Bangladesh Power Sector at the Crossroads

October 2, 2023

BloombergNEF

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2025

Year when PV becomes the cheapest source of new electricity generation in Bangladesh

4.2x

LCOE of a retrofitted coal plant running on 100% green ammonia imported from Australia compared to solar with batteries in 2050

3.7x

LCOE of a retrofitted gas plant running on 100% green hydrogen produced in Bangladesh compared to solar with batteries in 2050

Bangladesh's heavy reliance on fossil-fueled thermal power plants has intensified its energy trilemma. This report examines the different electricity generation technologies applicable for Bangladesh and demonstrates how investing in wind and solar resources can help improve energy security and affordability, while also reducing emissions.

- Bangladesh currently relies on fossil fuels for 97% of power generation and plans significant coal (4.5GW) and gas (5.2GW) additions over the next three years. The rise in fossil fuel commodity prices in 2022 has already led the state-owned utility to cut back on fuel procurement, leading to rolling blackouts. Further expansion of fossil-fueled thermal power plants would further jeopardize the country's energy security.
- Renewables, in particular solar, are set to be the cheapest option for Bangladesh to meet growing electricity demand. The levelized cost of electricity (LCOE) for a new utility-scale solar project in Bangladesh ranges from $97-135/MWh today, compared to $88-116/MWh for a combined cycle gas turbine (CCGT) and $110-150/MWh for a coal power plant. By 2025, solar becomes the cheapest option, thanks to continued technology cost reduction. By 2030, solar with batteries will also achieve a cheaper LCOE than new thermal power plants.
- Bangladesh is still considering building more thermal power plants this decade. Starting in 2030, it is considering using co-firing ammonia with coal and blending hydrogen with natural gas to reduce emissions. Our analysis shows this approach will not be cost-effective in reducing emissions. To achieve tangible emission reduction, an existing coal power plant would have to be retrofitted to be capable of co-firing ammonia with coal at energy ratios above 50%. At such high ratios, however, costs would be far higher than solar plus batteries or wind plus batteries. The same applies to retrofitting CCGTs for hydrogen.

Figure 1: Levelized cost of electricity comparison for new renewables and retrofitted combined cycle gas turbines for hydrogen blending

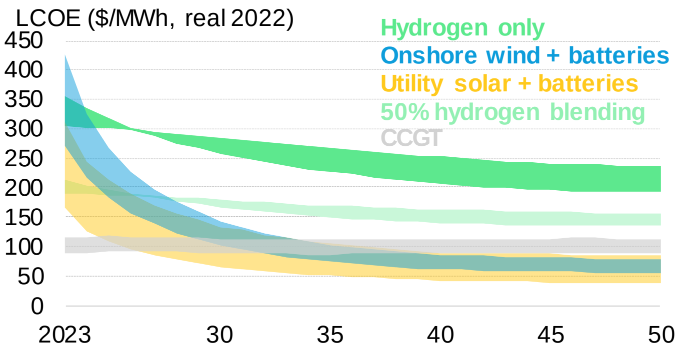
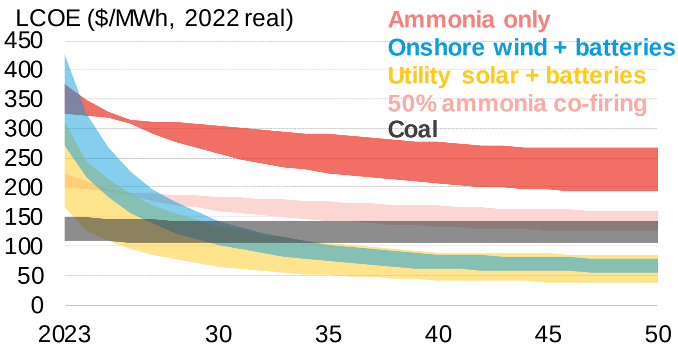


Figure 2: Levelized cost of electricity comparison for new renewables and retrofitted coal power plants for ammonia co-firing



Source: BloombergNEF. Note: Blending ratio based on energy content. Hydrogen and ammonia combustion ranges show costs for imported molecules. Assuming fleet-level capacity factors for coal, CCGT. PV and onshore wind+batteries modeled with 4-hour battery storage systems.

Section 2. Introduction

Bangladesh's electricity supply is dominated by gas-fired power plants, historically fueled by the country's domestic gas fields. As of the end of 2022, the country has a generation capacity of 23.2GW, 50% of which comes from gas-fired power plants, followed by oil-fired power plants (33%) and coal-fired power plants (12%). Since 2015, the country has seen modest growth in solar installations, reaching just over 1GW by the end of 2022.

Figure 3: Historical installed power capacity

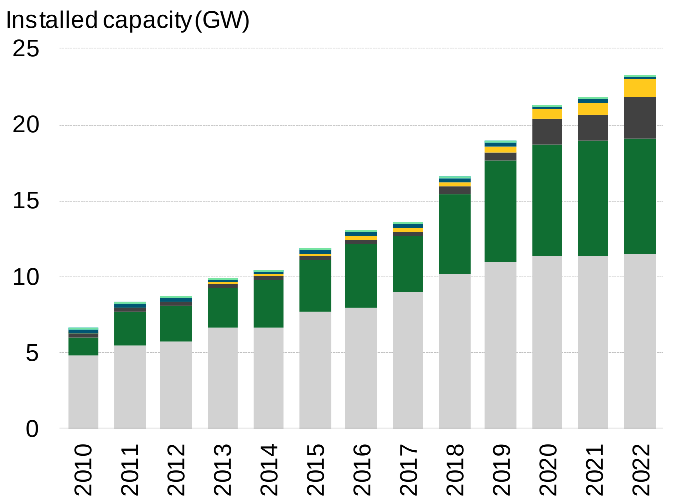
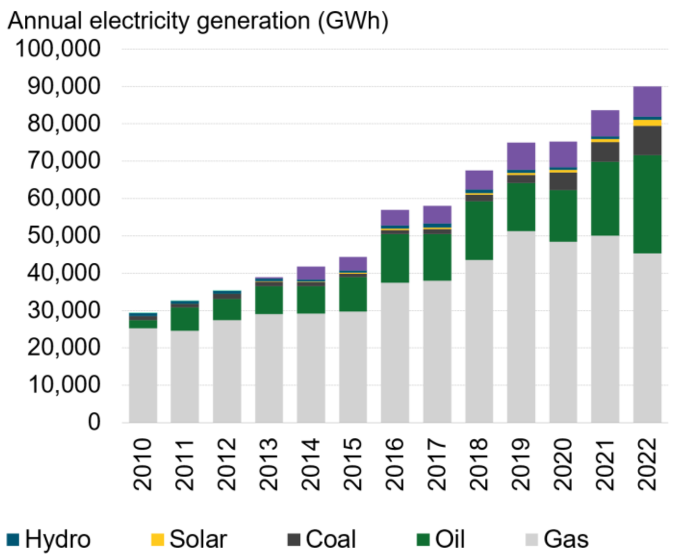


Figure 4: Historical electricity generation



Sources: BloombergNEF, Bangladesh Power Development Board

Fossil-fueled thermal power plants accounted for 97% of electricity generated in 2022, with gas accounting for 55%, followed by oil at 32% and coal at 10%. Power imports from neighboring countries are also growing and accounted for 9% of the total power supply in 2022. The country imported 8.2TWh of electricity from neighboring countries in 2022 – 58% higher than in 2018.

Figure 5: Cumulative gas power capacity, historical and planned expansions

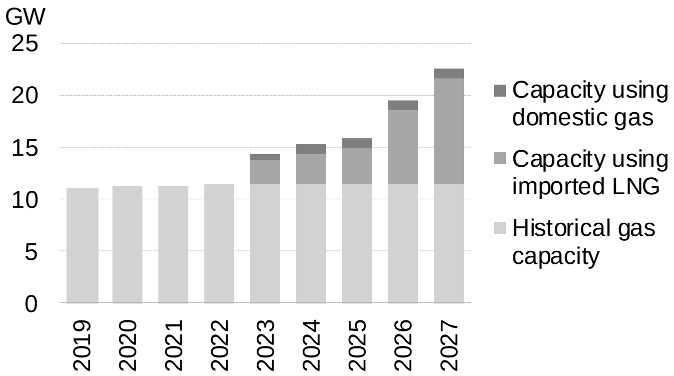
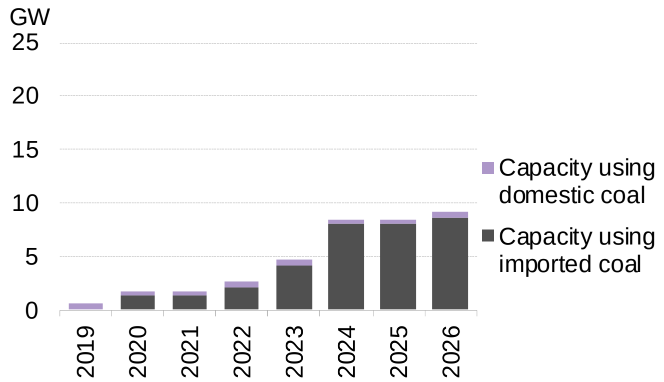


Figure 6: Cumulative coal power capacity, historical and planned expansions



Sources: BloombergNEF, Bangladesh Power Development Board. Note: LNG = liquefied natural gas.

Bangladesh plans to add 11.1GW of new gas-fired capacity by 2027 (Figure 5) with the majority dependent on imports of liquefied natural gas (LNG) due to dwindling domestic gas production. The country is also planning to add 6.5GW of new coal capacity by 2026 (Figure 6), all of which will be dependent on coal imports.

Under its Mujib Climate Prosperity Plan, published in September 2021 in the runup to the 26th United Nations Climate Change conference (COP26), Bangladesh aims to increase the share of renewables to 30% by 2030 and at least 40% by 2041 “with international and other investment support”. Beyond renewables such as solar and wind, the government plans to expand low-carbon technologies such as nuclear, while also seeking to reduce emissions from fossil-fueled power plants via co-firing coal with ammonia, blending natural gas with hydrogen and applying carbon capture and storage (CCS) as a way to reduce emissions from the power sector and to meet rising power demand.

Bangladesh is currently drafting a new *Integrated Energy and Power Master Plan* with support from the Institute of Energy Economics, Japan (IEEJ) and the Japan International Corporation Agency (JICA). The IEMP is reportedly considering three scenarios– a reference scenario, an advanced technology scenario, and a net-zero scenario.

This report examines the levelized cost of electricity generation (LCOE) for the different power generation technologies applicable for Bangladesh, namely solar, wind, combined cycle gas turbines and coal power plants. Beyond LCOE, the report also examines the advantages and disadvantages each technology has for Bangladesh’s energy security and affordability as well as emissions.

Levelized cost of electricity

LCOE refers to the long-term offtake power price on a MWh-basis required to recoup all project costs to meet the equity investment hurdle rate. BNEF uses its proprietary *Energy Project Asset Valuation Model* to calculate the LCOE based on input data relevant for each technology in consideration of the location where the project would be built. The calculation is based on a project finance schedule accounting for the full life of the project. This allows us to capture the project cost impact of the timing of cash flows, development and construction costs, multiple stages of financing, interest and tax implications of long-term debt instruments and depreciation, among other factors. For the input parameters used in the LCOE calculations in this report, please refer to Appendix A.

Section 3. Economic analysis

Utility-scale solar is starting to challenge a combined cycle gas turbine (CCGT) plant for the lowest LCOE among all technologies applicable for Bangladesh today. By 2030, onshore wind and solar with batteries would both be cheaper than building new thermal power plants. The LCOE for CCGTs, on the other hand, will rise due to higher fuel costs as Bangladesh becomes more reliant on LNG imports. Post 2030, using clean hydrogen or its derivative ammonia as fuel will not become a cost-effective route to decarbonization of existing thermal power plants.

3.1. New power plants

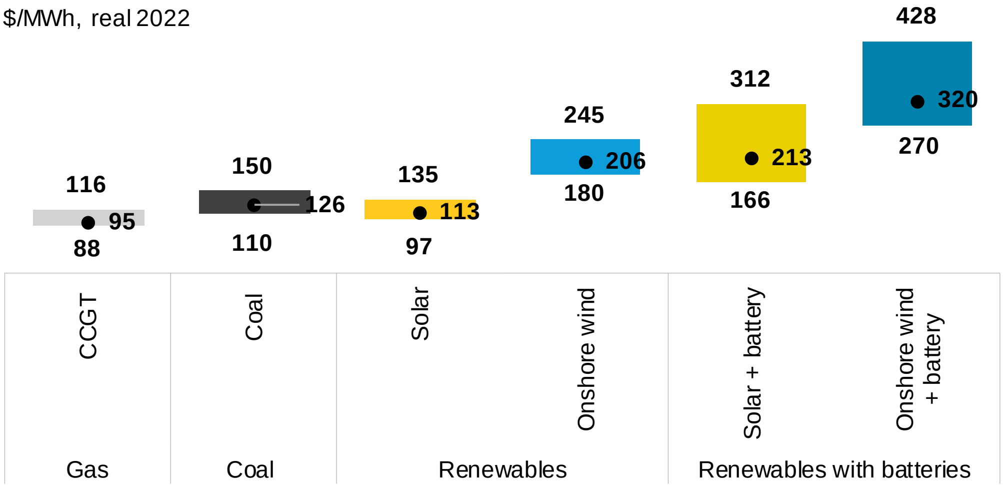
Utility-scale solar is already cost-competitive against a new coal plant in Bangladesh

Utility-scale solar projects have already reached the same LCOE range as CCGTs

Bangladesh's natural gas endowment has provided the country with affordable gas for power generation. The LCOE for a new CCGT plant would be in the range of $88-116/MWh. Thanks to continued declines in solar module prices, utility-scale solar projects have already reached the same LCOE range as CCGTs.

Dwindling domestic gas production has pushed Bangladesh to diversify its energy supply including imports of coal, LNG, and power as well as domestic renewables. Bangladesh added 2.2GW of coal power plants over 2018 to 2022, supported by implicit coal subsidies. The country's lone domestic coal mine is unable to support the growing coal demand, increasing Bangladesh's reliance on imported coal. The rise in global coal prices and the high taxes[1] imposed on coal imports have led to the rising cost of coal generation. The LCOE of a new coal plant today ranges between $110-150/MWh, making it a less economical choice than a new solar plant with generation costs. Onshore wind development is still nascent in Bangladesh, with only 3MW operational. The LCOE of a new onshore wind plant is high due to weak wind speed.

Figure 7: Bangladesh new power plant levelized cost of electricity, 2023



Source: BloombergNEF. Note: Assuming fleet level capacity factors for coal, CCGT. PV and onshore wind+batteries modeled with 4-hour battery.

[1] Coal imports in Bangladesh are subjected to 15% VAT, 5% advance income tax and 5% advance tax

Renewables become the most cost competitive option by 2030

Solar in 2050 is estimated to be less than a quarter of the LCOE of a new CCGT plant and less than a fifth that of coal

By 2030, the cost-competitive landscape of the different power generation technologies changes significantly with solar becoming the cheapest. Thermal power plant technologies are mature and well developed, with little cost reduction expected while the costs of solar, wind and batteries are expected to decline further thanks to increasing economies of scale and technology improvements. The LCOE of a new solar plant in Bangladesh is estimated to decline by 63% between now and 2030. The cost of new onshore wind is also expected to undercut that of a new gas and coal plant by the end of this decade.

By 2050, solar and onshore wind remain the cheapest sources of new bulk electricity generation in Bangladesh by a large margin compared to fossil-fueled thermal power plants. Solar in 2050 is estimated to be less than a quarter of the LCOE from a new CCGT plant and less than a fifth that of coal. Onshore wind sees slightly higher LCOEs compared to solar but it is still cost-competitive against fossil-fueled generators.

Figure 8: Bangladesh new power plant levelized cost of electricity, 2030

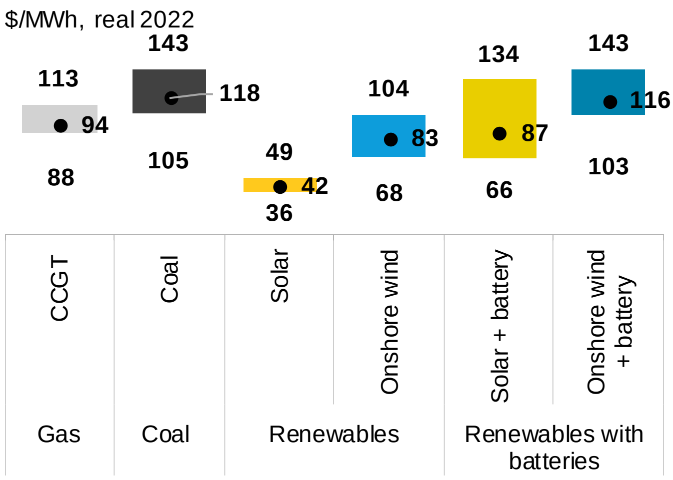
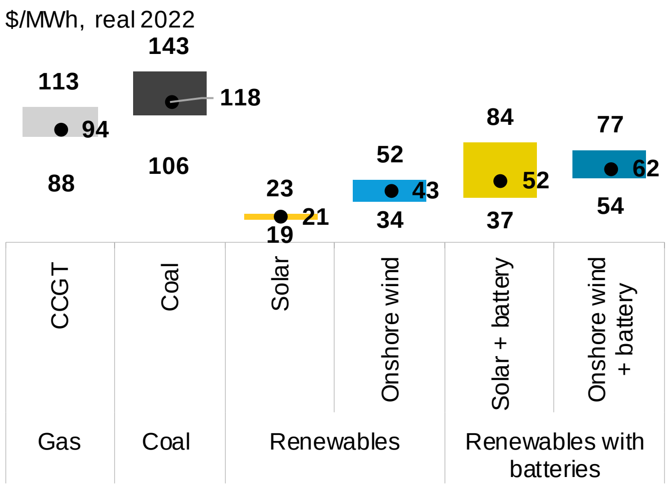


Figure 9: Bangladesh new power plant levelized cost of electricity, 2050



Source: BloombergNEF. Note: Assuming fleet level capacity factors for coal, CCGT. PV and onshore wind+batteries modeled with 4-hour battery.

Solar with batteries is set to be cheaper than thermal power plants by 2030

Onshore wind with batteries would be cheaper than new coal and gas in the first half of the 2030s

BloombergNEF estimates solar photovoltaic-plus-energy storage using batteries (PVS) in Bangladesh is already cost-competitive against some diesel and oil generators due to the latter's high fuel costs. PVS systems are set to become cost-competitive against new coal and gas power plants in Bangladesh by the end of this decade (Figure 10, Figure 11). The LCOE of a PVS system is expected to fall to $66-134/MWh by 2030 and $37-84/MWh by 2050, thanks to declining lithium-ion battery prices. These ranges are based on the size of the battery relative to PV capacity. The upper bound of the LCOE shows 100% capacity and the lower bound shows 25% capacity. Similarly, in the first half of the 2030s, onshore wind paired with batteries is also expected to become cheaper than new coal and gas.

Figure 10: LCOE of solar-plus-battery against new coal and gas plant in Bangladesh

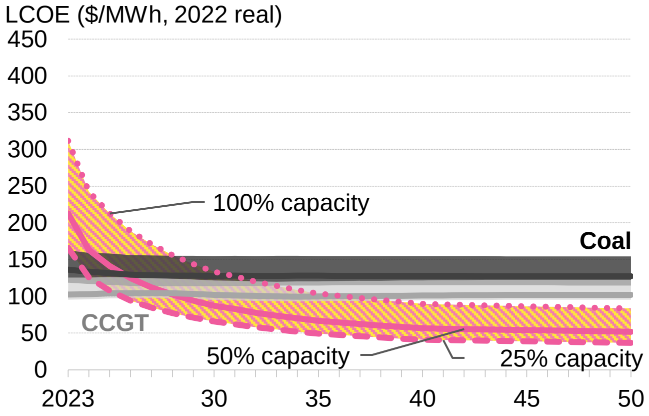
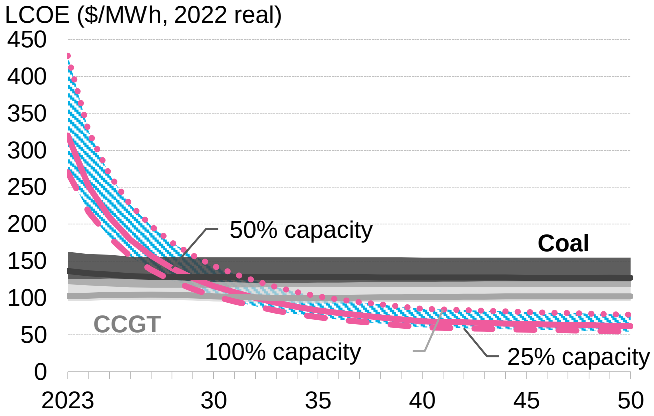


Figure 11: LCOE of onshore wind-plus-battery against new coal and gas plant in Bangladesh



Source: BloombergNEF. Note: LCOE range for PV-plus-battery represents storage sized between 25% and 100% of PV capacity. Does not account for additional costs incurred through local cost provisions on battery.

LCOE of new solar becomes cheaper than the short-run marginal cost of existing coal and gas plants by 2033 and 2038, respectively

The expected cost declines for solar and onshore wind technologies mean their LCOEs will get cheap enough to outcompete the costs of running existing thermal power plants in Bangladesh.

Due to increased reliance on LNG to supplement domestic gas supply, the gas fuel price for power generation in Bangladesh is expected to rise by 123% to $8.3/MMBtu in 2030 from an estimated $3.7/MMBtu in 2023. This more than doubles the marginal cost of an existing CCGT plant between 2023 and 2030. In 2028, BNEF estimates the LCOE of a new utility-scale PV plant at $53/MWh will outcompete the marginal cost of an existing CCGT plant at $61/MWh in the same year (Figure 12). The higher expected short-run marginal cost (SRMC) for a CCGT plant also allows a new onshore wind plant to be cost-competitive by 2038.

Around 2033, the LCOE of a new solar plant at $37/MWh undercuts the marginal cost of running an existing coal plant. The cheapest new onshore wind plant gets close to the marginal cost of existing coal plants by the late 2040s (Figure 13).

Figure 12: LCOE of a new PV and onshore wind plant versus SRMC of an existing CCGT plant in Bangladesh

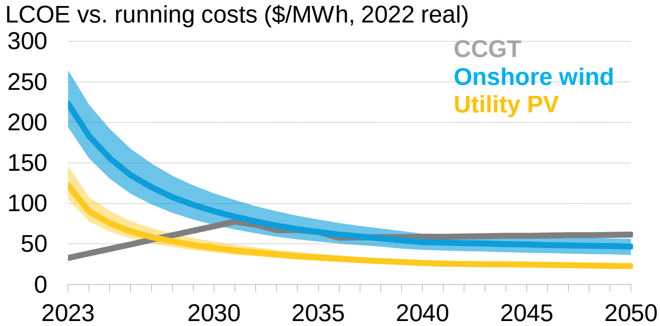
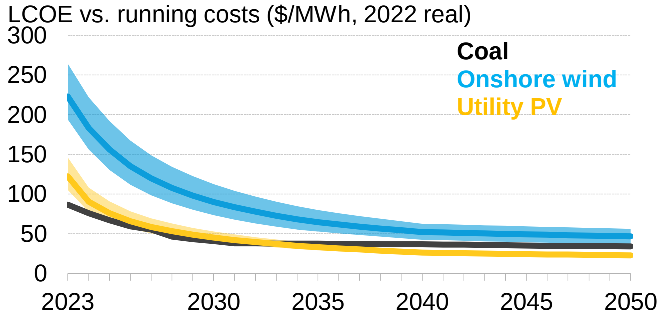


Figure 13: LCOE of a new PV and onshore wind plant versus SRMC of an existing coal plant in Bangladesh



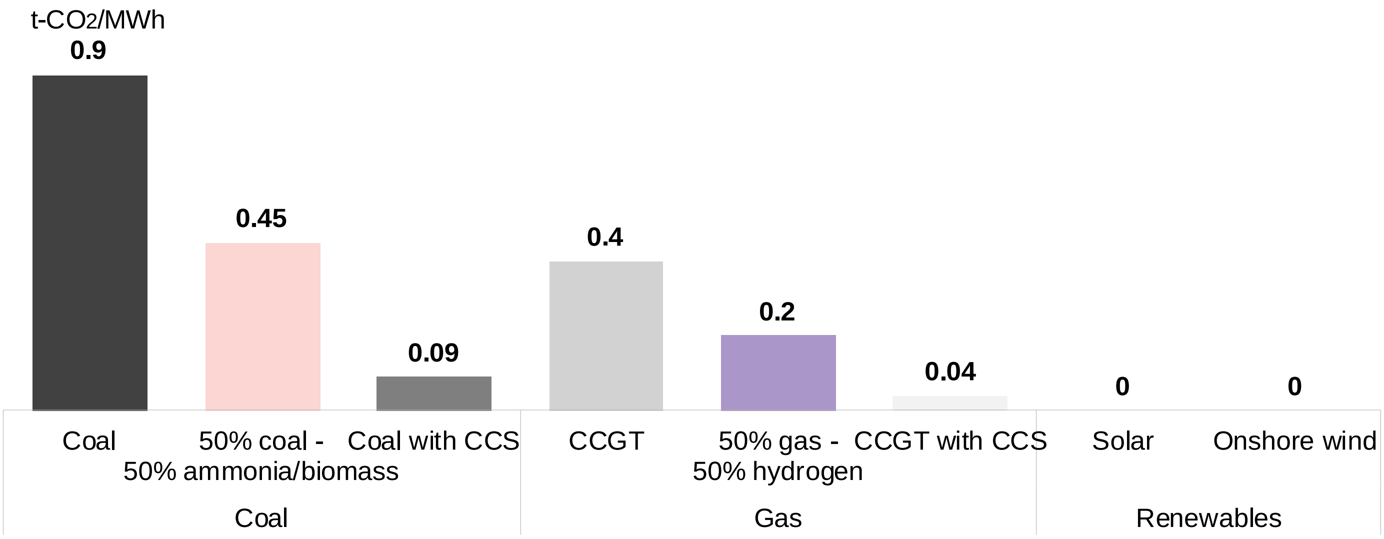
Source: BloombergNEF. Note: SRMC stands for short-run marginal cost.

3.2. Retrofitting thermal power plants for hydrogen and ammonia fuels

Abated thermal power plants entail higher risks and costs than renewables

A few countries, notably Japan and South Korea, are considering the use of co-firing coal with ammonia and blending natural gas with hydrogen to lower emissions from thermal power plants. Bangladesh aims to follow this strategy. Molecules such as hydrogen and ammonia do not release carbon dioxide during combustion given the absence of carbon in their molecular chemistry. Still, such approaches entail higher risks and costs than renewables. Currently, only co-firing 20% ammonia with coal (on energy content basis) has been tested in pilot projects. At such low levels, the CO_2 emission factor for the coal power plant would only marginally improve.

Figure 14: Emission intensity during electricity generation



Source: BloombergNEF. Note: Blending ratio based on energy content. Assuming green hydrogen and green ammonia used. Assuming 90% capturing rate for carbon capture and storage (CCS) technologies.

Environmental benefits limited when using hydrogen and ammonia for power generation

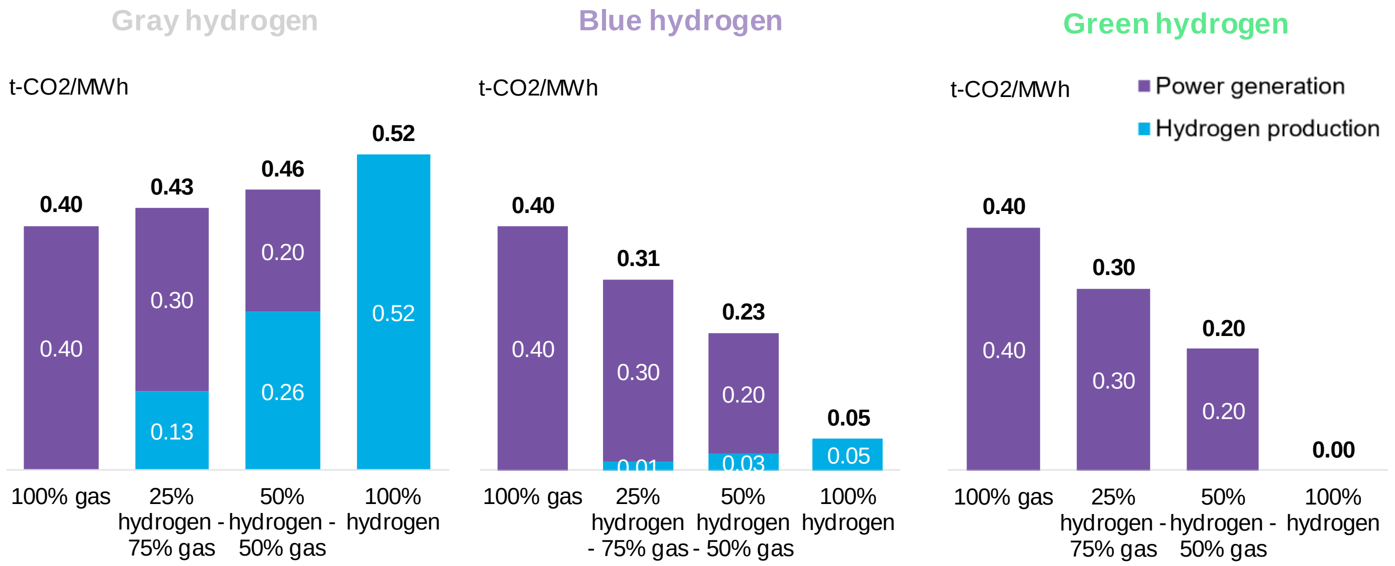
Combustion of gray hydrogen emits more carbon dioxide emissions than burning gas

To achieve significant CO_2 emission reduction from a thermal power plant, the ratio of hydrogen to natural gas as well as ammonia to coal must be very high. Additionally, the hydrogen – and its derivative ammonia – would have to be produced in a low-emission manner either as green hydrogen − as in hydrogen produced from water electrolysis using clean electricity − or blue hydrogen, or hydrogen made from fossil fuels with emissions subject to carbon capture and storage.

Combustion of fuels such as ammonia or hydrogen at high temperatures leads to nitrogen oxides (NOx) emissions. Since hydrogen and ammonia burn hotter than fossil fuels, the nitrogen and oxygen present in the air during their combustion react at a higher rate, leading to more NOx emissions. NOx are a class of air pollutants that contribute to the greenhouse gas effect indirectly as well as to rain acidification. These combustion technologies also emit nitrous oxide (N_2O), which is a greenhouse gas. The global warming potential (GWP) of nitrous oxide specifically is 273 times greater than that of carbon dioxide over a 100-year timescale.

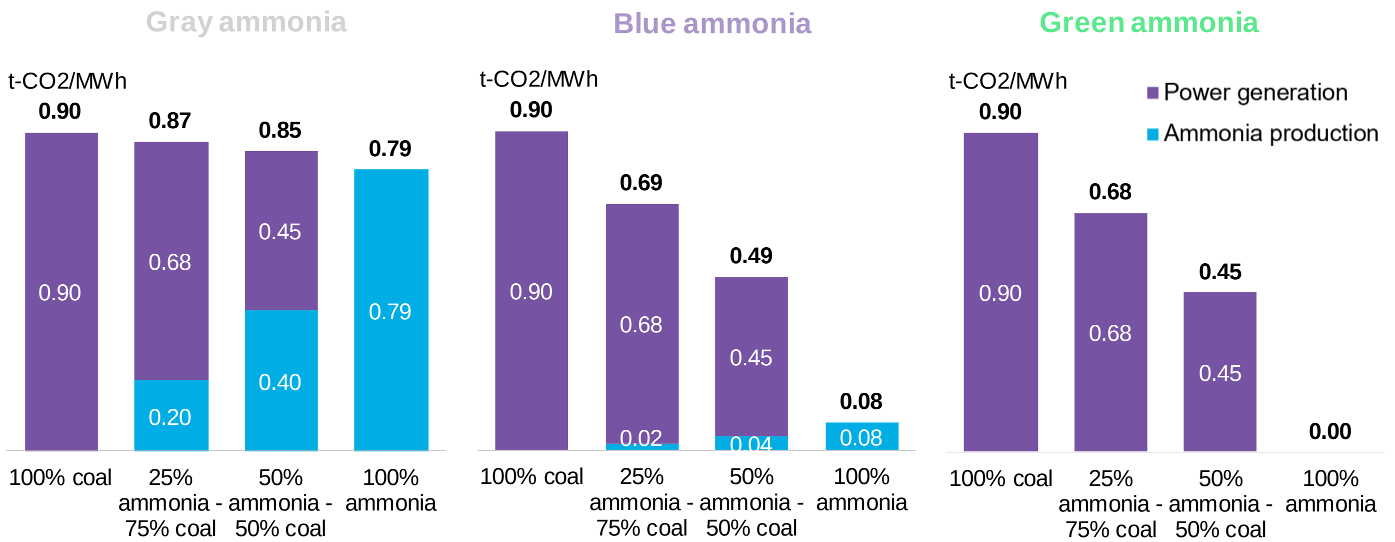
Retrofitted thermal power plants for hydrogen or ammonia combustion would also need to invest in technologies to capture both NO_X emissions and nitrous oxide emissions to reduce air pollution sources while ensuring GHG emission reduction benefits. This further undermines the poor economics of this strategy.

Figure 15: CCGT emissions during electricity generation depending on fuel type



Source: BloombergNEF. Note: Blending ratio based on energy content.

Figure 16: Coal power plant emissions during generation depending on fuel type



Source: BloombergNEF. Note: Blending ratio based on energy content.

Renewables a more economical decarbonization pathway than hydrogen and ammonia

At low co-firing and blend ratios, clean ammonia and hydrogen (Figure 17, Figure 18) retrofitted thermal power plants appear to be cheaper than renewables today. To achieve significant emission reduction, thermal power plant, however, must be retrofitted for at least 50% combustion of hydrogen or ammonia, which would be far more expensive than renewables.

Figure 17: Bangladesh LCOE for gas plants retrofitted for hydrogen compared to renewables, 2023

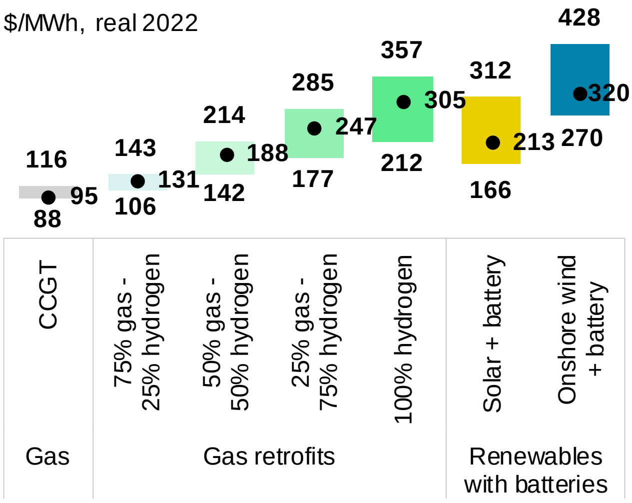
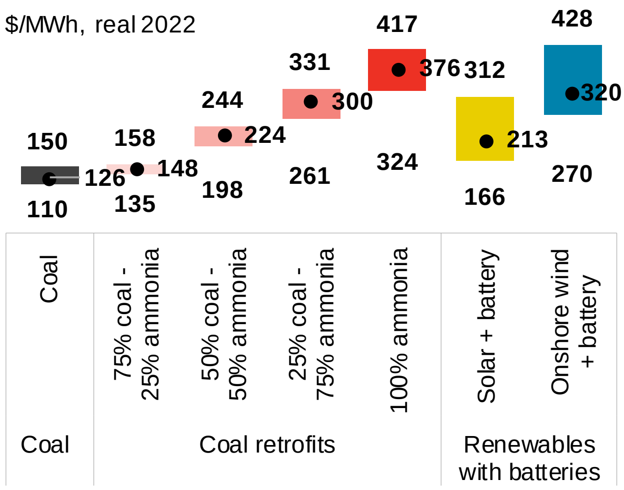


Figure 18: Bangladesh LCOE for coal plants retrofitted for ammonia compared to renewables, 2023



Source: BloombergNEF. Note: Blending ratio based on energy content. Assuming fleet level capacity factors for coal, CCGT. PV and onshore wind+batteries modeled with 4-hour battery.

By 2030, solar with batteries would be the cheapest dispatchable technology (Figure 19, Figure 20). Similarly, onshore wind with batteries would become economically competitive against CCGT retrofits with 25% hydrogen blending and coal retrofits with 25% ammonia co-firing. These trends would continue throughout 2050, showing the economic competitiveness of renewables with batteries over hydrogen or ammonia combustion in the long term (Figure 21, Figure 22).

Figure 19: Bangladesh LCOE for gas plants retrofitted for hydrogen compared to renewables, 2030

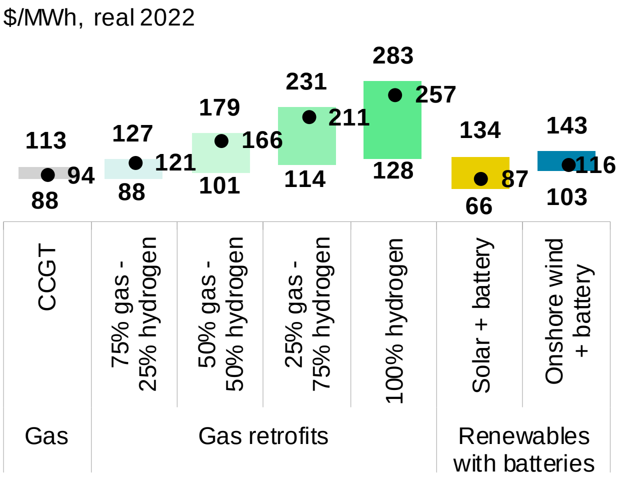
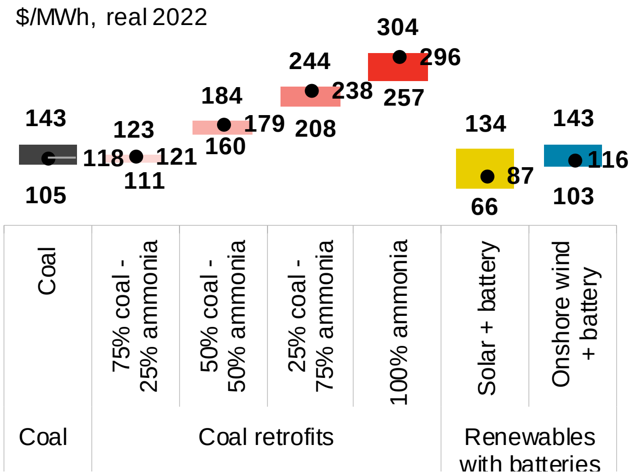


Figure 20: Bangladesh LCOE for coal plants retrofitted for ammonia compared to renewables, 2030



Source: BloombergNEF. Note: Blending ratio based on energy content. Assuming fleet level capacity factors for coal, CCGT. PV and onshore wind+batteries modeled with 4-hour battery.

See Appendix B (delivered costs of hydrogen and ammonia), Appendix C (production costs of hydrogen and ammonia), and Appendix D (blended fuel prices) for more details on hydrogen and ammonia relevant to Bangladesh.

Figure 21: Bangladesh LCOE for gas plants retrofitted for hydrogen compared to renewables, 2050

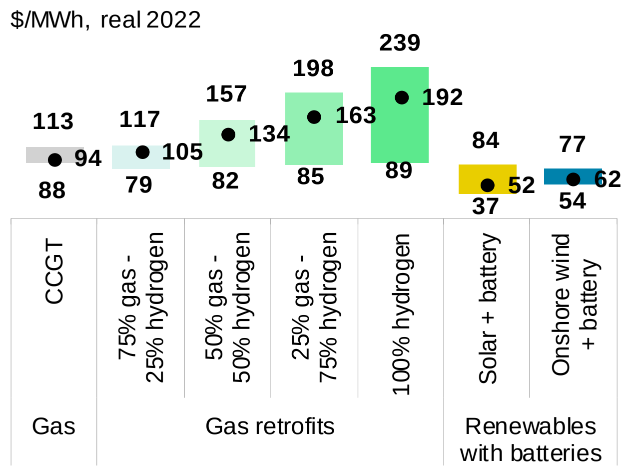
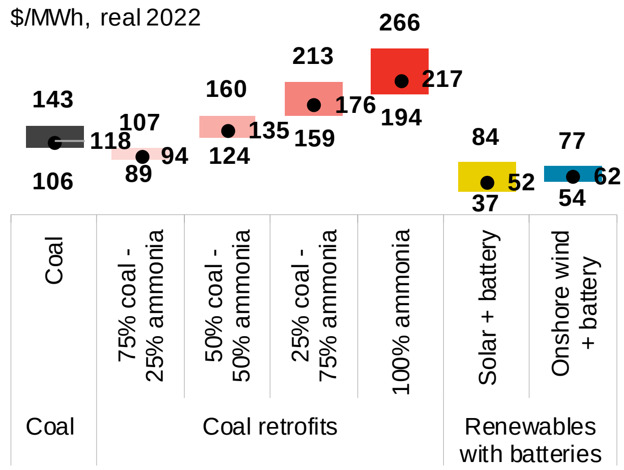


Figure 22: Bangladesh LCOE for coal plants retrofitted for ammonia compared to renewables, 2050

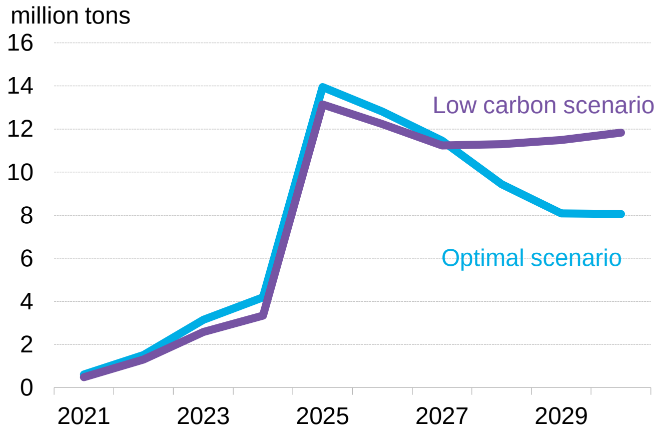


Source: BloombergNEF. Note: Blending ratio based on energy content. Assuming fleet level capacity factors for coal, CCGT. PV and onshore wind+batteries modeled with 4-hour battery.

3.3. Retrofitting coal power plants for biomass co-firing

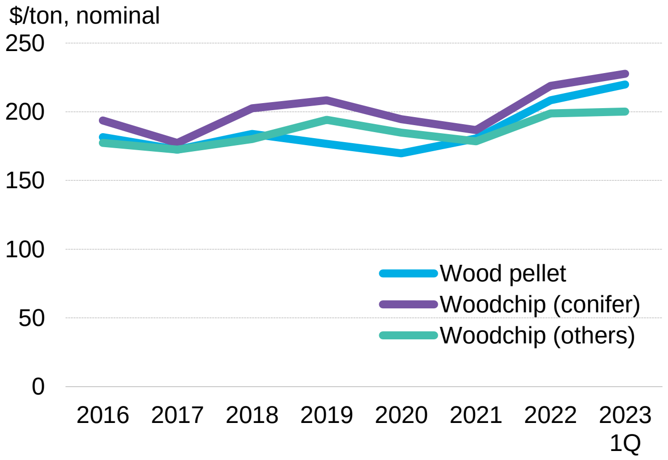
Co-firing biomass with coal entails similar challenges to co-firing with ammonia. At a low co-firing ratio, emission reduction benefits are limited. At high co-firing ratios, significant upgrades to the coal power plant would be needed.

Figure 23: Indonesia's projected biomass fuel requirement



Source: Indonesia's Ministry of Energy and Mineral Resources, PLN's RUPTL 2021-30

Figure 24: Japan's biomass import price



Source: Japan customs, BloombergNEF. Note: Prices are on CIF basis.

Securing sufficient continuous supply of biomass would be challenging

Securing sufficient continuous supply of biomass for high co-firing ratios would also be challenging given the limited availability of biomass feedstock in Bangladesh. If the country decides to adopt a strategy of co-firing coal with biomass, Bangladesh will need to ramp up its domestic biomass feedstock supply chains or look to imports to ensure sufficient fuel supply. However, Bangladesh may face potential competition for biomass imports. Current biomass exporters in Asia such as Indonesia and Vietnam are also pursuing co-firing of coal with biomass as a decarbonization strategy for their own power plants.

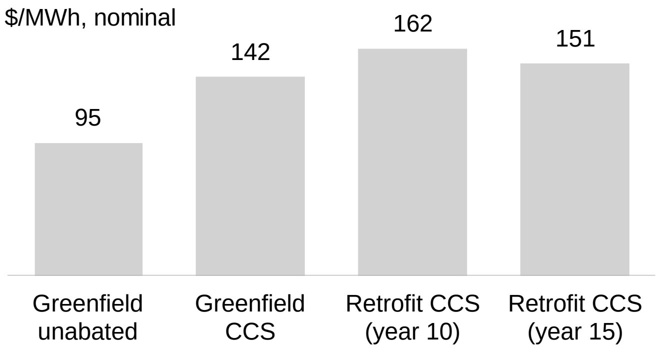
Indonesia's state-owned utility, PT Perusahaan Listrik Negara, in its current 10-year electricity supply business plan projects a 23- to 27-fold ramp up in required biomass fuel in 2025 from the 0.5-0.6 million tons required in 2021 to support the country's co-firing ambitions (Figure 23). This may limit the amount of biomass available for export in the future. Bangladesh will also have to compete with other biomass importers such as Japan and South Korea, while also potentially being exposed to price competition (Figure 24).

3.4. Using carbon capture and storage

Retrofitting existing plants with CCS won't reduce the reliance on fossil fuels and is costlier

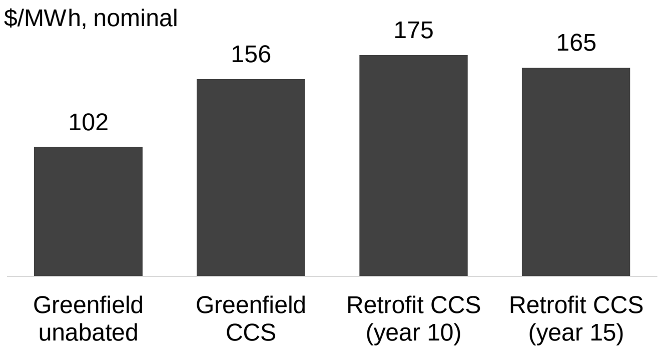
The use of carbon capture and storage (CCS) to reduce emissions from thermal power plants is under consideration by many countries, though there are few operational projects to date. BNEF has modeled the LCOE for several CCS scenarios: greenfield thermal power plants with CCS as well as retrofitting existing thermal power plants with CCS at 10 years and 15 years after the commercial operational date. Our analysis suggests that a greenfield coal or gas plant equipped with CCS upfront is the most economical scenario due to higher capex required for retrofits than a greenfield project designed with CCS in mind. Retrofitting a thermal power plant 15 years later would be slightly cheaper than retrofitting 10 years later due to the expected reduction in CCS costs. Although CCS scenarios appear to be more economical than co-firing ammonia with coal or blending hydrogen with natural gas at high energy ratios, these CCS scenarios are still more expensive than solar and wind in Bangladesh. The amount of potential carbon storage available in Bangladesh as well as the feasibility of transporting captured emissions from existing thermal power plants to carbon storage sites are also currently unknown.

Figure 25: Bangladesh LCOE for a new CCGT plant and CCGT with carbon capture and storage



Source: BloombergNEF. Note: Greenfield plants represent a plant financed today and expected to commission in 2025. Retrofits at the 10th and 15th year refer to 2035 and 2040 specifically.

Figure 26: Bangladesh LCOE for a new coal plant and coal with carbon capture and storage



Source: BloombergNEF. Note: Greenfield plants represent a plant financed today and expected to commission in 2026. Retrofits at the 10th and 15th year refer to 2036 and 2041 specifically.

Section 4. Challenges with hydrogen as fuel for electricity generation

The previous section explored the LCOE associated with retrofitting thermal power plants for co-firing with clean fuels derived from hydrogen. Here we examine additional safety, as well as energy security and affordability challenges, associated with retrofitting thermal power plants for clean fuels.

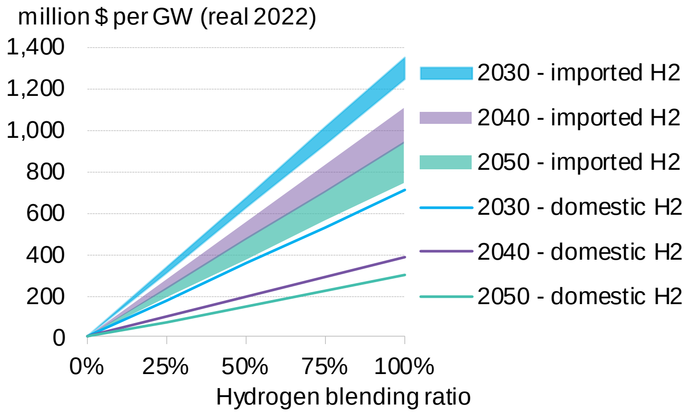
Reliance on hydrogen as a fuel for electricity would increase the financial burden on Bangladesh

Hydrogen and ammonia are more expensive fuels than gas and coal on an energy-equivalent basis due to these molecules' lower volumetric energy density. This explains the rise in LCOE at higher ratios of hydrogen or ammonia. Reliance on such fuels would increase power prices and/or the financial burden on taxpayers depending on whether the government decides to support the higher costs of these clean fuels through a rise in regulated electricity tariffs or taxes.

Imported hydrogen procurement could be four to five times more expensive than natural gas procurement

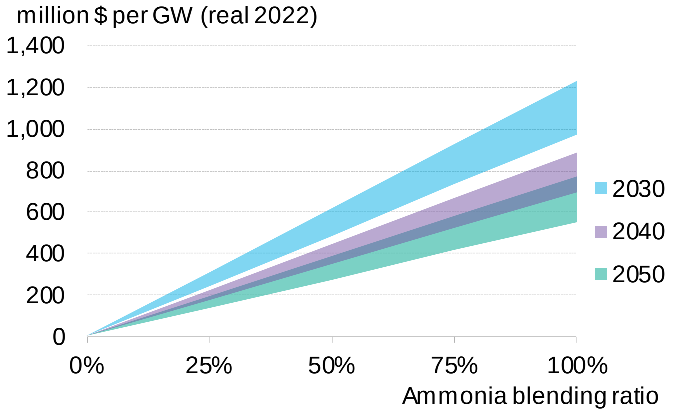
We estimate a retrofitted 1GW gas power plant running on 100% hydrogen would annually need 246,300 tons of hydrogen. To source this much locally, annual hydrogen procurement costs per GW would be $706 million in 2030, $390 million in 2040, and $302 million in 2050 (Figure 27). These would be cheaper than the cost of imported hydrogen procurement: $1,242-1,350 million in 2030, $932-1,103 million in 2040, and $746-947 million in 2050. To generate the same amount of electricity, CCGT plants in the country would only spend $253 million per GW in 2030, $212 million in 2040, and $229 million in 2050 annually on gas procurement. Imported hydrogen procurement could be four to five times more expensive than gas procurement, leading to the need for much higher power tariffs.

Figure 27: Bangladesh annual hydrogen procurement cost per GW of CCGT power plants, by blending ratio and year



Source: BloombergNEF. Note: We estimate 0.06 tons of hydrogen is needed to generate 1MWh of electricity. Assuming a CCGT power plant operates at 49% capacity factor, or a fleet-level average in 2022. Blending ratio based on energy content.

Figure 28: Bangladesh annual ammonia procurement cost per GW of coal power plants, by blending ratio and year



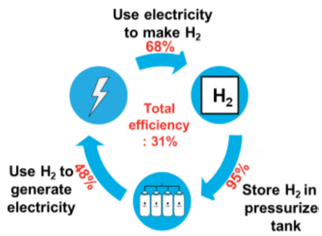
Source: BloombergNEF. Note: We estimate 0.5 tons of ammonia is needed to generate 1MWh of electricity. Assuming a coal power plant operates at 36% capacity factor, or a fleet-level average in 2022. Blending ratio based on energy content.

Ammonia procurement could be seven to nine times more expensive than coal procurement

For a retrofitted 1GW coal power plant in Bangladesh, the required volume of ammonia would be 790,900 tons of ammonia for 50% co-firing and 1.58 million tons for 100% firing. We estimate 50% ammonia co-firing in 2040 would cost $345 million–$442 million per GW annually (Figure 28). In addition, burning only ammonia at the same size of coal power plants would require $978 million–$1,228 million per GW in 2030, $691 million–$885 million in 2040, and $548 million–$776 million in 2050. On the other hand, burning only coal at a 1GW coal power plant in Bangladesh would annually cost $135 million in 2030, $120 million in 2040, and $111 million in 2050. Ammonia procurement would be 7 to 9 times more expensive than coal procurement.

4.1. Marginal abatement cost for thermal power plants retrofitted for hydrogen and ammonia

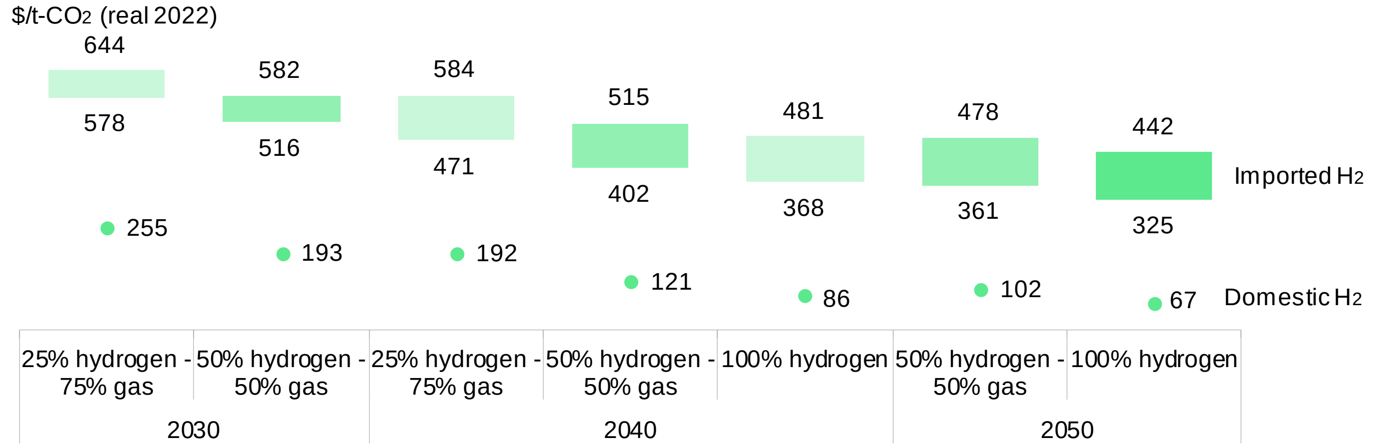
Figure 29 Efficiency of hydrogen to power



Source: BloombergNEF

While using domestically produced green hydrogen would theoretically have a lower marginal abatement cost (Figure 30), production of that fuel would be dependent on using domestic renewable electricity for producing hydrogen and then using the hydrogen for producing electricity. Such an indirect use of renewable electricity would be less efficient and much more expensive than directly using the electricity generated by renewables. To domestically supply hydrogen needed to power a 1GW retrofitted CCGT plant, the country would need to build 9.3GW of solar projects[2]. For reference, only 2.8GW of solar would be needed to generate the same amount of electricity. Similarly, to produce ammonia locally for a 1GW retrofitted coal power plant, Bangladesh would need to add 9.9GW of new solar builds. This is more than four times larger than solar capacity needed (2.1GW) to generate the same amount of electricity as the coal plant.

Figure 30: Marginal abatement cost for CCGT retrofitted for hydrogen blending

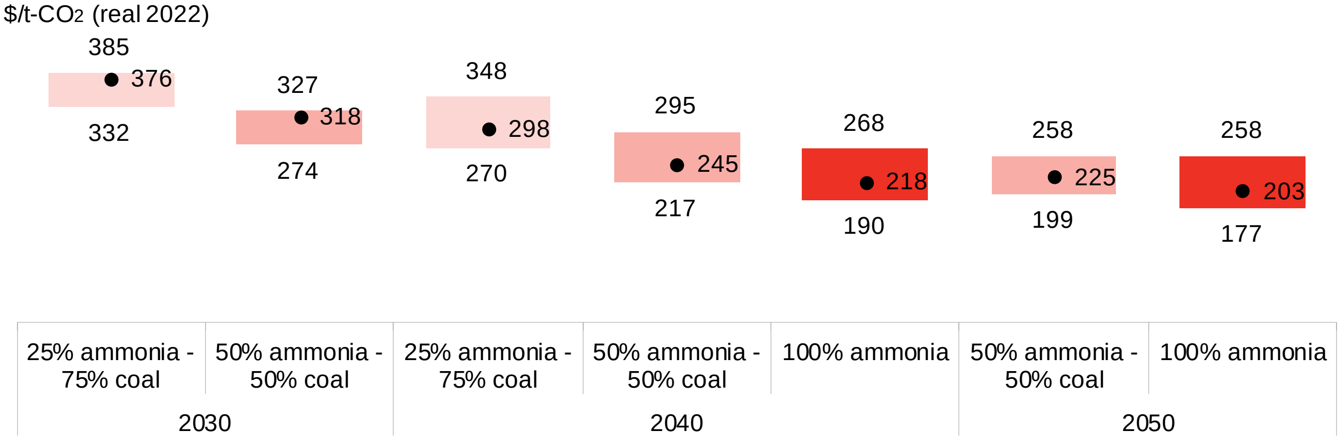


Source: BloombergNEF. Note: Blending ratio based on energy content.

We estimate the marginal abatement cost for 25% ammonia co-firing in 2030 would be in the range of $332-385/t-CO2 (Figure 31). For 50% ammonia co-firing, the abatement cost would be $217-295/t-CO2 in 2040 and $199-258/t-CO2 in 2050. These levies would be a huge financial burden to power plant owners and electricity end-users. If Bangladesh would put in carbon prices anywhere near these levels, power plant owners would likely opt for shutting down their existing thermal power plants and building cheaper renewables.

[2] Assuming 53kWh of electricity needed to produce 1kg of hydrogen. No renewables curtailment assumed.

Figure 31: Marginal abatement cost for coal power plant retrofitted for ammonia co-firing



Source: BloombergNEF. Note: Blending ratio based on energy content.

4.2. Safety

Figure 32: Hydrogen-related accident in the US in 2007

Source: WHA International.

Ammonia and hydrogen must be handled with care due to their high flammability (Table 1). At a poultry plant in China's Jinlin province, ammonia leakage caused a fire and killed 120 people in 2013. In the same year, another ammonia leakage killed 15 and injured 25 at a frozen seafood plant in Shanghai, China. In 2017, hydrogen leakage from a coolant at a coal-fired power plant in Ohio in the US caused an explosion that killed one person and injured 10. Since hydrogen does not have distinct odors and colors, hydrogen leaks are difficult to detect.

Ammonia is also highly toxic. The molecule reacts with water to form ammonium hydroxide, which is corrosive and damages cells in the body on contact. While ammonia leaks are easier to detect due to odor, contact with ammonia can be fatal.

Table 1: Safety comparison of ammonia, hydrogen, and natural gas

	Ammonia	Hydrogen	Natural gas (methane)
Flammability	Flammable	Flammable	Flammable
Explosiveness	May explode if heated	May explode if heated	May explode if heated
Toxicity	Acute poisoning from inhaling, skin/eye/respiratory damages	None. Still, high levels of hydrogen could cause a lack of oxygen in the body.	None. Still, high levels of methane could cause a lack of oxygen in the body.
Odor	Strong (easy to detect)	None (hard to detect)	None (hard to detect); Gas companies add artificial odor.
Visibility (color)	Colorless (hard to detect)	Colorless (hard to detect)	Colorless (hard to detect)

Source: BloombergNEF, The Globally Harmonized System of Classification and Labeling of Chemical (GHS) classification. Red color shows danger. Green shows no harm.

Section 5. Way forward for Bangladesh

Renewable power, in particular solar, is set to be the most economic option to meet Bangladesh's growing electricity demand. Retrofitting existing thermal power plants for combustion of hydrogen or ammonia is unlikely to become an economically viable option. To resolve its energy trilemma, Bangladesh needs to accelerate renewable expansion while limiting thermal power expansion.

5.1. Measures to accelerate renewable power expansion

Use auctions to support utility-scale renewables

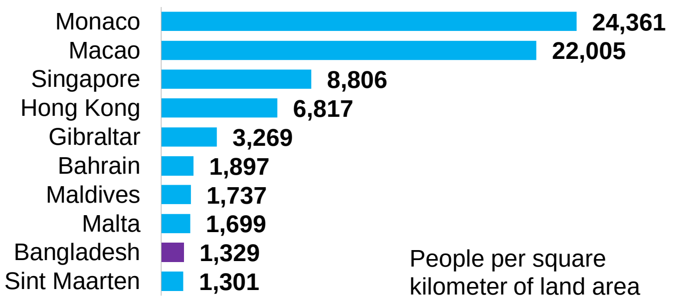
Land acquisition is the most commonly cited challenge for power plant development in Bangladesh due to the country's high population density. Bangladesh also caps land ownership at 100 bigha (approximately 13.4 hectares) with a sub-cap of 60 bigha of agricultural land per family. This, alongside a poor national registry of land ownership, makes it difficult for project developers to acquire land. Bangladesh can learn from the experience of its neighbor India as well as other markets such as Cambodia to set up a renewable auction program including access to land and grid connection. A well-designed auction program with transparent rules increases competition, thus lowering the cost of renewable electricity. Thanks to inclusion of grid and land access, developers would be facing lower risks. As a result, their financing costs will also be lowered.

Case study: Cambodia's solar park auction

Cambodia's first solar auction was launched in 2019. A total of 26 bidders, including international companies, vied for 60MW, the first phase of a 100MW solar park where land and the necessary grid infrastructure were prepared by the government. This removed two of the largest development risks for investors. Prime Road Alternative Company, a Thai-based firm, submitted the winning bid of $38.77/MWh, significantly below the ceiling of $76/MWh.

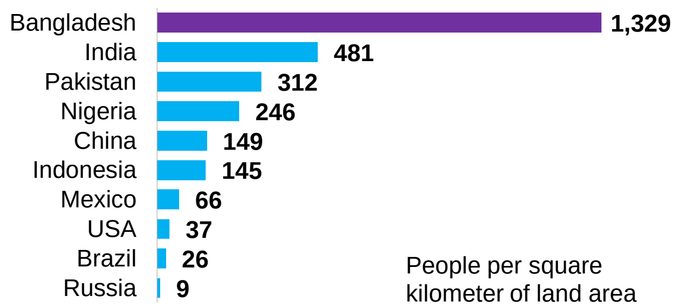
The auction – developed in partnership with the Asian Development Bank – was the country's first solar procurement scheme and fostered high levels of competition. The result was the lowest solar power bid in Southeast Asia. This shows how, even in a nascent market, physical auctions can help mitigate risks and speed up cost declines.

Figure 33: Top 10 most densely populated economies, 2023



Source: United Nationals Population Division, BloombergNEF

Figure 34: Population density of top 10 most populous countries, 2023



Source: United Nationals Population Division, BloombergNEF

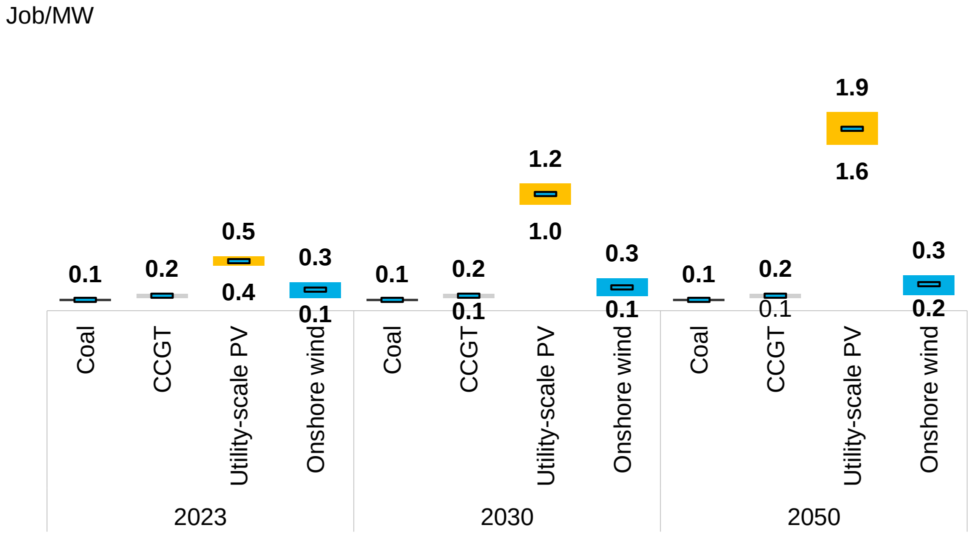
Increase support for rooftop as well as floating solar

Given its land constraints, Bangladesh will need to leverage all potential surface areas for power capacity installation. This includes rooftops for solar or water surfaces for floating PV systems. Bangladesh has already had modest success with rooftop solar, thanks to projects supported by Infrastructure Development Company Limited, a non-bank financial institution owned by the government. The government's net metering guidelines allowing commercial and industrial customers to install rooftop solar are also a step in the right direction. Expanding net metering to all building types and allowing third-party developers to aggregate multiple installations would be critical to accelerate rooftop solar deployment. The government would also need to identify and designate water bodies for floating solar deployment. Floating solar is moving relatively quickly in the country, with a 3.2MW floating solar project coming online in June.

Plan training programs for clean tech jobs

Renewable energy projects can create long-term job opportunities, and help Bangladesh address its high youth unemployment. Our analysis suggests renewables have a significantly higher employment factor for local labor than thermal power plants. To take full advantage of the renewables' job creation dividend, the government will need to ensure that relevant training programs are available. It will also need to ensure the programs can expand in tandem with renewable energy market growth.

Figure 35: Anticipated operation & maintenance jobs per $1 million of capex investment



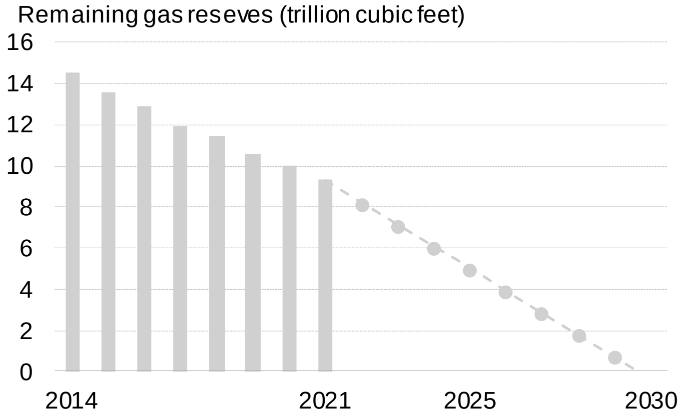
Source: BloombergNEF. Note: $1 million of capex investment is in real 2022 terms.

5.2. Benefits of limiting thermal power expansion

As Bangladesh expanded thermal power capacity, it has become significantly more dependent on fossil fuel imports. Costs have risen as a result. Bangladesh had to increase the regulated gas tariff for power generation to Tk14 per cubic meter ($3.8/MMBtu) in February 2023 from Tk5.02 per cubic meter ($1.5/MMBtu) in June 2022. Similarly, the regulated gas tariff for captive power, or self-generation, had to be raised to Tk30 per cubic meter ($8.2/MMBtu) from Tk16

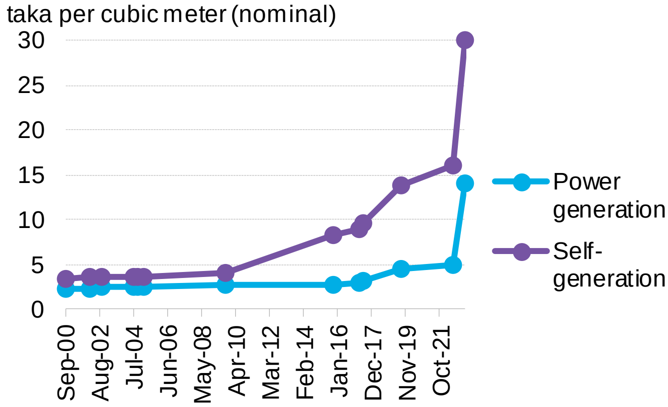
($4.7/MMBtu) over the same period. At the current consumption pace[3] without discovery and development of new domestic gas reserves, the country will become solely dependent on LNG imports post 2030. That said, our sensitivity analysis shows that it would only delay cost parity between renewables and thermal power plants by a few years even with depressed fuel costs and would not change the long-term dynamics that solar and wind are more economic options for the power sector. See Appendix E for more details.

Figure 36: Bangladesh gas reserves, historical trends and projection



Source: BloombergNEF, Petrobangla. Note: An average of annual gas production from 2017 to 2021 is used to estimate when local gas reserves may run out.

Figure 37: Bangladesh gas tariff for power generation



Source: Petrobangla

The higher expenditure on fossil fuel imports, along with the negative impact of the pandemic, have depleted the country's foreign currency reserves which in turn have weakened the country's currency. This in turn has made it more difficult to pay for more fossil fuel imports. For example, on May 25, 2023, one of the two 660MW units at the Payra coal-fired power plant shut down operations because the plant couldn't pay for coal imports. Many existing thermal power plants developed in partnership with private investors have rigid power purchase agreements including capacity payments. This means that when such power plants are not fully utilized, they still receive partial payments. While such mechanisms are helpful in getting the power plants financed, they can saddle the country with an additional financial burden and pose a hindrance to future renewable capacity expansion.

By limiting thermal power plant additions and deploying more renewables, Bangladesh can bring down energy costs and emissions while improving the country's energy security. Investing in renewables can create more opportunities and support the country's economic growth.

[3] The country's average daily gas production was 2,940 million cubic feet for the period of 2017-2021 (link)

Appendices

Appendix A. LCOE assumptions

Table 2: LCOE assumptions, nominal

Technology	Variable	Unit	2023	2030	2050
Coal	Capex	$/MW	1,700,000	1,961,103	2,933,570
	Fixed opex	$/MW/Year	34,000	38,179	56,442
	Variable opex	$/MW	2.43	2.7	4.03
	Capacity factor	%	36	37	37
	Hurdle IRR	%	14	14	14
	Cost of debt	bps	810	810	810
	Debt-to-equity ratio	%	75	56	49.3
	Loan tenor	Years	17	17	17
CCGT	Capex	$/MW	1,200,000	1,384,308	2,070,755
	Fixed opex	$/MW/Year	36,000	40,425	59,762
	Variable opex	$/MW	1.71	1.9	2.84
	Capacity factor	%	49	50	50
	Hurdle IRR	%	14	14	14
	Cost of debt	bps	810	810	810
	Debt-to-equity ratio	%	75	68	65
	Loan tenor	Years	17	17	17
Utility-scale solar	Capex	$/MW	1,200,000	580,916	533,852
	Fixed opex	$/MW/Year	12,000	11,495	15,170
	Variable opex	$/MW	-	-	-
	Capacity factor	%	16	16	16
	Hurdle IRR	%	14	12	7
	Cost of debt	bps	810	534	453
	Debt-to-equity ratio	%	75	75	75
	Loan tenor	Years	15	15	15
Onshore wind	Capex	$/MW	1,901,900	1,884,750	2,312,269
	Fixed opex	$/MW/Year	37,500	36,578	45,655
	Variable opex	$/MW	-	-	-
	Capacity factor	%	17	29	34
	Hurdle IRR	%	14	12	7
	Cost of debt	bps	810	534	453
	Debt-to-equity ratio	%	75	75	75

Loan tenor	Years	15	15	15

Source: BloombergNEF

Adjustment for retrofits of fossil fuel power plants

Retrofits of fossil fuel power plants to blend hydrogen, ammonia, or biomass require new equipment or facilities added to existing power plants. Table 3 below summarizes our assumptions of adjustments to project costs and efficiency used in our research based on interviews with market players and literature research.

Table 3: Impacts of fossil fuel power plant upgrades to burn hydrogen, ammonia, or biomass

	Coal retrofits with ammonia	Coal retrofits with biomass	CCGT retrofits with hydrogen
Capex	11% of coal capex	4.5% of coal capex	20% of CCGT capex
Variable opex	Not appliable	Not applicable	+20% from CCGT variable opex
Fixed opex	+10% from coal fixed opex	Not applicable	+12.5% from CCGT fixed opex
Efficiency	-12% from coal plant efficiency	-4% from coal plant efficiency	-7.5% from CCGT efficiency
Emission reduction	Same as blending ratio of ammonia in energy	Same as blending ratio of biomass in energy	Same as blending ratio of hydrogen in energy
Lifetime	20 years	20 years	20 years
Financing	Same as a new coal plant	Same as a new coal plant	Same as a new CCGT plant

Source: BloombergNEF. Note: Assuming retrofits take place after full depreciation of original power plants.

Coal retrofits with **ammonia** include upgrading burners and additional balance of plant expenses to receive and store ammonia. Controlling the exhaust NO_X emissions will be key in each plant's combustion strategy, too. Coal retrofits with more than 20% ammonia co-firing have not been tested or commercialized. Our research applied the same retrofit cost assumptions used in Japan's 20% ammonia co-firing as the retrofit costs for more than 20% co-firing including 25%, 50%, 75% and 100%. In reality, a higher ammonia co-firing ratio will likely require higher capex because boilers would require major upgrades or even replacements. Storage tanks for ammonia would also need to be bigger at a higher co-firing ratio. More advanced equipment to capture NO_X emissions would be needed as well. See *Japan's Costly Ammonia Coal Co-Firing Strategy* (web | terminal) for more details.

Coal retrofits with **biomass**, especially at a low blending ratio, only require a small upgrade such as a new covered silo storing feedstock. This is because the volume of to-be-blended biomass feedstock would be negligible at a low blending ratio. Like ammonia co-firing, a high biomass blending ratio would likely need major reinforcement as a large amount of biomass feedstock would need to be processed separately before blending fuels.

Hydrogen combustion also requires new equipment including more resilient materials to sustain higher combustion temperatures and more operations and maintenance to deal with higher combustion temperatures and increased use of water for cooling. The scale of these adjustment-associated costs and efficiency will likely decline over time. For this analysis, we refer to estimated cost and efficiency of a hydrogen-fueled turbine relative to state-of-the-art natural gas turbines between 2019 and 2040. To estimate additional costs and lower efficiency for retrofits, we took simple averages of these two categories and applied the adjustments to CCGT plants. See *Hydrogen: The Economics of Power Generation* (web | terminal) for more details.

Retrofitted coal power plants for **biomass** co-firing typically run at a low blending ratio, although some power plants run with 100% biomass. Retrofitted coal power plants for co-firing with biomass at a low ratio require limited upgrades such as a new covered silo for storing biomass.

Appendix B. Assumptions for delivered costs of clean fuels relevant to Bangladesh

Hydrogen labeling

The hydrogen industry uses labels such as green and blue as shorthand for how hydrogen is made. Production methods differ on the volume of greenhouse gases they emit. The most common hydrogen labels are:

- Green, made via electrolysis of water using renewable electricity – this releases few or no greenhouse gas emissions.
- Blue, made via steam reforming of methane or gasification of coal coupled with CO2 capture and storage (CCS) – this releases more emissions than green hydrogen, but less than gray.
- Gray, made via steam reforming of methane or gasification of coal without CCS – the most common method today that releases large volumes of CO2

Our research incorporates three different types of clean molecules: green hydrogen/ammonia produced in Bangladesh, green hydrogen/ammonia imported from Australia, and blue hydrogen/ammonia imported from the Middle East. Both Australia and the Middle East are aiming to become clean hydrogen exporters. Australia has cheap solar with vast land areas while the Middle East has ample availability of oil and gas, as well as potential carbon storage sites. Leveraging on these resources, many companies in these regions have been partnering with hydrogen buyers in other markets to develop hydrogen supply chain.

Our research does not consider fossil fuel-based hydrogen and ammonia without emission mitigation, although almost all ammonia and hydrogen produced today is gray. Use of these molecules without emission abatement defies the justification of promoting these technologies in the first place. Many markets are also encouraging the use of clean molecules by defining 'low-carbon' hydrogen or ammonia.

We estimate fuel hydrogen/ammonia prices by the costs of hydrogen production, conversion to ammonia, (conversion back to hydrogen if needed) and shipping to Bangladesh.

Hydrogen production

Since ammonia is produced from hydrogen, we rely on the hydrogen production costs derived from BNEF's *Hydrogen Project Valuation Model*. Below are the assumptions of technologies used for hydrogen production.

- Bangladesh: alkaline electrolysis using fixed-axis PV projects and Chinese electrolyzers (green hydrogen)
- Australia: alkaline electrolysis using tracking PV projects and Western electrolyzers (green hydrogen)
- Middle East: steam methane reforming using natural gas (blue hydrogen)

Conversion to ammonia from hydrogen

Next, we added the cost of converting hydrogen to ammonia based on the following assumptions. We expect economies of scale to kick in post-2027 and push down the conversion cost going forward.

Table 4: Cost of conversion to ammonia from hydrogen

	$/kg of H_2, real 2022
Up to 2027	1.61
2028-2049	Linear interpolation for each year using values for 2027 and 2050
2050	1.00

Source: BloombergNEF

Transportation of ammonia

Ammonia produced outside Bangladesh needs to be shipped to the country. Below is our assumption on transportation costs added to ammonia produced in Australia and the Middle East. To estimate shipping distance, we refer to shipping routes for LNG trade flows: 3,084 nautical miles between Dampier in Australia and Bangladesh and 3,266 nautical miles between Das Island in the United Arab Emirates and Bangladesh. Shipping ammonia is already mature, so these transportation costs are used throughout the modeling period:

- Molecules from Australia: $0.21/kg of hydrogen (real 2022)
- Molecules from the Middle East: $0.22/kg of hydrogen (real 2022)

Conversion back to hydrogen from ammonia

Shipped ammonia must be converted back from hydrogen if end-use sectors use hydrogen, not ammonia. Similar to the conversion to ammonia, below shows the conversion cost to hydrogen.

Table 5: Cost of conversion to hydrogen from ammonia

	$/kg of H_2, real 2022
Up to 2027	1.63
2028-2049	Linear interpolation for each year using values for 2027 and 2050
2050	1.07

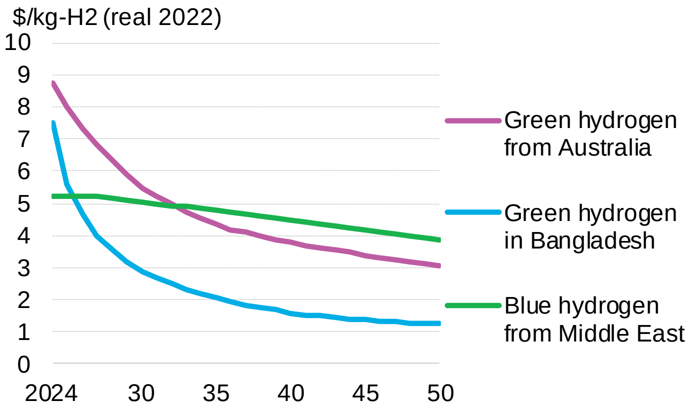
Source: BloombergNEF

Appendix C. Production cost of hydrogen and ammonia

Domestic green hydrogen is the cheapest option in 2026 and onward

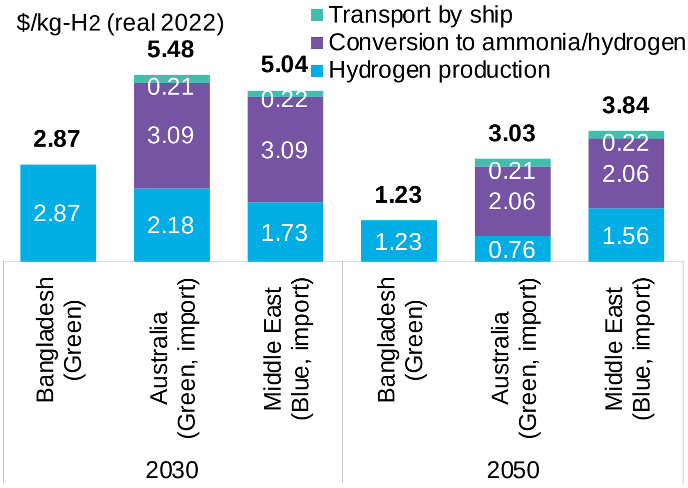
Blue hydrogen imported from the Middle East would be cheaper than other hydrogen types included in our research until 2025 (Figure 38). Green hydrogen produced in Bangladesh would become the cheapest in 2026 by undercutting the production cost of blue ammonia from the Middle East. Costs of green hydrogen production in Bangladesh would fall due to cost reductions of renewable electricity and electrolyzers (Figure 39). Imported clean hydrogen from Australia and the Middle East would cost twice or three times more than green hydrogen in Bangladesh.

Figure 38: Production cost of hydrogen delivered in Bangladesh, 2024-2050



Source: BloombergNEF

Figure 39: Cost of hydrogen supply relevant to Bangladesh



Source: BloombergNEF

The biggest cost driver behind imported hydrogen is the conversion processes. In our analysis, we assume that hydrogen is exported to Bangladesh from Australia or the Middle East in the form of ammonia as it is the most economic shipping option[4]. This requires ammonia synthesis using hydrogen. Once in Bangladesh, ammonia must be converted back to hydrogen (and nitrogen) via thermolysis, the reverse of ammonia synthesis. These conversion processes are costly and increase costs of imported hydrogen production.

We have not considered the scenario of domestically produced blue hydrogen in Bangladesh. Directly using carbon capture and storage (CCS) to capture emissions from thermal power plants would be cheaper than using CCS to capture emissions from the process of converting imported LNG or coal to hydrogen or ammonia, and then using that resulting blue hydrogen/ammonia in thermal power plants. Applying CCS directly to the thermal power plant is a more energy efficient

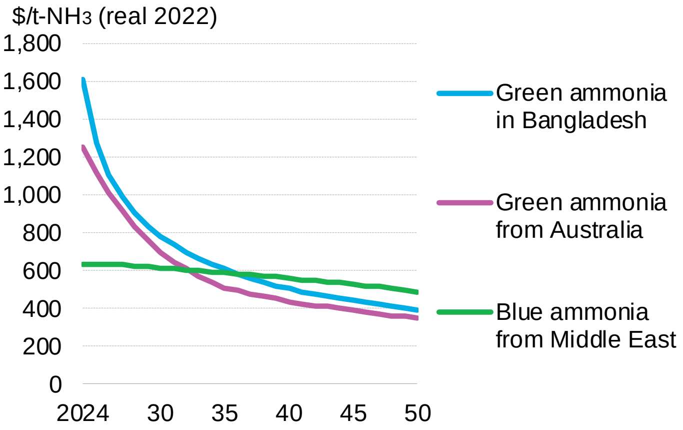
[4] Liquid ammonia has a very high hydrogen density (107-121 kg of hydrogen per cubic meter) – higher than liquid hydrogen (at 70.8 kg per cubic meter). In addition, ammonia can be shipped in liquid form at -33C, which is technically more manageable than liquid hydrogen that needs to be chilled at -253C.

process than using CCS for hydrogen production and then running thermal power plants on hydrogen or its derivative.

Blue ammonia from the Middle East becomes the most expensive by 2036

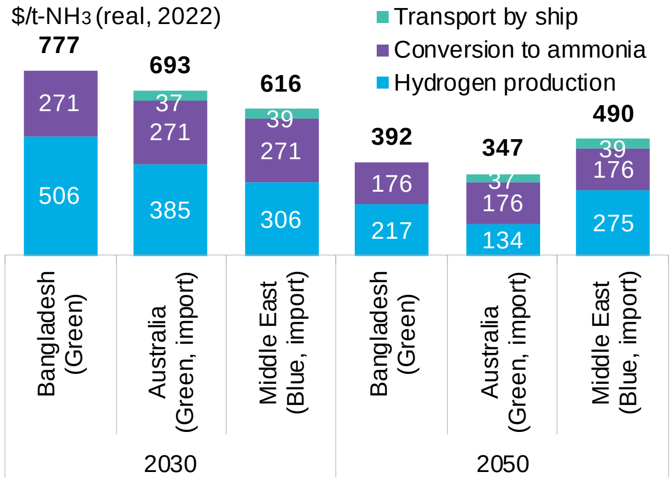
Local green ammonia in Bangladesh would be the most expensive in the near term because of the high cost of renewables in the country (Figure 40, Figure 41). Green ammonia imported from Australia would be cheaper than local green ammonia but would be costlier than blue ammonia imported from the Middle East. Production costs of imported green ammonia from Australia and local green ammonia in Bangladesh should undercut the costs of blue ammonia from the Middle East in 2033 and 2036, respectively. From 2036, blue ammonia from the Middle East would be the costliest option. Blue ammonia (as well as blue hydrogen) has limited cost reduction potential because of the limited cost reduction of fossil fuels in the future.

Figure 40: Production cost of ammonia delivered in Bangladesh, 2024-2050



Source: BloombergNEF

Figure 41: Cost of ammonia production relevant to Bangladesh



Source: BloombergNEF

Appendix D. Blended clean fuel prices

Hydrogen-gas blended fuel prices, by blending ratio

Figure 42: Blended fuel price for 25% hydrogen mix

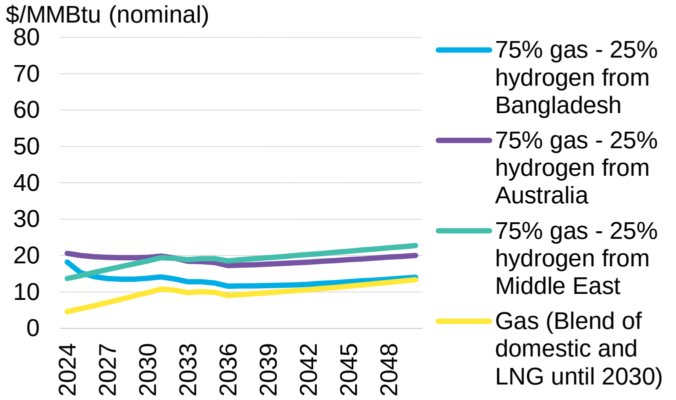
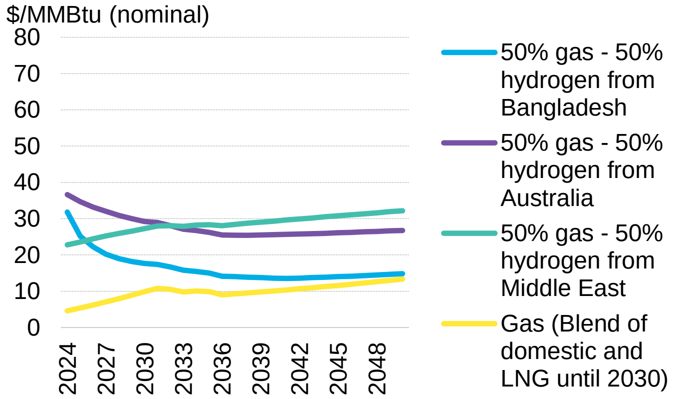


Figure 43: Blended fuel price for 50% hydrogen mix



Source: BloombergNEF. Note: Blending ratio based on energy content.

Figure 44: Blended fuel price for 75% hydrogen mix

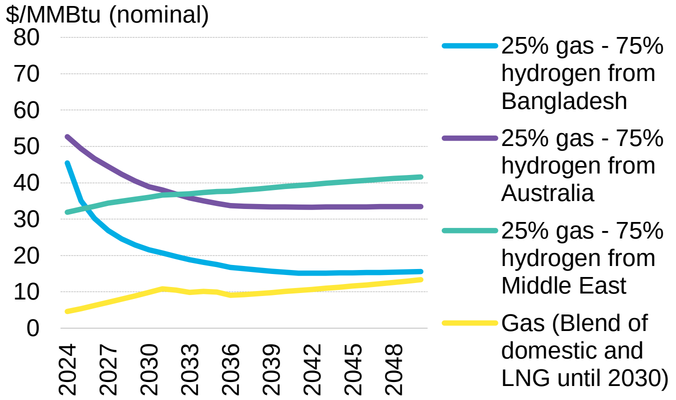
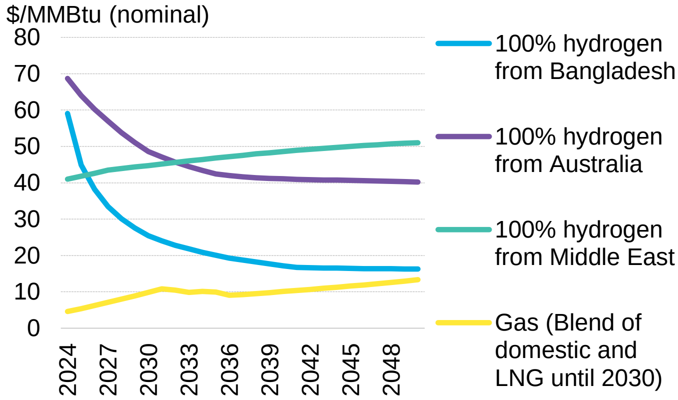


Figure 45: Blended fuel price for 100% hydrogen mix



Source: BloombergNEF. Note: Blending ratio based on energy content.

Ammonia-coal blended fuel prices, by blending ratio

Figure 46: Blended fuel price for 25% ammonia mix

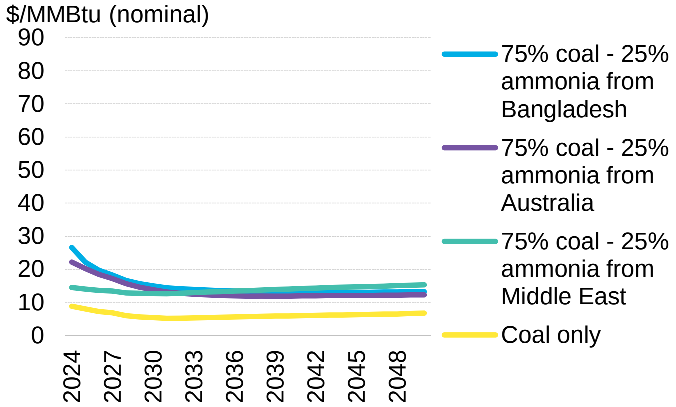
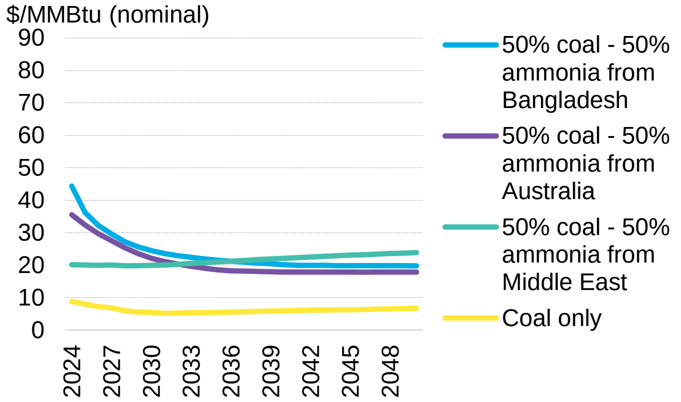


Figure 47: Blended fuel price for 50% ammonia mix



Source: BloombergNEF. Note: Blending ratio based on energy content.

Figure 48: Blended fuel price for 75% ammonia mix

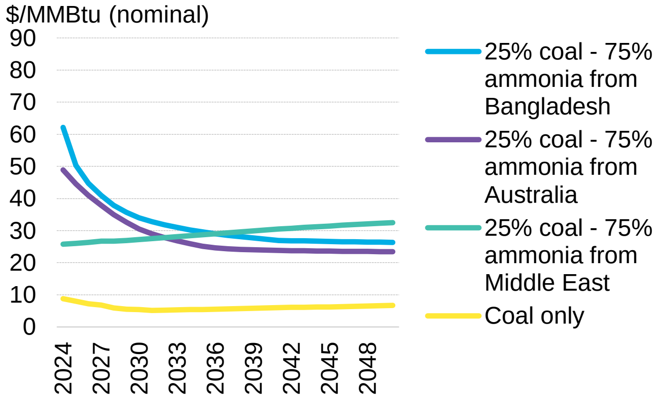
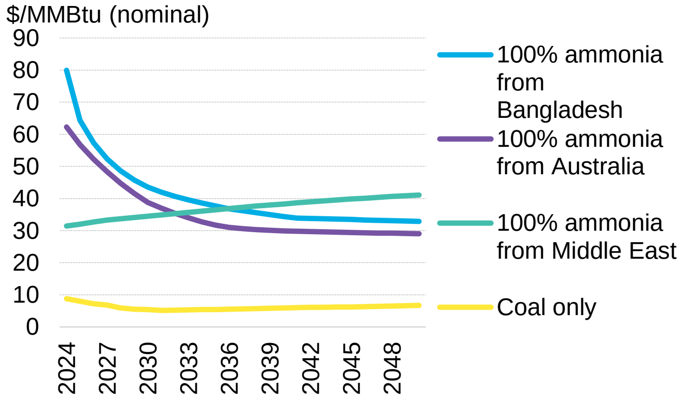


Figure 49: Blended fuel price for 100% ammonia mix

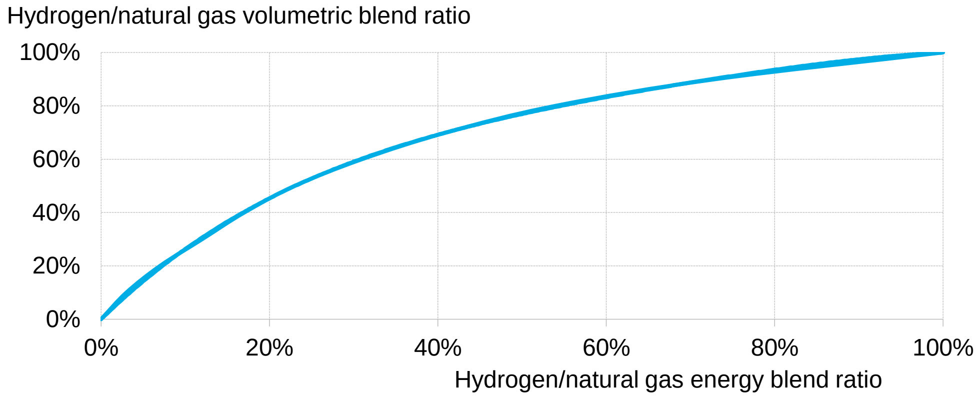


Source: BloombergNEF. Note: Blending ratio based on energy content.

Energy density of hydrogen

As hydrogen has a lower volumetric energy density than natural gas, higher volumes of hydrogen than natural gas are required to achieve a similar energy blend ratio. As a result, higher volumes of hydrogen than natural gas would have to be consumed to significantly reduce carbon dioxide emissions from CCGT. Throughout this report, we use energy content blend ratio.

Figure 50: Relationship between energy and volume for hydrogen blending



Source: BloombergNEF, GE Power to Gas: Hydrogen for Power Generation

Appendix E. Sensitivity analyses

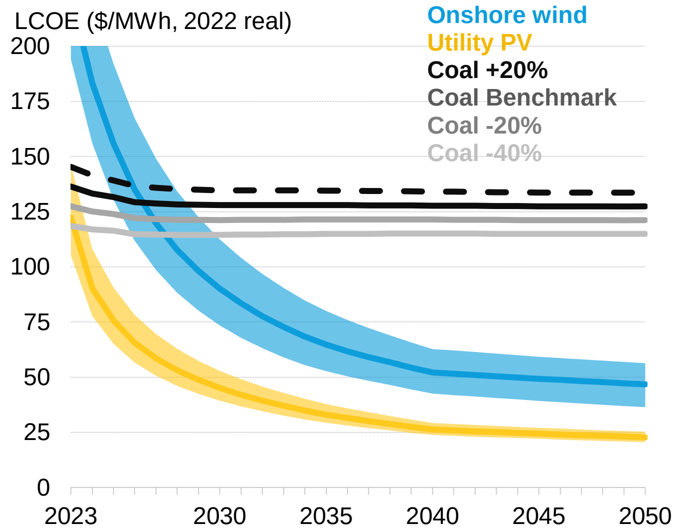
Depressed fuel costs insufficient to compete with the cost evolution of a new PV and onshore wind plant

As the growth of cost-competitive renewables displaces coal and gas power generation, it is possible that less global demand could cut coal and gas prices, resulting in lower LCOEs and marginal running costs of fossil-fueled power plants. On the other hand, geopolitical tensions could raise fuel prices, increasing the LCOE further. To explore what the competitiveness landscape of the different power generation technologies would look like in such a scenario, the LCOE of a new coal and CCGT plant was calculated with the fuel cost set at a 20% premium to a discount of 40% against the benchmark case, which is covered in Section 3.1.

A 40% drop in seaborne thermal coal prices would lower the LCOE benchmark of a new coal plant by 10.3% on average throughout the forecast duration (Figure 51). This would only delay the tipping point where a new utility-scale PV plant and a new onshore wind plant achieves cost parity with a new coal plant just marginally by a year for both technologies, compared to the tipping point years of 2023 and 2027 under the benchmark scenario, respectively.

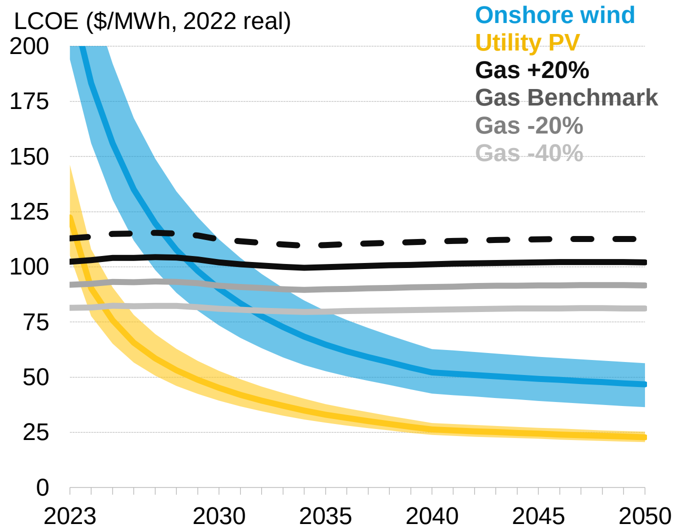
Reduced gas prices have a more significant impact on the LCOE of a new CCGT plant. The LCOE of a new CCGT plant could be reduced by an average of 20.5% against the benchmark case throughout the forecast duration (Figure 52). Like the case of coal, this would only delay when a new utility-scale PV plant achieves cost-parity against a new CCGT plant by just a year to 2025. The lower fuel price helps a new CCGT plant remain cost-competitive against a new onshore wind plant for slightly longer, delaying the cost-parity year by three years from 2029 to 2032 but it does not change the long-term cost dynamics.

Figure 51: Bangladesh LCOE of a new solar and onshore plant versus range of LCOE for a new coal plant



Source: BloombergNEF

Figure 52: Bangladesh LCOE of a new solar and onshore plant versus range of LCOE for a new gas plant

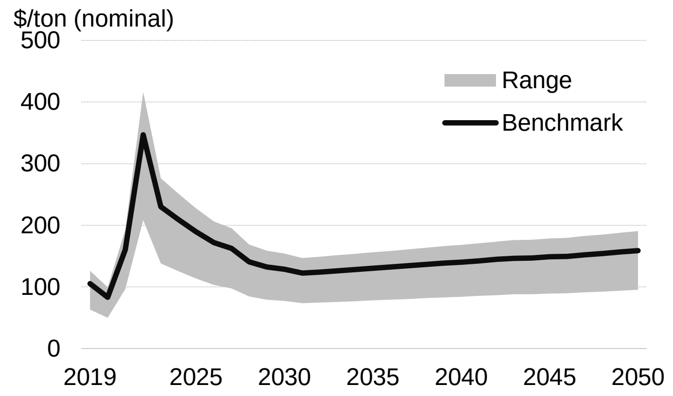


Source: BloombergNEF

Significant fuel price reduction would be needed to keep existing coal and gas plants competitive

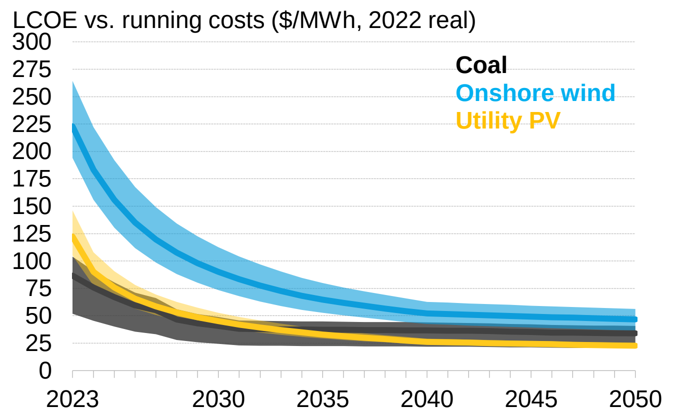
Due to the cost competitiveness of renewables, fossil fuel power plants could be stranded in the future as expensive power generation sources. Without significant fuel price reductions, thermal power plants wouldn't be economically viable in Bangladesh's power system. For instance, the coal fuel price will have to drop by at least 33% (average of $71.1/ton in nominal terms between 2023 and 2030) against our benchmark fuel price scenario to allow the SRMC of an existing coal plant to be cheaper than that of a new utility-scale PV plant.

Figure 53: Range of coal prices used for sensitivity analysis



Source: BloombergNEF. Note: Range of coal prices represents a 20% premium on the upper end and a 40% discount on the low end against the benchmark price.

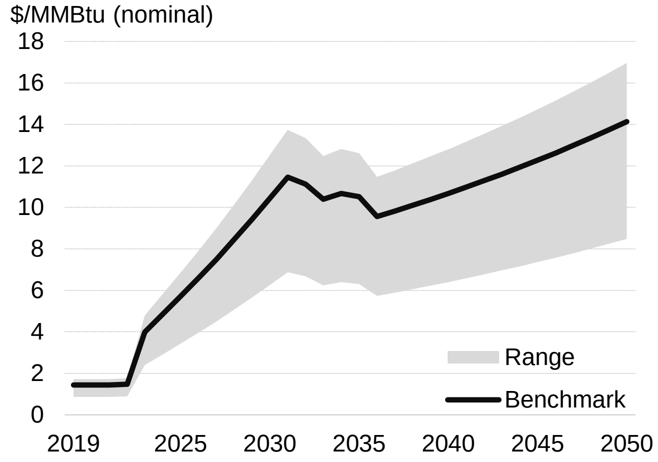
Figure 54: Bangladesh LCOE of a new PV and onshore wind plant versus SRMC of an existing coal plant



Source: BloombergNEF. Note: SRMC stands for short-run marginal cost. Range of coal LCOE depicts a fuel cost of +20% against the benchmark fuel price on the upper range and a -40% discount on the low scenario.

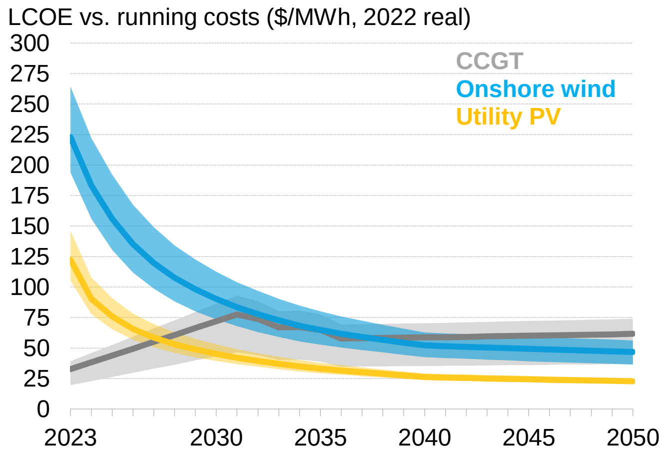
A new PV plant in Bangladesh will undercut the SRMC of an existing CCGT plant even with a steep fuel cost reduction. A 40% reduction in fuel cost delays when a new utility-scale PV undercuts the marginal running cost of an existing CCGT plant by three years to 2031 instead of 2028 under the benchmark case. To compete against a new onshore wind plant throughout the forecast duration of 2023 and 2025, an existing CCGT plant will need to run on fuel cost that is 25% below our benchmark case.

Figure 55: Range of gas prices used for sensitivity analysis



Source: BloombergNEF. Note: Note: Range of gas prices represents a 20% premium on the upper end and a 40% discount on the low end against the benchmark price.

Figure 56: Bangladesh LCOE of a new PV and onshore wind plant versus SRMC of an existing CCGT plant



Source: BloombergNEF. Note: SRMC stands for short-run marginal cost. Range of CCGT LCOE depicts a fuel cost of +20% against the benchmark fuel price on the upper range and a -40% discount on the low scenario.

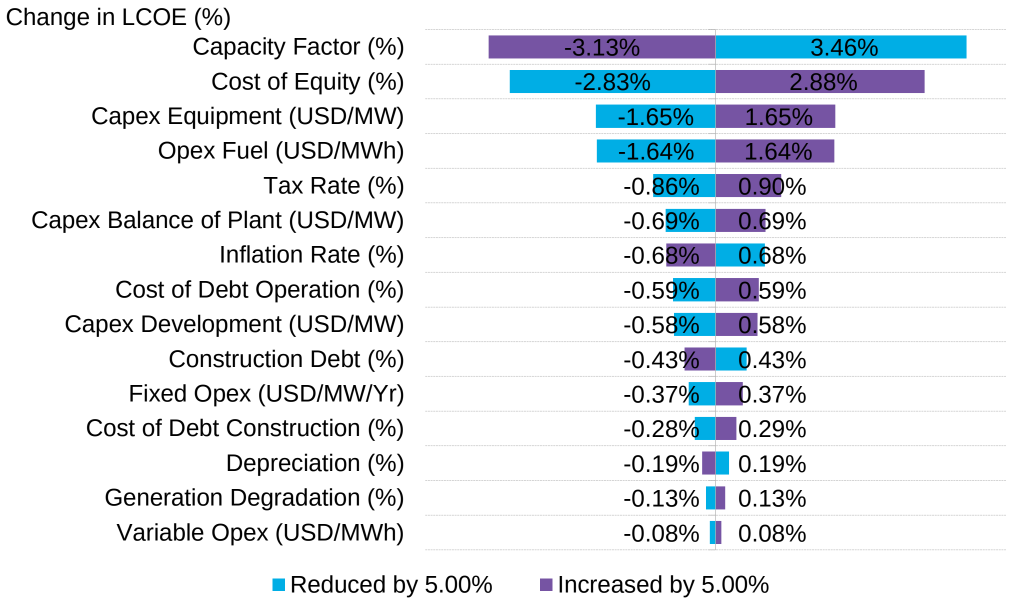
Other factors could also negate the effect of fuel price reduction such as higher-than-expected financing costs for fossil-fueled power assets or the introduction of a carbon price in Bangladesh in the future.

Changes in capacity factors to make the biggest impact on the LCOE

When considering the cost-competitiveness of different power generating technologies, it is imperative to consider the potential realized capacity factor of each plant due to its significant contribution to LCOEs, especially that of a fossil fuel power plant, instead of the technical potential of the plant.

BNEF's analysis shows that capacity factor has the largest impact on the LCOE of a coal plant. A 5% increase in the capacity factor reduces the LCOE of a coal plant by 3.13% while a 5% reduction in capacity factor results in a 3.46% rise in LCOE (Figure 27).

Figure 57: Sensitivity analysis of the LCOE of a coal power plant



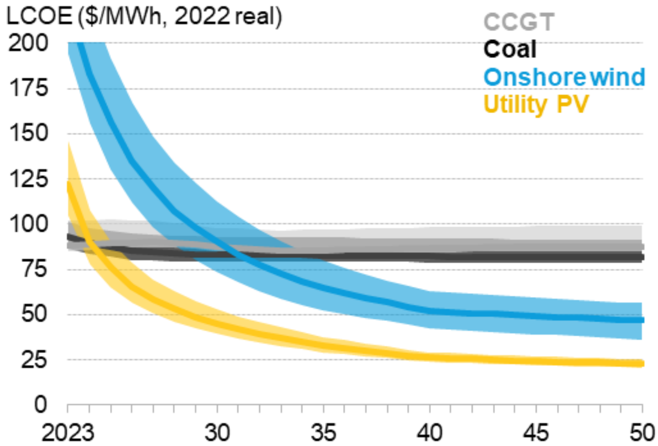
Source: BloombergNEF. Note: Chart shows the percentage impact on the LCOE of a coal plant in Bangladesh with a +/- 5% variance on each variable based on the benchmark cost scenario.

Bangladesh's power system currently faces power overcapacity, which has limited the running hours of the country's coal and CCGT plants. According to historical power system data, the capacity factor of the national fleet of coal and CCGT power plants averaged just 33% and 45%, respectively, in 2022.

Considering the actual utilization rate of coal plants in Bangladesh, we calculated the LCOE of a new coal and CCGT plant with two sets of capacity factor assumptions – an assumption of 65-75% and an average of the last five years' historical capacity factor for each technology.

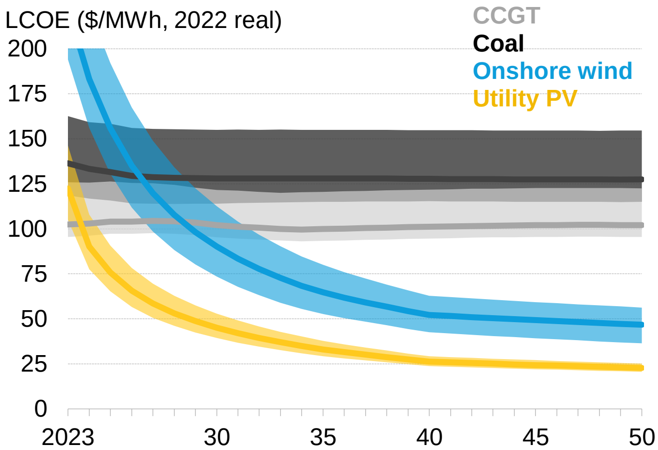
BNEF's analysis suggests that for a new coal plant commissioning in 2035, the LCOE of a plant with capacity factor at 37% ($128/MWh real 2022) is 54% higher than the LCOE of a coal plant with a capacity factor of 72% ($83/MWh real 2022). For a new CCGT plant coming online in the same year, a 50% capacity factor leads to a 17% increase in LCOE compared to a plant with a 72% capacity factor. This significantly changes the cost-competitiveness between a new coal and CCGT plant and a new PV and onshore wind plant (Figure 58, Figure 59).

Figure 58: Bangladesh LCOE of a new coal and gas plant with capacity factor between 65% and 75%



Source: BloombergNEF

Figure 59: Bangladesh LCOE of a new coal and gas plant with capacity factor based on historical average



Source: BloombergNEF. Note: Capacity factor for a new coal and CCGT plant assumed at an average of 37% and 50.4% respectively.

Bangladesh's power purchase agreements for coal and CCGT plants have often been structured with a capacity payment linked to a certain level of availability of the plant that Bangladesh Power Development Board is obligated to pay regardless of offtake. This provides some level of revenue protection for project owners. However, securing further coal and gas power supply under the current overcapacity environment on the same structure will impose additional financial burden on the state utility as they pay for idle capacity, likely leading to a need to raise power tariffs for cost recovery.

Increasing financing costs further threatens the economics of a new coal or gas plant

The global turn away from fossil fuel assets, especially coal, has seen the widespread fleeing of capital from new coal and increasingly gas power plants. The growing reluctance to invest in fossil-fueled power plants is likely to lead to an increase in debt costs for new projects.

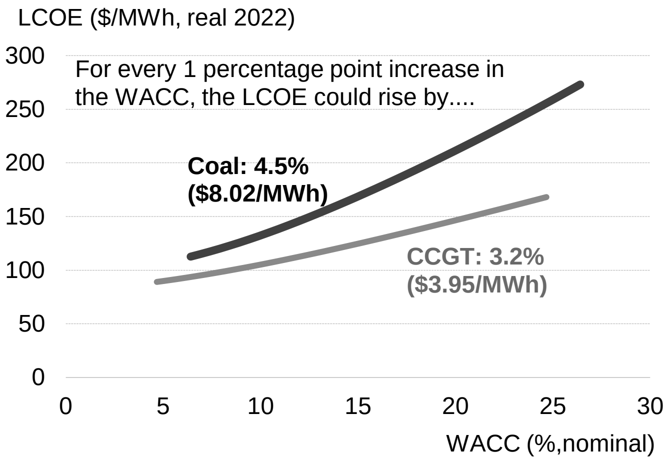
Our analysis suggests that a 1 percentage point increase in the weighted average cost of capital (WACC)[5] will drive the LCOE of a new coal plant commissioning in 2035 up by about $8.02/MWh (equivalent to 4.5% increase). For a new CCGT plant coming online in the same year, the LCOE rises by $3.95/MWh (equivalent to 3.2% increase). In addition to higher financing costs, coal and CCGT plants could face increasingly challenging financing conditions such as lower debt-to-equity ratio and shorter loan tenors that would add further pressure on costs.

A new utility-scale PV and PV-plus-storage plant sees LCOE increase by $3.19/MW (equivalent to 6% increase) and $6.14/MWh (equivalent to 5.8% increase) respectively with a 1 percentage point rise in WACC – lower than coal LCOE increase in absolute values. Due to the lower equipment costs and benchmark LCOE of a new PV plant in 2035, the impact from a rise in financing costs in absolute terms is the lowest for PV compared to all other technologies. Yet, a new onshore wind and onshore wind-plus-storage plant also sees quite significant impact from an

[5] Currently, a new coal power plant financed today has a WACC of 7.6%.

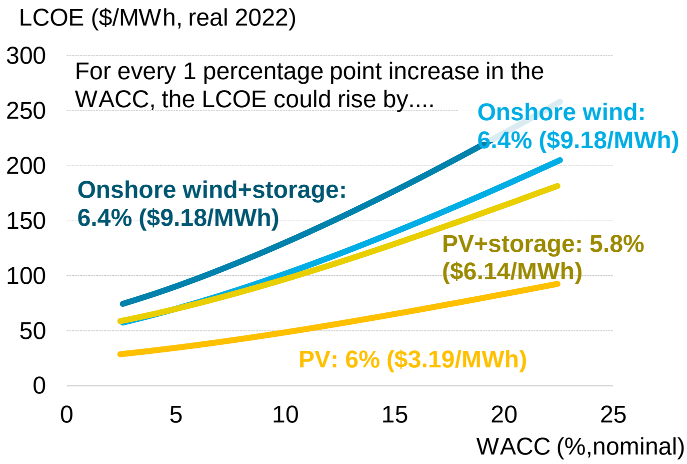
increase in capital costs. A 1 percentage point increase in WACC translates to an increase of 6.4%, or approximately $9.18/MWh, in the LCOE of both plant types.

Figure 60: LCOE of a new coal and gas plant with varying cost of capital in Bangladesh



Source: BloombergNEF. Note: WACC is the weighted average cost of capital. Chart shows the LCOE for a power plant commissioned in 2035.

Figure 61: LCOE of renewable plants with varying cost of capital in Bangladesh



Source: BloombergNEF. Note: WACC is the weighted average cost of capital. Storage cost is based on a 4-hour battery storage system. Chart shows the LCOE for a power plant commissioned in 2035.

Appendix F. Technology factsheets

To mitigate climate change, an immediate reduction in greenhouse emissions is necessary.

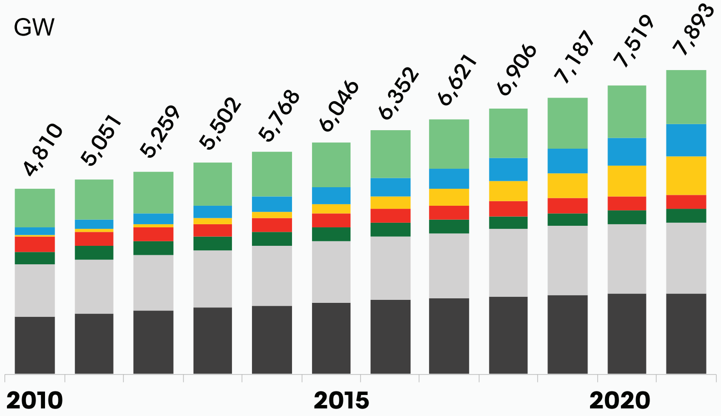
Electricity generation is the single largest source of emissions due to heavy reliance on fossil fuels.

The decline in the cost of solar and wind technologies means they are now the cheapest source of electricity generation in most countries.

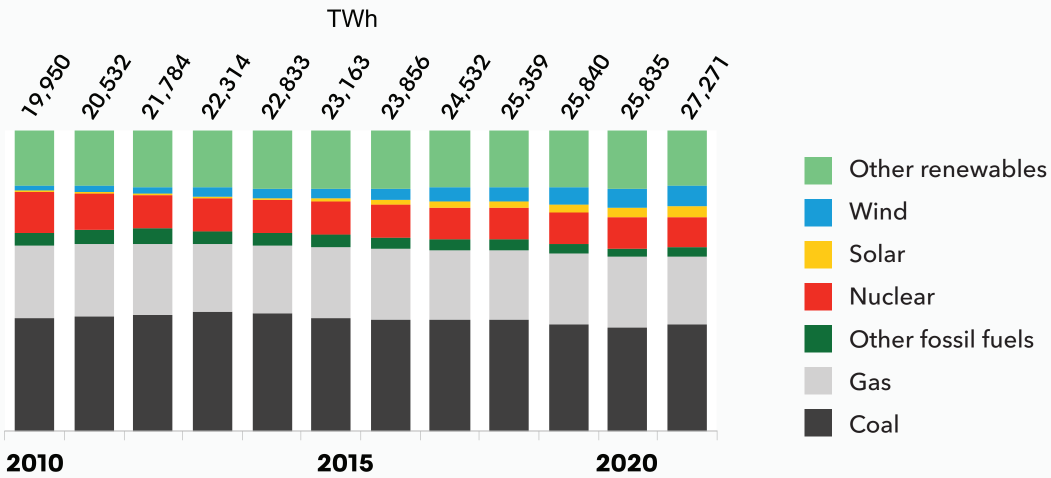
Power sector transition

Coal and gas power plants have historically dominated power generation. However, the share of solar and wind are growing thanks to their cheaper costs and supportive policies.

Global installed power generation capacity



Global generation mix

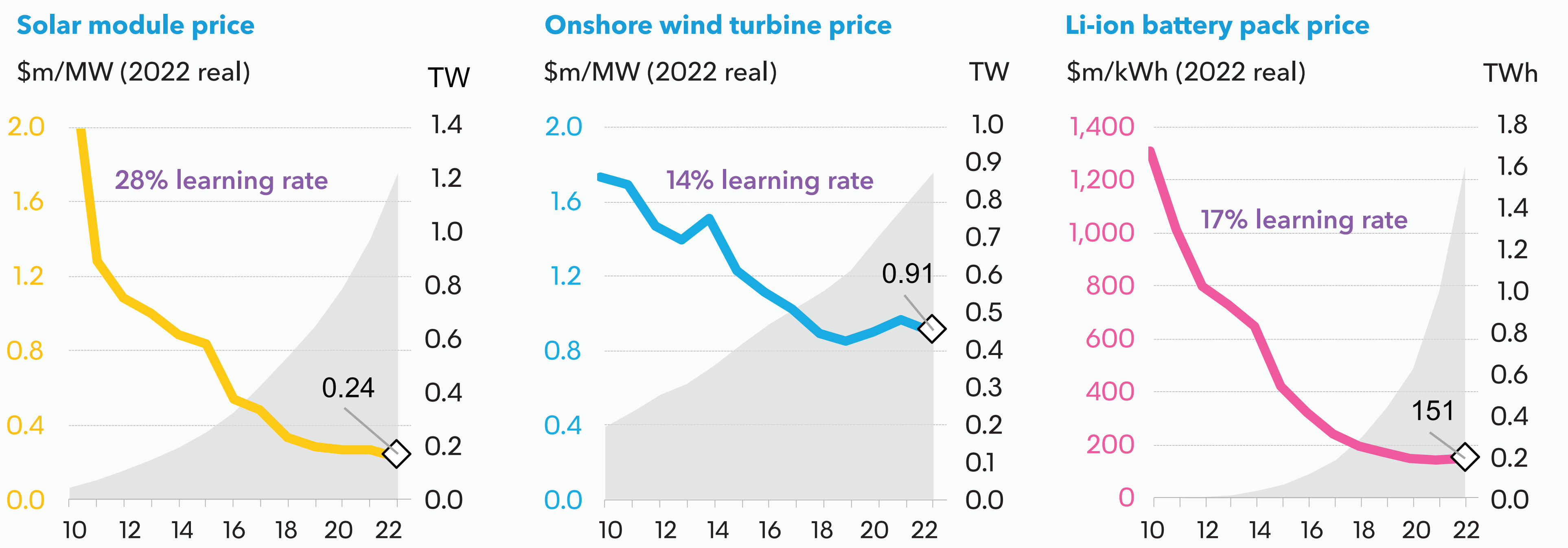


Source: *BloombergNEF.*

BloombergNEF

Power sector transition

Utility scale solar or onshore wind are now the cheapest sources of bulk electricity generation in countries accounting for 82% of global electricity generation. The scale-up in manufacturing and deployment of renewables, coupled with technology improvements, has resulted in significant cost reduction.



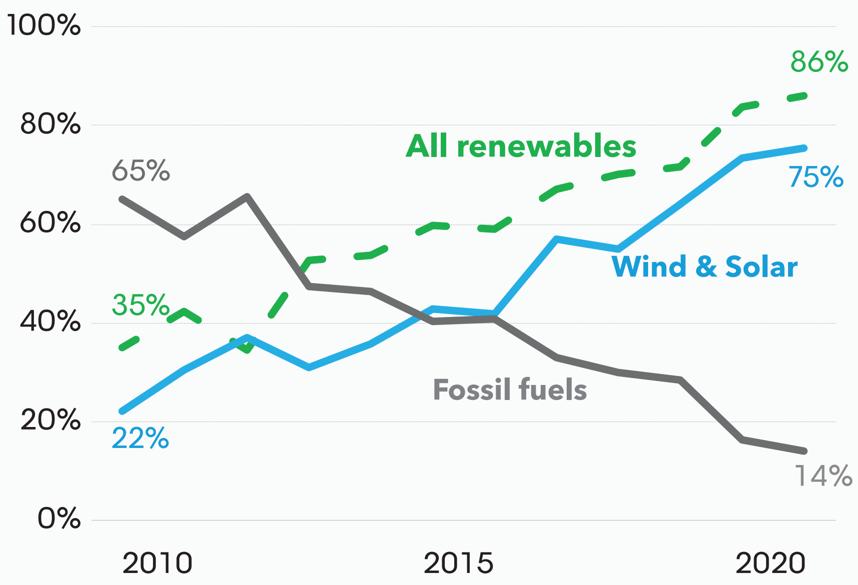
Source: *BloombergNEF.*
Note: Gray area shows the cumulative global installed capacity of each technology.

BloombergNEF

Power sector transition

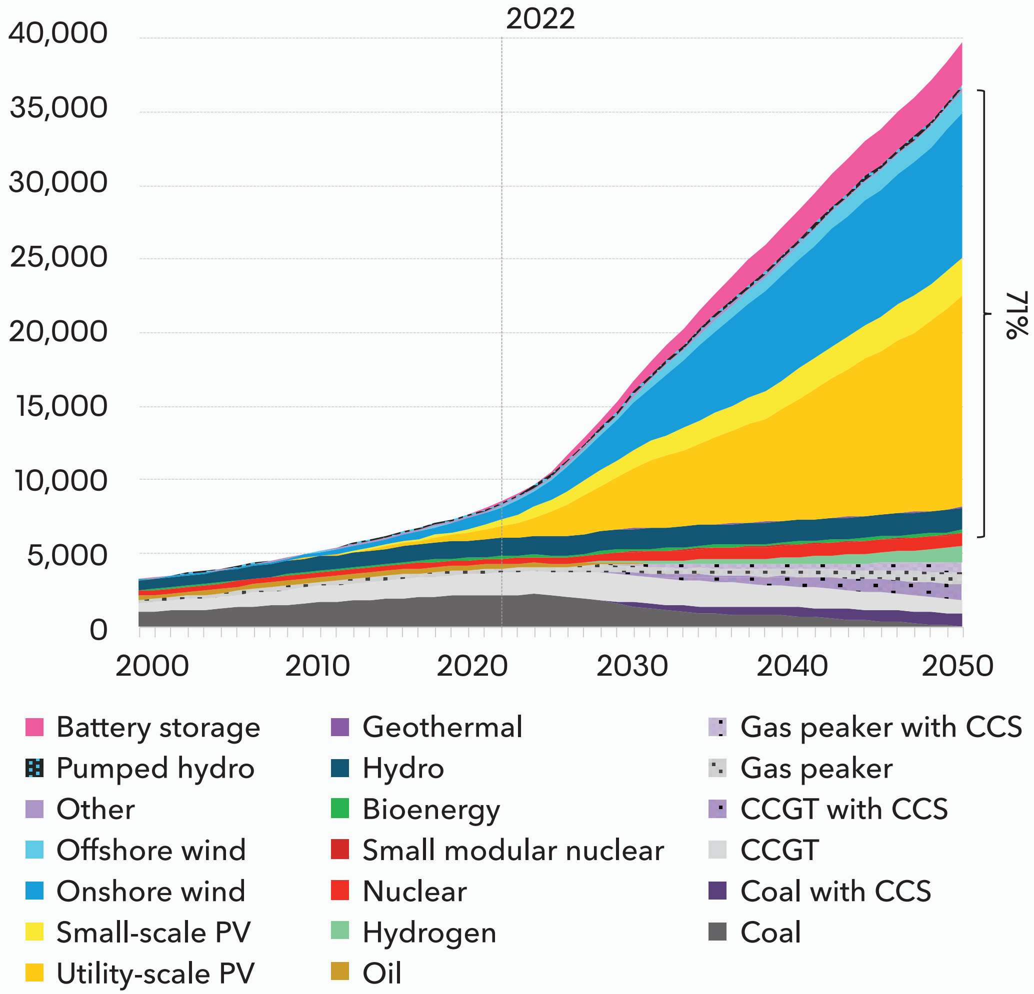
Solar and wind capacity additions exceeded 50% of annual global net capacity additions in 2017. Under BNEF's Net Zero Scenario, solar and wind would account for 71% of global power capacity in 2050.

Global share of net capacity addition by technology



Source: *BloombergNEF*

Global power capacity, Net Zero Scenario



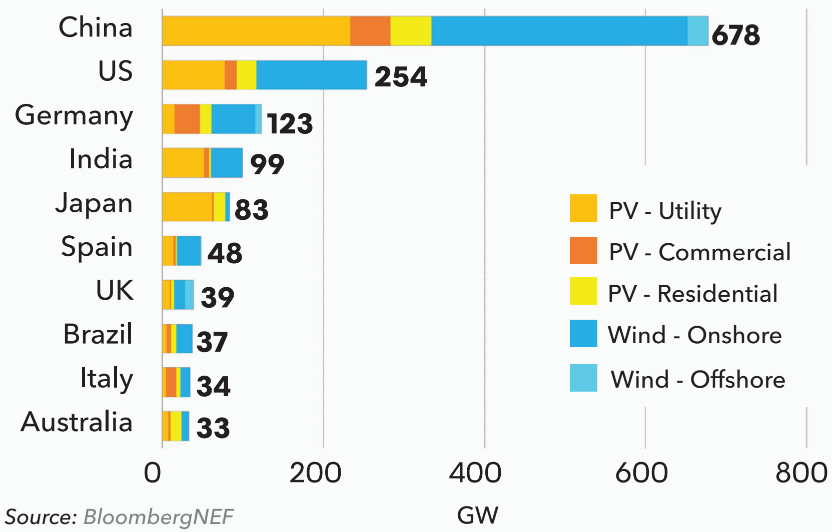
Source: *BloombergNEF New Energy Outlook 2022*

BloombergNEF

System integration of solar and wind

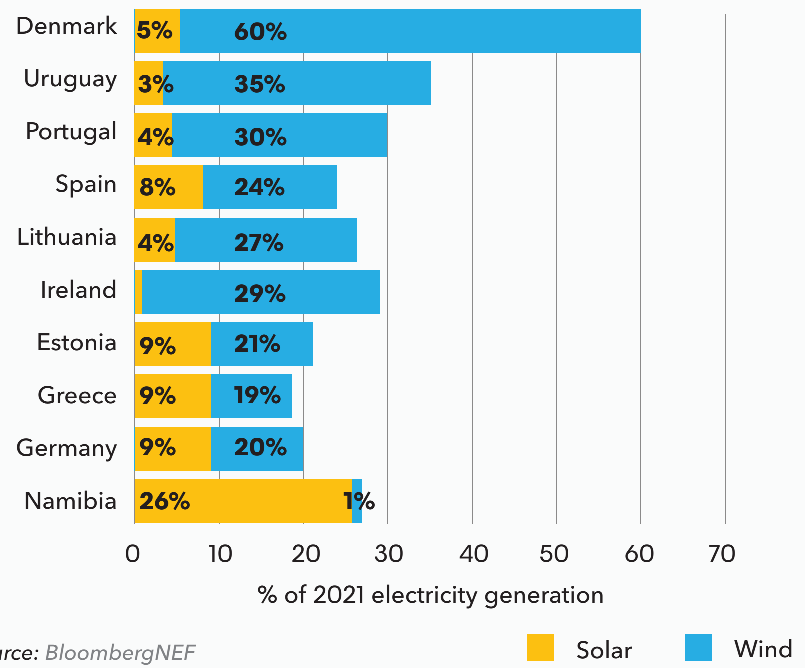
The variability of solar and wind electricity generation often raises operational concerns, as most power markets have been organized around dispatchable thermal power plants. However, as system flexibility becomes a defining characteristic of power systems operations, software and hardware solutions already exist to integrate renewables.

Top-10 countries with the highest installed wind and solar capacity in 2021



Source: BloombergNEF

Top-10 countries with highest wind and solar annual generation share, 2021



Source: BloombergNEF

Solar and wind already contribute more than a quarter of annual electricity generation in a variety of countries.

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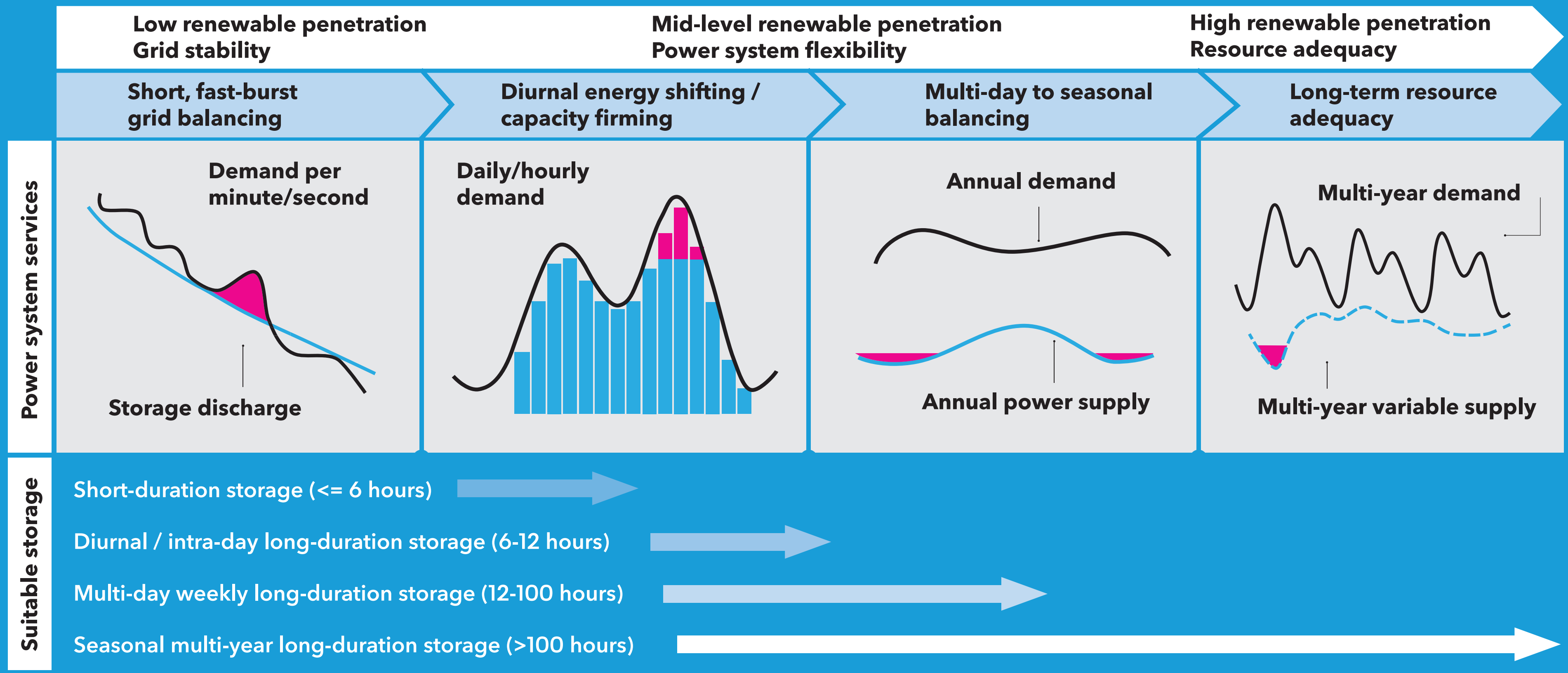
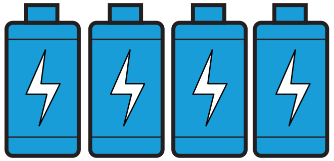
System integration of solar and wind

Different balancing duration required



Source: BloombergNEF

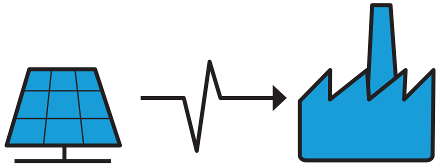
System integration of solar and wind



Batteries

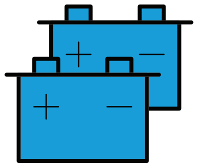
The fast response ability of batteries – in particular lithium-ion batteries – makes them well-suited to smooth the variability of wind and solar. These include applications such as frequency control as well as hourly energy shifting. By the end of 2022, BloombergNEF estimates that over 16GW/35GWh of energy storage systems were using batteries globally.

Batteries can store excess electricity generation from renewables during times of low demand and/or high local grid congestion, and then discharge the stored electricity during times of higher demand and/or lower grid congestion. In this manner, they help system operators and renewable project owners by reducing the need for curtailment, while reducing overall electricity system costs by improving grid utilization.



Supply and demand side management

Variable renewable generation, while variable, is not unpredictable. The deployment of load and generation forecasting tools can help reduce the uncertainty from variable renewable energy generation and aid in grid operations. Use of controllable load assets such as virtual power plants, demand response and interruptible load schemes can help stabilize the grid and provide additional flexibility.



Long-duration energy storage systems

High penetration of renewables calls for flexibility sources over different timescales, from milliseconds to multi-year capacity. Compared to short-duration batteries, long-duration energy storage systems such as pumped hydro and compressed air storage can provide a wider suite of grid services.

Most of the technologies are, however, still much more expensive than lithium-ion batteries and may struggle with low economic viability today.

Technology options to reduce emissions from thermal generation

In the power sector, the most direct and cost-efficient way to mitigate emissions is through the scaling up of renewable energy, a solution that can be deployed now.

What is co-firing or blending of fuels?

Coal power plant

Co-firing of coal with cleaner alternative fuels refers to the replacement of a portion of the coal used for power generation with ammonia or biomass.

Gas power plant

Blending of hydrogen involves the injection of hydrogen into the natural gas fed to the gas turbine.

At low levels of co-firing or blending, limited modifications to the existing thermal power plant are required. However, at such low levels, there is minimal emission reduction.

Co-firing coal with ammonia or biomass and the blending of hydrogen with natural gas can be discussed in terms of a volume ratio or energy ratio. Each fuel has a different volumetric energy density. The cleaner fuels (hydrogen, ammonia and biomass) all have lower volumetric energy densities than fossil fuels. As a result, a higher volume of cleaner fuels is needed to replace the same amount of energy produced by consuming fossil fuels.

During electricity generation, the average emission factor for a coal power plant is around 0.9 tCO_2/MWh, whereas the average emission factor for a combined cycle gas turbine (CCGT) is around 0.4 tCO_2/MWh. For the coal power plant to achieve a lower emission factor than the CCGT, it would have to co-fire ammonia with coal at an energy content ratio higher than 50% (or about 80% volumetric blend ratio).

During electricity generation, renewables have zero emissions, making them the best choice for lowering power sector emissions.

Some countries and companies are considering reducing emissions from fossil-fueled thermal power plants by switching to non-carbon fuels such as hydrogen and/or installing carbon capture and storage (CCS).

These strategies are dependent on the commercial scale-up of complex nascent technologies, and the establishment of new global supply chains.

These strategies would also have to compete for carbon storage capacity and clean fuels with other applications such as aviation and shipping, which have fewer alternative pathways to decarbonization.

Technology options to reduce emissions from thermal generation

Options

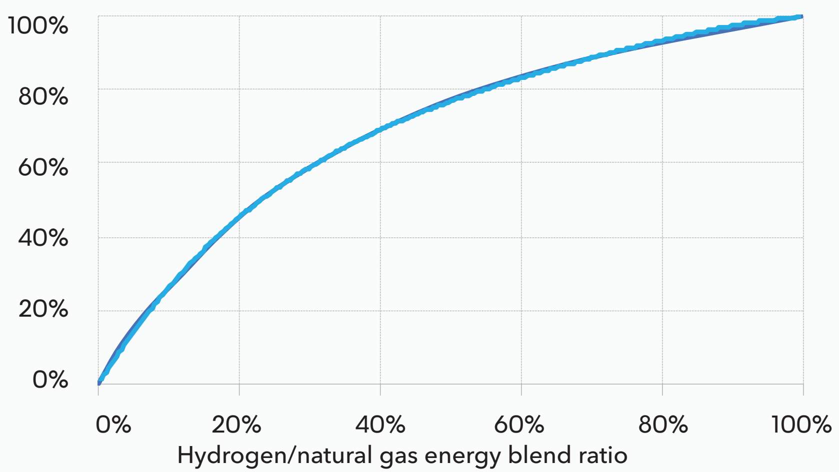
Co-firing coal with ammonia (NH3)

Blending gas with hydrogen (H2)

Co-firing coal with biomass

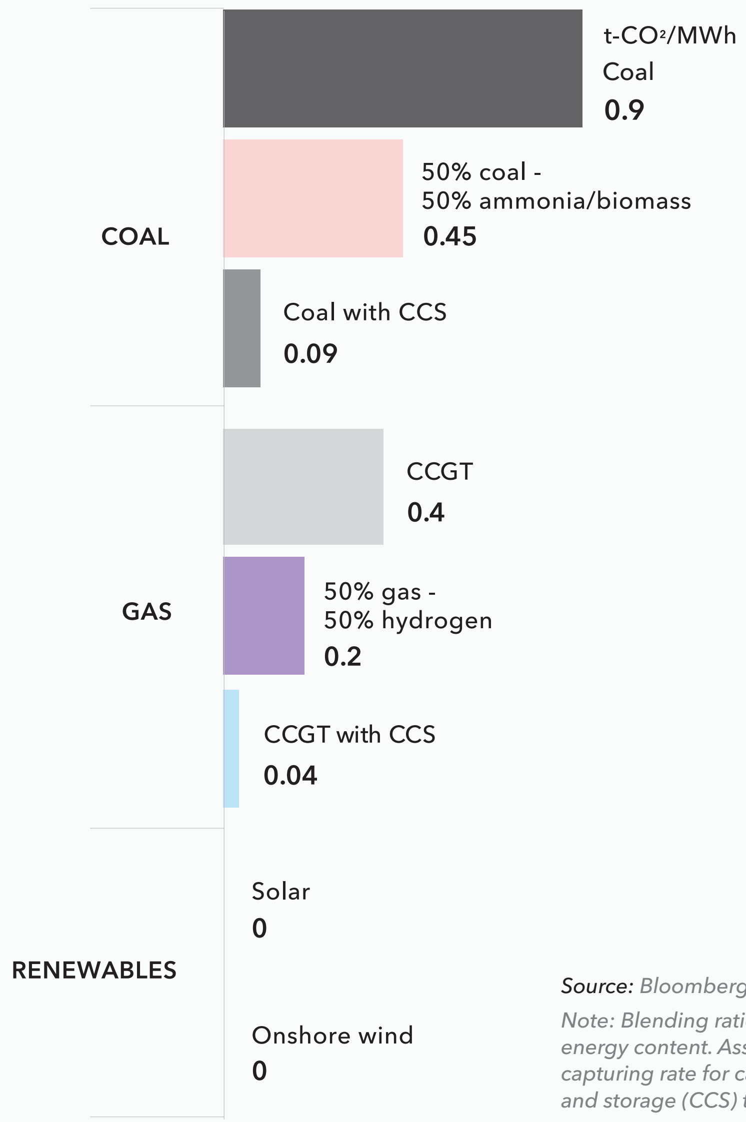
Carbon capture and storage (CCS)

Relationship between energy and volume for hydrogen blending



Source: *BloombergNEF, GE Power to Gas: Hydrogen for Power Generation*

Average emissions intensity of various power generation technologies during operation



Source: *BloombergNEF.*

Note: Blending ratio is based on energy content. Assuming 90% capturing rate for carbon capture and storage (CCS) technologies.

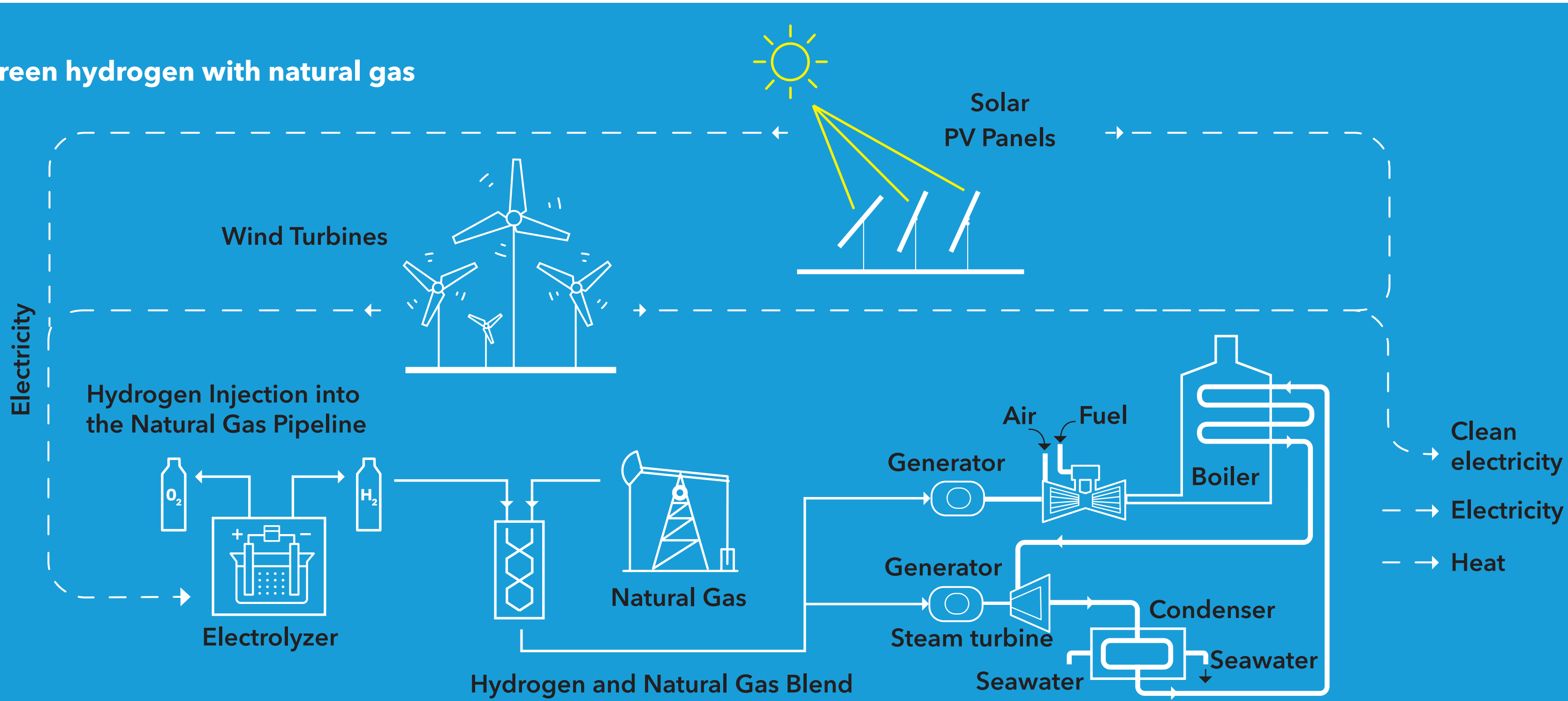
Retrofitting gas power plants for hydrogen

Blending hydrogen with natural gas as a lower carbon fuel for combined cycle gas turbines (CCGT) is under consideration by some countries and companies. To achieve zero-emission, the CCGT would need to be capable of handling 100% hydrogen fuel.

The hydrogen fuel would also have to be produced in an emission-free manner. Hydrogen leakage during the production, transport and consumption would also have to be minimized, as hydrogen is an indirect greenhouse gas, with significantly higher global warming potential than carbon dioxide.

Significant investment would be required to retrofit existing CCGTs to make them compatible with high concentrations of hydrogen fuel. Additionally, the production, transport and storage of clean hydrogen would require significant new investment.

Blending of green hydrogen with natural gas



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Retrofitting gas power plants for hydrogen

Hydrogen labeling

The hydrogen industry uses labels such as green and blue as shorthand for how hydrogen is made. Production methods differ on the volume of greenhouse gases they emit. The most common hydrogen labels are:

GREEN

Made via electrolysis of water using renewable electricity – this releases few or no greenhouse gas emissions.

BLUE

Made via steam reforming of methane or gasification of coal coupled with CO2 capture and storage (CCS) – this releases more emissions than green hydrogen, but less than gray.

GRAY

Made via steam reforming of methane or gasification of coal without CCS – the most common method today. Large volumes of CO2 are released.

Where can hydrogen be more suitable for decarbonization?

Decarbonization of ammonia production

Production of green ammonia from clean hydrogen can be used to decarbonize the production of fertilizers and the agriculture sector, as well as decouple fertilizer prices from natural gas prices.

Decarbonization of hard-to-abate sectors

Clean hydrogen could be deployed in heavy industrial sectors where direct electrification is challenging or impossible, such as methanol production, steel and aluminum production, shipping and aviation as well as providing peaking power.

Risks and considerations for blending hydrogen with natural gas

Fuel and infrastructure cost

Seaborne transport of hydrogen will be significantly more expensive than LNG, regardless of type of hydrogen carrier used. The process would also require new shipping infrastructure.

Impact on power tariffs

The higher fuel costs would lead to higher power tariffs, risking energy affordability especially in emerging economies.

Emissions reduction benefit

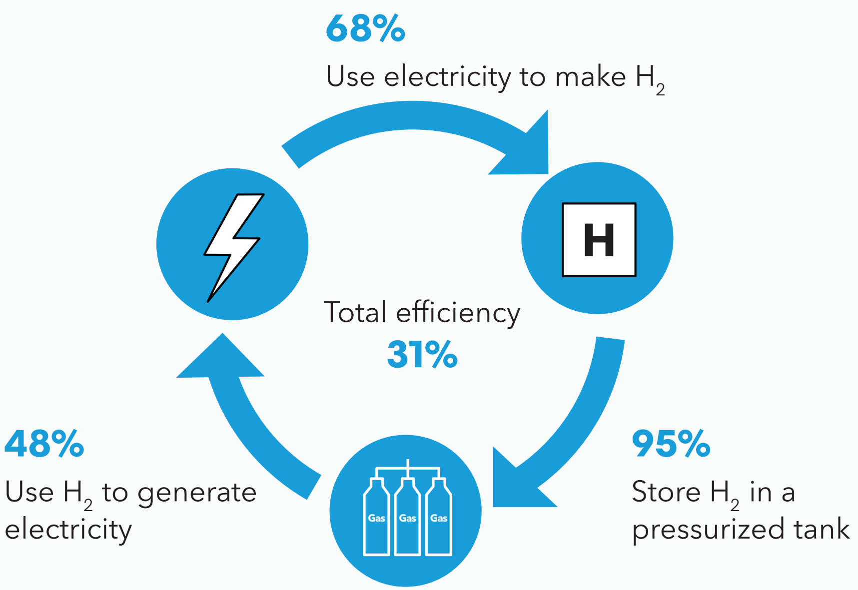
Due to the lower volumetric energy density of hydrogen, tangible emissions reduction is only possible at blending ratios above 50% even for green or blue hydrogen. This necessitates procurement of a large volume of hydrogen which will be costly. Additionally, CCGTs running on high hydrogen blend rates are still in the development phase.

Safety

Similar to natural gas, hydrogen is also highly flammable. Due to its smaller molecular size, lack of odor and color, detecting hydrogen leaks can be more difficult. Due to hydrogen embrittlement, much of the existing natural gas pipeline infrastructure cannot be used for high concentrations of hydrogen.

Retrofitting gas power plants for hydrogen

Round-trip efficiency of electrical storage via hydrogen



Source: BloombergNEF.

Generating electricity from hydrogen is less efficient than using electricity from renewable energy power plants directly.

The low round-trip efficiency of using clean power to first produce hydrogen, and then use the hydrogen in a CCGT to produce electricity, means such an approach is not economically viable.

For the same amount of power generation, 3-5 times the solar capacity is needed to produce the required hydrogen as compared to direct use of the renewable electricity.

Using a limited quantity of clean hydrogen to fuel open cycle gas turbines providing back-up services in a renewable-heavy grid may become economically viable in the future. However, the high volume of fuel that CCGTs consume means using clean hydrogen to decarbonize 'baseload' power plants will not become economic.

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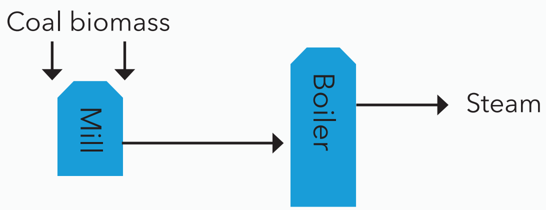
Retrofitting coal power plants for co-firing

Co-firing of coal with biomass

Co-firing of coal with biomass involves a partial substitution of the coal used for power generation with biomass through direct co-firing, or gasification of biomass or parallel co-firing. Biomass co-firing has been widely deployed in many markets including the US and Europe. The substitution with biomass reduces greenhouse gas emissions compared to pure coal-fired power generation.

Direct co-firing

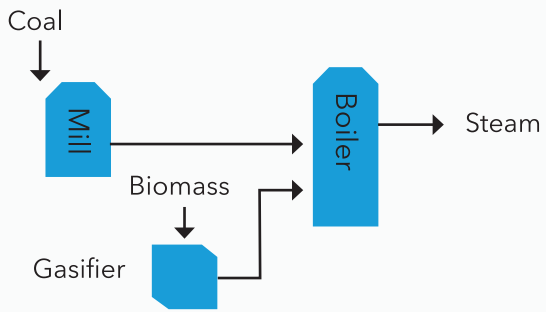


Biomass is processed (if required), mixed with coal and fed directly into the boiler.

This requires the fewest modifications. At low levels of blending, only a small upgrade such as a new covered silo storing feedstock is needed.

Direct co-firing of coal with biomass, however, could lead to slagging and fouling due to ash production, resulting in a limitation in the range of co-firing proportions.

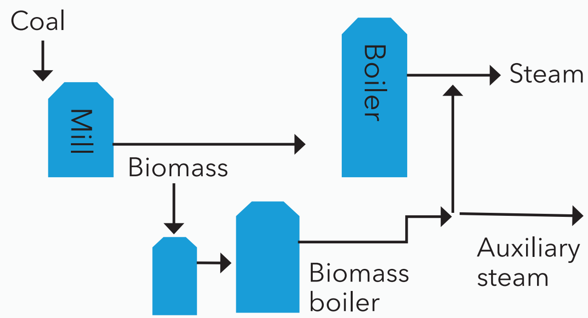
Gasification of biomass



Solid biomass is converted into synthesis gas in a gasifier, which is then injected into the boiler to be used for power generation.

This reduces the slagging as biomass is not fed directly into the boiler. However, a separate gasifier is required to be installed, increasing retrofit costs.

Parallel co-firing



Biomass is processed and combusted in a separate boiler to produce steam, which is then used for electricity generation in the coal power plant.

This technology could achieve higher co-firing ranges but will be the costliest due to the need for additional infrastructure builds. The feasibility of the retrofit will also be subject to the existing site's design.

Retrofitting coal power plants for co-firing

Risks and considerations

Suitability of biomass feed-stock

The type of suitable biomass and processing required on the feedstock (e.g. particle size) will vary by the coal combustion technology of the power plant.

Sustainability considerations

Biomass is often considered emissions-neutral. There is, however, rising scrutiny on the quality of biomass fuel supply, including the sustainability and environmental aspects of the biomass fuel sources, including deforestation concerns.

Logistics

Economic feasibility of co-firing of coal with biomass can vary by project and its location. The lower energy density of biomass by volume compared to fossil fuels results in higher logistical costs.

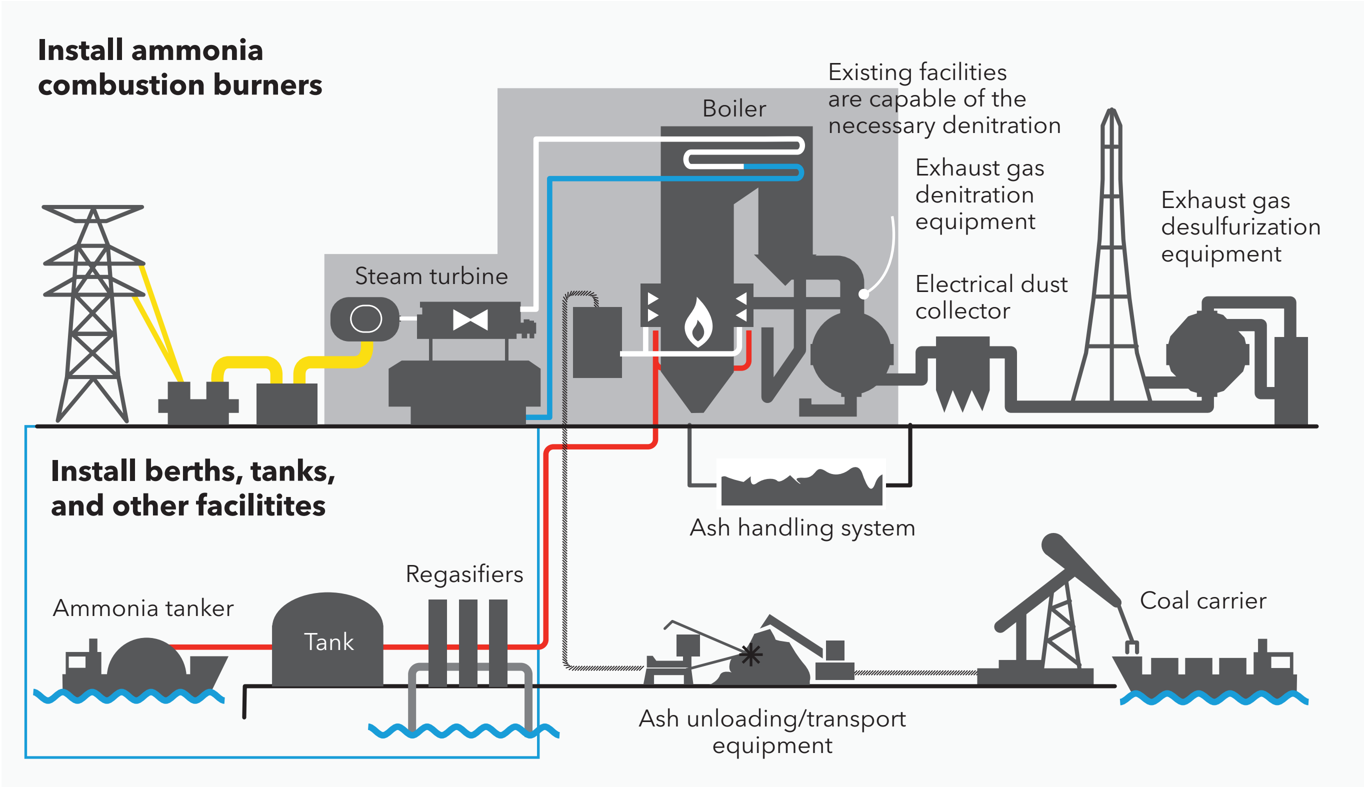
Co-firing of coal with ammonia

Co-firing of coal with ammonia refers to the partial substitution of the coal used for power generation with ammonia. To date, commercial coal power plants have not yet been tested for co-firing with ammonia at energy ratios above 20%.

A higher ammonia co-firing ratio requires higher capital expenditures for upgrading for the coal plant's boilers, as well as onsite storage of ammonia and more advanced equipment to capture nitrogen oxide emissions.

Ammonia is often referred to as a "low-carbon" fuel as it produces no carbon emissions during combustion. The actual emissions reduction benefit from co-firing coal with ammonia is dependent on the type and production source of the ammonia.

Gray ammonia derived from hydrogen produced from unabated fossil fuels will only reduce emissions slightly, even at a 100% co-firing ratio. The technology is also often criticized as a lifetime extension for coal power plants.



Retrofitting coal power plants for co-firing

Ammonia labeling

The hydrogen industry uses labels such as green and blue as shorthand for how hydrogen is made. Production methods differ on the volume of greenhouse gases they emit. The most common hydrogen labels are:

GREEN
Derived from hydrogen produced via electrolysis of water using renewable electricity.

BLUE
Derived from hydrogen produced via steam reforming of methane or gasification of coal coupled with carbon capture and storage (CCS).

GRAY
Derived from hydrogen produced via steam reforming of methane or gasification of coal without CCS – the most common method today that releases large volumes of carbon emissions.

Where could ammonia be more suitable for decarbonization?

Displacement of fossil-fueled based ammonia

Ammonia is the foundational compound for fertilizers, which make mass food production possible. Worldwide, 81% of ammonia produced is used for this purpose, while the rest is used for industrial processes. Green ammonia can be used to decarbonize the production of fertilizers and the agriculture sector, and decouple fertilizer prices from natural gas prices.

Decarbonization of hard-to-abate sectors

Ammonia could be deployed in heavy industrial sectors where direct electrification is challenging or impossible, such as shipping and aviation.

Risks and considerations for co-firing of coal with ammonia

Fuel cost

BNEF's current analysis suggests that the blended fuel costs of coal and ammonia are more costly than the coal fuel price even at low levels of co-firing ratios. For imports of ammonia, logistical costs (shipping, storage and conversion costs) have a great impact on the final delivered costs. Currently, these costs could more than double the final landed cost of ammonia compared to the production costs of hydrogen.

Impact on power tariffs

The higher fuel costs would lead to higher power tariffs, risking energy affordability especially in emerging economies.

Emissions reduction benefit

Due to the lower volumetric energy density of ammonia, tangible emissions reduction is only possible at co-firing ratios above 50% even for green and blue ammonia. This necessitates procurement of a large volume of ammonia, which will be costly.

Safety

Ammonia is highly flammable and explosive with heat. The toxicity of ammonia necessitates careful storage of the fuel as the molecules could pose a big threat to human health. The molecule reacts with water to form ammonium hydroxide, which is corrosive and damages cells in the body on contact. While ammonia leaks are easier to detect due to its odor, contact with ammonia could be fatal.

Carbon capture and storage

Retrofitting an existing thermal power plant with CCS can be costly depending on proximity to carbon storage site. Current CCS technologies also do not capture 100% of emissions.

Considerations for carbon capture and storage

Technical feasibility

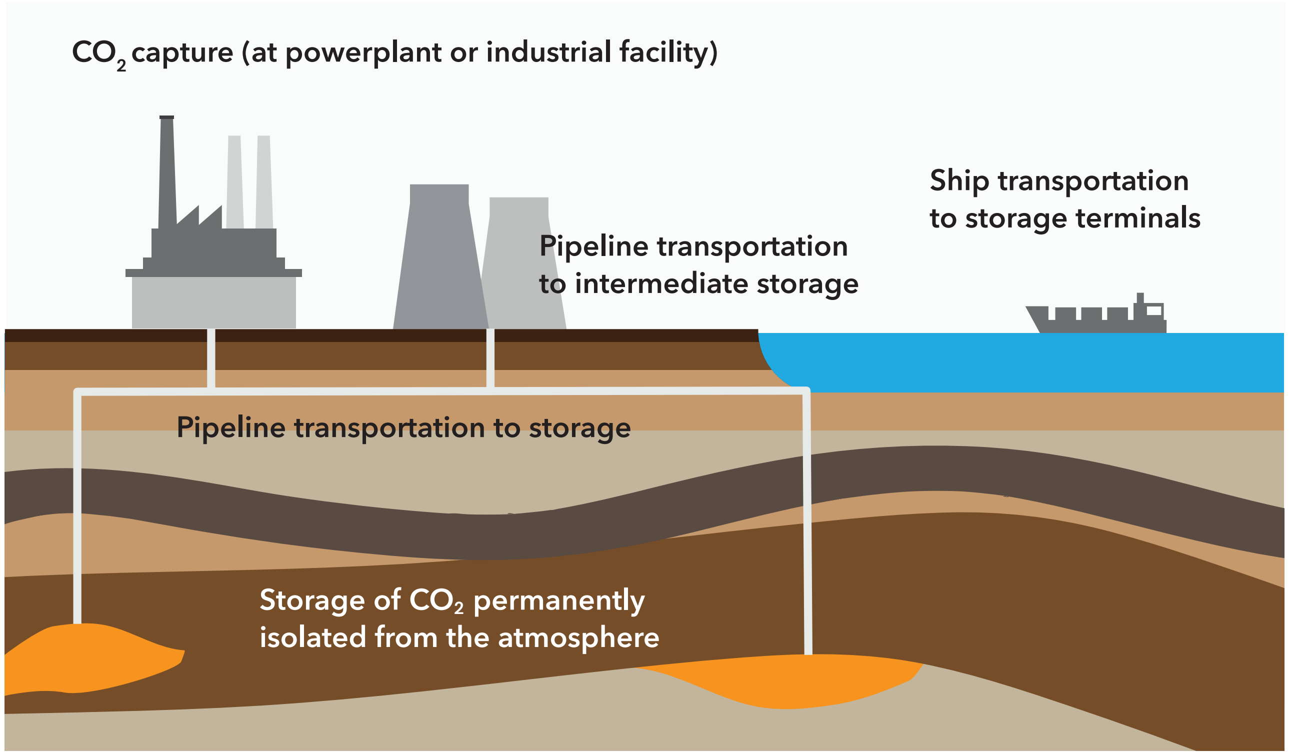
The original site of an existing thermal power plant would have been designed to meet the initial design specifications. There could be technical and logistical complexity of adding an additional system to the site. Not every thermal power plant can be economically retrofitted with CCS due to these constraints.

Availability of carbon storage sites

Implementation of the technology requires the availability of carbon storage sites such as depleted oil and gas fields or saline aquifers at appropriate depths.

Performance

A carbon capture and storage project typically targets a 90% carbon capture rate. However, the capture rates for existing projects have been lower than 90%.



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