- **Hybrid heat pumps** combine a boiler with an electric heat pump. The boiler operates only when the heat pump cannot meet heating demand. Hybrid heat pumps are an interesting option in cold climates where hydrogen can be used to cover peak demand during very cold periods, but they have additional capital costs and require both electricity and hydrogen connections.
- **Gas-driven heat pumps** have a gas engine that produces electricity to run a heat pump. Thousands of units are already operating in Asia and Europe, primarily in non-residential buildings.

Status of hydrogen and fuel cells for buildings

In 2020, hydrogen's share in heating energy demand was extremely limited (at less than 0.005%) even though countries began supporting demonstration projects and programmes to deploy hydrogen-compatible technologies, spark market adoption and reduce upfront consumer costs as early as the 2000s. Largely focused on stationary fuel cells, these programmes have tended to rely on natural gas, but their lessons are applicable to the use of pure hydrogen. These projects are sited in countries that together cover ~40% of global heat demand, with significant heating seasonality and where natural gas covers a large share of heat production in buildings.

Stationary fuel cells

Deployment of micro-cogeneration stationary fuels cells (<1 kW of electrical output [kW_e] for residential applications, and up to 50 kW_e) has been greatest in Japan (more than 350 000 units operating) and Europe, especially in Germany (15 000), Belgium and France. Korea has 15.7 MW_e (units of <100 kW_e) installed in buildings (CEM H2I surveys), while US installations are primarily industrial-scale units (>100 kW_e).

Fuel cells have been deployed in almost all building types – from residential to commercial/public building applications, including military installations, hospitals and data centres – to provide primary or backup power, or co-generation. Most run on natural gas. Fuel cells for residential applications are mostly PEM and tend to be relatively small (0.7-1.5 kW_e but also up to 5 kW_e), with several governments offering financial incentives to support their deployment.

Homeowners in the United States can qualify for federal tax credits (>USD 3 300/kW_e) when installing residential units of >0.5 kW_e. Other government schemes offer subsidies for fuel cell technologies, such as New Jersey's Clean Energy Program for micro-cogeneration technologies. Korea is among the countries using renewable energy certificates and subsidies. Support generally covers the upfront costs of installation, or rewards power generation rather than heat production.

Hydrogen blending and pure hydrogen applications

There are a number of projects around the world at various stages for exploring the impact of hydrogen blending in existing gas networks. Frontrunner, launched in 2007 on the Dutch island of Ameland, tested injection volumes of up to 20% for heating and cooking using standard appliances. More recently in France (June 2018 to March 2021), the GRHYD project tested injection (max. 20%) for >100 dwellings, while the three-phase UK HyDeploy project aims to prove the safety of blending up to 20%. The first phase, concluded in 2021, involved a live demonstration in the Keele gas network to assess what level of blending is safe with existing domestic appliances.

Other initiatives aiming to demonstrate hydrogen use in dedicated networks in a few hundred dwellings are now under development, particularly in north-western Europe. These include H100 Fife (300 households starting in 2022) in the United Kingdom and Hoogeveen and Stad aan 't Haringvliet (600 households from 2025) in the Netherlands. Larger projects, such as the United Kingdom's H21, are at early stages of development.

The UK government also supports the Hy4Heat project to assess the technical, economic and safety aspects of replacing natural gas with hydrogen in residential and commercial buildings and in gas applications. Under this programme, a Worcester Bosch 100% hydrogen-ready prototype boiler – which can be converted to run on hydrogen by modifying just two or three components – won Best Heating Innovation in the 2021 Green Home Awards.

In a first trial in single-family, semi-detached and terraced houses, the project found that 100% hydrogen use is as safe as natural gas for heating and cooking. More research is needed to assess safety in multi-family homes and houses with limited natural ventilation, and to determine the safety of supplying homes through gas networks. The project is also assessing the first home (in Low Thornley, Gateshead) to be entirely fuelled by hydrogen, from boilers to cookers.

The WaterstofWijk Wagenborgen project (in the Netherlands) is a pilot that will connect 1970s buildings to a hydrogen network. Wagerborgen hybrid heat pumps will be installed in each house, running as much as possible on electricity and switching to hydrogen during cold periods only; houses will also be equipped with solar panels and induction cooking.

Natural gas use in the buildings sector and selected key projects, initiatives, programmes, announcements for deploying hydrogen or hydrogen-compatible equipment by country or region, 2020

Region	Share of global heating consumption (%)	Share of water heating in heating consumption (%)	Share of natural gas in:		Initiative details
			Heating (%)	Cooking (%)	
United States	17	19	64	60	New Jersey's Clean Energy Program provides financial incentives for co-generation and fuel cell installations.
United Kingdom	2.5	21	70	50	HyDeploy for hydrogen blending applications. H21 Leeds City Gate and H21 Network innovation for 100% hydrogen application. Hy4Heat project.
Korea	1.5	22	48	63	Announced intentions to create three hydrogen power cities by 2022, in line with hydrogen roadmap goal of providing households and other buildings 2.1 GW of power from fuel cells.
European Union	15	20	40	32	Ene.field project, Europe-wide field trials for residential fuel cells, concluded in 2017.
					PACE (Pathway to a Competitive European Fuel Cell micro-Cogeneration Market), ends in 2021. ComSos, (Commercial-scale SOFC systems), ends in 2022. National innovation Programme for hydrogen and fuel cell technology (Germany), 2007-16. KfW433 (Germany), dedicated fuel cell programme since 2016;
					overall impact: >15 000 fuel cells deployed in EU.
					GRHYD (France): power-to-gas testing with hydrogen blending rates of up to 20% per volume, 2018-21. WaterstofWijk Wagenborgen planned project (Netherlands): demonstration project for hybrid heat pumps for 40 residents.
Japan	3	35	32	39	Ene.Farm project, >350 000 commercial fuel cells deployed.

Notes: Listed projects include concluded as well as ongoing and announced initiatives related to buildings. Heating consumption includes space and water heating.

Regional insights on hydrogen in buildings

Japan

With more than 350 000 units installed as of March 2021, Japan leads global deployment of micro-cogeneration fuel cells in buildings. The ENE-FARM programme is the main contributor to uptake, recently reporting sales of 40 000 units/yr. Models on the market are mostly fuelled by natural gas; most are PEMFC units, but SOFCs have also emerged recently. ENE-FARM subsidies were eliminated in FY2019 for PEMFCs as they reached maturity, but SOFCs remained eligible for subsidies until FY2020 (March 2021).

In 2020, to support the next phase of subsidiary projects and show that fuel cells can be a source for Japan's electricity market, 300 kW of domestic fuel cells were successfully tested to generate electricity at prices similar to those of the electricity retailer. Decarbonising buildings will require a fuel shift for fuel cells, from natural gas to low-carbon gases (such as hydrogen or synthetic methane produced with CO_2 from sustainable sources). Already Panasonic is deploying pure hydrogen fuel cell generators to power streetlights and air conditioning units at the HARUMI FLAG residential complex in Tokyo.

In both the Announced Pledges and Net zero Emissions scenarios, fuel cells in the Japanese market operating on pure hydrogen reach ~1 million installed units by 2030, requiring the development of hydrogen infrastructure.

Korea

The Korean Ministry of Trade, Industry and Energy is currently subsidising fuel cells (as well as solar power and heat, and geothermal and wind energy) to power residential and commercial buildings, with subsidies covering up to 80% of equipment installation costs. As further incentive, the government reduced the price of grid gas used in fuel cells by 6.5% from typical consumer prices, both in buildings and at utility scale.

Total installed stationary fuel cell capacity within buildings was 15.7 MW_e in 2021 according to CEM H2I surveys, largely PEMFC units with capacities ranging from 600 W to 10 kW for residential and commercial buildings. Doosan and S-FuelCell dominate the market, and market attention is shifting towards SOFC units and the use of fuel cells (equivalent to battery power) to boost flexibility in the electricity grid. The Hydrogen Economy Roadmap of Korea targets the cumulative installation of at least 2.1 GW_e of stationary fuel cells by 2040.

Europe

Several European countries are testing fuel cell applications and exploring the technical feasibility of hydrogen blending or pure hydrogen for buildings sector applications. Demonstration projects are ongoing to verify the technology and gain the technical experience necessary to build a regulatory framework.

To date, stationary fuel cell deployment for buildings has been concentrated primarily in domestic units (commercial and industrial systems are less common). The market for fuel cells for residential applications has been supported mainly by projects co-funded by the FCH JU and the European Union, and by the German KfW 433 programme, which aims to enable manufacturers to eventually industrialise this technology.

The ene.field project (concluded in 2017) deployed >1 000 small fuel cell applications (~1.15 MW_e operating on natural gas) in ten countries, in different climates and dwelling types. The subsequent PACE (Pathway to a Competitive European Fuel Cell micro-Cogeneration Market) project aims to deploy >2 800 fuels cells by 2021. In the framework of this project, nearly 740 units were installed in Belgium and more than 710 in Germany.

Commercial-scale units (10-60 kW) are currently being demonstrated through the EU-funded ComSos project, which focuses solely on SOFC units and aims to install 25 in non-residential buildings such as supermarkets.

Germany

With >15 000 units operating, Germany has been the most successful market for stationary fuel cell installations in Europe, according to CEM H2I. Of the >1 000 units demonstrated by the Ene.field project, >750 were installed in Germany.

Fuel cell ramp-up was spurred by Germany's KfW 433 programme, launched in 2016 by the Federal Ministry for Economics and Energy and still ongoing. The programme provides a combination of grants and output-related subsidies of up to USD 3 400 for units with a capacity of 250 W to 5 KW_e, in both new and existing residential and non-residential buildings.

The Netherlands

Although the Netherlands has traditionally relied heavily on natural gas for residential heat, in 2018 the Gas Act was amended to ban gas connections for new homes and buildings. Subsequently, the Natural Gas-Free Districts Programme was implemented to help the country become natural gas-free by 2050. Forty-six municipalities are currently participating as test sites and to map how the transition can be scaled up, with a total of 1.5 million homes to shift from natural gas to low-carbon heating by 2030.

The Netherlands' Government Strategy on Hydrogen and Green Gas Roadmap aim to accelerate large-scale production and use of low-carbon hydrogen and biogas, with the government supporting pilot projects to demonstrate hydrogen. Meanwhile, the Green Deal H2 Neighbourhoods project aims to improve understanding of the techno-economic, safety, social, legal and administrative aspects of using existing gas infrastructure for hydrogen distribution.

Pilot projects in Hoogeven (100 new buildings and 427 existing households converted to run on hydrogen for heating) and Stad aan 't Haringvliet (600 existing buildings disconnected from natural gas by 2025) will help identify barriers and operational needs to scale up hydrogen use in buildings.

United Kingdom

Driving low-carbon hydrogen growth is part of the UK government's Ten Point Plan for a Green Industrial Revolution. To support the buildings sector, it proposes a timescale to have hydrogen heating trials in a neighbourhood by 2023 and to launch larger village trials by 2025, which could lead to a hydrogen town by the end of the decade. Completion of testing to support up to 20% hydrogen injection in the gas network for all homes by 2023 is among the project's target milestones.

In addition to the Hy4Heat and H21 projects (see above), the H100 Fife project (Scotland) intends to deliver an end-to-end 100% hydrogen demonstration using the gas network, to prove its technical viability. Initially, some 300 domestic properties are targeted to be connected and operational for 4.5 years (i.e. until 2027), with each provided with boilers, cookers and hobs.

Another demonstration, the BIG HIT project (Building Innovative Green Hydrogen Systems in Isolated Territories, 2016-2022), is under way in the Orkney Islands (Scotland). Hydrogen produced from local curtailed renewable energy generation on smaller islands is transported to Orkney, where it is used to demonstrate several end-use applications, including heating in buildings. The project is funded by the FCH JU and involves 12 partners from the United Kingdom, Italy, France, Denmark, Spain and Malta.

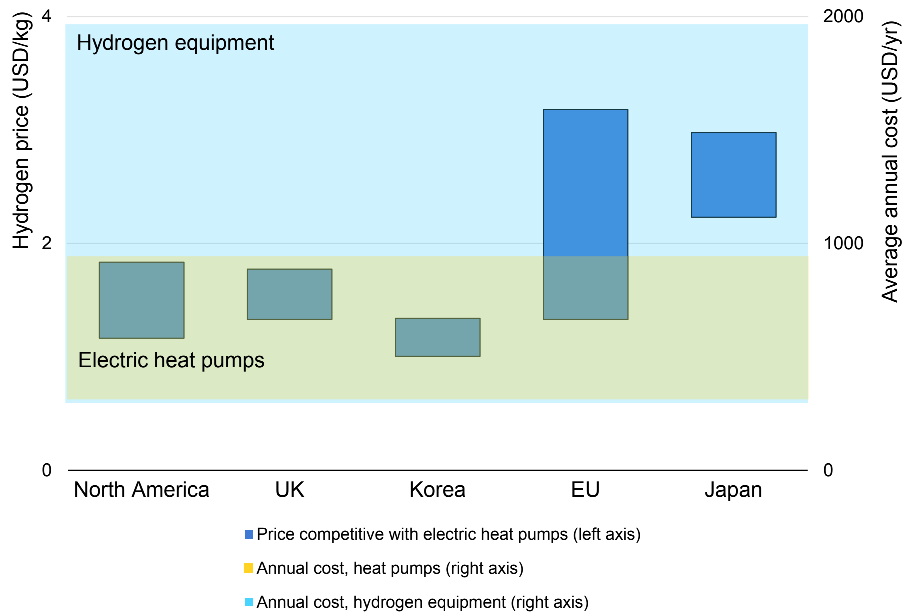
Outlook for hydrogen in building applications

At present, the main markets for fuel cell deployment in buildings are Japan, Europe and Korea, the last having a target of 2.1 GW_e installed by 2040 and focusing mostly on fuel cells for power applications. In these markets, fuel cell deployment is not focused explicitly on hydrogen but more broadly on scaling up and reducing the capital costs of these systems.

Hydrogen uptake in buildings will depend on many factors, including equipment, infrastructure and hydrogen production costs. Competition among direct electrification, hydrogen and district heating affects other factors such as the retrofit potential of buildings; building footprints and heat demand densities; hydrogen and electricity prices in relation to equipment costs; consumer preferences; the potential to supply hydrogen; and requirements for renewable capacity. The flexibility and demand-response potential that hydrogen could provide to energy systems are also key considerations.

In the Announced Pledges Scenario, in major markets hydrogen would need to be priced at USD 0.9-3.5/kg in 2030 to compete with electric heat pumps in buildings. Assuming these price ranges and considering the capital costs of equipment and of using hydrogen equipment in existing buildings, the cost to heat a home of 100 m^2 could range from USD 350/yr to USD 2 000/yr in those markets. This range is broader than for electric heat pumps due to the large efficiency gap: for the same heat output, electric heat pumps require five to six times less electricity than a hydrogen boiler.

Potential spread of competitive hydrogen prices and annual cost per household of running heating equipment in selected regions in the Announced Pledges Scenario, 2030



Note: Techno-economic assumptions available in the Annex.

Demonstration projects over the next decade will be vital to define cost uncertainties and better understand the implications of using hydrogen in buildings, ultimately helping to shape solutions for the direct use of pure hydrogen. Testing in dense urban centres will be needed to understand potential barriers, overcome operational constraints, address consumer safety concerns and train operators.

In the Announced Pledges Scenario, heating demand in 2030 is 20% lower than in 2020 thanks to better building envelopes and enhanced equipment efficiency. In parallel, hydrogen demand grows to more than 2 Mt H_2 (around 0.5% of global heat demand) but remains limited as planned actions are not strong enough to accelerate blending in gas networks.

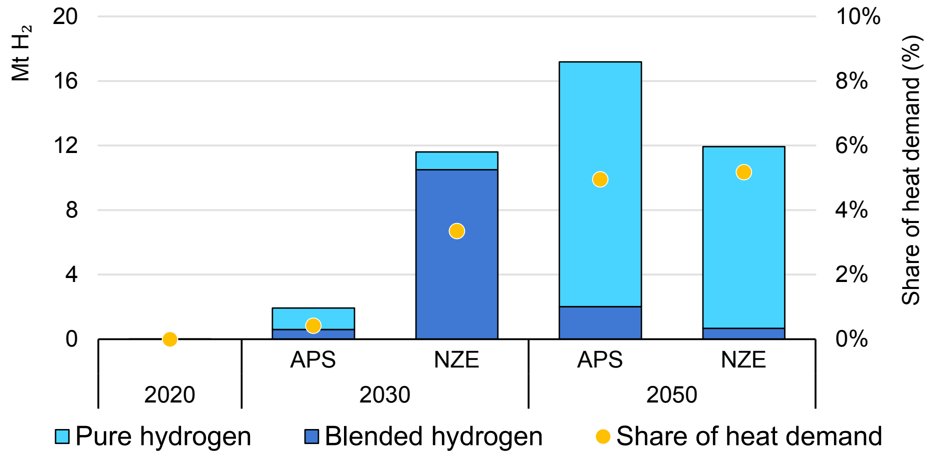
With pure hydrogen applications making inroads post-2030, this share jumps to 5% by 2050. Almost all installations are in existing buildings and are largely aligned with retrofits to ensure that replacing conventional fossil fuel-fired equipment with heat-driven units has minimal impact on building structure and heating distribution systems.

Hydrogen blending rates ramp up much more rapidly by 2050 in the Net zero Emissions than in the Announced Pledges Scenario. Due to its limited decarbonisation potential, blended hydrogen volumes in gas networks decrease after 2030 at the same time as most gas furnaces and boilers are phased out.

In 2050, pure hydrogen makes up 95% of hydrogen demand in buildings – in absolute value lower than in the Announced Pledges Scenario – as larger economies of scale, higher efficiency rates and more developed electricity demand management options are deployed.

In the Net zero Emissions Scenario, hydrogen accounts for 3.5% of final energy use for heating in 2030. Due to its lower efficiency, however, hydrogen meets slightly more than 5% of global heating needs in 2050.

Hydrogen use in buildings and shares of heat demand in the Announced Pledges and Net zero Emissions scenarios, 2020-2050



Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario.

Electricity generation

Greater hydrogen penetration can help expand renewable electricity generation

Current uses of hydrogen in the power sector

Hydrogen use in power generation is negligible at present. It accounts for less than 0.2% of the electricity supply, linked mostly to the use of mixed gases with high hydrogen content from the steel industry, petrochemical plants and refineries, and to the use of by-product pure hydrogen from the chlorine-alkali industry.[24]

Hydrogen can be used as fuel in reciprocating gas engines and gas turbines. Today's reciprocating gas engines can handle gases with a hydrogen content of up to 70% (on a volumetric basis), and various manufacturers have demonstrated engines using 100% hydrogen that should be commercially available in upcoming years.

Gas turbines can also run on hydrogen-rich gases. In Korea, a 45-MW gas turbine at a refinery has been operating on gases of up to 95% hydrogen for 20 years. Manufacturers are therefore confident of delivering standard gas turbines that can run on pure hydrogen by 2030.

A key consideration, however, is that as hydrogen generates a higher combustion temperature than natural gas, its use in gas turbines can drive up NOx emissions, requiring a larger or more efficient selective catalytic reduction (SCR) system to avoid them. Dry, low-emission combustion systems are an alternative to minimise NOx emissions from hydrogen in gas turbines, and systems with up to 50% hydrogen blends have been demonstrated.

Fuel cells can convert hydrogen into electricity and heat, producing water but no direct emissions. Fuel cell systems can achieve high electrical efficiencies (over 60%) and can maintain high efficiency even operating at part load, making them particularly attractive for flexible operations such as load balancing.

The main fuel cell technologies for electricity and heat generation are:

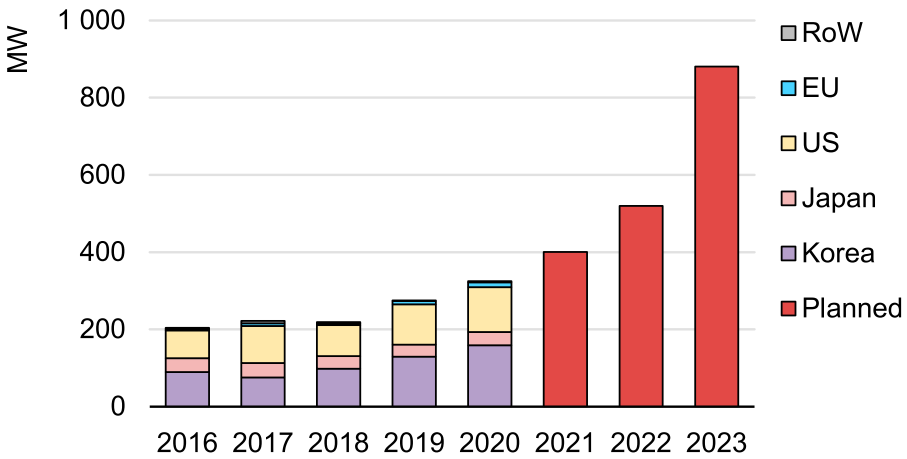
- **Polymer electrolyte membrane fuel cells (PEMFCs),** which operate at low temperatures and are used as micro-cogeneration units.
- **Phosphoric acid fuel cells (PAFCs),** used as stationary power generators with outputs in the range of 100-400 kW.
- **Molten carbonate fuel cells (MCFCs)** and **solid oxide fuel cells (SOFCs**), which operate at higher temperatures (600°C and 800-1 000°C, respectively) and can be used for heating and cooling in buildings and industry.

[24] Though mentioned here, the hydrogen content of mixed gases and by-product hydrogen from the chlorine-alkali industry are generally not included in hydrogen supply and demand presented in this report.

- **Alkaline fuel cells (AFCs),** which operate at low temperatures and can be used in stationary applications, although very few units have been deployed to date.

Global installed capacity of stationary fuel cells has grown rapidly over the past ten years, reaching ~2.2 GW in 2020. At present, only 150 MW use hydrogen as fuel; most run on natural gas. Of the 468 000 units installed globally, micro-cogeneration systems dominate. Japan's ENE-FARM initiative accounts for the majority, with 350 000 such systems.

Stationary fuel cell capacity deployment, 2016-2023



Notes: RoW = rest of world. Data for 2020 estimated based on Q1-Q3 information. Planned capacity (2021-23) based on capacity increases and historic trends.
Source: E4tech.

Stationary fuel cells can also provide backup power (e.g. for data centres and hospitals) and off-grid electricity, applications that currently rely on diesel generators. As switching to fuel cells can reduce local air pollution and eliminate the need to potentially import diesel, many countries use fuel cells with a capacity of a few kW, fuelled by methanol, liquefied petroleum gas (LPG) or ammonia, as backup or off-grid electricity for radio and telecom towers. In 2020, Ballard Power was awarded a contract for 500 fuel cell systems for digital radio towers in Germany to ensure backup power for 72 hours.

Ammonia could also become a low-carbon fuel option for the power sector, either through imports to countries with limited options for low-carbon dispatchable generation or by being used as a medium to store electricity over longer periods to balance seasonal variations in renewable electricity supplies or electricity demand. Ammonia can be converted to hydrogen for use in gas turbines, used directly in internal combustion engines or fuel cells (AFCs and SOFCs), or fed into coal power plants in a co-firing arrangement.

Co-firing a 1% share of ammonia was successfully demonstrated by Chugoku Electric Power Corporation (Japan) at a commercial coal-fired power station in 2017. JERA, Japan's largest utility company, has started work on demonstrating a 20% co-firing share of ammonia at a 1-GW coal-fired unit, with the aim of completing tests by 2025.

To date, the direct use of ammonia has been successfully demonstrated only in micro gas turbines (up to 300 kW capacity). Its low combustion speed and flame stability issues have been identified as barriers to using ammonia in larger gas turbines (along with increased NOx emissions). However, Mitsubishi Power recently announced plans to commercialise a 40-MW gas turbine directly combusting 100% ammonia by around 2025.

Hydrogen and hydrogen-based fuels (such as ammonia and liquid organic hydrogen carriers) also offer seasonal and large-scale storage options for the power sector. While being immensely more cost-effective, these options have low round-trip efficiencies (around 40%) compared with batteries (around 85%), limiting their use for storing energy over longer periods.

Salt caverns, being well sealed and having low contamination risk, are already used to store pure hydrogen underground (see Chapter Infrastructure and trade). Alternately, hydrogen-based fuels (e.g. ammonia) can be used for storage in regions lacking access to salt caverns – i.e. surplus electricity can be converted to ammonia, which can be burned in power plants when solar PV and wind generation drop.

Another option is the large, refrigerated liquid ammonia tanks (e.g. 50-m diameter and 30-m height) typically used in the fertiliser industry, which can store 150 GWh of energy, comparable to the annual electricity consumption of a city of 100 000. Siemens demonstrated the use of ammonia for electricity storage in 2018 in the United Kingdom, using electrolysis to convert wind electricity into hydrogen and then into ammonia for storage. The stored ammonia was later burned in an internal combustion engine as needed to produce electricity.

Future hydrogen trends

Very few countries have explicit targets for using hydrogen or hydrogen-based fuels in the power sector. Japan is one of the exceptions: it aims to use 0.3 Mt H_2/yr in electricity generation by 2030, corresponding to 1 GW of power capacity, rising to 5-10 Mt H_2/yr (15-30 GW) in the longer term. Meanwhile, Korea's hydrogen roadmap targets 1.5 GW of installed fuel cell capacity in the power sector by 2022 and 8 GW by 2040.

Several countries recognise hydrogen's potential as a low-carbon option for co-generation and for providing flexibility as they reach high shares of variable renewable power. Germany's National Hydrogen Council's action plan envisions 0.6 Mt H_2 of power sector hydrogen demand by 2030, increasing to 9 Mt H_2 by 2040.

Co-firing with hydrogen and ammonia can be a means to reduce the emissions of existing gas- and coal-fired power plants in the near term. In the longer term, as variable renewable energy shares increase, hydrogen- and ammonia-fired power plants can be a low-carbon flexibility option.

Capacity linked to hydrogen-based fuels reaches 30 GW by 2030 and 480 GW by 2050 in the Announced Pledges Scenario, and 140 GW (by 2030) and 1 850 GW (by 2050) in the Net zero Emissions Scenario. Still, in 2050, hydrogen-based fuels account for only 1-2% of total global generation in the two scenarios. With modest additional investments (but relatively high fuel costs), co-firing of hydrogen-based fuels is targeted towards reinforcing power system stability and flexibility rather than providing bulk power.

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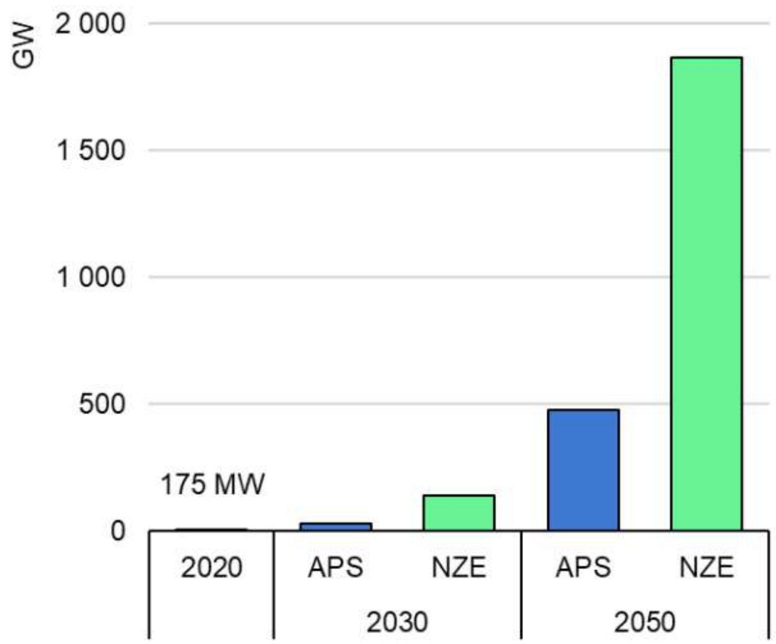
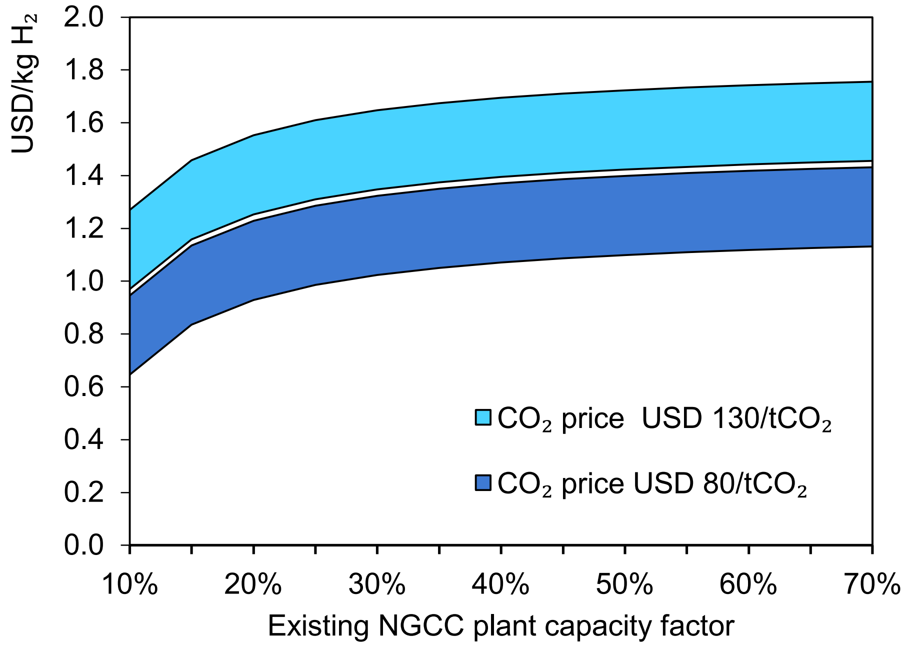
Hydrogen- and ammonia-fired electricity generation capacity in the Announced Pledges and Net zero Emissions scenarios, 2020-2050



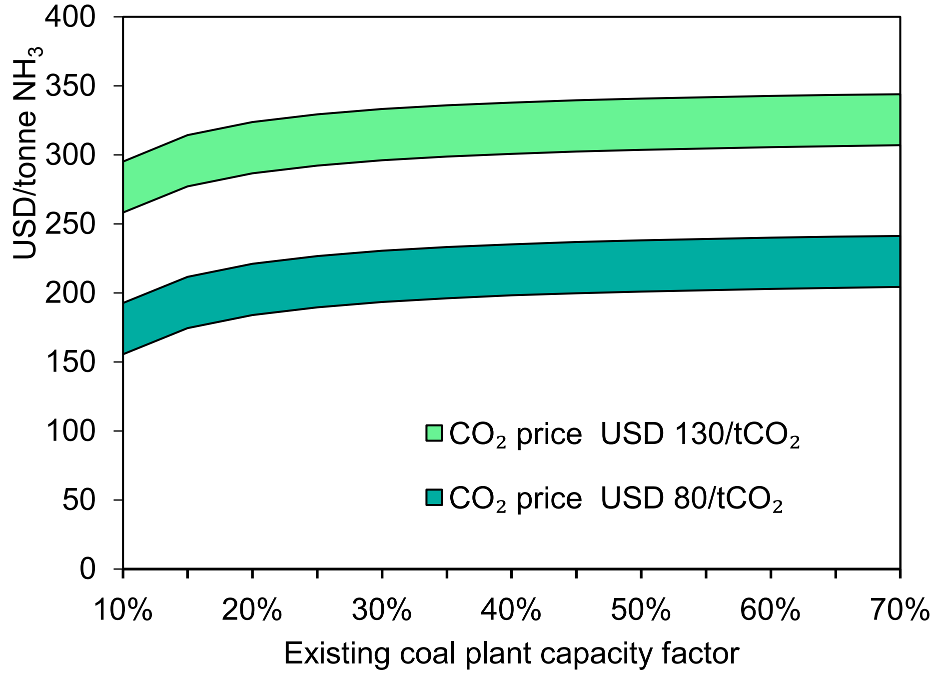
Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario.

Economic analysis of co-firing hydrogen and ammonia in fossil fuel power plants

Break-even hydrogen price for an existing natural gas power plant, 2030



Break-even ammonia price for an existing coal power plant, 2030



Notes: NGCC = natural gas combined cycle. Techno-economic assumptions available in the Annex.

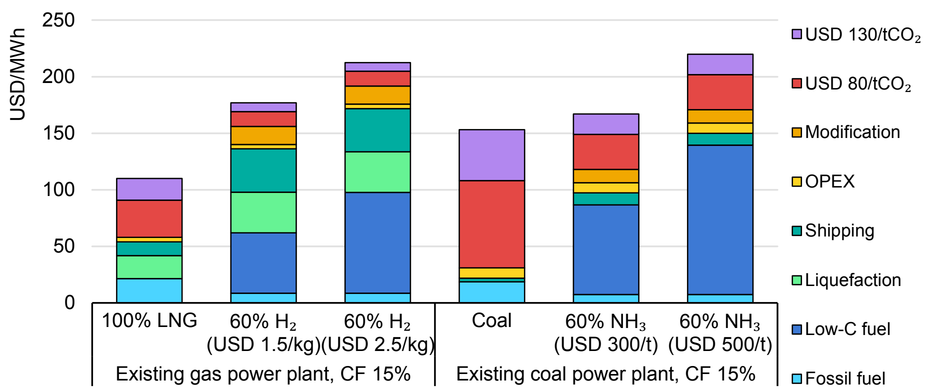
A basic condition must be met to make switching to low-carbon fuel economically attractive for existing thermal power plants: the combined cost of required plant modifications and of low-carbon fuel must be lower than the combined cost of the fossil fuel and any penalties for CO_2 emissions from combustion. Due to coal's higher carbon content, coal plants are more sensitive to carbon prices than natural gas plants, but both cases would require very high carbon prices and/or cheap low-carbon fuels to incentivise a switch. While relatively small modifications are required to enable co-firing of hydrogen or ammonia in existing gas or coal power plants, the cost of such modifications is more consequential if power plants operate at low capacity factors. However, the value of the energy produced can be much higher when operations are similar to peaking plants, which can compensate for the increased costs.

In some cases, fuel transport costs also affect overall co-firing costs significantly. This is especially the case for waterborne transport of hydrogen, which is currently at a low technology readiness level and requires expensive preparation (e.g. liquefaction). Similar cost impacts are associated with transporting natural gas as liquefied natural gas (LNG), although they are moderated somewhat by the wider availability of large-scale LNG tankers and the higher liquefaction temperature of natural gas (compared with hydrogen), which requires less energy.

Ammonia (compared with hydrogen and natural gas) has the highest vaporisation temperature, and the commercial availability of ammonia ship carriers makes transport costs lower. Although converting hydrogen to ammonia incurs thermal losses and greater capital investment, if marine transport is required, the higher levelised cost of ammonia (compared with hydrogen) can be offset (in part or fully) by lower transportation costs.

Despite the costliness of low-carbon hydrogen and ammonia, high carbon prices can largely counterbalance the additional cost of co-firing by reducing CO_2 emissions and associated carbon price penalties. This is especially the case for existing coal-fired plants. The IEA's forthcoming report The Role of Low-Carbon Fuels in Clean Energy Transitions of the Power Sector will provide more details on the potential use of hydrogen and ammonia in electricity generation.

Existing thermal power plants' levelised cost of energy with co-firing, 2030



Notes: LNG = liquefied natural gas. CF = capacity factor. Low-C fuel = low-carbon fuel. Techno-economic assumptions available in the Annex.

Electricity sector hydrogen projects under development

Power plant/project	Location	Start-up date	Capacity (MW)	Description
Daesan Green Energy	Korea	2020	50	PAFCs fuelled by by-product hydrogen from petrochemical industry
Long Ridge Energy Terminal	US	2021	485	Initially blending 15-20% hydrogen with natural gas at new CCGT; moving to 100% hydrogen in next 10 years
Magnum	Netherlands	2023	440	Conversion of existing natural gas-fired CCGT; hydrogen from natural gas + CCUS; currently on hold
Keadby Hydrogen	United Kingdom	2030	1 800	Being developed together with Keadby 3, a natural gas-fired power plant + CCUS
JERA-Hekinan	Japan	2024	200	20% co-firing of ammonia in 1-GW Unit 4 of coal-fired Hekinan power plant
Air Products' Net zero Hydrogen Energy Complex	Canada	n.a.	n.a.	Hydrogen produced from natural gas-fuelled ATR + CCUS
Ulsan	Korea	2027	270	Conversion of CCGT from natural gas to hydrogen
Hyflexpower	France	2023	12	Combining hydrogen production from renewables, hydrogen storage and electricity generation from hydrogen in a gas turbine
Intermountain Power Project	United States	2025	840	Conversion of a 1.8-GW coal power plant into 840-MW CCGT with gradually increasing hydrogen co-firing, from 30% in 2030 to 100% by 2045

Notes: ATR = autothermal reformer. CCGT = combined-cycle gas turbine.

Hydrogen supply

Overview and outlook

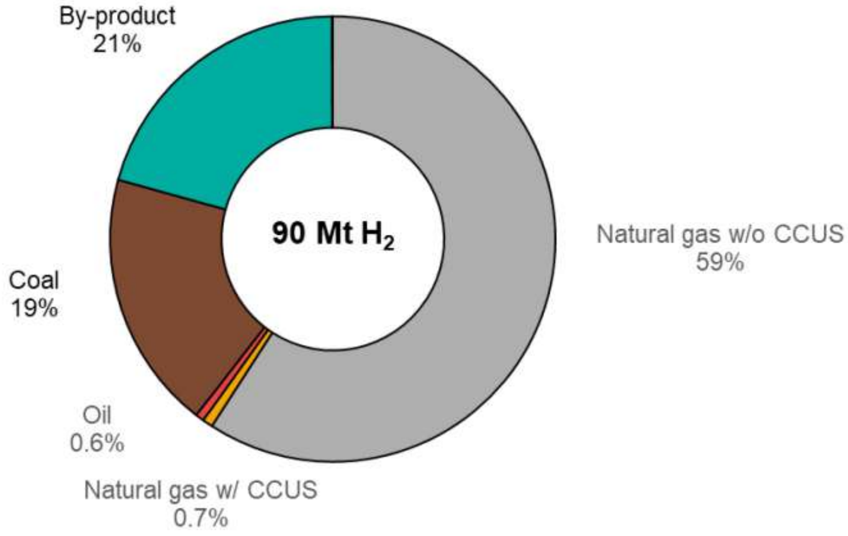
Hydrogen production in 2020

Global hydrogen demand of 90 Mt in 2020 was met almost entirely by fossil fuel-based hydrogen, with 72 Mt H_2 (79%) coming from dedicated hydrogen production plants. The remainder (21%) was by-product hydrogen produced in facilities designed primarily for other products, mainly refineries in which the reformation of naphtha into gasoline results in hydrogen. Pure hydrogen demand, mainly for ammonia production and oil refining, accounted for 72 Mt H_2, while 18 Mt H_2 was mixed with other gases and used for methanol production and DRI steel production.

Natural gas is the main fuel for hydrogen production, with steam methane reformation being the dominant method in the ammonia and methanol industries, as well as in refineries. Using 240 bcm (6% of global demand in 2020), natural gas accounted for 60% of annual global hydrogen production, while 115 Mtce of coal (2% of global demand) accounted for 19% of hydrogen production, reflecting its dominant role in China. Oil and electricity fuelled the remainder of dedicated production.

The dominance of fossil fuels made hydrogen production responsible for almost 900 Mt of direct CO_2 emissions in 2020 (2.5% of global CO_2 emissions in energy and industry), equivalent to the emissions of Indonesia and the United Kingdom combined. For a clean energy transition, emissions from hydrogen production must be reduced.

Sources of hydrogen production, 2020



Note: CCUS = carbon capture, utilisation and storage.

Various technology options exist to produce low-carbon hydrogen: from water and electricity via electrolysis; from fossil fuels with carbon capture, utilisation and storage (CCUS); and from bioenergy via biomass gasification. However, they account for very small shares of global production: at 30 kt H_2, water electrolysis made up ~0.03%, and 16 natural gas with CCUS plants produced just 0.7 Mt H_2 (0.7%).[25]

Water demand for hydrogen production

In addition to energy, hydrogen production requires water. Water electrolysis has the smallest water footprint, using about 9 kg of water per kg of hydrogen. Production from natural gas with CCUS pushes water use to 13-18 kg H_2O/kg H_2, while coal gasification jumps to 40-85 kg H_2O/kg H_2, depending on water consumption for coal mining.

In the Net zero Emissions Scenario, global water demand for hydrogen production reaches 5 800 mcm, corresponding to 12% of the energy sector's current water consumption. While total water demand for hydrogen production is rather low, individual large-scale hydrogen production plants can be significant consumers of fresh water at the local level, especially in water-stressed regions.

Using seawater could become an alternative in coastal areas. While reverse osmosis for desalination requires 3-4 kWh of electricity per m^3 of water, costing around USD 0.70-2.50 per m^3, this has only a minor impact on the total cost of water electrolysis, increasing total hydrogen production costs by just USD 0.01-0.02/kg H_2. As the direct use of seawater in electrolysis currently corrodes equipment and produces chlorine, various research projects are investigating ways to make it easier to use seawater in electrolysis in the future.

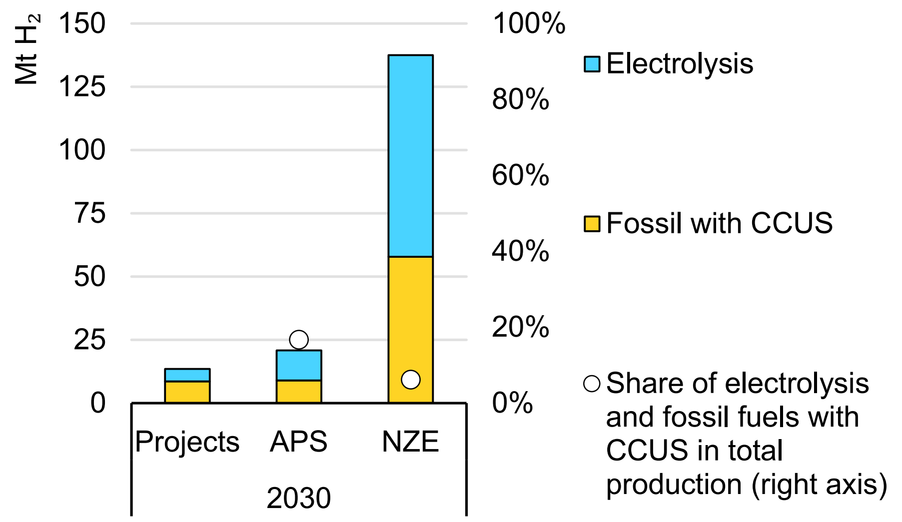
25 These include facilities that produce pure hydrogen and capture CO_2 for geological storage or sale; CO_2 captured from ammonia plants for use in urea manufacturing is excluded.

Low-carbon hydrogen production projects are multiplying rapidly, but fall short of climate ambitions

Judging by projects under construction or planned, low-carbon hydrogen production could grow rapidly to 2030.[26] Some 350 projects could push electrolytic hydrogen production to 5 Mt H_2, while 47 projects for fossil fuels with CCUS could reach 9 Mt H_2 (including the 16 existing plants). Taking into account another 40 projects at an early development stage, electrolytic hydrogen production could reach 8 Mt H_2 by 2030.

Although production from electrolysers falls far short of the 12 Mt H_2 needed in the Announced Pledges Scenario in 2030, the 9 Mt H_2 from natural gas with CCUS is on target. Together, however, expected production from planned projects is only two-thirds of what is needed. This gap widens significantly in the Net zero Emissions Scenario, which requires electrolytic hydrogen production of 80 Mt H_2 and 60 Mt H_2 from natural gas with CCUS in 2030. Nevertheless, more projects are likely to be developed in upcoming years, reducing shortcomings of the current project pipeline.

Electrolysis and fossil fuel + CCUS hydrogen production in the Projects case, Announced Pledges and Net zero Emissions scenarios, 2030



Notes: APS = Announced Pledges Scenario. NZE = Net zero Emissions Scenario. CCUS = carbon capture, utilisation and storage. Hydrogen from fossil fuels with CCUS does not include production that uses the CO_2 to produce urea; this production totals 13 Mt H_2 in 2030 in both the APS and NZE.

[26] If not otherwise specified, planned projects are those for which a final investment decision (FID) has been taken or a feasibility study is in progress.