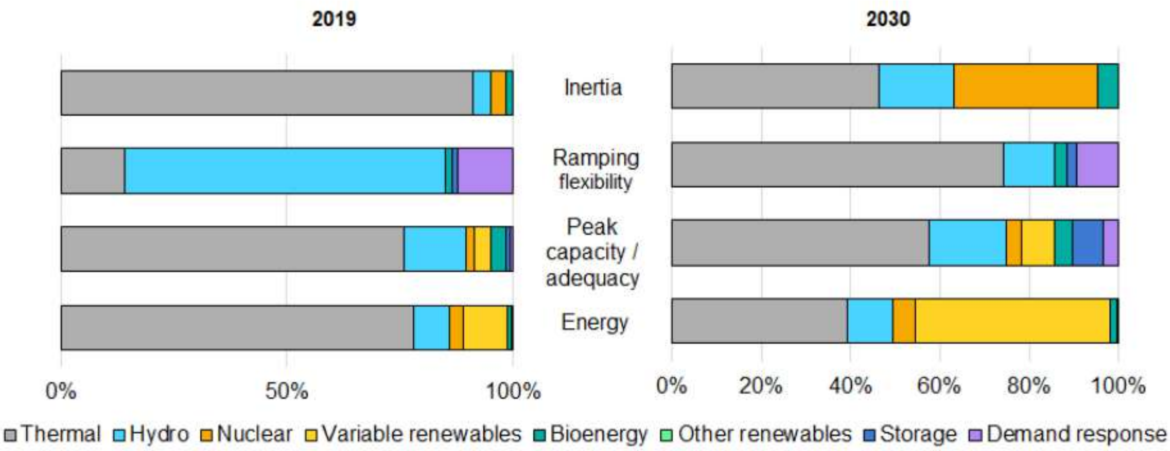
services. This is because the contribution of renewable energy to system services can be limited due to the variability of wind and solar PV, while hydropower can face constraints from hydrological conditions, environmental restrictions and irrigation requirements.

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



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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.

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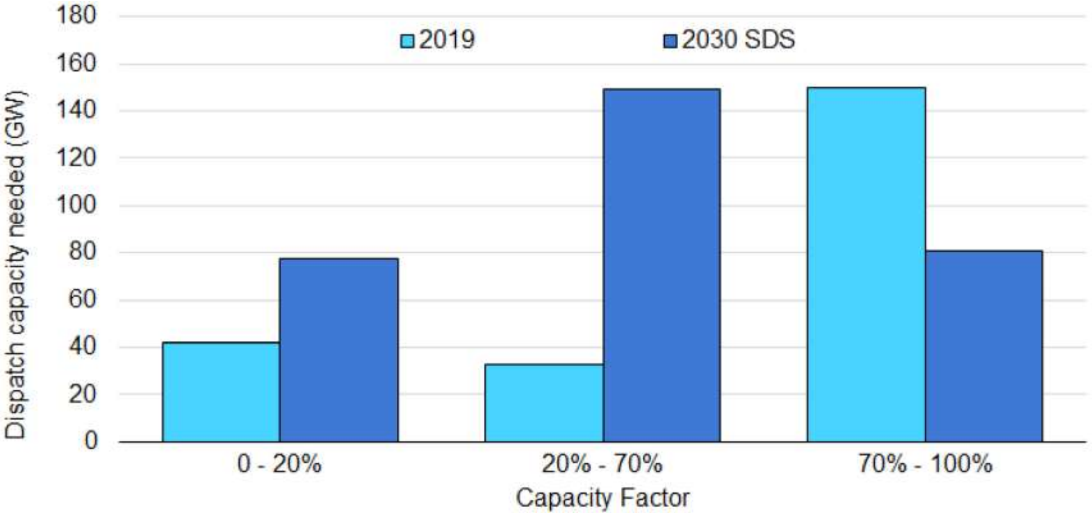
Demand for dispatchable capacity for each range of capacity factor in India in the Sustainable Development Scenario, 2019 and 2030



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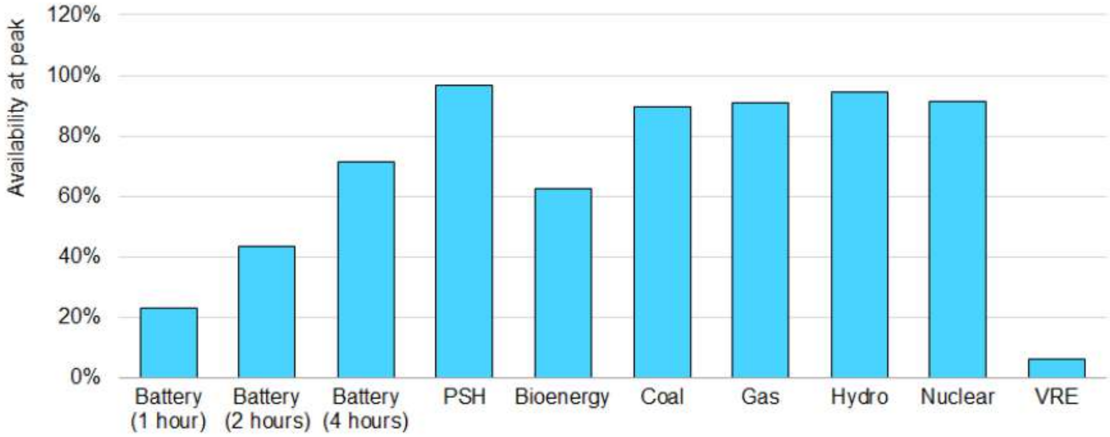
Note: The capacity factor for this figure did not take into account outages and other technical operational constraints. Traditionally, capacity factors of peak, intermediate and baseload generation are 0-20%, 20-70% and above 70%, respectively.

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



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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.

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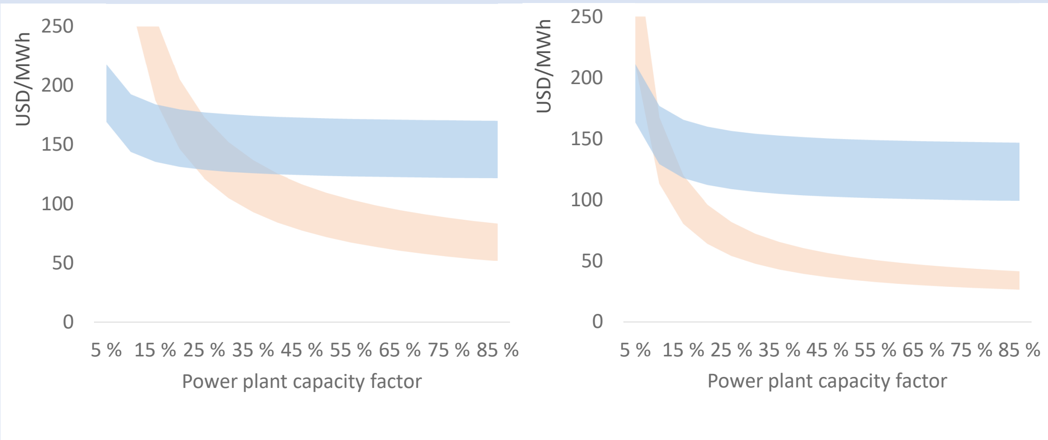
Decarbonising power generation from existing thermal power plants in India through the use of solid biomass, low-carbon fuels as well as CCUS is a plausible and cost-effective option. The relatively low capital costs of retrofitting existing thermal plants to use low-carbon fuels compared to new resources 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



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Source: IEA Analysis.

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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.

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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.

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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.

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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.

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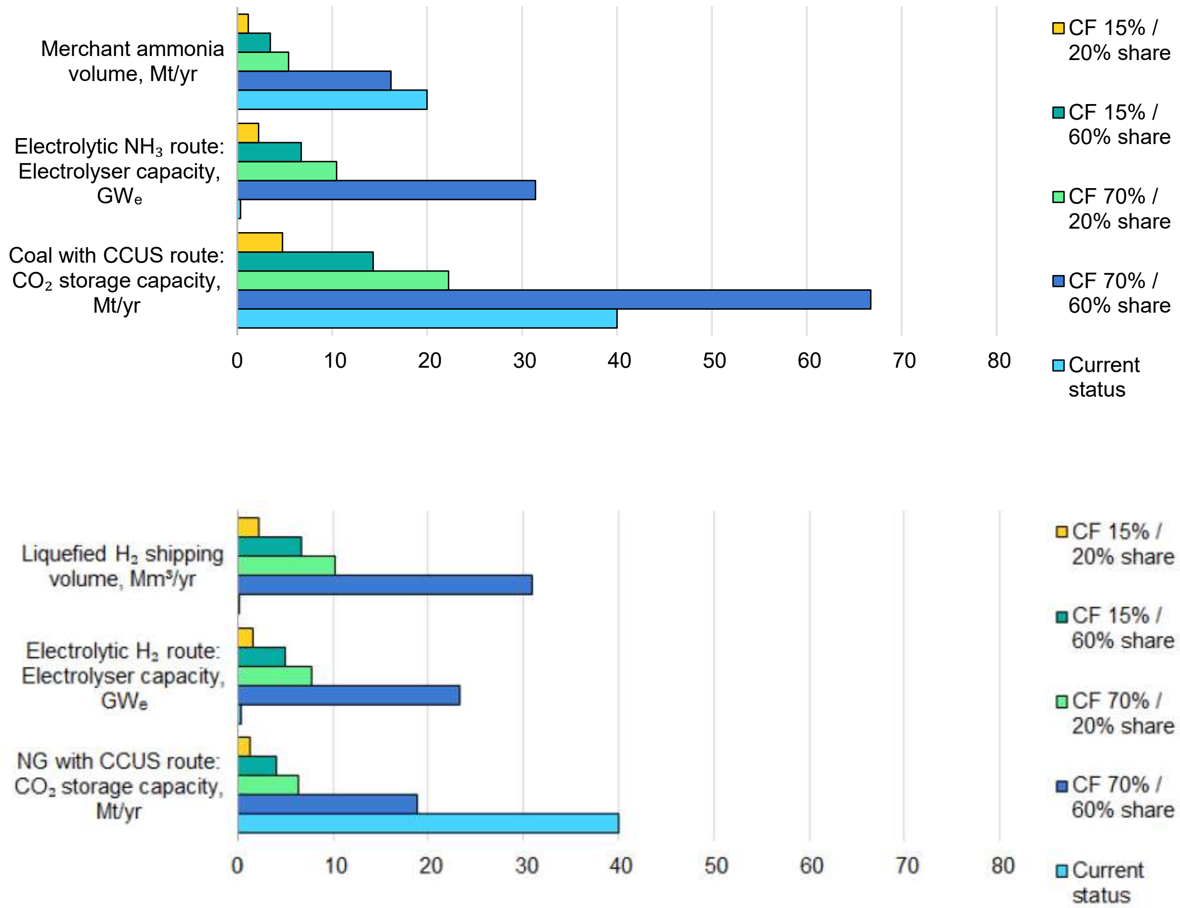
Supply infrastructure requirements for co-firing ammonia in a 10 GW_e coal fleet (upper panel) or for co-firing hydrogen in a 10 GW_e natural gas fleet (lower panel)



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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.

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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

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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

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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.

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