The Role of Low-Carbon Fuels in the Clean Energy Transitions of the Power Sector

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Abstract

Governments around the world are faced with the challenge of ensuring electricity security and meeting growing electricity uses while simultaneously cutting emissions. The significant increase in renewables and electrification of end-uses plays a central role in clean energy transitions. However, due to the variable nature of solar PV and wind, a secure and decarbonised power sector requires other flexible resources on a much larger scale than currently exists today. These include low-carbon dispatchable power plants, energy storage, demand response and transmission expansion. The availability and cost of these technologies depends on local conditions, social acceptance and policies.

The possibility to combust high shares of low-carbon hydrogen and ammonia in fossil fuel power plants provides countries with an additional tool for decarbonising the power sector, while simultaneously maintaining all services of the existing fleet. The relevant technologies are progressing rapidly. Co-firing up to 20% of ammonia and over 90% of hydrogen has taken place successfully at small power plants, and larger-scale test projects with higher co-firing rates are under development.

Ultimately, using large volumes of low-carbon hydrogen and ammonia in the power sector will help establish supply chains and drive down costs through economies of scale and technological improvements, thereby complementing and mutually reinforcing the use of low-carbon in fuels in other hard-to-abate sectors such as long-haul transport and industry.

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Executive summary

Using low-carbon hydrogen and ammonia in fossil fuel power plants can play an important role to help ensure electricity security in clean energy transitions

Governments around the world are faced with the challenge of ensuring electricity security and meeting growing electricity uses while simultaneously cutting emissions. The significant increase in renewables and electrification of end-uses plays a central role in clean energy transitions. However, due to the variable nature of solar PV and wind, a secure and decarbonised power sector requires other flexible resources on a much larger scale than currently exists today. These include low-carbon dispatchable power plants, energy storage, demand response and transmission expansion. The availability and cost of these technologies depends on local conditions, social acceptance and policies.

Thermal generation is the largest source of power and heat in the world today, also providing key flexibility and other system services that contribute to the security of electricity supply. These plants are also long-lasting: By 2030, 79% of the coal and gas-fired plants in advanced economies will still have useful technical life, before declining to 43% in 2040. In emerging economies, due to recent investments, these figures are 83% in 2030 and 61% in 2040. Countries that rely strongly on fossil fuel-based power generation will be required to make very significant efforts to achieve decarbonisation objectives to comply with the Paris Agreement or Net Zero targets, where applicable.

The possibility to combust high shares of low-carbon hydrogen and ammonia in fossil fuel power plants provides countries with an additional tool for decarbonising the power sector, while simultaneously maintaining all services of the existing fleet. The relevant technologies are progressing rapidly. Co-firing up to 20% of ammonia and over 90% of hydrogen has taken place successfully at small power plants, and larger-scale test projects with higher co-firing rates are under development.

The value of low-carbon fuels in the power sector depends on system contexts and regional conditions

The value of low-carbon dispatchable power capacity depends on several variables, such as market design, availability of other flexibility options, energy mix and the price of carbon, which can vary greatly across regions.

By 2030, thermal power plants using low-carbon fuels could play a growing role as a dispatchable resource for covering peak demand periods when the value of the produced electricity is high, and for providing a range of system services to ensure energy security and capacity adequacy to avoid costly disruptions in the energy supply. For example, dispatchable thermal power plants in India are expected to provide 40% of energy, 50% of system inertia, almost 60% of peak capacity and over 70% of ramping flexibility services in the IEA Sustainable Development Scenario (SDS) by 2030.

Low-carbon fuels can play an especially important role in countries or regions where the thermal fleet is young, or when the availability of low-carbon dispatchable resources is constrained. In these settings, they can allow existing assets to continue operating even when climate regulations are tightened, thereby diminishing the risk of creating stranded assets. This is particularly the case in the East and Southeast Asia.

This report provides a detailed assessment of three supply chain categories for using low-carbon hydrogen and ammonia in the power sector in 2030: importing low-carbon fuels to an advanced economy (Japan); importing low-carbon ammonia to an emerging economy (Indonesia); and using domestically produced low-carbon hydrogen in an emerging economy (India).

Production costs of low-carbon fuels must decrease further

Natural gas with carbon capture, utilisation and storage (CCUS) is currently the lowest-cost production route for low-carbon fuels. Cost estimates for 2030 are generally in the range of USD 8-16/GJ (USD 0.9-1.9/kg) for hydrogen and USD 12-24/GJ (USD 230-440/t) for ammonia in regions with access to low-cost natural gas and availability of CO_2 storage.

Production costs for the electrolytic route are decreasing rapidly due to continuing reductions in the cost of renewable electricity and economies of scale in electrolyser manufacturing. By 2030, costs are estimated to be in the range of USD 13-19/GJ (USD 1.5-2.2/kg) for hydrogen and 22-33/GJ (USD 400-620/tNH3) for ammonia in regions with excellent wind and solar resources.

By 2030 the cost of low-carbon hydrogen and ammonia for use as chemical feedstock becomes comparable to those of unabated production from fossil fuels. However, for use as a fuel, they are expected to remain significantly more expensive than projected prices of coal and natural gas in 2030 in the SDS.

Full value chains, including transport and storage, must be considered when comparing the cost of using low-carbon fuels from different sources

An extensive transport and storage infrastructure is a prerequisite for establishing global value chains, and connecting low-cost production regions with users of low-carbon fuels.

Transmission of hydrogen and ammonia via pipelines is a mature technology and represents a relatively small proportion of the overall supply cost. Intercontinental ammonia transport is also well developed, relying on chemical and semi-refrigerated liquefied petroleum gas (LPG) tankers.

For marine transport, hydrogen can be liquefied in a manner similar to what is done for natural gas. However, liquefaction is a very energy- and capital- intensive process. Transporting fuels via shipping over a distance of 10 000 km is estimated to cost USD 14-19/GJ for liquid hydrogen, while it is only USD 2-3/GJ for ammonia. The resulting total supply projected costs in 2030, including production and marine transport, are respectively USD 22-35/GJ (USD 2.6-4.2/kg) for hydrogen and USD 14-27/GJ (USD 260-500/t) for ammonia.

The use of low-carbon fuels in fossil fuel power plants must lead to significant and measurable life-cycle emission reductions

Substantial greenhouse gas (GHG) life-cycle emissions reductions can be achieved by substituting fossil fuels with low-carbon hydrogen and ammonia in thermal power plants. Indicatively, switching from natural gas-based power generation to hydrogen derived from fossil fuels with 95% CO_2 capture delivers about 70% GHG reduction, while electrolytic hydrogen from renewables reduces emissions by 85-95%. Similarly, switching from coal-based power generation to low-carbon ammonia delivers about 80% reduction in emissions when ammonia is produced from fossil fuels with 95% CO_2 capture, and 90-95% when ammonia is produced from wind and solar.

There are currently no internationally agreed rules or standards on the maximum allowable GHG emissions associated with the production of hydrogen and/or hydrogen-derived fuels. In the case of the CCUS route, such standards would dictate minimum eligible CO_2 capture rates and place limits on the maximum allowable upstream emissions. At the same time, such rules and standards are also relevant for electrolysers if grid electricity is used, as the power mix will significantly influence life-cycle emissions.

Going forward, standards are needed to create end-user confidence towards fuels that are carbon-free at the point of consumption, but might produce significant

GHG emissions during production, transport and final distribution. For example, switching from coal to unabated fossil ammonia can double life-cycle GHG emissions, and even triple them in the case of switching from natural gas to unabated fossil hydrogen.

A versatile mix of supply routes for low-carbon fuels will enhance diversification and security of supply while contributing to cost predictability

A diverse mix of supply locations and technologies can help ensure secure supplies should producers struggle to meet rapidly growing demand. Costs for renewables and the electrolytic route are more predictable and can help to balance possible disruptions in the supply and price swings of natural gas and coal, which affect the production costs of the fossil fuel with CCUS route.

Low-carbon hydrogen and ammonia production can be kick started in places where production can build on existing infrastructure and demand. There are also possibilities to integrate the electrolytic and fossil fuel with CCUS processes into a hybrid plant that can offer increased efficiency and potentially lower capital investment requirements.

If the biomass feedstock is sustainably produced, carbon-negative hydrogen and ammonia can be produced by capturing by-product CO_2 from a biomass conversion plant, a particularly interesting option in high-price carbon jurisdictions.

The overall strategies and policies to incentive low-carbon fuels should be kept open for different technology options as long as basic sustainability criteria are met. This is likely to increase competition and accelerate cost reductions, while increasing diversification and security of supply.

A portfolio of policies is required to compensate for cost gaps and foster uses that maximise system value

By 2030, low-carbon hydrogen and ammonia are likely to remain expensive energy carriers for power generation. However, in Japan the gap between the generation cost and the value of the produced electricity is moderated by the wholesale electricity market that allows higher prices during peak demand periods, and by the high carbon price assumed in the SDS for advanced economies by 2030. Our analysis suggests that co-firing 60% of low-carbon ammonia in a Japanese coal power plant in 2030 would lead to a generation cost that is 30% higher than energy market value in baseload, but just 15% higher in peak load conditions. In addition, these generators will be able to compete on Japan's capacity market, striving for an additional source of revenue. By contrast, using the same low-carbon ammonia in Indonesia would lead to a four-fold increase in generation costs compared with the variable operating costs of a coal power plant. The impact would be fully felt due to the absence of both a wholesale electricity market and a carbon price.

To support the use of low-carbon fuels in the power sector, electricity markets should be redesigned to reward flexibility, capacity and other system service contributions provided by low-carbon thermal power plants. This could be accompanied by support measures such as carbon pricing and/or other complementary policies, as well as regulatory frameworks to further decrease the remaining cost gap with incumbent generation. Support measures should be tailored towards cost-effective system integration and maximising the value of low-carbon dispatchable generation. They should also aim at fostering competition and improving environmental performance over time.

In any case, given expectations of increased competition from other forms of low-carbon dispatchable resources and other flexibility and storage options, as well as from possible retrofitting of fossil fuel plants with CCUS, the feasibility and competitiveness of low-carbon thermal power plants will need to be continuously and carefully assessed.

Developing markets for low-carbon fuels and their supply chains by 2030 will establish significant opportunities in many countries and economic sectors

It is vital that economies with strong drivers for using low-carbon fuels successfully create demand, bring down costs and stabilise value chains by 2030. Only their success will open up opportunities to expand low-carbon fuel use in emerging and developing economies.

This is particularly relevant for countries with young fossil fuel fleets, after having implemented and utilised most of their existing flexibility resources, such as grids and interconnections, storage and demand-side response. For example, low-carbon fuels use is a possible long-term option for emerging economies in Southeast Asia. Power systems in this region already have considerable other latent flexibility that can be activated by targeted policy measures to address flexibility needs in the short term, while in the longer term there are opportunities for using low-carbon fuels in the existing thermal power plant fleet.

Displacing meaningful amounts of fossil fuels from power generation will require a major expansion of the supply infrastructure. This implies not just massive investments but also concerted and coordinated efforts across many stakeholders, including duly addressing health & safety risks related to the handling of hydrogen and ammonia.

Electrolyser and hydrogen transport capacity especially need to massively expand many times over their current size. Despite already being widely traded, transport volumes of ammonia are also small in comparison to the needs of the power sector. For example, co-firing 60% of ammonia in a coal power plant fleet of just 10 GW_e – about 10 large coal plants -- would mobilise an amount almost equivalent to the total ammonia traded worldwide today.

While the expansion of the supply infrastructure is a condition to develop markets for low-carbon hydrogen and ammonia in the power sector, it is also an important investment opportunity. Ultimately, using large volumes of low-carbon hydrogen and ammonia in the power sector will help establish supply chains and drive down costs through economies of scale and technological improvements, thereby complementing and mutually reinforcing the use of low-carbon in fuels in other hard-to-abate sectors such as long-haul transport and industry.

Chapter 1. The role of thermal generation in clean energy transition

Highlights

- **Thermal power plants have supplied the bulk of increasing electricity demand in the last two decades, particularly in China and emerging economies.** The capacity of the worldwide fleet of coal and gas plants doubled from 2000 to 2019, from 1.8 TW to 3.7 TW. More than half of these plants have been in service since 2005, and more than half of those in China have been in service since 2008. In India, plants which have been in service since 2012 comprise more than half of the fleet.
- **These plants have technical lifetimes that extend well into the future**. By 2030, 79% of the coal and gas-fired plants in the advanced economies will still have useful technical life, before declining to 43% in 2040. In the emerging economies, due to the amount of recent investments in coal and gas-fired capacity, these figures are 83% in 2030 and 61% in 2040.
- **But the emissions from coal and natural gas use must be reduced drastically in order to align with the objectives of the Paris Agreement and – where applicable – with more recent Net Zero country pledges.** Alongside using less coal and gas by operating the plants at lower utilisation rates or by retiring them early, the other pathway to reduce emissions is to retrofit the plants to generate with low-carbon fuels or to capture and store the carbon emissions. A number of factors, including the pace of cost reductions in the technologies, renewable energy resource potential and geographic location, will drive the balance between the two pathways.
- **Meanwhile, massive expansion of solar PV and wind is rapidly transforming power systems across the world, calling for a profound transformation in the way that these systems are planned and operated to maintain electricity security.** In the SDS, VRE will need to increase rapidly in the advanced economies, rising from 11% of total energy in 2019 to 50% in 2040. In the emerging economies, this share will rise even more rapidly, from 6% in 2019 to 43% in 2040. Due to their variable nature, in every region, this growth in VRE generation will entail a significant increase in the need for flexibility from other sources of supply and demand in the power system.
- **Low-carbon retrofitting of thermal power plants would allow the re-use of existing assets and their associated infrastructure in the future as low-emission sources of firm capacity**. Thermal plants can balance the variability of wind and solar generation in the power system by generating when those resources are unavailable, or by adjusting up or down based on instantaneous or hourly and daily fluctuations in VRE output. The rotational mass of thermal plants supplies inertia which helps maintain frequency for secure operation of the power system. Currently, gas and coal-fired generation accounts for over half of current flexibility capacity globally. Dispatchable power plants will likely continue to contribute to electricity security in regions with large thermal fleets, in particular those with limited other options: in the SDS in Japan and ASEAN, dispatchable capacity is almost equal to variable renewable capacity still by 2040.

The power sector is in rapid transformation

Thermal generation, fired mainly by coal and natural gas, dominates today's power systems. Fossil-based thermal generation has historically been the one of the cheapest sources of electricity, but it is also dispatchable and flexible – it can sustain its output over long periods and respond to expected and unexpected changes to demand and other generation sources. Thermal generation is therefore able to contribute a very high share of its installed capacity towards meeting peak demand, or system adequacy. Thermal generation also provides key system services in meeting flexibility needs particularly inertia, a key source of grid stability, through the rotating mass of its turbines.

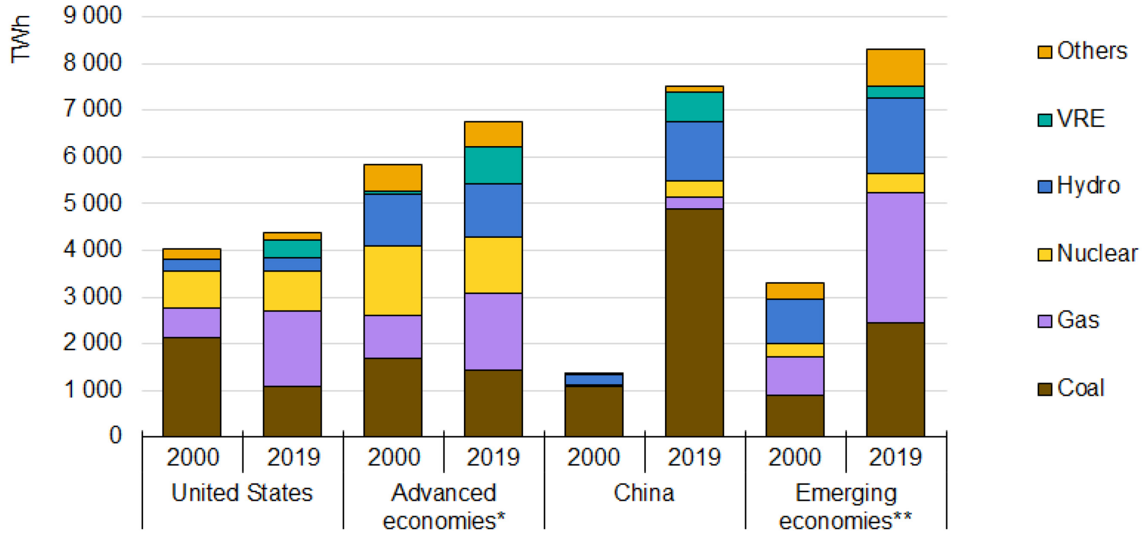
However, the resulting emissions from the unabated use of coal and natural gas in thermal generation must be reduced drastically in order to align with the objectives of the Paris Agreement and – where applicable – with more recent net zero pledges. Wind and solar generation will need to replace the bulk of emissions-producing fossil fuels during the transition to cleaner power systems, rising rapidly from 7 percent of electricity generation in 2019 to 29 percent in 2030 and 45 percent in 2040 globally in the Sustainable Development Scenario (SDS). This will require power systems to increase sources of flexibility in order to respond to variability and uncertainty of these sources. Investments in large-scale transmission network upgrades and measures to increase demand-side flexibility will be needed. Investments in technologies that provide key system services like, like battery storage and low-carbon dispatchable energy technologies, will also be required. Governments will also need to manage the transition away from coal and gas to ensure that economic and social disruption is minimised and costs are contained.

Given the constraints of affordability, security and decarbonisation driving clean energy transitions across the globe, low-carbon fuels have the potential to play a significant role, particularly in regions where the potential to integrate more variable renewable energy (VRE) is low. In addition to the cost-saving potential of the use of existing assets and transmission networks, thermal generation using low-carbon fuels is uniquely positioned as a resource that is clean, dispatchable and flexible.

Electricity demand has increased dramatically over the past 20 years

Electricity demand, driven by increasing energy access and industrialisation in the emerging economies and the People's Republic of China (hereafter 'China') has increased rapidly over the past 20 years, by over 150% and 400%, respectively. By contrast, total electricity demand has increased by only 13% in the advanced economies, mainly by improving end-use energy efficiency and switching to less energy-intensive industries.

Electricity generation (TWh), 2000-2019

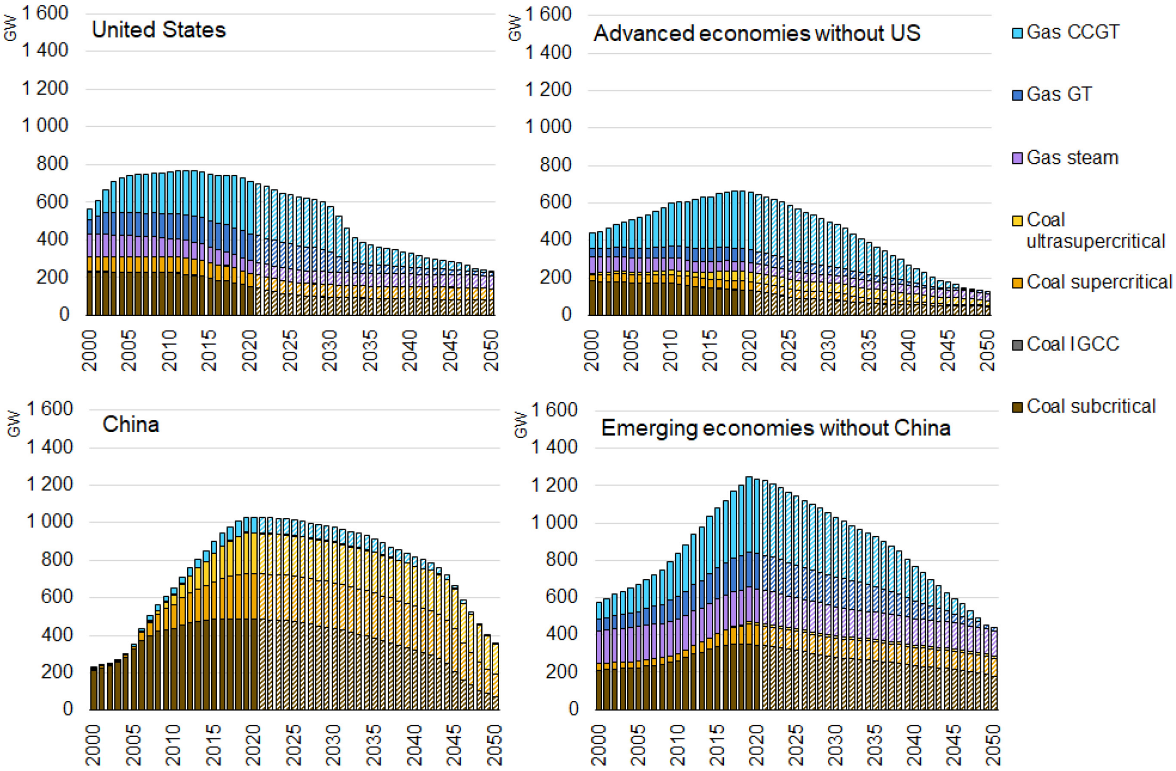


*Does not include United States. **Does not include China.
Note: IEA definitions of advanced and emerging economies from the World Energy Outlook.
Source: Data from IEA World Energy Outlook (2020).

Increasing demand has been satisfied mostly by thermal power plants

Extensive investments in new coal and gas capacity have been made to support this increase in demand. The worldwide fleet of coal and gas plants doubled from 2000 to 2019, from 1.8 to 3.7 TW. More than half of these plants have entered service since 2005, and in China more than half have entered service since 2008. In India, plants built since 2012 comprise more than half of the fleet. These plants have technical lifetimes that ensure that the bulk of this capacity will still be capable of operation well into the future. By 2030, 79% of the coal and gas-fired plants in the advanced economies will still have useful technical life, before declining to 43% in 2040. In the emerging economies, due to the amount of recent investments in coal and gas-fired capacity, these figures are 83% in 2030 and 61% in 2040. In China and India in 2030, the figures are 95% and 86%, before declining to 79% and 73% in 2040.

Cumulative capacity by 2019 and expected retirement of the existing fleet by 2050 based on technical lifetime (GW)



Source: Data from IEA World Energy Outlook (2020).

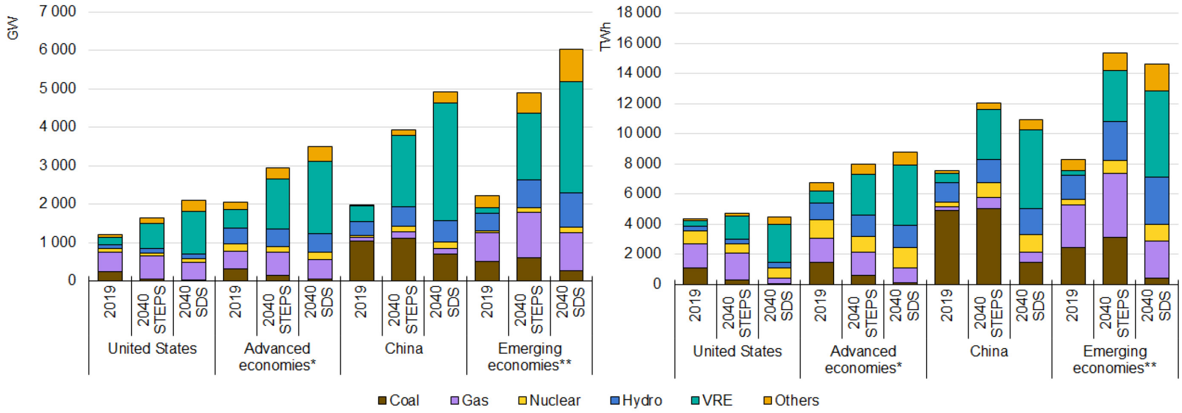
Globally, coal and gas-fired generation accounted for almost two-thirds of the increase in global demand between 2000 and 2019. The emerging economies account for almost all of the additional coal and gas generation, with coal plants in China alone making up half of the total increase. Coal-fired generation actually declined over 30% in the advanced economies, due either to lower natural gas prices, as in the United States, or policy-driven phase-outs of coal-fired generation, as in Europe, or a combination of the two as in Canada.

Electricity demand will continue to increase in the future in all scenarios

In both the Stated Policies Scenario ("STEPS") and the SDS, the two central scenarios considered in the IEA's World Energy Outlook 2020, further significant increases in electricity demand are foreseen by 2040. In the STEPS, which includes all stated commitments to reduce emissions by governments, electricity demand will increase by 49% globally, with demand in China increasing by 60% and demand in the emerging economies (excluding China) increasing by 85%. In the emerging economies in particular, reaching universal energy access, including secure round-the-clock electricity availability, as well as the replacement of traditional biomass for heating and cooking, will drive growth in electricity consumption. In the advanced economies, increases in energy efficiency will offset increased electrification of end-uses, resulting in relatively stable electricity consumption.

In the SDS, VRE will need to increase rapidly in the advanced economies, rising from 11% of total energy in 2019 to 50% in 2040. In the emerging economies, this share will rise even more rapidly, from 6% in 2019 to 43% in 2040. In every region, this increase in VRE generation will entail an increase in the need for flexibility from other sources of supply and demand in the power system.

Installed capacity and generation by source in the Stated Policies and Sustainable Development Scenarios (2019 and 2040)

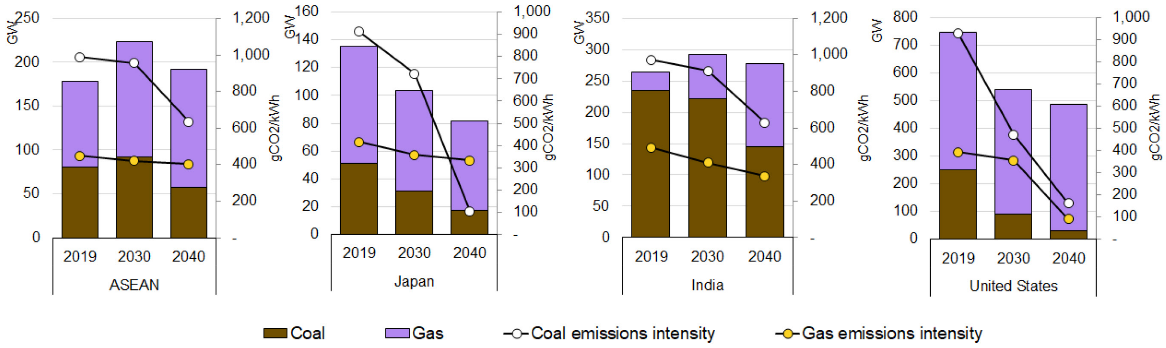


*Does not include United States. **Does not include China.
Source: Data from IEA World Energy Outlook (2020).

Emissions reductions from fossil-based thermal generation sources are necessary

Reducing the emissions from the coal and gas fleet will need to be a key focus of the global clean energy transition. In the SDS, the global coal and gas fleet must reduce its emissions by a factor of seven in the period between now and 2040. This is particularly true for coal, where the emissions intensity must drop about six fold in the US and nine fold (912 g CO_2/kWh in 2019 to 105 g CO_2/kWh in 2040) in Japan (see Figure below).

Dispatchable fossil fuel-based capacity and emissions intensity in the SDS, 2019-2040



Source: Data from IEA World Energy Outlook (2020).

In the SDS, the two available options to accomplish this reduction are retiring the most emissions-intensive coal generation technology and retrofitting some amount of capacity with carbon capture use and storage (CCUS) technology. This report introduces another option, one that is not contemplated in the SDS – retrofitting thermal power plants for use with low-carbon fuels.

Lower utilisation and early retirement of thermal generation

In the SDS, global installed capacity of coal-fired generation is 20% below the level in the STEPS in 2030 (2 v 1.6 TW) and 40% lower in 2040 (1.9 v 1.1 TW). The capacity factors of the coal-fired plants are reduced from 53% in the STEPS in 2030 and 2040, to 35% in 2030 and 21% in 2040 in the SDS. As a result, the global share of total energy provided by coal-fired generation is reduced from 22% in the STEPS to 5% in the SDS. Gas-fired generation follows a similar course, but the reductions occur at a slower pace, reflecting its lower emissions intensity. VRE replaces the vast majority of the coal- and gas-fired generation, with smaller contributions from additional nuclear power and energy efficiency in the SDS.

A transformation of this type will have vast implications for the power sector. From an operational perspective, it will require managing the variability of renewables with flexible resources, including dispatchable power plants, energy storage, demand response and transmission expansion on a much larger scale than currently exists today.

From a social and economic perspective, the transformation will have consequences for regions that rely on energy-intensive industries to support economic activity and employment. Early retirement of coal- and gas-fired generation will require additional investment in those affected regions to ensure a just transition and avoid economic and social disruption. Financial pressure will also increase on the owners of the assets that would become stranded as a result of policy decisions.

Local conditions will dictate the suitability of additional wind and solar investments, and some systems suffer from a lack of sites with high potential to exploit wind and solar generation. This will lead to lower output than global averages, and much lower output than systems with high potential for development. For example, the average capacity factor of wind generation in the Association of Southeast Asian Nation (ASEAN) region in the SDS is 25.3% in 2030 and 26.5% in 2040, compared to 38.4% and 42.0% respectively in the United States, and 29.5% and 32.4% globally. In Japan, the average solar capacity factor will reach only 9.3% in the SDS in 2040, compared to 17.1% globally and 22.8% in the Middle East. Lower capacity factors increase the average cost of energy provided by these assets, making alternatives sources of generation more attractive.

Integrating power systems through enhanced cross-border trading is one way to solve the issue of local resource constraints when attempting to increase the use of low-carbon energy sources. Large power systems are able to integrate higher shares of VRE. The benefits of integration also extend beyond the integration of renewables, including increased electricity security by allowing the pooling of reserves and decreasing the variability of both supply and demand. However, integrating power systems requires a new set of rules to manage unexpected power flows and avoid cascading outages that can cause major blackouts. The cost of interconnection can also be prohibitive to regions where physical barriers like bodies of water, mountains and long distances complicate the routing of new infrastructure. Geopolitical constraints can also limit the potential for collaboration.

Retrofit to use low-carbon fuels or CCUS

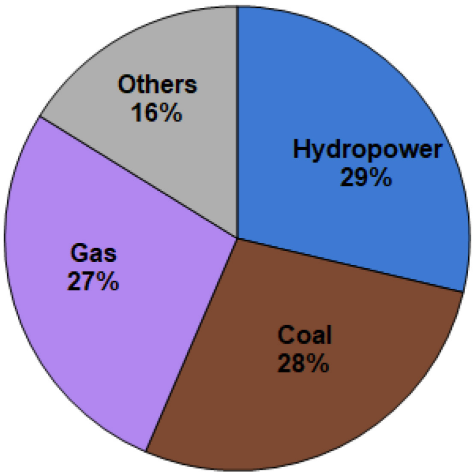
The second major pathway to decarbonise the power sector is to retrofit plants to enable the use of low-carbon fuels or to capture and store carbon using CCUS technology (see Chapter 2). This approach would allow these thermal plants to operate into the future as low-emission sources of firm capacity, while reusing existing assets and their associated infrastructure (transmission networks) and supply chains. It would also reduce costs, while reducing the economic and social dislocations associated with the large-scale transformation of the power sector. Retrofits for use of low-carbon fuels and CCUS also provide a hedge against the risk that cost reductions in newer generating technologies like offshore wind, enhanced geothermal or advanced nuclear do not materialise.

Decoupling the generation technology from the fuel allows these plants to accept feed from a variety of sources. This opens a wide set of decarbonisation opportunities for the power sector while keeping security of supply, depending on the pathways that look the most promising. In particular, co-firing would allow a gradual transition away from fossil fuels, while continuously expanding the production and transport infrastructure for low-carbon fuels.

The role of thermal generation in providing electricity security

Currently, gas and coal-fired generation accounts for over half of current flexibility capacity globally (see figure below). Thermal plants can balance the variability of wind and solar generation in the power system by generating when those resources are unavailable, or by adjusting up or down based on instantaneous or hourly and daily fluctuations in VRE output. The rotational mass of thermal plants supplies inertia, which helps maintain frequency for secure operation of the power system.

Global dispatchable capacity by fuel, 2019



Source: Net Zero by 2050: A Roadmap for the Global Energy Sector.

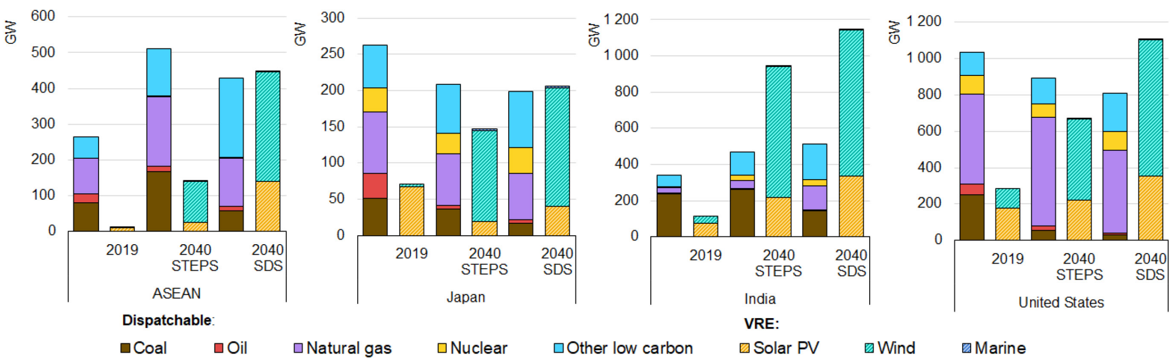
Thermal generation will remain relevant in future decarbonised power systems, even is producing lower quantities of energy, because they provide these key services that contribute to the security of supply. The outlook for other technologies that can replicate these services is uncertain. Batteries have the ability to respond to the variability of wind and solar over short time periods but do not yet possess the capability to provide long-duration or seasonal energy economically. Hydropower, nuclear, geothermal and fossil fuel thermal power plants with CCUS are other technologies that are capable of providing many of the services needed for a stable grid. However, these technologies are dependent on local conditions and resources that are not universally available to meet anticipated demand or, in the case of nuclear, are strongly dependent on policies. For hydropower, there are some constraints that could limit their use including hydrological conditions and other priority applications including irrigation, flood control and recreation. Thermal power plants are therefore the most likely source of providing dispatchable generation, but reducing emissions from these sources must be a priority in order to reach decarbonisation goals while maintaining electricity security.

Four selected regions with large thermal fleets

To demonstrate the role of thermal power plants in providing electricity security, we present four regions, each with large current fleets of thermal generation. They have otherwise varied economic and industrial characteristics and natural resource endowments. The STEPS and SDS for each of these regions show that they each expect to add substantial wind and solar capacity over the next 20 years (see Figure below). While this is sensitive to the policy environment, in both scenarios, the ratio of dispatchable capacity to VRE will decline, despite the addition of new coal, gas and hydro capacity. In the ASEAN region, the ratio declines from 18.9 to 1 in 2019 to 3.6 to 1 in the STEPS and 0.96 to 1 in the SDS in 2040. In the US, the ratio declines from 3.6 to 1 in 2019 to 1.3 to 1 in the STEPS and 0.73 to 1 in the SDS in 2040. India will expect to have the lowest ratio of dispatchable sources to VRE, declining from 3.0 to 1 in 2019 to 0.49 to 1 in the STEPS and 0.45 to 1 in the SDS in 2040. In the SDS, each of these four regions will have greater VRE generation than dispatchable capacity in 2040.

To examine the role of dispatchable thermal power plants in ensuring electricity security in a low-carbon future, we conducted a detailed case study of India's power system, which is presented in Chapter 5.

Dispatchable capacity of selected countries in the STEPS and SDS, 2040



Note: Other low-carbon includes hydro, geothermal, biomass and concentrated solar power (CSP).
Source: IEA World Energy Outlook (2020).

Firm dispatchable capacity will still be needed in these regions

The STEPS and SDS maintain dispatchable generation capacity despite the increasing competitiveness of new solar and wind investment compared to coal and gas. For example, in the United States, the cost of onshore wind is currently estimated at USD 35/MWh in levelised cost of energy (LCOE) terms and is expected to decline to USD 25 in 2040, while new solar PV is currently estimated at USD 50/MWh and is expected to be reduced by half in 2040 to USD 25/MWh. This is compared to a combined-cycle gas turbine (CCGT) that is estimated to cost USD 65/MWh in 2019 and USD 95/MWh in 2040 under the SDS.

In purely LCOE terms, new solar and wind is cheaper than the alternatives — mainly gas, but also coal, hydro, geothermal and nuclear. However, the capacity and flexibility provided by these plants is required in order to maintain secure operation. This is captured by the World Energy Model (WEM), the framework upon which the STEPS and SDS are built, through the value-adjusted levelised cost of energy (VALCOE) metric. VALCOE assigns additional value to resources that are able to contribute to meeting hour-by-hour demand reliably. This results in lower VALCOE when compared to the LCOE for dispatchable generation. The impact can be quite substantial – for example, in the European Union under the STEPS, the LCOE of a new gas CCGT in 2040 is USD 110/ MWh in LCOE terms but only USD 75 in VALCOE terms. This is in contrast to a weather-dependent resource like solar PV, where the LCOE is USD 50 USD/MWh but the VALCOE is USD 80/ MWh. If looking only at the LCOE, additional solar PV is cheaper by USD 60/MWh, but when using the VALCOE to consider overall system value, the gas CCGT is the cheaper option.

Chapter 2. Technical options for decarbonising thermal power plants

Highlights

- **Co-firing with low-carbon fuels is a complementary approach for decarbonising existing fossil fuel power plants, alongside retrofitting with carbon capture, utilisation and storage (CCUS)**. As countries search for context-specific tools and solutions for achieving clean energy transitions, low-carbon hydrogen (H_2) and ammonia (NH_3) are emerging fuel options for co-firing. Both approaches would allow plants to operate with firm capacity while reusing existing assets and infrastructure.
- **A few Asian countries have stated explicit targets for the use of hydrogen or ammonia in the power sector.** Hydrogen plays only a negligible role in the power sector today, accounting for less than 0.2% of electricity generation globally. However, Japan is aiming to use 0.3 Mt/yr of hydrogen and 3 Mt/yr of ammonia in the power sector by 2030. Korea has a target of 1.5 GW installed fuel cell capacity in the power sector by 2022 and of 15 GW by 2040.
- **Using hydrogen in turbines is already a common practice in industry.** Gas turbine suppliers have significant experience in combusting hydrogen-containing fuels, with some smaller units already operating at a >90% share of hydrogen in refineries and in chemical and petrochemical applications. A number of projects have announced plans to convert large-scale (up to 500MW_e) plants for hydrogen co-firing around the world.
- **Combustion of 20% ammonia in a 1-GW coal-fired unit is announced for 2025.** Modifying existing coal plants for ammonia co-firing requires boiler modifications and investment in additional facilities like ammonia tanks and vaporisers. Through RD&D efforts, plans exist in Japan to demonstrate higher co-firing shares at commercial scale by 2040. In addition, gas turbine manufacturers have announced plans to offer large-scale ammonia-fired gas turbines around 2025.

Existing fossil fuel power plants can be decarbonised by switching to low-carbon fuel or by retrofitting with a CCUS technology. Both approaches would allow these plants to operate into the future as low-emission sources of firm capacity, while reusing existing assets and their associated infrastructure. In particular, co-firing would allow a gradual transition away from fossil fuels, while continuously expanding the production and transport infrastructure for low-carbon fuels.

Co-firing with low-carbon hydrogen

Hydrogen plays only a negligible role in the power sector today, accounting for less than 0.2% of electricity generation globally, linked mostly to the use of hydrogen-containing mixed gases from the steel industry, petrochemical plants and from refineries.

Global installed stationary fuel cell capacity has been rapidly growing over the last ten years, reaching almost 2.2 GW in 2020, although only around 150 MW use hydrogen as fuel. Most of the existing fuel cells today run on natural gas. The number of globally installed fuel cell units is around 468 000, largely dominated by micro co-generation systems.

Selected activities in co-firing of hydrogen in gas turbines

Project	Description	Status	Location
FLEXnCONFU	European consortium developing power to fuel to power solutions.	On-going	Five testing sites in Europe.
Hydrogen to Magnum	Aims to convert one 440 MW gas turbine unit to 100% hydrogen by 2025	Announced	Netherlands
Mitsubishi Power	Developing NH_3-fired 40 MW gas turbine by 2024, and NH_3 cracking to H_2 with turbine exhaust heat by 2025	Announced	Japan
GE	25 gas turbines have operated on fuels with at least 50% (by volume) hydrogen.	In operation	Various locations
EnergyAustralia	Over 300 MW gas turbine plant with blending of H_2 by 2024	Announced	Australia
HyFlexPower	Modification of a 12MW$_e$ CHP unit for hydrogen-firing.	On-going at pilot scale	France
Long Ridge Energy Terminal	Transition of 485 MW combined-cycle power plant to co-firing 5% of hydrogen with intention to reach 100% over the next decade.	First phase completed	USA
Mitsubishi Power	Three projects initially capable of co-firing 30% of hydrogen, with future capability of 100% hydrogen.	Targeted to come online between 2023 and 2025	Three locations in the USA

Very few countries have stated explicit targets for the use of hydrogen or hydrogen-based fuels in the power sector. Japan is one of the few exceptions: it is aiming to reach 1 GW of power capacity based on hydrogen by 2030, corresponding to an annual hydrogen consumption of 0.3 metric tonnes of (Mt), rising to 15–30 GW in the longer-term, corresponding to annual hydrogen use of 5–10 Mt H_2. In its hydrogen roadmap, Korea has set a target of 1.5 GW installed fuel cell capacity in the power sector by 2022, and 15 GW by 2040. A number of countries have, however, recognised the potential of hydrogen as a low-carbon option for power and heat generation, e.g. to provide flexibility for an energy system with high shares of VRE.

Modification requirements for hydrogen co-firing

Reciprocating gas engines today can handle gases with a hydrogen content of up to 70% (on a volumetric basis), while testing has been successfully completed with engines running on pure hydrogen. Gas turbine suppliers already have significant experience in combusting hydrogen-containing fuels, with some smaller units already operating at a >90% share of hydrogen in refineries and in chemical and petrochemical applications. For example, in Korea a 40 MW gas turbine at a refinery has run on gases with a hydrogen content of up to 90% for 20 years. However, blend rates vary depending on the specific technology, condition of the equipment, available infrastructure and their suitability to hydrogen blending.

Most experience has been gained on diffusion flame (non-premixed) combustion systems, which offer high flame stability but utilise an expensive and bulky water or steam injection system (Wet Low Emissions technology) to reduce the high NO_x emissions associated with very high flame temperatures, resulting in large efficiency penalties. State-of-the-art gas turbines (GTs) for power generation are of Dry Low NO_x (DLN) type, which utilise lean-premixed or multi-cluster combustion technology to achieve single digit NO_x levels (with non-premixed systems used only during start up and/or at low load to ensure combustion stability). The maximum allowable H_2 concentration in commercial DLN NG-fired turbines can vary significantly across the fleet of different manufactures, due to the different burner design and combustion strategy implemented, with typical values ranging from 30-60% by volume. R&D activities are in progress to develop DLN GTs which are able to handle the full range of 0-100% fixed H_2 contents blended with natural gas. A successful verification of 100% hydrogen-fuelled Dry Low NOx combustion technology was recently achieved in Japan at 1 MW_e scale.

Challenges associated with the use of H_2/NG blends with high H_2 content in DLN GTs are due to different thermo-chemical properties and combustion characteristics of the two fuels. These include higher risks of autoignition and flashback, due to the higher reactivity and flame speed of H_2, increased risk of combustion instabilities (thermo-acoustic and lean blow out), and higher NO_x emissions due to higher flame temperature. Other combustion-related challenges include changes in the Wobbe Index due to the larger volumetric fuel flow rate required when using H_2 instead of natural gas for a given power, and the need to introduce enhanced cooling measures to avoid overheating of components arising from the higher heat transfer caused by the increased moisture content in the exhaust gas. Importantly, these issues also mean that operating a gas turbine is easier with a fixed blend of H_2 to NG than a variable one, while blend ratios could vary through a gas pipeline distribution network.

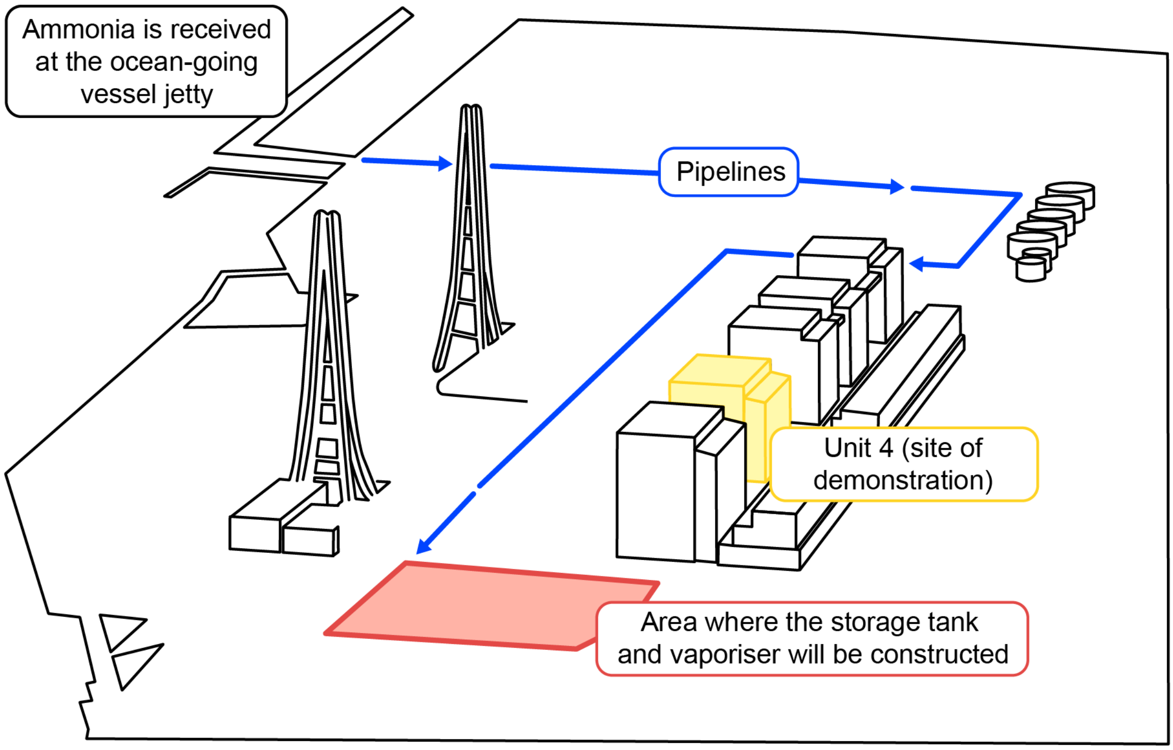
Refurbishment of gas turbine installations to H_2-containing fuels also requires consideration of issues other than those directly related to the combustion process and re-configuration of the burner design/nozzles. Fuel systems operating with high H_2 fractions must be re-configured to allow up to three times higher volume flow to obtain the same heating value input as natural gas. Material compatibility of the fuel system must be ensured, including use of appropriate sealing components. Ventilation, gas/flame detection, fire suppression and electrical systems suitable for H_2-containing environments must be installed in the enclosure to ensure fire safety. There could also be changes in the exhaust energy from the gas turbine necessitating a review of heat recovery steam generator (HRSG) limits. The extent of the modification depends on the type and age of the turbine, fuel composition and emissions requirements.

Co-firing with low-carbon ammonia

The possibility to co-fire with ammonia in existing coal plants has received increasing attention in Japan. Using a 1% share of ammonia was demonstrated in 2017 by Chugoku Electric Power Corporation at one of their commercial coal power stations. Another Japanese utility, JERA, plans to demonstrate a 20% ammonia co-firing at a 1 GW coal-fired unit from 2021 to 2024. For gas turbines, a 70% ammonia co-firing on a 2 MW turbine was recently reported by IHI Corporation. This was achieved by spraying liquid ammonia directly into combustors, thereby eliminating the need for ammonia vaporisation and related peripheral equipment.

For gas turbines, the direct use of ammonia to date has been successfully demonstrated in micro gas turbines with a power capacity of only up to 300 kW. The low combustion speed of ammonia and flame stability have been identified as possible issues preventing its use in larger gas turbines alongside the aspect of increased NO_x emissions. Yet, Mitsubishi Heavy Industries have announced plans to commercialise a 40-MW gas turbine directly combusting 100% ammonia by 2025.

Hekinan Thermal Power Station, where the first large-scale co-firing tests of ammonia with a 20% share are planned to be held in 2024



In the SDS, the use of ammonia for co-firing in coal power stations climbs to 60 Mt per year and 140 TWh of electricity generation by 2050, up from a handful of pilot and demonstration scale projects today. Despite providing only around 0.2% of global electricity generation in 2050, this application accounts for around a third of the consumption of ammonia for purposes other than its existing uses today. A single 1 GW coal power plant will require some 500,000 t/yr of NH_3 for co-firing NH_3 with a 20% share, which represents 2.5% of globally traded ammonia today.

Modification requirements for ammonia co-firing

Modifying existing thermal plants for ammonia co-firing requires boiler modifications and investment in additional facilities like ammonia tanks and vaporisers. As ammonia combustion is characterised by a low flame temperature and generally narrow combustible range, it can cause issues in keeping a stable flame during co-firing. Co-firing also reduces the amount of soot and coal powder particles in the furnace, leading to lower radiative heat transfer but also to reduced ash deposition on heat transfer surfaces and improved boiler performance. The possible formation of large amounts of NO_x from ammonia is a concern. However, the use of NH_3 is already established in coal power plants to reduce NO_x emissions through selective catalytic reduction (SCR) of flue gases. Hence, the required infrastructure and know-how for handling NH_3 already exist.

The NH_3-to-coal ratio and injection methods are two important additional parameters to be considered in ammonia co-firing. With 60% co-firing share, the radiative component of heat transfer was observed to decrease significantly, although total heat transfer to the walls was lowered only by some 3%. In one experiment, NO_x emissions did not rise up to 30% co-firing, when ammonia was mixed in the coal nozzle or injected from the ammonia gun.

Gas turbine systems are also developed for ammonia as a fuel. Such systems can either combust H_2 derived from ammonia (NH_3), blends of NH_3 and H_2 or NH_3 directly. The technology currently has a lower technology readiness level compared to hydrogen co-firing, but gas turbine manufacturers are announcing plans to offer large-scale NH_3-fired GTs around 2025. Ammonia-fired systems benefit from the easier storing of ammonia relative to hydrogen, but the use of NH_3 as fuel poses additional technical challenges arising from its toxic and corrosive nature. Technology is also being developed to supply liquid ammonia directly to the gas turbine without evaporisation, which would lead to a reduction in costs and increase in efficiency. Cracking part of the ammonia back to hydrogen, and combusting the unseparated mix of NH_3, H_2 and N_2 would be one way to achieve combustion characteristics more similar to hydrocarbons.

Co-firing with sustainable biomass

The co-firing of biomass with coal has been developed and practised for over 20 years, first in Western Europe and North America and now in Asia. The main types of biomass that have been co-fired with coal are wood, agricultural residues and grasses. Since relatively high co-firing shares can be achieved with biomass, it provides a quick way to reduce the use of fossil fuels at existing large-scale power plants at capital costs that are much lower than investment in a new thermal power plant.

Key technical options for the conversion of large, pulverised coal (PC) boilers to the firing and co-firing of biomass have been successfully demonstrated over the past 15 to 20 years. Co-firing in PC boilers has dominated the sector for the last

20 years, and remains the most popular method for co-firing in countries such as Japan and South Korea. However, in China co-firing via gasification has been preferred.

Waste materials, agricultural residues and cereal straws are relatively inexpensive feedstock options, but tend to have higher ash content and more problematic ash compositions. They can therefore be used at only modest co-firing ratios. Feedstocks based on clean wood tend to have lower ash content, and can be used at higher co-firing ratios. For 100% direct biomass firing, only the higher grade and more expensive wood materials are currently suitable.

Higher co-firing ratios incur higher retrofitting costs

Three principal methods exist for modifying an existing coal-fired utility boiler for biomass co-firing. In the co-milling method, biomass is mixed with coal and passed through the existing milling system. This method can be implemented relatively quickly with minimal capital cost, involving only investments in biomass storage and handling systems, but the amount of biomass is limited typically to 5-10% co-firing (on energy basis) or less.

In an alternative method, biomass is processed separately either in a modified coal mill, or a new dedicated mill. The separately milled biomass can then be fired together with coal or alone in a modified coal or a new dedicated biomass burner. With separate milling, the co-firing ratio can be significantly increased, but at the expense of higher retrofitting costs.

One of the principal concerns when considering the conversion of a coal boiler to 100% biomass firing is the risk of increased ash depositions and excessive slag formation on the superheater elements, around the burners and on other refractory surfaces in the furnace. These issues can be reduced by modifying the reheater and superheater for larger spacing, using more corrosion resistant high alloy materials, increasing soot blowing and lowering the final temperature. However, the risk should be low with high-grade wood pellet materials that have low ash content and modest levels of alkali metals.

In the third method, biomass is converted to fuel gas in a separate gasifier, followed by combustion either in a boiler or a turbine. This method incurs higher investment costs, but allows up to a 100% co-firing share and the use of lower quality and thus cheaper biomass and waste feedstocks.

This indirect biomass co-firing approach has been realised in Finland, where the world’s largest biomass gasification plant was commissioned by a local utility company in 2012. The 140-MWth gasification plant was built adjacent to an existing 565 MW_e coal-fired plant, originally constructed and commissioned in 1982, with the intention to replace 25-40% of the power station's coal use with forest (wood) residue sources within 100 km from the plant. Operation with solely biomass-derived fuel gas was demonstrated in 2014, and since then, the boiler has been run on 100% biomass when the load is low during autumn and spring.

The project involved construction of feedstock handling systems, a circulating fluidised-bed gasifier and modifications to the existing coal boiler. A dryer was built to reduce and control the moisture content of the biomass feedstock using by-product heat from the plant. The dryer further widens the feedstock base, and allows the use of lower quality and therefore cheaper biomass residues.

Co-firing shares can be increased gradually over time

A conversion to 100% biomass firing can be carried out either in a relatively short period of time, or gradually over the course of many years. Drax power station in the UK is an example of converting a large-scale coal-fired power plant to 100% biomass firing through several intermediate stages. The power station itself was commissioned in the 1970s (units 1-3), expanded in the 1980s (units 4-6), and is comprised of six pulverised bituminous coal boilers and turbine units, each of 660 MW_e capacity. The first biomass trials were held in 2003, pre-mixing biomass with coal and using existing coal milling and feeding systems with a few or no modifications. Although this approach would have allowed the co-firing of up to a 10% share of biomass, the share was constrained at the level of the power station to 3%, due to limitations imposed by biomass reception, handling and mixing systems.

As a next step, a direct injection co-firing system was demonstrated in 2005-2006 and eventually realised in 2007-2010. The system enabled the co-firing of around 1.5 Mt of wood pellets, equivalent to around 400 MW_e or 10% of the generation capacity of the total station. During the period of 2012-2016, three generation units were converted to 100% biomass with the help of state aid from the UK government, representing 50% of the stations generating capacity, or around 2 000 MW_e.

In May 2021, the utility announced it had started the planning process for deploying a bioenergy with carbon capture and storage (BECCS) system at the power station. This next step in the gradual conversion of the power station would make it possible to start capturing and permanently storing biogenic

CO_2 emissions. Building works could commence in 2024 with plans to become operational by 2027.

Retrofitting with CCUS

Retrofitting with CO_2 capture equipment can enable the continued operation of existing power plants in a low-carbon energy system, as well as the operation of associated existing infrastructure and supply chains, but with significantly reduced emissions (85-98% lower CO_2 emissions than unabated power plants, depending on the technology). In addition to adding capture equipment at the power plant, CO_2 transport and storage infrastructure needs to be built to handle the captured CO_2.

To date, CCUS[1] has been applied to two commercial power plants, the Petra Nova Carbon Capture project in Texas and the Boundary Dam Carbon Capture project in Canada, which are both CCUS retrofits to existing coal-fired power plants. At 240 MW, the Petra Nova project, commissioned in 2017, is the largest post-combustion capture system installed on a coal-fired power plant. The Petra Nova project captured up to 1.4 $MtCO_2$ annually for use in enhanced oil recovery, until CO_2 capture operations were suspended in 2020 in response to low oil prices.

Experience with building and operating CCUS facilities has contributed to progressive improvements in CCUS technologies as well as significant cost reductions. At around USD 65/tCO_2 the capture cost of the Petra Nova coal-fired power plant is more than 30% lower than the Boundary Dam facility, which started operations in 2014. Detailed engineering studies show that retrofitting a coal-fired power plant today could cost around USD 45/tCO_2. There are now plans to equip as many as 29 power plants with capture equipment (including in China, the United Kingdom and the United States). With further RD&D and growing practical experience, there is considerable potential to further reduce energy needs and costs.

In a study for the IEA Coal Industry Advisory Board, the International CCS Knowledge Centre identified a series of opportunities to reduce the cost of retrofitting post-combustion capture at the plant level. Their findings are based on the knowledge and experience gained from the Boundary Dam and Petra Nova

[1] In this report, carbon capture and storage (CCS) includes applications where the CO_2 is captured and permanently stored. Carbon capture and utilisation (CCU) or CO_2 use includes where the CO_2 is used, for example in the production of fuels and chemicals. Carbon capture, utilisation and storage (CCUS) includes CCS, CCU and also where the CO_2 is both used and stored, for example in enhanced oil recovery or in building materials, where its use results in some or all of the CO_2 being permanently stored.

facilities and the 2018 Shand CCS feasibility study. Reductions can be achieved in capital costs, operating costs and CO_2 transport and storage costs.

Capital costs are an important component of CCUS projects and account for more than half of the total cost of capture at the two CCUS retrofitted plants. The operating costs for CCUS-equipped plants are typically higher than for unabated plants due to the additional energy required to operate the capture facility. Further operating expenses relate to the consumption of solvents, chemical reagents, catalysts, the disposal of waste products and additional staff needed to run the CCUS facilities.

Cost reduction potential for next-generation CCUS projects by cost type

Cost component	Cost reduction measure
Capital costs	Scaling up the CCUS plant
	Improved site layout and modularisation
	Increasing capture capacity
	Increased efficiency of the host power unit
	Optimising CCUS operating envelope
	Development of a CCUS supply chain
Operating costs	Reduced amine degradation
	Lower maintenance costs
	Optimisation of thermal energy
	Optimised water consumption
	Increased compression efficiency
	Digitalisation
Transport and storage costs	Siting with complementary partners in industrial CCUS hubs, allowing for shared infrastructure

Note: Based on International CCS Knowledge Centre (2019).

Modification requirements

At the level of an individual plant, the cost of a CCUS retrofit depends on the age and technological characteristics of the asset as well as on the market conditions and regulatory framework. In many cases, the early retirement of assets before full repayment of capital costs is an expensive option for plant owners and governments, particularly in emerging economies with younger assets. Retrofitting these assets with CCUS to allow continued operation can provide plant owners with an asset protection strategy and may prove cheaper than early retirement.

A CCUS retrofit of a coal-fired power plant would involve adding a capture unit to separate CO_2 from the flue gases before they are released to the atmosphere. This is known as "post-combustion capture". The most cost-effective approach today is absorption of CO_2 by amine-based solvents that are regenerated by heating, which liberates the absorbed CO_2 to be compressed for transport. To avoid contamination of the solvent, the flue gas needs first to undergo flue gas desulphurisation (FGD).

Another approach to retrofitting CO_2 capture while upgrading the plant could involve replacing the boiler with a so-called oxy-fuel boiler whereby the coal is combusted in an oxygen-rich environment. This requires a more extensive and expensive upgrade of the plant and energy is required for the production of oxygen from air, but there is a cost saving in CO_2 separation because the resulting flue gas stream is almost 100% CO_2. A solution could come in the future from electrolysis-based hydrogen plants, which produce large amounts of oxygen as a by-product. This can represent a local opportunity not only for power plants but also for waste to energy plants to implement oxy-combustion. While oxy-fuel retrofits cannot be ruled out, the additional retrofit costs and less developed status of the technology are factors that favour post-combustion capture.

Adding CCUS to a power plant incurs an operational cost due to the reduction of efficiency caused by the energy requirements of CO_2 capture, transport and storage. CO_2 capture is responsible for the overwhelming majority of additional energy requirements which translate into fuel costs for the power plant operator. The efficiency penalty depends on the type of CO_2 capture technology used, but for current, state-of-the-art designs, it is usually considered to be in the order of 5-9%. Other additional operational costs like solvent purchases, have lower costs compared to the impact on fuel purchases per unit of output.

The retrofit at Boundary Dam involved adding an amine-based CO_2 capture plant to remove 90% of the CO_2 in the flue gas, compress it and inject it into a pipeline to an oil production operation. Most of the CO_2 is used for enhanced oil recovery (EOR)[2] and the power plant operator is paid for the CO_2 it supplies. Boiler modifications were also made: the old steam turbine was replaced with a new state-of-the-art turbine and an FGD system was added to remove virtually all of

[2] CO_2-EOR is a proven technology for rejuvenating the production of oil at mature oilfields but can also provide a means of storing CO_2 permanently, as much of the gas injected is ultimately retained in the reservoir over the life of the project. For a CO_2-EOR/CCUS project to be considered a genuine climate mitigation measure, the CO_2 has to come from an anthropogenic source, such as a power station or natural gas processing plant. In practice, about 70% of the CO_2 used in the United States EOR projects today comes from naturally occurring underground reservoirs (not included here as CCUS). Several additional activities would also need to be undertaken before, during and following CO_2 injection, including additional measurement, reporting and verification of stored volumes.

the SO_2 from the flue gas. Energy requirements have been minimised by using a combined SO_2/CO_2 capture system and with selective heat integration. After allowing for the energy requirements of the capture plant, the net generating capacity of the retrofitted Unit 3 was reduced to 120 MW from 140 MW, and the refurbishment extended its life by at least 30 years.

The Petra Nova project retrofitted post-combustion amine-based CO_2 capture to a 240 MW slipstream at a 610-MW unit located at NRG Energy's Parish sub-bituminous coal-fired power station. This capture unit is designed to capture 1.4 $MtCO_2$ per year at a capture rate of up to 90%. The captured CO_2 was compressed and transported via a 130-km pipeline to the West Ranch oil field, for injection for EOR at a depth of 1-2 km. A key difference between the Boundary Dam and Petra Nova facilities is that steam and power for the capture unit at Petra Nova are provided by a 75-MW gas-fired co-generation unit that came online in 2013. As a result, the retrofit did not result in a de-rating of the existing asset because steam and power from the base plant was not redirected for CO_2 capture. Energy from the co-generation unit that is not needed for CO_2 capture can be sold to the grid at times of high electricity demand or supply shortage, due to the flexibility advantages of a single cycle turbine.

From a broader economic perspective, retrofitting CCUS generally makes most sense for power plants and industrial facilities that are young, efficient and located near places with opportunities to use or store CO_2, and where alternative generation or technological options are limited. Other technical features that must be considered when assessing whether a retrofit is likely to make commercial or economic sense are capacity, availability of on-site space for carbon capture equipment, load factor, plant type, proximity to CO_2 transport infrastructure and confidence in the long-term availability of CO_2 storage.

If there is insufficient space available at the power plant site on which the CO_2 capture facility could be hosted, the plant may be technically unsuitable for a CCUS retrofit. The total land needed to accommodate a CO_2 capture facility, including compressors, has been estimated in different studies to range from 0.03 to 0.08 hectares per MW retrofitted for units of 300 MW to 600 MW.

Transport and storage requirements

After capture, a CCUS retrofit requires the CO_2 to be transported to suitable locations for use or permanent geological storage. Transport of large volumes of CO_2 in pipelines (average pipeline capacity range is 3-30 $MtCO_2$/year) is a known and mature technology, with significant experience from more than 8 000 km of

CO_2 pipelines in North America – mostly in the United States. CO_2 is transported 66 km from the Boundary Dam plant in Saskatchewan, Canada. There is also experience, albeit limited, with transport of CO_2 using offshore pipelines, for instance at the Snøhvit project in northern Norway. CO_2 is also transported by ship, but in small quantities.

Carbon capture retrofits at power plants require a high confidence in the availability of CO_2 storage or demand for use. Geological storage involves the injection of CO_2 into suitable geologic formations and the subsequent monitoring of injected CO_2. Suitable geologic formations include saline aquifers, depleted oil and gas fields, oil fields with the potential for EOR and, potentially, coal seams that cannot be mined with potential for enhanced coal-bed methane (ECBM) recovery.

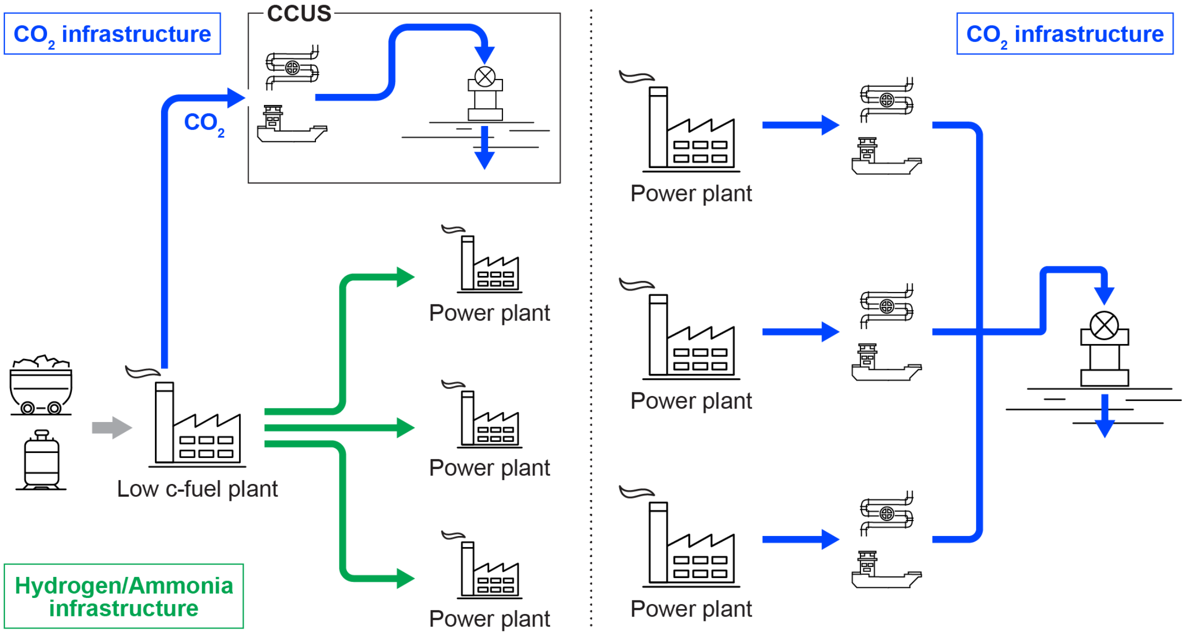
The fundamental physical processes and engineering aspects of geological storage are well understood, based on decades of experience. For example, the Sleipner project off Norway has been storing around 1 Mt CO_2/year in a deep saline aquifer under the North Sea since 1996, and six further projects around the world are now storing large volumes of CO_2 in dedicated geological formations (that is, not associated with EOR). This project experience is supported by decades of research and modelling, operation of analogous processes (e.g. acid gas injection, natural gas storage and EOR), studies of natural CO_2 accumulations and pilot projects.

When CO_2 is injected into a reservoir, it flows through it, filling the pore space. The gas is usually compressed first to increase its density, turning it into a liquid. The reservoir typically needs to be at depths greater than 800 metres to retain the CO_2 in a supercritical state. The CO_2 is permanently trapped in the reservoir through several mechanisms: structural trapping by the seal, solubility trapping in pore space water, residual trapping in individual or groups of pores and mineral trapping by reacting with the reservoir rocks to form carbonate minerals. CO_2 storage can be undertaken safely – provided there is proper site selection, planning and operations – but it has to be recognised that all storage reservoirs are different and therefore need extensive dedicated characterisation.

Comparing CCUS-based pathways to decarbonise thermal plants

CCUS can support emission reductions from existing thermal power plants in two key ways: through direct retrofitting to the power plant or by enabling low-carbon production of hydrogen or ammonia that is subsequently co-fired in the plant (see Chapter 3).

Comparison of applying CCUS to different parts of the low-carbon electricity value chain



Note: On the left side, CO_2 is captured from the concentrated process gases of the fuel conversion plant. Then the decarbonised fuel is shipped to the power plant. On the right side, CO_2 is captured from the dilute flue gases of the power plant. Then the CO_2 is shipped and stored.

The two pathways bring benefits and trade-offs when considering the potential for emission reductions across the value chain, the CO_2 transport and storage needs and the operation of the power plant.

Applying CCUS at the fuel production stage (upstream) to facilitate the co-firing of low-carbon ammonia and hydrogen can have several advantages over direct retrofitting of a thermal power plant. They include:

- lower cost CO_2 capture opportunities due to a more concentrated CO_2 stream,
- the potential to locate new production facilities near CO_2 storage resources or CO_2 utilisation facilities (reducing transport infrastructure requirements), and
- a more attractive business case for CCUS infrastructure investment where this investment can underpin the supply of low-carbon hydrogen or ammonia to

meet growing demand from a large number of customers (reducing commercial risk and creating economies of scale).

Moreover, fuel production facilities operate at baseload and do not have to follow a varying demand. Therefore, upstream CCUS can operate at baseload as well. However, the approach would require dedicated ammonia or hydrogen transport and handling infrastructure to supply the fuel to power plants, in addition to the CO_2 transport and storage infrastructure at the production site.

Retrofitting CCUS directly to a power plant (downstream) involves higher-cost CO_2 capture (per tonne of captured CO_2) relative to ammonia or hydrogen production due to the more diluted CO_2 concentration in the flue gas. The investment needs for CO_2 transport and storage infrastructure may also be greater where existing power plants are not located in close proximity to CO_2 storage resources or industrial clusters that can support shared infrastructure. Further, the utilisation (or load factor) for the capital-intensive infrastructure may be lower where CCUS-equipped plants are operated in a flexible manner, increasing costs. However, the overall efficiency of the value chain (in energy terms) is higher for CCUS retrofits as only one conversion step is needed from fuel to final output (electricity).

Both power plants retrofitted with CCUS, and plants co-firing ammonia or hydrogen can be run flexibly to help integrate renewables into the power system. Both could also be operated in a baseload capacity, but with higher costs for co-fired plants due to the higher-cost fuel. The plant modification requirements for CCUS retrofitting (discussed above) are greater than for co-firing.

Comparison of CCUS-based pathways to decarbonise fossil fuel power plants

	Coal route		Natural gas route	
	CCUS retrofit of power plant	NH_3 co-firing with CCUS applied to fuel production	CCUS retrofit of power plant	H_2 co-firing with CCUS applied to fuel production
Value chain assessment				
Overall efficiency (fuel to electricity)	35%	22%	41%	38%
CO_2 storage needs (tCO_2 / MWh_e)	1.0	1.8	0.4	0.5
Capacity factor of CO_2 infrastructure	Variable	High	Variable	High

Power plant operation				
CO_2 emissions reduction	85-98%	Dependent on co-firing share	85-98%	Dependent on co-firing share
Cost impact of flexible operation	High	Low	High	Low
Modification requirements	Large	Small	Large	Small
Technology readiness level (power plants)	9	5-8	8	6-9

Note: "Overall efficiency (fuel to electricity)'' for CCUS retrofitted power plants includes efficiency losses due to CCUS, while for co-firing it includes both CCUS-equipped fuel production efficiency and unabated power generation efficiency. Co-firing is not assumed to affect power generation efficiency, which is assumed to be 44% for ultra-super critical coal-based generation and 52% for combined-cycle gas turbine-based generation. Natural gas to hydrogen efficiency with CCUS is estimated at 74%, and for coal to ammonia with CCUS it is estimated at 49%.

Chapter 3. Production and transport of low-carbon hydrogen and ammonia

Highlights

- **Global hydrogen demand was 90 million tonnes (Mt) in 2020 and was responsible for almost 900 Mt of CO_2 emissions.** Hydrogen production is dominated by fossil fuels, with water electrolysis accounting for an estimated 30 ktH_2 in 2020, less than 0.03% of global production. With sixteen plants in operation, hydrogen production from natural gas with CCUS amounted to 0.7 MtH2 in 2020, 0.7% of global production.
- **Ammonia production was 185 Mt in 2020 and was responsible for around 450 Mt of CO2 emissions.** While CO2 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. Ammonia is already a widely traded commodity. Its global trade was about 20 Mt, or 10% of production in 2019.
- **Substantial GHG emission reductions can be achieved with low-carbon hydrogen and ammonia when compared to the unabated production from fossil fuels.** This means both maximising CO_2 capture from fossil fuels based hydrogen production and minimising upstream emissions from the production and delivery of natural gas and coal. Especially at high CO_2 capture rates, the emissions of the fossil fuel route become dominated by upstream emissions. For the electrolytic route, very low emissions can be achieved if electricity from wind, solar PV or other low-carbon sources are used. Capturing and permanently storing CO_2 from biomass-based hydrogen production would allow the production of carbon-negative hydrogen and ammonia.
- **The cost of low-carbon hydrogen and ammonia depends strongly on regional conditions.** Natural gas with carbon capture, utilisation and storage (CCUS) is currently the least-cost production route for low-carbon hydrogen and ammonia in regions with cheap natural gas, and access to CO_2 storage. Due to continuing reductions in the cost of renewable electricity and scale benefits in electrolysers, the costs of the electrolytic route are decreasing fast and are estimated to reach USD 13/GJ (USD1.5/kg) for hydrogen and 22/GJ (USD 400/tNH_3) for ammonia in regions with excellent wind and solar resources by 2030. Although the costs of low-carbon hydrogen and ammonia are becoming comparable with respective production costs from unabated fossil fuels for use as a chemical feedstock, they are still expected to remain significantly more expensive than coal and natural gas for energy use in 2030.
- **Marine transport costs can represent a significant share of the total supply costs of low-carbon fuels.** The cost estimate for marine transport of low-carbon fuels for a distance of 10 000 km is USD 14-19/GJ (USD 1.7-2.3/kgH_2) for liquid hydrogen, while for ammonia it is significantly lower at USD 2-3/GJ (USD 40-60/tNH_3).

Hydrogen market

In 2020, global hydrogen demand was around 90 megatonnes (this includes more than 70 Mt used as pure hydrogen and less than 20 Mt was mixed with other gases for methanol production and for a direct reduced iron [DRI] steel manufacturing process) and has grown 50% since the turn of the millennium. Around 72 Mt H_2 (or 79%) were covered by dedicated hydrogen production plants, while the remainder was by-product hydrogen (21%), i.e. hydrogen that is produced in facilities and processes that are designed primarily for other products.

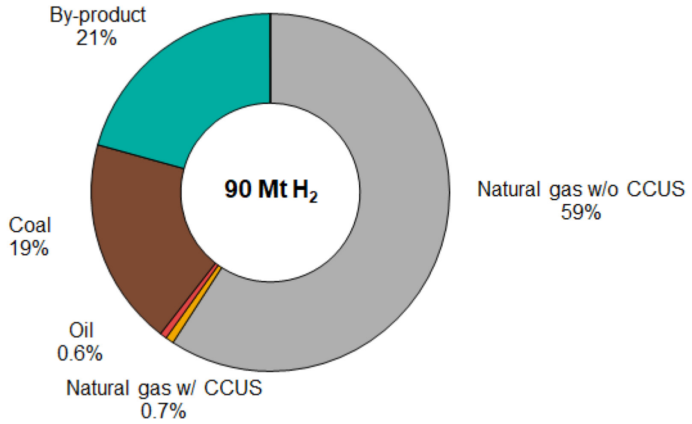
Practically all hydrogen demand comes from refining and industrial uses. Refineries consume close to 40 Mt H_2 to remove impurities (especially sulphur) and to upgrade heavy oil fractions into lighter products, whereas the industrial sector consumes more than 50 Mt H_2, mainly as a feedstock. Chemical production accounts for around 45 Mt H_2 demand, three-quarters of which are consumed in ammonia production and another quarter in methanol production. The remaining five Mt H_2 is consumed in DRI steelmaking. This distribution of hydrogen demand among end-uses has remained almost unchanged since 2000, with a slight increase in the contribution from DRI.

The vast majority of hydrogen production is based on natural gas reforming with some exceptions, like the use of coal gasification in Chinese refineries, which makes up close to 20% of dedicated hydrogen production in the country's refineries.

Hydrogen production

Around 240 billion cubic metres (bcm) of natural gas were used in 2020 for hydrogen production, accounting for 60% of annual global hydrogen production (representing 6% of global natural gas use). Coal comes next, due to its dominant role in China: it accounts for an estimated 19% of global hydrogen production and uses 115 Mt of coal (2% of global coal use). Oil and electricity account for the remainder of the dedicated production.

Sources of hydrogen production in 2020



Source: Global Hydrogen Review 2021

As a consequence of the dominance of fossil fuel use, hydrogen production was responsible for almost 900 million tonnes of direct carbon dioxide (Mt CO_2) emissions in 2020 (2.5% of global CO_2 emissions in energy and industry), equivalent to the CO_2 emissions of Indonesia and the United Kingdom combined.

Various low-carbon pathways exist to produce hydrogen: from water and electricity through electrolysis, from fossil fuels with CCUS and from bioenergy. Production from water electrolysis accounted for an estimated 30 kt of hydrogen in 2020, less than 0.03% of global production. With 16 plants in operation, hydrogen production from natural gas with CCUS amounted to 0.7 MtH_2 in 2020, 0.7% of global production. These include facilities that produce pure hydrogen and capture CO_2 for geological storage or sale. CO_2 captured from ammonia plants for urea manufacturing is excluded.

Hydrogen from natural gas

Steam methane reforming (SMR) is the dominant process for the production of hydrogen. The SMR process usually starts by receiving the feed gas under pressure. Any sulphur compounds it may contain are transformed by reaction with hydrogen to hydrogen sulphide, which can be then absorbed in a bed of zinc oxide pellets at 300-400°C. The desulphurised feed is then mixed with steam and further preheated before entering the reformer, where it reacts at 800-900°C with steam to produce a mixture of carbon monoxide, carbon dioxide and hydrogen as the main constituents. The reaction takes place in furnace tubes packed with nickel catalyst, and the intense heat needed to drive this endothermic reaction is supplied by natural gas burners in the furnace radiation box.

After reforming, the process gas is cooled in a waste heat boiler and fed to a shift conversion step where the hydrogen content of the gas is maximised. The gas is then further cooled in a heat recovery train to about 30°C and sent to a pressure swing adsorption (PSA) unit for purification. The PSA process operates at about 18 – 30 bar and separates hydrogen from the gas mixture by adsorbing other compounds. The separation efficiency of the PSA unit is between 85-90% depending on the number of adsorbers in sequence and the operating conditions. The remaining hydrogen together with adsorbed impurities like carbon dioxide, carbon monoxide, methane and nitrogen forms an off-gas stream that is released from the PSA system at ambient pressure. The PSA off-gas has heating value and is used in the process as a reformer fuel. The CO_2 from the PSA off-gas can be further separated and used for other industrial processes or in food and beverages. While it could be compressed and transported for permanent storage, today almost all CO_2 that is not utilised is simply released into the atmosphere.

Autothermal reforming (ATR) is another example of a commercially available process for producing hydrogen from natural gas, although it is much less common today than SMR. A major difference from SMR is that the reaction heat needed for reforming is generated in the ATR by internal combustion with oxygen. Since this eliminates the need for heat from external burners, all the CO_2 formed in the process remains concentrated in the process gas and can be conveniently captured as a part of hydrogen purification.

Methane pyrolysis (MP), also known as methane cracking, is an alternative technology to conventional SMR for producing low-carbon hydrogen, which is rapidly approaching large-scale demonstration phase. It is carried out by cracking the fuel through high temperature heat to produce solid carbon and H_2 in a one-step process. This avoids the direct production of CO_2 (and hence the need for its disposal) and co-produces solid carbon. Its emissions depend on the source of energy needed to drive the endothermic reaction, the source of methane and end use of the carbon product. The competitiveness and positioning depend on future trends in gas prices and global market demand for solid carbon like carbon black and other value-added solid carbon products as each tonne of hydrogen produced results in around 3 tonnes of solid carbon co-product. The current market for carbon black is about 13 Mt per year, so producing the global pure hydrogen demand by methane pyrolysis would co-produce almost 20 times as much carbon black as the current market demand. Hence, new markets for carbon black would be needed to significantly decrease the cost of hydrogen production.

Full electrification of methane reforming, also known as e-SMR, is another emerging technology, presently in the early stage of development, but with potential for rapid upscaling. This technology offers the potential to reduce the formation of CO_2 by a third in comparison with conventional SMRs, and delivers all CO_2 in a concentrated stream that would be amenable to capturing. It also brings additional advantages including a more compact reactor design due to the absence of a firing section, faster response times and more uniform heating. However, to realise its full CO_2 mitigation potential, low-carbon electricity needs to be used, which might have added cost either in the form of electrical energy storage or due to intermittent operation.

Hydrogen from coal

Hydrogen can also be produced from coal via gasification. Coal gasification processes use pure oxygen, which is produced from air using a cryogenic air separation unit. The coal feed is milled and made into a slurry with water. The feed is then heated in the presence of oxygen to about 1200-1500°C to generate a gas mixture rich in carbon monoxide, carbon dioxide and hydrogen. The produced gas is then cleaned from impurities like soot and slag to protect downstream processes. The remaining process steps include a water-gas shift reaction for maximising the hydrogen content, CO_2 removal and sulphur removal. Hydrogen production via coal gasification is considerably more emissions-intensive than natural gas-based production.

Hydrogen from biomass

Biomass gasification for synthetic fuel applications was demonstrated a few times in the 2010s using fluidised-bed gasifiers followed by upgrading to different end-products like Fischer-Tropsch fuels, synthetic gasoline and biomethane. The largest demonstration plant to date was built as a part of the GoBiGas demonstration project in Sweden. It was commissioned in 2014 by Göteborg Energi in Gothenburg, and featured a 30 MW_{th} dual fluidised-bed biomass gasifier that converted pellets to raw synthesis gas. The syngas was purified with scrubbers and filters, and converted to synthetic methane over a nickel catalyst at elevated temperature and pressure.

Unlike coal, biomass feedstocks are characterised by a high content of volatiles that form a range of light hydrocarbons and tars during gasification. These impurities need to be treated before the gas can be further processed using commercially available technologies. Cost-effective and reliable treatment of tars from biomass gasification has for long been a key R&D challenge and as a result, two main approaches have been developed: scrubbing with organic solvents and catalytic reforming. The latter approach is especially suitable for synthesis 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

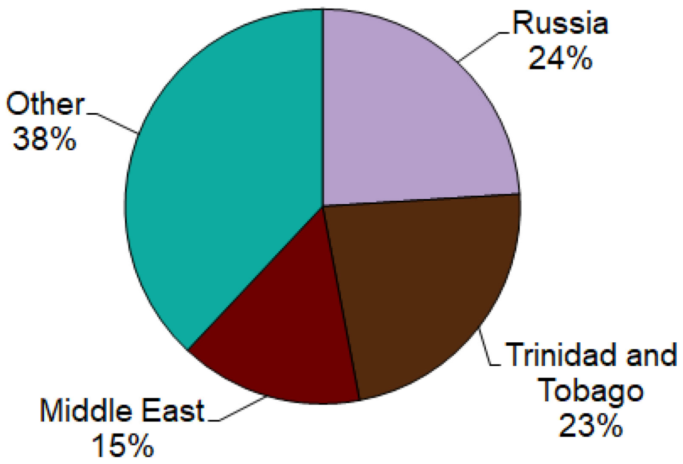
Ammonia is a key product of the chemical and petrochemical sector and the precursor of all synthetic nitrogen fertilisers. It was the largest volume primary chemical in 2020 at 185 Mt of production,[3] of which 72% was from natural gas-based steam reforming, 26% from coal gasification, about 1% from 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.

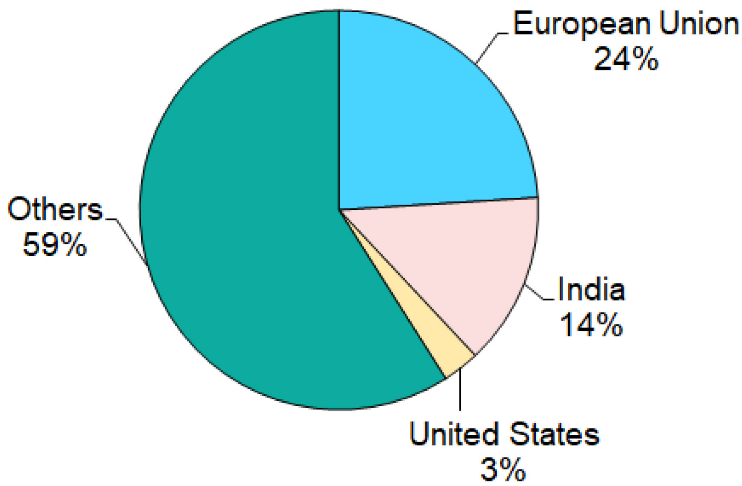
[3] Primary chemicals are the key large-volume, energy-intensive products of the chemical and petrochemical sector, and include ethylene, propylene, benzene, toluene, mixed xylenes, ammonia and methanol. Sulphuric acid has a larger production volume than ammonia, but is not energy-intensive to produce.

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



Top importing regions and countries, 2019



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%.

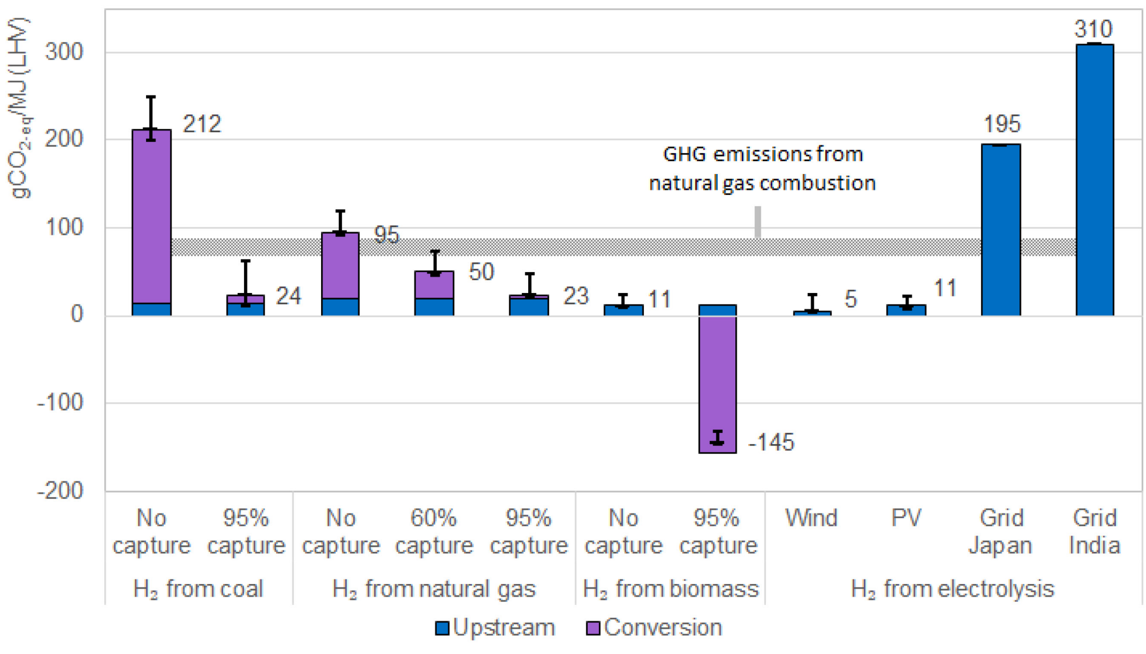
The CO_2 emissions resulting from ammonia production are governed by the hydrogen production step. In 2020, global ammonia production accounted for around 2% (8.6 EJ) of total final energy consumption and 1.3% (450 Mt) of CO_2 emissions from the energy system (40% of this energy was consumed as feedstock 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



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.

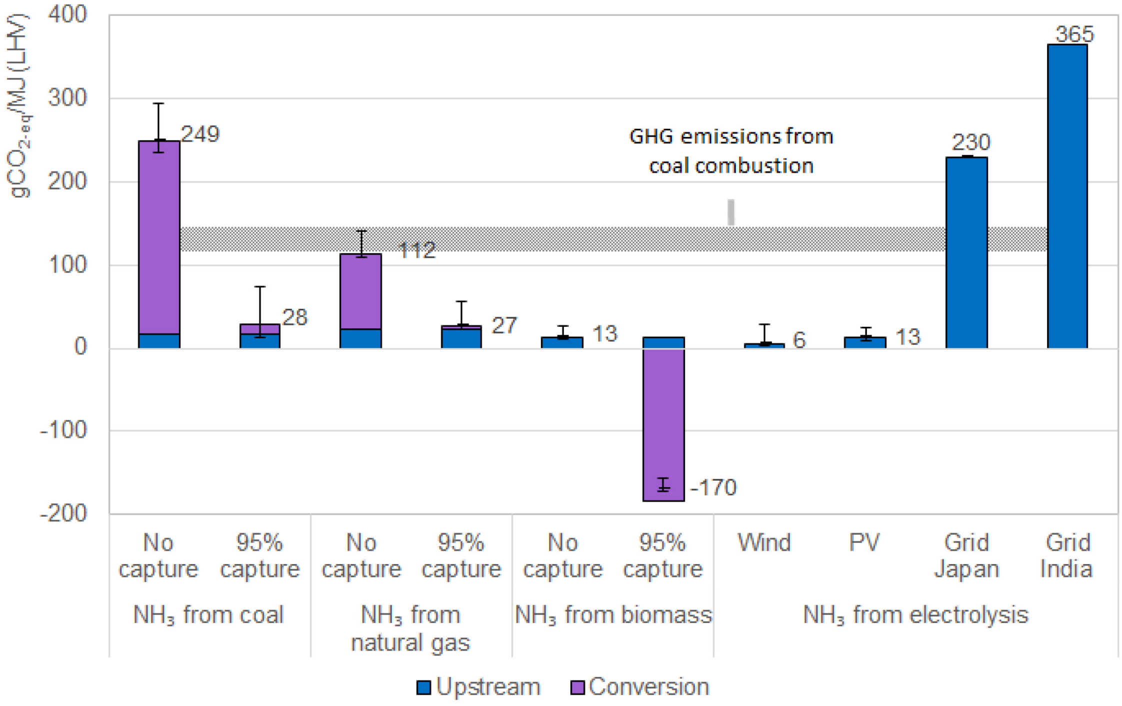
Even despite the high 95% share of capture, the overall emissions of the fossil fuel routes are not reduced close to zero. This is due to the upstream emissions associated with the production of coal and natural gas, which cannot be captured at the hydrogen plant. As a result, upstream emissions govern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

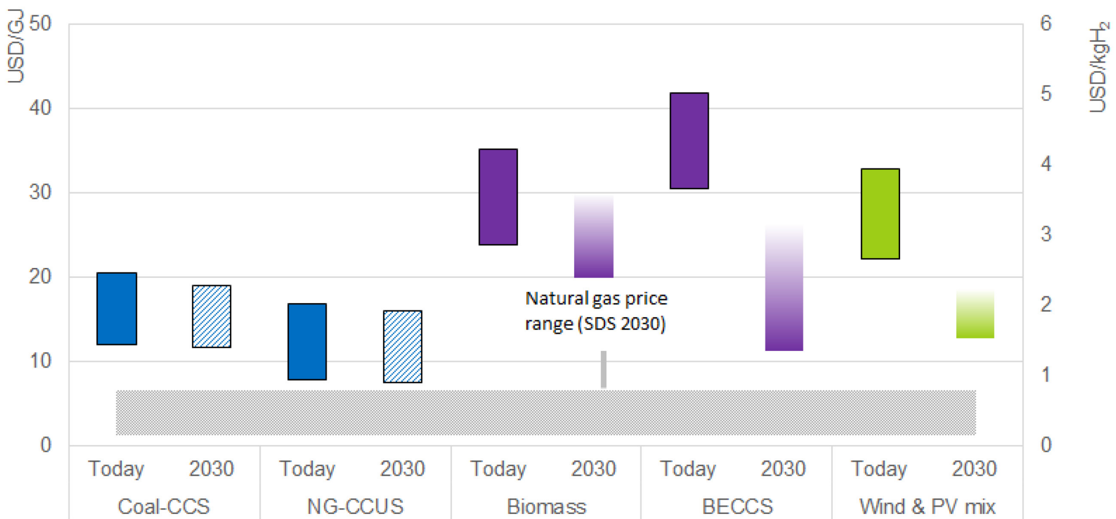
Production cost estimates

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.

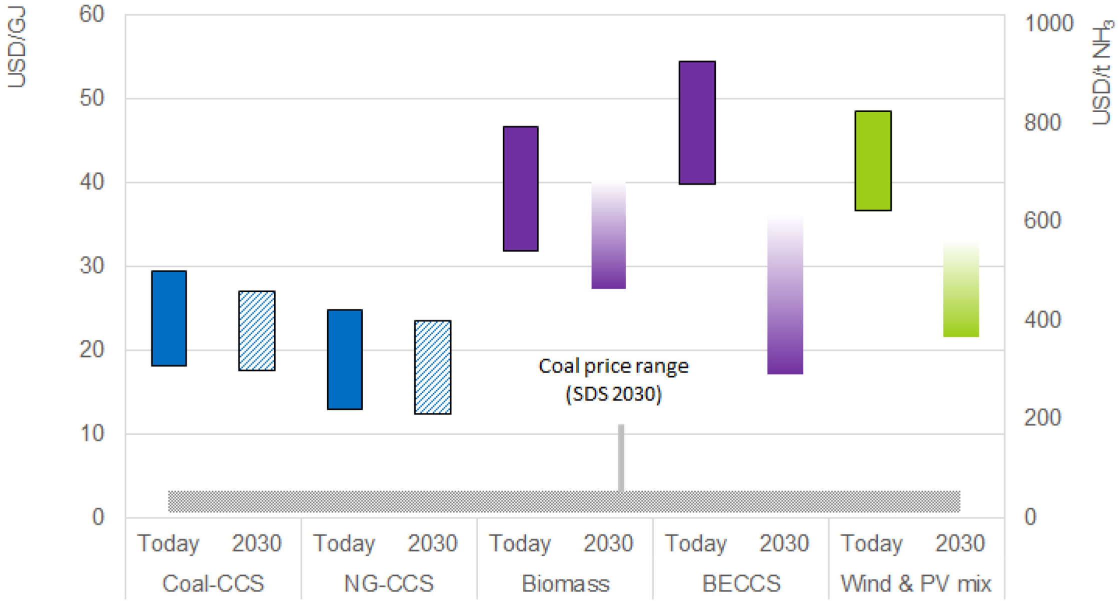
The cost of producing low-carbon hydrogen is becoming comparable with the production of unabated hydrogen by 2030. However, when low-carbon hydrogen is used in the power sector, its price should be compared with the price of natural gas rather than with unabated hydrogen. In the SDS, the price of LNG 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.

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



Note: WACC 5%; Coal 15-80 (today), 12-62 USD/t (2030); Natural gas 1.2-6.6 (today) 1.2-5.3 USD/GJ (2030); biomass residues $50-100/t(dry) (today & 2030); CAPEX estimates for ammonia plants: Coal with CCUS USD 3500/kW_{H2}; NG with CCUS USD 2830/kW_{H2}; Biomass USD 7470/kW_{H2} (today), USD 6170/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, pipeline and storage cost USD 20/tCO_2. Results for electrolytic ammonia are based on a dynamic optimisation of the wind/PV mix for the process, see Annex A for details.

Prices for unabated ammonia have been fluctuating between USD 160-700/t during recent years. However, when low-carbon ammonia is used in the power sector, it should be compared with the price of coal that it replaces. In the SDS, the price of steam coal imports for Japan and Europe in 2030 are USD 55-65/t, or USD 2-3/GJ. This would compare with a fuel ammonia price of just USD 40-50/t. Adding carbon price of USD 82/tCO_2, would increase the coal price by about USD 10/GJ and lead to a comparable fuel ammonia price of USD 210-230/t.

Transport and storage of ammonia

Ammonia pipelines and ships have been transporting liquid ammonia for the fertiliser industry for several decades. Ammonia is well developed also in terms of intercontinental transmission, which relies largely on semi-refrigerated liquefied petroleum gas (LPG) tankers. Trade routes today include transport from the Arabian Gulf and Trinidad and Tobago to Europe and North America. TogliattiAzot in Russia produces up to 3 Mt of ammonia per year, most of which then travels about 2 500 km to Odessa along the world's longest ammonia pipeline, followed by shipping to a number of locations globally.

Ammonia liquefies at -33°C or at 8.6 bar. The current largest refrigerated ammonia tanks in the world are located in Qatar and each has a capacity of 50 kt. The United States alone has over 10,000 ammonia storage sites, many of which connect to a pipeline network stretching more than 3 000 km and connecting the Gulf of Mexico to the Midwest. The current largest plant in the world is the SAFCO IV site in Saudi Arabia with a capacity of 1.3 Mt of ammonia per year.

If ammonia is used only as a hydrogen carrier and is to be reconverted back to hydrogen before end-use, the advantages related to transport and storage need to be weighed against energy losses (about 25-30% depending on the required hydrogen purity) and the required equipment for the conversion and reconversion back to hydrogen.

Transport and storage of hydrogen

The most appropriate storage medium for hydrogen depends on the volume to be stored, the duration of storage, the required speed of discharge and the geographic availability of different options. Salt caverns are used today in the UK and the US for large-scale and long-term hydrogen storage. They provide significant economies of scale, high storage efficiency, low operational costs and low land costs. These characteristics mean that they are likely to be the lowest-cost option for hydrogen storage even though hydrogen has low energy density compared to natural gas.

Where geology does not allow storage in caverns, hydrogen needs to be stored in tanks either in compressed or liquefied form. Today, hydrogen is most commonly stored in small tanks as a gas or liquid for small-scale mobile and stationary applications. Much larger storage options would need to become available if hydrogen were used to bridge major seasonal changes in electricity supply or heat demand, or to provide system resilience.

Hydrogen transmission via pipelines is a mature technology. Currently there are about 4 600 km of hydrogen pipelines, with over 90% located in Europe and the United States. These are usually closed pipeline systems owned by large merchant hydrogen producers and are concentrated near industrial consumer centres (such as petroleum refineries or chemical plants). The cost of transporting hydrogen via pipelines represents a relatively small part of the overall hydrogen costs, generally in the range of USD 0.2-0.7/kg for a distance of a 1 000km assuming a large pipeline with a transport capacity of 500 tH_2 per day.

For marine transport purposes, hydrogen can be liquefied in a manner similar to what is done for natural gas to increase its density. However, liquefaction of hydrogen requires cooling it to -253°C and the required cooling work is equivalent to 20% - 30% of the energy content of the liquefied hydrogen itself. This is considerably more energy than is required to liquefy natural gas, which consumes the equivalent of 10% of the energy content of natural gas. The efficiency of the liquefaction system is also sensitive to size, and large-scale systems can achieve higher efficiencies.

Currently no commercial ships can transport liquefied hydrogen. Such ships would be broadly similar to LNG ships and would require the hydrogen to be liquefied prior to transport. Excellent insulation of the ship's storage tanks is required to keep the unavoidable boil-off from exceeding the average consumption of the propulsion system, thereby avoiding net losses. The expectation is that these ships will be powered by hydrogen that boils off during the journey (around 0.2% of the cargo would likely be consumed per day, similar to the amount of natural gas consumed in LNG carriers). The world's first prototype liquefied hydrogen carrier, the Suiso Frontier, features a double-shelled and vacuum-insulated 1,250 m^3 tank to hold the liquefied hydrogen.

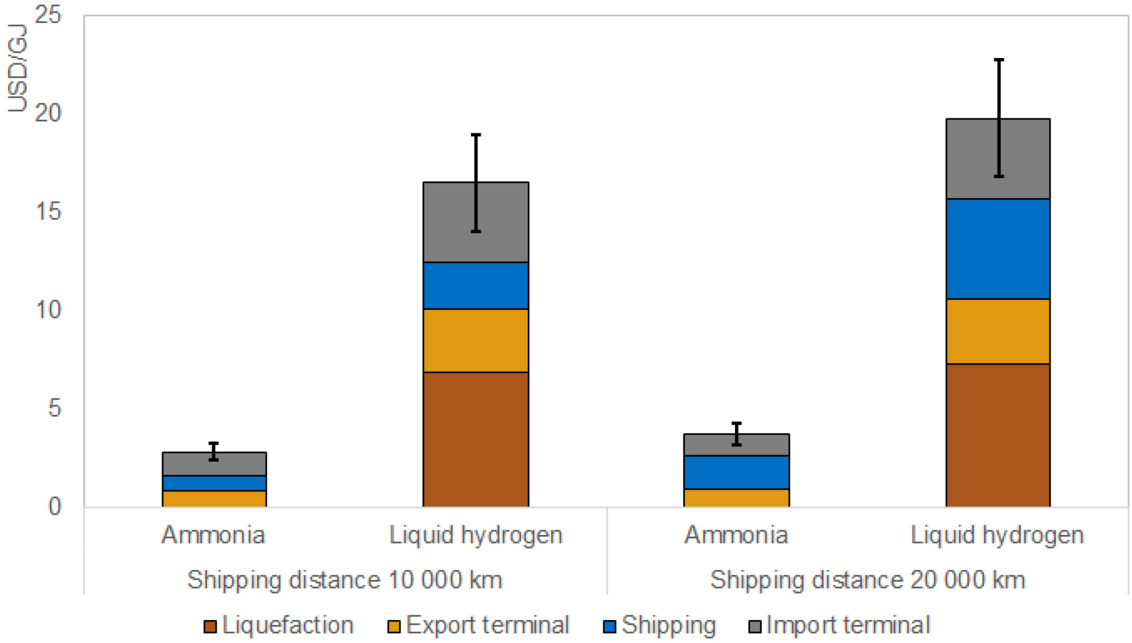
An alternative to liquid hydrogen shipping is the use of liquid organic hydrogen carriers (LOHCs), which involves loading a carrier molecule with hydrogen, transporting it, and then extracting pure hydrogen again at its destination. LOHCs have similar properties to crude oil and oil products, and their key advantage is that they can be transported as liquids without the need for cooling. However, there are costs associated with the conversion and reconversion processes, and carrier molecules are often expensive.

Several different LOHC molecules are under consideration, each with their own characteristics. Methylcyclohexane (MCH) is considered a relatively low-cost LOHC option with toluene as the carrier molecule. Around 22 Mt of toluene is currently produced annually (for commercial products), a quantity that could carry 1.4 MtH_2 if it were to be used as an LOHC. It costs around USD 400–900 per tonne. However, toluene is toxic and would require careful handling. A non-toxic alternative LOHC is dibenzyltoluene. Although it is much more expensive than toluene today, scaling up could make it a more attractive option in the long-term, especially given its non-toxic nature.

Transport cost estimates

The overall cost estimate for transporting LH_2 via shipping for a distance of 10 000 km is USD 14-19/GJ (USD 1.7-2.3/kgH_2); while for ammonia it is significantly lower at USD 2-3/GJ (USD 40-60/tNH_3). In the long-term, further efficiency improvements and process optimisation could reduce the transport costs, and thus the total supply costs for all carriers. The cost of shipping increases with transport distance, but not very significantly. The overall cost estimate for shipping LH_2 over a distance of 20 000 km is USD 17-23/GJ (USD 2.0-2.7/kgH_2) compared to USD 3-4/GJ (USD 60-80/tNH_3) for ammonia.

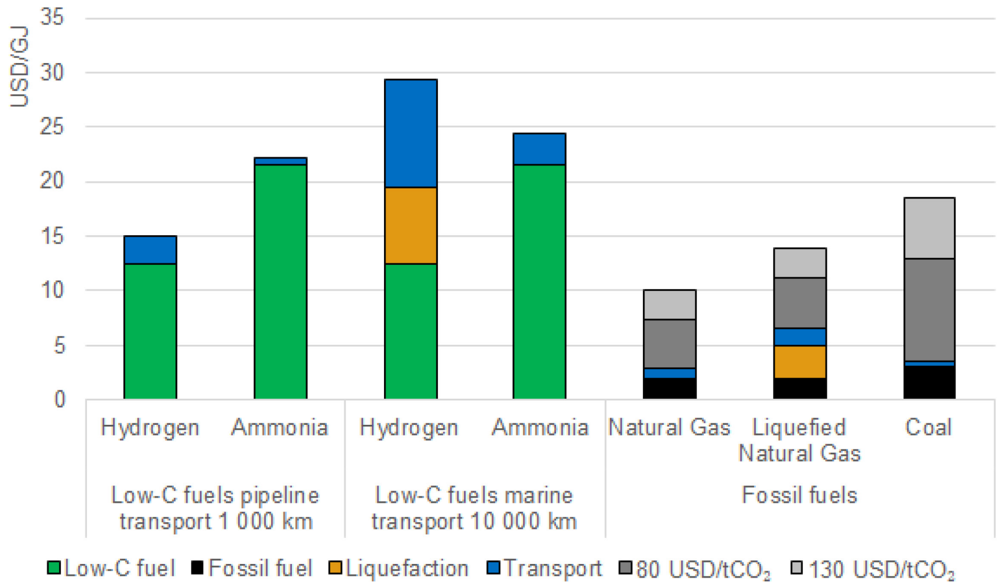
Marine transport cost estimates for ammonia and liquid hydrogen



Note: WACC 5%; energy consumption of H_2 liquefaction 6 kWh/kgH_2. Storage costs included in the cost of terminals. All assumptions available in the Annex.

Although marine transport of liquid hydrogen is significantly more expensive than of ammonia, hydrogen is about 30-40% cheaper to produce, and if hydrogen is needed for the end-use application, reconversion of ammonia to high-purity hydrogen after transport involves further conversion losses and additional costs.

Delivered cost of low-carbon hydrogen and ammonia based on pipeline or marine transport in comparison to the cost of fossil fuels



The overall impact of transport on the supply cost of low-carbon fuels is illustrated above, together with a comparison to fossil fuels at different carbon price assumptions. The cost of pipeline transfer is only a small fraction of the production cost, and does not alter the relative cost difference between hydrogen and ammonia. However, the liquefaction step and more stringent requirements associated with low-temperature storage make hydrogen significantly more expensive to transport by sea than ammonia. As a result, marine transport can double the cost of low-carbon hydrogen, increasing its overall supply cost above that of ammonia. However, both low-carbon hydrogen and ammonia remain expensive fuels compared to natural gas, LNG and coal, even under high carbon price assumptions.

Chapter 4. Case studies

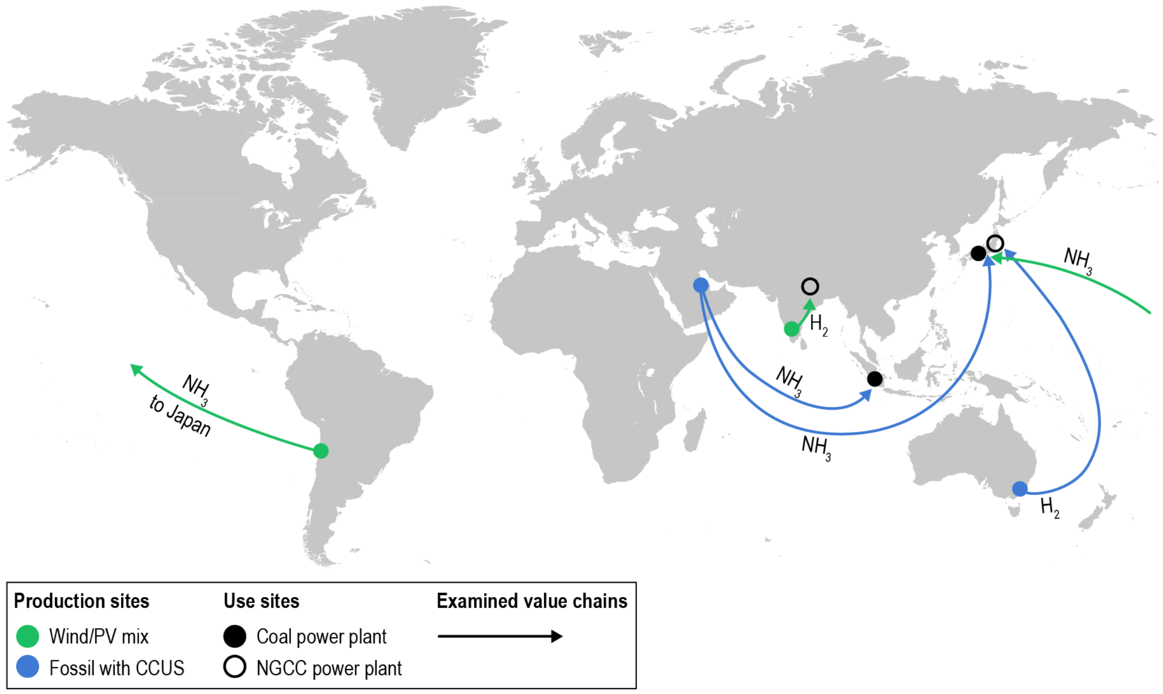
Highlights

- **Three different use categories are examined for low-carbon fuels in the power sector in 2030**. These are: Using imported low-carbon hydrogen and ammonia in an advanced economy having a carbon price of USD 82/tCO_2 (Cases I – III); Using imported low-carbon ammonia in a developing economy without a carbon price (Case IV); Using domestically produced low-carbon hydrogen in a developing economy without a carbon price (Case V).
- **Certain regions are well-positioned to produce low-cost low-carbon hydrogen and ammonia.** Our analysis suggests the following indicative production costs in 2030: USD 210-310/tNH_3 for natural gas based low-carbon ammonia on the east coast of Saudi Arabia, USD 400-540/tNH_3 for renewables based electrolytic ammonia in the Taltal region of Chile, USD 1.3-2.1/kgH_2 for coal-based low-carbon hydrogen in the Latrobe valley of Australia, and 1.3-1.7/kgH_2 for renewables based electrolytic hydrogen in the Karnataka state of India.
- **Low-cost hydrogen and ammonia in one location do not mean low-cost hydrogen and ammonia everywhere.** Full supply chains, including transport and storage, must be considered when comparing the routes and options of low-carbon fuels as delivery by sea can significantly add to the costs. This is especially the case with hydrogen.
- **The impact of co-firing on the levelised cost of electricity (LCOE) at an existing power plant depends on many local factors.** These include the type and efficiency of the power plant, the modification cost, the share of co-firing, the average capacity factor and the carbon price. Our analysis suggests following indicative LCOEs for existing power plants co-firing 60% of low-carbon fuels and operating on average at a capacity factor of 15% in 2030: Japanese coal plant using imported ammonia: USD 119-172/MWh; Japanese gas plant using imported low-carbon hydrogen: USD 152-222/MWh; Indonesian coal plant using imported ammonia: USD 99-142/MWh; Indian gas plant using domestic low-carbon hydrogen: USD 85-115/MWh.
- **High carbon prices in the power sector compensate for increases in generation costs from low-carbon fuels.** In the Japanese case studies that feature USD 82 t/CO_2 carbon price in the SDS in 2030, a large part of the cost increase is compensated by reductions in emission costs. For Indonesia and India, the cost increase from co-firing is reflected fully in the LCOE due to the absence of a carbon price in the SDS in 2030.
- **The LCOE from co-firing should be compared with the system value**. Although the LCOE of co-firing is somewhat higher when operating at a low average capacity factor (CF) compared to a high average CF, higher energy market values are likely achieved at low CFs.

For low-carbon fuels to reach their full potential in clean energy transitions, they will need to be stored in large quantities for long periods of time, and often transported over long distances. The delivery infrastructure is therefore a critically important part of global value chains, and in many instances will govern the cost and availability of low-carbon fuels. When fuels have been delivered, they can be used for displacing fossil fuels at existing power plants leading to reduced emissions depending on the share of co-firing.

With the help of case studies, three different use categories for low-carbon fuels in the power sector in 2030 are examined. These are: Using imported low-carbon hydrogen and ammonia in an advanced economy having a carbon price of USD 82/tCO_2 (Cases I – III); Using imported ammonia in a developing economy without a carbon price (Case IV); Using domestically produced low-carbon hydrogen in a developing economy without a carbon price (Case V).

Examined value chains for the production and use of low-carbon fuels in thermal power plants



Our analysis covers the production of low-carbon hydrogen or ammonia in a low-cost region, transport of the fuel to an existing fossil power plant, modification of the power plant for co-firing, and the ensuing impact on the LCOE under different co-firing shares, operating regimes and carbon price assumptions.

The import terminals are assumed to distribute fuels also for industrial users and other customers beyond the power sector, so that the utilisation rate of the transport infrastructure remains independent of the operation of the power plant (whether peak, mid-merit or baseload).

The calculated LCOEs should be considered in the context of system value because the value of the generated electricity is likely to be higher during peak load times, than the average value of the electricity across the whole year. The system value aspects of using low-carbon hydrogen and ammonia in the power sector are discussed in more detail after case studies in Chapter 5.

Case study I: Natural gas-based low-carbon NH_3 from Saudi Arabia to an existing coal plant in Japan

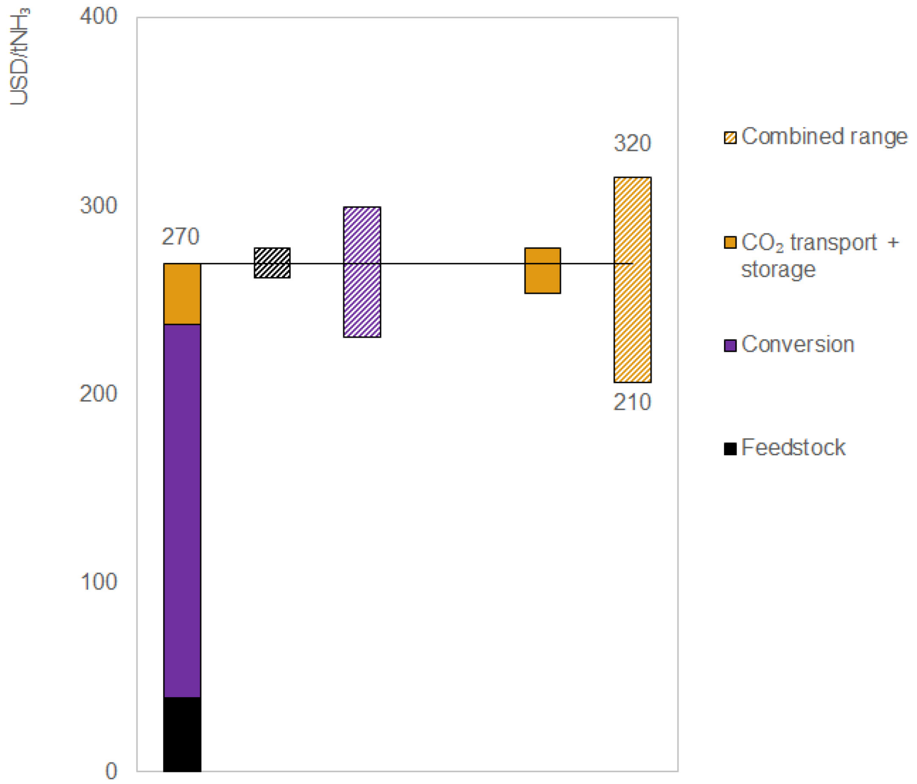
Saudi Arabia could be seen as a potential powerhouse for the production of low-carbon fuels, due to its abundance of natural resources and strategic location for exports. It seeks to become a top exporter of low-carbon fuels produced from both renewables and natural gas with CCUS. The west coast provides a base for exports to Europe, while the east coast has good opportunities to leverage existing ammonia infrastructure, including production plants and ammonia port facilities, to serve the Asian market.

Saudi Arabia has the world's fourth largest proven gas reserves, accounting for 4% of the global total. Most of the natural gas produced in this country is associated with oil production and is therefore available at very low cost. Oil production in Saudi Arabia – and thus also associated natural gas – has low average GHG emission intensities compared to other regions, due to highly productive reservoirs, low energy consumption for the extraction and processing of the oil and gas, and low flaring rates. The Saudi government has been looking for opportunities to capitalise on associated gas resources, such as through LNG exports and investing in low-carbon fuel capacity.

The Middle East has an estimated theoretical CO_2 storage capacity of more than 2,500 billion tonnes (Gt) of CO_2, with the substantial majority of it in Saudi Arabia in the form of saline aquifers. In particular, the east coast of Saudi Arabia has good onshore sedimentary basins, depleted gas and oil reservoirs as well as opportunities for EOR using CO_2. However, more detailed studies are required to determine the exact potential in Saudi Arabia. The cost of CO_2 transport and storage is expected to be relatively low in Saudi Arabia, especially when storing CO_2 in depleted oil and gas reservoirs. The Uthmaniyah project is currently the only operational large-scale CCUS project in the country. It captures 0.8 Mt of CO_2

per year at the Hawiyah gas plant and transports it via 85 km of pipelines to Uthmaniyah where it is used for EOR in the Ghawar field.

Indicative levelised cost of low-carbon ammonia in 2030 from natural gas with CCUS on the east coast of Saudi Arabia

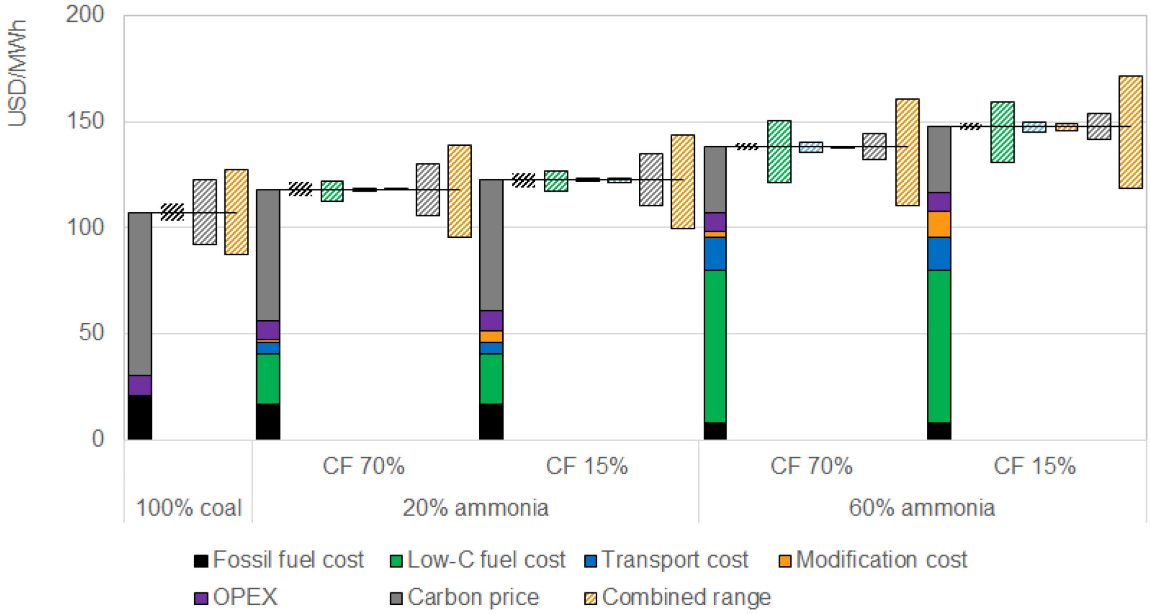


Notes: LCOA = levelised cost of ammonia production; WACC 5%, natural gas USD 1.1-1.6/GJ; ATR efficiency 63%, OPEX 4% of CAPEX; 95% CO_2 capture, CO_2 transport and storage cost = USD 10-25/tCO_2, carbon price = USD 0/tCO_2.
Source: IEA analysis.

The national oil and gas company Saudi Aramco is operating a CCUS pilot project at the SABIC's SAFCO ammonia plant in Jubail, which produces low-carbon ammonia in existing infrastructure. In September 2020, 40 tonnes of ammonia produced from natural gas with CCUS were shipped to Japan for use in power generation. Of the 50 tonnes of CO_2 captured from the pilot project, 30 tonnes were used in methanol production and 20 tonnes were injected for CO_2-EOR in the Ghawar field. The next step would be the scale-up to commercial plant sizes.

The cost of producing low-carbon ammonia in a large-scale facility on the east coast of Saudi Arabia is estimated to be between USD 210-320/tNH_3, depending mainly on the investment cost estimate, natural gas price and cost for CO_2 transport and storage. Due to the high 95% CO_2 capture, carbon emissions from the fuel production plant are minimised. Large plant sizes and the use of existing ammonia infrastructure is important to minimise the costs in the early stages. Autothermal reforming (ATR) plant sizes of 1.0 Mt/yr are possible and would allow for the exploitation of economies of scale. The produced ammonia would have to be transported by pipeline to an ammonia export terminal, after which it would be shipped to an import terminal in Japan over a distance of approximately 12 000 km for co-firing in an existing coal power plant modified for ammonia use. The terminal and shipping steps are estimated to cost on average USD 60/tNH_3 (USD 50-70/t), resulting in an ammonia delivery cost of USD 260-390/tNH_3 to Japan.

Indicative LCOEs for an existing coal power plant in Japan co-firing imported low-carbon ammonia from Saudi Arabia under different shares and operating regimes



Note: Coal USD 52-78/t, Low-carbon NH_3 USD 210-320/t, transport cost USD 50-70/tNH_3 coal plant efficiency 44%, carbon price USD 66-98/tCO_2.
Source: IEA analysis.

The cost impact of ammonia co-firing is illustrated in the figure above. Assuming a 2030 coal price of USD 52-78/t and a carbon price of USD 66-98/tCO_2 for Japan from the IEA SDS, the LCOE of an existing power plant (considering the initial capital investment as a sunk cost) is USD 88-127/MWh.

Co-firing 60% of low-carbon ammonia at a capacity factor of 70% (CF 70%) would lead to a relatively small increase in the LCOE to USD 111-161/MWh given the switch to a much more expensive fuel. However, due to the high implied carbon price of the SDS for advanced economies in 2030, the increase in fuel cost is largely offset by reductions in emissions costs. The increase in costs would be somewhat higher at USD 119-172/MWh if the plant were operated only under peak-load mode (CF 15%), but the value of the generated electricity is also likely to be higher during peak load times as will be discussed in Chapter 5.

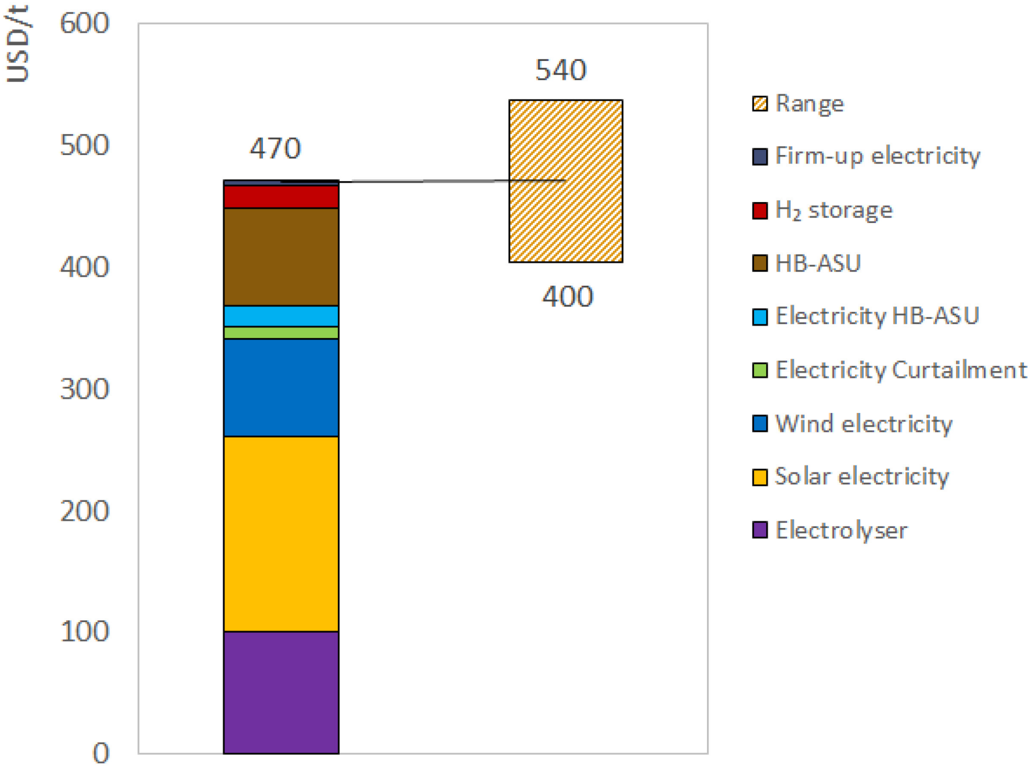
Case study II: Wind and PV-based low-carbon NH_3 from Chile to an existing coal plant in Japan

Thanks to its abundant and high-quality renewable resources, Latin America has the potential to produce large amounts of low-carbon hydrogen from renewable electricity. While many parts of the region could see competitive prices in the long-term, the lowest production costs could be located in southern Patagonia (Argentina and Chile) and the Atacama region (Argentina, Bolivia, Chile and Peru), as well as in northern Mexico and northeastern Brazil, among many other regions.

In the Argentine Patagonia, the Hychico pilot project Patagonia has been producing hydrogen from wind power since 2008, using two alkaline water electrolysers with a joint capacity of 0.55 MW. The hydrogen is mixed with natural gas and is used for power generation, using a 1.4MW generation unit that can operate with a large interval of gas/hydrogen blends, as well as pure hydrogen. The Hychico project also comprises Latin America's only hydrogen pipeline system (2.3km) and an underground storage facility. Since 2011, the Ad Astra Rocket pilot in Costa Rica has been producing around 0.8 tH_2/yr from solar and wind power, using a 5 kW PEM electrolyser, to power the first fuel cell bus in the region, as well as four fuel cell cars. Finally, the Cerro Pabellón microgrid pilot project in Chile's Atacama desert has been using solar power to produce 10 tH_2/yr of hydrogen since 2019, using a 50 kW PEM electrolyser. The project provides dispatchable renewable electricity to cover the needs of a microgrid serving a community of over 600 technicians working in the geothermal plant.

Chile has already made relevant announcements in terms of establishing a long-term vision for, and engaging the private sector in low-carbon hydrogen. In November 2020, Chile launched a comprehensive hydrogen strategy. It identified the replacement of fossil-based hydrogen in the country's refineries and new applications in long-distance and heavy-duty transport as key opportunities, and set a target of 5 and 25 GW of electrolysis capacity installed or under development by 2025 and 2030, respectively. Two major low-carbon hydrogen projects have been announced, initially aimed at replacing imported ammonia for applications in the mining sector (HyEx) and synthetic fuel production from methanol (Haru Oni). Both projects plan to target export markets in the long term.

Indicative levelised cost of electrolytic ammonia in 2030 from a mix of wind/solar PV in the Taltal region of Chile

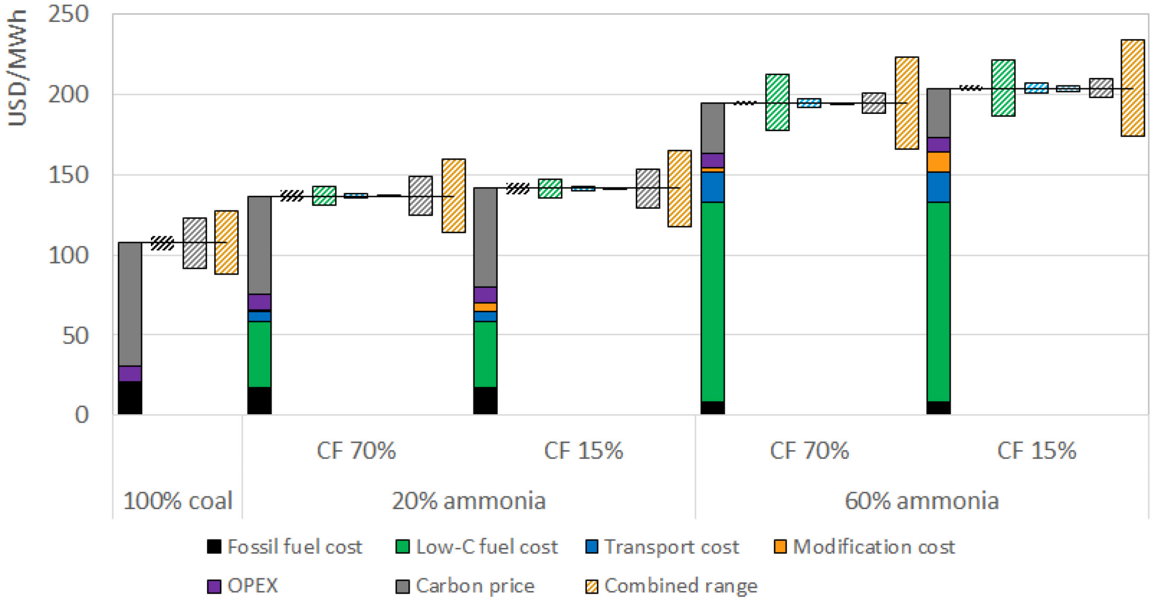


Note: WACC 5%, CF solar 32.5%, CF wind 43.8%, CF hybrid 50.8%, LCOE solar USD 24/MWh, LCOE wind USD 37/MWh, H_2 storage size 1.1 days, HB-ASU firm-up electricity 7%, gain from hybridisation 6%.
Source: IEA analysis.

The cost of producing electrolytic ammonia in the Taltal region of Chile in 2030 is estimated to be USD 400-540/tNH_3 based on a dynamically modelled production from a mix of wind and solar PV generation (see Annexes for details). By optimising the size and share of wind and solar power generation, a hybrid capacity factor of 50.8% can be achieved for the ammonia plant, leading to 6% hybridisation gains in costs.

The produced ammonia would have to be transported by pipeline to an ammonia export terminal, after which it is shipped to an import terminal in Japan over a distance of approximately 20 000 km for co-firing in a thermal power plant. The average transport cost is estimated at USD 75/tNH_3 (USD 60-85/tNH_3), resulting in an ammonia delivery cost of USD 460-625/tNH_3 to Japan.

Indicative LCOEs in 2030 for an existing coal power plant in Japan co-firing imported low-carbon ammonia from Chile under different shares and operating regimes



Note: Coal USD 52-78/t, Low-carbon NH_3 USD 400-540/t, transport cost USD 60-85/tNH_3 coal plant efficiency 44%, carbon price USD 66-98/tCO_2.
Source: IEA analysis.

The impact of co-firing ammonia imported from Chile on the LCOE of an existing Japanese coal plant in 2030 is illustrated in the above figure. Co-firing 60% of ammonia at a plant operating on average at a 70% capacity factor would lead to an LCOE of USD 166-224/MWh, a significant increase from the USD 88-127/MWh level. At an average capacity factor of 15%, the costs would increase further to the USD 174-234/MWh level.

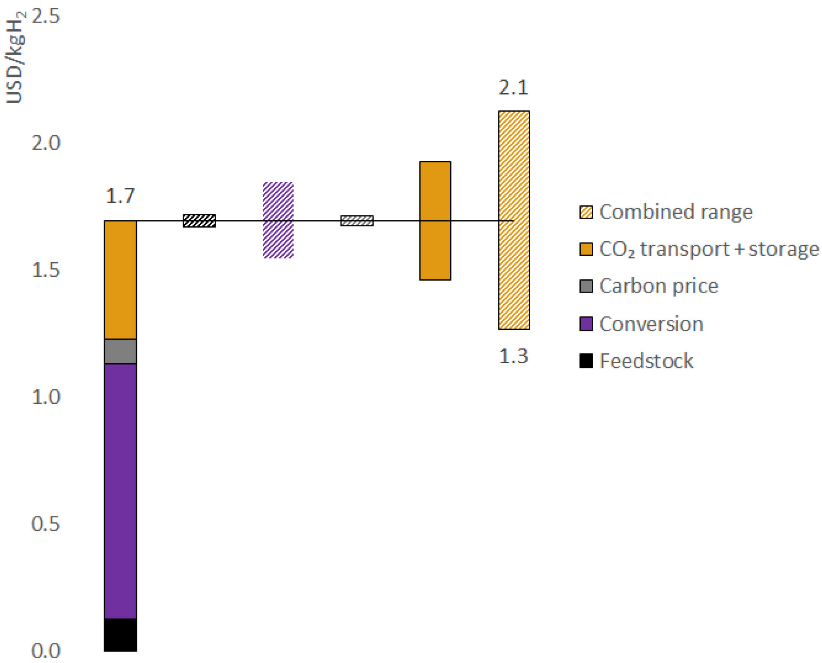
Case study III: Coal-based low-carbon H_2 from Australia to an existing natural gas plant in Japan

Australia has excellent natural resources to make low-carbon fuels. Coal gasification with CCUS is an attractive production route due to the availability of abundant and cheap brown coal reserves in close proximity to high-quality geological reservoirs for CO_2 storage. Considering these two requirements together with the availability of water needed for the gasification process, prospective areas are along the Western Australian coast, Queensland and Victoria. Victoria State is of particular interest for early projects.

The Latrobe Valley in Victoria – which is situated in the Gippsland region – is home to the second largest brown coal (lignite) reserves in the world. It lends itself to low-cost, large-scale mining with relatively stable coal prices. The Victorian Government is looking for opportunities to gradually shift the use of brown coal from its ageing and emissions-intensive power stations to the production of high-value, low-carbon products – such as hydrogen – for domestic and international markets. A gradual transition towards the production of low-carbon hydrogen would safeguard existing jobs in the coal mining industry, while creating a new industry with high-value jobs.

To this end, the federal and Victorian Governments are jointly developing a large-scale, multi-user CCUS CarbonNet project, which could be operational by 2030. The network would have an initial capacity of 1-5 $MtCO_2$ per year and connect multiple CO_2 sources via an underground pipeline (onshore: 130km; offshore 10km) with storage sites beneath the seabed in the Gippsland basin. The large size of the basin (>31 $GtCO_2$) and its high permeability, meaning few injection wells are needed, result in low storage costs. Pipeline costs are also expected to be low because routing and maintenance can be shared with other pipelines. Given these favourable conditions, the cost of CO_2 transport and storage is expected to be relatively low. The Department of Industry, Science, Energy and Resources has set a target to bring the cost for CO_2 compression, transport and storage down to under USD 15/tCO_2 (AUS 20/tCO_2).

Estimated levelised cost of hydrogen in 2030 from coal with CCUS in the Latrobe Valley (Victoria State) in Australia

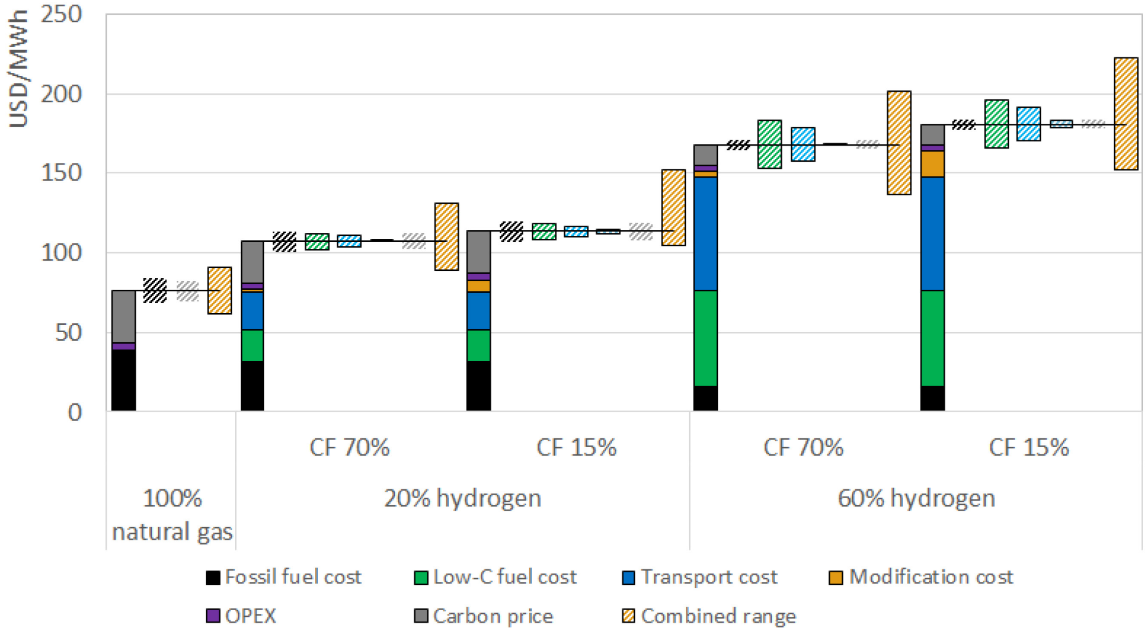


Notes: WACC 5%, coal USD 12-18/t, Hydrogen plant efficiency 58%, OPEX 5% of CAPEX, 95% CO_2 capture, CO_2 transport and storage cost = USD 10-30/tCO_2.
Source: IEA analysis.

Large-scale gasification systems offer economies of scale, which are needed to minimise the cost of hydrogen production. The hydrogen production cost is estimated to be USD 1.3-2.1/kgH_2 for a large production facility of 500 000 cubic metres of hydrogen a day in 2030, including the costs for transport and storage of CO_2. Due to the high 95% CO_2 capture, the production cost is not sensitive to the high carbon price assumption of USD 66-98/tCO_2.The produced hydrogen would have to be transported by pipeline to a nearby liquefaction facility, where it is temporarily stored before being shipped in liquid form to Japan over an approximate distance of 8 000 km. The liquefaction step is very expensive and requires large amounts of low-carbon electricity. The combined cost of liquefaction, shipping over a distance of 8 000 km and storage in terminals is estimated to be USD 2.0/kgH_2 (USD 1.7-2.3/kgH_2), resulting in a hydrogen delivery cost of USD 3.0-4.4/kgH_2 in Japan.

Australia is currently working with Japan on a hydrogen energy supply chain project, which includes hydrogen production from coal, transport to the Port of Hastings for liquefaction and shipment to Japan. The first step was a one-year pilot project (testing hydrogen production and shipping only) to treat 160 t/yr of brown coal to produce 3 tH_2/yr, which commenced operation in 2021. The next step is a commercial large-scale plant of 246 ktH_2/yr (356 000 Nm^3/d) for the year 2030. The AUS 500 million (USD 380 million) pilot project is delivered by a consortium of industry partners from Japan and Australia, and supported by the Victorian, Australian and Japanese governments. The related CarbonNet project presents a potential solution for mitigating CO_2 separated from the hydrogen production process in the commercial phase.

Indicative LCOEs in 2030 for an existing coal power plant in Japan co-firing imported low-carbon hydrogen from Australia under different shares and operating regimes.



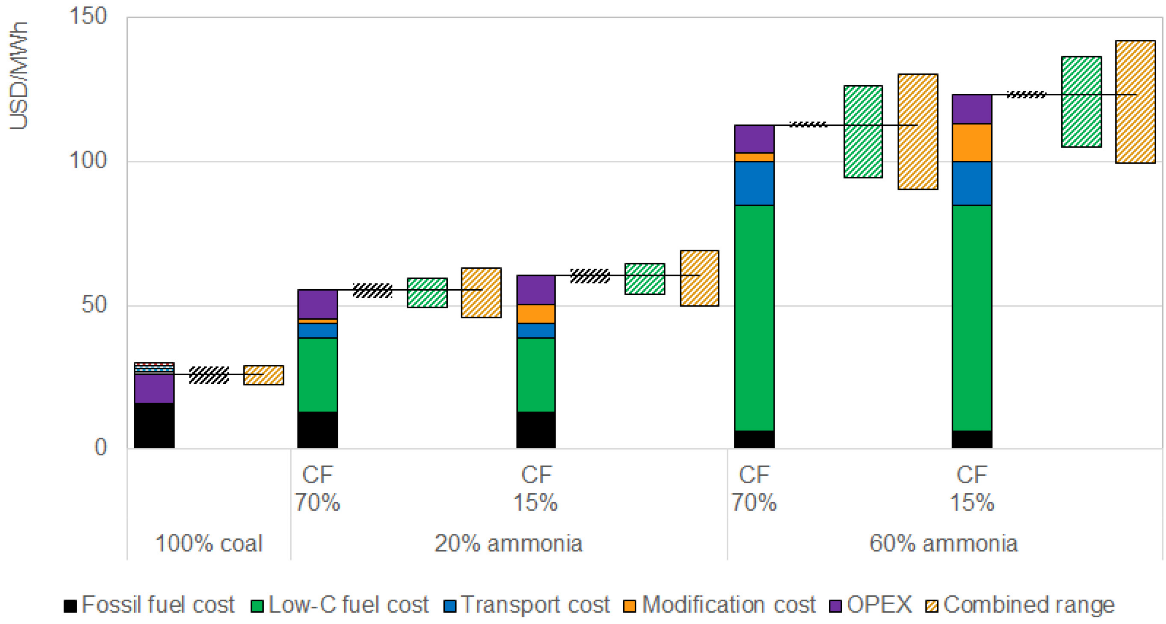
Note: natural gas USD 4.4-6.6/GJ, Low-carbon H_2 USD 1.3-2.1/kg, transport cost USD 1.7-2.2/kg, gas plant efficiency 51%, carbon price USD 66-98/tCO_2.

The impact of co-firing hydrogen imported from Australia on the LCOE of an existing Japanese natural gas plant is illustrated above. Assuming a 2030 natural gas price of USD 4.4-6.6/GJ and a carbon price of USD 66-98/tCO_2 for Japan from the SDS in 2030, the LCOE for an existing power plant (considering the initial capital investment as sunk cost) is USD 62-90/MWh. Co-firing 60% of hydrogen would lead to an LCOE of USD 137-202/MWh or USD 152-222/MWh when operating the modified plant under CF 70% or CF 15%, respectively.

Case study IV: Natural gas-based low-carbon NH_3 from Saudi Arabia to an existing coal plant in Indonesia

This case study is a based on the same ammonia produced from natural gas with CCUS in Saudi Arabia, but now imported for an existing coal power plant in Indonesia. The LCOE analysis therefore features different transport distance, Indonesian coal price estimate and assumption on no carbon price in the power sector in 2030.

Indicative LCOEs in 2030 for an existing coal power plant in Indonesia co-firing imported low-carbon ammonia from Saudi Arabia under different shares and operating regimes



Note: Coal USD 35-53/t, Low-carbon NH_3 USD 210-320/t, transport cost USD 45-60/tNH_3 coal plant efficiency 40%, carbon price USD 0/tCO_2.
Source: IEA analysis.

The impact of ammonia co-firing on the LCOE is illustrated in the figure above. The same low-carbon ammonia from Saudi Arabia is imported by ship over a distance of approximately 9 000 km leading to a transport cost estimate of USD 55/tNH3 (USD 45-60/t), resulting in an ammonia delivery cost of USD 255-380/tNH_3 to Indonesia. Assuming a 2030 coal price of USD 35-50/t and no carbon price for Indonesia from the SDS, the LCOE for an existing power plant (considering the initial capital investment as a sunk cost) is USD 23-29/MWh.

Co-firing 60% of the ammonia at a capacity factor of 70% would significantly increase the LCOE to USD 91-130/MWh, as the cost hike from using expensive low-carbon ammonia would not be offset by reductions in emissions costs. Operating the plant mainly on peak-load mode at an average capacity factor of 15% would increase the LCOE further to a level of USD 99-142/MWh.

Case study V: Domestically produced wind and PV-based low-carbon hydrogen to an existing gas power plant in India

India has recently proposed a specific National Hydrogen Energy Mission that would put forward a hydrogen strategy for the short term (4 years), and establish principles for the long-term with the intent to help India become a global hub for the manufacturing of hydrogen and fuel cell technologies across the value chain.

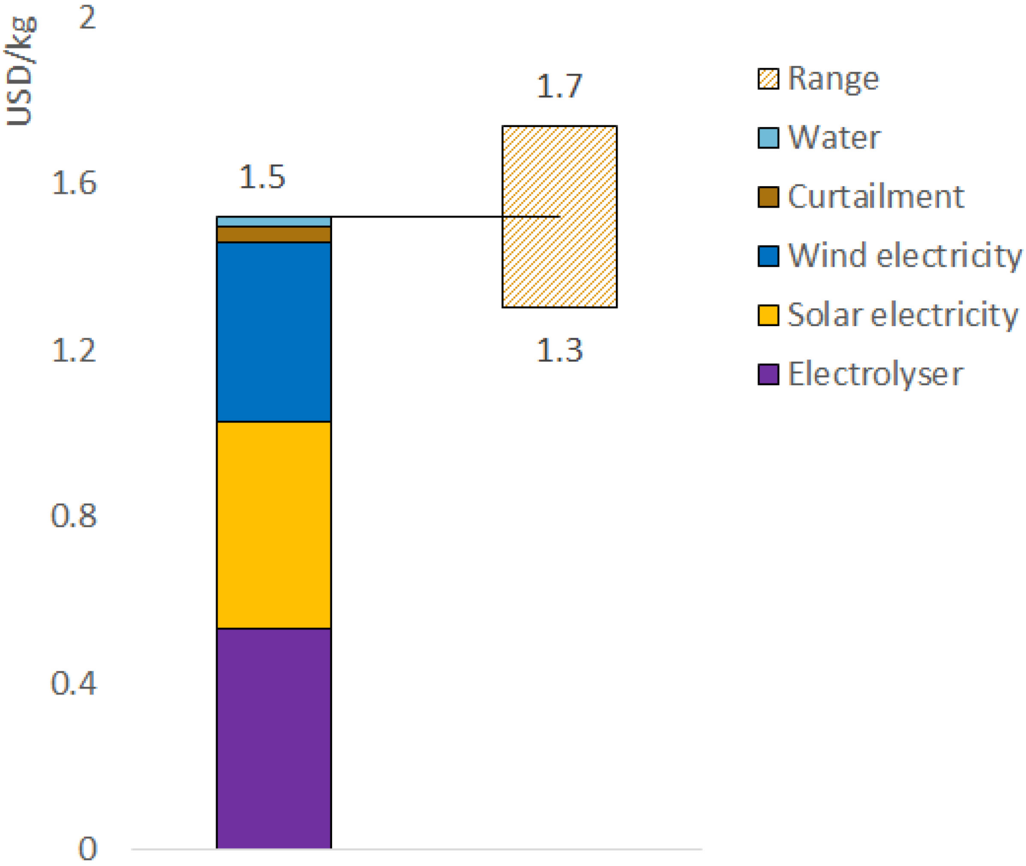
The Indian Ministry of Power has also recently announced plans to establish a National Mission on the use of biomass in coal-based thermal power plants. The goal of this mission is to increase the level of biomass co-firing from the present 5% and to unlock the supply chain constraints on biomass pellets and agro-residues and on their transport to the power plants.

A recent report by TERI on The Potential Role of Hydrogen in India found that hydrogen demand could increase fivefold by 2050, with use in industry being the major driver. Given the scale of the prospective market, India could be proactive in manufacturing electrolysers to produce green hydrogen. In transport, hydrogen is expected to play a role mainly in long-distance and heavy-duty applications. In power generation, hydrogen could provide inter-seasonal storage from 2040. Hydrogen could also play a role as a form of long-term energy storage, absorbing excess electricity during certain periods of the year, to be used again at times of sustained low renewable output. Scaling up the use of domestically produced hydrogen could significantly reduce energy imports.

Current Indian hydrogen initiatives include plans to develop and demonstrate biomass gasification-based hydrogen production. Indian Oil and IISc will jointly work for the optimisation of both biomass gasification and hydrogen purification processes, followed by scale-up and demonstrated at Indian Oil's R&D Centre at Faridabad. The produced hydrogen is planned for use in fuel cell-powered buses. In addition, Indian Oil plans to become the first company in India to produce electrolytic hydrogen from wind power and use it in the Mathura Refinery.

Reliance Industries Limited (RIL) has announced four 'Giga' factories. Two such factories include an electrolyser factory for green hydrogen production and fuel cell production, in addition to solar PV modules production and advanced battery storage manufacturing. The related investment would be Rs. 75 000 crore (USD 10 billion) over the next three years. RIL is co-leading the India Hydrogen Alliance along with Chart Industries that aims to work together with policymakers, industry players, research agencies, think-tanks, etc. to support concerted public policy and private sector actions to develop the hydrogen economy and a domestic hydrogen supply chain in India. This is expected to be followed by the creation of a national hydrogen taskforce and the identification of large demonstration projects in the country.

Estimated levelised cost of hydrogen in 2030 from a PV/wind mix in the Karnataka state of India

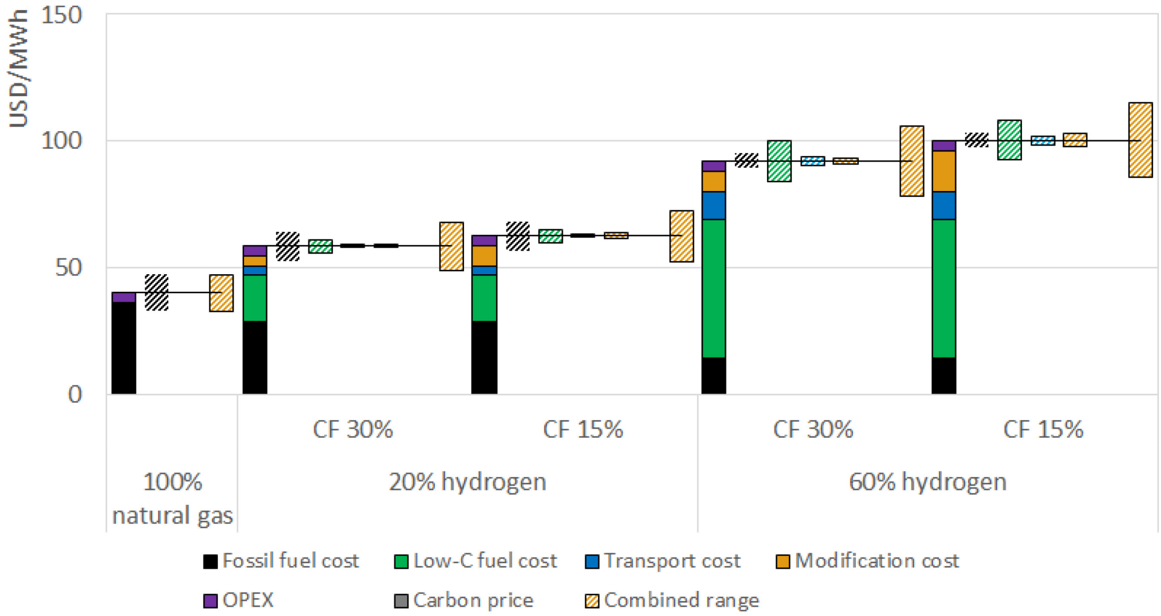


Notes: WACC 5%, CF solar 24.1%, CF wind 43.9%, CF hybrid 52.1%, LCOE solar USD 16/MWh, LCOE wind USD 25/MWh curtailment 4%, gain from hybridisation 2%.

The cost of producing electrolytic hydrogen in the Karnataka state of India in 2030 is estimates to be USD 1.3-1.7kgH_2 based on a dynamically modelled production from a mix of wind and solar PV generation (see Annex for details). By optimising the size and share of wind and solar power generation, a hybrid capacity factor of 52.1% can be achieved for the electrolysers, leading to 2% hybridisation gains, while curtailment is 4%.

The produced hydrogen would be transported by pipeline to an existing natural gas power plant, which would be modified for the use of hydrogen. The average cost of pipeline transport is estimated at USD 0.21/kgH_2 (USD 0.18-0.24/kgH_2), resulting in a hydrogen delivery cost of USD 1.5-1.9/kgH_2 at the power plant.

Indicative LCOEs in 2030 for an existing gas power plant in India co-firing domestic low-carbon hydrogen under different shares and operating regimes



Note: natural gas USD 4-6/GJ, Low-carbon H_2 USD 1.3-1.7/kg, transport cost USD 0.18-0.24/kg, gas plant efficiency 50%, carbon price USD 0/tCO_2.

The impact of co-firing hydrogen with domestically produced electrolytic hydrogen in an existing natural gas plant is illustrated above. Unlike in previous case studies, only a peak load operation at either CF30% or CF15% is examined as wind and solar PV generators can be connected directly to the Indian electricity grid for the bulk generation. Also the ability to transport hydrogen in pipelines as compressed gas without liquefaction significantly reduces the overall cost of delivered hydrogen.

Assuming a 2030 natural gas price of USD 4.0-6.0/GJ and no carbon price for India, the LCOE for an existing power plant (assuming the initial capital investment is a sunk cost) is USD 33-47/MWh. Co-firing hydrogen at a 60% share would lead to an LCOE of USD 79-106/MWh or USD 85-115/MWh when operating the modified plant at an average capacity factor of 30% or 15%, respectively.

Chapter 5. System value aspects of low-carbon thermal plants

Highlights

- **Transitioning to a low-carbon future with a high share of renewables requires a range of services to meet flexibility needs and to ensure electricity security.** In addition to electricity grids, storage and demand response, low-carbon thermal power plants will play a valuable role in providing system services, particularly in systems with a large and young fossil fleet.
- **The value of low-carbon dispatchable power capacity hinges on system-specific factors that vary significantly across regions**. LCOEs for plants using low-carbon fuels are high, but need to be compared with the value of electricity and system services at different periods and contexts.
- **Japan already experiences high volatility in energy prices, reflecting the system value of units that are available during critical periods.** A high carbon price in 2030 significantly reduces the gap between the LCOEs from co-firing and the energy market value. For example, co-firing 60% ammonia in a coal power plant is expected to cost 30 USD/MWh more than the carbon-adjusted energy value for baseload operation, which is reduced to 18 USD/MWh in peakload operation. Capacity payments will also provide a major source of revenue for these plants, improving competitiveness.
- **Deployment of low-carbon fuels could be a plausible long-term option for emerging economies, such as in Southeast Asia.** The absence of carbon price by 2030 in the SDS significantly increases the cost gap between low-carbon fuel use and variable operating costs of existing power plants in ASEAN. Power systems in this region have considerable latent flexibility that can be activated by targeted policy measures to address flexibility needs in the short term, while in the long term there are opportunities for using low-carbon fuels in the existing fleet.
- **Dispatchable power plants are expected to provide crucial system services for maintaining electricity security in India by 2030**. As the net system peak load is expected to increase with higher shares of wind and solar, thermal generation will be required to ensure system adequacy as well as to provide inertia and flexibility. In the SDS by 2030, dispatchable thermal power plants are expected to provide 40% of energy, 50% of inertia, almost 60% of peak adequacy capacity and over 70% of ramping flexibility services.
- **The optimal use of CCUS depends on system characteristics.** CCUS plants offer lower operating costs but higher upfront investment cost than plants using low-carbon fuels, and would play a different role than low-carbon fuels in highly decarbonised systems where both approaches would be available. Systems with stable net peak demand would likely require more baseload plants and would thus be best paired with plants using CCUS. Systems with high variability of net peak load would have a higher need for peaking delivered by low-carbon fuels.

With greater deployment of VRE in the power sector, system flexibility becomes more important to ensure the security of electricity supply. Therefore, the value of technology options should also reflect their capability in providing a range of system services to meet the increasing flexibility needs of the system. As described in Chapter 1, thermal power plants are a key source of flexibility, in addition to electricity grids, storage and demand response. With the technical capabilities of thermal power plants in providing system services, they have the potential to contribute to a low-carbon future, particularly in emerging economies which have a large fossil fuel fired thermal fleet. The use of thermal plants for flexibility can therefore reduce the level of investment needed in other flexibility resources while maintaining security of supply.

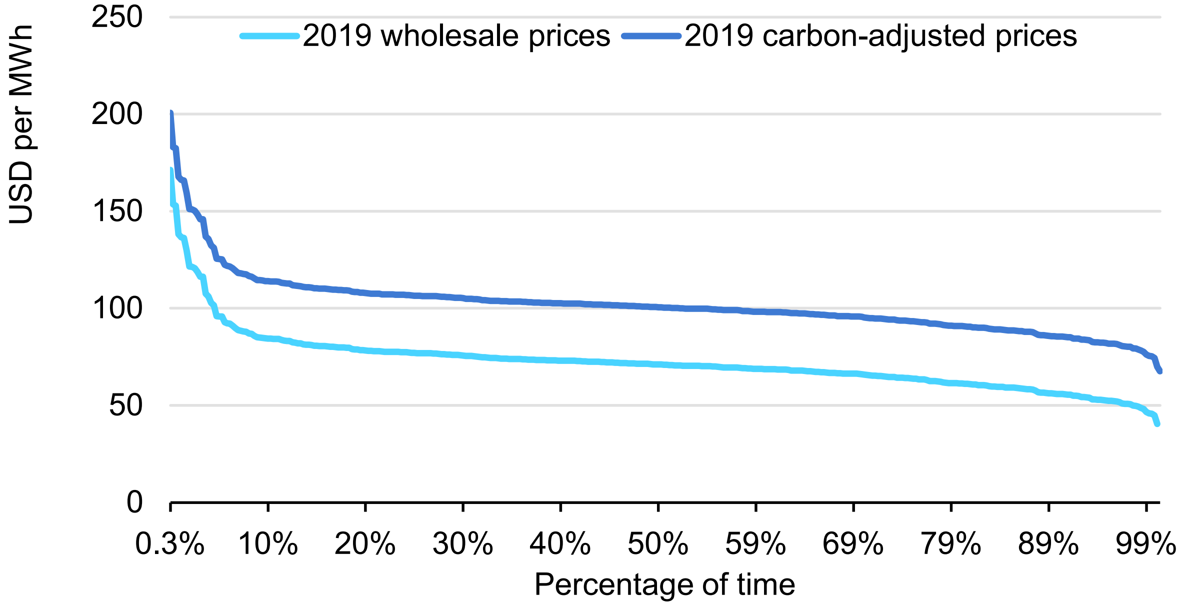
Energy value of low-carbon fuels in Japan

The LCOE does not capture the full value of technologies since it represents only the average lifetime costs for providing a unit of output without considering other key aspects of power generation, such as flexibility and dispatchability.

The value of different power generation technologies also depend on a large number of other factors, including shifts in the supply and demand balance, and the level of competition in the sector and services they can provide to maintain the security and reliability of the system, which are context specific.

The value of energy can be much higher during critical periods than during typical periods, which is reflected by high energy prices. For example, the average price during the top 5% of hours in Japan in 2019 was around USD 125/MWh while the average price for the period outside the top 5% was USD 69/MWh (see the Figure below). The high LCOEs of low-carbon fuels operating as peaking units with low capacity factors, to a degree, reflect their value and contribution during these critical periods.

Wholesale energy price duration curve in Japan, 2019

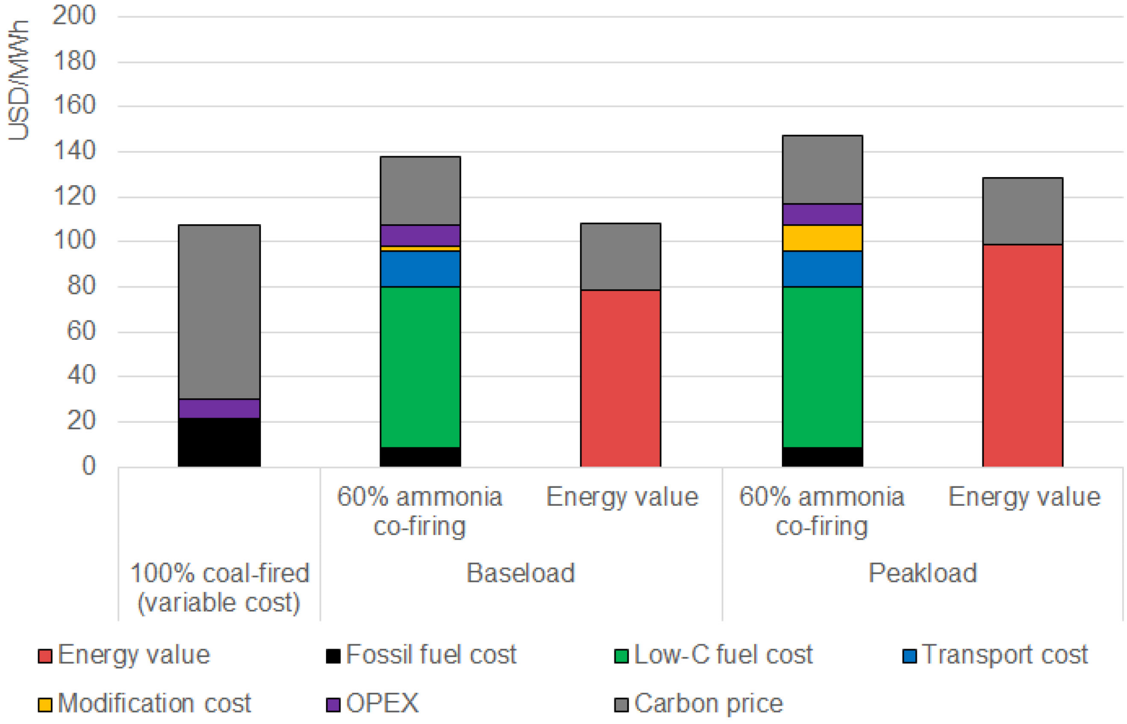


Source: Japan Electric Power Exchange (2021).

In the figure below, the 2019 wholesale energy prices for Japan are modified by adding a SDS 2030 carbon price of USD 82/tCO2 for advanced economies. The peak load energy value represents the average of the top 15% of hours, while the baseload energy value represents the average of the top 70% of hours. These energy market values are then compared against the generation cost of an existing coal power plant, co-firing 60% of imported low-carbon ammonia from Saudi Arabia operating respectively under baseload (CF 70%) and peak or mid-merit load (15%).

As discussed in Chapter 4, the generation costs are higher for a plant that operates under peak or mid-merit than under baseload. However, higher generation costs can be compensated by capturing higher wholesale prices for the generated electricity.

Energy value and LCOE of ammonia co-firing for Japan in the Sustainable Development Scenario 2030

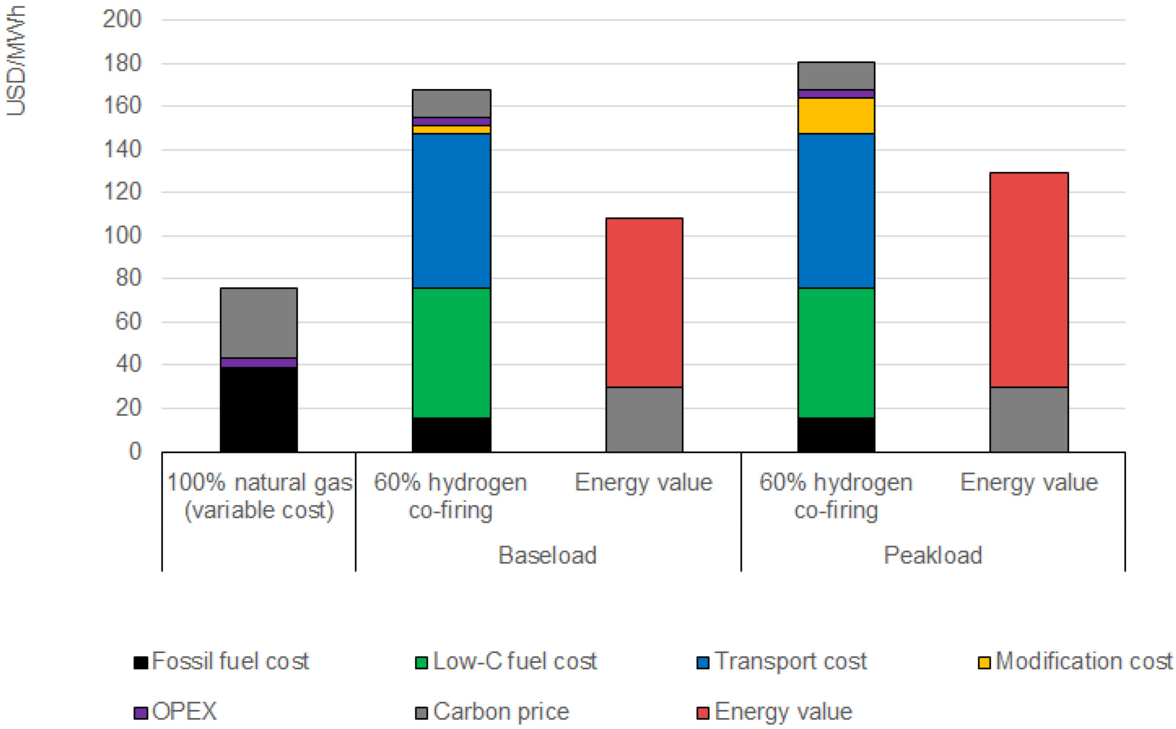


Note: Ammonia produced from natural gas with CCUS in Saudi Arabia and shipped to an existing coal-fired power plant in Japan. Energy value is based on 2019 wholesale energy price duration curve in Japan, adjusted with USD 82/tCO_2 carbon price for advanced economies in the SDS in 2030.

This is exemplified in the above figure that illustrates generation costs and carbon-adjusted energy values for baseload and peakload operation. Co-firing 60% ammonia in a coal power plant is expected to cost 30 USD/MWh (138 USD/MWh – 108 USD/MWh) more than the carbon-adjusted energy value for baseload operation, which is reduced to 18 USD/MWh (147 USD/MWh -129 USD/MWh) under peakload operation.

Similar comparison is illustrated in the figure below for a natural gas power plant. The gap between the cost of co-firing 60% low-carbon hydrogen and its average market energy value under peakload operation (181 USD/MWh - 129 USD/MWh = 52 USD/MWh) is smaller than the respective gap under baseload operation (168 USD/MWh - 108 USD/MWh = 60 USD/MWh). However, in absolute terms the gaps are wider than for ammonia co-firing, which is explained by the higher supply cost of hydrogen via sea, and the lower impact of carbon price on the cost of natural gas than coal.

Energy value and LCOE of hydrogen co-firing for Japan in the Sustainable Development Scenario 2030



Note: Hydrogen produced from coal with CCUS in Australia and shipped to an existing natural gas fired power plant in Japan. Energy value is based on 2019 wholesale energy price duration curve in Japan, adjusted with USD 82/tCO_2 carbon price for advanced economies in the SDS in 2030.

As Japan's power system evolves towards more renewable capacity, the average energy value of peak hours is expected to increase. This will further reduce the gap between low-carbon generation costs and value. The newly created capacity market will provide an additional source of revenue to plants using low-carbon fuels that will further enhance competitiveness.

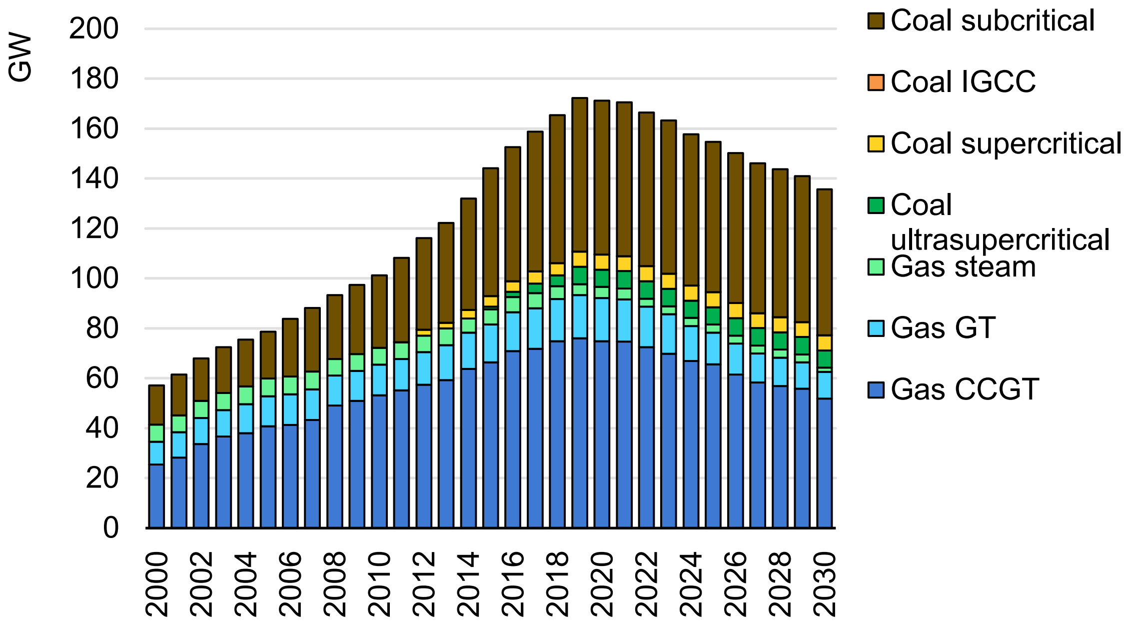
Drivers and conditions for low-carbon fuels use in Southeast Asia

In order to reach their NDC's the countries of Southeast Asia will need to decarbonise their power sector. While net zero targets are yet to be officially announced by any of the ASEAN Member States, the region does have an aspirational target of 23% renewable energy (excluding traditional use of biomass) in total primary energy demand by 2025. Looking further into the future, even higher targets of renewable energy need to be realised in Southeast Asia in order to keep the world on track for 1.5°C temperature increases. Several ASEAN countries are also developing long-term strategies towards carbon neutrality.

Southeast Asia has a large and young thermal power plant fleet

Southeast Asia has a large thermal fleet in which coal and gas are the major sources of electricity generation at present. The composition of the fleet varies from country to country. In Thailand, around 60% of electricity generation in 2020 was from gas-fired generation, while Indonesia generated around 70% of its electricity in 2020 from coal-fired power plants.

Cumulative capacity in ASEAN without new additions from 2020

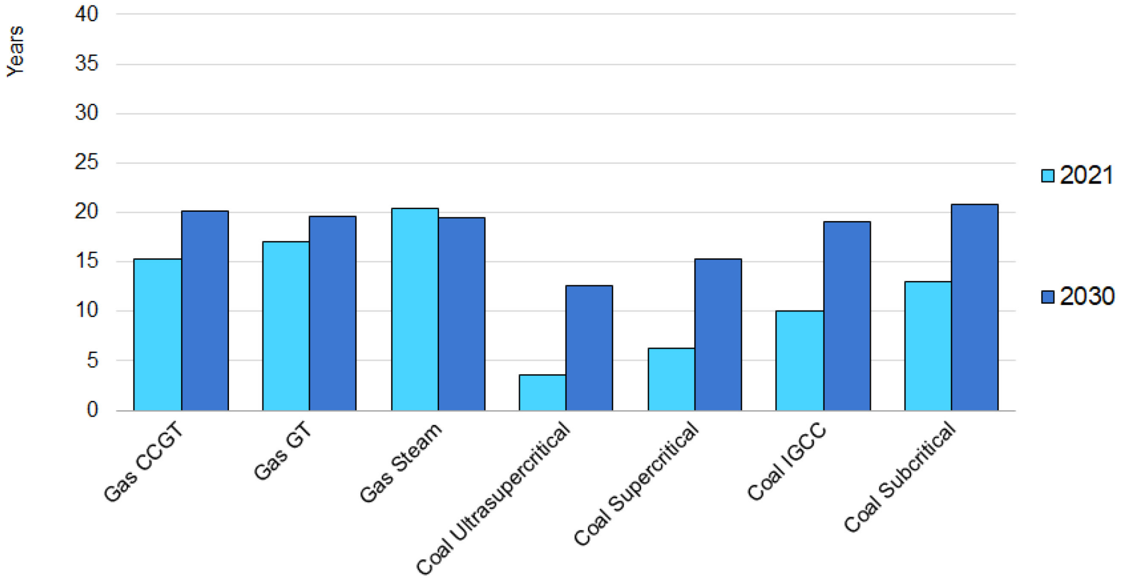


Source: IEA (2020).

The age of the thermal power plants in this region is relatively young. The current average age of the ultra-supercritical and supercritical coal plants in Thailand and Indonesia is today between 5 and 10 years. By 2030, a substantial portion of these coal assets will have used less than half of their technical life expectancy.

Given the large share of existing thermal fleet, many of the ASEAN countries are considering power plant retrofits as one of the options to improve technical flexibility. For example, there is a pilot project at a gas-fired power plant in Thailand to improve key operational characteristics. This opportunity could also provide a long-term pathway for decarbonising existing thermal power plants in this region to run on less carbon-intensive fuels.

Capacity-weighted average age today (2021) and in 2030 (without new additions) in ASEAN



Note: The technical lifespan assumptions of coal and gas plants are 40 years and 30 years, respectively.
Source: IEA (2020).

Currently some of the countries, including Indonesia and Thailand, are facing the issue of generation overcapacity and a high reserve margin. In Thailand, the reserve margin is in the range of 40%, which is expected to remain in the short- to medium-term due to the impact of Covid-19. By 2035, the reserve margin is expected to drop to around 25%.

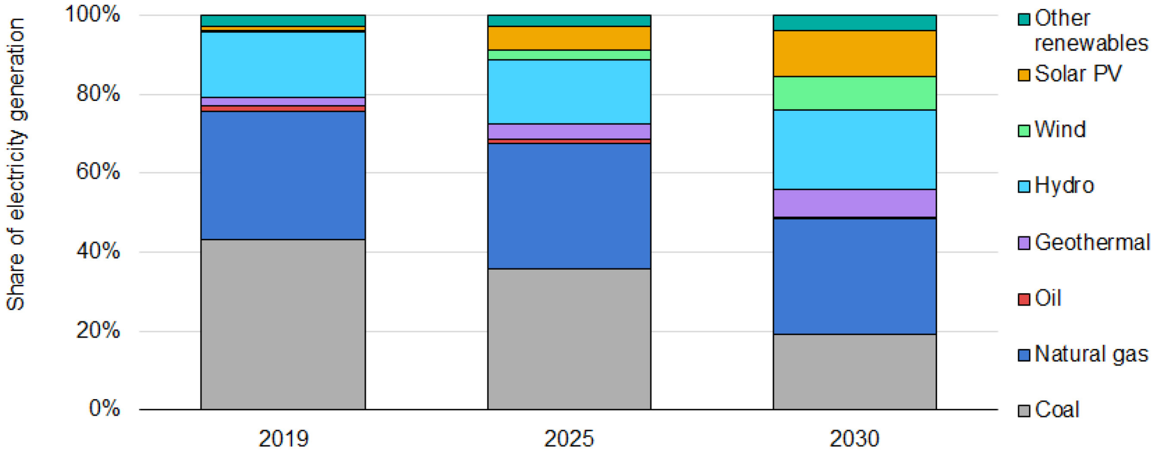
In the coming decades, electricity demand in Southeast Asia is expected to grow strongly. In fact, the demand growth is expected to be among the world's highest along with India and Africa. There are several factors influencing demand growth. Population growth, with economic growth as well as targeted policies for electrification of transport and clean cooking, for example, are among the long-term drivers of electricity demand growth in the AMS.

Thermal generation still provides bulk of system flexibility in ASEAN in 2030

In meeting the demand growth, the generation capacity in the ASEAN region will significantly increase in the coming decades. The bulk of generation capacity additions will come from renewables. This region has a very diverse range of renewable energy resources including biomass, hydro, wind, solar, geothermal and a potential for ocean energy. By 2040, renewable generation accounts for more than 70% in the SDS with solar PV, wind and hydropower being the largest sources, at a combined capacity of over 600 GW in 2040. The booming growth of solar PV will continue, as has been the case in recent years in countries such as Thailand and Vietnam.

The very high share of renewable energy requires sufficient flexibility resources to ensure the reliability and security of the power system while the ASEAN countries move towards decarbonisation. Currently many of the power systems in this region have considerable latent flexibility that can be activated by targeted policy measures. This includes conventional plants (both thermal and hydropower) and grid infrastructure (including cross-border interconnectors).

Shares of ASEAN electricity generation in the Sustainable Development Scenario, 2025-2030



Source: IEA (2020).

In the short term, increasing the efficiency of the key power system assets will unlock enough flexibility to integrate renewable energy to meet the 2025 targets. However, in order to increase efficiency to meet longer-term requirements, appropriate policies and regulatory support frameworks are needed.

In Indonesia, implementing updated system operation procedures, such as advanced day ahead forecasting, will be an important tool to manage the variability of renewable energy in the grid. Building out grid infrastructure and connecting islands like Sumatra and Java will also increase the reliability of the system and improve electricity security while allowing for higher shares of renewable energy to be integrated into the system.

In Thailand, a recent IEA study on Thailand power system flexibility shows that one of the major barriers to flexibility in the country is contractual structures, which limit the utilisation of the system's latent technical flexibility from current assets. High minimum-take obligations in power purchase agreements as well as daily-take or pay clauses in gas supply contracts hinder the optimal operation of the generation fleet. These constraints prevent the thermal fleet, which has technical capability, to operate flexibly to accommodate the integration of renewable energy. This pattern is also identified as an issue for other countries such as Indonesia and Vietnam. The contractual constraint is likely to present a major obstacle for the region's young gas fleet. Thus, the governments could consider the co-firing option with low-carbon fuels, particularly hydrogen and ammonia.

One of the main sources of flexibility in this region is cross-border interconnectors with the option for multilateral power trade, which will allow resource sharing among ASEAN countries, particularly renewable resources. In Thailand, for example, a more dynamic setup for multilateral power trade will enable hydropower from Laos PDR to contribute to increased flexibility in the country thereby facilitating integration of variable renewable energy and reducing the overall costs of the system. By making use of the existing assets, the low-carbon option in the form of hybrid power plants is also becoming a viable means from both the technical and economic perspectives. Hydro-floating solar PV hybrid power plants have been planned or carried out in Indonesia, Singapore, Thailand and Vietnam. For example, in Thailand, the first hydro-floating solar hybrid project of 45 MW capacity was completed in 2021.Indonesia is planning to install a -MW floating solar PV project on a reservoir in West Java. It will be the largest in the ASEAN region.

In general, there are many short- to medium-term actions that ASEAN countries can take to increase flexibility and enable significantly higher shares of renewable energy which are cost-effective, reliable and secure.

Long-term pathways for implementing low-carbon fuels in the ASEAN Region – opportunities and challenges

When looking beyond the 2025 targets in ASEAN, the flexibility options described above may not be enough. Emerging technologies are also gaining much interest from policymakers and key stakeholders in this region, including battery storage and longer-term storage options in order to cope with the challenges from the high share of VRE.

In the longer-term, there are opportunities for hydrogen-derived fuels, which could play a role in ASEAN countries in achieving carbon neutrality. Indonesia, Malaysia, the Philippines and Thailand are also gaining experience in piloting green hydrogen and fuel cell systems for remote power provision in many sectors. Wind and solar PV are expected to become the main sources of electricity generation in this region. As this can pose challenges for the grid, some of the ASEAN countries are expressing an interest in exploring the role of hydrogen to cope with such challenges given their long-term storage attribute. Thailand EGAT, which is the leading state-owned power utility, built a wind-hydrogen hybrid system prototype project in 2019 for utility-scale application. This project combines a 24-MW wind power plant with a 1-MW electrolyser and a 300-kW fuel cell to provide clean electricity to a building during high demand periods. For Indonesia, a country comprised of about 6 000 inhabited islands, solar PV will be the main source of electricity. In addition, given that the off-grid generator set (genset) has been the source of electricity generation, there is an opportunity to convert such a genset from using diesel oil to use ammonia, which can be relatively easy to store and transport by trained personnel.

Despite the potential and interest, it is important to note that because capital is very constrained in this region, the ASEAN countries are highly price sensitive.

In order for low-carbon fuels to be economically feasible in ASEAN, it is important that the costs associated with these options come down. Developed economies can play a key role by investing in maturing the technologies for low-carbon fuels along with creating global supply chains and infrastructure that the countries of ASEAN can tap into.

Low-carbon fuels may be needed in the ASEAN region to achieve carbon neutrality in the long-term, but currently the ASEAN countries are still in the early phases of transitioning towards clean energy. In the short- to medium-term, the priority is to switch fuel from coal to gas when available, and to utilise the existing latent flexibility in the system to integrate more renewables. Deployment of low-carbon fuels could be an option in the longer-term if targeted policy reforms are successfully implemented and significant cost reductions are achieved by the world's more advanced economies first. The markets and technologies will require significant maturing to become viable in the ASEAN region.

Electricity security in India and the value of thermal power plants in a low-carbon future

Coal-fired power has historically been the primary source of electricity generation in India. However, further capacity additions over the next decades will come mostly from solar PV and wind due to their falling costs. With the rising share of variable resources and changes in demand and supply, coal-fired thermal plants in India's power system have needed to become more flexible. Despite the decline in the utilisation, dispatchable thermal power plants are likely to remain a valuable resource in meeting the increasing need for flexibility in the system and in ensuring the security of electricity supply.

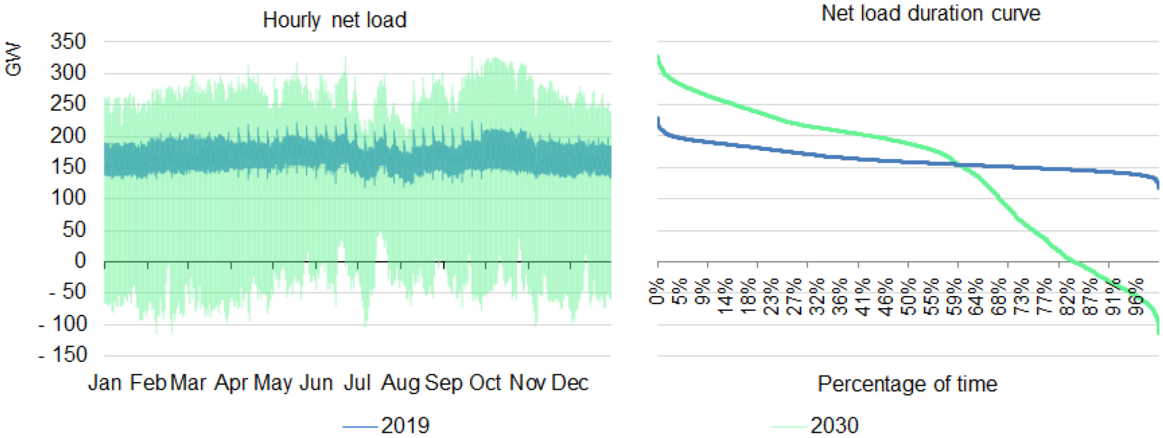
To provide context for the obtained results, we conducted a power system modelling exercise to analyse the potential role of dispatchable fossil fuel based thermal power plants in clean energy transitions, and their contribution in maintaining the security of supply of India's power system.

High shares of wind and solar PV increase variability in net load profiles

Under the SDS, renewable energy will become the main source of electricity generation in India in 2030 with an annual share of around 60%, with wind and solar PV together accounting for almost 40%. High penetration of VRE and increased use of air-conditioning present the main challenges for India's power system.

The variability of India's net demand (demand minus VRE generation) will continue to increase over all timescales- –from minutes to hours, days and weeks and seasons, and will lead to significant changes in the net load profiles in 2030 (see Figure below). By 2030, the hourly net demand ranges from a low of -110 GW (more VRE generation than demand resulting in potential VRE curtailment) to a high of over 300 GW, a difference of 410 GW. This difference is about four times higher (low of 120 GW to a high of 225 GW) than in 2019. The system will experience higher hourly and sub-hourly ramps, and larger differences between minimum and maximum daily demand, which will require additional resources to meet flexibility needs to avoid large curtailment of wind and solar generation (see the Figure below). Key flexibility resources include grid infrastructure and distributed energy resources such as cold storage in cooling devices based on distributed PV, which can also reduce strain on the grid.

Net load profiles in India in the Sustainable Development Scenario, 2019 and 2030

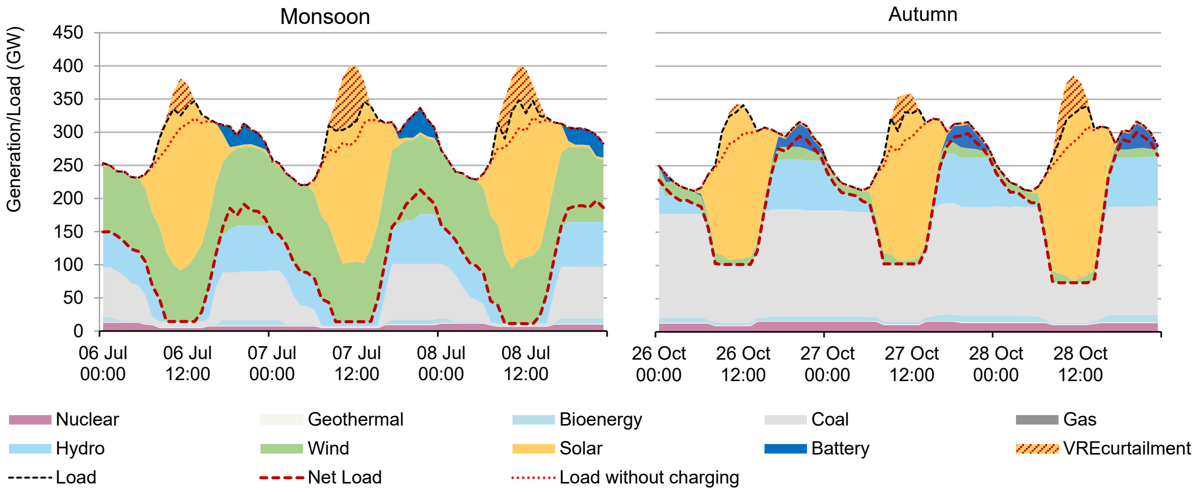


Note: The net load profiles did not take into account demand response and batteries in order to illustrate the underlying challenge.
Source: IEA analysis.

The role of dispatchable resources in providing system flexibility in India

Today, thermal power plants are the primary source of electricity in India, accounting for over 70% of the total generation mix. In the SDS, the share of thermal power generation (mainly coal- and gas-fired) in India's power system is reduced by 25% to 45% in 2030. With the high share of wind and solar PV, dispatchable thermal plants will contribute to meeting the daily, weekly and seasonal flexibility requirements. For example, each day begins with a high ramp (variation in net demand) period and during the evening peak period when solar PV output decreases, demand is ramping up (see Figure below). During the transition to a low-carbon future, thermal power plants will no longer provide the traditional baseload. They will combine the features of both intermediate and peaking generation and need to ramp up, start up and shut down more frequently to suit the needs of the system.

Generation pattern in the Sustainable Development Scenario for a low net load day occurring in the monsoon season and a high net load day in autumn, 2030

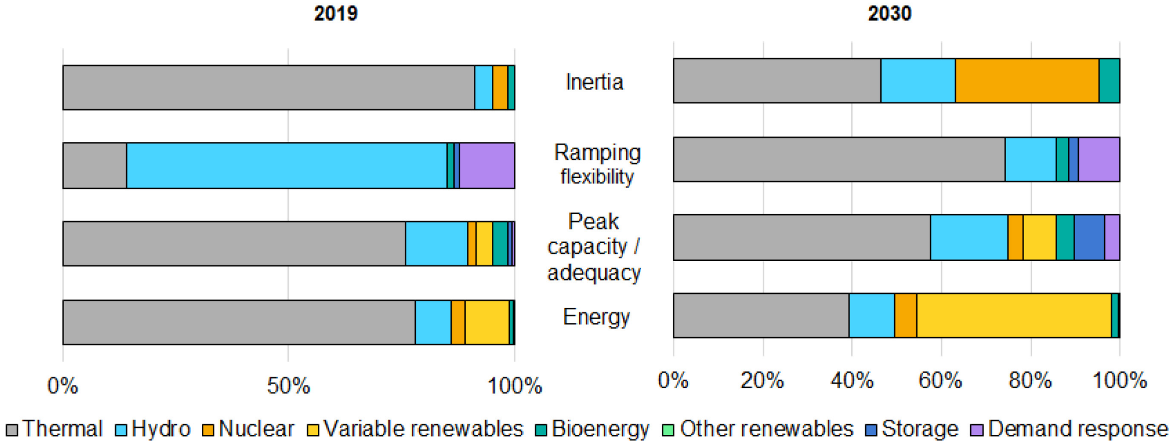


Source: IEA analysis.

India's electricity demand and renewable generation output also vary throughout the year according to seasonal patterns (winter, summer, monsoon and autumn). Dispatchable thermal plants can provide the needed flexibility to meet the seasonal variability of demand, and more notably the fluctuating supply of power from renewables. They presently contribute most to the system between October and November when the output from renewables (mainly wind and hydropower plants) is low. During India's monsoon season (June to September), which is characterised by high wind and reasonable hydropower generation output, the contribution of thermal generation can be as low as 13% of total generation, particularly during the day due to high solar PV output that often results in curtailment. However, thermal generation still contributes to the system during the off-peak period at night. The generation pattern of dispatchable thermal plants across the year reflects their flexibility attributes in being able to start/stop, and ramp up and down to accommodate the net demand variability.

India's transition to a low-carbon future with a high share of renewables requires a range of services from different technologies to meet flexibility need and ensure electricity security in the power system. In 2019, India's thermal power plants provided a major contribution to energy; peaking capacity and inertia since they operated as the traditional baseload generation while hydropower was the main source for ramping given its flexible technical capabilities (see Figure below). By 2030, when renewables become the main source of electricity generation and with the rise of other emerging technologies, thermal power plants will still provide multiple key system services. Despite the lower contribution to energy by thermal generation, these plants will still provide peak capacity and ramping flexibility services. This is because the contribution of renewable energy to system services can be limited due to the variability of wind and solar PV, while hydropower can face constraints from hydrological conditions, environmental restrictions and irrigation requirements.

Contribution of different technologies in providing system services in India in the Sustainable Development Scenario, 2019 and 2030

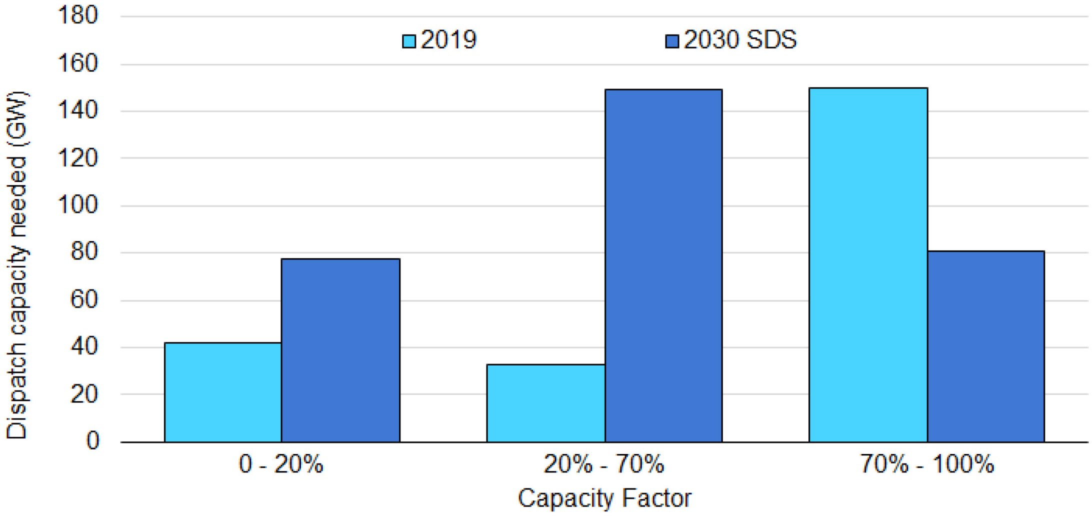


Notes: Inertia is the indicator used for assessing system stability in this case study because it is one of the key drivers of frequency stability. Ramping flexibility is calculated from the contribution to the top 100 hourly ramps. Peak capacity is based on contribution to the top 100 hours and energy is the amount of annual energy supplied.

Dispatchable power plants remain valuable assets that can keep India's power system secure and reliable.

The need for dispatchable thermal capacity to operate at a low to moderate capacity factor (0 - 70%) in India is increased by 2030 (see Figure below). In modern power systems, the traditional baseload, intermediate and peak generation paradigm in long-term power system planning will no longer apply in a decarbonised power system, particularly with a significant share of VRE.

Demand for dispatchable capacity for each range of capacity factor in India in the Sustainable Development Scenario, 2019 and 2030

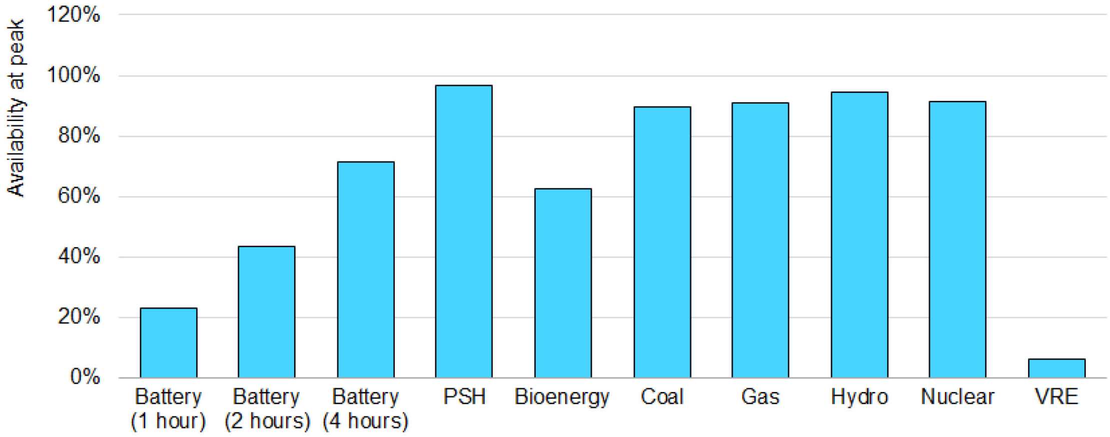


Note: The capacity factor for this figure did not take into account outages and other technical operational constraints. Traditionally, capacity factors of peak, intermediate and baseload generation are 0-20%, 20-70% and above 70%, respectively.

Despite the fact that thermal plants will operate less frequently in 2030, they will need to be available during critical peak hours when the availability of VRE towards system adequacy is limited (see Figure below). The dispatchability and flexibility of coal- and gas-fired power plants will make them important assets to keep the Indian power system reliable.

The existing thermal power plants can be modified to become fully dispatchable and flexible by changes in operational practices and plant retrofits. At present, policymakers and system operators in India are implementing regulatory mechanisms to enhance the flexibility of thermal power plants, both existing and new.

Availability of different generation technologies during peak periods in India in the Sustainable Development Scenario, 2030



Note: PSH = pumped storage hydro. Availability at peak periods is determined from the actual contribution and reserve margin provided by each technology during the top 100 hours of demand.

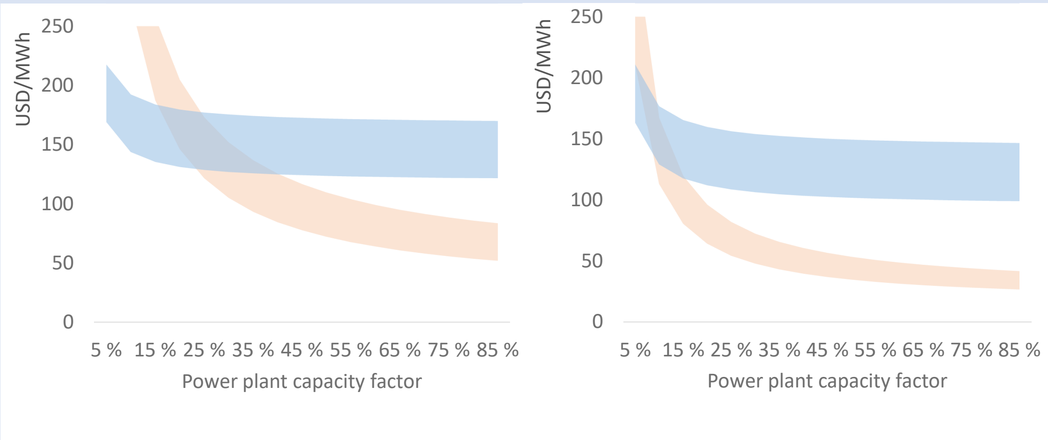
Decarbonising power generation from existing thermal power plants in India through the use of solid biomass, low-carbon fuels as well as CCUS is a plausible and cost-effective option. The relatively low capital costs of retrofitting existing thermal plants to use low-carbon fuels compared to new resources means that investment into new forms of energy can be delayed in some parts of the country. The dispatchability and ability to provide a range of system services will ensure electricity security during the transition towards a clean energy system.

Different characteristics of CCUS retrofit and modification for low-carbon fuel use

From the perspective of power system operation, the use of low-carbon fuels can be most directly compared to retrofitting power plants with CCUS as each can provide output with comparable characteristics (low-carbon, dispatchable and flexible). However, their cost profiles are quite different. Retrofitting with CCUS has a higher upfront capital cost, but lower operating costs than plants modified for co-firing. As a result, both will have a distinct role in power system operation.

Plants converted to CCUS will likely operate at higher capacity factors when compared to plants generating with low-carbon fuels, if both options are feasible in a given location. Co-firing of ammonia in a coal power plant is cheaper than CCUS at low capacity factors, competes with retrofitted CCUS in load-following mode and is more expensive as a baseload option. Co-firing hydrogen in gas turbines is interesting only for peak power operation. The inflection point at which one technology becomes cheaper than the other will depend on local system conditions, including the distance, fuel transport method, and the cost and availability of CO_2 storage.

Comparing the cost of CCUS retrofitting and modification for low-carbon fuel use for an existing thermal power plant



Source: IEA Analysis.

In addition, systems with stable net peak demand would likely require more baseload plants and would thus be best paired with plants using CCUS. Systems with high variability of net peak load would have a higher need for peaking capacity and would thus be best paired with plants using low-carbon fuels.

Chapter 6. Resource requirements and other uses of low-carbon fuels

Highlights

- **In the power sector, the total demand for low-carbon fuels is governed by the share of co-firing, the size and number of fossil fuel power stations and their capacity factors.** The amount of resources required to supply the resulting fuel demand is directly related to the overall energy efficiency of the fuel supply chain.
- **The use of low-carbon hydrogen and ammonia in the power sector has a low overall efficiency.** Given the many conversion steps and associated conversion losses, the power-to-power efficiency is only 21% for hydrogen and 22% for ammonia. For the fossil fuel with CCUS approach, the fuel-to-power efficiency is 25% for hydrogen and 26% for the ammonia route. Efficiency improvements in electrolysis and in hydrogen liquefaction has the potential to increase overall efficiencies by 2-6% depending on the route.
- **Displacing meaningful amounts of fossil fuels from power generation will require major expansion of the supply infrastructure.** The required electrolyser and hydrogen transport capacity will need to be expanded many times over the current global status. Although ammonia is already widely traded, current transport volumes would be small in comparison to the needs of the power sector. For example, co-firing 60% of ammonia in a coal power plant fleet of just 10 GW_e would mobilise an amount almost equivalent to the total ammonia traded worldwide today.
- **Using large volumes of low-carbon hydrogen and ammonia in the power sector will help establish supply chains and drive down costs.** This will complement and mutually reinforce the use of low-carbon fuels in other hard-to-abate sectors such as long-haul transport and industry.

The use of low-carbon hydrogen and ammonia is expected to be spread over many sectors and end uses. Aggregating targets from individual uses leads to substantial overall demand and necessitates new investments into a wide range of technologies and solutions. Depending on the selected production routes, very different types of resources would be needed to satisfy the demand.

Value chain efficiences

In the power sector, the total demand for low-carbon fuels is governed by the share of co-firing, the size and number of fossil fuel power stations and their capacity factors. The amount of resources required to supply the resulting fuel demand is directly related to the overall energy efficiency of the fuel supply chain, summarised in the table below. A sizeable amount of energy is lost already during the initial conversion to hydrogen. Low-temperature water electrolysers currently operate at around 64% (LHV) efficiency with an expected improvement to 69% by 2030, while natural gas can be converted to hydrogen at about 74% efficiency.

When hydrogen is converted to ammonia, a further 15% of the chemical energy is lost as heat. Although this conversion loss is avoided in the hydrogen route, the liquefaction for marine transport also requires a lot of energy. Currently about 10 kWh of electricity is needed to liquefy a kilogram of hydrogen, with prospects for reducing the energy consumption in the near future to 6 kWh/kgH_2 for large-scale liquefaction plants operating at more than 50 tpd capacity. The preparation of hydrogen for marine transport, either via conversion to ammonia or by liquefaction, consumes a comparable amount of energy.

As discussed in Chapter 3, both hydrogen and ammonia could be used as fuels for propulsion during marine transport to minimise supply emissions. For a 10 000 km distance, losses caused by fuel demand (considering a two-way voyage) would amount to about 6% of the total payload. Small losses are also likely to occur during storage and loading/unloading but these can be minimised by re-liquefaction and are small in comparison to the fuel needs in propulsion. The largest losses in the value chain occurs during electricity generation assuming 51% efficiency for an existing natural gas-fired power plant and 44% for an existing coal-fired power plant.

Efficiencies associated with using low-carbon hydrogen and ammonia as fuel in the power sector based on marine transport of 10 000 km

	Hydrogen value chain		Ammonia value chain	
	Electrolytic	Natural gas with CCUS	Electrolytic	Natural gas with CCUS
Hydrogen production	64% (69%)	74%	64% (69%)	74%
Ammonia production	-	-	85%	85%
Liquefaction	70% (82%)	70% (82%)	-	-
Marine transport	94%	94%	94%	94%
Power plant	51%	51%	44%	44%
Overall efficiency	21% (27%)	25% (29%)	22% (24%)	26%

Note: 2030 esimates are given in parenthesis.
Source: IEA analysis.

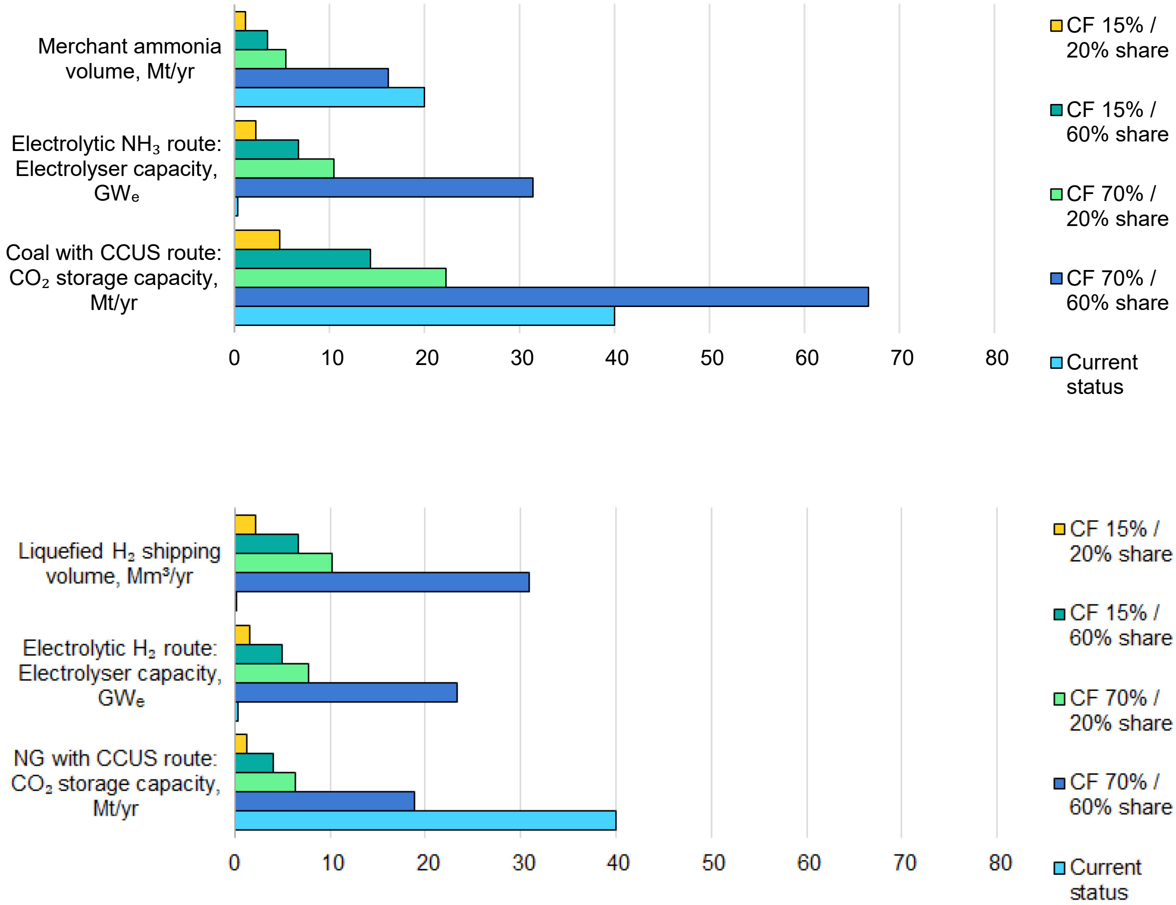
The overall efficiencies of the fuel value chains are in the range of 21%-28%, depending on the different combinations and expectations of future efficiency improvements. Producing 1 TWh of low-carbon electricity from hydrogen requires either 4.7 TWh (3.7 TWh in 2030) of electricity, or 2.8 TWh of natural gas and 0.6 TWh (0.4 TWh in 2030) of electricity (for liquefaction) depending on the production route. Similarly, producing 1 TWh of low-carbon electricity from ammonia requires 4.4 TWh (4.1 TWh in 2030) of electricity, or 3.8 TWh of natural gas.

Resource requirements

Significant investments in new electricity generation and associated infrastructure are needed to establish low-carbon fuel value chains. To illustrate the scale of the challenge, infrastructure requirements for co-firing low-carbon fuels in a 10 GWe fossil fuel fleet has been analysed below.

Co-firing 20% of ammonia in a 10 GWe coal-fired fleet would require 1.2 Mt/yr of low-carbon ammonia under peak load, and 5.4 Mt/yr under baseload operation. At 60% co-firing share the ammonia demand would be 3.5 Mt/yr under peakload, and 16.2 Mt/yr (equivalent of 80% of the globally traded ammonia today) under baseload operation.

Supply infrastructure requirements for co-firing ammonia in a 10 GW_e coal fleet (upper panel) or for co-firing hydrogen in a 10 GW_e natural gas fleet (lower panel)



Source: IEA analysis.

Satisfying ammonia demand via electrolysis would require 11-32 TWh/yr of low-carbon electricity under peak load operation and 50-151 TWh/yr under baseload operation, for co-firing shares of 20% and 60% respectively. This would require the installation of 2-7 GW_e (peak load) or 10-31 GW_e (baseload) of new electrolyser capacity, compared with the current global installed electrolyser capacity of 0.35 GW_e.

If the ammonia demand was satisfied solely through the CCUS route, the required CO_2 storage capacity would be 5-14MtCO_2/yr (peak load) or 22-67MtCO_2/yr (baseload) for the coal-based ammonia route. For natural gas-based ammonia, the CO_2 storage requirement would be 2-5 MtCO_2/yr (peak load) or 9-26 MtCO_2/yr (baseload), reflecting the lower carbon-content of natural gas. These can be compared with the 40 Mt/yr of CO_2 that is globally stored underground today.

Finally, if the ammonia demand was to be supplied solely via the biomass-based route, the needed amount of lignocellulosic biomass would be 2-7 Mt/yr (peak load) or 11-32 Mt/yr (baseload). If all fuel production plants would incorporate a BECCS design, the production of ammonia could additionally create up to 4-11 $MtCO_2$/yr (peak load) or 18-53 $MtCO_2$/yr (base load) of negative emissions.

Similarly for co-firing with hydrogen in a 10 GW_e fleet of gas power plants, the total demand for low-carbon hydrogen ranges from 0.2 to 2.2 Mt/yr. If all the required hydrogen were to be shipped overseas, the liquid hydrogen volume would be 2.2-6.6 Mm^3/yr (peak load) or 10.3-30.9 Mm^3/yr.

The required electrolyser capacity to satisfy the low-carbon hydrogen demand is 2-5 GW_e (peak load) or 8-23 GW_e (baseload) for 20% and 60% co-firing shares, respectively. The requirements for newly installed electrolyser capacity are smaller in comparison with the ammonia route, as conversion losses associated with ammonia production are avoided. However, the renewable electricity demand is on a comparable level with the ammonia route, due to the compression energy requirement for hydrogen liquefaction.

Finally, the CO_2 storage requirements range from 4 to 49 $MtCO_2$/yr for the coal-based hydrogen route, and from 1 to 19 $MtCO_2$/yr for the gas-based route. The overall demand for lignocellulosic biomass would be 2-24 Mt/yr, and in the BECCS mode, hydrogen prouciton would incur 3-39 $MtCO_2$/yr of negative emissions.

Opportunities beyond the power sector

Low-carbon fuels are expected to make important contributions to various sectors of the economy in the clean energy transitions. The pathway towards net zero emissions by 2050 requires an expansion of the use of hydrogen in existing applications, such as in the chemical industry, but there would also be a significant uptake of hydrogen and hydrogen-derived fuels in new uses like marine transport.

Nitrogen fertiliser production

Approximately 70% of global ammonia production and its derivatives is currently used to produce fertilisers. Since the early 20th century, synthetic fertilisers have formed an integral part of our food system. Researchers estimate that around half of the global population is sustained by synthetic nitrogen fertilisers.

About 55% of the global production of ammonia is used for producing urea that involves reacting ammonia with CO_2 sourced from hydrogen production. About

75% of urea production is used directly as fertiliser, 5% is converted into urea ammonium nitrate (UAN) for use as fertiliser, and the remainder is used for industrial purposes.

In the IEA STEPS and SDS, the Asia Pacific continues to dominate global ammonia production, though its production share declines from 47% today to 42% in 2050. Strong growth is seen in the Middle East, Africa and Central and South America, each of which roughly doubles its production levels by 2050.

The CO_2 emission reductions in the SDS translate into a massive need for an overhaul of the fertiliser sector. Large-scale investment in new, near-zero emission processes and infrastructure will be needed. For example, by 2050 the global fertiliser sector will need to install 155 GW of electrolyser capacity and infrastructure to transport and store 90 Mt of CO_2.

The SDS will require an average of USD 14 billion in capital investment in process technologies for ammonia production each year between now and 2050, of which 80% are at near-zero emission capacity. About 30% of the investments are towards hydrogen-based routes, including electrolysers and synthesis units to produce ammonia from electrolytic hydrogen, while 50% of the investments are towards CCUS-equipped routes, including the CO_2 capture equipment itself and the equipped SMR units. This means that a considerable portion of the investments will go towards new technologies – a third of cumulative investments are in technologies that are in the demonstration or prototype stage today.

In addition to the 250 Mt of ammonia demand from existing uses in 2050, 170 Mt of ammonia are used as an energy carrier in the SDS, which brings total ammonia demand to 420 Mt, more than twice the 185 Mt produced in 2020. The use of ammonia as a precursor for nitrogen fertilisers is addressed in more detail in other IEA publications, including a forthcoming Ammonia Technology Roadmap: Towards More Sustainable Nitrogen Fertilizer Production.

Marine transport

Hydrogen-derived fuels are also receiving considerable attention as alternative maritime fuels, especially for large ocean-going vessels. The maritime transport sector is currently a major source of GHG emissions, accounting for about 2.5% of global energy-related CO_2 emissions. International shipping with bulk carriers, tankers and containerships makes up the largest component – over 80% – of total maritime transport emissions. The CO_2 emissions from maritime shipping are projected to rise again following the 2020 drop related to the Covid-19 pandemic. In the ETP 2020, the CO_2 emissions from shipping peak in the early 2020s at about the same level as 2019, i.e. 710 Mt, and thereafter decline to 120 Mt in 2070. This trajectory is broadly in line with the initial International Maritime Organization (IMO) GHG emissions strategy to cut emissions by at least 50% by 2050 compared to 2008.

Ammonia- and hydrogen-based propulsion technologies are expected to become steadily more competitive, gradually replacing vessels using fossil fuels as they retire. Together they are used on over 60% of new vessels sold after 2060. Major industrial players have announced plans to make pure ammonia fuel engines available, and to offer ammonia retrofit packages for existing vessels. An ammonia retrofit would require modifications to the fuel storage and injection systems of engines, but would avoid a costly replacement of the entire propulsion system. Ship-owners are also already familiar with the handling of ammonia, as it is used on many vessels as a refrigerant and on some as a catalyst for de-pollution devices. These are primary considerations for ship-owners and other marine stakeholders, explaining the interest that many are currently expressing towards using ammonia as a marine fuel.

To enable hydrogen and ammonia fuel use in shipping, ports will need to build out the corresponding fuelling infrastructure. In the IEA's report The Future of Hydrogen, ports and coastal industrial clusters were identified as one of four near-term opportunities to 2030 to support the scale-up of the production and use of low-carbon hydrogen. Today, much of the global refining and chemical production that uses hydrogen is concentrated in coastal industrial zones, such as the North Sea in Europe, the Gulf Coast in North America and southeastern China. Encouraging industries that are located in such clusters to shift from unabated to low-carbon hydrogen will help drive down the overall costs. These industries can also drive the demand for hydrogen fuels by fuelling ships and trucks serving the ports, and power other nearby industrial facilities, like steel plants.

The launch of the Global Ports Hydrogen Coalition in 2021 under the CEM H2I is a first step in this direction. It aims to provide government decision makers with advice on what measures could be taken to stimulate ports and industrial coastal clusters to increase the production and use of low-carbon hydrogen. In the 2030 timeframe, hydrogen fuelling infrastructure at ports is expected to remain limited to "first movers" such as the signatories of the Global Ports Hydrogen Coalition and others who have already begun investigating and testing hydrogen solutions. For ammonia infrastructure, the first movers could be ports that have high cargo throughput and either existing ammonia terminals or plans to integrate new fuels.

Chapter 7. Conclusions

Using low-carbon hydrogen and ammonia in fossil fuel power plants can play an important role to help ensure electricity security in clean energy transitions

Governments around the world are faced with the challenge of ensuring electricity security and meeting growing electricity uses while simultaneously cutting emissions. The significant increase in renewables and electrification of end-uses plays a central role in clean energy transitions. However, due to the variable nature of solar PV and wind, a secure and decarbonised power sector requires other flexible resources on a much larger scale than currently exists today. These include low-carbon dispatchable power plants, energy storage, demand response and transmission expansion. The availability and cost of these technologies depends on local conditions, social acceptance and policies.

Thermal generation is the largest source of power and heat in the world today, also providing key flexibility and other system services that contribute to the security of electricity supply. Countries that rely strongly on fossil fuel-based power generation will be required to make very significant efforts to achieve decarbonisation objectives to comply with the Paris Agreement or Net Zero targets, where applicable.

The possibility to combust high shares of low-carbon hydrogen and ammonia in fossil fuel power plants provides countries with an additional tool for decarbonising the power sector, while simultaneously maintaining all services of the existing fleet. The relevant technologies are progressing rapidly. Co-firing up to 20% of ammonia and over 90% of hydrogen has taken place successfully at small power plants, and larger-scale test projects with higher co-firing rates are under development.

The value of low-carbon fuels in the power sector depends on system contexts and regional conditions

By 2030, thermal power plants using low-carbon fuels could play a growing role as a dispatchable resource for covering peaking needs when the value of the produced electricity is high, and for providing a range of system services to ensure energy security and capacity adequacy to avoid costly disruptions in the energy supply.

Low-carbon fuels can play an especially important role in countries or regions where the thermal fleet is young, or when the availability of low-carbon dispatchable resources is constrained. In these settings, they can enable continued operation of existing assets even when climate regulations are tightened, thereby diminishing the risk of creating stranded assets. This is particularly the case in the East and Southeast Asia.

Production costs of low-carbon fuels must decrease further

Today, the cost of producing low-carbon fuels is still significantly higher than the cost that fossil fuel power plants generally pay for their fuels. However, the need to decarbonise hard-to-abate sectors like industry and transport is fostering the production of hydrogen and hydrogen-derived fuels, and this is expected to lead to cost reductions due to scale benefits and learning.

Natural gas with CCUS is currently the least-cost production route for low-carbon hydrogen and ammonia in regions with cheap natural gas, and access to CO_2 storage. By 2030, the economic attractiveness of the CCUS route could improve further, though it remains exposed to fossil fuel price variations.

Due to continuing reductions in the cost of renewable electricity and scale benefits in electrolysers, the costs of the electrolytic route decrease faster, and by 2030 the costs of low-carbon fuels from renewables become comparable with those of fossil fuels in the CCUS route, and can become the lowest cost route in regions with excellent wind and solar resources. However, in the absence of a price on carbon, low-carbon hydrogen and ammonia are still expected to remain more expensive than coal and natural gas in 2030.

Full value chains, including transport and storage, must be considered when comparing the cost of using different low-carbon fuels

An extensive transport and storage infrastructure is a prerequisite for establishing global value chains based on hydrogen and ammonia, and connecting low-cost production regions with users of low-carbon fuels. Such infrastructure involves massive investments combined with concerted and coordinated efforts across many stakeholders, including duly addressing health & safety risks.

The storage and long-distance transport of low-carbon fuels can lead to a substantial increase in the cost of delivered fuel. In the case of hydrogen, liquefaction is a very energy- and capital- intensive process that contributes to high transport costs which can significantly impact the cost difference between hydrogen and ammonia, and in some cases tilts the overall balance in favour of ammonia.

The use of low-carbon fuels in fossil fuel power plants must lead to significant and measurable life-cycle emission reductions

There are currently no internationally agreed rules or standards on the maximum allowable limit of GHG emissions that can be associated with the production of hydrogen and/or hydrogen-derived fuels. Standards are however needed to create end-user confidence towards fuels that are carbon-free at the point of consumption, but might be associated with significant GHG emissions along the supply chain, from production to transport and final distribution.

In the case of the CCUS route, as it will dictate minimum eligible CO_2 capture rates and put limits on the maximum allowable upstream emissions because they cannot be captured at the production plant.

At the same time, such rules and standards are also relevant for the electrolytic route if the use of grid electricity is allowed for the production plants, as the power mix will significantly influence life-cycle emissions.

A versatile mix of supply routes for low-carbon fuels will enhance diversification and security of supply while contributing to cost predictability

Our cost analysis indicates clear differences among the production costs of different production technologies. Despite possible rapid cost reductions for electrolysers, in most locations the renewable route is likely to remain more expensive than fossil fuels with CCUS in 2030.

However, the lowest cost production route is subject to location conditions and – as supply chains struggle to meet rapidly growing demand – a diverse mix of supply locations and technologies can help enhance the security of supply for end-users. The costs of the renewable route are more predictable and can help to balance possible disruptions in the supply of natural gas and swings in commodity prices, to which the fossil fuel-based routes are exposed.

Early opportunities for low-carbon hydrogen and ammonia production are identified in places where production can be built on existing infrastructure and demand. There also exist possibilities to integrate the two approaches into a hybrid plant that can offer increased efficiency and potentially also require lower capital investment requirements.

If the biomass feedstock is sustainably produced, capturing by-product CO_2 from a biomass conversion plant would enable the production of carbon-negative hydrogen and ammonia. This form of BECCS configuration would lead to increases in production costs. However, if the plant received revenue from negative emissions (i.e., from permanent storage of biogenic CO_2), this would significantly improve the economics of biomass-based fuels under high carbon price jurisdictions.

For the above-mentioned reasons, the overall strategies and policies incentivising the deployment of low-carbon fuels should be kept open for different technology options so long as basic sustainability criteria are met. This is likely to increase competition and accelerate cost reductions, while contributing to increased diversification and security of supply

A portfolio of policies is required to compensate for cost gaps and foster uses that maximise system value

By 2030, low-carbon hydrogen and ammonia are likely to remain expensive energy carriers for power generation. Power markets should be redesigned to reward flexibility and capacity contributions from low-carbon thermal power plants.

This could be accompanied by support measures such as carbon pricing and/or other complementary policies and regulatory frameworks to further decrease the remaining cost gap with incumbent generation. Support measures should be tailored towards cost-effective system integration and maximising the value of low-carbon dispatchable generation. They should also aim at fostering competition and improving environmental performance over time.

In any case, given the expected increasing competition from other forms of low-carbon dispatchable resources as well as other flexibility and storage options, the availability, feasibility and competitiveness of low-carbon thermal power plants will need to be continuously and carefully assessed.

Developing markets for low-carbon fuels and their supply chains by 2030 will establish significant opportunities in many countries and sectors of the economy

It is vital that economies with strong drivers for low-carbon fuel use are successful in creating demand, bringing down the costs and stabilising value chains by 2030. Only their success will open up opportunities to expand the use of low-carbon fuels in the emerging economies of the world.

This is particularly relevant to countries that have young fossil fuel fleets, and have already implemented and utilised most of their existing flexibility resources, such as grids and interconnections, storage and demand-side measures.

Ultimately, using large volumes of low-carbon hydrogen and ammonia in the power sector will help establish supply chains and drive down costs through economies of scale and technological improvements, thereby complementing and mutually reinforcing the use of low-carbon in fuels in other hard-to-abate sectors such as long-haul transport and industry.

Annexes

Annex A - Dynamical modelling of hydrogen and ammonia costs from a mix of wind and solar via water electrolysis

The cost and availability of electricity governs the cost of fuels produced via the electrolytic route. By connecting the electrolyser plant directly to a mix of wind and solar PV power plants, a fully renewable fuel production process can be established. Because the solar and wind resources are distributed unevenly across the globe, certain locations are better suited for producing low-cost fuels via electrolysis.

For the purposes of this report, the levelised cost of hydrogen (LCOH) and the levelised cost of ammonia (LCOA) have been dynamically modelled and analysed following a methodology explained in more detail in the paper: "Flexible production of green hydrogen and ammonia from variable solar and wind energy: Case study of Chile and Argentina".

The table below summarises the capacity factors (CFs) and LCOE estimates for wind and PV for selected locations in 2030. The capacity factors for solar electricity range from 15.1% (Magallanes, Chile) to 32.5% (Taltal, Chile) while for wind generation the CFs range from 15.3% (Rajasthan, India) to 51.8% (Magallanes, Chile). The resulting LCOEs for solar PV range from USD 16 to 51/MWh and for wind from USD 25 to 77/MWh.

Levelised cost of electricity estimates for selected locations in 2030

	Taltal	Magallanes	Gujarat	Karnataka	Rajasthan	Port Headland, Australia	Aqaba, Saudi Arabia	Abu Dhabi
CF solar (%)	32.5	15.1	23.7	24.1	23.2	25.2	27.1	27.6
CF wind (%)	43.8	51.8	45.6	43.9	15.3	42.2	48.0	29.2
LCOE solar (USD/MWh)	24	51	31	16	17	30	23	22
LCOE wind (USD/MWh)	37	30	30	25	77	40	36	67

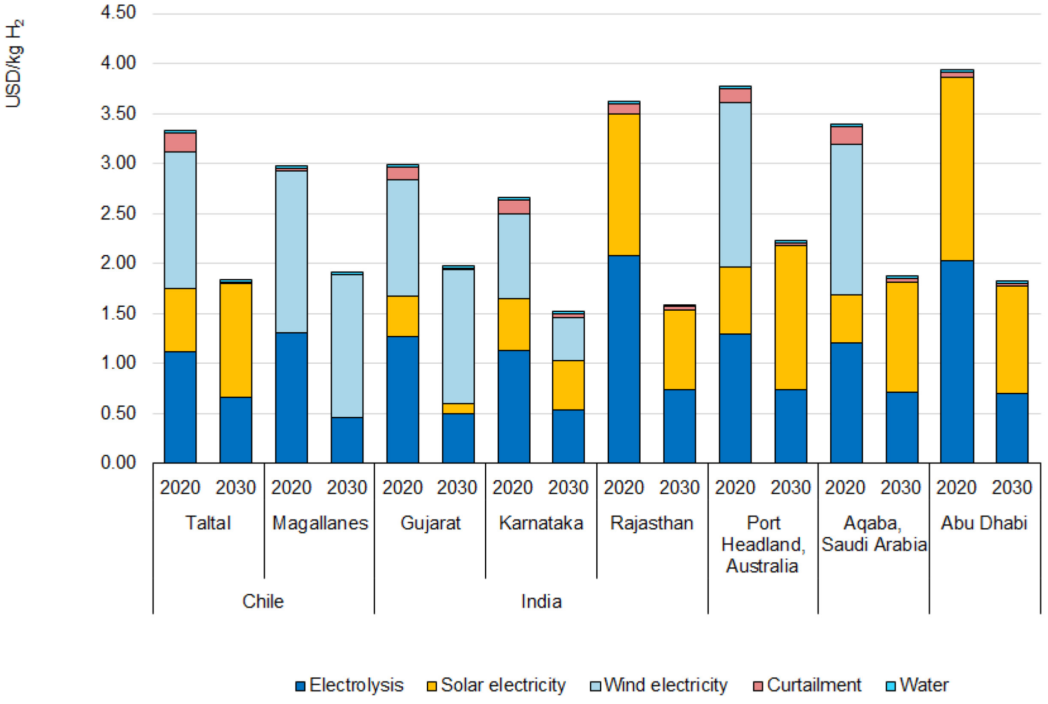
Based on local conditions, as summarised in the form of CFs and LCOEs, the LCOH has been dynamically modelled and summarised in the table below. By optimising the solar (P_{solar}) and wind farm capacities (P_{wind}) relative to the size of the electrolyser unit (P_{H2}), the electrolyser's capacity factor (CF hybrid) as well as the total curtailment of electricity (electricity generation that exceeds electrolyser capacity) can be calculated. Out of the examined locations, the lowest LCOH of USD 1.52/kg is achieved in Karnataka, followed by USD 1.59 /kg in Rajasthan.

The cost reduction from hybridisation, i.e. from optimising the wind/PV mix is limited for most of the examined hydrogen cases, though for Karnataka an almost 3% cost reduction can be achieved. Higher hybridisation gains can be generally achieved when the local daily and yearly cycles of solar and wind combine favourably, leading to an increased capacity factor for the electrolyser. On the other hand, at lower electrolyser CAPEX the hybridisation gains are also lower.

Process parameters and production cost estimates for electrolytic hydrogen from locally optimised mixes of solar PV and wind in 2030

	Taltal	Magallanes	Gujarat	Karnataka	Rajasthan	Port Headland, Australia	Aqaba, Saudi Arabia	Abu Dhabi
P_{solar}/P_{H2}	1.25	0	0.145	1.45	1.64	1.45	1.45	1.44
P_{wind}/P_{H2}	0	1.18	1.16	0.436	0	0	0	0
CF hybrid (%)	40.5	61.2	55.9	52.1	36.4	36	37.7	38.5
curtailment (%)	0.83	0.12	1	4	4.2	1.9	4.3	2.9
Hybridisation gain (%)	0	0	0.2	1.8	0	0	0	0
LCOH	1.84	1.91	1.97	1.52	1.59	2.23	1.88	1.83

Cost breakdown of LCOHs in 2020 and 2030 for selected regions



Similarly to LCOHs, the LCOAs have also been optimised for local conditions and summarised in the table below. However, dynamical modelling of an electrolytic ammonia plant is substantially more complex than modelling a hydrogen electrolyser. In the HB process, the produced hydrogen is combined with nitrogen captured from the air using a cryogenic air separation unit (ASU), and catalytically converted to ammonia under elevated pressure and temperature. The Haber-Bosch synthesis loop is much less flexible than an electrolyser, thus an intermediate storage of hydrogen is used to stabilise the flow of hydrogen to the ammonia synthesis. For this purpose, steel tanks for compressed hydrogen storage were considered, which is quite costly, but currently commercially available. The additional electricity consumption caused by the ASU and HB is based as much as possible on wind and solar generation, but is complemented with “firm-up” electricity purchased either from the grid or generated locally at a cost of about USD 100/MWh when wind or solar are not available.

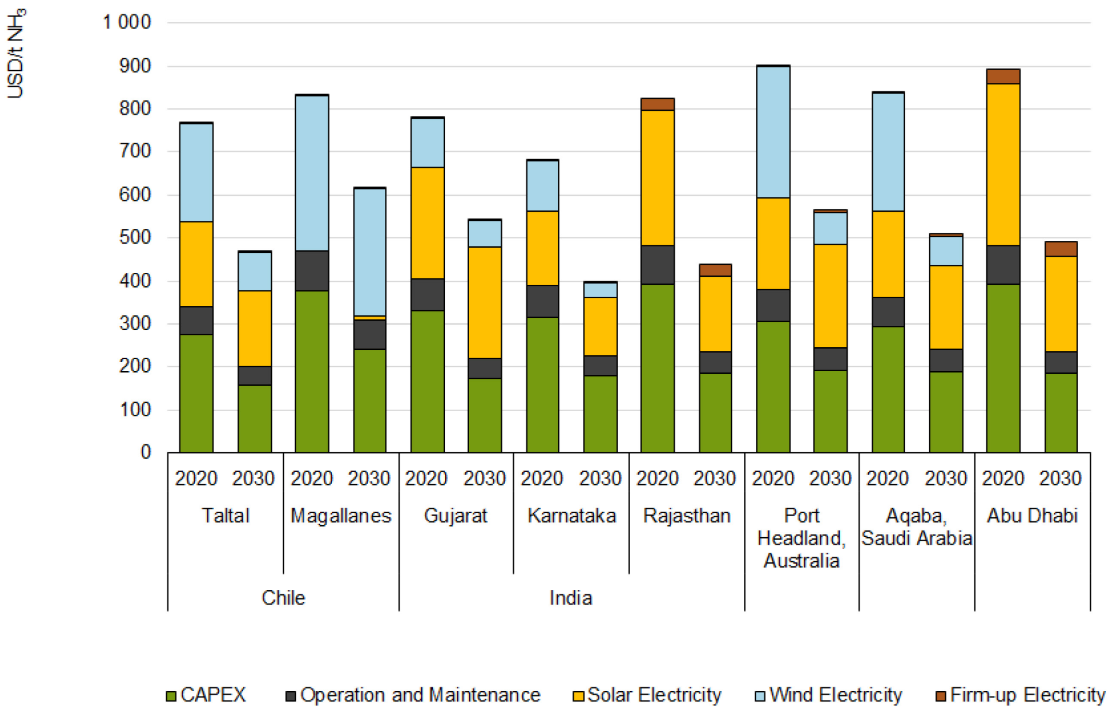
The LCOA depends, as the LCOH, on the sizes of wind and solar power plants relative to the electrolyser capacity P_{H2}, but additionally on the capacity of the HB synthesis reactor relative to P_{H2}, which is described by the oversizing of the HB capacity relative to the mean hydrogen flow. When HB oversizing equals 1, the H_2 buffer storage manages to absorb all of the fluctuations in upstream hydrogen production so that the ammonia synthesis can operate the whole year at a constant nominal load. This is however not the optimal configuration due to the high cost of H_2 storage to achieve perfectly continuous H_2 supply to the HB reactor.

The results show that hybridisation gains are higher for electrolytic ammonia than for electrolytic hydrogen, providing cost reductions up to 8.0% (Gujarat). A second observation relates to the large hydrogen storage requirements for locations like Magallanes (7.4 days of H_2 production) where wind variability is very strong. Due to the high cost of H_2 storage, an optimal configuration requires substantial oversizing of the renewable power supply, leading to an electrolyser capacity factor of 64.7% and a large 5.5% share of curtailed electricity. Of the examined locations, the lowest LCOA of USD 400/tNH3 (USD 77/MWh) is achieved in Karnataka, followed by USD 439 /tNH3 (USD 85/MWh) in Rajasthan.

Process parameters and production cost estimates for electrolytic ammonia from a locally optimised mix of solar PV and wind in 2030

Optimisation results	Taltal	Magallanes	Gujarat	Karnataka	Rajasthan	Port Headland, Australia	Aqaba, Saudi Arabia	Abu Dhabi
P_{solar}/P_{H2}	1.31	0.09	1.71	1.6	2.01	1.51	0	1.57
P_{wind}/P_{H2}	0.31	1.4	0.23	0.14	0	0.2	1.36	0.2
HB oversizing	1.1	1.34	1.16	1.08	1.13	1.13	1.16	1.13
Hybrid CF (%)	50.8	64.7	43.9	40.4	39	41.8	44.3	39.6
Curtailment (%)	3.6	5.5	7.4	3.5	13.2	3.8	9.0	6.6
H2 storage (days of H2 production)	1.1	7.4	1.1	1.3	1.4	2.3	2.3	1.5
HB-ASU firm-up elec. (%)	6.6	3.9	3.2	8.2	51.2	6.0	9.3	49.3
Hybridisation gain (%)	6.4	0.2	8.0	4.5	0.0	5.0	1.5	0.0
# stops HB	0	0	0	0	0	0	0	0
LCOA (USD/tNH3)	471	617	544	400	439	565	511	490
LCOA (USD/MWh)	91	119	105	77.3	84.8	109	98.7	94.6

Cost breakdown of LCOAs in 2020 and 2030 for the selected regions



Annex B - Assumptions

This annex collects the various assumptions that underpin the analyses throughout the *The Role of Low-Carbon Fuels in the Clean Energy Transitions of the Power Sector* report. The analysis is based on the IEA Sustainable Development Scenario (SDS).

General

- Weighted average cost of capital, WACC: 5%
- CAPEX range: ±15%
- Learning to 2030: 2% (Commercial technologies)
- Learning to 2030: 20% (Biomass technologies)
- Runtime of thermal fuel production: 8000 hours/year
- Plant lifetime: 25 years

Main investment cost assumptions

Electrolyser	Unit	Today	2030 SDS
CAPEX	USD/kW$_e$	1477	562
OPEX	% of CAPEX	1.5	1.5
Lifetime	years	28	30
Stack lifetime	Operating hours	95000	95000
Efficiency (LHV)	%	64	69

Solar PV – Large-scale	Unit	Today	2030 SDS
Brazil (Latin America) *			
CAPEX	USD/kW$_e$	1250	720
Annual O&M	USD/kW$_e$	18	16
India			
CAPEX	USD/kW$_e$	610	360
Annual O&M	USD/kW$_e$	12	8
Australia			
CAPEX	USD/kW$_e$	1220	700
Annual O&M	USD/kW$_e$	18	16

* Used for Chile

Wind - Onshore	Unit	Today	2030 SDS
Brazil (Latin America) *			
CAPEX	USD/kW$_e$	1560	1460
Annual O&M	USD/kW$_e$	38	38
India			
CAPEX	USD/kW$_e$	1060	1000
Annual O&M	USD/kW$_e$	26	26
Australia			
CAPEX	USD/kW$_e$	1560	1440
Annual O&M	USD/kW$_e$	38	36

* Used for Chile

Main transport assumptions

Nautical distances	Unit		
Australia to Japan	km		8,000
Saudi Arabia to Japan	km		12,000
Saudi Arabia to Indonesia	km		9,000
Chile to Japan	km		20,000
Shipping parameters	**Unit**	**LH_2 carrier**	**NH_3**
Ship speed	km/h	30	30
Ship capacity	m^3	160,000	86,700
Ship CAPEX	M$	412	89
Ship OPEX	USD/day	10,000	10,000
Loading flash rate	%	1	0.1
Propulsion energy demand	GJ/km	4	4
Unloading flash rate	%	1	0.1
Export terminal parameters	**Unit**	**LH_2 carrier**	**NH_3**
Tank capacity	m^3	192,000	104,000
CAPEX	M$	1161	209
OPEX	% of CAPEX	2	2
Electricity consumption	kWh/kg	0.2	0.001
Duration one loading	days	1.5	1.5
Time between loadings	days	15	15
Import terminal parameters	**Unit**	**LH_2 carrier**	**NH_3**
Tank capacity	m^3	200,000	81,000
CAPEX	M$	1271	291
OPEX	% of CAPEX	2	2
Electricity consumption	kWh/kg	0.2	0.001
Boil-off rate	%	0.1	0.1
Duration one loading	days	1.5	1.5
Time between loadings	days	15	15
Liquefaction parameters	**Unit**		
Size of liquefier unit	t/d	115	
Liquefier unit CAPEX	M$	195	
Liquefier unit OPEX	% of CAPEX	2	
Electricity consumption	kWh/kg	6	

Cost assumptions based on data from the Institute of Applied Energy (Japan) report: "Economical Evaluation and Characteristic Analyses for Energy Carrier Systems (FY 2014–FY 2015) Final Report". Link: www.nedo.go.jp/library/seika/shosai_201610/20160000000760.html

Main fuel cost and power plant assumptions

2030 prices in the SDS		Japan			Australia			Indonesia			India			Saudi Arabia			USA		
Item	Unit	*L*	*C*	*H*	*L*	*C*	*H*	*L*	*C*	*H*	*L*	*C*	*H*	*L*	*C*	*H*	*L*	*C*	*H*
Coal	USD/t	52	65	79	12	15	18	35	44	53	40	50	60		n/a		27	34	41
NG	USD/GJ	4.4	5.5	6.6	3.6	4.5	5.4		n/a			n/a		1.1	1.3	1.6	1.7	2.1	2.5
CO_2	USD/tCO_2	66	82	98	66	82	98	0	0	0	0	0	0	0	0	0	66	82	98
Biomass (wood chips)	USD/t		n/a			n/a			n/a			n/a			n/a		50	75	100

Efficiency		Japan	Australia	Indonesia	India	Saudi Arabia	USA
Item	Unit						
NGCC efficiency (young)	% (LHV)	51	52	n/a	n/a	n/a	45
Coal plant efficiency (USC)	% (LHV)	44	n/a	40	40	n/a	n/a
NGCC OPEX	USD/MW$_{th}$h				2		
USC OPEX	USD/MW$_{th}$h				4		

Carbon price for advanced economies in SDS 2030 is 74-90 USD/tCO_2. The letters *L*, *C*, and *H* in the table refer to Low, Central and High values, respectively. Coal price is for an assumed LHV value of 6000 kcal/kg.

Hydrogen production

Pathway	Parameter	Unit	Now	2030
NG reforming with CCUS	CAPEX	USD/kW$_{H2}$	1470	1440
	OPEX	% of CAPEX	4	4
	Efficiency (LHV)	%	74	74
Coal gasification with CCUS	CAPEX	USD/kW$_{H2}$	2040	2000
	OPEX	% of CAPEX	5	5
	Efficiency (LHV)	%	58	58
Biomass w/ and w/o CCUS*	CAPEX	USD/kW$_{H2}$	5410	4330
	OPEX	% of CAPEX	5	5
	Efficiency (LHV)	%	62	62

*Cost impact of adding CCS to the biomass plant is accounted through capture costs.

Ammona production

Pathway	Parameter	Unit	Now	2030
NG reforming with CCUS	CAPEX	USD/kW$_{NH3}$	2830	2770
	OPEX	% of CAPEX	4	4
	Efficiency (LHV)	%	63	63
Coal gasification with CCUS	CAPEX	USD/kW$_{NH3}$	3500	3430
	OPEX	% of CAPEX	5	5
	Efficiency (LHV)	%	49	49
Biomass w/ and w/o CCUS*	CAPEX	USD/kW$_{NH3}$	7470	6170
	OPEX	% of CAPEX	5	5
	Efficiency (LHV)	%	53	53

***Cost impact of adding CCS to the biomass plant is accounted through capture costs.**

Main CCUS and GHG emissions assumptions

CCUS parameter	Unit	Value
Capture rate from ATR and gasification	%	95
Capture costs, concentrated streams	USD/tCO_2	25
Capture costs, concentrated and diluted streams	USD/tCO_2	40
Cost of transport and storage	USD/tCO_2	20

Abbreviations and acronyms

ASU	air separation unit
ATR	autothermal reforming
BECCS	bioenergy with carbon capture and storage
BEV	battery electric vehicle
BF-BOF	blast furnace-basic oxygen furnace
CAES	compressed air energy storage;
CAPEX	capital expenditure
CCGT	combined-cycle gas turbine
CH3OH	methanol
CF	Capacity factor
CNG	compressed natural gas
CO	carbon monoxide
CSP	Concentrated solar power
CO2	carbon dioxide
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CNG	compressed natural gas
CSA	Central and South America
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAC	direct air capture
DLN	Dry Low NOx
DRI	direct reduced iron
DRI-EAF	direct reduced iron-electric arc furnace
EAF	electric arc furnace
ECBM	Enhanced coal-bed methane
EOR	enhanced oil recovery
FC	fuel cell
FCEV	fuel cell electric vehicle
FGD	Flue gas desulphurisation
FLH	fuel load hours
FT	Fischer-Tropsch
GT	Gas turbines
HB	Haber-Bosch
HFO	Heavy fuel oil
HRSG	Heat recovery steam generator
LCOA	Levelised cost of ammonia
LCOE	Levelised cost of energy
LCOH	Levelised cost of hydrogen
LOHC	Liquid organic hydrogen carriers
LPG	Liquefied petroleum gas
MP	Methane pyrolysis
PC	Pulverised coal
PEM	Polymer electrolyte membrane

PSA	Pressure swing adsorption
SCR	Selective catalytic reduction
SDS	Sustainable Development Scenario
SMR	Steam methane reforming
SOEC	Solid oxide electrolyser cells
UAN	Urea ammonium nitrate
VALCOE	Value-adjusted levelised cost of energy
VRE	Variable renewable energy
WEM	World Energy Model

Glossary

bbl	barrel
bbl/d	barrels per day
bcm	billion cubic metres
bcm/yr	billion cubic metres per year
cm/s	centimetres per second
gCO2	gram of carbon dioxide
gCO2/kWh	grams of carbon dioxide per kilowatt hour
GJ	gigajoule
Gt/yr	gigatonnes per year
GtCO2	gigatonne of carbon dioxide
GtCO2/yr	gigatonnes of carbon dioxide per year
GW	gigawatt
GWh	gigawatt hour

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