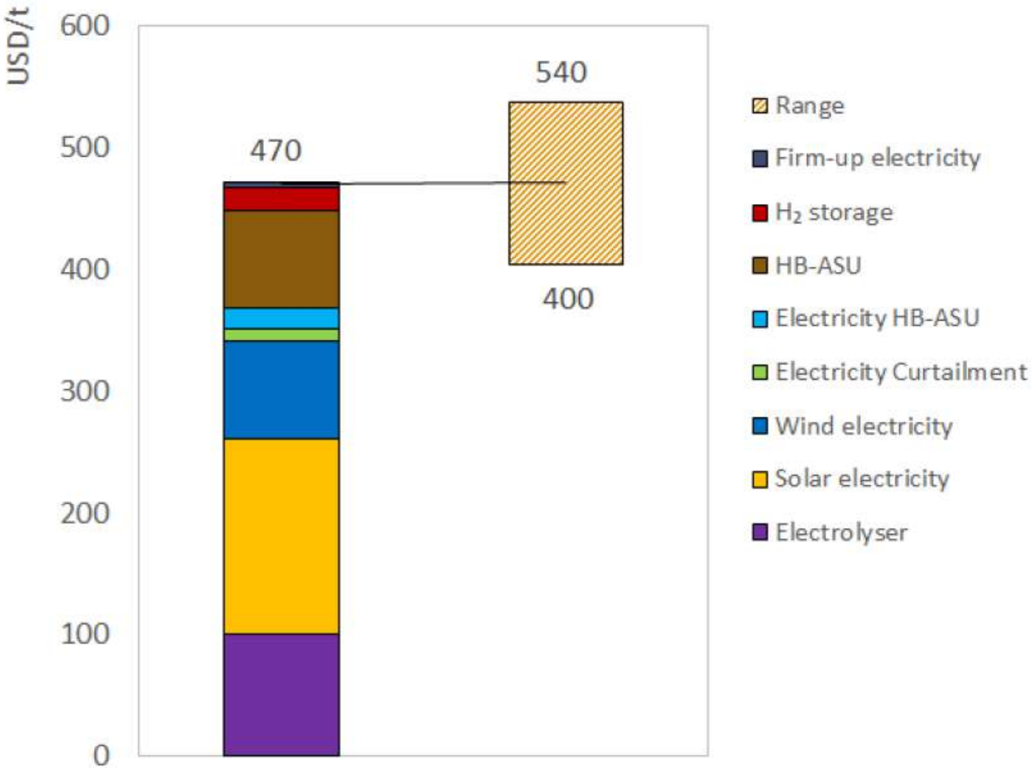
Indicative levelised cost of electrolytic ammonia in 2030 from a mix of wind/solar PV in the Taltal region of Chile

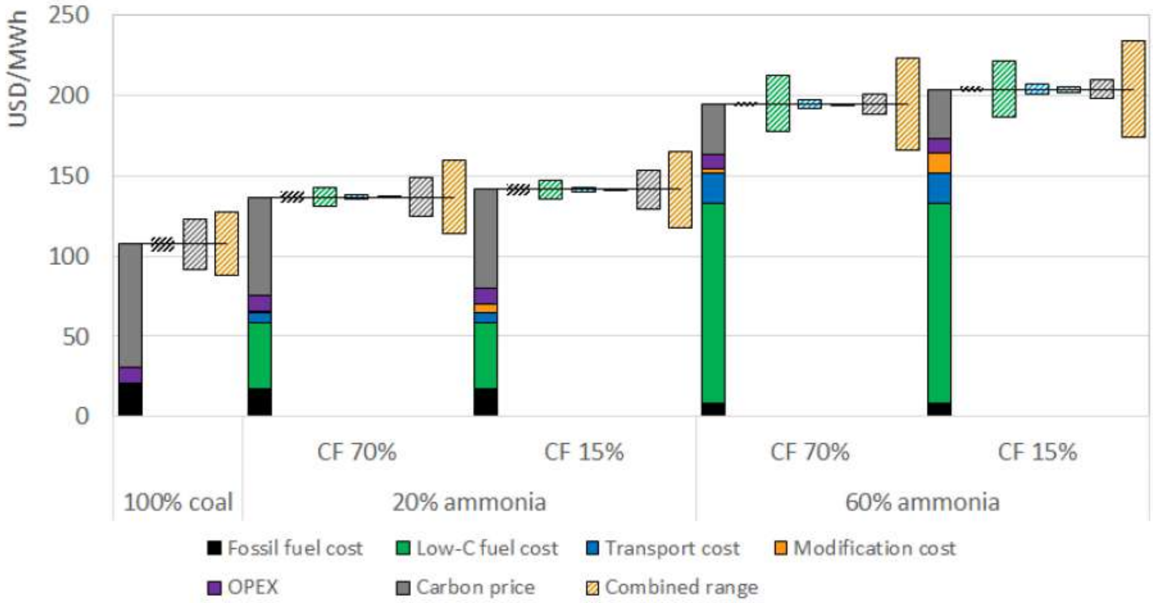


Note: WACC 5%, CF solar 32.5%, CF wind 43.8%, CF hybrid 50.8%, LCOE solar USD 24/MWh, LCOE wind USD 37/MWh, H_2 storage size 1.1 days, HB-ASU firm-up electricity 7%, gain from hybridisation 6%.
Source: IEA analysis.

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.

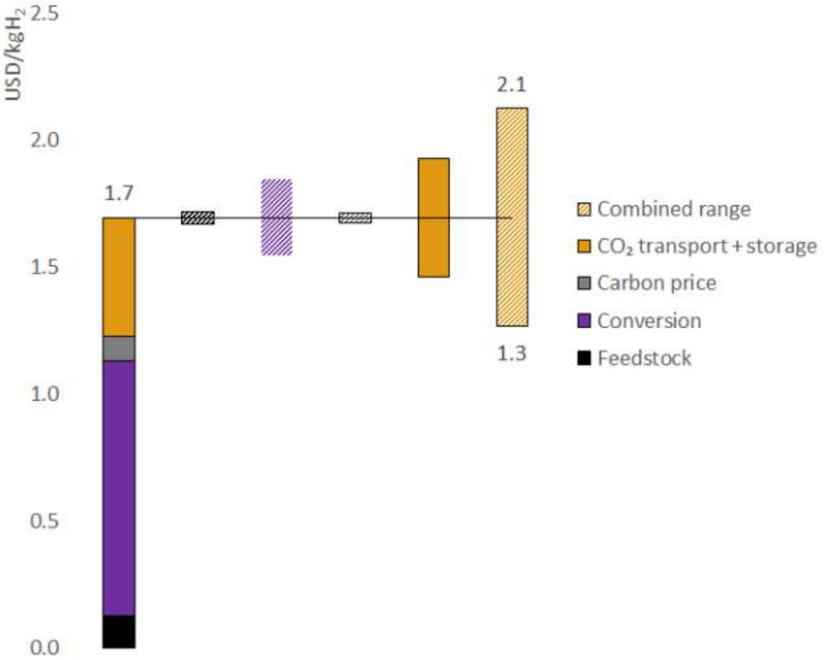
Case study III: Coal-based low-carbon H_2 from Australia to an existing natural gas plant in Japan

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

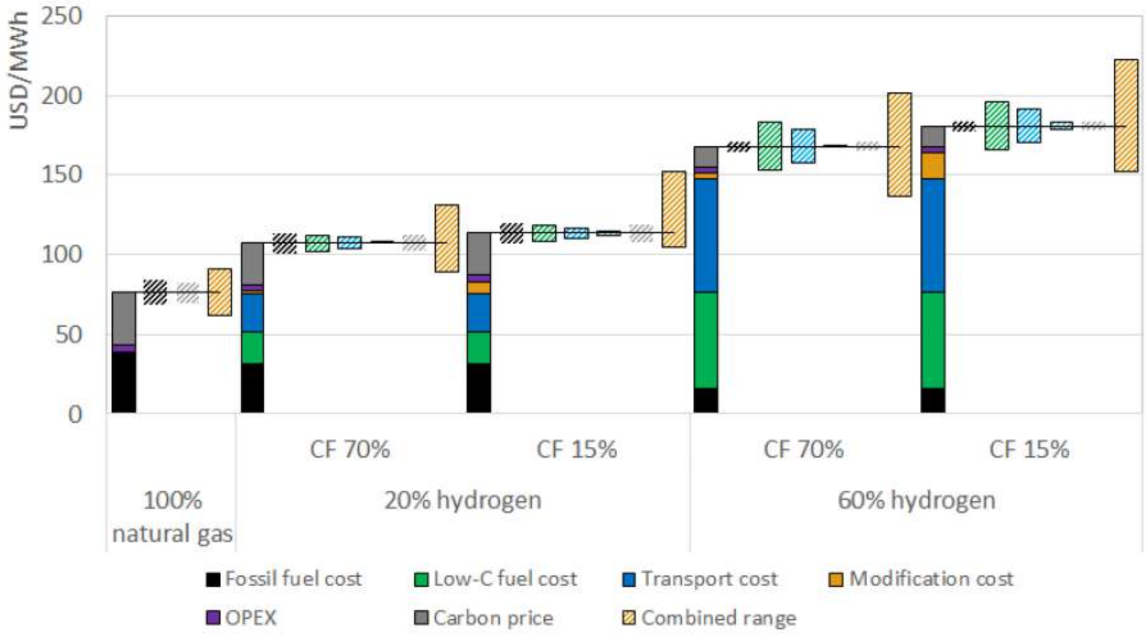


Notes: WACC 5%, coal USD 12-18/t, Hydrogen plant efficiency 58%, OPEX 5% of CAPEX, 95% CO_2 capture, CO_2 transport and storage cost = USD 10-30/tCO_2.
Source: IEA analysis.

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.



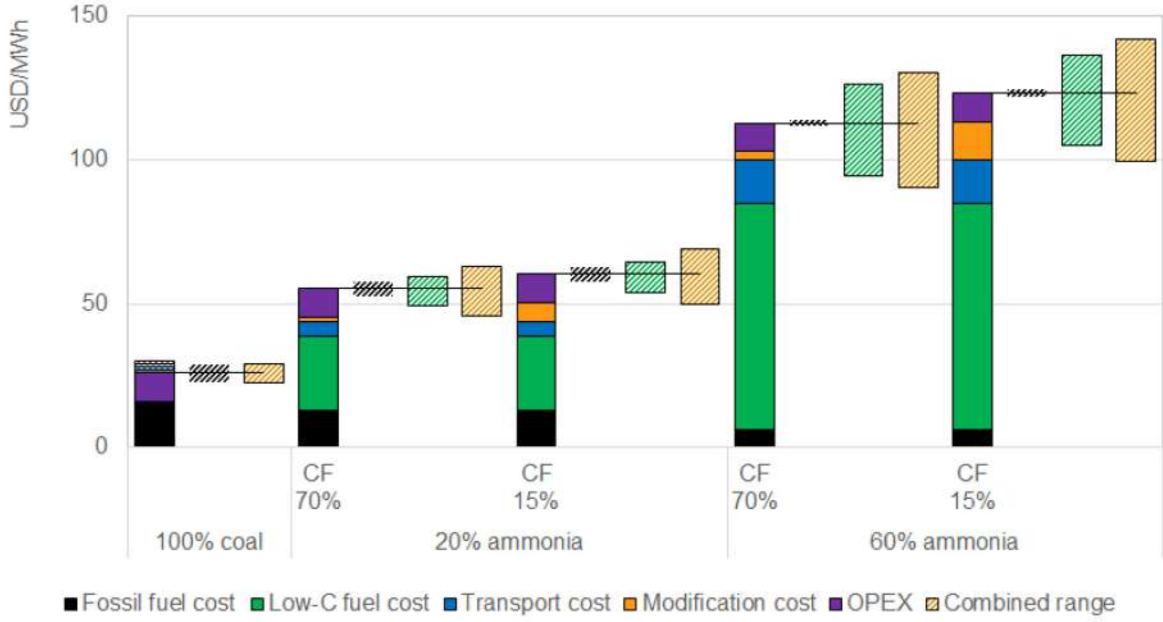
Note: natural gas USD 4.4-6.6/GJ, Low-carbon H_2 USD 1.3-2.1/kg, transport cost USD 1.7-2.2/kg, gas plant efficiency 51%, carbon price USD 66-98/tCO_2.

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.

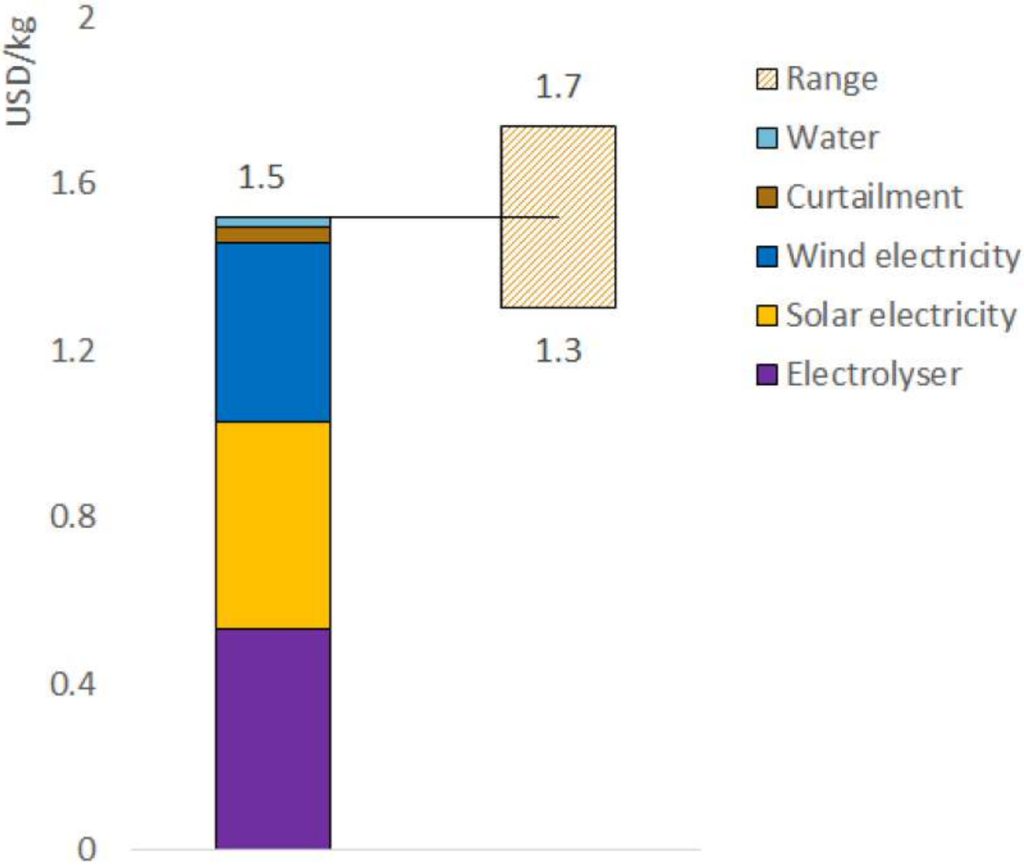
The Indian Ministry of Power has also recently announced plans to establish a National Mission on the use of biomass in coal-based thermal power plants. The goal of this mission is to increase the level of biomass co-firing from the present 5% and to unlock the supply chain constraints on biomass pellets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

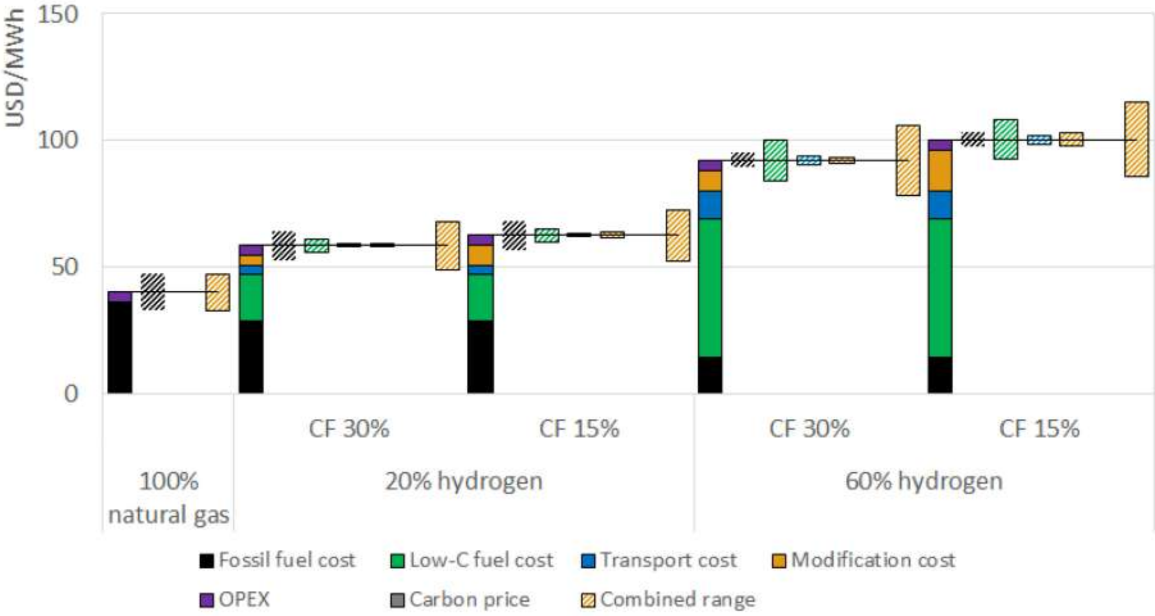


Notes: WACC 5%, CF solar 24.1%, CF wind 43.9%, CF hybrid 52.1%, LCOE solar USD 16/MWh, LCOE wind USD 25/MWh curtailment 4%, gain from hybridisation 2%.

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.