STUDY

The Roaring '30s

A clean hydrogen acceleration story

Roland Berger

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By the year 2040 it is possible that hydrogen will have become a key pillar of global decarbonization efforts. If so, how will we have traveled from where we are today, with the hydrogen market still in its infancy, to full-scale industrial deployment? What will the period of acceleration between 2030 and 2040 look like and what should we be doing now, in the remaining years of the current decade, to prepare for this massive expansion?

In this study we attempt to answer those questions. We present a snapshot of 2030, when we expect total hydrogen supply to be in the region of 110 million tons, of which 12 percent could be green hydrogen. We then take that snapshot and compare it with an aspiration level that we calculate for 2040, namely 1 TW of installed electrolyzer capacity and approximately 240 Mt per year hydrogen production. This allows us to draw a picture of what must happen in the decade from 2030 to 2040, a period we call the Roaring '30s.

What do our back-of-the-envelope calculations show? In order to achieve 1 TW of installed electrolyzer capacity, we need to install the same amount of capacity each year in the 2030s as we did in the entire decade from 2020 to 2030. By the year 2040, two-thirds of global hydrogen production could well be clean. Blue hydrogen will support the decarbonization agenda, but gray hydrogen will likely remain a significant part of the global mix, representing a reliable base for those industries that still depend on it, especially in Asia.

The remaining years of the current decade will be crucial for determining whether demonstration projects that aim to bring down emissions by using hydrogen are actually effective or not. If these projects fail to deliver the expected efficiencies, the debate may shift to relocating energy-intensive industries to countries with low production costs thanks to their availability of low-cost clean energy, incentives or better regulatory frameworks.

In the meantime, to ensure demand for hydrogen, it is vital that we move away from a piecemeal view of the system in which we focus on aligning standards, setting up funding programs and defining technical criteria for measuring carbon emissions. Instead, we must concentrate on the structural measures (policies, mandates, incentive systems, regulation) that ensure the fundamental economics that will lead to long-term demand at scale: Making clean hydrogen an affordable alternative for users.

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Cover Alexandr Gnezdilov Light Painting/Getty Images

Back to the future

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This study is in the nature of a thought experiment. Our hypothesis is that by the year 2040, hydrogen will have become a key pillar of global decarbonization efforts. If that is indeed the case, how do we get from where we are today, with hydrogen still in its infancy in market terms, to full-scale industrial deployment by the end of the 2030s?

To explore the consequences of our hypothesis, we first calculate the size of the hydrogen economy in 2030 using a bottom-up approach. We then examine what needs to happen in the decade between 2030 and 2040 – a decade of acceleration that we call the Roaring '30s. If the hydrogen economy is to realize its full potential for global decarbonization, we will need to overcome an immense implementation challenge. We dissect that challenge, looking at all stages of the value chain, and in so doing provide a frame of reference for the actions that need to be taken today.

We believe that the remaining years of the current decade will be crucial for the hydrogen economy, laying the basis for the scaling that will be necessary post-2030. As yet, the economics of clean hydrogen are not always compelling. Today, developers cite a lack of offtakers at current renewable H_2 prices compared to gray, component delivery issues, teething problems with first-of-a-kind facilities, uncertainty around standardization and certification, and a slower pace of development on transportation and storage infrastructure as crucial challenges. Industry, policymakers and the financial sector therefore need to make a concerted effort to prepare the ground for acceleration, starting today. The single most important factor, we argue, will be making clean hydrogen an affordable alternative for users, thereby securing fundamental demand. And that means rolling out the right structural policies, incentives, regulations and approaches now.

The hydrogen economy needs a concerted effort to overcome an immense implementation challenge.

Building a foundation

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How will the clean hydrogen economy develop over the coming years? We identify three phases from now to 2040.

The first phase is the **commercialization phase**, taking us from the present day to around the year 2030. We consider the 2020s the first hydrogen decade: Unlike the 2010s, when the focus was on commercialization studies, theory, prototype end uses and demonstration projects, the 2020s have already seen the scaling up of clean hydrogen technologies. Governments have strongly ramped up their support and presented hydrogen strategies – Japan as early as 2017, Germany in 2020 and the United States in 2023 – and we see a powerful political drive for increasing energy independence. This is accompanied by increasing maturity of hydrogen technologies and end-use applications, including in hard-to-abate sectors. The hydrogen ecosystem has gained significant traction and hydrogen has established itself as a strong pillar of decarbonization efforts. The second half of the decade is likely to see further scaling-up in specific regions and the extension of captive supply chains.

The second phase in the story of clean hydrogen is the **emerging market**. In the years through 2035, new use cases for hydrogen with large volumes will appear, such as its use in the steel industry or shipping. Projects will become bigger and more international, the transportation of hydrogen will expand and flexible carriers will arrive on the scene. Public support will continue to be important, as in the commercialization phase, with a particular focus on regulation in the form of quotas, carbon contracts for difference (CCfDs) and carbon pricing. We will see the formation of hydrogen demand centers, driven by the decarbonization of industry and declining transportation costs. A project-based over-the-counter market will be established to minimize the sales risk and there will be an increasing need for brokers. During this second phase, we expect to see the large-scale use of clean derivatives for ammonia, methanol or e-fuels.

Finally, the period to 2040 will witness the establishment of a **commodity market**. Supply and demand centers around the globe will be connected, implying a stronger

A From commercialization to commoditization
The 3 phases of a developing green hydrogen economy

PHASE 1 **Commercialization phase**	PHASE 2 **Emerging market**	PHASE 3 **Commodity market**
· **Access to hydrogen mainly given to project partners** of first-of-their-kind pilot, demonstration and lighthouse projects · **Captive or project-based OTC market** to minimize sales risk	· **Formation of hydrogen demand centers** driven by decarbonization of industry and increasing project size · **Only project-based OTC market** to minimize sales risk with increasing need for brokers	· **Fixed hydrogen supply chains** with corresponding import/export and pipeline infrastructure · Guarantees of Origin framework for green hydrogen · **Liquid commodity market for hydrogen** with strong demand for brokers and trading
Coming 5 years	**5-10 years**	**>10 years**

Source: Roland Berger

role for hydrogen transportation, including a pipeline network and flexible carriers. Public support schemes will be phased out by the beginning of this period, although governments will retain a role in the area of fundamental regulation. In terms of market dynamics we will see fixed hydrogen supply chains with corresponding infrastructure and a liquid commodity market for hydrogen, with strong demand for brokers and trading. A standardized Guarantee of Origin (GO) framework for green hydrogen will also emerge in this period. ▶ A

These three market phases characteristically involve different "archetypes" of hydrogen projects, which form the nucleus of a hydrogen economy.

#1 SMALL-SCALE, MOBILITY-FOCUSED PROJECTS

Projects typically with between one and ten megawatts capacity, used for local green hydrogen production. These projects generally serve mobility applications and are therefore coupled with hydrogen refueling stations and fleet decarbonization efforts. Increasingly, they are captive or semi-captive. They are typically supplied by power from the grid with green certificates and are often led by private initiatives with substantial public involvement. This archetype is already thriving in the European Union, Japan and the United States. Examples: Hydrospider (CH), Zero Emission Valley (Auvergne-Rhône-Alpes, FR), Hydrogen Valley South Tyrol (IT), SoHyCal (US).

#2 ON-SITE INDUSTRIAL PROJECTS

Local or regional green hydrogen production projects located at the site of the large industrial consumers that represent their "anchor load", often refineries, fertilizer plants or steelworks. These projects are seamlessly integrated into production processes and sometimes also feature smaller offtakers. The key challenge for this second archetype is the ability to secure renewable power supply at the project location. Projects are mostly led by offtakers, sometimes in partnership with energy companies. The number of such projects is growing, with initial projects up to 20 MW already operational in the European Union and United States. Examples under development: Hydrogen Holland I (NL), HyNet North West (UK).

#3 CENTRALIZED GIGA-PROJECTS

Large-scale green hydrogen export projects with 250+ MW and in some cases multi-GW. These are regional or international projects producing hydrogen, ammonia, methanol and the like at low cost for export. Their focus is on connecting supply and demand globally. Typically, they are co-located with additional renewables capacity, such as pure photovoltaic (PV), PV plus onshore wind, or pure offshore wind. Projects are mostly led by private or sovereign developers. This third archetype is currently emerging, with the first final investment decisions (FIDs) about to be taken. Examples: NEOM Green Hydrogen (SA; the only project with FID as of today), Asian Renewable Energy Hub (AU), AquaVentus (DE), Hyport Duqm (OM).

Today, in the first phase of development of the hydrogen economy, we see many projects of the first archetype (small-scale projects) and increasingly projects of the second archetype (on-site industrial projects). As yet, only a few type-3 giga-projects are underway, due to limited demand-side willingness to engage in long-term offtake agreements. Besides the examples listed above, the third archetype has recently received a significant push in the United States with the nomination by the US Department of Energy of seven hydrogen hubs, which could receive total funding of up to USD 7 billion for infrastructure development. The imminent scale-up of electrolysis plants offers a unique opportunity for OEMs to establish a robust market share, by building a strong track record for reliable technical and operational performance of their electrolysis equipment.

Snapshot of 2030

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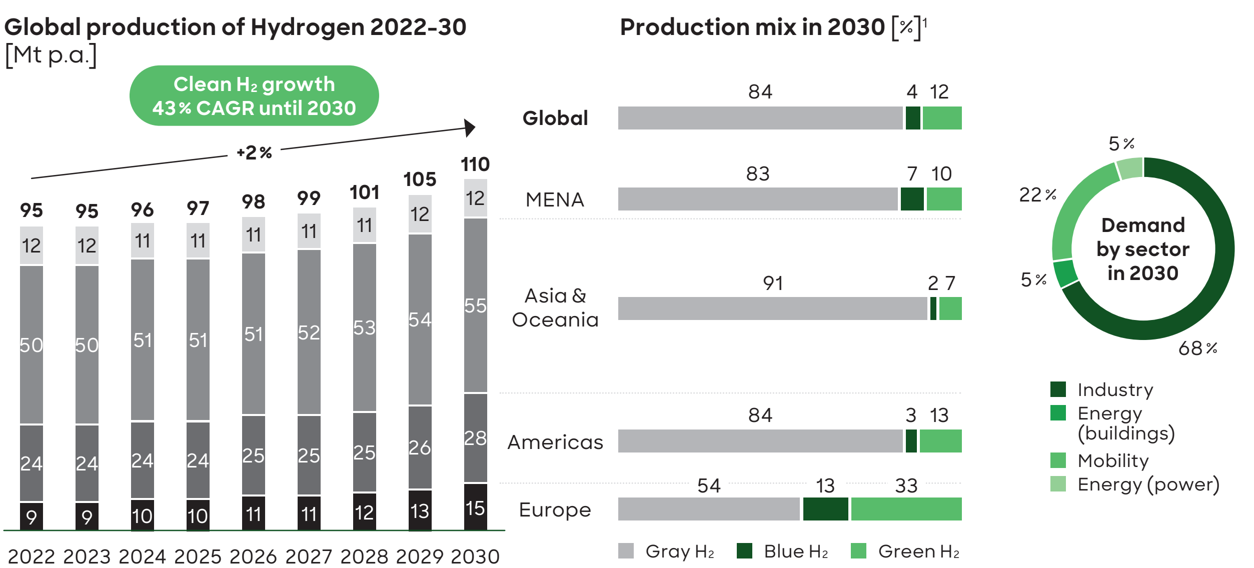
Many experts consider the year 2030 to be the key milestone for the hydrogen economy, a critical date in terms of the ramp-up of supply and demand, cost depreciation and infrastructure build-out. Any new targets and project announcements that have not been made as of today will most probably not materialize before 2030. That means that we can already draw a fairly good picture of what the hydrogen economy will probably look like at the end of this decade. And that picture is mixed: Although many exciting developments are taking place in the hydrogen space, things are not moving fast enough to ensure that by 2030 we will be on the pathway to net zero. Below, we look at the developments expected by the end of the current decade in upstream, midstream and downstream areas.

Upstream, the ramp-up of green hydrogen is progressing well, albeit below the expectations of the market and not fully in line with the announced ambitions of policymakers. By 2030 we expect total hydrogen supply to be in the region of 110 million tons, of which 12 percent could be green hydrogen (hydrogen derived from water electrolysis using renewable electricity) and an additional four percent "blue" hydrogen (generally produced from natural gas via steam reforming, capturing the carbon emitted). Accordingly, "gray" hydrogen (produced from natural gas, with no carbon capture) will still play an important role in the hydrogen economy, accounting for around 84 percent of supply. ▶ B

Based on current progress, we realistically expect to see 119 GW installed global capacity of electrolyzers by 2030.

B Hydrogen in 2030

By 2030 green Hydrogen could account for 12% of total Hydrogen



1 Figures are rounded

Source: Roland Berger

We arrive at this figure by using a bottom-up approach, taking announced projects and their level of maturity and factoring in the typical failure rate of clean energy build-out projects, which is around 65 to 70 percent.[1] This figure of 119 GW is less than half the 260 GW capacity committed to in government targets, and around one-fifth of the 590 GW required by 2030 to ensure we are on the path to meet the 1.5°C target set out in the Paris Agreement. ▶ C

The speed of the build-out of green hydrogen capacity is driven by many factors. The economics of green hydrogen production remain challenging, resulting in a lack of committed offtake. Even where conditions for the production of green hydrogen are conducive, current production costs without subsidies are between three and six dollars a kilogram, making prices uncompetitive compared to current fossil alternatives and to some extent other clean options. For example, on a USD/MWh comparison, natural gas production is currently between 10 and 40 times less expensive than green hydrogen. Moreover, the development of renewables in general is still progressing slowly. Despite this, green hydrogen is still a massive clean tech growth story, with an expected compound annual growth rate (CAGR) of around 65 percent to 2030 according to our predictions. The underlying projects will generally belong to the second archetype.

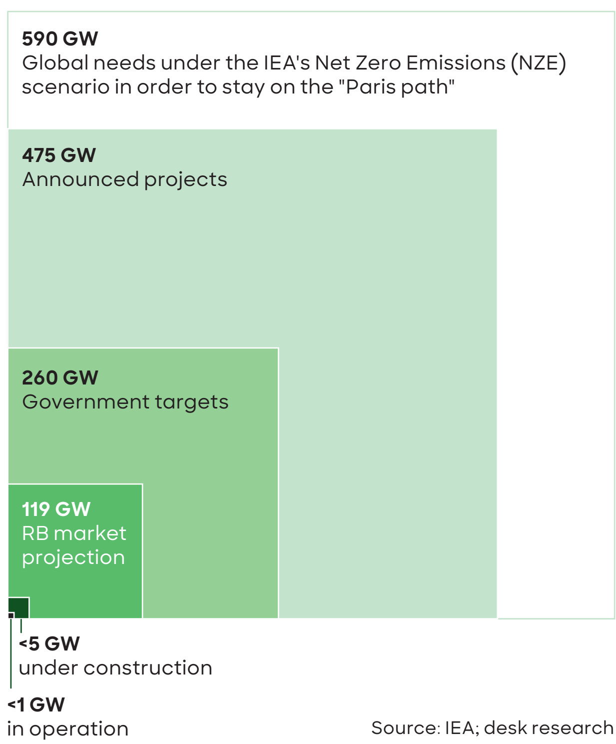
Midstream, we expect to see a basic infrastructure build-out supported by public funding, until such time as substantial volumes of hydrogen are being transported. Based on current planning and announcements by market actors such as gas transmission system operators (TSOs), energy companies and port operators, we will see the development of basic infrastructure for the conversion (and reconversion), transportation and storage of hydrogen. In Germany, for example, FNB Gas has laid out concrete plans for building a hydrogen backbone in the form of pipelines across the country.

1 Harvard Business Review, 2021; Merrow, 2012

In many cases these infrastructure development plans seem rather ambitious from today's perspective. However, we believe that their initial stages will have been realized by 2030 in Europe, connecting the first large-scale import facilities and production centers with industrial offtake areas. An example is the planned pipeline from Rotterdam to North Rhine-Westphalia in Germany.

We expect to see the first large-scale projects for hydrogen export come onstream around 2030. The

C A long way to go
Cumulative global installed electrolyzer capacity through 2030 of total hydrogen



Source: IEA; desk research

economics of seabound transportation of hydrogen remain challenging. Assuming that hydrogen will be shipped, the main form of transporation will likely be seabound, using green ammonia as a carrier, with some liquefied hydrogen and liquid organic hydrogen carrier (LOHC) projects demonstrating feasibility by 2030. Cost competitiveness with established legacy distribution of oil or LNG will probably still not be reached by then. We discuss further aspects of the transportation of hydrogen in our 2021 study Transporting the fuel of the future. ▶ D

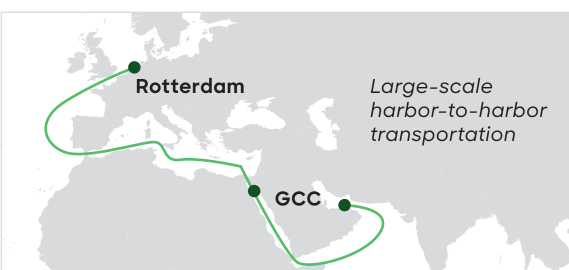
Within Europe, the first import infrastructure (terminals, reconversion/ammonia cracking) will be built in selected ports in Western Europe, with Southern and Northern European ports offering export infrastructure and associated storage.

Downstream, hydrogen will continue to be used mainly as feedstock or to produce process heat. The replacement of gray hydrogen with green hydrogen will be the main driver of demand in market segments where funding and financing instruments come together to make green hydrogen competitive, such as in direct reduced ironmaking (DRI) in Europe (see discussion below). Mobility will be the first area where hydrogen is used in hard-to-abate sectors, for example in the refining process to produce synthetic aviation fuel (SAF) or to decarbonize maritime transportation. ▶ E

D Cost-effective hydrogen carriers

Ammonia, liquefied hydrogen and LOHC

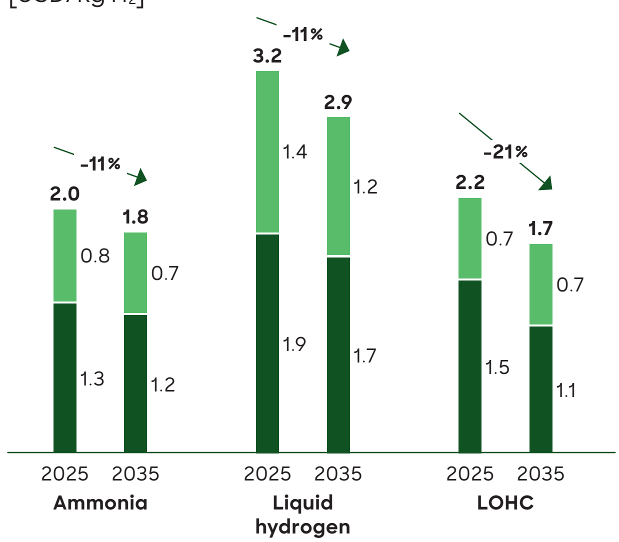
Import/export archetype



Hydrogen production location:	GCC region, e.g. KSA
Hydrogen import country:	Europe, e.g. NL
Transportation mode:	Long-distance via ship
Renewables mix:	Dedicated PV asset

Transportation costs per key hydrogen carrier

[USD/kg H_2]

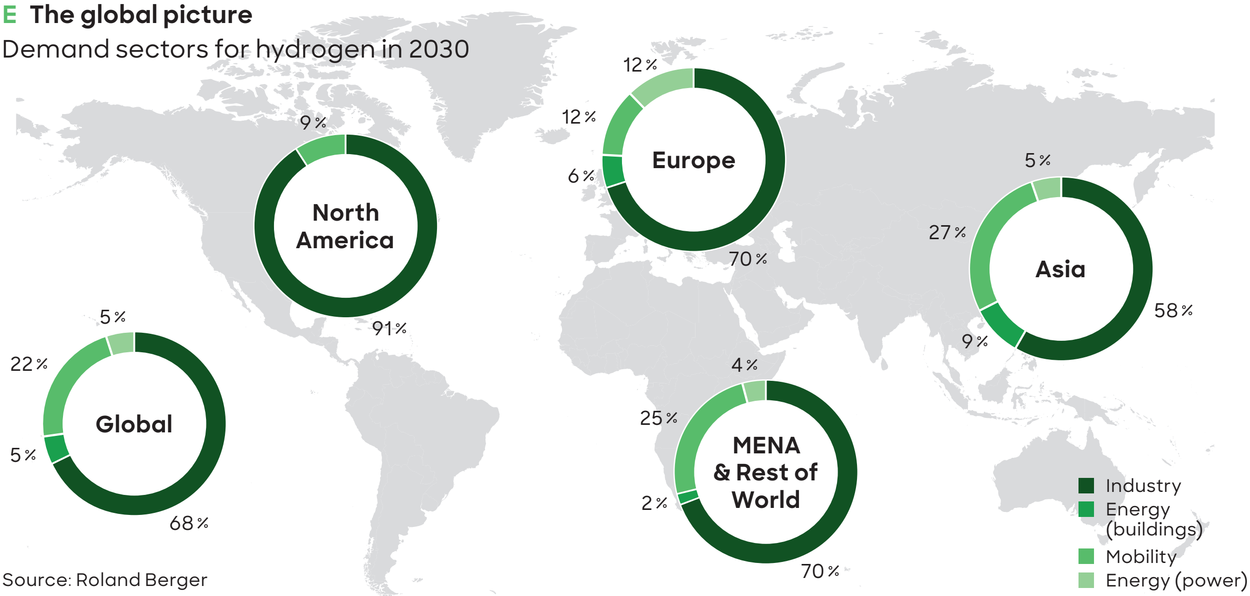


OPEX CAPEX

Source: Roland Berger

E The global picture

Demand sectors for hydrogen in 2030



Source: Roland Berger

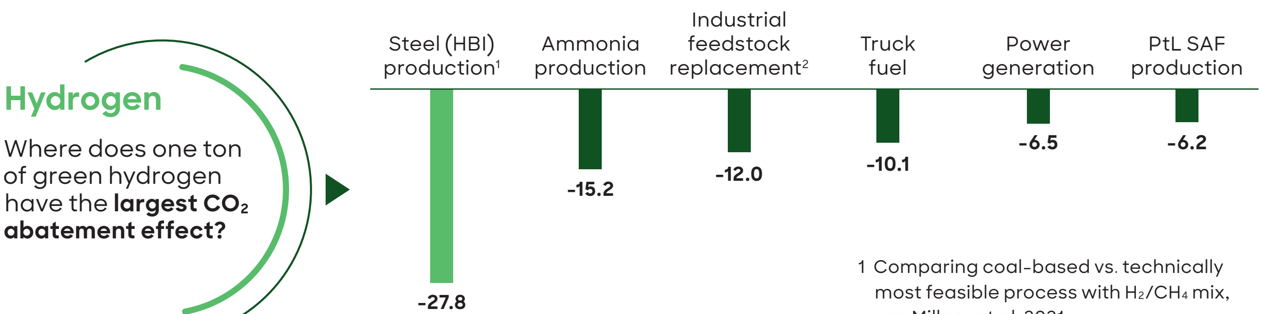
The main challenge for the years through 2030 will be the lack of binding offtake commitments. In 2030 we expect to see three main factors driving demand for hydrogen and its derivatives: legislation, public funding and a few commercial use cases. In terms of legislation, Europe has introduced a binding quota of 1.2 percent power-to-liquid (PtL) jet fuel by 2030, for example, creating a fairly predictable market in a short amount of time. We expect this mandate to lead to total demand for e-kerosene of 1.1 Mt and an associated volume of hydrogen of 0.52 Mt by 2030. Public support schemes, such as Germany's carbon contracts for difference and the Inflation Reduction Act (IRA) in the United States, will bridge some cases of higher costs and lead to investments in infrastructure that will be operational by 2030, we predict. As far as commercial use cases are concerned, one early example is the use of hydrogen as a decarbonization option in direct reduced ironmaking, where it has an abatement potential of ~28 tons of CO_2eq per ton of hydrogen. We expect to see in the region of ten DRI plants up and running in Europe by 2030. ▶ F

KEY TOPICS FOR THE FIRST HYDROGEN DECADE: 2020-30

A number of topics will dominate the rest of the current decade, shaping our position in 2030. The cost of financing, inflation and the increasing cost of equipment, for example, will be major issues slowing down progress on certain projects. In an optimistic scenario, however, interest rates will gradually come down from 2024 onwards and we will see political awareness for the need to enable transformative investments.

Another key point of discussion concerns blue hydrogen. If capture rates improve, the technology matures and a secure

F Where could green hydrogen have the biggest impact?
Ranking of use cases by level of carbon abatement [tons of CO_2eq]



1 Comparing coal-based vs. technically most feasible process with H_2/CH_4 mix, see Millner et al. 2021
2 On average

Source: Carbon Commentary, EU, GE

supply chain can be established, current hydrogen users who produce in countries where fossil fuels are currently cheap, such as the Middle East and the United States, may shift to blue hydrogen. At scale, blue hydrogen is expected to be competitive until green hydrogen reaches a price range of 1.5 to 2 USD/kg. However, the ramp-up of blue hydrogen faces difficulties in particular regarding infrastructure limitations and restrictive regulatory environments.

Countries such as Germany are currently opening up to carbon capture, utilization and storage (CCUS). This may boost other decarbonization options that are cheaper than hydrogen. The abatement costs for alternative technologies in energy-intensive industries, such as the chemical industry, may make these decarbonization alternatives more and more attractive unless the cost of clean hydrogen comes down. For example, we expect hydrogen to be able to compete with CCUS for steam production at a price of maximum EUR 2/kg of hydrogen in 2030.

The remaining years of the current decade will also be key for determining whether demonstration projects that aim to bring down emissions by using hydrogen are actually effective or not. If these projects fail to deliver the expected efficiencies, the debate may shift to relocating energy-intensive industries to countries with low production costs thanks to their availability of low-cost clean energy, incentives or better regulatory frameworks. This will have significant implications for where investments are located in the 2030s.

Overall, we see significant momentum in the market for clean hydrogen, driven by climate action and related commitments. The growth in the production of clean hydrogen that we foresee by 2030 needs to be matched by reliable demand, which translates into offtake. This requires a conducive regulatory framework. In the mid term, regulation, incentives and public financing will often have to bridge the gap to a fully commercial offering of clean hydrogen. Action will thus be needed to stabilize demand, in the form of mandates, CCfDs and the like.

The Roaring '30s

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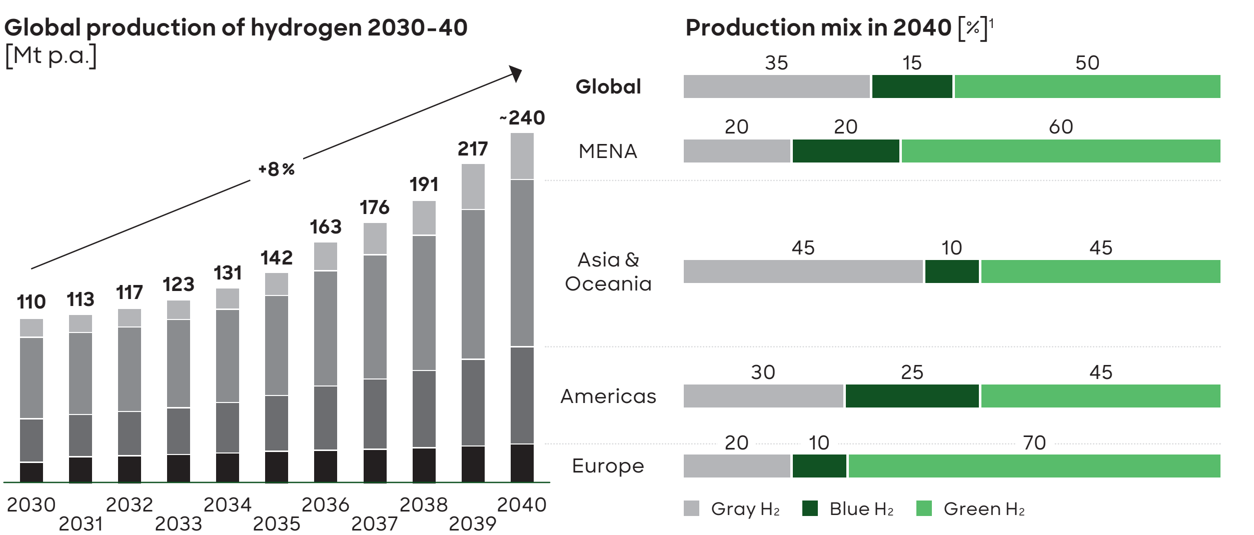
As we saw in the previous chapter, the remaining years of the current decade, up to the milestone year of 2030, will be crucial for laying the basis for the decade that follows. We call that decade – the second decade of hydrogen deployment – the Roaring '30s, a decade of massive acceleration in decarbonization and the hydrogen industry.

To determine what trajectory the Roaring '30s will take, we can look at our snapshot of 2030 and compare it with an aspiration level for 2040, namely 1 TW of installed electrolyzer capacity and approximately 240 Mt per year of hydrogen production (see methodology box for how we reach this figure). Taking this as our end point, we can then investigate what different segments of the hydrogen value chain will have to look like in order to achieve this ambition.

By the year 2040, we believe that two-thirds of global hydrogen production will be clean. Green hydrogen will have seen steady growth in Europe and strong market expansion in the Americas and Asia throughout the 2030s. The Middle East and North Africa (MENA) will also account for a significant share of the global market thanks mainly to the region's favorable environment for renewable energy. On average, 50 percent of production pathways globally will be green in 2040, with MENA and Europe leading the way. Blue hydrogen will support the decarbonization agenda, especially in the Americas and MENA, with CCUS technology used to transform the use of fossil resources. However, gray hydrogen will still form a significant part of the global mix, representing a reliable base for the industries that depend on it, especially in Asia. ▶ G

G Hydrogen in 2040

By 2040 green hydrogen could account for 50% of total hydrogen

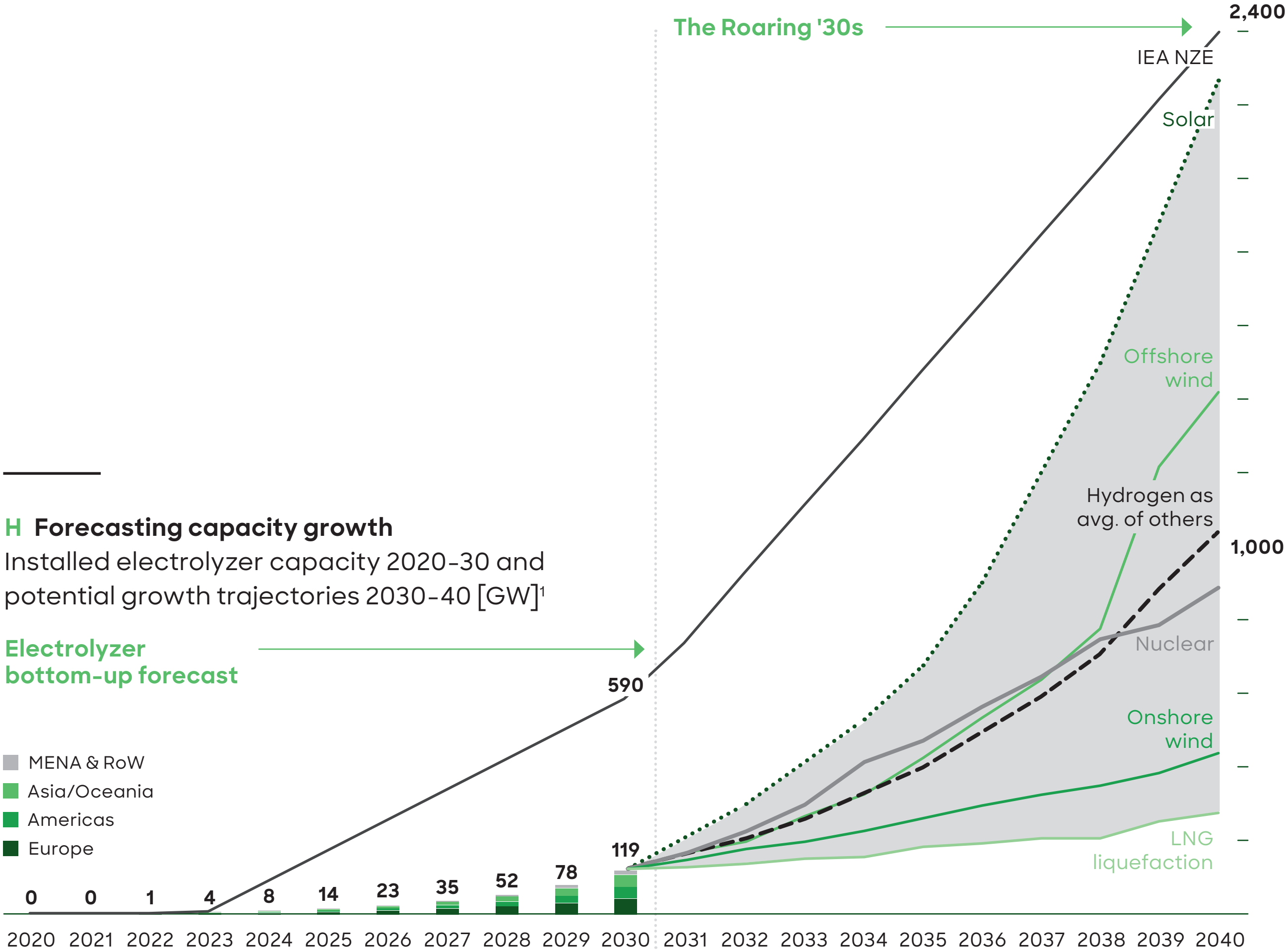


1 Figures are rounded

Source: Roland Berger

H Forecasting capacity growth

Installed electrolyzer capacity 2020-30 and potential growth trajectories 2030-40 [GW][1]



1 Methodology: Deployment growth rates of comparable technologies in second decade of market uptake applied to Roland Berger market projection for electrolyzers (solar/onshore wind: 2010-20; offshore wind: 2012-22; LNG: 2000-10; nuclear: 1970-80)

Source: Statista, GIIGNL, Roland Berger

METHODOLOGY

Why do we take 1 TW of installed electrolyzer capacity and approximately 240 Mt per year of hydrogen production as our aspiration level for 2040?

The figures are based on our analysis of the historic growth trajectories and scaling decades of comparable technologies, such as offshore and onshore wind. These technologies have similar structural enablers to electrolysis. In particular, we analyzed the degree of decentralization that is possible for the deployment path. Solar panels, for example, can be installed by private individuals on their rooftop or deployed as multi-MW solar parks, while offshore wind parks require a major initial investment and so are only viable if a sufficiently large GW scale can be installed in one offshore location. Electrolyzers fall somewhere in-between: They are less dependent on centralized decisions than offshore wind parks, but considerably more dependent on centralized decisions than an individual solar panel. ▶ H

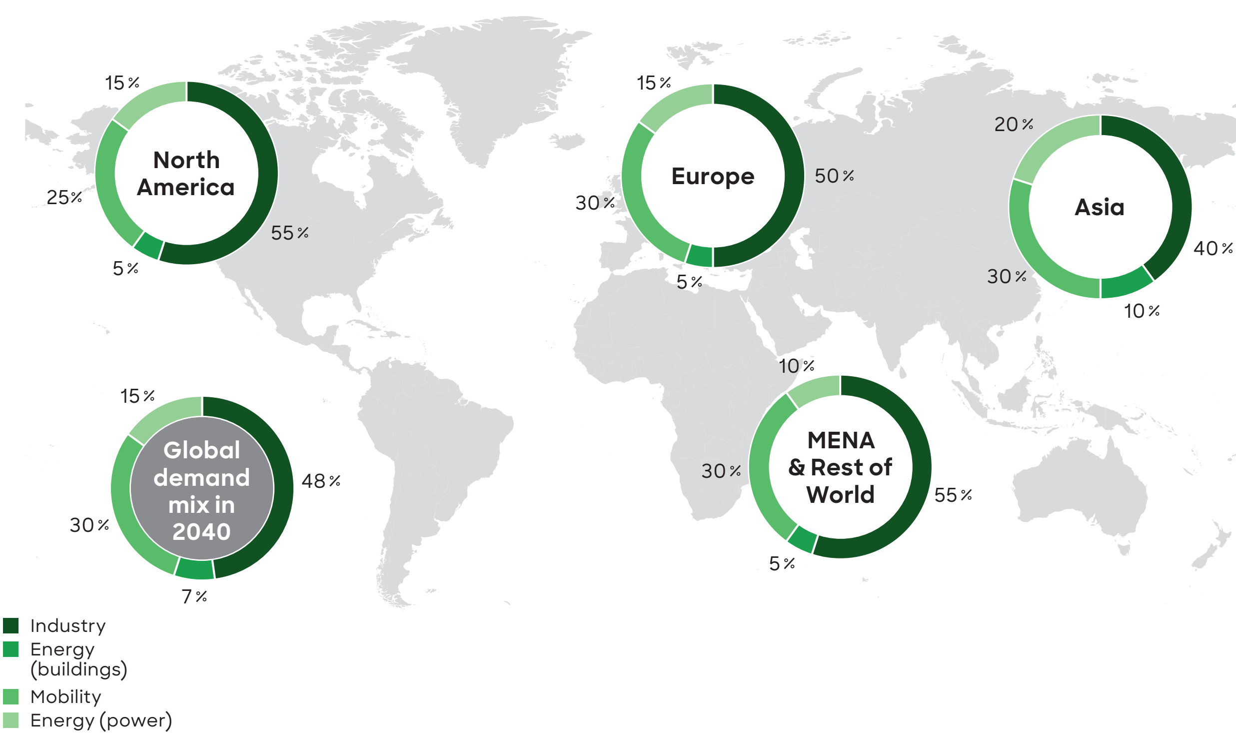
We also considered infrastructure-related limitations in our analysis. While large-scale energy assets require dedicated infrastructure, seamlessly scalable systems can more easily build on existing infrastructure. Here, again, electrolysis is somewhere in the middle compared to other technologies, as a system that is relatively adaptive to local infrastructure conditions.

Using our methodology, we calculate that in order to achieve 1 TW of installed electrolyzer capacity, the world will need to install the same amount of capacity each year in the 2030s as it did in the entire decade from 2020 to 2030.

The period between 2030 and 2040 will not only be an acceleration phase for hydrogen but also the period in which industry becomes less dominant as the major offtaker and other sectors gradually gain in importance, creating a more diversified picture overall. The mobility and energy sectors in particular will require more and more hydrogen. The hard-to-abate aviation and maritime transportation sectors will need hydrogen to achieve a large-scale switch from traditional to clean synthetic fuels, ammonia and methanol. In the energy sector, hydrogen will gradually take over the role of natural gas and coal in the context of an increasing share of intermittent renewable energy in the mix. At the same time, the use of hydrogen to decarbonize building heat will be a less important but constant source of demand.

The global picture

Demand sectors for hydrogen in 2040



Source: Roland Berger

CASE STUDIES

Below, we present four case studies along the hydrogen value chain during the Roaring '30s. All four relate to areas with great potential that has not yet been drawn on significantly. The first two are upstream case studies, namely the build-out of **offshore wind** and an increase in the number of **electrolysis giga-projects**. The third is midstream, namely the construction of **pipeline infrastructure**, while the fourth is downstream, namely boosting activity in **offtake sectors**. For each of the four case studies, we examine the implications of our 2040 ambition level of 1 TW of installed electrolyzer capacity and total global production volume of approximately 240 Mt per year, drawing a realistic sketch of the challenges that lie ahead. We support this with back-of-the-envelope calculations to demonstrate the size of the challenges and what we need to do today to prepare for the coming decade.

Case study I: Offshore wind

The build-out of offshore wind is a critical enabler for the large-scale production of green hydrogen. This is because the entire green hydrogen value chain starts with the renewable energy sources that are required for its production. However, renewables are currently a major bottleneck: A threefold increase in generation capacity is needed globally by 2030 – equivalent to an additional 1,000 GW of capacity per year – in order to ensure that we are on the 1.5°C pathway.

Offshore wind power, currently responsible for just 63 GW or around two percent of installed renewable capacity, is a prime example of untapped potential. It has several advantages over onshore wind and solar power, such as fewer space constraints, higher full load hours (FLH) and the fact that green hydrogen can be produced directly at sea via offshore electrolysis and transported via pipelines to the shore, avoiding any power grid constraints. Offshore electrolysis at large scale also has cost advantages over transmitting wind power by cable to produce hydrogen onshore.

According to the Global Wind Power Tracker, as of May 2023, some 289 offshore wind farms were in operation globally, 97 were under construction and 666 were in the pre-construction phase. A further 341 wind farm projects had been announced.[2] Currently operational offshore wind farms have a combined capacity of 65 GW, with projects in the construction phase adding 36 GW and those in the pre-construction phase a further 520 GW. Announced projects could in theory deliver an additional 452 GW, but it is highly unlikely that all of them will be implemented.

Of course, only a fraction of this total capacity would be used for green hydrogen production. Moreover, today only a small share of the renewable energy used for green hydrogen production comes from offshore wind. The International Energy Agency (IEA) expects that by 2030 less than ten percent of announced low-emission hydrogen production will rely on offshore wind.

To make the necessary acceleration in the Roaring '30s possible, offshore wind power will need to become a key pillar of global decarbonatization efforts in specific regions. We will need to master challenges such as undersubscription in auctions, permitting delays and restrictions on turbine placement – all factors that have impeded the expansion of offshore wind in recent years. Competitiveness of offshore wind LCOE (levelized cost of electricity) for hydrogen production needs to be revisited in a case of deployment at scale. Resolving these issues during the remaining years of the current decade will be imperative in order to unleash the full potential of this sector for green hydrogen production.

2 IEA Global Hydrogen Review 2023, https://iea.blob.core.windows.net/assets/8d434960-a85c-4c02-ad96-77794aaa175d/GlobalHydrogenReview2023.pdf

The use of offshore wind needs to increase particularly in Northern Europe, China, the United States, Japan, Korea, India, Argentina and Chile.[3,4] A rapid increase in hydrogen giga-projects in these regions is crucial to decarbonization. The number of offshore electrolysis projects must also rise steeply so that we can leverage the lower costs, faster rollout, improved reliability, access to storage and environmental impact advantages of such projects – as we discuss in our 2021 study *Innovate and industrialize. How Europe's offshore wind sector can maintain market leadership and meet the continent's energy goals*. This fast expansion relies on appropriate policy support and regulatory frameworks.

Until such time as offshore wind in combination with electrolysis proves its commercial viability, the industry should be led by governments. Offtake agreements will be needed in order to achieve financial viability. In terms of infrastructure, pipelines between offshore electrolyzers and land must be in place by the late 2030s, avoiding the need for flexible carriers.

The offshore wind industrial supply chain is currently under severe stress, with key turbine manufacturers facing financial challenges. To achieve the build-out targets for offshore wind and unlock it as a key green power source for electrolysis, the sector needs to increase its production capacities so that developers and operators can tap into a competitive, delivery-ready supply chain. Moreover, significant product development groundwork is needed if offshore electrolysis is to become the next frontier. Electrolyzer and turbine manufacturers need to align on technology concepts and interfaces and ultimately develop standardized equipment for offshore electrolysis, whether in centralized setups on larger platforms fed by multiple turbines or in fully decentralized settings where electrolyzers are attached to individual wind turbines.

In terms of our figures, if 20 percent of renewable electricity for the 1 TW electrolyzer capacity in 2040 originates from offshore wind, more than 20,000 offshore wind turbines will need to be deployed, each with a capacity of 20 MW – the equivalent of one turbine every 610 meters around the entire UK coastline. The challenge in terms of financing is equally striking: Assuming a mid-term average cost point of around USD 3,000 per kW installed capacity, investment requirements will be in excess of USD 1 trillion by 2040.[5]

Case study II: Electrolysis giga-projects

To meet the demand for green hydrogen from different offtakers, the hydrogen economy will need centralized electrolysis giga-projects – our third project archetype, as described in Chapter 2. Giga-projects will be located close to sources of cheap renewable energy and will typically be co-located with renewable energy production facilities. They will produce green hydrogen for export, their low production costs outweighing increasing transportation costs. Most often, such projects will be owned by major private energy companies or sovereign investors, who are able to bear the large initial investment costs.

To make 1 TW of installed capacity for hydrogen production by 2040 possible, a number of developments are necessary. The assumed average size of giga-projects could be around 3 GW; for reference, the largest project today, in Neom (Saudi Arabia), will produce roughly 2 GW. The share of giga-projects in total installed capacity will also need to grow from around 34 percent today to 60 percent, largely at the expense of the first project archetype (small-scale, mobility-focused projects). And the total number of giga-projects of 3 GW each will need to increase to around 210, compared to zero today and 197 announced by 2030, with 2.3 GW average capacity and a high failure rate expected.

3 Global Wind Atlas 3.0, https://globalwindatlas.info/en

4 IEA Offshore Wind Outlook 2019, https://iea.blob.core.windows.net/assets/495ab264-4ddf-4b68-b9c0-514295ff40a7/Offshore_Wind_Outlook_2019.pdf

5 US Department of Energy

Generally speaking, original equipment manufacturers (OEMs) appear to be confident that they can cater to global electrolyzer needs, and more capacity build-outs seem likely with new OEMs entering the market through 2040. The technology of giga-projects will also change: By 2030, alkaline and polymer electrolyte membrane (PEM) technologies will likely account for more than 80 percent of the market.

Giga-projects for hydrogen production have a number of specific requirements. First, they need space, particularly for energy generation. For example, Bhadla Solar Park in India – with 2.7 GW installed capacity the second-largest solar park in the world – spans an area of 5,700 hectares, or about 8,000 soccer fields.[6] A 3 GW electrolysis system (incl. renewable energy sources) will likely require even more space than that. Wind farms are expected to be more space efficient, especially depending on the capacity per turbine, but face other challenges in terms of infrastructure.

The second key requirement of giga-projects is energy. As mentioned above, ideally the electrolyzer is located close to a dedicated renewable energy park that is at least as big as the electrolyzer, in other words, 3 GW. However, if we assume 3,000 full load hours, an optimal wind farm (with around 4,000 FLH) of 2.3 GW could be sufficient. Similarly, if solar panels can be spread out far enough to achieve an average of 2,000 FLH, a solar park of 4.5 GW would produce around 3,000 FLH of electricity for the 3 GW electrolyzer. The scale of the challenge is clear when we look at the largest parks that exist today: Golmud Solar Park in China has an installed capacity of 2.8 GW of solar energy.[7] For wind farms, the picture looks a little better: Although there is currently only one wind park globally with a capacity of more than 2 GW, plans exist to increase the capacities of single wind turbines and multi-GW farms, especially offshore.[8]

Third, giga-projects need water. Electrolysis typically requires around ten liters of clean water per kilogram of hydrogen produced. For 150-200 kt of hydrogen a year, this translates into around 1.6 billion liters of water a year – the water consumption of a minor German city. This poses significant challenges, particularly as favorable spots for solar energy, such as Australia or the MENA region, often have limited access to clean water. Large-scale desalination plants could be the solution. From the perspective of hydrogen developers, however, the water supply issue is typically manageable, water (including desalination if necessary) representing around just one to two percent of the hydrogen production cost.

To determine the financial backing needed for these giga-projects, we took a closer look at the expected electrolyzer costs for around 210 projects. Assuming an average installed capacity of 3 GW per project and a long-term cost average of 600 USD/kW[9] installed across the technology mix, our calculation gives us a pure capital expenditure investment need of roughly USD 380 billion globally, or around USD 1.8 billion per project, just for the required electrolyzers. Countries or individual developers planning multiple projects will need to make careful financial preparations and dedicated investment decisions, likely years in advance.

Assuming that 65 to 70 percent of large-scale energy infrastructure assets fail to reach a final investment decisions, statistically we would need to see on average three giga-project announcements every month from January 2024 to December 2040 in order to make sure that the required 210 projects were up and running by 2040.[10]

6 Top 10: Largest Solar Power Parks | Energy Magazine (energydigital.com)

7 Top 10: Largest Solar Power Parks | Energy Magazine (energydigital.com)

8 Ten gigantic wind farms | Discover Cleantech

9 Data from IRENA and interviews with market participants

10 For statistical reasons, we assume a linear trajectory across the timeframe.

Case study III: Pipeline infrastructure

Hand in hand with the build-out of giga-projects across the globe, midstream infrastructure must develop to enable the transportation of hydrogen from supply centers to demand centers. Hydrogen pipelines allow the cost-efficient short- and medium-distance transportation of hydrogen via transmission and distribution pipelines within countries and with neighboring countries, and in some cases even the long-distance export of hydrogen between continents, for example from North Africa to Europe.

A tremendous effort will be required to achieve the envisioned pipeline capacity by 2040. Yet it is hard to imagine that it will be possible to transport the hydrogen at scale by any other means. Global production of approximately 110 million tons of hydrogen a year would translate into around 220 million single hydrogen tube trailer fillings of 500 kg, or 10,500 singe liquid hydrogen vessel capacities, assuming these state-of-the-art vessels became available by 2030. Even if only 25 percent of hydrogen were transported by hydrogen transport vessels, more than 200 vessels would be required by 2030 – a number almost impossible to achieve within the next six years. To solve this challenge, many project developers plan to convert hydrogen to derivates such as ammonia, which is already traded as a commodity today. However, the reconversion of derivates comes with significant energy requirements and costs.

Clearly, a strategically developed hydrogen pipeline infrastructure is required by 2030. Around 5,000 km of hydrogen pipelines exist today,[11] while estimates of the amount required vary from 19,000 km (IEA) to 28,000 km (European Hydrogen Backbone initiative) by 2030, and 44,000 km to 53,000 km by 2040. There are multiple plans to repurpose existing natural gas pipelines or construct new hydrogen pipelines, including Norway's intention to have a hydrogen pipeline to pump an initial 2 GW of blue hydrogen to Germany by 2030,[12] Germany's plan to have a core network of new and repurposed hydrogen pipelines by 2030, and Spain, France and Portugal's joint plan to build a 450 km undersea hydrogen pipeline to transport two million tons of hydrogen a year from the Iberian Peninsula to France by 2030.[13] However, of the many plans announced, few are in construction as yet.

Europe will likely be a frontrunner in hydrogen pipeline networks in the 2030s, despite the challenges. Technically, the production of the mainly steel pipes is not a complex process, but the potential embrittlement of the steel and welds needs to be addressed, as does possible hydrogen leakage from connection points such as valves and seals. In terms of supply chains, equipment such as compressor/pump stations, control rooms, meter regulator stations and so on need to be available in sufficient quantities. For offshore pipeline construction, specialized pipelay vessels are needed, and with multiple hydrogen pipeline projects happening simultaneously, close coordination is essential. On the permitting front, governments will also need to define standards and safety regulations for repurposing existing natural gas pipelines and put rules and regulations in place for blending hydrogen into natural gas grids.

Another major hurdle is the size of the investment required. Taking the IEA estimate of 44,000 km globally (less the 5,000 km that already exists), this midstream investment does not come cheap. Assuming 40 percent of the pipelines are new build and 60 percent retrofitted, we would need to add around 2,300 km of pipelines a year, the equivalent of one typical international transmission pipeline each and every year from 2024 to 2040. Taking a mix of new build and retrofitted into account, the associated cost would be on average USD 2.8 billion a year.

In conclusion, given the speed of the necessary expansion and the size of the pipeline network required, infrastructure operators and investors need to accelerate their efforts and launch the required feasibility studies immediately.

11 IEA
12 Equinor press release
13 Reuters

Case study IV: Offtake sectors

To reach the envisioned 1 TW installed capacity in 2040, securing offtake agreements will be essential. This means boosting downstream activities in key offtake sectors using mechanisms such as public funding and mandates. Below, we discuss two key offtake sectors in detail: green steel and sustainable aviation fuel (SAF).

Green steel

Today's steel production depends on coal as a reducing agent for extracting iron from iron ore and providing the necessary carbon for steel. Steel production accounts for seven percent of global greenhouse gases,[14] with more than half of process emissions coming from blast furnaces and an additional 12 percent from coke ovens. Hydrogen is an efficient decarbonization option in terms of the amount of emissions it can reduce in this sector, with an abatement potential of 28 tons of CO_2eq per ton of hydrogen used in direct reduced iron, to produce hot briquetted iron (HBI). Currently, only gray hydrogen is used in this process – around 5.3 million tons of it in DRI in 2022 as an admix to natural gas.[15,16]

It is expected that hydrogen will play a major role in the steel sector by 2030. Based on project announcements, we foresee that in 2030 around ten DRI plants will be operational in Europe. However, to reach the 1 TW goal by 2040, many more DRI plants will be needed. DRI expansion is expected to advance fastest in Europe, where the steel sector is subject to various environmental regulations, such as the EU Emissions Trading System (ETS) and the Carbon Border Adjustment Mechanism (CBAM). The number of low-emission steel production announcements is also constantly growing around the world, especially in Canada, the Middle East, Australia and China. This expansion needs to include Asia, which is responsible for 70 percent of global steel production, including 53 percent in China alone in 2021. We expect that five percent of global steel production will be green by 2030, with Europe the frontrunner and the United States lagging three to five years behind.

Based on announced projects and data from our network of experts, we expect to see European production capacity for green steel reaching 20.5 MT by 2030. However, even if the desired production capacity and transition to DRI is achieved, it is highly likely that initial tests will be with natural gas, as delays and changes in the planned clean hydrogen supply are expected. Where European players do plan to use green hydrogen, this will probably be produced next to the steel plant in order to save transportation costs. Another option would be to build pipelines, either to hydrogen production sites or to ports.

If we assume that the European steel sector has hydrogen demand of around 1.2 MT in 2030 and 4.8 MT in 2040, we could see nine or ten European DRI plants operating by 2030 and more than 40 by 2040 – an increase of 400 percent within a decade. To meet global demand for green steel in 2040, we would need as many as 160 DRI plants. For the G20 countries this would mean around nine DRI plants per country by 2040. The overall decarbonization of the steel sector could thus require a total investment volume of around USD 480 billion.

Sustainable aviation fuel

Like the steel industry, the mobility and transportation segment is under pressure to decarbonize, driven by growing regulation. Stimulating offtake of hydrogen in this sector, especially in aviation and shipping, will be crucial for the acceleration foreseen in the Roaring '30s.

In 2022, aviation accounted for two percent of global energy-related carbon emissions, at almost 800 Mt of CO_2,

14 Iron and Steel Technology Roadmap – Analysis | IEA

15 IEA Global Hydrogen Review 2023 (windows.net)

16 Today, hydrogen in DRI is still mostly used by blending with natural gas. DRI with CCUS is also fairly efficient and hence a challenger for hydrogen.

or about 80 percent of its pre-pandemic level. Reducing the carbon footprint of aviation is challenging due to the sector's high energy needs and global scale, and will require a coordinated effort across borders. One way to achieve reduced emissions is through the use of sustainable aviation fuel.

Recent developments, including the EU-mandated quota for SAF and the rise of power-to-liquid based fuel, a type of SAF, make the economic case highly interesting. The European Union's binding quota for 2030, set at six percent for SAF (including 1.2 percent for PtL SAF), is creating a sudden market shift, leading to increased investment within local industry. Around the globe, and especially in the United States, we can see a bandwagon effect with bankable projects driven by voluntary airline commitments in line with the decarbonization ambitions of the air travel sector.

In 2030, in line with forecast developments in air travel, we expect to see European demand for PtL SAF of 1,050 kt. This demand will be binding and fairly predictable. Voluntary announcements are not likely to exceed this figure in Europe, in contrast to the US, where voluntary commitments are stronger. By 2040, Europe, with a quota of ten percent, will need a total of around 11,700 kt of PtL SAF. If we assume that the United States, countries in the Middle East and also Southeast Asia and China will introduce similar mandate schemes for PtL SAF just a few years behind Europe (say, a five percent quota by 2040), total demand for PtL SAF by 2040 could reach approximately 26,000 kt globally, requiring more than 170 SAF plants. This would mean an estimated average of nine SAF plants per G20 nation by 2040, costing upwards of USD 62 billion. ▶ J

J The 1 TW world
Hydrogen in the 2030s

	2040 Approx. 240 Mt p.a. global hydrogen production 1 TW electrolyzers				
	Offshore wind	**Green H_2 giga-projects**	**Pipelines**	**Steel**	**PtL SAF**
What it will take	One offshore wind turbine every 610 meters around the entire UK coastline	Three giga-project announcements every month from 2024 to 2040	1/2 of a GASUN pipeline every year between 2030 and 2040	Nine large-scale DRI production facilities in every G20 country by 2040	Nine large-scale production facilities in every G20 country by 2040
Invest-ment	**USD >1 tn**	**USD >380 bn** just for electrolyzers	**USD >50 bn**	**USD >450 bn**	**USD >63 bn**
H_2	**to produce approx. 25 Mt p.a.**	**installing approx. 600 GW**	-	**using approx. 18 Mt p.a.**	**using approx. 26 Mt p.a.**
	Upstream →		Midstream →	Downstream →	

Source: Roland Berger

Making it happen

5/

We believe that the Roaring '30s will be decade of massive expansion driven by large-scale, reliable, long-term demand. For this to happen, the single most important factor will be creating attractive economics that make clean hydrogen an affordable alternative for users. Our task for the remainder of the current decade is to ensure that the framework conditions are in place for clean hydrogen economics to work at scale.

In the previous chapter we looked in detail at four case studies along the value chain, areas where there is still major potential to be exploited: the build-out of offshore wind, investment in hydrogen giga-projects, the construction of a large pipeline network and boosting activity in offtake sectors such as green steel and SAF. Investment in the large-scale production of components for hydrogen production and the building of import and storage infrastructure will also be vital. Importantly, we must close the gap between supply announcements and reliable offtake announcements. In this way, we will be able to tap into economies of scale and ensure that the infrastructure is actually built.

We believe that it is time to move away from a piecemeal view of the system, one in which we focus on aligning standards, setting up funding programs and defining technical criteria for measuring carbon emissions or for what qualifies as green hydrogen. Single incentives and individual regulations lead to single projects. That worked well in the 2010s in the context of demonstration projects, but it is not sufficient for the 2020s and '30s. These individual elements are important, of course, but without the fundamental economics that create long-term demand at scale, no market for hydrogen will exist. Once the fundamentals are secured, the other elements will become simply hygiene factors.

In the absence of robust demand for low-emission hydrogen, the current race to secure market share for equipment such as electrolyzers will have no winners. There is no set pathway for propelling demand. To date, most of the world's largest financed projects for hydrogen production from electrolysis or with carbon capture, utilization and storage have been designed to serve existing demand. But new demand segments have also been successfully created, such as in steel, aviation and shipping. These new users may turn out to be more dynamic than the legacy areas due to regulation, incentives, end consumers' willingness to pay or other reasons.

To secure fundamental demand, we must move consistently towards structural policies, incentives and mandates. By definition, these are longer-term and predictable. Demand can be created by means of funding and incentives, by introducing structural enablers such as conducive carbon pricing and by applying quotas and mandates. To finance structural incentives, it would make sense to discuss a transition of the currently existing subsidies for the fossil-based energy to green energies and hydrogen. Based on the cost per ton of avoided CO_2, a CO_2 tax needs to be around 250 EUR/ton for green hydrogen to be competitive.

To some extent we are already seeing this taking shape. Thus, the tax credits in the Inflation Reduction Act in the United States strongly support the production of clean hydrogen at low cost. They are easily accessible and predictable. Similarly, in Europe, policies such as the SAF mandate or the quota for alternative fuels have created a reliable, predictable market overnight, leading to investments and long-term offtake agreements.

The question now is how can these structural policies be scaled and expanded to ensure that we trigger the fundamental demand needed by 2030? For example, can we expand the SAF quota in Europe to other regions or into other sectors, such as maritime transportation? What other steps are possible? To make the vision for 2030 and beyond a reality, we need to roll out the right structural policies, incentives, regulations and approaches now. Putting the fundamentals in place today will enable the hydrogen acceleration story that we desperately need – and ensure that we are on track with the global goal of decarbonization.

Credits

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FURTHER READING

- *TRANSPORTING THE FUEL OF THE FUTURE*
- *INNOVATE AND INDUSTRIALIZE: OFFSHORE WIND ENERGY*
- *VALUE CAPTURE IN GREEN HYDROGEN*
- *PORTS AND GREEN HYDROGEN: MATCH MADE IN HEAVEN?*
- *CLEAN HYDROGEN RADAR*

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