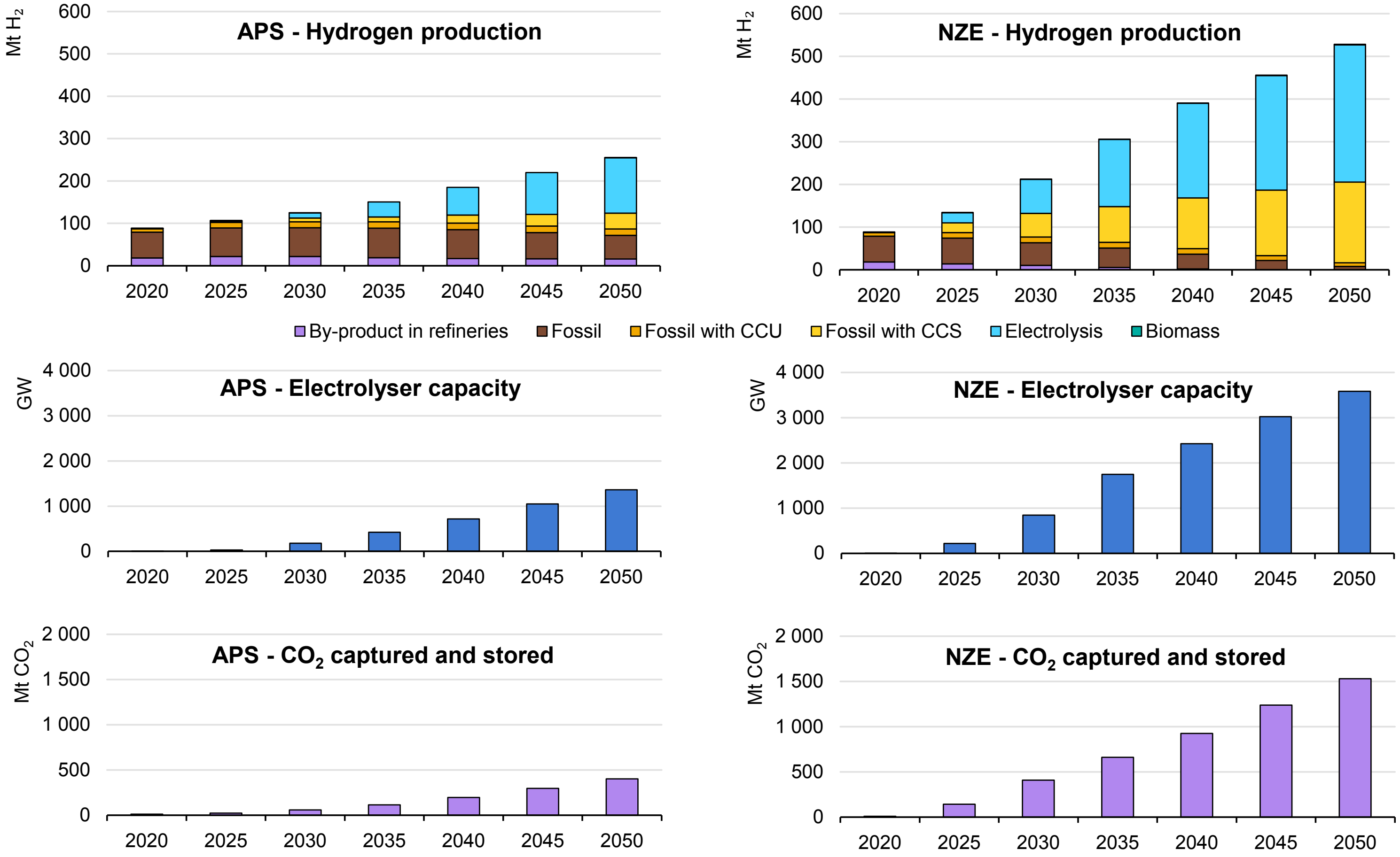
By 2050, global hydrogen production reaches 250 Mt H_2 in the Announced Pledges Scenario, with 51% provided by electrolysis, 15% by fossil fuels with CCUS and the remainder by fossil fuels without CCUS. This corresponds to global electrolyser capacity of 1 350 GW and the capture of 0.4 Gt CO_2/yr.

In the Net zero Emissions Scenario, global production doubles compared to the Announced Pledges Scenario, with shares of 60% from electrolysis and 36% from fossil fuels with CCUS as installed electrolyser capacity reaches 3 600 GW and the capture rate climbs to 1.5 Gt CO_2/yr. Notably, this corresponds to electricity consumption of almost 15 000 TWh (20% of global generation) and 925 bcm of natural gas (50% of global natural gas demand).

Decarbonising hydrogen production will require rapid electrolysis and CCUS roll-out

Global hydrogen production, installed electrolysis capacity and CO_2 captured and stored in the Announced Pledges and Net zero Emissions scenarios



Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. CCS = carbon capture and storage; CCU = carbon capture and use. Hydrogen production from fossil fuels with CCU refers to ammonia production in which captured CO_2 is used to produce urea fertiliser. When urea fertiliser is applied to soil, it breaks down again into ammonia and CO_2, with the latter released into the atmosphere.

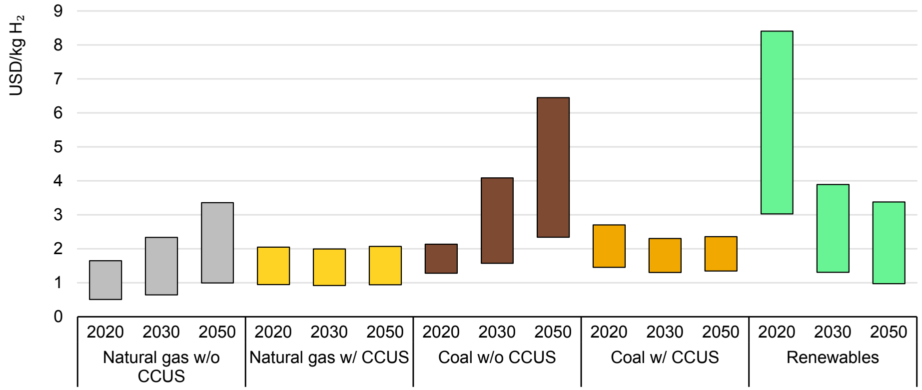
The cost challenge of low-carbon hydrogen

In most parts of the world, producing hydrogen from fossil fuels is currently the lowest-cost option. Depending on regional gas prices, the levelised cost of hydrogen produced from natural gas is in the range of USD 0.50-1.70/kg H_2. Using renewables is much costlier in most places, at USD 3.00-8.00/kg H_2. In fact, renewable electricity costs can make up 50-90% of total production expenses, depending on both electricity costs and the full-load hours of the renewable electricity supply.

As both renewable electricity and electrolyser costs fall, however, the price gap between production methods is expected to shrink quickly. Pricing CO_2 emissions (e.g. through carbon prices) could further narrow the gap by pushing up the cost of hydrogen produced from fossil fuels. For example, a carbon price of USD 100/t CO_2 corresponds to a cost increase of USD 0.90/kg H_2 for natural gas-based production without CCUS, or USD 2.00/kg H_2 for coal gasification without CCUS.

At high capture rates (90-95%), the impact of CO_2 prices on hydrogen production costs from fossil fuels with CCUS can be drastically reduced. Depending on gas prices, natural gas with CCUS entails a production cost of USD 1.00-2.00/kg H_2 – about USD 0.50/kg H_2 higher than without CCUS. A CO_2 price of USD 70/t CO_2 would therefore be needed to close this cost gap.

Levelised cost of hydrogen production by technology in 2020, and in the Net zero Emissions Scenario, 2030 and 2050



Notes: CCUS = carbon capture, utilisation and storage. Ranges of production cost estimates reflect regional variations in costs and renewable resource conditions.
Sources: Based on data from the Hydrogen Council; IRENA (2020); IEA GHG (2014); IEA GHG (2017); E4Tech (2015); Kawasaki Heavy Industries; Element Energy (2018).

Meanwhile, reducing the cost of low-carbon electricity will be critical to bring down the expense of producing hydrogen from electrolysis. Hydrogen production costs of USD 1.00/kg H_2 – the 2030 goal of the US Hydrogen Earthshot initiative – translate into electricity prices of USD 20/MWh, without any CAPEX or fixed OPEX (at 70% efficiency, lower heating value). To reach this targeted hydrogen production cost, electricity prices must therefore be sufficiently below USD 20/MWh to allow for additional CAPEX and OPEX costs.

In regions with good solar resources – and thus relatively high full-load hours for the electrolyser – solar PV can fall below this cost threshold. In fact, tenders for utility-scale solar PV in the Middle East in 2019 and 2020 secured bids of USD 14-17/MWh (though these prices are very market-specific and reflect favourable financing conditions).

Furthermore, technology improvements to boost electrolyser efficiency moderate how electricity costs affect hydrogen production costs. Efficiency improvements are not limited to the electrolyser itself; optimising components such as rectifiers and inverters for anticipated operation at part load (i.e. not nominal load) is vital if variable renewables are the main electricity source. The projected cost of hydrogen production after 2030 is therefore very uncertain and will depend on the impacts of scaling up, learning by doing and other technological progress.

Electrolysis

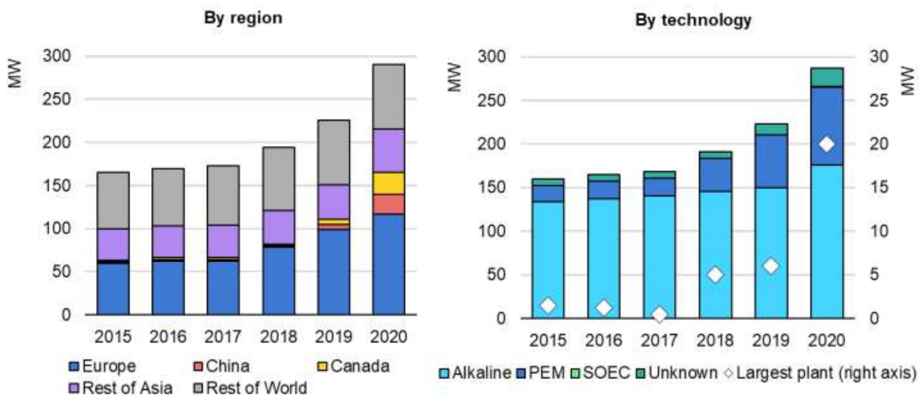
Electrolysis deployment is expanding quickly

Water electrolysis is an electrochemical process that uses electricity to split water (H_2O) into hydrogen (H_2) and oxygen (O_2). In 2020, this process accounted for ~0.03% of hydrogen production for energy and chemical feedstocks.[27] Of installed global electrolyser capacity of 290 MW, more than 40% is based in Europe with the next-largest capacity shares in Canada (9%) and China (8%).

Four main electrolyser technologies exist today: alkaline; proton exchange membrane (PEM); solid oxide electrolysis cells (SOECs); and anion exchange membranes (AEMs) (see Emerging Technologies below for more on SOECs and AEMs). Alkaline electrolysers dominate with 61% of installed capacity in 2020, while PEMs have a 31% share. The remaining capacity is of unspecified electrolyser technology and SOECs (installed capacity of 0.8 MW).

Used since the 1920s for hydrogen production in the fertiliser and chlorine industries, alkaline electrolysis is a mature commercial technology. The operating range of alkaline electrolysers covers a minimum load of 10% to full design capacity. As they do not require precious materials, capital costs are relatively low compared with other electrolyser technologies.

Global installed electrolysis capacity by region and technology, 2015-2020



Notes: PEM = proton exchange membrane; SOEC = solid oxide electrolysis cell.
Source: IEA (2021), Hydrogen Projects Database.

The area requirements of PEM electrolyser systems are relatively small, making them potentially more attractive than alkaline electrolysers in dense urban or industrial areas. Current materials for electrode catalysts (platinum, iridium), bipolar plates (titanium) and membrane materials are expensive, however, so overall costs for

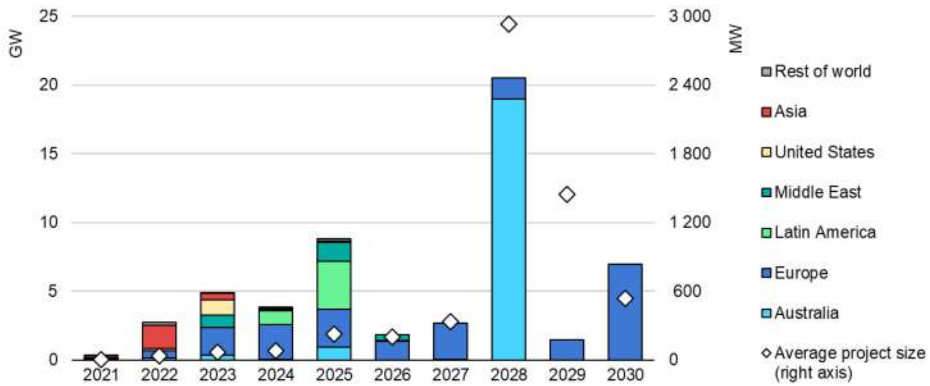
[27] If not otherwise specified, electrolysis refers to water electrolysis, i.e. excluding chlor-alkali electrolysis.

PEMs (USD 1 750/kW) are higher than for alkaline electrolysers (USD 1 000-1 400/kW). Additionally, PEM systems currently have a shorter lifespan.

By 2030, global installed electrolyser capacity could climb to 54 GW, given capacity under construction and planned. If all projects at the very early planning stages are counted, capacity could even reach 91 GW by 2030. Geographically, Europe and Australia lead with 22 GW[28] and 21 GW of projects under construction or planned, followed by Latin America (5 GW) and the Middle East (3 GW).

Many projects are linked to renewables as a dedicated electricity source, and around a dozen demonstration projects (combined electrolyser capacity of 250 MW) explore using nuclear power for hydrogen production (Canada, China, Russia, the United Kingdom and the United States). Not all these projects will be realised, however. So far, only 4 GW (7%) are linked to projects under construction or with a final investment decision, leaving 50 GW still at various earlier stages of development (e.g. at the front-end engineering design, feasibility study and concept phases).

New installed electrolyser capacity based on projects under construction or planned, 2021-2030



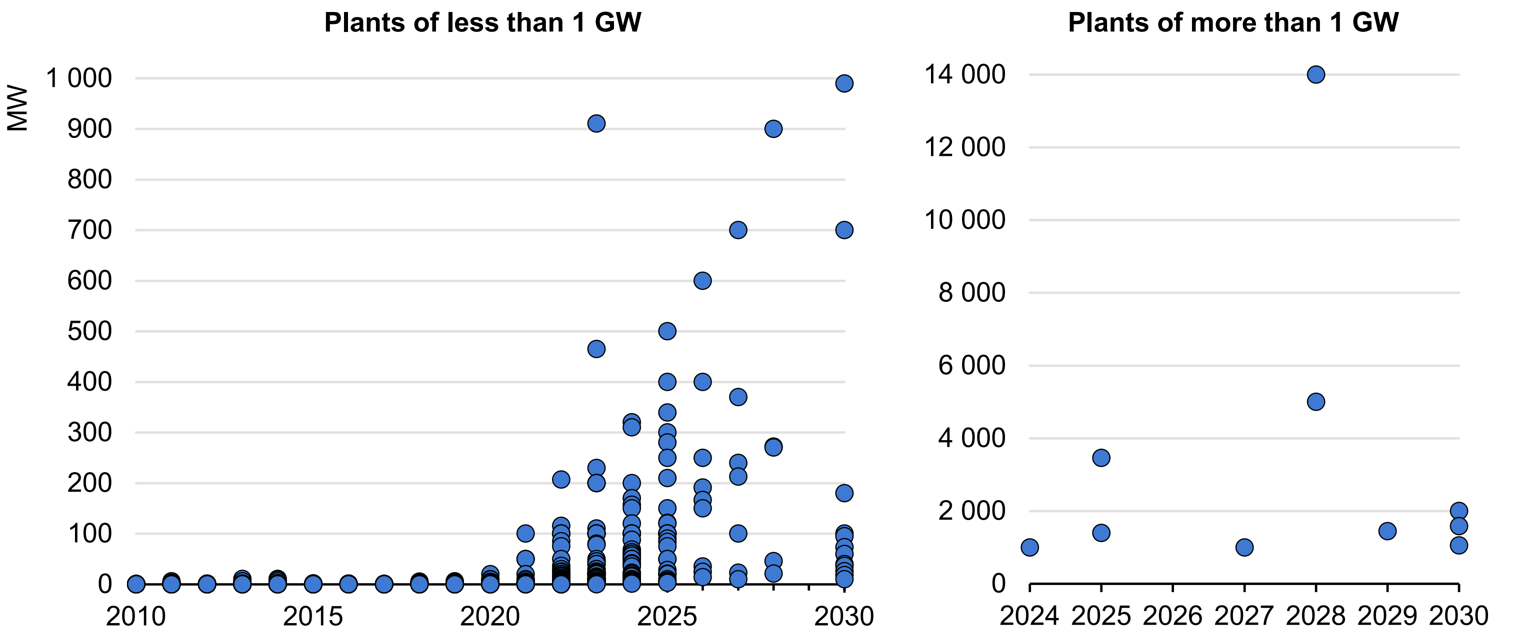
Notes: Based on ~350 projects under construction or planned. Only projects with a known start year of operation are considered.
Source: IEA (2021), Hydrogen Projects Database.

As global electrolyser capacity scales up, the average project size increases. Notably, the average of 0.6 MW in 2020 includes the largest alkaline electrolyser plant in operation (the 25-MW Industrial Cachimayo plant in Peru, which is connected to the electricity grid) and the largest PEM electrolyser plant in operation using dedicated renewables (20 MW using hydropower, inaugurated in 2020 by Air Liquide in Bécancour, Canada).

[28] For Europe, some projects with unknown completion dates (e.g. the 67-GW HyDeal project) are not included. If realised, they could push electrolyser capacity well beyond 23 GW by 2030.

Some 80 projects under construction or being planned have capacities of >100 MW, and 11 projects reach ≥1 GW. The planned Western Green Energy Hub (Australia) is in the GW scale: with a solar PV and wind capacity of up to 50 GW, it will produce 3.5 Mt H_2/yr for conversion into 20 Mt of ammonia for export. As the average project size increases to 230 MW by 2030, economies of scale and learning effects are expected to bring down electrolyser costs.

Size of electrolyser projects (existing, under construction and planned), 2010-2030



Note: Years refer to the planned start of operations; only projects with a known start year are considered.
Source: IEA (2021), Hydrogen Projects Database.

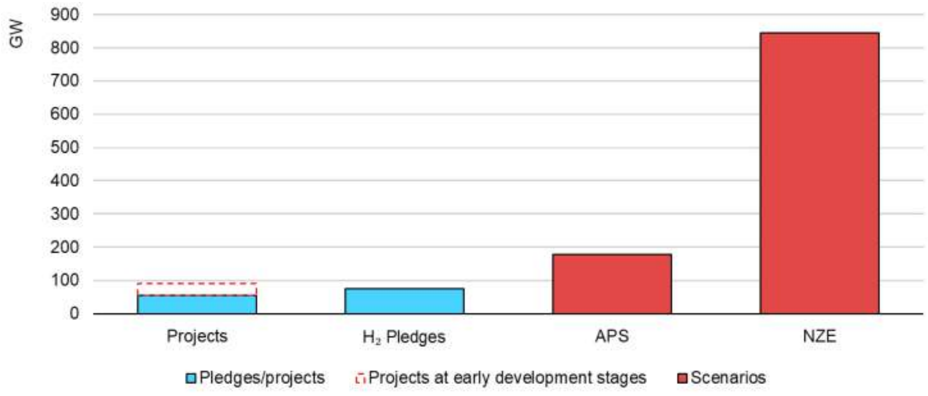
Deployment must accelerate further to meet climate targets

Several countries, as well as the European Union, include electrolyser capacity deployment goals in their hydrogen strategies. Together, these pledges could result in installed capacity of 75 GW by 2030, with the majority linked to the targets of the European Union (40 GW) and Chile (25 GW). However, planned projects do not necessarily match national or regional targets. In the EU case, only 22 GW are currently under construction or planned – barely half of the targeted 40 GW by 2030.

In the Announced Pledges Scenario, global installed electrolyser capacity increases to 180 GW by 2030, twice as much as national targets and three times the projects under construction and planned, and still 70% higher when including in the Projects case also projects at earlier development stages.

In the Net zero Emissions Scenario, capacity requirements in 2030 are 850 GW, some nine times the project pipeline when including projects at early development stages. Despite such significant gaps, current efforts are a good basis from which to expand and accelerate deployment, raising ambition as new projects are developed and more countries build hydrogen into their national strategies.

Electrolysis capacity in the Announced Pledges and Net zero Emissions scenarios in 2030 compared with the current project pipeline and government deployment pledges



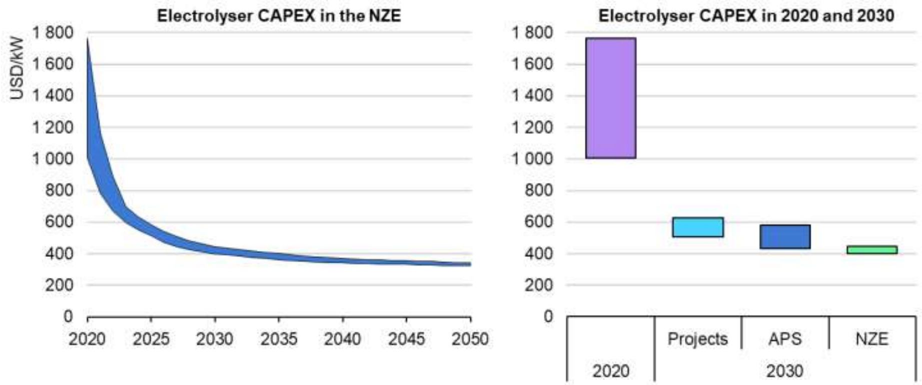
Greater electrolyser deployment will speed cost declines

Projections for hydrogen costs reflect the IEA cost database, recently updated with input from a range of industry participants under the Hydrogen Council and through collaborations with researchers in China. In 2020, costs fell within the range of USD 1 000-1 750/kW (including electric equipment, gas treatment, plant balancing, and engineering, procurement and construction [EPC]), with the lower cost applying to alkaline electrolysers produced in China and the upper representing PEM electrolysers.

The cost of alkaline electrolysers in China – USD 750-1 300/kW, with some sources reporting as low as USD 500/kW[29] – falls well below the average of USD 1 400/kW in the rest of the world. Although concerns over the reliability and durability of Chinese electrolysers have been raised in the past, manufacturing is improving quickly. As recently as a few years ago, Chinese manufacturers had to import several components, limiting their ability to reduce costs through industrial clustering and economies of scale. Local component manufacturing is expanding, however, so cost savings should be realised soon.

Learning effects in manufacturing and economies of scale will also drive down electrolyser costs. A component-wise learning-curve approach was used to analyse future electrolyser costs as a function of cumulative capacity deployment. Based on a literature review, a learning rate of 15% is assumed for the electrolyser stack, which also takes account of learning rates for fuel cells that rely on the same electrochemical processes.

Evolution of electrolyser capital costs under the Projects case, Announced Pledges and Net zero Emissions scenarios



Notes: APS = Announced Pledges Scenario. NZE = Met Zero Emissions Scenario.
Sources: Based on data from the Hydrogen Council.

[29] Based on CAPEX for the electrolyser system itself of USD 200/kW (China EV100, 2020; MOST, 2021). Including inverter and EPC the overall CAPEX increases to USD 500/kW.

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The cumulative capacity deployment of projects under construction and planned would reduce capital expenses by almost 60% by 2030. With capacity deployment in the Announced Pledges Scenario being almost triple the current project pipeline, costs may be 65% lower in 2030 than in 2020. This is not very different from the Net zero Emissions Scenario, for which larger capacity deployment could bring capital expenses down almost 70% from 2020, to USD 400-440/kW.

Shortfalls in electrolysis manufacturing capacity could impede deployment of all projects currently under development, which could derail long-term government climate ambitions (those reflected in the Announced Pledges Scenario) and the Net zero Emissions Scenario. Global electrolysis manufacturing capacity was ~3 GW/yr in 2020, with alkaline designs accounting for 85% and PEMs for less than 15%, plus some very small, artisanal manufacturing of SOECs and AEMs.

The largest shares of manufacturing capacity are in Europe (60%) and China (35%). Interest in the technology is growing among major companies such as Thyssenkrupp, Nel Hydrogen, ITM, McPhy, Cummins and John Cockerill, all of which have announced plans to expand their manufacturing capacities. If all announced expansions are realised, manufacturing capacity could reach ~20 GW/yr, with process automation or improved procurement driving down manufacturing costs.

A dedicated industrialised supply chain and a corresponding industrial supplier landscape will be essential to meet capacity demands to 2030 and beyond. If available soon, this manufacturing capacity could meet the deployment needs of the current pipeline of projects and government pledges (an average of 6-8 GW/y from 2022 to 2030) and approach Announced Pledges Scenario needs (20 GW/yr). But projections still show a shortfall in meeting Net zero Emissions requirements (>90 GW/yr).

Increased electrolyser production will affect demand for minerals, particularly nickel and platinum group metals (depending on the technology type). While alkaline electrolysis does not require precious metals, current designs use 800-1 000 t/MW of nickel. Even if alkaline electrolysis dominates the market by 2030, in the Net zero Emissions Scenario this would entail nickel demand of 72 Mt (which is actually much lower than the amount needed for batteries).

The catalysts in PEM electrolysers require 300 kg of platinum and 700 kg of iridium per GW. Therefore, if PEMs supplied all electrolyser production in 2030 in the Net zero Emissions Scenario, demand for iridium would skyrocket to 63 kt, nine times current global production. Experts believe, however, that demand for both iridium and platinum can be reduced by a factor of ten in the coming decade. Recycling PEM electrolyser cells can further reduce primary demand for these metals and should be a core element of cell design.

Meanwhile, SOEC production requires nickel (150-200 t/GW), zirconium (40 t/GW), lanthanum (20 t/GW) and yttrium (<5 t/GW). Better design in the next decade is expected to halve each of these quantities, with technical potential to drop nickel content to below 10 t/GW. Due to the higher electrical efficiency of SOECs, these mineral requirements are not directly comparable with alkaline and PEM electrolysers.

Low-cost electricity can boost electrolysed hydrogen production

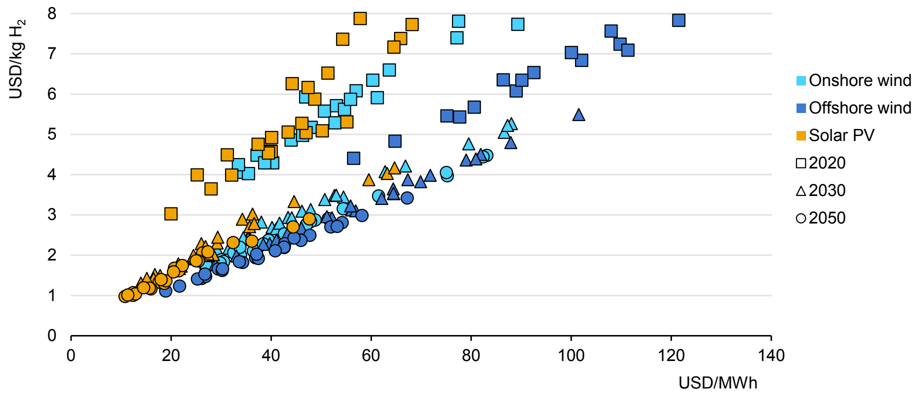
Of the various technical and economic factors that determine how much it costs to produce hydrogen from water electrolysis, the most pertinent are electricity costs, capital expenses, conversion efficiency and annual operating hours.

Electricity costs are the most important consideration, as they account for 50-90% of the overall levelised cost of hydrogen production. Using grid electricity is often rather expensive, with electricity prices of USD 50-100/MWh resulting in hydrogen production costs of USD 3.00-5.00/kg H_2 (at an electrolyser capacity factor of 90% and CAPEX of USD 500/kW).

With shares of variable renewables increasing, surplus grid electricity may be available at low cost to produce hydrogen and to store it for later use. Unfortunately, even if surplus electricity were available at zero cost for 750 hrs/yr, the hydrogen cost would remain at USD 3.00/kg H_2 (CAPEX of USD 500/kW). Running an electrolyser solely on surplus grid electricity therefore may not be an economical way to produce hydrogen and may fail to provide the volumes needed for some demand cases.

However, co-locating hydrogen production with dedicated electricity generation from renewables or nuclear power often avoids or minimises electricity transmission costs. Renewable electricity is thus the dominant source for hydrogen projects currently under construction or being planned.

Hydrogen production costs in the Net zero Emissions Scenario as a function of renewable electricity costs for solar PV and onshore and offshore wind, 2020, 2030 and 2050



Notes: Points represent electricity and hydrogen production costs for different regions around the world, taking local renewable resource conditions into account.
Sources: Based on data from the Hydrogen Council; IRENA (2020).

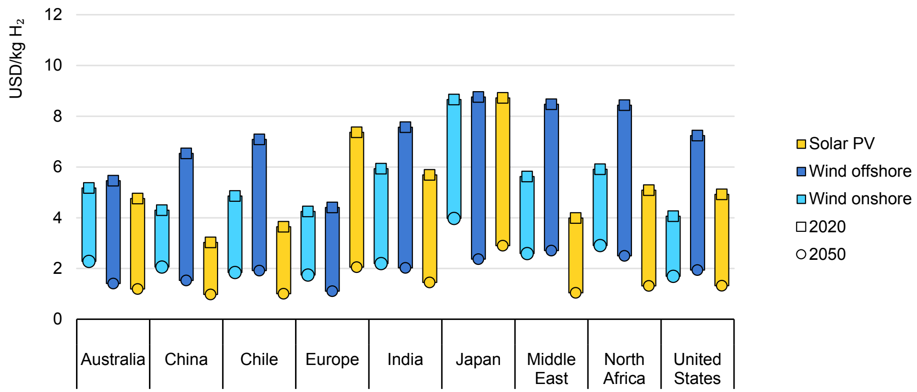
Solar PV has become one of the most affordable energy sources for electricity generation. In locations with excellent solar conditions (i.e. relatively high capacity factors such as the Middle East), solar PV generation costs can be USD 20/MWh or lower, corresponding to hydrogen production costs of USD 3.00/kg H_2 (at an electrolyser capacity factor of 32% and CAPEX of USD 1 000/kW).

With solar PV and electrolyser costs declining in the Net zero Emissions Scenario, hydrogen produced from solar PV in the Middle East at USD 17/MWh could cost less than USD 1.50/kg H_2 in 2030 (at a CAPEX of USD 320/kW), a level comparable to production from natural gas with CCUS. By 2050, with a solar PV cost of USD 12/MWh, hydrogen costs could fall to USD 1.00/kg H_2 (CAPEX of USD 250/kW), making hydrogen from solar PV cost-competitive with natural gas even without CCUS.

Several projects in Europe target offshore wind as an electricity source for hydrogen production. In fact, producing hydrogen offshore and transporting it to shore by pipeline is an alternative to the rather expensive use of electricity cables. Several current and planned pilot and demonstration projects (e.g. the Oyster project in Denmark) are therefore exploring this approach, and the Dutch NorthH$_2$ project aims to reach 4 GW of offshore electrolysis by 2030 while Germany's AquaVentus targets 10 GW by 2035.

Opportunities exist to further reduce costs by repurposing oil and gas assets, for instance by using platforms for electrolyser installations or oil and gas pipelines for hydrogen transport. There are still some uncertainties, however, about the suitability of using certain oil and gas assets for these purposes and the challenges of simultaneously phasing out oil and gas activities while ramping up electrolysis.

Levelised cost of hydrogen production from renewables by technology and region in the Net zero Emissions Scenario, 2020 and 2050



Notes: Higher values of the ranges correspond to 2020, lower values to 2050.
Sources: Based on data from the Hydrogen Council; IRENA (2020).

At USD 60/MWh, electricity generation from offshore wind was relatively costly in 2020, resulting in hydrogen costs of USD 4.50/kg H_2 (at a 50% capacity factor). With declining costs for offshore electricity generation (USD 30/MWh) and larger turbines resulting in higher capacity factors (57%), hydrogen production costs in the North Sea in the Net zero Emissions Scenario could fall to USD 2.00/kg H_2 by 2030 and to below USD 1.50/kg H_2 by 2050 (based on electricity costing USD 25/MWh and a capacity factor of 60%).

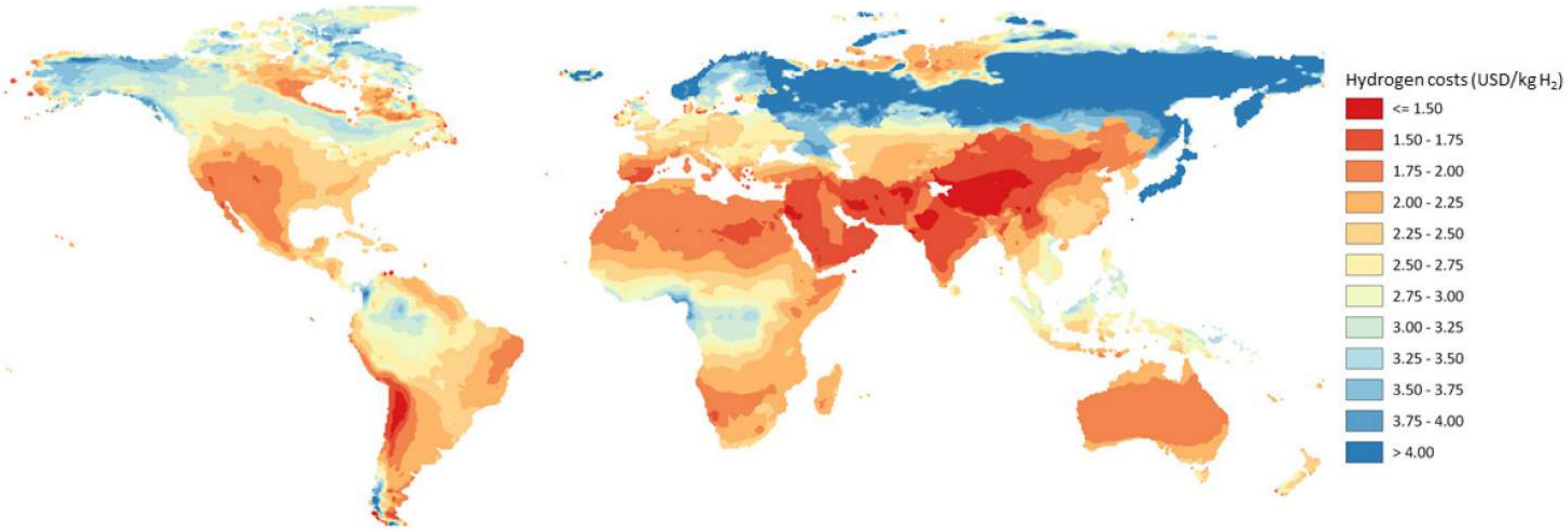
While production costs using offshore wind in Europe remain higher than for solar PV in the Middle East or North Africa, accounting for hydrogen transport costs could make sourcing domestic supplies from offshore wind a more economically feasible option for some parts of Europe.

However, considering solely the levelised cost ignores three other important factors: the number of hours the electrolyser operates; the volume of hydrogen produced throughout the year; and costs that may arise from needing to smooth out renewable hydrogen supply fluctuations (daily or seasonal). While electrolysers can operate quite flexibly to accommodate the variability of renewable electricity supplies, downstream hydrogen users (whether consuming it directly or converting it into other fuels and feedstocks) generally require supply stability. In such cases, hydrogen storage is likely needed to ensure supply constancy.

For the production of hydrogen-based fuels, however, it may be more economical – despite higher hydrogen production costs and fewer full-load hours – to choose a renewable electricity supply with variability patterns that requires less storage, e.g. solar PV (which typically requires daily storage) over wind power (which often requires capacity for several days or weeks of storage). Combining renewable resources in a hybrid plant (e.g. solar PV and onshore wind) may be a cost-effective way to stabilise the hydrogen supply and achieve higher full-load hours, minimising the volume of hydrogen storage needed.

Hydrogen from electrolysis can compete with hydrogen from gas in several regions in the long term

Hydrogen production cost from hybrid solar PV and wind systems in 2030



Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. For each location, production were derived by optimising the mix of solar PV, onshore wind and electrolyser capacities, resulting in the lowest costs and including the option to curtail electricity generation.

Sources: Based on hourly wind data from Copernicus Climate Change Service and hourly solar data from Renewables.ninja.

Fossil fuels with carbon capture

Hydrogen production from fossil fuels, and current CCUS status and adoption

Hydrogen produced from natural gas using reforming processes and from coal using gasification are well-established technologies. As noted earlier, these methods dominate hydrogen production and are the sector's primary source of CO_2 emissions.

CCUS is important in the production of low-carbon hydrogen from fossil fuels for two reasons. First, it can reduce emissions from existing hydrogen plants in the refining and chemical sectors, which account for 2.5% of global emissions; and second, it is a low-cost option to scale up production for new hydrogen demand in countries where the conditions are conducive.

CCUS refers to a suite of diverse technologies expected to be important in helping countries meet their energy and climate goals. In its first stage, CCUS involves the capture of CO_2 from large point sources (including power generation or industrial facilities that use fossil fuels or biomass for fuel) or directly from the atmosphere.

Many opportunities exist to use CO_2 captured through CCUS technologies. Urea synthesis with CO_2 captured at ammonia plants (>130 $MtCO_2$/yr in 2020) is currently the only large-scale application, but its anticipated future uses include cement and synthetic fuel production.

Storage refers the practice of injecting captured CO_2 into deep geological formations (typically depleted oil and gas reservoirs or saline formations) where it will be permanently absorbed into the rock. If not being used at the capture site, CO_2 can be compressed and transported to other facilities by pipeline, ship, rail or truck – for either use or storage.

Current large-scale CO_2 capture capacity for injection into geological formations (for dedicated storage and use in enhanced oil recovery) is in the order of 40 $MtCO_2$/yr. Around two-thirds of this capacity is in natural gas processing facilities, with the remainder distributed in roughly equal shares in power generation, synthetic fuel, ammonia and hydrogen applications, with smaller quantities captured from bioethanol and steel production.

In natural gas-based hydrogen production, steam methane reforming (SMR), the leading production route, creates direct CO_2 emissions of 9 kg CO_2/kg H_2 while upstream methane emissions from natural gas production and transport can add another 1.9-5.2 kg CO2eq/kg H2 (global average of 2.7 kg CO2eq/kg H2), reflecting regional variations. Efforts need to be taken to address them. Technologies to reduce upstream methane emissions are already available and are often cost-effective without additional support.

Among direct emissions of the SMR process, 30-40% arise from using natural gas as the fuel to produce steam and heat, giving rise to a "diluted" CO_2 stream. The rest of the natural gas used in this process is split (with the help of the steam) into hydrogen and more concentrated "process" CO_2. While capturing CO_2 from the concentrated process stream can reduce overall emissions by 60%, capturing the more diluted gas stream can boost overall emissions reductions to 90% or higher. The cost of capturing both combined is USD 50-70/t CO_2.

Autothermal reforming (ATR) is an alternative technology in which the process itself produces the required heat. This means that all related CO_2 is produced inside the reactor, resulting in a more concentrated flue gas stream that, when compared with the SMR process, allows for higher CO_2 capture rates (95% or higher) or for the same capture rate at lower capture costs.

ATR uses oxygen instead of steam, which requires electricity (rather than methane) as its fuel input. A large share of global ammonia and methanol production already uses ATR technology, though without CCUS. Two projects in the United Kingdom – HyNet and H2H Saltend – plan to combine ATR with CCUS.

Partial oxidation (POx) is a technology option that supports hydrogen production from gaseous or liquid fuels. The process does not require a catalyst (unlike ATR) and can accept feedstock impurities. POx uses oxygen (similar to ATR), requiring electricity as the energy input. Traditionally, the process has been deployed where it is possible to use low-value waste products or heavy feedstocks to produce hydrogen or syngas (e.g. in refineries).

The technology is available at commercial scale but has been modified only recently with the express aim of producing hydrogen from natural gas with CCUS. Several projects based on POx are under development and show CO_2 capture rates of up to 100%. A POx hydrogen plant at a Dutch refinery (using oil residues) that has been operating since 1997 began capturing CO_2 in 2005 for use in greenhouses (at a rate of 0.4 $MtCO_2$/yr, not fully utilising the installed capture capacity of 1 Mt CO_2/yr, which may be exploited by the Porthos project).

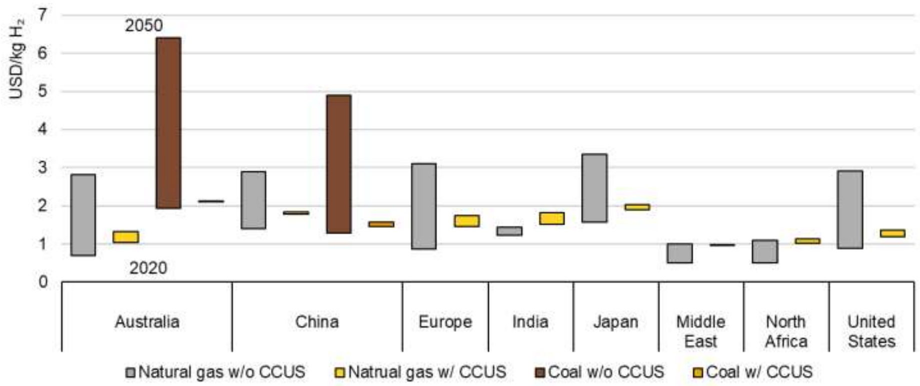
Meanwhile, coal gasification is a mature technology used mainly in the chemical industry to produce ammonia, particularly in China. At 20 t CO_2/t H_2, unabated hydrogen production from coal is very emissions-intensive. Though some technical challenges remain to be overcome, coal gasification can be combined with CCUS. However, since gas separation technologies focus on either hydrogen or CO_2 removal, few can produce both high-purity hydrogen and CO_2 pure enough for other uses or storage.

The choice and design of capture technology therefore depends on the hydrogen end-use and production costs. With the aim of producing hydrogen for export to Japan, the planned Hydrogen Energy Supply Chain project (Australia) seeks to produce it from brown coal using gasification, with CO_2 being transported and stored via the CarbonNet project.

Sixteen projects are currently generating hydrogen from fossil fuels with CCUS; with annual combined production of just over 0.7 Mt H_2, they also capture close to 10 Mt CO_2. Ten are commercial-scale plants with CO_2 capture capacity above 0.4 Mt CO_2/yr: four are at oil refineries and three are at fertiliser plants.[30] Notably, six are retrofits of existing sites, with scales ranging from <100 MW_{H2} to >1 GW_{H2}, with 1 GW_{H2} corresponding to annual production of 0.25 Mt H_2. Planned projects reach a capacity of up to 20 GW_{H2}.

In regions with low-cost domestic coal and natural gas, where CO_2 storage is available – e.g. the Middle East, North Africa, Russia and the United States – the use of fossil fuels with CCUS is currently the most affordable option to produce low-carbon hydrogen and ammonia. Depending on local gas prices, costs for producing hydrogen from natural gas with CCUS were in the range of USD 1.00-2.00/kg H_2 in 2020 – about USD 0.50/kg H_2 higher than for natural gas without CCUS, due to CO_2 capture, transport and storage costs. As the CO_2 price penalty on uncaptured CO_2 emissions (5-10%) rises over time, production costs from fossil fuels with CCUS will increase slightly.

Levelised hydrogen production costs from natural gas and coal by region in 2020 and in the Net zero Emissions Scenario in 2050



Notes: The lower values of the ranges correspond to 2020, higher values to 2050.
Sources: Based on data from the Hydrogen Council; IEA GHG (2014); IEA GHG (2017); E4Tech (2015); Kawasaki Heavy Industries; and Element Energy (2018).

[30] These include facilities that produce pure hydrogen and capture CO_2 for geological storage or sale. CO_2 captured from ammonia plants for use in urea manufacturing is excluded.

Hydrogen production from fossil fuels with CCUS is gaining momentum

Projects for producing hydrogen from fossil fuels with CCUS, operational or under development

Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Mature projects are projects under construction or for which a final investment decision has been taken.

Source: IEA (2021), Hydrogen Projects Database.

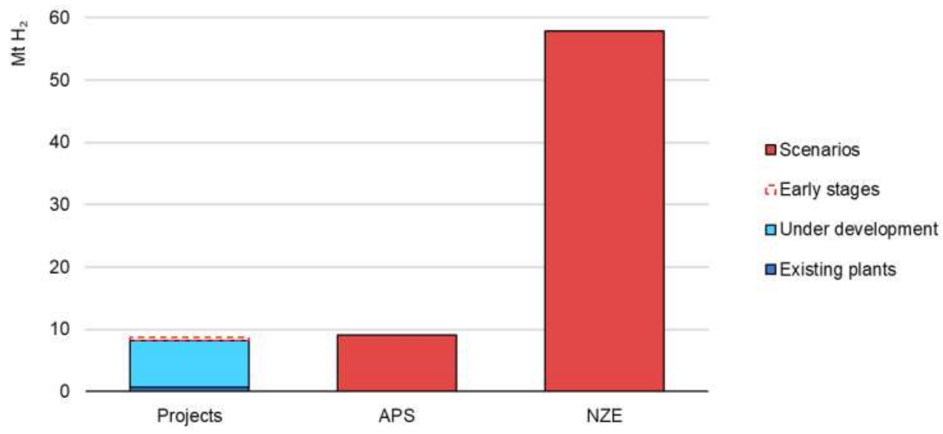
Outlook for hydrogen production with CCUS

Globally, 47 projects for producing hydrogen with CCUS are under development, with a total of four currently under construction in China and the United States. Of these, 41 rely on natural gas with CCUS, four are linked to coal and one to oil. Geographically, Europe hosts 23 projects (largely in the Netherlands and the United Kingdom), while North America hosts 4 and China has 2.

Based on planned projects and existing plants, global hydrogen production from fossil fuels with CCUS could reach 9 Mt by 2030. While several national strategies and roadmaps consider this a low-carbon hydrogen production option, almost none define deployment targets for hydrogen with CCUS, in contrast to electrolysis. Exceptions are the United Kingdom, with a technology-neutral target of domestic low-carbon production capacity of 5 GW_{H2} by 2030, and the low-carbon supply targets of Japan (420 kt H_2) and the Czech Republic (10 kt H_2). Assuming these targets were fulfilled solely by hydrogen production with CCUS, it would correspond to 1.7 Mt H_2 annually.

Estimated production of 9 Mt H_2 in 2030 from planned and existing plants aligns with the Announced Pledges Scenario. The jump to 58 Mt H_2 from fossil fuels with CCUS in the Net zero Emissions Scenario is around seven times the project pipeline, implying that – by 2030 – some 230 hydrogen plants with capacity of 1 GW_{H2} need to be newly built or retrofitted with CCUS. While this number may seem huge, it corresponds to roughly 80% of current unabated production capacity from fossil fuels.

Hydrogen production from fossil fuels with CCUS in the Announced Pledges and Net zero Emissions scenarios, compared with the project pipeline and government pledges, 2030



Source: IEA (2021), Hydrogen Projects Database.

Industrial ports – where a large share of unabated fossil hydrogen production plants for refining and the petrochemical industry is located – could become hubs for scaling up hydrogen production. In addition to offering offshore storage potential, they could share CO_2 transport and storage infrastructure across different industries, benefitting from economies of scale that could reduce investment risks. Active examples are the Port of Rotterdam (Porthos) project