applications as it can be used to simultaneously convert light hydrocarbons like methane (also a by-product of biomass gasification) to synthesis gas leading to increased conversion efficiency.

Although the production of pure hydrogen or ammonia has not been targeted in any of these projects, the developed technologies would be suitable also for the production of pure hydrogen, which could be then post-processed to ammonia using a standard Haber-Bosch process. An early reference for a similar type of process was the Kemira ammonia plant in Finland that started the production of peat-based ammonia via gasification in 1988.

About 55% of the global production of ammonia is used for producing urea that involves reacting ammonia with CO_2. Currently fossil CO_2 from hydrogen production is used, but to produce low-carbon urea for fertilisers, some other source of CO_2 would need to be used. Using CO_2 from biomass-based hydrogen production could be one possible solution.

Hydrogen from water using electricity

Water electrolysis involves applying an electric current to split water molecules to hydrogen and oxygen. Several different types of electrolysers exist, including designs that are commercially available and others that are still under development. Alkaline electrolysers have been used since the 1920s for hydrogen production in the fertiliser and chlorine industries, and have reached unit capacities well above 100 MW. Alkaline electrolysers continue to dominate the electrolyser market today with 61% of installed capacity in 2020. Since alkaline electrolysers do not require precious metals, their capital costs are relatively low compared to those of alternative designs.

Polymer electrolyte membrane (PEM) electrolysers are a much more recent design and account for a 31% share. They can operate at high current densities, making them more compact, but materials for electrode catalysts (platinum, iridium), bipolar plates (titanium) and membrane materials are expensive.

Solid oxide electrolyser cells (SOEC) are also under development but have not yet reached the commercial stage. Their key advantage is the potential for considerably higher conversion efficiencies compared to other designs, especially if steam or by-product heat is available.

The largest electrolyser plant in operation today is the 25 MW alkaline Industrias Cachimayo plant in Peru. In early 2021, Air Liquide inaugurated the largest PEM electrolyser to date with a capacity of 20 MW in Quebec, Canada.

Current capacity and outlook

By 2030, global installed electrolyser capacity could reach 54 GW, taking into account capacity under construction and announced projects. Europe and Australia lead with 22 GW, 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, while around a dozen demonstration projects (combined electrolyser capacity of 250 MW) explore the use of nuclear power for hydrogen production. However, to date only 4 GW (7%) are linked to projects under construction or to a final investment decision, leaving 50GW at various earlier stages of development.

Sixteen projects currently generate hydrogen from fossil fuels with CCUS, reaching an annual combined production of just over 0.7 MtH_2 and capturing close to 10 $MtCO_2$. In addition, 47 projects for producing hydrogen with CCUS are under development. Of these, 41 rely on natural gas with CCUS, four are linked to coal and one to oil. 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. More complete analysis of existing and planned hydrogen projects is available in the IEA's 2021 Global Hydrogen Review.

Ammonia market

Ammonia is a key product of the chemical and petrochemical sector and the precursor of all synthetic nitrogen fertilisers. It was the largest volume primary chemical in 2020 at 185 Mt of production,[3] of which 72% was from natural gas-based steam reforming, 26% from coal gasification, about 1% from oil products and a fraction of a percent point from electrolysis. Based on market prices of USD 300 per metric tonne (USD/t) over the last decade, the size of the global ammonia market has been around USD 55 billion per year.

China is currently the largest ammonia producer, accounting for 30% of global production in 2019, followed by the Russian Federation (hereafter Russia) (10%), the United States, the Middle East (9% each), European Union and India (8% each). China is also the largest consumer of ammonia at 54.3 Mt.

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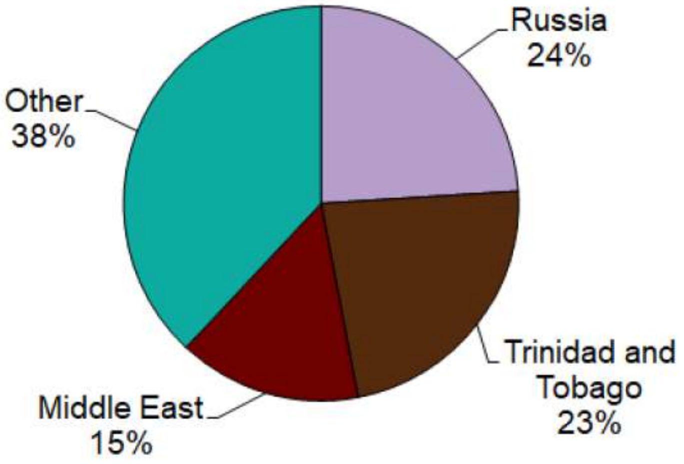
[3] Primary chemicals are the key large-volume, energy-intensive products of the chemical and petrochemical sector, and include ethylene, propylene, benzene, toluene, mixed xylenes, ammonia and methanol. Sulphuric acid has a larger production volume than ammonia, but is not energy-intensive to produce.

Ammonia is traded around the world. In 2019, global trade was almost 20 Mt, or about 10% of production. Key exporting countries and regions were Russia, Trinidad and Tobago, and the Middle East, representing respectively 24%, 23% and 15% of global ammonia exports that year. Key importing regions and countries were the European Union, India and the United States, with 24%, 14% and 13% of global imports, respectively. Urea, the single largest derivative product of ammonia, saw an even greater share of its total production volume traded in global markets, at around 28% in 2018.

Top exporting regions and countries in 2019



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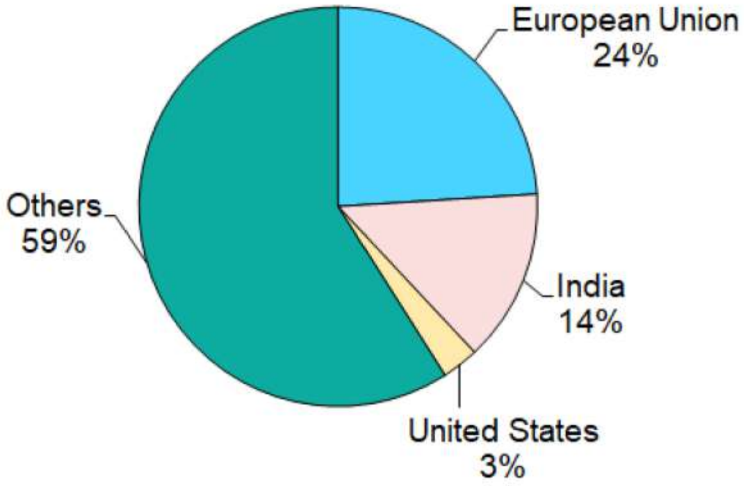
Top importing regions and countries, 2019



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Ammonia production

Ammonia can be produced from hydrogen via the Haber-Bosch (HB) ammonia synthesis. The world's first ammonia plant was commissioned in 1913 by BASF in Oppau, Germany. Today's modern plants still retain the same basic configuration, reacting a hydrogen-nitrogen mixture on an iron catalyst at elevated temperature in the range 400-500°C and operating pressures above 100 bar. The ammonia synthesis is the same process regardless of the hydrogen source.

Electrolysis provides a pathway to fully electrified ammonia production, requiring 36 GJ of electricity per tonne of ammonia produced with an efficiency of 64% on a lower heating value basis for the electrolyser. Most of the electricity (95%) is used for hydrogen production, while a small amount is needed to separate nitrogen gas from air and for pressurising the gas mixture for the ammonia synthesis loop. No direct CO_2 emissions are produced as a result of the HB process, and zero-emission ammonia production is possible if the used electricity is essentially carbon-free.

The integration of a SOEC with a HB synthesis into a hybrid plant could provide an opportunity to achieve a step-change in performance. This concept operates at high temperature and avoids the need for an air separation unit to generate the needed nitrogen due to the co-electrolysis of steam and air. Steam for the electrolyser is generated by recovering heat from the ammonia synthesis to boost the overall process efficiency to 26 GJ/t. This would make it more efficient than today's best state-of-the-art natural gas-fed ammonia plants that consume around 28 GJ/t, and significantly more efficient than the 36 GJ/t required processes based on low-temperature electrolysers. Higher efficiency, combined with a prospect of lower CAPEX, could improve the economics of the process, though the technology is presently in the development phase and is therefore limited to small scales.

In addition to electrifying the traditional ammonia process, new approaches like reverse fuels cells, are also being developed for the production of zero-emission ammonia.

Current capacity and outlook

After decades of decline, multiple projects are scheduled to come online in the coming years, bringing total electrolytic ammonia production for conventional uses to nearly 4 Mt by 2030, considering announced projects as of June 2021. A key difference compared to past production is that a considerable proportion of planned capacity will use variable renewable electricity as opposed to dispatchable large-scale hydropower.

While CO_2 capture is widespread in the ammonia industry, with more than 130 Mt CO_2 captured in 2020, only a small fraction of the captured CO_2 is geologically stored (around 2 Mt CO_2 per year). This fraction comes from the only four large-scale ammonia CCUS projects that are currently operating worldwide (two based in the United States, one based in Canada and one based in China), transporting CO_2 via pipeline and storing it for enhanced oil recovery (EOR) in nearby oil production facilities. The rest of the captured CO_2 is utilised for urea synthesis.

Emissions from the production of hydrogen and ammonia

The amount of greenhouse gas (GHG) emissions associated with the production of hydrogen and ammonia vary considerably depending on the feedstock, conversion technology and whether CCUS is applied or not. In the fossil fuel routes, CO_2 by-product is formed simultaneously with other main synthesis gas components. Given that CO_2 removal from syngas is an inherent part of the production process, a CCUS configuration would need only to add compression of the separated CO_2 stream to prepare it for utilisation or for transport and storage. Utilisation is commonplace today – in 2020, about 130 Mt CO_2 was utilised for urea production, most of it supplied from ammonia production.

In the SMR process, about 40% of the total natural gas use goes to provide the necessary heat to run the endothermic reaction at high temperature. Burning natural gas with air for heat results in a flue gas stream where CO_2 is diluted by nitrogen. Additional CO_2 capture equipment would need to be installed to also capture this CO_2 stream and to achieve near-zero emissions. Given the comparatively higher cost of two capture systems – one for the concentrated process emissions and one for the dilute fuel combustion emissions – ATR may become the preferred technology over SMR for producing near-zero emission hydrogen and ammonia from fossil fuels. Capturing the concentrated emissions of ATR alone would reduce ammonia production emissions by over 90%.

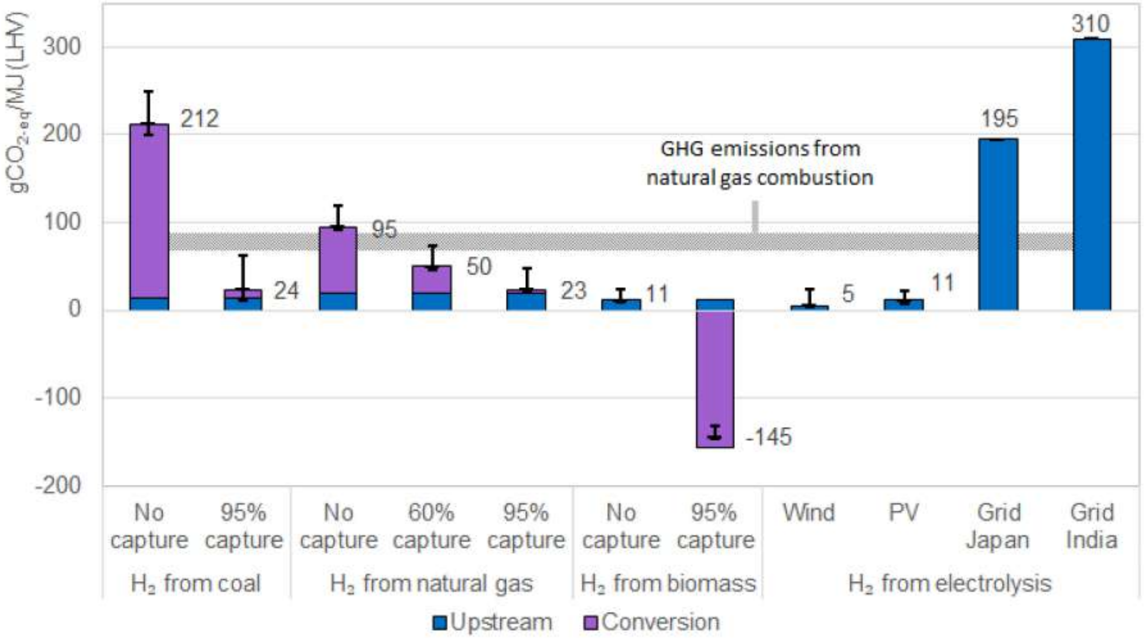
The CO_2 emissions resulting from ammonia production are governed by the hydrogen production step. In 2020, global ammonia production accounted for around 2% (8.6 EJ) of total final energy consumption and 1.3% (450 Mt) of CO_2 emissions from the energy system (40% of this energy was consumed as feedstock and the remainder as process energy). There is considerable variability in the energy intensity among individual plants and regions, with regional averages ranging from about 35 to 50 GJ per tonne.

Similarly to fossil fuel processing, by-product CO_2 from biomass gasification plants can be captured either for utilisation or for storage purposes. A key difference between biomass and fossil-based CCUS technologies is that biomass-based CCUS can lead to strong negative net GHG emissions due to the storage of biogenic CO_2 originally sequestered from the atmosphere by photosynthesis. However, the overall climate change mitigation potential of such BECCS configurations depends on a number of factors, spanning from land use aspects to conversion efficiency, share of carbon capture, transportation of CO_2 and the permanence of storage. The scale of the BECCS deployment is also crucial for its sustainability considering the limited resources of sustainable biomass, and impacts on biodiversity.

Currently, the only large-scale BECCS facility is the Illinois Industrial CCS plant that captures annually up to 1 Mt of CO_2 from the fermentation process of a Decatur corn ethanol plant. The CO_2 is injected into a geological storage beneath the facility. In addition, four smaller ethanol plants have been operated as BECCS facilities using most of the captured CO_2 for EOR.

A recent IEAGHG study found that a biomass gasification plant producing hydrogen from forest residues could capture 90-97% of the feedstock carbon depending on the process configuration.

Indicative GHG emissions of natural gas and hydrogen for different production routes



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Note: Coal upstream emissions 0.6 (low), 8.0 $gCO_{2\text{-eq}}$/MJ (median), 30.2 (high), and combustion emissions 115 gCO_2/MJ; Natural gas upstream emissions 11.9 (low), 14.4 $gCO_{2\text{-eq}}$/MJ (median), 32.4 (high), and combustion emissions 56.2 gCO_2/MJ; Wood chips from forest residues upstream emissions 5.5 (low), 7.1 (base), 14.5 $gCO_{2\text{-eq}}$/MJ (high), and combustion emissions 0 gCO_2/MJ; Wind electricity emissions 7 (low), 11 (base), 56 $gCO_{2\text{-eq}}$/kWh (high); PV electricity emissions 20 (low), 27 (base), 40 $gCO_{2\text{-eq}}$/kWh (high). Average grid emissions in 2019 for Japan 457gCO_2/kWh and for India 725 gCO_2/kWh, Horizontal band includes both upstream and combustion emissions of natural gas. For fossil fuel upstream emissions, the top and bottom 5% of the data points are excluded as outliers.
Source: IEA 2021.

GHG emissions associated with the production of hydrogen are illustrated above for different process routes, together with emissions from natural gas combustion to facilitate easy comparison with the fossil reference fuel and the low-carbon alternative (hydrogen). The emissions are separated into upstream emissions (emissions released during feedstock production and transport) and to conversion emissions (emissions released during hydrogen production). In the case of natural gas, upstream emissions include energy use, vented CO_2, emissions associated with transportation and methane emissions (for production, processing and transmission). In the case of coal, upstream emissions include emissions from transport, production and methane from coal mines. In all cases, methane emissions are converted to CO_2 equivalent emissions ($CO_{2\text{-eq}}$) using 100-year Global Warming Potential (GWP_{100}) of 30.

As described above, the production of hydrogen via coal gasification is a highly carbon-intensive operation, leading to 212 $gCO_{2\text{-eq}}$/MJ median GHG emissions for the produced hydrogen, which is three times the median GHG emissions of natural gas. However, by capturing and storing 95% of CO_2 emissions from the process, the median GHG emissions can be reduced to 24 $gCO_{2\text{-eq}}$/MJ level.

For natural gas-based hydrogen production, the unabated route has median GHG emissions of 95 $gCO_{2\text{-eq}}$/MJ. This can be reduced with CCUS to 50 $gCO_{2\text{-eq}}$/MJ or 23 $gCO_{2\text{-eq}}$/MJ by capturing 60% or 95% of the process emissions, respectively.

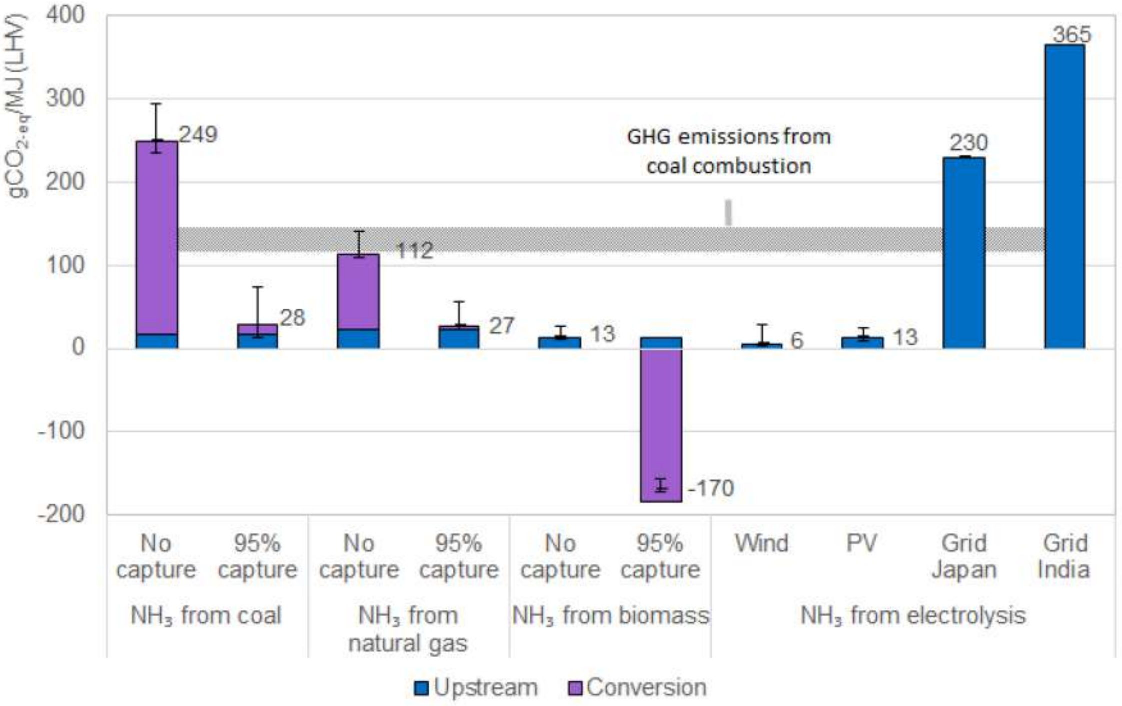
Even despite the high 95% share of capture, the overall emissions of the fossil fuel routes are not reduced close to zero. This is due to the upstream emissions associated with the production of coal and natural gas, which cannot be captured at the hydrogen plant. As a result, upstream emissions govern the overall emissions associated with fossil fuel-derived hydrogen at high shares of CO_2 capture.

The intensity of methane emissions varies widely across countries that produce oil and gas. Based on annual data for 2020, the IEA has estimated that the emissions intensity among the worst performing countries is more than 100 times higher than that among the better ones. This underlines that many countries should rapidly be able to achieve huge improvements in performance. It should be technically possible to avoid around three quarters of today's methane emissions from global oil and gas operations, and a significant share of these could be avoided at no net cost, as the cost of the abatement measure is less than the market value of the additional gas that is captured. The IEA's Methane Regulatory Roadmap and Toolkit provides a step-by-step guide for policymakers and regulators looking to develop new policies and regulations on methane.

For the forest residues-based route to hydrogen, the GHG emissions are 11 gCO_{2eq}/MJ for the base case, and deeply negative -145 $gCO_{2\text{-}eq}$/MJ at a 95% share of capture due to the underground storage of biogenic CO_2. The biomass feedstock used here is assumed to be free of any additional emissions related to direct or indirect land use change, or other carbon stock changes in the forests or soils, which can be considered as a prerequisite for sustainable biomass use.

With electrolytic routes, no direct CO_2 emissions are associated with the production of the hydrogen itself, but significant emissions can be associated with the generation of the used electricity. When only electricity from wind or solar PV is used, the overall hydrogen emissions are about 5 $gCO_{2\text{-}eq}$/MJ and 11 $gCO_{2\text{-}eq}$/MJ, respectively. However, using grid electricity can in some cases lead to very high overall emissions. For example, operating an electrolyser with Japan's average 2019 grid emissions (457 gCO2/kWh) would lead to hydrogen having more than twice the emissions than from using natural gas directly. With India's average 2019 grid emissions (725 gCO2/kWh) hydrogen emissions would be over three times those of natural gas.

Indicative GHG emissions of coal and ammonia for different production routes



Note: Coal upstream emissions 0.6 (low), 8.0 $gCO_{2\text{-}eq}$/MJ (median), 30.2 (high), and combustion emissions 115 gCO_2/MJ; Natural gas upstream emissions 11.9 (low), 14.4 $gCO_{2\text{-}eq}$/MJ (median), 32.4 (high), and combustion emissions 56.2 gCO_2/MJ; Wood chips from forest residues upstream emissions 5.5 (low), 7.1 (central), 14.5 $gCO_{2\text{-}eq}$/MJ (high), and combustion emissions 0 gCO_2/MJ; Wind electricity emissions 7 (low), 11 (central), 56 $gCO_{2\text{-}eq}$/kWh (high); PV electricity emissions 17 (low), 26.5 (central), 50 $gCO_{2\text{-}eq}$/MJ (high). Average grid emissions in 2019 for Japan 457gCO2/kWh and for India 725 gCO2/kWh, Horizontal band includes both upstream and combustion emissions of coal. For fossil fuel upstream emissions, the top and bottom 5% of the data points are excluded as outliers.
Source: IEA 2021.

GHG emissions associated with ammonia production are similarly illustrated above for different process routes together with emissions from coal combustion to facilitate easy comparison with the fossil reference fuel and the low-carbon alternative (ammonia). Since CO_2 emissions of ammonia production are governed by the hydrogen production step, the results remain largely unchanged relative to each other. However, as about 15% of hydrogen's energy is lost in conversion to ammonia, the absolute emissions intensities are higher in comparison (same amount of CO_2 released but less chemical energy produced). The median GHG emissions from unabated production of ammonia from coal are 249 $gCO_{2\text{-eq}}$/MJ, which are about two times the GHG emissions of coal itself. The median emissions of natural gas-based ammonia production are 112 $gCO_{2\text{-eq}}$/MJ, which are comparable to the median GHG emissions of coal.

The amount of CO_2 emissions associated with the production of hydrogen and ammonia varies considerably depending on the feedstock and processing route. Although hydrogen and ammonia are both carbon-free at the point of consumption, the emissions associated with their production can in some cases be significantly higher than those of the coal or natural gas that they are replacing in co-firing. Therefore, the full scope of emissions needs to be carefully assessed when considering possible climate benefits from their use.

If CCUS is combined with biomass gasification, it could enable the production of carbon-negative hydrogen and ammonia if biomass feedstock is sustainably produced. The electrolytic route is highly sensitive to the carbon intensity of the used electricity and can only reach low GHG emissions if the electricity is essentially carbon-free.

Finally, emissions from transport should also be included when considering overall emissions associated with the supply of low-carbon fuels. Currently heavy fuel oil (HFO) is used as main fuel for ships, and using HFO to transport low-carbon fuels would add about 3-10 gCO_2/MJ to the emissions, depending on the length of the voyage and size of the carrier. However, LNG carrier vessels use boil-off gas as fuel for the ship's propulsion instead of HFO. Currently, several companies are developing ammonia gas engines and hydrogen gas engines , which would also allow to use part of the low-carbon fuel cargo for propulsion, thereby minimising emissions from transport. For liquid hydrogen, the boil-off issue is unavoidable and it could be used as main engine fuel. Current ammonia carrier ships use on board re-liquefaction systems to avoid exhaust of the boil-off gas into the atmosphere, but boil-off could be used as fuel in future ammonia carriers.

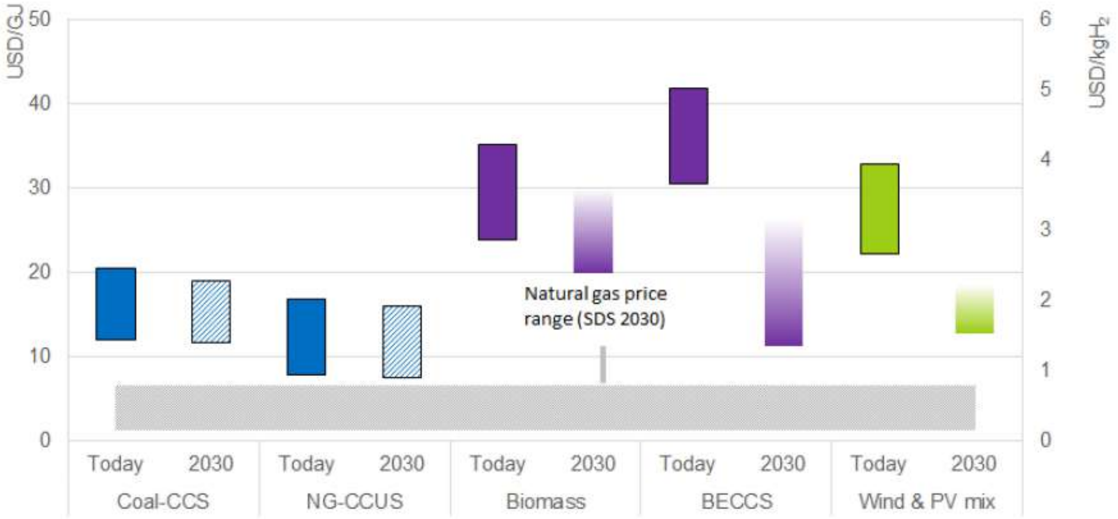
Production cost estimates

The cost of producing low-carbon hydrogen and ammonia depends on various factors such as the cost of the feedstock, availability of existing infrastructure, access to CO_2 storage capacity and prior experience with similar technologies. In addition, local weather patterns play a decisive role in the production cost of electrolytic hydrogen and hydrogen-derived fuels.

Levelised cost of low-carbon hydrogen

The estimated production cost of natural gas-based hydrogen with CCUS in 2030 is USD 8-16/GJ (0.9-1.9/kgH_2) on a lower heating value basis, making it the lowest cost route to low-carbon hydrogen featured in our study. For coal-based hydrogen with CCUS, the estimated cost range in 2030 is USD 12-19/GJ (USD 1.4-2.3/kgH_2). For electrolytic hydrogen using an optimised mix of wind and solar PV, the estimated production cost range is today USD 22-33//GJ (USD 2.7-3.9/kgH_2). By 2030, the cost of the electrolytic route is expected to be reduced due to economies of scale and technological improvements, reaching as low as USD 13/GJ (USD 1.5/kgH_2) in the best locations. If the biomass-based production plant has access to low-cost forestry, agriculture or waste biomass resources as in some regions of the US, the estimated production cost range today is USD 24-35/GJ (USD 2.9-4.2/kgH_2), but by 2030 it could be reduced to USD 20/GJ level (USD 2.4/kgH_2).

Production cost estimates for low-carbon hydrogen for today and 2030



Note: WACC 5%; Coal 15-100 (today), 12-78 USD/t (2030); Natural gas 1.2-6.6 (today) 1.1-6.6 USD/GJ (2030); biomass residues \$50-100/t(dry) (today & 2030); CAPEX estimates for hydrogen plants: Coal with CCUS USD 2040/kW_{H2}; NG with CCUS USD 1470/kW_{H2}; Biomass USD 5410/kW_{H2} (today), USD 4330/kW_{H2} (2030); Electrolyser USD 1480/kW_e (today), USD 560/kW_e (2030); CAPEX range for thermo-chemical routes ±15%; CO_2 capture cost from BECCS: USD 25/tCO_2, transport and storage cost USD 20/tCO_2. Results for electrolytic hydrogen are based on a dynamic optimisation of the wind/PV mix for the electrolyser, see Annex A for details.

The addition of CCUS to the biomass plant would increase production costs, but process economics would be completely upended if the plant were to receive revenue from negative emissions (from the permanent storage of biogenic CO_2). For example, using the IEA SDS 2030 carbon price of USD 82/tCO_2 for advanced economies as a basis of revenue would reduce the production cost range to USD 11-26/GJ (USD 1.4-3.2/kgH_2) for hydrogen via BECCS.

The cost of producing low-carbon hydrogen is becoming comparable with the production of unabated hydrogen by 2030. However, when low-carbon hydrogen is used in the power sector, its price should be compared with the price of natural gas rather than with unabated hydrogen. In the SDS, the price of LNG imports for Japan in 2030 is 5-6 USD/GJ before regasification. Adding carbon price of USD 82/tCO2, would lead to about USD 4.5/GJ price increase, leading to an overall cost for natural gas in the power sector of USD 10/GJ.

Levelised cost of low-carbon ammonia

Production cost estimates for low-carbon ammonia are illustrated in the figure below. Since the hydrogen production step governs the economics of ammonia production, the relative competition between different routes does not change much. In 2030, the cost range is USD 12-24/GJ (USD 230-440/t) from natural gas and USD 18-27/GJ (USD 330-500/t) from coal. The electrolytic route to ammonia is slightly less competitive due to investments in dedicated air separation unit for nitrogen supply, and also in hydrogen buffer storage to limit variation in hydrogen input from a mix of variable wind and solar PV generation. For electrolytic ammonia, the indicative production cost range for today is USD 37-48/GJ (USD 680-900/tNH_3). By 2030, the cost of electrolytic ammonia is expected to reach as low as USD 22/GJ (USD 400/tNH_3) in the best locations.

For biomass-based ammonia, the estimated cost range today is USD 32-47/GJ (USD 590-870/t). By 2030, the costs could potentially be reduced down to USD 27-40/GJ (USD 510-750/t) level through learning from large-scale plants. As with hydrogen, the production of carbon-negative ammonia would be profoundly influenced by revenue from carbon removals, and could reach a lower limit of USD 17/GJ (USD 320/t) under USD 82/tCO_2 carbon price assumption in 2030.