project 500 tonnes of H_2 for DRI produced through electrolysis in Europe by 2050.

5.3 Hydrogen as energy

5.3.1 Demand for hydrogen in buildings

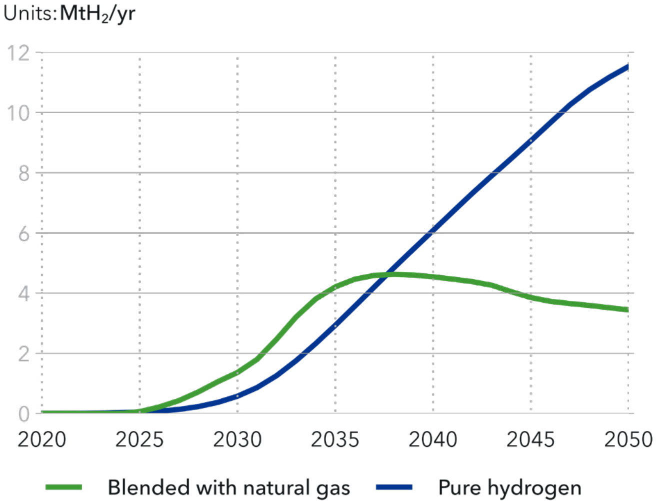
The uptake of hydrogen in buildings is expected to be relatively limited on a global scale, and is likely to be most prominent in regions with developed gas distribution networks. Among end-use sectors, using hydrogen for space and/or water heating in buildings may be lower in priority than sectors where hydrogen (or hydrogen derivatives) is currently the only feasible pathway towards decarbonization, such as in maritime, long-haul aviation, and steelmaking. The limited projected uptake of hydrogen in buildings is explained by comparative efficiency, costs, and infrastructure availability in relation to competing technologies, mainly electric heat pumps and district heating. Nevertheless, a buildings fuel mix that includes hydrogen alongside electricity for heat pumps will help balance out potential seasonal peaks in power demand.[5]

Evidence suggests that hydrogen can readily be blended into existing natural gas pipelines with a share of up to 20% by volume, without a need for retrofitting existing appliances or pipelines.[6] Initial blending of hydrogen into natural gas networks can induce substantial and dependable demand for hydrogen in its early deployment, providing an impetus towards accelerated

FIGURE 5.11

Global hydrogen demand in buildings: blended and pure

Units: MtH_2/yr



learning and reduced cost of hydrogen due to the operation of the self-reinforcing virtuous cycles of cost-learning dynamics. Over time, this will slowly make the use of pure hydrogen in buildings economically viable in some regions.

Using pure hydrogen in buildings that are currently on the gas grid has advantages and disadvantages relative to electrification. The key trade-offs are:

Running cost versus upfront cost: Due to higher efficiency and expected lower electricity prices in future, heat pumps are likely to cost less to run than hydrogen boilers, particularly in homes with good insulation. We forecast that in 2050, heating by hydrogen will be around 50% more costly than heat pumps on average, although this will differ by building type. But hydrogen boilers have a lower upfront cost, which is an important factor for less well-off consumers. And hydrogen-ready boilers can quickly be refitted in a future hydrogen switch-over, reducing the upfront cost to consumers to almost zero.

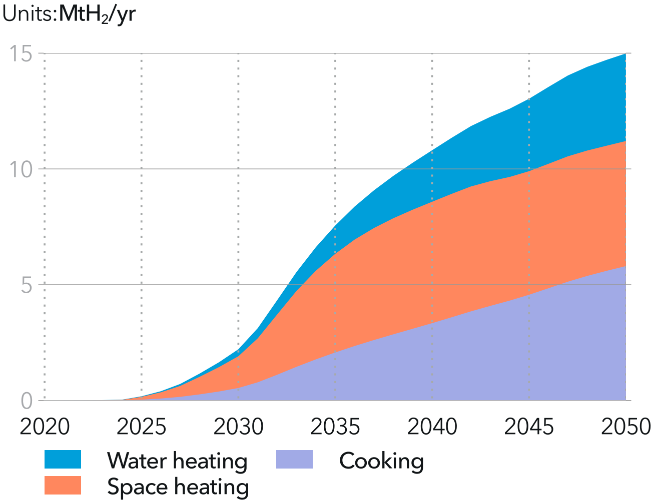
Efficiency versus infrastructure capacity and peak load demand: Heat pumps are around 3x more efficient than hydrogen boilers, and more so if the losses in green hydrogen production are also included. But a nation-wide heat pump roll-out to replace gas boilers would require large investments in electricity grid reinforcement, and may require an electricity generation and storage system to be sized for peak heating loads, with considerable spare capacity in summer periods. Re-used gas networks bring this storage capacity and peak load capacity automatically. We forecast that hydrogen use in buildings will mostly be in blended form during the early deployment phase. In our forecast, use of pure hydrogen in buildings only overtakes blended hydrogen during the late 2030s (see Figure 5.11).

In our analysis, we project an uptake of 1.9 EJ/yr (~15.8 MtH_2/yr) of hydrogen in buildings by 2050, constituting a mere 1.3% of the total energy demand in the buildings sector. The largest shares of the demand will come from space and water heating (36 and 38%, respectively), as shown in Figure 5.12. We expect hydrogen to have a slightly higher share of total demand (about 3-4%) in space and water heating than in the building sector as a whole. However, the share of hydrogen is still minuscule compared with the share of natural gas which accounts for over a third of buildings heating demand by 2050. Use of hydrogen in buildings will be concentrated in four regions with existing natural gas infrastructures and with access to relatively more affordable hydrogen – North America, Europe, Greater China and OECD Pacific.

FIGURE 5.12

Global buildings hydrogen demand by end use

Units: MtH_2/yr



Hydrogen use in buildings will mostly be in blended form during the early deployment phase. Pure hydrogen will overtake blended in late 2030s.

5.3.2 Demand for hydrogen in manufacturing

Various industrial heat applications, such as steam crackers and cement kilns, remain challenging to decarbonize via direct electrification. In such contexts, hydrogen can be used instead of fossil fuels to generate high-temperature heat. However, at present, negligible quantities of hydrogen are used for industrial high-heat processes. This is because hydrogen remains an expensive alternative fuel, uncompetitive against conventional fossil-fuelled technologies, and losing out to bioenergy in most contexts even under higher carbon prices. Nevertheless, low-carbon hydrogen is expected to play an important role in the manufacturing sector by 2050 in front-runner regions, such as Greater China and Europe.

In the iron and steel industry, hydrogen is already widely used (instead of carbon) for the reduction of iron ore (see Section 5.2). The replacement ratio of hydrogen to coal in iron ore reduction is expected to increase. Besides being used as reducing agent, hydrogen or hydrogen-rich gases also show great potential as fuels in steelmaking. Hydrogen as blended gas is already used for heat in blast furnaces which do not require high purity hydrogen. Once hydrogen becomes available at a competitive price, expanding the use of pure or blended hydrogen also has the potential to increase efficiency due to its higher calorific value than presently used coke gases in the steel industry.[7]

Within the base materials subsector, in the production of non-ferrous metals such as copper, electrification towards decarbonization is challenging since fossil fuels are not only used for heating but also as reducing agent. Here again, as with the production of iron, hydrogen holds significant promise as it can also act as reducing agent.[8] In the paper industry, pilot projects using

hydrogen to make low-carbon paper have already started. Essity, a Swedish paper mill manufacturer, has started a pilot plant in Germany using green hydrogen for the energy-intensive operation of a paper machine.[9]

Unlike the aforementioned high heat processes, the cement sector is not expected to become an important hydrogen user since hydrogen is not considered an attractive decarbonization option. This is because CCS is, in any case, a must in the cement industry, with 60% of total emissions being process-related, emitted as a result of the calcination process in cement production.

In addition, the fly ash resulting from burning fossil fuels is used as an ingredient which adds strength to the resulting concrete from the cement. Therefore, cement plants are expected to continue to use low-cost fuels (such as coal, pet coke, or waste-based bioenergy) for their energy-intensive clinker production process while capturing both combustion and chemical process emissions via CCS. Nevertheless, there have been recent pioneering demonstration projects where a hydrogen kiln has been designed and tested to produce carbon-neutral cement, e.g., by German cement producer Heidelberg in a UK factory.[10]

In our forecast (Figure 5.13), demand for hydrogen as an energy carrier in manufacturing is set to grow gradually up to nearly 10.1 EJ/yr (~84 MtH_2/yr) by 2050, amounting to around 7.0% of total manufacturing energy demand, and around 7.4% of global demand for hydrogen as energy carrier. In terms of direct use of hydrogen (as opposed to blended hydrogen or hydrogen derivatives), manufacturing will dominate usage with an over 90% share until 2030 and over 65% share in 2050. The largest share of hydrogen demand in manufacturing (2.8 EJ/yr or 28% of total) comes from the iron and steel industry. This is in addition to the non-energy demand of hydrogen used for direct reduction of iron at 1.6 EJ/yr (~13.5 MtH_2/yr) (see Section 5.2). Following iron and steel, base-materials production (which consists of subsectors such as paper, pulp and print, wood and non-ferrous metals) and the plastics and other petrochemical subsectors will be the next largest hydrogen consumers in manufacturing, with a share of around one-fifth of the total each. The manufactured goods subsector comes next with around 1.8 EJ/yr (~15 MtH_2/yr) by 2050, with construction and mining following with 1.3 EJ/yr (~11 MtH_2/yr). As explained earlier, hydrogen use in cement production is projected to remain negligible.

Regionally, our forecast shows how the uptake of hydrogen for industrial high-heat processes will be most notable in regions where relatively inexpensive hydrogen will be accessible. By 2050, the top four consumer regions of hydrogen within manufacturing are expected to be Greater China, Europe, the Indian Subcontinent, and North America with shares of 23%, 20%, 15% and 13%, respectively (Figure 5.14). Hydrogen is not expected to have any significant penetration within manufacturing in the North East Eurasia and Sub-Saharan Africa regions due to its unfavourable cost competitiveness against fossil fuels as a result of low carbon price levels in these regions.

In summary, while there is great potential for hydrogen in decarbonizing energy-intensive industrial processes, providing the quantities of affordable low-carbon hydrogen necessary to meet demand will be the main bottleneck. Among the subsectors, iron and steel and among the regions, Europe will spearhead growth in demand for hydrogen for energy purposes in the manufacturing sector. As with other sectors, we foresee a higher share of blended hydrogen initially during the early deployment phase, which will over time give way to pure hydrogen usage.

FIGURE 5.13

Global hydrogen demand in manufacturing by subsector

Units: MtH_2/yr

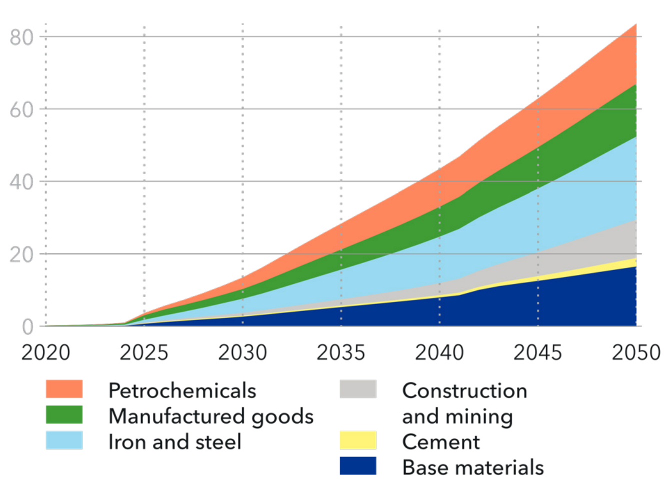
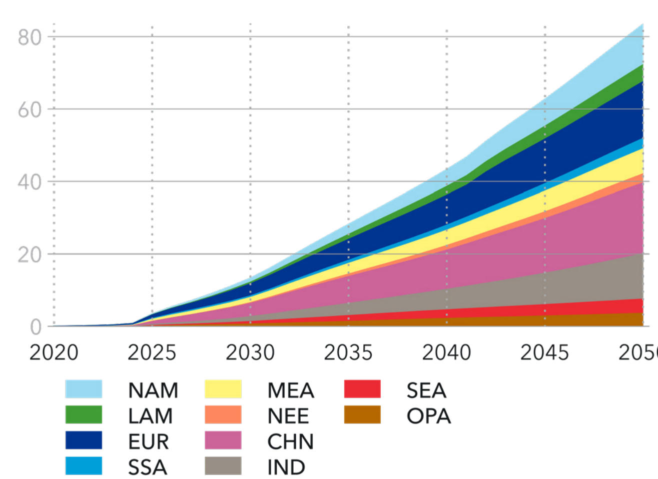


FIGURE 5.14

Global hydrogen demand in manufacturing by region

Units: MtH_2/yr



5.3.3 Demand for transport

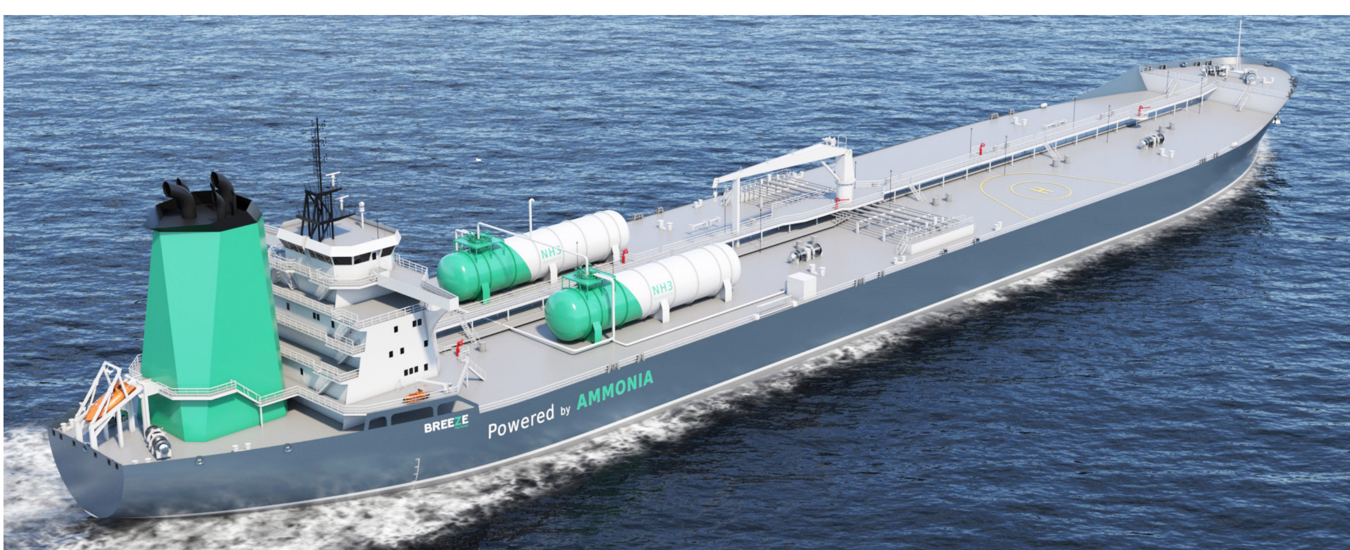
Maritime

Maritime transport is by far the most energy-efficient mode of transportation in terms of energy/tonne-kilometre. Nearly 3% of the world's final energy demand, including 7% of the world's oil, is presently consumed by ships, mainly by international cargo shipping. The present International Maritime Organization (IMO) strategy targets a 50% absolute reduction in CO_2 emissions from 2008 to 2050. Compared with 2018 when the strategy was established, there is now mounting pressure from regulators as well as parts of the maritime industry for the strategy to be further strengthened, and IMO plans to revise the strategy. Our analysis expects that the present IMO strategy of 50% reduction will be met driven by the decarbonization push. The main lever towards 2050 will be a massive fuel switching from oil to natural gas and further to low- and zero-carbon fuels such as ammonia, e-methanol, e-methane and various forms of biofuel. Improved fleet and ship utilization, wind assisted propulsion, on-board CCS, as well as energy-efficiency improvements will also contribute to emissions reduction.

The potential for electrification in the maritime sector is limited to shore power when berthing as well as the short-sea shipping segment, as the energy density of batteries both today and in the future is likely to remain too low to play any sizable role in deep-sea shipping. Therefore, other low- and zero carbon fuel options are needed.

In the forthcoming Maritime forecast to 2050 (DNV, 2022[11]) we will detail various maritime decarbonization pathways, both those complying with the present IMO GHG strategy, and those that have a net zero in 2050 approach. For the purpose of this hydrogen forecast, we have chosen a combination of some of these maritime scenarios to arrive at a likely future, which includes a modest ammonia and e-fuel uptake in the coming 10 years.

As there is currently marginal demand for hydrogen in international shipping, bunkering infrastructure buildout is an extensive task and its timing will influence uptake. Pure hydrogen, in compressed or liquid form, is not likely to have large scale use in international shipping, mainly due to its low energy density, with safety concerns and lack of infrastructure as additional challenges. While hydrogen in pure form will not be a significant fuel in maritime shipping, its derivatives will be. Hydrogen is needed to produce fuels such as ammonia or e-methanol



Concept design for Norway's Green Shipping pilot project 'Ammonia-powered tanker', led by Equinor. Image by and courtesy of Breeze Ship Design.

and their widespread use in shipping will create a significant demand for low-carbon hydrogen.

Methanol can be produced from a large variety of feedstocks ranging from coal, natural gas, biomass to renewable electricity. However, e-methanol and bio-methanol are the most likely shipping options. The use of methanol benefits from some existing bunkering infrastructure, and lower costs for storage tanks on ships, either as new or retrofits, compared with ammonia. Ships are now being built that can use methanol as fuel, but availability of sufficient renewable electricity at a low cost will be a major challenge to widespread uptake of both e-methanol and e-ammonia. Towards 2050, the availability of low-cost sustainable CO_2 needed to produce e-methanol may also be a challenge. Our forecast of the most likely hydrogen future to 2050 includes e-methanol uptake in shipping of 360 PJ (2% of shipping fuel mix) in 2030, 1400 PJ (10%) in 2040 and 1800 PJ (14%) in 2050.

Low-carbon (blue or green) ammonia is another highly promising alternative fuel in maritime shipping to achieve decarbonization, although it also has several challenges. Similar to e-methanol, ammonia can use large parts of the existing infrastructure, but has the same challenges with significantly higher production costs than the present alternatives. If produced from renewable energy, the conversion losses are significant, and we would need a massive ramp-up of renewable power. Capturing CO_2 from natural gas during ammonia production is, however, relatively simple, and the dominant share of ammonia being used in shipping in the forecast will likely be blue ammonia.

Use of ammonia by ships has toxicity challenges as described in Chapter 1, but we believe this will be solved and that there will be large-scale transport taking place from cheap producing regions to the global bunkering hubs. Ammonia will likely have a lower initial uptake than e-methanol until 2040, but then scale faster towards the end of the forecast period. This hydrogen forecast, which looks at the most likely future, includes ammonia uptake in shipping of 43 PJ (0.3% of shipping fuel mix) in 2030, 1100 PJ (8%) in 2040 and 4500 PJ (35%) in 2050.

Aviation

The aviation industry emits about 2.5% of global carbon dioxide emissions today, and decarbonization is of high importance. While other sectors, such as power production and road transportation, have taken steps towards decarbonization, emissions from aviation have not decreased significantly in the last decade, except indirectly as a result of covid-related impacts over the last 3 years. Constant improvement on energy efficiency of engines, fuselages and route optimization will not be sufficient, and aviation fuel-mix changes are therefore essential to decarbonize the sector.

From a technology standpoint, aviation has relatively limited options to replace oil-based fuel and is frequently termed a hard-to-abate sector. Batteries will not work for long-haul flights as battery weight makes electrification a realistic option for propulsion only in the short-haul flight segment. The two remaining routes investigated and expected to change the aviation fuel mix are pure hydrogen and sustainable aviation fuels (SAFs), including biomass-based first and second generation fuels as well as power-to-liquid- / e-fuels based on hydrogen. Common for all alternative solutions is that costs, both short term and towards 2050, will be higher than current oil-based fuel. All fuel- and technological changes are therefore expected to come as the result of regulatory and industry-supported forces such as: the ReFuelEU Aviation initiative, as part of the 'Fit for 55' legislative package, which will oblige blending of increasing levels of SAFs, higher carbon pricing from removal of free allowances to airlines from 2027 in the EU emissions-trading scheme (EU ETS), as well as net zero pledges from airlines.

Pure hydrogen as a fuel in aviation possesses some advantages over SAFs. Produced from renewable sources, a hydrogen value chain in aviation could guarantee almost zero emission transport, assuming the produced by-products (water vapour and NOx emissions) are treated carefully. The anticipated penetration of hydrogen in other industries could potentially reduce overall production costs and increase handling and safety knowledge. Consequently, the aviation industry is now initiating extensive research into hydrogen as a possible future fuel, which is likely most promising for

Hydrogen-electric aviation solutions provider ZeroAvia initiated a testing and demonstration programme of a 19-seat aircraft in the US in May 2022 (Image, courtesy ZeroAvia)

medium-haul flights. The first flight of an actual commercial-grade aircraft propelled by hydrogen capable of carrying passengers was conducted in 2020 in a retrofitted Piper M-class aircraft. This indicates that a more widespread use of hydrogen in aviation is still a long way off and we expect to see hydrogen-powered airplanes in regular commercial use only after 2040 in the first few regions such as Europe, North America and Greater China.

Long-haul flights could potentially be served by hydrogen propelled aircraft as well. However, it is less suitable from a technical perspective due to the low energy density, and the hydrogen tanks needed for the large amount of hydrogen would require a very different airplane design with higher costs per passenger. In addition, the implementation of new designs takes at least 20 years due to the long operation time of aircrafts. Besides aircraft design and infrastructure adjustments, handling and safety regulation would need to be adjusted as well, and will need to evolve in synchrony with technology developments.

All of these barriers to a widespread implementation of pure hydrogen in aviation before mid-century result in a relatively small share for pure hydrogen in the sector's energy demand by 2050 of around 4%, which equals about 1000 PJ (8.4 MtH_2/yr) (Figure 5.15).

About three times more is projected to be supplied by e-fuels, a form of SAF. SAFs can be biobased as well, which is the dominant path for SAFs throughout our forecast. However, in this analysis we look at hydrogen-based SAFs. Those liquid e-fuels from renewable power are better suited for decarbonizing the aviation sector because they are a viable drop-in fuel, using existing infrastructure and combustion technology. We will see small shares of e-fuels in aviation from the 2030s onwards, however as with hydrogen, significant uptake will only happen in the 2040s.

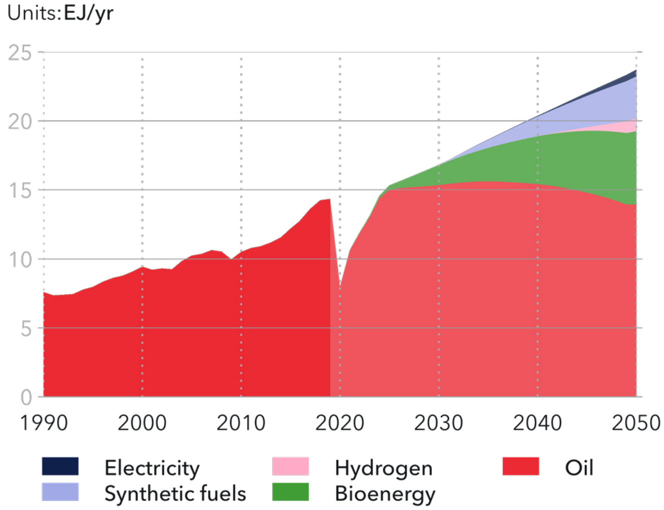
It is worth considering why there has been so little uptake of e-fuels to date. One reason is that the use of e-fuels is only environmentally beneficial if renewable hydrogen is used as the basis, which requires massive amounts of renewable energy. A wider use of e-fuels is achievable only with an immense scale-up of renewable power production, because there are several offtakers of renewable electricity, such as road transport, buildings heating, etc. Moreover, the current cost difference of a factor of four to five, compared with fossil kerosene, needs to be reduced. Weighing the different advantages of hydrogen and e-fuels against each other, we will see three times more e-fuels than pure hydrogen in the aviation sector, representing a 13% share, mainly due to the fact that e-fuels as a type of drop-in fuel can serve all types of flights, whereas hydrogen is limited to mainly medium-haul flights. In combination, the share of pure hydrogen and hydrogen-based e-fuel represents around 17% of energy use in the aviation sector by 2050.

Of the 3 EJ/yr of e-fuels that we will see in 2050, a fifth is consumed in both North America and Greater China, and a tenth in both Europe and South East Asia. North East Eurasia and Sub-Saharan Africa will see only marginal uptake of e-fuels. Hydrogen might have its role in hybrid (in combination with battery-electric) or pure hydrogen propelled intra-continental short- to medium-haul flights, but is outcompeted by SAFs mainly due to the fact that long aircraft lifespans slow down the uptake of new aircraft and engine designs.

FIGURE 5.15

Aviation sector final energy demand by carrier

Units: EJ/yr



Historical data source: IEA WEB (2021)

Road Transport

Electric passenger vehicles, both battery electric vehicles as well as plug-in vehicles make up about 1% of the global passenger car fleet at the moment. By mid-century, electricity will dominate passenger vehicle propulsion, outcompeting every other source. Despite being responsible for less wheels on the road by mid-century, fossil fuels will still take up the lion's share of primary energy used in road transport (Figure 5.16) because they are very inefficient. Where does that leave hydrogen?

Road transport is currently heavily dependent on oil-based fuels (92%), with a minor share of biofuels (3%) and natural gas (4%) as shown in Figure 5.16. Electrification is key to reducing road transport emissions, with only minor roles to be played by biofuels and natural gas. Supported by push-and-pull strategies, the uptake of electric vehicles (EVs) – which we use as an umbrella term for battery electric vehicles (BEV) and fuel-cell powered vehicles (FCEV) – has begun in many parts of the world. Ongoing policy support such as emissions reduction targets and bans of sales of internal combustion engine vehicles (ICEs) will further drive EV uptake and thus reduce overall costs.

FCEVs can reach an overall well-to-wheel efficiency of between 25–35%, significantly lower than the 70–90% for BEVs. Furthermore, FCEV propulsion is more complicated, and thus more costly, than that of BEVs. For these reasons, major vehicle manufacturers have focused almost exclusively on BEV models for passenger transport. To date, fewer than five FCEV models for passenger transport have been released commercially, compared with hundreds of BEVs. All of the above leads to a global share for BEVs of 85% of new car sales in 2050, versus only 0.01% FCEVs. Regarding light commercial vehicles, the shares will be 64% and 4%, respectively in 2050.

Whereas the situation for passenger transport is clear – it is all about direct electrification – it is different for heavy-duty and long-distance commercial vehicles. Light-duty commercial vehicles will mainly be powered by electricity, as the same cost and infrastructure advantages apply as for passenger vehicles. In these segments, the upfront investment cost as well as operational costs are lower for BEVs than for FCEVs. Also, the recharging infrastructure is easier to install, as access to the electricity grid is easier to implement than hydrogen refuelling stations.

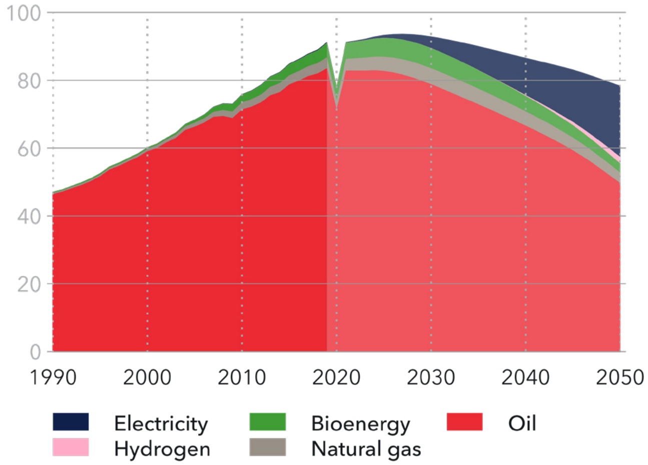
Certain sub-segments of heavy and long-haul commercial-vehicle transport present a clear opportunity for hydrogen applications. We foresee biomethane, both pure and blended with natural gas to have a transitional role in the decarbonization of heavy transport giving way to electricity and hydrogen in the long run.

Heavy-duty transport, especially long-haul trucking, has additional needs impacting the fuel choice. In this road-transport segment, the current market has bifurcated. Whereas some major OEMs (original equipment manufacturers) are betting on battery electric, others focus on hydrogen. The view on battery-electric solutions for heavy transport has changed in recent years with battery electric technology becoming more viable; and has also been impacted by the charging-station density increasing compared with the still-thin network of hydrogen refuelling stations. Hydrogen was long seen as the only solution to decarbonize heavy trucking, but as things now stand, battery-electric solutions are likely to have a decent share in this segment. Also, longer ranges are now believed to be viable for electric trucks, but not the longest distances. As a result, we project hydrogen to play only a minor role in road transport, namely for heavy-duty long-distance trucking. By mid-century, hydrogen will account for a 2.5% share of road transport energy demand, slightly less then biomass and natural gas. Accounting for the fact that hydrogen will be used in heavy-duty and long-distance trucking where fuel consumption is naturally higher, this still amounts to about 2,000 PJ in 2050 (16.7 MtH_2/yr). Half of this will be consumed in Greater China alone, owing to the large vehicle fleet and policy focus on decarbonized transport, followed by Europe and North America each having a 15% share and OECD Pacific with a 9% share. Regions such as Sub-Saharan Africa or North East Eurasia will not see hydrogen uptake for road transport until mid-century due to a lack of supporting policies, which is key for hydrogen uptake in this transport segment.

FIGURE 5.16

Road sector final energy demand by carrier

Units: EJ/yr



Historical data source: IEA WEB (2021)

5.3.4 Role of hydrogen in power and seasonal storage

Hydrogen production from renewable electricity has almost zero carbon emissions and is a clean and cost-effective way to valorise excess electricity generation from variable renewable energy sources, VRES (DNV, 2018[12]). This excess electricity stored as hydrogen can potentially later be used to generate electricity during periods of high electricity prices. The situation of excess electricity typically comes into play at penetration levels of 25–30% of variable renewables in the total electricity supply.

Historically, the electricity system has been shaped by the variability of demand following daily, weekly, and annual cycles, and by conventional power generators responding to this variability by adjusting their supply. Prices have been set by the marginal cost of the most-expensive generation technology, providing revenue for all generators. However, with the growth of production from solar and wind, combined with changing demand through storage, Power-to-X and e.g., electric transport, a new order and new rules will emerge, pushing conventional generation into a supporting role, indicated by Figure 5.17 and Figure 5.18, using the case of North America in 2050. A high penetration of VRES will affect the electricity market and hydrogen as a re-conversion and storage option. Hours of the year are sorted, left to right, according to wholesale electricity price. Flexible load segments are capable of adjusting their demand in response to changes in price. Each demand segment has a normalized profile that represents regional demand over a year. These profiles are established on the basis of a representative year and do not change between years (DNV, 2021[13]). Consequently, we will see hydrogen production at times of cheap electricity and re-conversion to power at times of higher electricity prices. The existence of electrolysers in the power system reduce the number of hours with zero electricity price, and consequently helps VRES technologies avoid losing profitability for further investments.

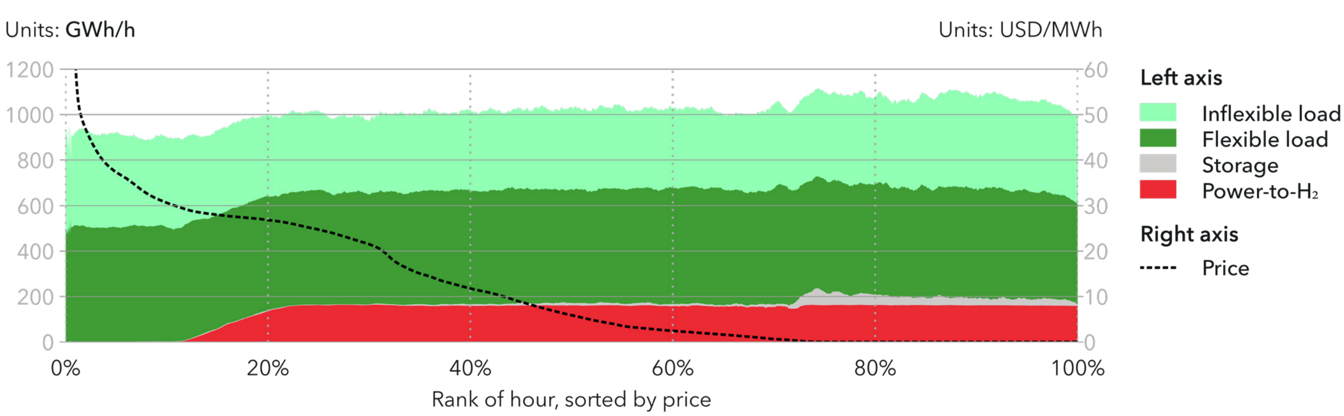
More detailed information about these developments can be read in our latest *Energy Transition Outlook* 2021, and associated hydrogen position papers (DNV, 2019[14]; DNV, 2020[15]).

Regarding hydrogen production, we project that in 2050, one of the biggest buyers of cheap electricity in the North American electricity market will be 300 GW of grid-connected electrolysers. To break even with competing hydrogen production routes, grid-connected electrolysers should not pay more, on average, than USD 13/MWh for electricity. This competition ultimately determines the threshold price for power-to-hydrogen.

In 2050, the North American wholesale electricity price is expected to drop to zero for about 29% of the time within

FIGURE 5.17

North America's hourly electricity demand by segment in year 2050, sorted by price



Flexible load incudes EV charging, industrial demand, heating and cooling.

a year, because total supply from solar and wind will exceed demand. Thus, 545 TWh of solar and wind supply would be curtailed, which represents 11% of solar generation and 6% of wind generation. This amount would be much higher without flexibility technologies, particularly power-to-hydrogen production, which acts like seasonal storage by purchasing excess electricity, and converting it to hydrogen for future use as an energy source.

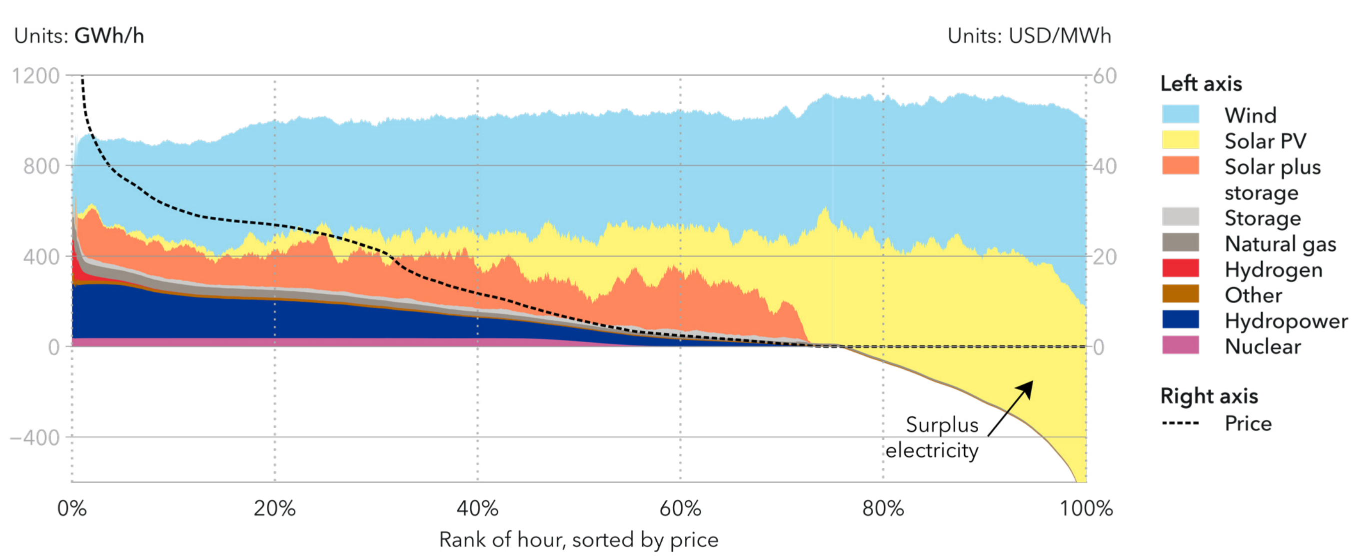
Although there are clear advantages in using hydrogen for peak balancing and long-term electricity storage, it needs to be clear that this comes with significant energy losses and storage demands. For hydrogen to be of interest in the power system, storage is key. Hydrogen needs to be available in sufficient amounts on request, which makes large-scale storage a prerequisite. Options for storage, their advantages and drawbacks are presented in Section 4.2 in more detail. We foresee global long-term storage demand for hydrogen to reach 11 Gm³ in 2030 and 136 Gm³ in 2050. On the average, this will correspond to 4-5 weeks' worth of demand for hydrogen used for energy in 2050. 8% of the 2050 capacity will be sites previously used for natural gas storage, as natural gas demand will start to decline in parts of the world. The percentage of long-term storage sites in 2050 that are repurposed from natural gas storage will be 4% in North America, 15% in Europe, 18% in Greater China and 24% in OECD Pacific.

Thinking about a merit order of hydrogen applications, re-electrification is likely to come last. In the short term, we will see hydrogen in power production as a result of blending into the gas grid while losing value and control of the final end use. Over time, natural gas-fired power plants might transition to run 100% on hydrogen. This option is attractive in countries with high shares of gas generation and less attractive in countries with high shares of hydropower.

We will see hydrogen being used in power stations from 2030 onwards, though in very small amounts and at first mainly due to feeding hydrogen into natural-gas grids. Later, peak-balancing increases the share. OECD Pacific will be the frontrunner in this development, followed by Europe and Greater China. The same regions will increasingly use hydrogen for electricity generation, and a small amount will be used in North America from the mid 2040s. By mid-century, we foresee that those regions will use almost 8 Mt hydrogen per year in power generation. In a net zero future by 2050, we would expect an increased amount of hydrogen in the power sector due to a higher share of variable renewables in the power system and an improved competitive situation for hydrogen, a conclusion supported by model sensitivity runs. Our tests also show that sustained high gas prices would also result in a significant higher share of hydrogen in the power mix as a peak balance option in the medium to long term.

FIGURE 5.18

North America's hourly electricity supply by technology in year 2050, sorted by price



6 TRADE INFRASTRUCTURE

As shown in Chapter 4, because the long-distance transport of hydrogen requires substantial infrastructure investments, there are considerable benefits in keeping transport distances as short as practicable.

The evolution of the non-energy hydrogen ecosystem to date underscores this point. A major use of ammonia and hydrogen today is for fertilizer feedstock. Transporting fertilizers is much cheaper than transporting hydrogen (by energy unit), so fertilizer manufacturing typically takes place close to where ammonia is produced. And since natural gas is the main ingredient of ammonia, fertilizer production usually occurs where gas supply is plentiful.

The fact that fertilizer production is often subsidized, in addition to the fact that fertilizer plants are often situated far from ports, explains why ammonia as feedstock seldom travels between regions.

But this situation is set to change. Limiting the use of ammonia as a fuel to maritime uses, and furthermore requiring such consumption to come from green ammonia, will open up a sea of possibilities: More than half of such ammonia will have originated in different regions than where it is consumed and it will be transported on keel, as shown in Figure 6.1.

The transport of pure hydrogen between regions will be relatively marginal. Pipeline transport is most economical if transported volumes are high, and at medium distances. Shorter distances and smaller volumes call for trucking and rail – in tanks, usually as ammonia. For longer distances seaborne transport is the logical alternative where depths and/or distances make pipeline transport uncompetitive[1]. However, that requires energy-intensive and costly liquefaction at the exporting end, and a similarly costly regasification at import locations, together adding USD 1.5-2/kgH_2 to costs. Less than 2% of global hydrogen will have spent time on keel in 2050, and only about 4% will come through interregional pipelines as shown in Figure 6.1.

6.1 Seaborne interregional transport

As explained in Section 4.5 in more detail, hydrogen is a gas that can be transported on keel in three different ways, all of which require liquefaction: liquid ammonia, liquid hydrogen (LH_2), or with liquid organic hydrogen carriers (LOHC). Typically, the energy loss of dual conversion is 20 to 30% of the hydrogen transported. All three technologies exist and may become the technology of choice[2].

However, given that there already exists a global value chain for seaborne transport of ammonia, and that ammonia is likely to be the zero-emission fuel of choice for international shipping, the present analysis assumes that all seaborne hydrogen transport is liquid ammonia.

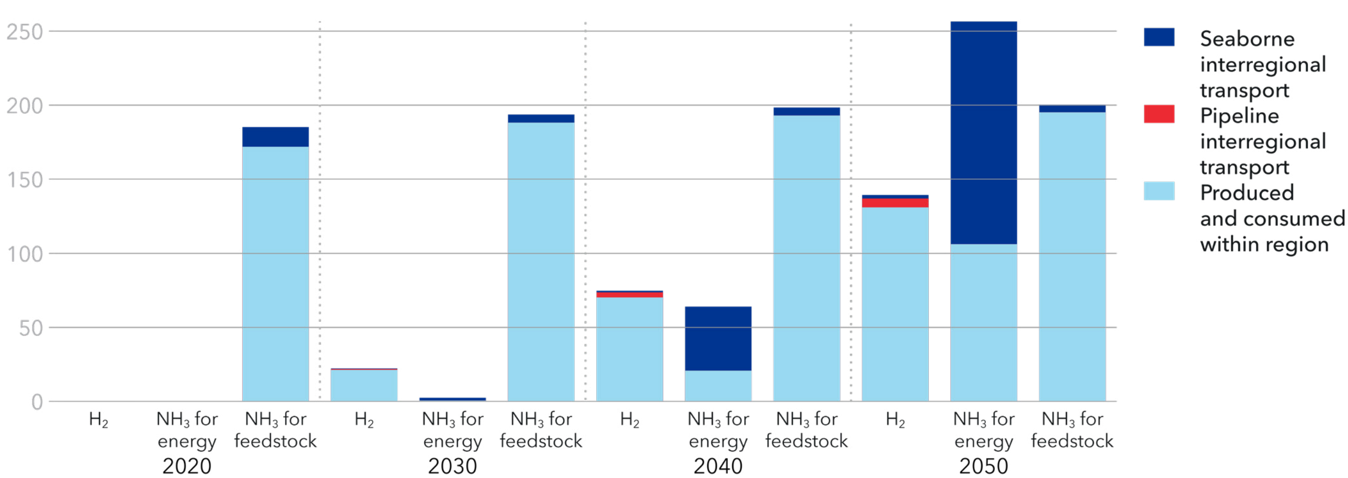
Seaborne trade in ammonia (NH_3) takes place on purpose-built tankers that can also carry liquid petroleum gas (LPG). But this trade is currently not extensive. LPG tankers devote less than 20% of their capacity to ammonia transportation, and LPG tankers constitute less than 1% of global shipping tonnage, and less than ¼ of the global gas (LNG + LPG) tonnage. All ammonia transported on keel originates as ammonia, and is consumed as such, and thus there is virtually no hydrogen transported on keel. Seaborne ammonia trade results from the fact that it is typically less expensive per energy unit to transport ammonia on keel than to transport its main input – natural gas (CH_4). About 10% of ammonia produced globally spends time on keel, with seaborne trade globally varying between 11 and 14 million tonnes per year since 1980. Such ammonia is used as a feedstock in the manufacture of various products, mineral fertilizer in particular.

The coming decade will see little change in trading volumes and patterns, but as ammonia starts to be used in significant quantities as a maritime fuel, trade volumes will increase. We expect a twenty-fold increase in ammonia seaborne transport from 2030 to 2050, with fuel use growing from virtually nothing in the mid-2030s to 95% of the trade in 2050 – of a total shipment of 150 million tonnes at that time.

FIGURE 6.1

Transport of hydrogen and ammonia

Units: Mt/yr



All numbers displayed in mass terms: Mt of H_2 or Mt of NH_3. The mass of ammonia converted from H_2 is ~5.6 times the mass of H_2.

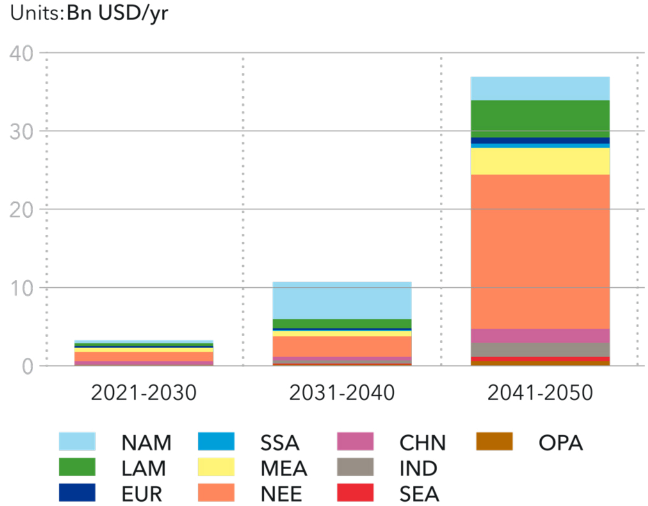
Today, North East Eurasia , Middle East and North Africa, and Latin America dominate seaborne ammonia trade as each account for a little less than a third of global exports. However, the ramping up of the trade between 2040 to 2050 will mean less growth for Latin America and for Middle East and North Africa, as the strongest export growth will happen from North East Eurasia, whose exports in 2050 will be almost twice as large as that of the three next exporter regions combined. Note how the region dominates global expenditure on ammonia terminals (Figure 6.2).

North East Eurasia will provide 60%, North America 15%, Latin America 12% and Middle East and North Africa 8 % of global shipments on keel. This split is reflected in the outlook for spend on building and operating ammonia terminals to facilitate exports, as shown in Figure 6.2, with a total of USD 525bn set to be spent globally through to 2050, with North East Eurasia accounting for almost half of this spend (USD 235bn). The world's by far biggest importer will be the Greater China region supplied by the North East Eurasia region, which will have 90 Mt seaborne exports in 2050, half of which will go to China.

FIGURE 6.2

Average annual expenditures for ammonia terminals by region

Units: Bn USD/yr



6.2 Pipeline transport

While there is negligible pipeline trade of hydrogen at present, natural gas is traded via pipelines interregionally in relatively large quantitites[3]. Given the repurposing potential of natural gas pipelines to transport H_2, and that pipeline transport is the most economical form of transport of hydrogen at high volumes and medium distances (distances less than 3000 km), we forecast about 4% of the demand being traded interregionally via pipelines. In other words, the vast majority of hydrogen molecules produced will be consumed in the same region in which they are produced.

Pipeline facilitated trade of H_2 does not begin to happen at scale until the 2040s, mostly due to a lack of demand. In 2030, a very small amount of H_2 is traded via pipelines (0.6 Mt per year). This increases to 3.3 Mt per year in 2040 and almost doubles to 6 Mt per year in 2050.

Repurposed natural gas pipelines will provide the vast majority of infrastructure for interregional transport of hydrogen. In 2050, 96% of the total installed capacity of interregional H_2 pipelines will be pipelines repurposed from the underused natural gas network. This result underscores the value of hydrogen in the future energy system, in terms of its ability to use existing infrastructure, while having the potential to decarbonize.

In 2050, we foresee the Indian Subcontinent, OECD Pacific and Europe regions being the largest importers of H_2 via pipelines (Figure 6.3). While the Indian Subcontinent will invest in some new interregional pipelines, Europe will repurpose its existing natural pipelines with Middle East & North Africa. Correspondingly, Middle East & North Africa and Greater China are the largest exporters of H_2 via pipelines. Greater China's majority import partner is OECD Pacific, specifically Republic of Korea.

The Republic of Korea in OECD Pacific does not currently have any interregional pipeline trade of natural gas. But, as mentioned, we foresee interregional H_2 pipeline capacity to be built between OECD Pacific and Greater China by 2030 (200 tonnes per year), which grows to 800 tonnes per year capacity by 2050. This is due to the vast amount of

dedicated renewables-based electrolysis that Greater China will install in the coming decades, along with the policy push in China for hydrogen (see Chapter 2), leading to excess capacity that Greater China may export to OECD Pacific.

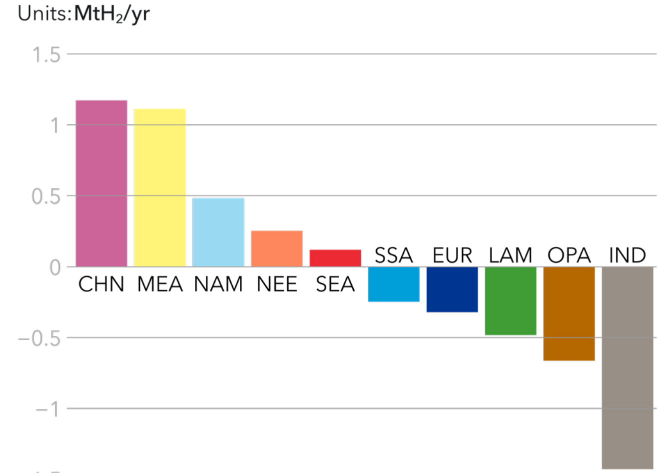
The Indian Subcontinent will also invest in new H_2 pipelines where natural gas pipelines do not currently exist. The subcontinent will supplement its very high domestic electricity demand, with H_2 imported from neighbouring regions. Thus, new H_2 specific pipelines will be built between countries like Pakistan and Bangladesh in the Indian Subcontinent and Greater China, Middle East & North Africa and South East Asia, among others.

Even in 2050, natural gas traded via interregional pipelines dwarfs H_2 traded via pipelines. We forecast 146 Mt of methane traded via pipelines in 2050, which is significantly lower than the 226 Mt traded in 2020. Yet, compared to the 6 Mt of H_2 piped long distances in 2050, natural gas is still very likely to be a commodity, while H_2 trade via pipelines is still nascent. There are many reasons for this: natural gas is a natural resource restricted by its geographical availability, while H_2 has the potential to be produced at scale with renewables, in almost all regions (as explained in Section 5.1); secondly, natural gas is an incumbent in the energy system in many regions and H_2 will play a far smaller role than natural gas in 2050; finally, the significant trade of maritime NH_3 will reduce the need for pipeline transport of H_2.

FIGURE 6.3

2050 interregional transport of H_2 via pipelines

Units: MtH_2/yr



Positive values indicate net exports, negative values net imports

7 DEEP DIVE: EVOLUTION OF SUPPLY CHAINS

7.1 Four competing hydrogen value chains

In this chapter we present an economic evaluation of four very different green hydrogen value chains supplying carbon-free hydrogen to Northwest Europe in 2030. Each of these value chains is driven by different energy sources and the hydrogen is transported by different means:

- Solar PV in Southern Spain (long-distance pipeline)
- Geothermal energy in Iceland (liquid hydrogen transported by ship)
- Offshore wind on the North Sea (electricity transport required)
- Nuclear power (short-distance pipeline)

These value chains are optimized financially and assessed against two main criteria: 1. Their ability to compete, and 2. Their pathway to growth.

The first criterion has to do with the competitiveness of various low-carbon energy sources in the future. Green hydrogen competes with fossil fuels + CCS, with renewable electricity, and with renewable heat. Customers tend to select their energy supply based on a combination of cost, continuity, and security of supply. However, in our view, they should also adopt a whole value chain perspective covering the robustness and viability of those areas in which they are not directly invested: production, transport and the fit to demand.

For comparison, we selected some of the best locations in Europe to produce carbon-free power at a low levelized cost of electricity, which can then be converted into hydrogen. We then add the additional costs of converting the hydrogen to a transportable form and the cost of the transport itself – assuming in these instances that the end consumer does not move to the location where the hydrogen is produced to avoid the added costs of transport.

FIGURE 7.1

Duration curves of the primary electricity sources considered in this chapter

Units: percentages

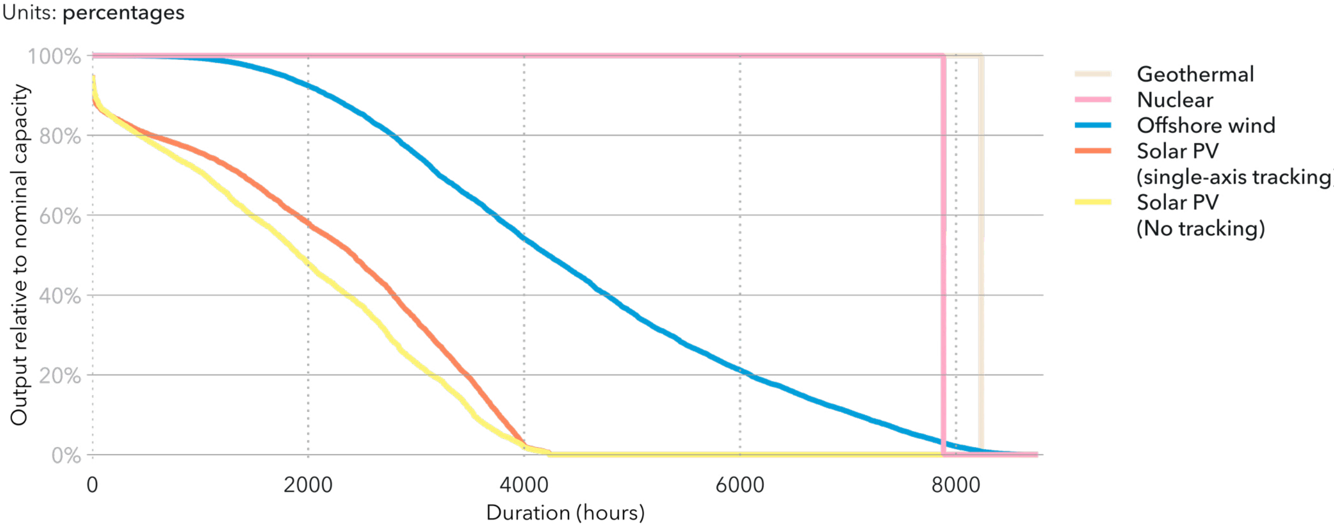
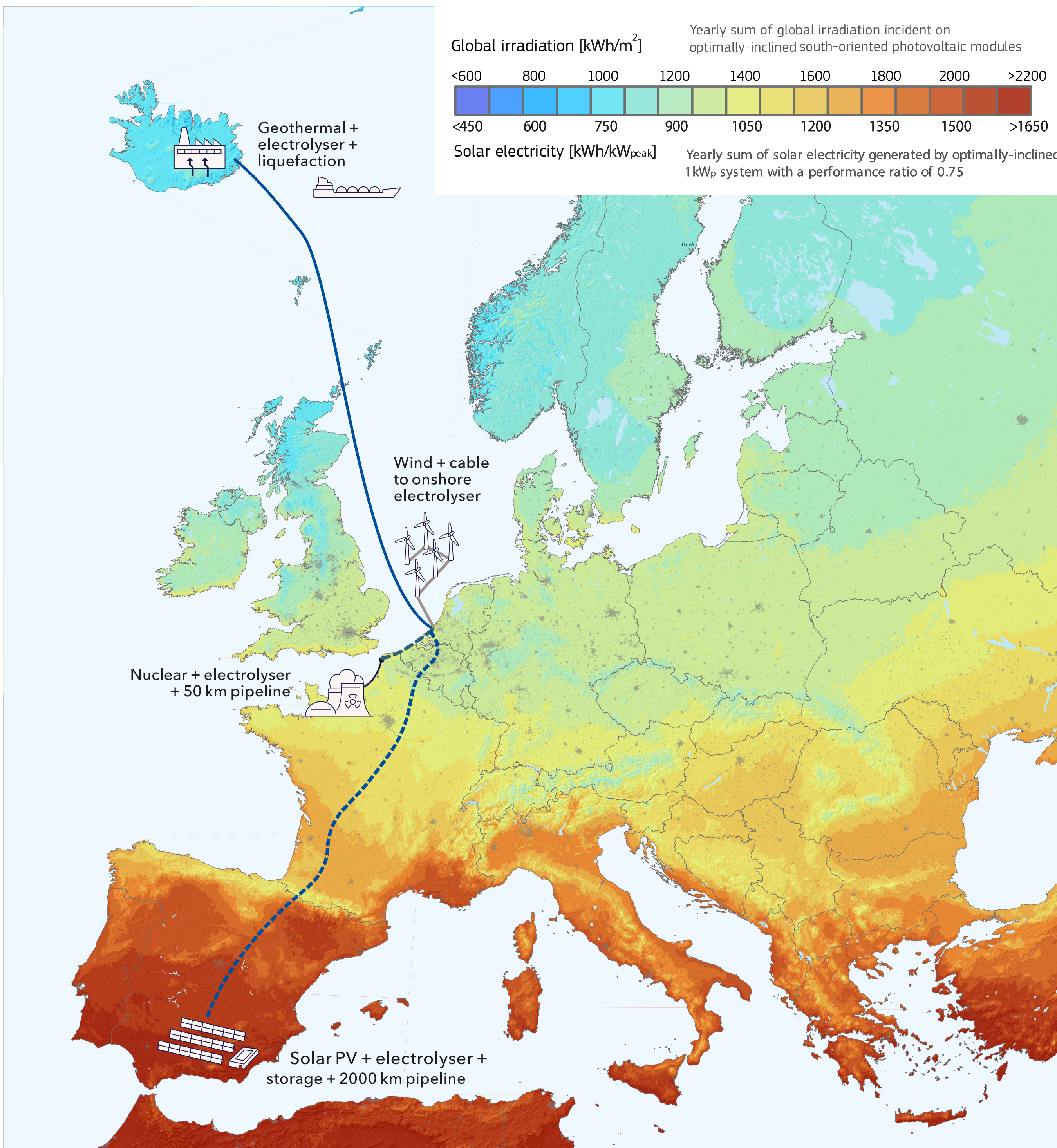


FIGURE 7.2

Four green hydrogen value chains converging in Northwest Europe



Irradiation map courtesy of Photovoltaic Geographical Information System (EU)

The supply of green hydrogen from variable renewables is a complicating factor. Often hydrogen supply does not match demand and storage is therefore required, for example in the process industry or when the hydrogen is to be mixed with natural gas in the gas grid. Instead of storage, a continuous hydrogen supply can be secured by switching from and to carbon-free hydrogen from another source such as blue hydrogen. As we discussed in our white paper Sector Coupling[1], a mix of energy carriers and even a doubling-up of infrastructure might prove to be optimal under certain circumstances.

The second criterion we discuss is a feasible pathway to growth. Hydrogen supply needs to grow in synchrony with demand, and that generally requires a gradual or stepwise pathway that allows unavoidable economic, technical and system risks to be identified in good time and mitigated. The dynamics of the growth path and interactions between hydrogen value chains are likely to result in different market 'niches', that suit different customers.

The economic evaluation of each value chain is based on capital and operating costs and considers the load duration curves of the generated electricity that feeds the electrolyser. Load duration curves represent the hourly generated electricity in one year but sorted by generated electricity instead of chronologically. They provide immediate insight in the variation of the available electricity, and not just the capacity factor (which corresponds to area below the curve). The effect of part-load efficiency of the electrolyser cannot be modelled correctly using only a capacity factor. The load duration curves are used to optimize the sizing of all components in the value chain.

As shown in Figure 7.1, load duration curves differ significantly for the chosen value chain options. For example, the duration curve of a solar plant with fixed PV panels in southern Spain (labelled "Solar PV no tracking" in Figure 7.1) shows that the maximum output is only reached for a couple of hours per year. It does not make economic sense to size the subsequent processes, such as transportation and conversion, to this peak capacity. For example, the optimal sizing of a solar plant inverter in Northwest Europe is currently some 70% to 80% of the peak capacity of the installed solar panels. If this inverter is connected to an electrolyser, the optimal sizing will be even smaller, resulting in a higher utilization of the relatively expensive electrolyser.

In each value chain description, we highlight an aspect of the value chain that lends itself to optimization. In the first case, where we use solar PV as the primary electricity source, we address the trade-off between investments and capacity factor. In the second case, where we propose geothermal energy as an electricity source, we discuss the effect of part-load electrolyser efficiency. In the third case, offshore wind, we address the effect of electricity transport combined with on-site hydrogen generation. Lastly, the fourth case, based on nuclear energy, deals with cogeneration of hydrogen and electricity and operational optimization of the nuclear power plant.

The four cases present the optimized levelized cost for delivering hydrogen to an industrial consumer using hydrogen for feedstock and/or energy purposes. For each case, this levelized cost is subdivided, as far as is applicable, into cost for input electricity, conversion, storage and transportation. Sections 7.2 to 7.5 each describe a single value chain, and Section 7.6 presents the comparison between cases and some conclusions.

7.2 Solar PV in southern Spain

7.2.1 Description of the value chain

Green hydrogen will be produced in locations optimal for renewable energy, which may well be located far from existing hard-to-abate activities. One option might be to relocate consumption near the hydrogen production site. Another could be to transport the hydrogen to the existing consumer; if that distance is sufficiently long it is more feasible to export the hydrogen itself rather than the renewable electricity. In this chapter, we estimate the cost of producing hydrogen in southern Spain and transporting it to an industrial site in Northwest Europe.

When considering large-capacity overland transport of hydrogen, pipelines emerge as the most cost-efficient way of transport within Europe, as highlighted in the 'backbone' discussion in Section 4.3. This is because green hydrogen production from solar energy is likely to be clustered around locations with the highest irradiation and lowest cost of solar electricity – e.g., southern Spain, Italy and Greece. It may also be feasible to link Europe to hydrogen produced by solar electricity in North Africa via a subsea pipeline. However, on a broader intercontinental scale, the export of hydrogen to Europe from key producers – like China, Namibia, and Chile – will take place by ship.

Compared with the other value chains discussed in this chapter, the solar value chain is characterized by a low utilization because of the limited capacity factor of solar energy. This means that all subsequent steps in the value chain after electricity generation, up to the storage, will have the same low utilization, unless these steps have a reduced capacity compared with the solar PV capacity. The low utilization caused by the low-capacity factor of solar PV places extra importance on minimizing capital costs for this value chain, even if that implies higher operational costs, lower efficiency or a lower expected lifetime.

7.2.2 Hydrogen production

A solar PV plant in southern Spain will have an energy output per installed capacity of about 1,600 MWh/MW_{peak} if based upon fixed panels, and up to 2,200 MWh/MW_{peak} if panels are tracking the sun (represented by the area under the load duration curves in Figure 7.1). These values represent the number of equivalent full load hours per year. Dividing them by the total number of hours per year (8760), results in the capacity factor. A solar farm in southern Spain thus has a capacity factor of about 18% for fixed panels and up to 25% for panels tracking the sun.

The direct current (DC) from the solar panels needs to be converted to a suitable voltage by the inverters, and then fed into the electrolysers. Integrating the power electronics from the PV plant and the electrolysers may result in significant cost savings relative to the cost of using standardized inverters for both the PV system and the electrolysers. However, it is uncertain how large those savings might be.

Figure 7.3 shows the optimal economic capacity of the power electronics and electrolysers based on the lowest levelized cost of hydrogen at the consumer site. As noted in Section 7.1, this capacity is less than the peak capacity of the PV panels. A solar system connected to the grid with power electronics of about 80% of the capacity of the panels will have the lowest levelized production cost of electricity. The added capital cost of the electrolysers reduces the optimal capacity of the inverters and electrolysers together to about 70% of the peak capacity of the solar panels, leading to the lowest levelized cost of hydrogen delivered to the customer.

This is demonstrated in the chart on the left of Figure 7.3, which shows respectively: the load duration curves of the output of the PV system that feeds the inverter; the output of the inverter that provides the input for the electrolyser; and the output of the electrolyser. Decreasing the capacity of the electrolyser to 70% of the capacity of the PV installation, increases the capacity factor of the electrolyser from 26% to 32%. The chart on the right shows this to be optimal for the relatively cheap electrolyser of USD 480/kW used in the calculations.

Electrolysers specially designed for this low capacity factor, are currently in development. These electrolysers, with an investment level of close to USD 480 per kW installed capacity, including balance of system, are expected to enter the market already in 2025[2].

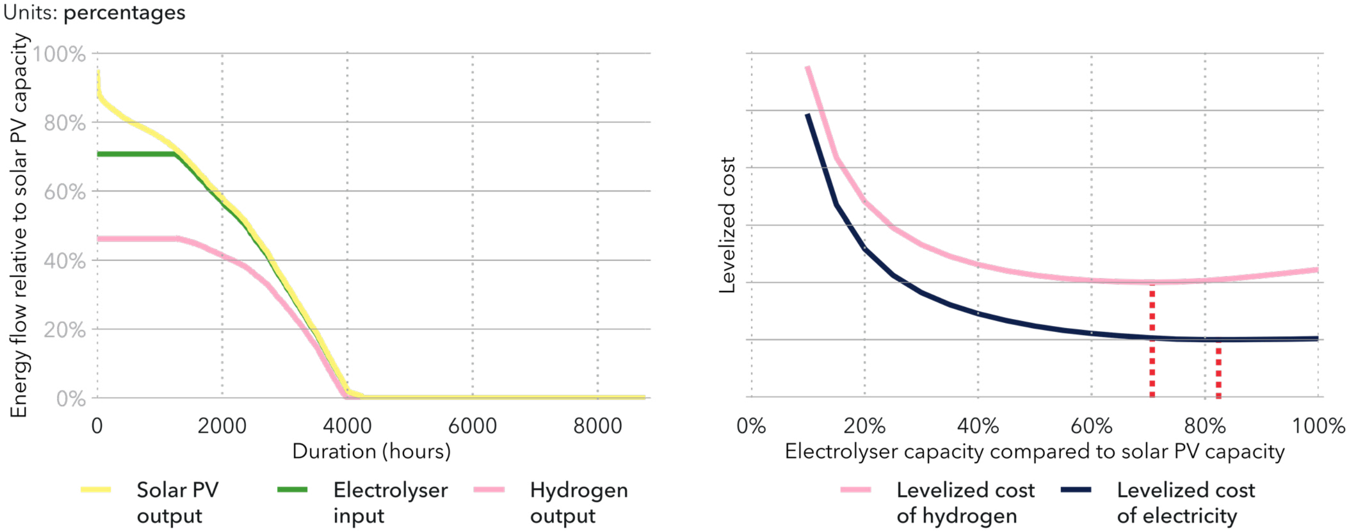
7.2.3 Hydrogen transport and storage

For this case, we assume a pipeline connection from the production location in Spain to the hydrogen transportation backbone in Northwest Europe. Hydrogen will need to be stored at the production site in sufficient quantities to bridge the day-night cycle in hydrogen production. This will lower the required peak capacity for the hydrogen transportation pipeline and thus reduce pipeline cost. In the event of large-scale hydrogen

FIGURE 7.3

Optimal sizing of an electrolyser

Units: percentages



Optimal sizing of the inverters and electrolyser to 70% of the capacity of the solar panels leads to a minimum levelized cost of hydrogen. An inverter of about 80% would lead to the lowest electricity cost. (Source – PV profile: PVGIS) production in southern Spain, linepack in the accompanying hydrogen transportation infrastructure might also provide a significant storage potential, reducing or eliminating the need for local storage.

An alternative to a dedicated hydrogen pipeline is to mix hydrogen with natural gas to decarbonize the existing natural gas grid. However, for this case we have not considered that option. Most end-use equipment, such as hydrogen-ready burners, is designed and tuned to handle a constant hydrogen fraction. This means that the mixing of hydrogen in the natural gas grid requires hydrogen storage and coordination of hydrogen feed-in to ensure that the hydrogen fraction is constant everywhere in the grid, irrespective of the hydrogen production rate or local gas demand. Increasing the fraction of hydrogen is possible but requires most equipment and appliances to be re-tuned. This entails planning and coordination and might be cost and/or labour intensive.

For this case we calculated a cost of USD 0.42 per 1000 km per kg of hydrogen for the pipeline between southern Spain and Northwest Europe assuming a large-scale hydrogen production facility (Khan et al., 2021)[3]

7.2.4 End use and specific considerations

Building a pipeline from southern Spain to Northwest Europe to accommodate large-scale hydrogen production is both a time and capital-intensive endeavour. Such a pipeline would likely transport hydrogen produced from many PV/electrolyser plants and would be built only if both hydrogen production in Spain and hydrogen demand in North West Europe are already present or certain to develop in a relatively short time frame.

Large-scale hydrogen production in southern Spain (or Italy, or Greece) will not materialize overnight but will grow gradually, and only if the hydrogen can be sold. If local demand is available, a local hydrogen infrastructure can be developed and expanded, which ultimately justifies a connection to a European hydrogen backbone and to other parts of Europe. Once in place, this transport hub will reduce merchant risks for local producers and sets in train a self-reinforcing cycle for the scaling of low-cost PV based hydrogen production.

7.3 Geothermal energy in Iceland

7.3.1 Description of the value chain

Virtually 100% of Iceland's electricity production is from renewable sources: geothermal, hydropower and wind turbines. This low cost, renewable power has attracted aluminium smelters that produce low-emission aluminium. Both the ore and aluminium are transported to and from Iceland by ship, but the availability of low-cost renewable power renders this value chain feasible. By extension, Iceland could arguably export its low-cost renewable power in the form of green hydrogen. The hydrogen would, however, need to be converted into a high-density form to make the long-distance transport viable.

Estimates on the future cost of electricity in Iceland vary and are dependent on the demand levels that could be boosted by large projects like ICELINK (the HVDC link between Iceland and the UK). Estimates as low as 27 USD/MWh have been reported by the Icelandic Energy Industry Association (Samorka). However, this cost level is probably only achievable for limited production locations. Considering future domestic requirements and competition for low-cost industrial locations, an average estimate of 35 USD/MWh is used in this study, which optimizes the value chain using geothermal power in Iceland. This cost level compares favourably with hydropower projects, and this case is thus analogous to hydrogen produced in isolated locations by hydropower.

Compared with the value chains driven by variable renewable energy, the geothermal driven value chain is characterized by a high utilization because of the continuous availability of geothermal power. This high utilization means that hydrogen production efficiency is extra important, even if this comes at a cost of a higher investment level. Liquefaction for transport to Northwest Europe involves high capital and operating costs due to the low condensation temperature of hydrogen and the ortho-para conversion needed to avoid excessive boil off[4]. However, since the liquefaction plant can run virtually continuously, this has less of an impact on the levelized cost than it would have for value chains with a

lower utilization.
In a low-utilization value chain, significant storage capacity for gaseous hydrogen would be required. In the geothermal case, storage – in liquefied, not pressurized form – also plays a role because transport of liquefied hydrogen by carrier is batched.

7.3.2 Hydrogen production

The efficiency of both a PEM and an alkaline electrolyser depends on the load factor. The lower the load, the lower the electrical and electrochemical losses in the stack and the higher the DC-efficiency of the electrolyser's stack. However, balance-of-plant components, such as pumps, compressors and electric components will become less efficient as they are dimensioned on the nominal capacity of the stack. Figure 7.4 shows how the combination of these effects results in the typical shape showing the trade-off between efficiency and output. For a given electricity production capacity, using an electrolyser with a higher capacity will increase the efficiency. Using a smaller electrolyser will increase the hydrogen output per investment.

In contrast to the solar PV case, an electrolyser coupled to a geothermal source produces hydrogen almost continuously during the year. Degradation scales with the number of operating hours and during a 25-year period the electrolyser stack will need to be replaced, adding costs over the lifetime of the project. An electrolyser used in this configuration is optimized for long duration use and high efficiencies. For this study we assume a PEM electrolyser with a nominal efficiency of 68% (LHV) and a specific capital investment of USD 970 per kW including stack replacement after 100,000 operating hours.

7.3.3 Hydrogen transport and storage

To efficiently transport hydrogen to mainland Europe, we assume that hydrogen is liquefied, and LH2-carriers are used. At the destination, liquid hydrogen must be re-gasified before it can be used. If re-gasification needs to be done quickly, external heat is required, e.g., by using sea water or by burning part of the hydrogen itself. For LNG, this is currently common practice and the energy potential stored in the cold LNG (so called cold energy, which is 1% to 2% of the total energy content) is not recovered.

In the case of liquid hydrogen, energy is also stored in cold form. From this cold energy approximately 3 to 4% is recoverable. This is about 15% of the electrical energy used to liquefy the hydrogen. It is valid to question whether the energy stored in the cold form can be valorised. We know from LNG that interdependencies are difficult to handle, so a potentially scalable solution within the same value chain is preferred. Hydrogen is liquified using relative low-cost Icelandic electricity. When this hydrogen is used for electricity generation in the receiving port, this cold energy can be utilized to generate electricity, benefiting from relatively high electricity prices at the destination location. A possible low-investment solution is a hydrogen turbine with pre-cooling from liquid hydrogen. Because of the increased Carnot efficiency such a system can serve as a relatively profitable peak power unit.

7.3.4 End use and specific considerations

Hydrogen produced in Iceland from cheap geothermal electricity competes with aluminium production and electricity exports via a DC connection to the UK. Which of these applications will emerge as the major user of geothermal energy will depend on the market position of Iceland compared with other locations for each of these commodities, as well as the stability of these commodity markets. Nevertheless, Iceland is in theory an interesting location for the production and export of hydrogen. The continuous availability of renewable power allows highly efficient (but expensive) electrolysers to operate with a high utilization.

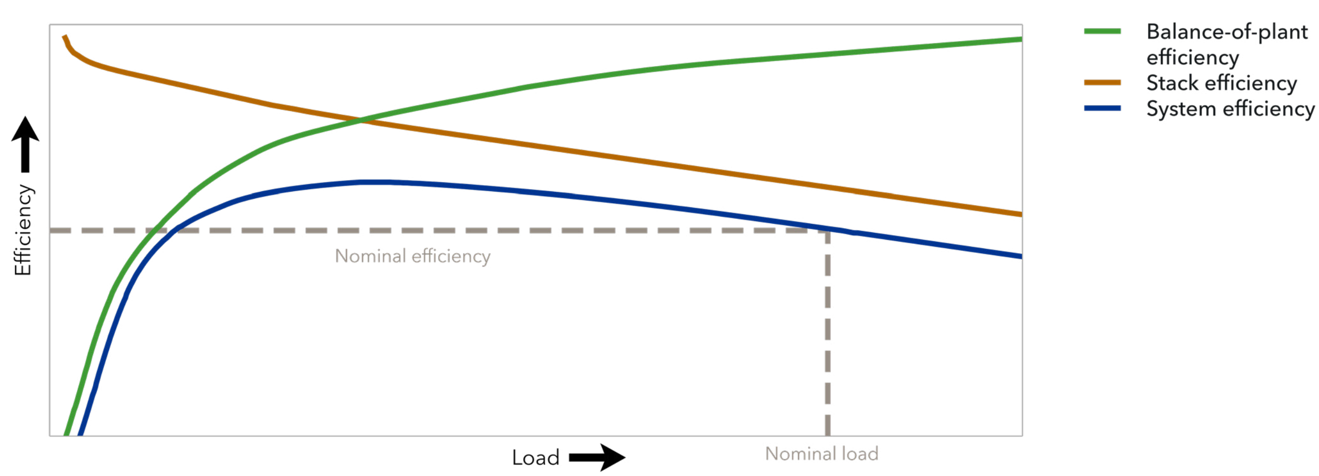
Transportation by ship is very flexible compared with a fixed connection like a power cable or pipeline. Hydrogen from Iceland can be transported all over the world and can serve different markets. Whether this is an advantage depends on the volatility of and price levels in these markets. The ambition of the European Union to make 50% of industrially-used hydrogen carbon free in 2030 makes Europe the most attractive green hydrogen market for long-term supply contracts. Although such an arrangement favours a hydrogen pipeline to Europe, shipping does allow for the cherry picking of other markets for some of the produced hydrogen at a relatively low additional cost.

Transporting the bulk of the hydrogen to Northwest Europe provides the financial stability needed to cover the investments. Hydrogen can be received using liquid hydrogen terminals that provide short-term storage and conversion to gaseous hydrogen to be fed into the hydrogen infrastructure. When combined with electricity generation from hydrogen turbines, this can lead to very efficient and flexible power generation providing power when the power system requires it, using the low evaporation temperatures of hydrogen to increase the efficiency of the turbines, while using the waste heat of the turbines to evaporate the liquid hydrogen.

FIGURE 7.4

Relation between the efficiency of an electrolyser and the load

Units: unitless



Source: Siemens

7.4 Offshore wind on the North Sea

7.4.1 Description of the value chain

Offshore wind farms close to, e.g., Rotterdam port offer the possibility of a value chain that is relatively short and can be controlled by only one party. This is a practical starting point for the development of green hydrogen. It requires a nearby renewable power source, transport of the power to an industrial site and integration of the electrolyser output with the hydrogen demand. The cost of offshore wind has reduced substantially in the last few years and the technology has evolved such that a more stable output over time is obtained with a load factor of over 50%. Power can be transported through HVDC cables but when the connection distance is relatively short (50-100 km), AC cables are a more cost-effective solution. Like the other cases discussed in this chapter, the primary energy source, in this case the wind farm, provides electricity exclusively for the production of hydrogen. The electric infrastructure can thus be specifically designed and (economically) optimized to provide energy to the electrolysers.

Unlike the other value chains discussed, there is no public infrastructure required. However, some storage, or a secondary source of hydrogen, will be required in cases where a continuous supply of hydrogen is needed, for example in the process industry. The utilization factor of the electrolyser lies in between those of the solar PV and geothermal cases discussed above.

7.4.2 Hydrogen production

Figure 7.1 shows the load duration curve of a modern offshore wind farm in the North Sea consisting of large 11 MW turbines, with a capacity factor of over 50%. With no connection to the public grid, the windfarm and its connections do not have to comply with public grid-code requirements, reducing the cost of the power infrastructure by an estimated 10% owing to engineering, legislative and partly technical simplifications.

However, other technical requirements apply. For example, the windfarm must be grid-forming, meaning it can create and maintain the grid frequency and voltage. This islanding capability is under development and expected to be readily available in 2030. In a similar manner as the solar PV case (Section 7.2), the cable and electrolyser are under-dimensioned compared with the nominal capacity of the wind farm to obtain the lowest levelized cost of hydrogen. Due to the relatively flat generation curve of the wind farm, the optimal size of the electric infrastructure, cable and electrolysers is close to the nominal capacity of the wind farm.

7.4.3 Hydrogen transport and storage

As with the solar PV case (Section 7.2), the hydrogen supply is not continuous. Assuming the supply needs to be continuous and in the absence of the benefits of linepack or large-scale storage as part of a European hydrogen back bone, local hydrogen storage or an alternative supply of hydrogen is required. Three days of short-term hydrogen storage is included in our assumptions for this case. If the hydrogen is to be used in existing industry, the alternative source could be hydrogen from existing natural gas-based hydrogen production capacity. This will supplement the hydrogen supply if the electrolysers produce too little due to lack of electricity from the wind farm or in case of maintenance or outages.

7.4.4 End use and specific considerations

The offshore wind value chain requires the least organizational effort to realize in a relatively short term. Only a few stakeholders need to be involved and the project can be realized within one country, avoiding cross-border regulations. It does not require (new) third-party infrastructure, such as a hydrogen backbone, hydrogen carriers or hydrogen terminals in ports. However, there remain technical challenges to overcome which require significant investment. The space to build electric generation in the North Sea is limited. Electrolysis therefore competes with other applications for the use of this electricity, mainly selling it directly on the European electricity markets. However, unlike the geothermal case (Section 7.3), generation of electricity from offshore wind is variable and the electricity prices vary with the availability of renewable electricity. Hydrogen production mitigates this price risk. There will be a significant correlation between offshore wind production and low electricity prices, given the strong ambition to realize offshore wind electricity production in North-West Europe. So, when electricity generation from offshore wind is low, there is a significant chance that electricity prices will be high. At these times it might be profitable to sell the electricity to the grid using a relatively small grid connection. Hydrogen can then be supplied from the alternative hydrogen source, i.e., natural gas-based production or from storage. This allows for price arbitrage to optimize revenues.

7.5 Nuclear power

7.5.1 Description of the value chain

The attractiveness of nuclear power is that it is a firm, almost carbon-free energy source. Firm capacity means that this capacity can be depended upon to be available and is controllable but not variable. Unlike geothermal energy and hydropower, it is less restricted to advantageous geographic locations and is not impacted by weather extremes like serious droughts.

Nuclear power as an electricity source for electrolysis results in a continuous and stable generation of hydrogen. Plant siting can be chosen relatively close to industries that require hydrogen. Because of safety management and controllability, we opted, in this case, for a relatively large-scale centralized nuclear power plant and assumed 50 km of hydrogen transportation pipelines.

7.5.2 Hydrogen generation

The required investments to build a nuclear power station are high and lead times are long, due, among other reasons, to permitting and additional legal and safety requirements. Like the geothermal case (Section 7.3), the required electrolysers need to be efficient and durable and, as a consequence, will be more costly than those used for solar. However, owing to a capacity factor nearing 100%, more running hours will be achieved than for solar-based electrolysers. This will reduce the impact of the higher upfront investment on the levelized cost of hydrogen. A notable feature of electrolysers is the increase in efficiency in part load operation (see also Section 7.3). The nominal power of an electrolyser is a trade-off between efficiency and cost. The sizing of the electrolyser therefore depends on the generation profile of the sourced electricity. The nuclear case shows that a continuous power supply warrants oversizing of the electrolyser as the gain in efficiency offsets the higher investment.

7.5.3 Hydrogen transport and storage

We assume the nuclear plant and electrolyser infrastructure can be built relatively close to the hydrogen demand in Northwest Europe. This means that the cost of the hydrogen infrastructure is limited and comparable to the cost of the hydrogen infrastructure required for onshore electrolysers powered by offshore wind.

We assume that hydrogen is either delivered directly to an industrial user with a continuous demand or is delivered to a hydrogen backbone. In both cases, hydrogen storage is not needed and thus not included in this case.

7.5.4 End use and specific considerations

A combination of a nuclear power plant and an electrolyser provides flexibility to switch from delivering electricity to delivering hydrogen. It will, however, still compete with renewable electricity because, in a competing market, other market parties will install electrolysers as well to profit from low electricity prices during periods of high renewable production, thus coupling the hydrogen price to the electricity price.

Although the price effect from combined hydrogen/electricity production is therefore limited in a developed market, there are other advantages to this combination. It may help to avoid expensive starts/stops of the nuclear unit and keep it running up up or above its minimum part load power. Additional reasons to build the combination are security of supply and independence from neighbouring production capacity.

It does not make much sense to build nuclear power to provide peak power to supplement variable renewables, due to the high investments and lead times for nuclear power plants. However, a relatively small capacity that is continuously producing hydrogen as a strategic reserve to reduce the seasonal dependency of the weather and absorb variations of renewable electricity generation between years might justify its high cost.

The attractiveness of nuclear power is that it is a firm, almost carbon-free energy source.

7.6 Comparison and conclusion

The European Clean Hydrogen Alliance already lists several hundred projects across Europe, and there are many more worldwide[5]. It is not clear, however, how green hydrogen projects are likely to cluster and form large-scale value chains, and when such value chains are likely to emerge. Some insight can be gleaned from our hypothetical exercise in comparing four distinct value chains delivering green hydrogen to Northwest Europe against the criteria of costs and plausible pathway to growth. Each of our four value chains has its own peculiarities and merits. The results of the evaluation in terms of optimized levelized cost of hydrogen are shown in Figure 7.5.

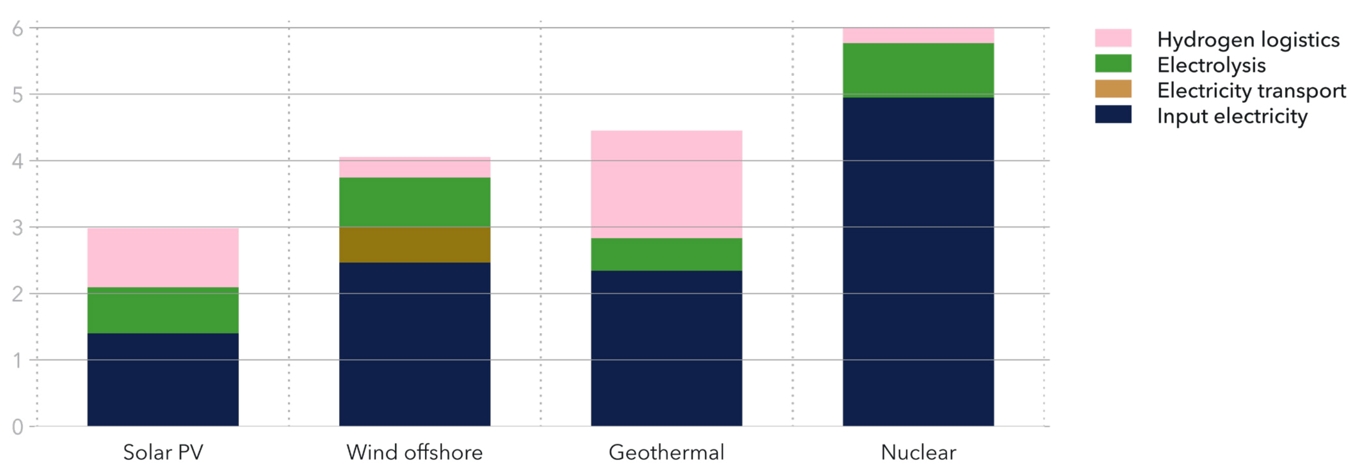
Figure 7.5 shows that hydrogen from solar-PV has the lowest levelized cost of hydrogen if produced in favourable location, and with an optimized capacity of equipment in the value chain. From a cost perspective this value chain is a winner. However, transport via a large pipeline adds significant costs and this value chain can only be realized economically at a large scale. Even with the costs of transmission, and assuming that a distribution infrastructure at the destination is available, it will still have the lowest levelized cost of hydrogen for supply to Northwest Europe.

Notably, this value chain can evolve and grow initially in southern Spain without a European hydrogen transport backbone in place. If the costs associated with transcontinental transport (summarized as 'logistics' in Figure 7.5) are stripped out, the hydrogen cost is close to USD 2.1 per kg H_2. These are attractive prices for any industry requiring green hydrogen, and will stimulate local demand. Indeed, Europe's largest green hydrogen project to date is taking shape in southern Spain – the HyDeal project, which is planned to start in 2025 with a total installed capacity expected to reach 9.5 GW of solar power and 7.4 GW of electrolysers by 2030. HyDeal will supply to local manufacturers of green steel, ammonia and fertilizer[6]. By 2030, low hydrogen costs in places like southern Spain will compete with carbon-priced natural gas prices, triggering even more local demand. In the longer term, as the business case for generating electricity with solar PV deteriorates – if the electricity market becomes saturated – hydrogen production might prove

FIGURE 7.5

Levelized cost of hydrogen in 2030 from four value chains in Europe

Units: USD/kgH_2



to be an alternative to equipping solar PV plants with large batteries.

Our results indicate that there is a significant upside to building the kind of transcontinental pipeline infrastructure for 2030 and beyond once it becomes apparent that hydrogen infrastructure is evolving locally and regionally on the back of demand for the green hydrogen that can be produced competitively in southern Spain.

All of the value chains covered in this chapter have the potential to materialize – either for reasons of cost advantage, timing or some other expediency.

The levelized cost of hydrogen from the offshore wind value chain is second lowest, at around USD 4.1 per kg; it is outcompeted by the PV value chain measured purely on the basis of cost. However, the solar PV case takes several years or more to evolve into a transcontinental value chain; the offshore wind value chain can be realized in a relatively short time frame. In theory it can be established by a single project developer controlling the hydrogen demand, the power cables and an offshore wind farm. This option is the most cost effective in the absence of the European Hydrogen Backbone bringing green hydrogen from the south. However, with the rapidly rising demand for green hydrogen and limited installation and realization potential for all options considered, there is likely to be considerable overlap in the development of these two kinds of value chains.

Hydrogen from geothermal energy in Iceland turns out to be more expense than the solar PV and wind value chain, mainly because of the transportation cost by ship and the required liquefaction. However, that does not rule out the case for producing hydrogen in Iceland to satisfy local demand and eventually international export.

Icelandic hydrogen has the second-lowest production cost (excluding hydrogen logistics) of the four locations we analyse. The liquefaction and transportation of hydrogen by ship adds significant cost, making it uncompetitive for structural supply – and effectively a sideshow in Iceland's evolving hydrogen ecosystem. It could be argued that once hydrogen markets mature worldwide, liquid hydrogen from Iceland might be used for arbitrage, being shipped to the continually changing hydrogen markets with the highest hydrogen prices. However, as discussed in Chapters 5 and 6, it is much more likely that Icelandic hydrogen will evolve competitive ammonia production, both for local use – attracting green industries to Iceland – and for bunkering and export.

Hydrogen produced from nuclear power is the costliest of the four value chains we examined. Economic arguments alone will not convince investors to finance this value chain. Government funding or guarantees are required. Renewable resource restrictions, land use restrictions, security of supply and energy independence arguments could trigger political support, regardless of the cost. A hybrid operation of a nuclear plant (producing both power and hydrogen) might have operational advantages, such as avoiding start-stop and part-load operation, though this will not decrease the levelized cost of hydrogen significantly.

All of the value chains covered in this chapter have the potential to materialize – either for reasons of cost advantage, timing or some other expediency. Local demand for hydrogen can act as a catalyst for a specific value chain to kick start and grow. Once established at sufficient scale, these value chains will likely be connected to a European Hydrogen Backbone and to large-scale storage facilities in salt caverns on depleted natural gas fields as part of an integrated green hydrogen market in Europe.

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