TransitionZero

Coal-de-sac

The role of advanced coal technologies in decarbonising Japan's electricity sector

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About TransitionZero

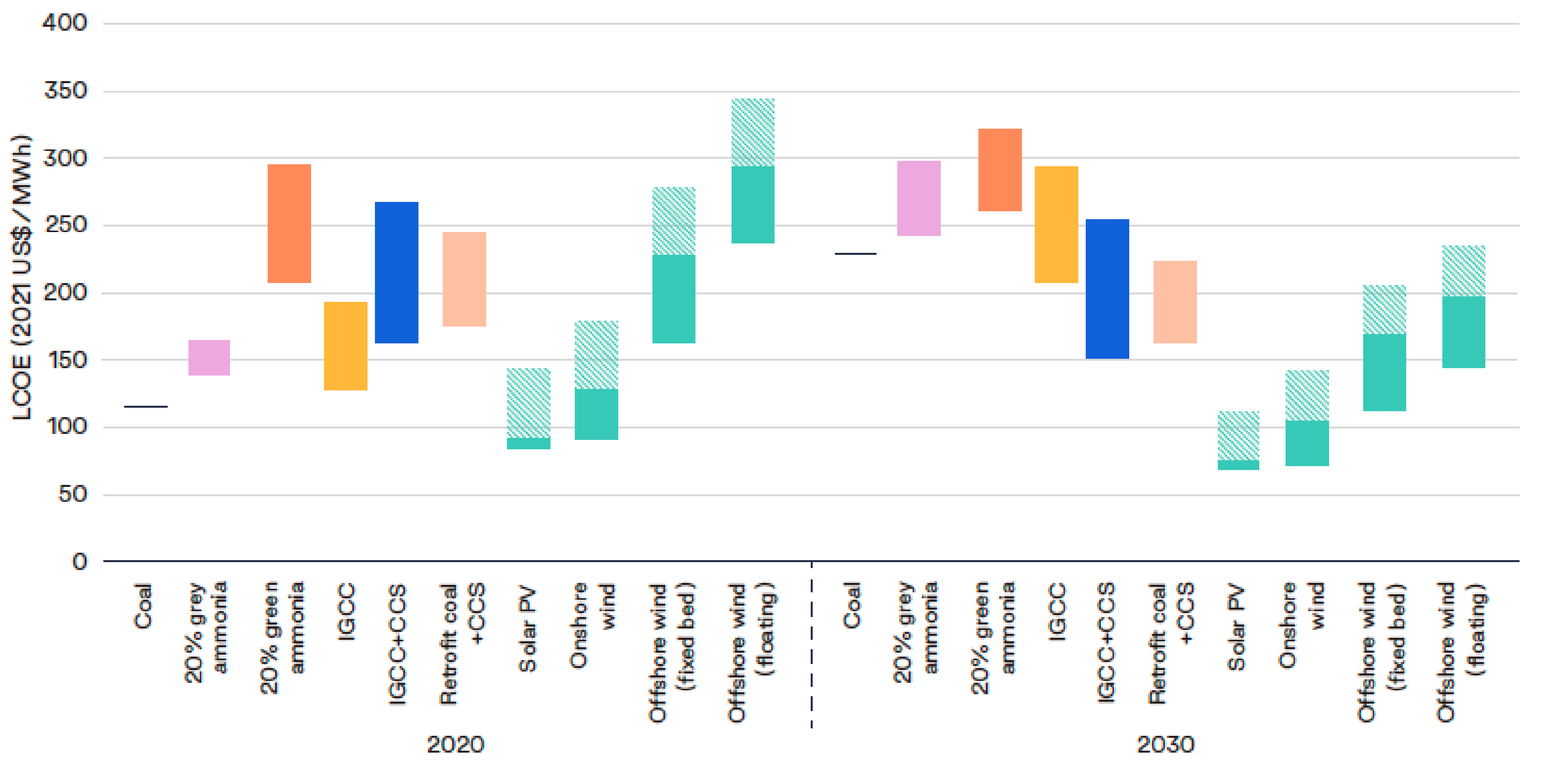
TransitionZero is a climate analytics not-for-profit established to clarify complexity with data transparency. We do this by developing open data and open source projects to support economic and financial decision making in electricity and industry sectors.

The work of TransitionZero has been made possible by the vision and innovation shown by Quadrature Climate Foundation, Generation Investment Management, Google.org and Bloomberg Philanthropies.

Executive Summary

Independent of climate considerations, advanced coal is high cost

Figure 1.1 *LCOE estimates across technologies, 2020-2030*

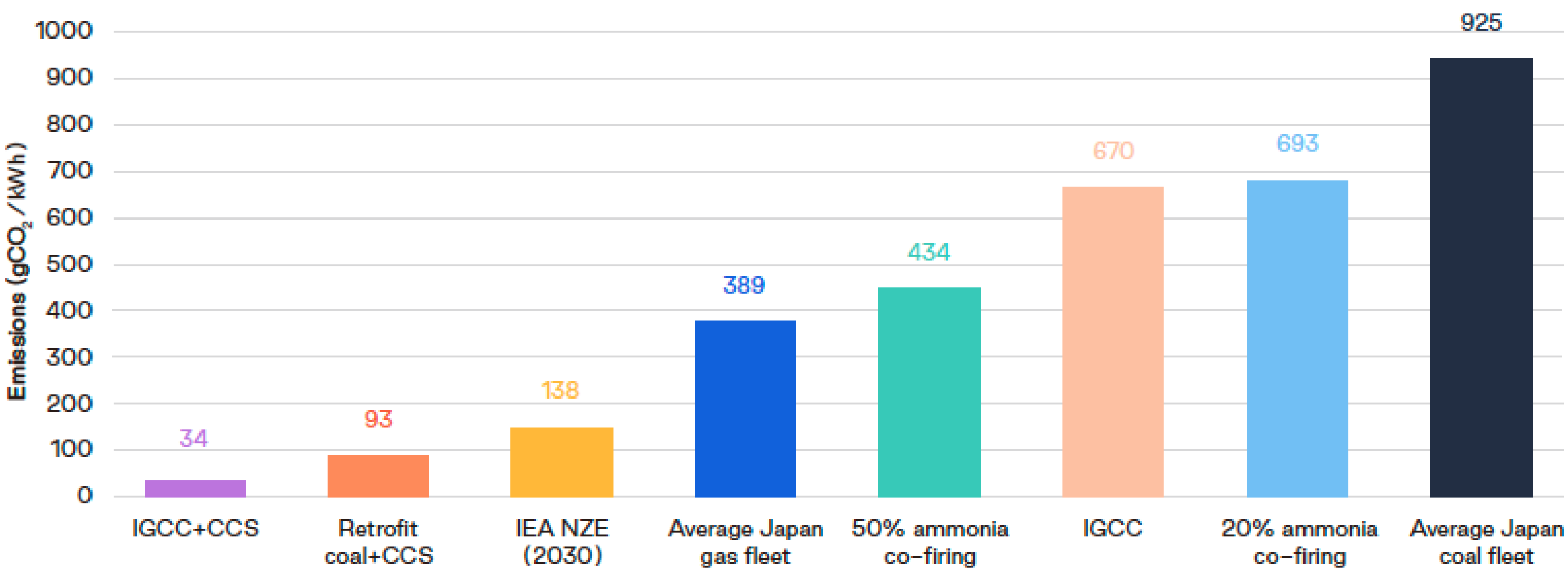


Source: TransitionZero

Note: A carbon price of US$5/tCO$_2$ and US$130/tCO$_2$ was assumed in 2020 and 2030, respectively. The 2030 carbon price is in line with IEA's NZE scenario. The shaded green bars represent the cost of storage, which is sized using half the power rating of the installed RE capacity, with a 4 hour duration.

Advanced coal technologies are inconsistent with a net-zero outcome

Figure 1.2 *Emissions reduction potential of advanced coal technologies*



Source: TransitionZero

CCS in Japan has considerable technical challenges

Limited CO_2 storage sites

- *Economic potential for CO_2 storage may **run out within a decade**, assuming all emissions are captured*

Cost limitations

- *At the lower end, CCS systems add about **$39-65/MWh** to the generation cost, equivalent to about half of Japan's 2020 electricity price*.*

High energy penalty

- *The efficiency penalty of CCS-equipped thermal plants may be **up to 25%,** meaning a quarter of the electricity produced is consumed within the plant.*

Source: TransitionZero
*Note: *Japan electricity price is the JAPEX day ahead price.*

Coal after COP26: Will Japan be the last major economy standing?

Figure 1.3 *Technological choice for Japan: advanced coal technologies or renewables?*

There is a growing international effort to phase down coal power in alignment with a 1.5°C goal.

Based on TransitionZero analysis, aligning global coal generation with a 1.5°C goal would require closing or repurposing nearly 3,000 coal units between now and 2030.

Japan's insistence on leaving the door open for advanced coal looks increasingly divorced from economic, climate and political realities.

Setting the scene

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Japan’s 2030 climate ambitions and carbon neutrality by 2050 goal

In April 2021, the former Japanese Prime Minister, Suga Yoshihide, announced an increase in climate ambition, to a *46-50% emissions reduction from 2013 levels by 2030*.

Alongside the increased 2030 climate ambitions, Japan has a long-term climate target to be **net-zero by 2050**.

To meet the coming 2030 goal, action over the next few years will be vital to *deliver the early emissions reductions required*.

Investments need to look to pave the way for technological breakthroughs to **unlock additional emissions reduction potential** to meet its net zero by 2050 target.

Figure 2.1 *Prime Minister FumioKishida speaking at COP26*

Ammonia co-firing

Key takeaways

01

Ammonia is high cost

- At present, 20% co-firing of the cheapest grey ammonia is set to double the fuel costs compared to coal.
- Co-firing ammonia with coal will only start to make financial sense in 2040, at a high carbon price of US$205/t$CO_2$.

02

Ammonia is high carbon

- At a 20% co-firing ratio, the emissions factor of ammonia co-firing is about five times what is needed to align with a net zero pathway
- Unless blue and/or green ammonia is utilised, there is no net emissions reduction from co-firing.

03

Ammonia's alternate use

- Despite its poor suitability in the power sector, ammonia has many other uses in the low-carbon economy, particularly in the transport and hard to abate industrial sectors.

Different shades of ammonia

Figure 3.1 *Different shades of ammonia*

Grey/brown ammonia	Blue ammonia	Green ammonia	Greener ammonia
■ Produced using Haber-Bosch process ■ Fossil fuel as feedstock for hydrogen	■ Produced using Haber-Bosch process ■ Fossil fuel as feedstock for hydrogen, but emissions captured using CCS	■ Produced using Haber-Bosch process ■ Hydrogen from electrolysis, powered by solar/wind	■ Novel ammonia synthesis process intended to replace energy intensive Haber-Bosch process

Source: TransitionZero

Note: Only blue and green ammonia can only be considered low or zero carbon fuel.

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Ammonia use in the power sector

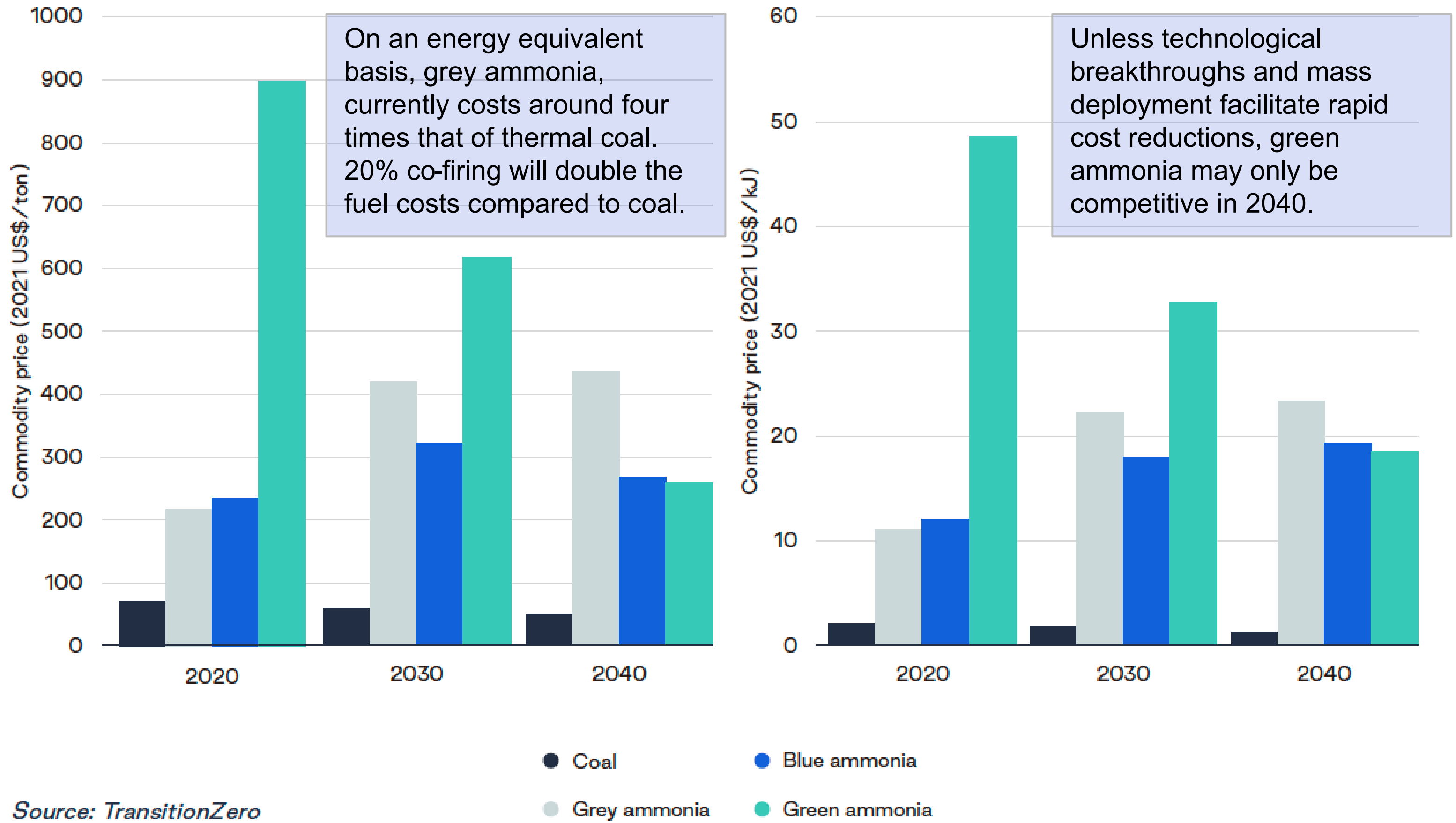
The Japanese government, with the support of industry players, have strongly pushed ammonia co-firing as a key abatement technology for coal in the power sector. Based on current technical constraints, *a co-firing ratio of 20% of ammonia with coal (based on energy content)* is considered technically feasible.

As the co-firing with ammonia ***does not require major retrofits in the existing coal plants***, this strategy is favoured by many Japanese utilities, due to the limited capital outlay.

Japanese government aims to achieve 50% ammonia co-firing with coal by 2030, alongside the goal of importing three million tons of ammonia by the same timeframe.

The first challenges of commercialising ammonia co-firing: high cost

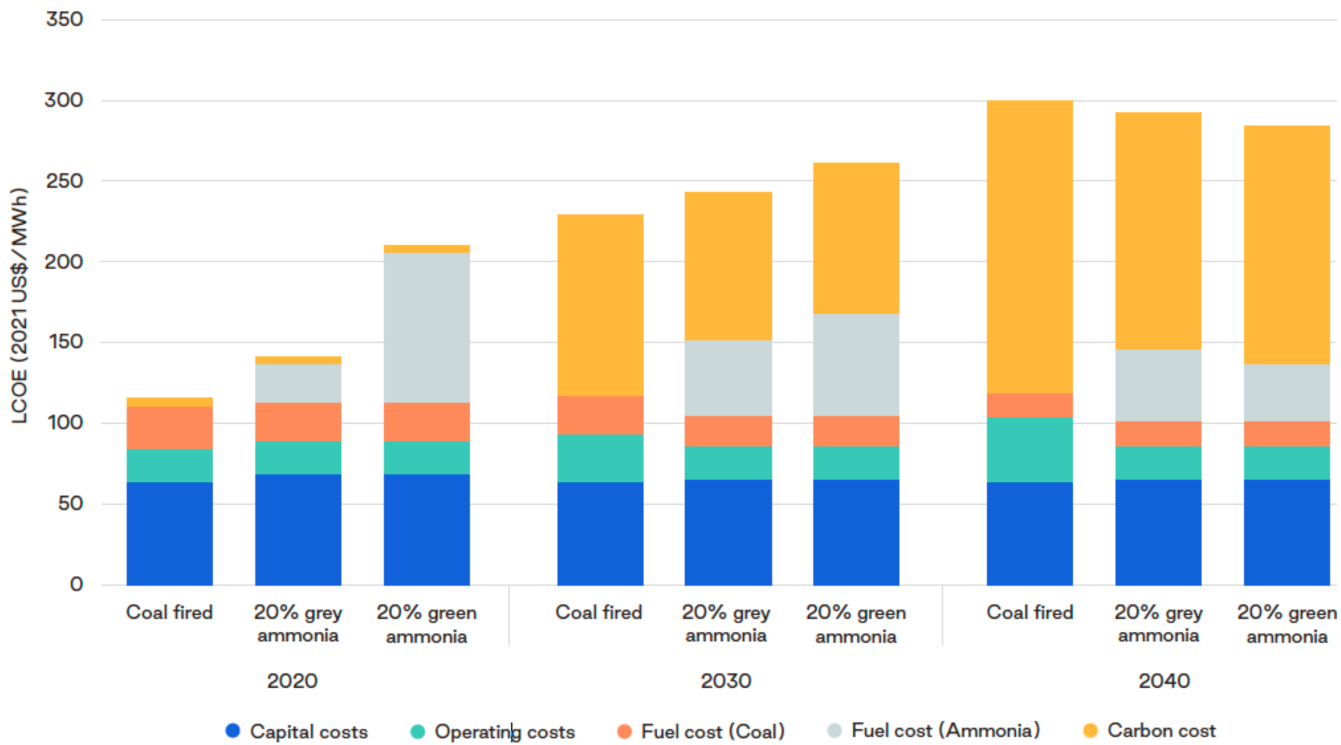
Figure 3.2 *Ammonia price forecast*



Source: TransitionZero

Ammonia co-firing delivers neither financial nor climate benefit

Figure 3.3 *Cost breakdown for ammonia co-firing in power generation*



Source: TransitionZero

Note: The carbon cost refers to the carbon costs associated with power generation in Japan, which stands at US$130/t$CO_2$ in 2030 and US$205/t$CO_2$ in 2040, in line with IEA's NZE scenario. The carbon costs associated with upstream production of ammonia, varies according to geography of production sites, and are embedded in the fuel cost component as part of the costs of ammonia. The estimated carbon price ranges between US$15–130/t$CO_2$ and US$35–205/t$CO_2$ in 2030 and 2040, respectively, and are in alignment with IEA's NZE scenario.

Flat learning curve due to lack of international traction on ammonia use in power

Figure 3.4 *Sectoral priorities of national hydrogen strategies*

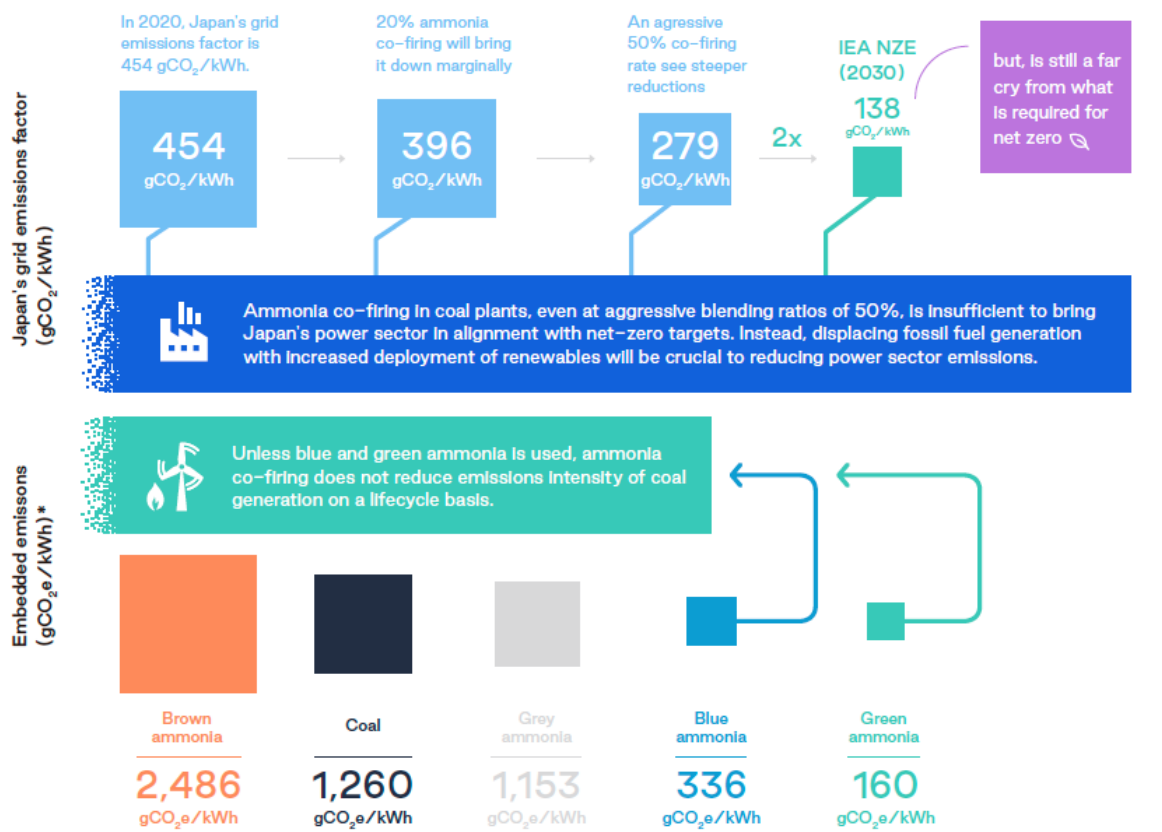
	Power generation		Industry					Transport		
Country	Power generation	Ancillary service	Iron and Steel	Chemical feedstock	Refining	Others (cement, etc)	Heating	Road transport	Maritime	Aviation
Australia	Low/No	Low/No	Medium	Immediate	Immediate	Low/No	Immediate	Immediate	Medium	Low/No
Japan	Immediate	Low/No	Medium	Immediate	Medium	Low/No	Immediate	Immediate	Low/No	Low/No
South Korea	Immediate	Low/No	Medium	Low/No	Low/No	Low/No	Low/No	Immediate	Low/No	Low/No
EU	Low/No	Low/No	Medium	Immediate	Immediate	Low/No	Medium	Immediate	Medium	Medium
France	Low/No	Low/No	Immediate	Immediate	Immediate	Immediate	Immediate	Immediate	Low/No	Immediate
Germany	Low/No	Low/No	Immediate	Immediate	Immediate	Low/No	Immediate	Immediate	Medium	Medium
Hungary	Low/No	Medium	Medium	Immediate	Immediate	Medium	Medium	Immediate	Low/No	Low/No
Netherlands	Low/No	Low/No	Immediate	Immediate	Immediate	Low/No	Immediate	Immediate	Low/No	Low/No
Norway	Low/No	Low/No	Medium	Immediate	Medium	Low/No	Low/No	Medium	Immediate	Low/No
Portugal	Low/No	Low/No	Immediate	Immediate	Immediate	Immediate	Immediate	Immediate	Medium	Medium
Spain	Low/No	Low/No	Medium	Immediate	Immediate	Medium	Low/No	Medium	Low/No	Low/No
Chile	Low/No	Low/No	Low/No	Immediate	Immediate	Low/No	Immediate	Medium	Medium	Medium
Canada	Low/No	Low/No	Immediate	Immediate	Immediate	Immediate	Immediate	Immediate	Medium	Medium

Source: TransitionZero, adapted from World Energy Council (2021)[26]

● Immediate ● Medium ● Low/No

Ammonia co-firing

Despite claims, ammonia cofiring does little to reduce emissions



Source: TransitionZero

*Note: *The embedded emissions considers both the emissions associated with upstream production, midstream transport and downstream combustion. This estimate also includes non-carbon emissions as well. A thermal efficiency of 37% is used for all plants as there has yet to be consensus on the impact of co-firing ammonia on coal plant efficiency. The net emissions benefit of blue ammonia, specifically when the captured carbon dioxide is utilised for enhanced oil recovery (EOR), which supports further emissions downstream may also be put into question. However, for this piece of analysis, the downstream applications of CCS are not considered.*

Other concerns

Technical considerations

The burning of ammonia to generate electricity faces troubles in *maintaining a stable flame*, which has a direct impact on the *efficiency and performance* of the power plant.

Limited scale of co-firing demonstration at Hekinan Unit 4 (8% of estimated annual consumption) suggests that technology is **not yet commercially ready.**

Air pollution

Lower flame temperatures and flame instabilities can result in localised air pollution from *NOx emissions*, unburned ammonia which reacts with NOx and SO2 to form *secondary PM2.5* and *unburnt carbon in fly ash*.

While the demonstration plants and test pilots have not seen a significant increase in exhaust gas pollution, the **complexities in technical designs** of the plant means that there is still a ***high risk of localized air pollution***.

Energy security

The large price differential between domestic ammonia and international imports means that Japanese utilities have few options but to rely on cheaper imports, with *negative implications for Japan's energy security.*

Assuming a 20% co-firing rate, Japan will require about **20-25 Mt of ammonia every year** for use in the power sector, more than *20 times its current demand.*

Ammonia co-firing

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Alternate use of ammonia sees potential for deep decarbonisation

Ammonia in industrial furnaces (e.g. steel)

Ammonia in transport

Ammonia as petrochemicals feedstock

Ammonia in shipping

Ammonia in aviation

Coal gasification (IGCC)

Key takeaways

01

IGCC plants make for poor investment opportunities

- IGCC has a chequered past, which saw frequent cost blowouts and project cancellations.
- Cost reduction potential for IGCC plants are limited, due to challenges in scaling up plant capacity.

02

IGCC offers poor abatement potential

- Unless coupled with CCS, IGCC plants do poorly in reducing carbon emissions.

03

New-build coal plants

- Retrofitting IGCC with pre-combustion CCS is technically infeasible.

- Investing in IGCC means new coal plants, which is inconsistent with Japan's net zero ambitions, and may lead to stranded assets in the future.

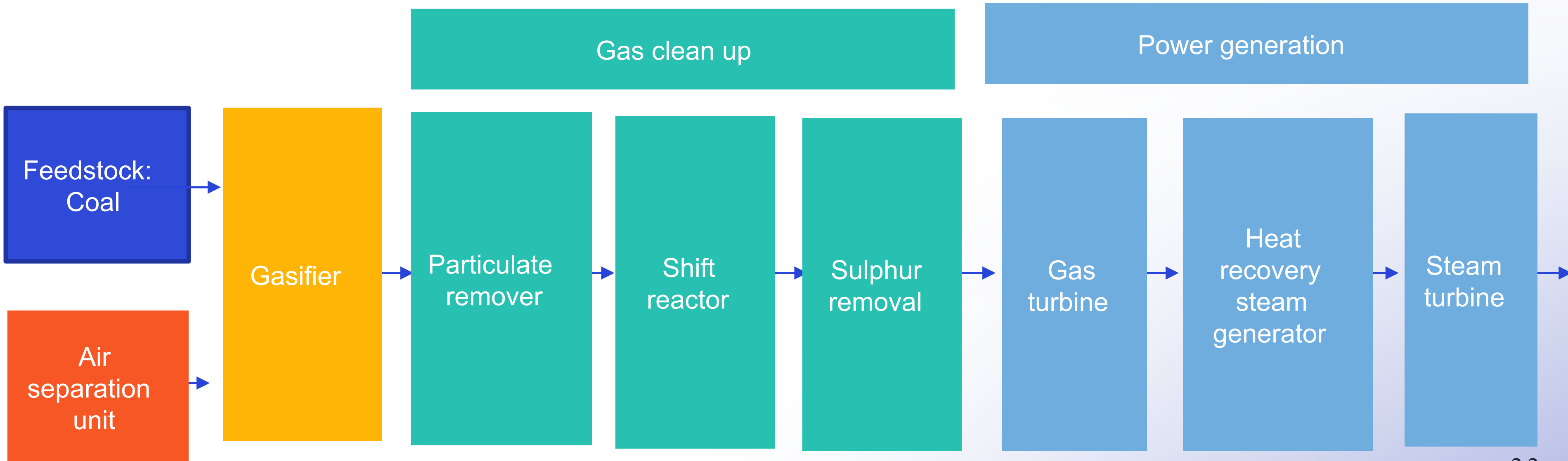
Coal gasification/IGCC

Basic set up of an IGCC plant

Integrated gasification combined cycle (IGCC) plants convert feedstock into synthesis gas, which is cleaned before burning in gas turbines to generate electricity.

IGCC plants have several advantages compared to traditional pulverized coal plants, including:

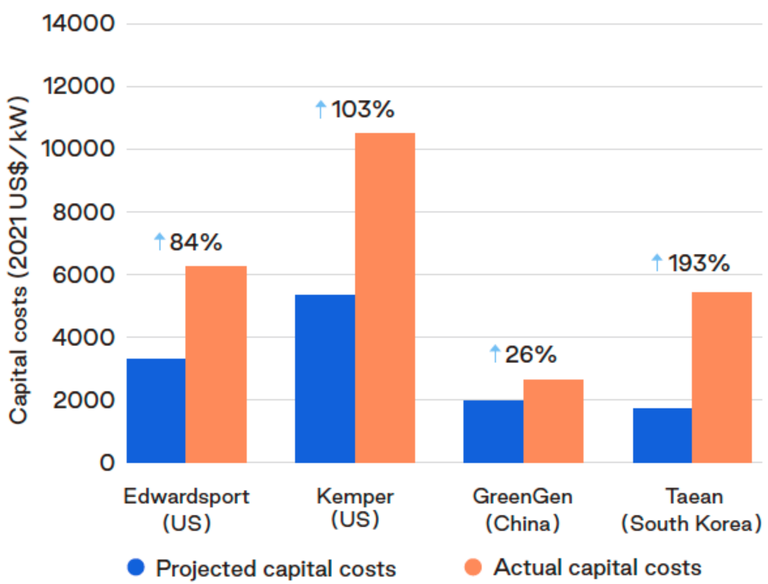
1. *Reduce air pollution*
2. *Higher thermal efficiency,*
3. *Greater coal quality flexibility*
4. *Easier/cheaper to integrate with pre-combustion CCS*



Source: *TransitionZero*

Chequered past with frequent cost blowouts

Figure 4.1 *Cost blow-outs for select IGCC projects*



Source: TransitionZero
Note: Kemper IGCC has higher capital costs due to its integration with CCS. GreenGen IGCC claimed to achieve lower capital costs due to the use of self-developed gasifiers instead of importing existing commercially available gasifiers. Thus, the result is hard to replicate. Despite GreenGen being touted as a success story, China did not build any new IGCC plants thereafter, possibly indicating that the technology has fallen out of favour.

Cost-overruns due to technical complexities of IGCC plants are one of the main contributors that led to the series of high-profile failures of IGCC plants.

Out of the 25 coal-gasification IGCC projects that were proposed in the US in early 2000s, only two projects were brought to completion.

Even for the projects that went ahead, budget overruns, sometimes to double that of original estimates, were common.

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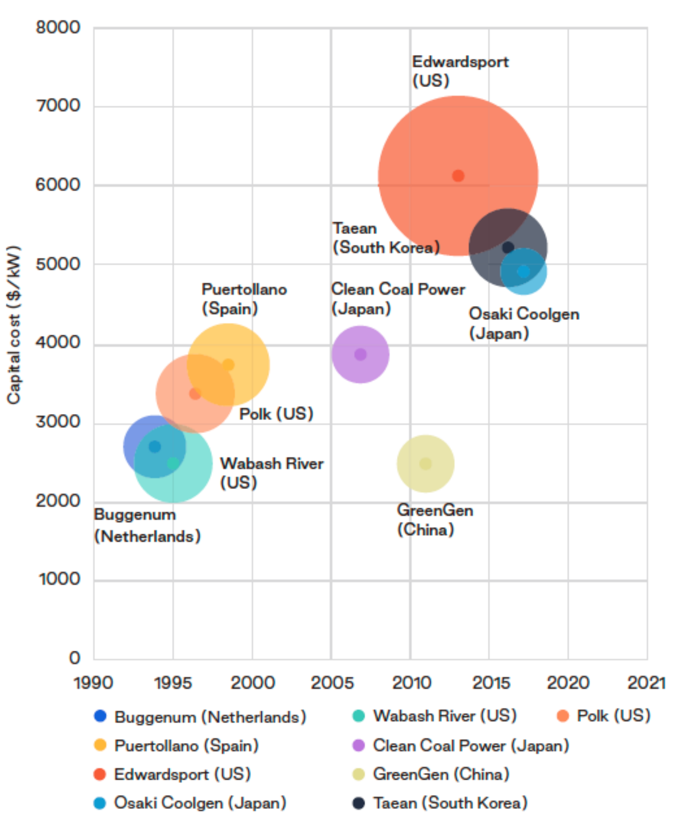
Flat learning curve: as projects get larger, the CAPEX per kW rises

Figure 4.2 *CAPEX of IGCC plants*



Source: TransitionZero
Note: The size of the bubble illustrates the size of the IGCC project. Kemper County IGCC is removed from this project list as it does not run as an IGCC plant and runs exclusively on gas.

Rising CAPEX/kW installed capacity poses significant challenges for scaling up deployment.

Anecdotal evidence from the ill-fated Edwardsport and Kemper County IGCC plants, both attempts to scale up from existing prototypes, illustrates the lack of transferability across different projects for IGCC plants.

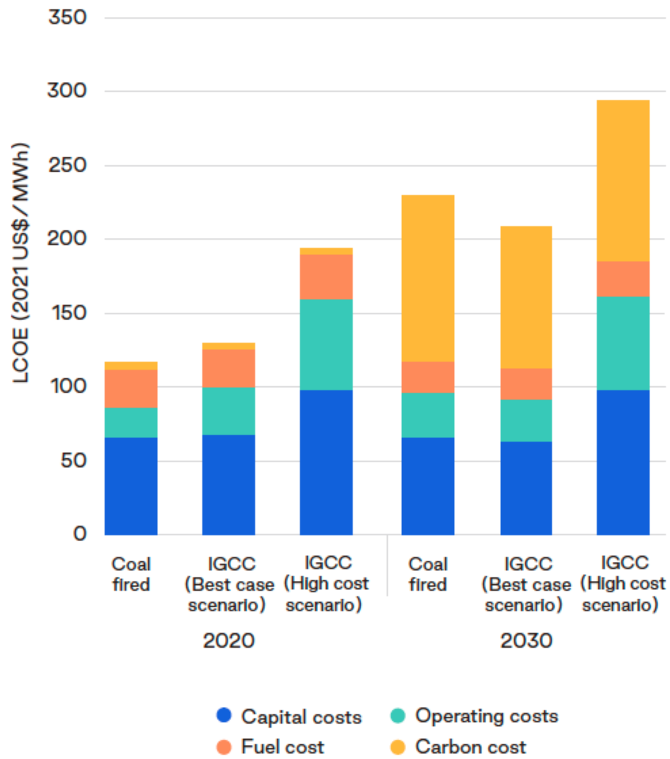
This leads to a rather **flat learning curve for the technology**, meaning that cost reductions are likely to remain low despite additional deployments.

IGCC is uncompetitive both as an abatement and power generation technology

Realistically, the cost of IGCC plants in Japan is likely to fall somewhere between the best-case scenario and the high-cost scenario.

Due to poor emissions reduction potential of IGCC plants, the economic efficacy of IGCC plants does not improve with a higher carbon price in 2030.

Figure 4.3 *Cost breakdown for IGCC power plants*



Source: TransitionZero

Note: The carbon cost refers to the carbon costs associated with power generation in Japan, which stands at US$5/ tCO_2 and US$130/ tCO_2 in 2020 and 2030 respectively. The assumed 2030 carbon price is in line with IEA's NZE scenario.

Other concerns

Stranded assets

IGCC plants **cannot be retrofitted** with pre-combustion CCS technologies. Additional investment into IGCC will directly translate into **new-build coal plants in Japan**.

This will not only **contradict Japan's overall climate ambitions**, do nothing to reduce grid emissions to put Japan on a net zero trajectory, but also result in **significant stranded asset risk** in the future.

Technical considerations

IGCC plants require **three to five years** to reach a stable level of availability. Even with such a long synchronisation phase, IGCC plants still face **consistent issues with reliability**, with high incidences of plant outages.

To improve availability, some plants have **burned natural gas as a backup fuel,** or **installed additional gasifiers.** Both options add costs to the plant.

Lifecycle impact

One of the key benefits of coal gasification (IGCC) lies in its ability to use a variety of coal grades, particularly the lower grade **lignite,** which is largely regarded as the **world's most pollutive and energy inefficient fuel.**

Should coal gasification gain mainstream status in the power sector, it could breathe new life into the sunset industry, raising concerns of a **jump in carbon emissions** instead of reduction.

Carbon capture and storage (CCS)

Key takeaways

01

High parasitic loads depress returns, lack of CCS value chain boosts costs

- Historically, 23% to 30% of generation is lost through energy efficiency penalty.
- Hidden costs more than doubles CCS costs for coal plant retrofits.

02

Limited domestic storage sites limits unchecked fossil fuel use

- The limited carbon storage potential in Japan necessitates careful prioritisation of its use.
- Presence of competitive renewable generation limits attractiveness of CCS in power.

03

Climate benefit of CCS in the power sector may be too little too late

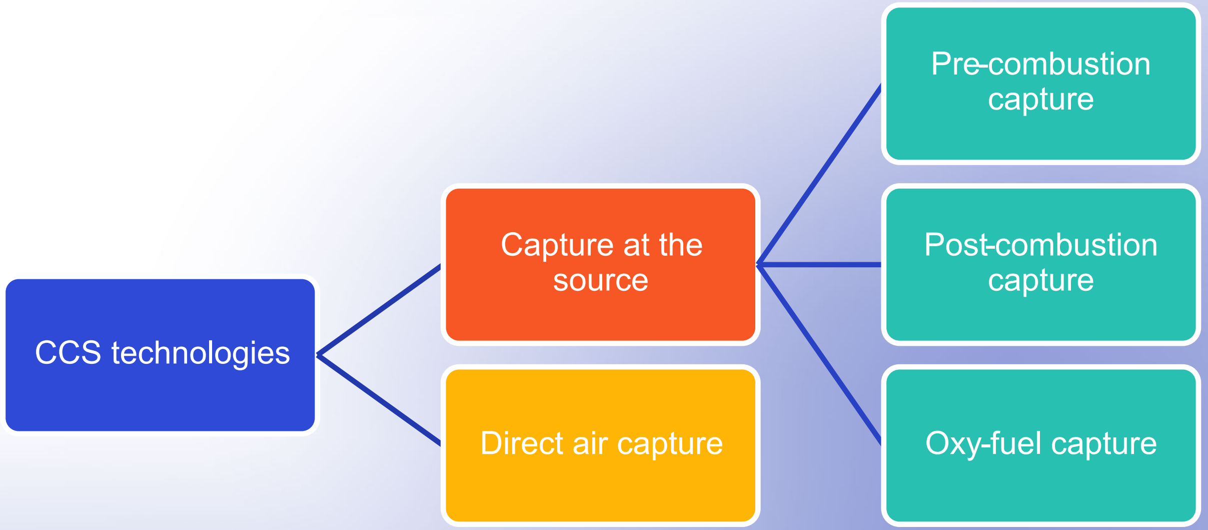
- High carbon price is needed to incentivize CCS, but by then it will be squeezed out by cheaper renewables.

Carbon capture technologies

CCS is used to describe a suite of technologies that aims to capture CO_2 emissions for permanent storage, primarily in saline aquifers, or in other geological storage sites

CCU (carbon capture and utilisation) can be considered an extension of CCS applications, where instead of going into permanent storage, captured CO_2 is utilised.

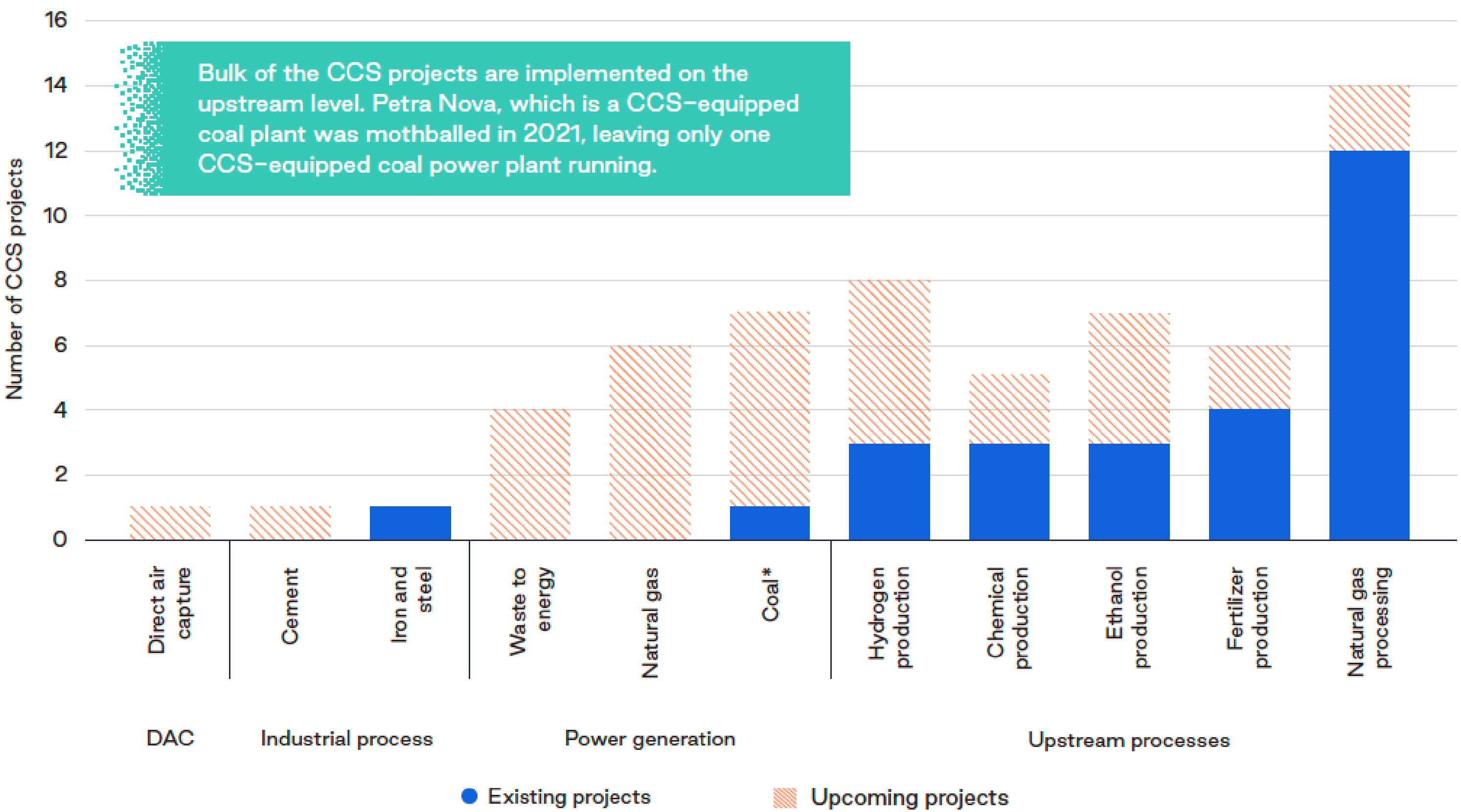
Figure 5.1 Carbon capture technologies



Source: TransitionZero

Overhyped: only one operating CCS project in power sector

Figure 5.2 CCS projects by project status



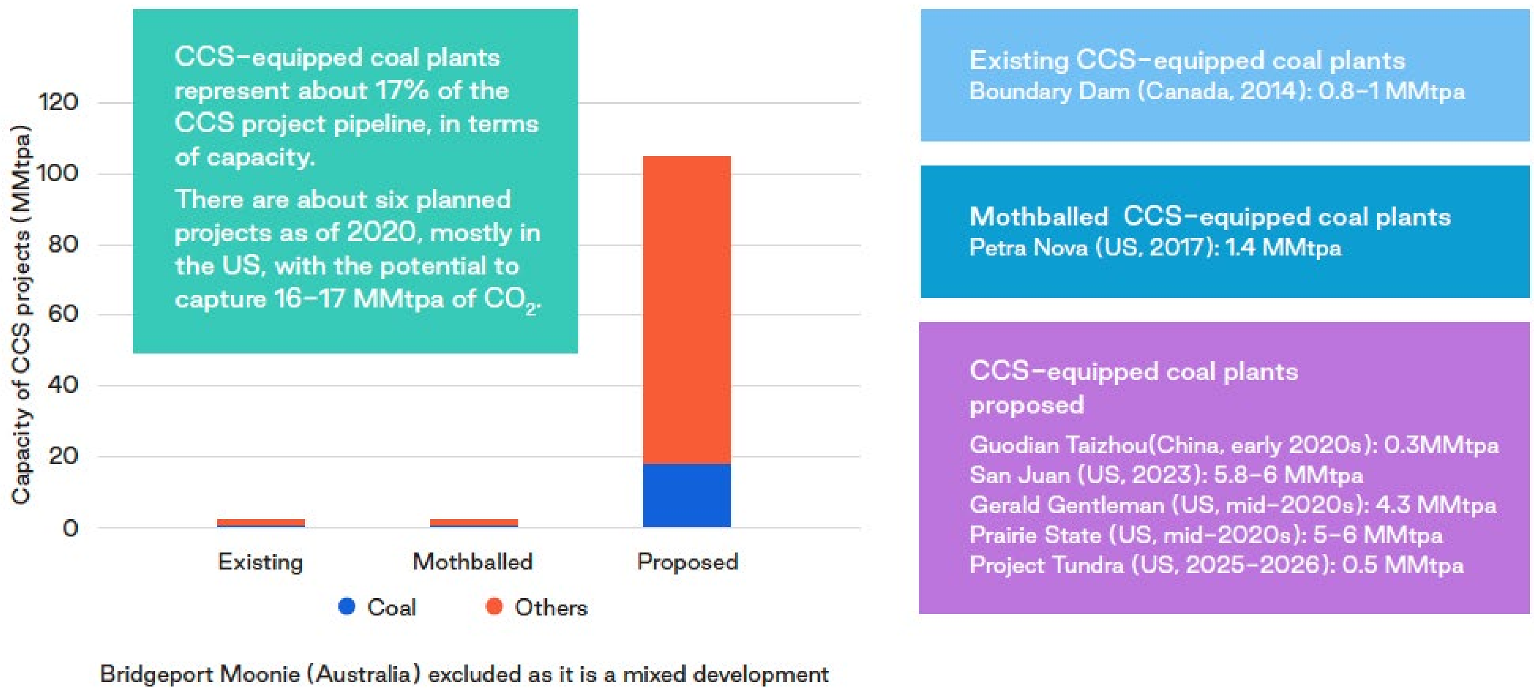
Source: Data from Global CCS Institute[57], TransitionZero analysis

Note: The CO_2 captured in the Petra Nova project was used in EOR operations. Due to the prolonged slump in oil prices, NRG announced that it will permanently mothball the project from June 2021.

A drop in the ocean: 17 Mt out of 9.8 Gt

There are about six planned CCS retrofits on coal projects, with the potential to capture up to 17 MMtpa of CO_2. This represents about 17% of the CCS project pipeline in terms of capacity, but only **0.17%** of the coal emissions from power generation in 2020.

Figure 5.3 CCS-equipped coal-fired power plants



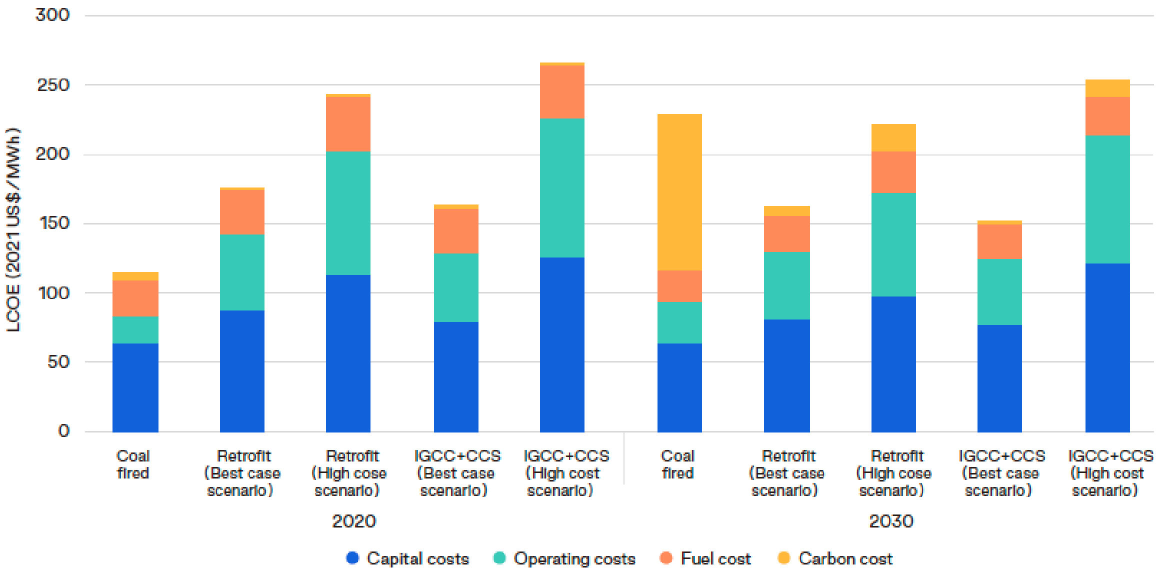
Source: *Data from Global CCS Institute; TransitionZero analysis*

Notes: *Petra Nova was mothballed in 2021. Bridgeport Moonies CCS (Australia) is not included as part of coal power plant based CCS projects as it is a mixed development project consisting of CCS applications for a variety of power and industrial processes.*

Carbon capture and storage (CCS)

Hidden cost double CCS costs to US$74/$tCO_2$

Figure 5.4 LCOE of CCS applications at coalfired power plants



			Retrofit CCS			IGCC+CCS		
			Low cost	Base case	High cost	Low cost	Base case	High cost
2020	Additional cost	\$/MWh	\$65	\$102	\$133	\$39	\$56	\$76
	Cost of CCS	\$/tCO_2	\$74	\$123	\$169	\$53	\$80	\$114
2030	Additional cost	\$/MWh	\$40	\$66	\$87	\$39	\$46	\$60
	Cost of CCS	\$/tCO_2	\$46	\$79	\$111	\$53	\$65	\$89

Source: TransitionZero

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Storage limitations requires prioritisation of hard to abate sectors

Japan CO_2 storage potential ($GtCO_2$)

As it stands, there is no real consensus on the CO_2 storage potential in Japan.

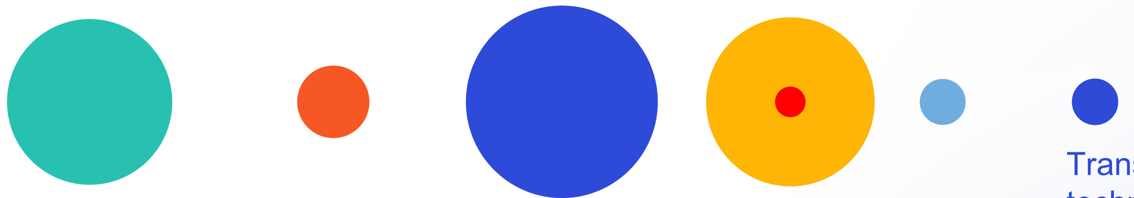
IEA Japan 2021 Energy Policy Review which estimates a technical storage potential of 146 $GtCO_2$ for Japan.

Minimum seen in literature : 28 $GtCO_2$

Maximum seen in literature : 197 $GtCO_2$

Global CCS Insitute places technical potential at 152 $GtCO_2$

RITE uses a CO_2 storage potential of 11.3 $GtCO_2$ in their net zero analysis



of which 3% is economically viable to tap

TransitionZero assumes a technical storage potential of 115 $GtCO_2$, of which 10% is economically viable to tap

Japan's annual emissions currently stands at around 1 $GtCO_2$ per year. This means that Japan's CO_2 storage may run out in about a decade. Japan suffers from a hard constraint on CCS applications due to limited storage sites, thus careful prioritization of its CCS application is required to support its decarbonisation journey.

Source: *TransitionZero*

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Other concerns

Efficiency penalty

Experience from operational CCS-equipped coal plants see **exorbitant penalty of 23% to 30%.**

This “parasitic” energy consumption reduces the electricity available to be sold, depressing plant profitability. Ultimately, the presence of heavy energy penalties may render a CCS **project financially non-viable.**

Environmental concerns

CO_2 leakages in offshore storage sites will have **negative consequences** to marine biodiversity. High frequency of seismic activity in Japan **increases risk** of carbon seepage.

Japan-specific risk assessment of offshore CO_2 storage sites is lacking. The risk here is primarily one of “**unknown unknowns**”. More work needs to be done before calculated risks can be taken on the operations of offshore subsea CO_2 storage sites.

Long project lead times

Due to the long project lead time (7-8 years), it is unrealistic to expect a rapid scale-up of CCS projects to meet 2030 goals.

CCS will, therefore, only be available as part of Japan’s **longer term technology suite**. However, by then, low-carbon alternatives, particularly low cost renewables, will have gained cost advantage.

Low carbon, least cost alternative: renewable energy

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Key takeaways

01

RE offers a more cost-competitive way of meeting Japan's climate targets and energy needs

- Currently, stand-alone solar and onshore wind are already cost-competitive.
- Presence of competitive renewable generation limits attractiveness of CCS in power.

02

Renewables integration is fundamental for Japan's net zero ambitions

- Japan's power market rules favour inflexible baseload generation, leading to RE curtailment.
- Pairing RE with storage improves dispatchability, but may present exaggerated integration cost.

03

With policy support, offshore wind holds significant promise

- Current cost profile for offshore wind in Japan is highly conservative due to weak project pipeline.
- Steep cost reductions are feasible.

Rise of a new dawn for RE in Japan's power sector

New resource potential estimates from the Ministry of the Environment reveals that Japan has **more than double** the renewable energy potential it needs to power its economy.

Table 6.1 Revised renewable energy potential in Japan

		Technical potential		Economic potential			
		Capacity	Generation	Capacity (GW)		Generation (TWh)	
		GW	TWh	Low	High	Low	High
Solar	Residential	210	253	38	112	47	137
	Industrial	2,536	2,969	0.2	295	0	367
	Total	2,746	3,222	38	406	47	504
Onshore wind		285	686	118	163	351	454
Offshore wind		1,120	3,461	179	460	617	1,558
Hydro		9	54	3	4	17	23
Geothermal		14	101	9	11	63	80
Total		4,174	7,523	347	1,045	1,095	2,619

Source: TransitionZero, reproduced from MOEJ

Low carbon, least cost alternative: renewable energy

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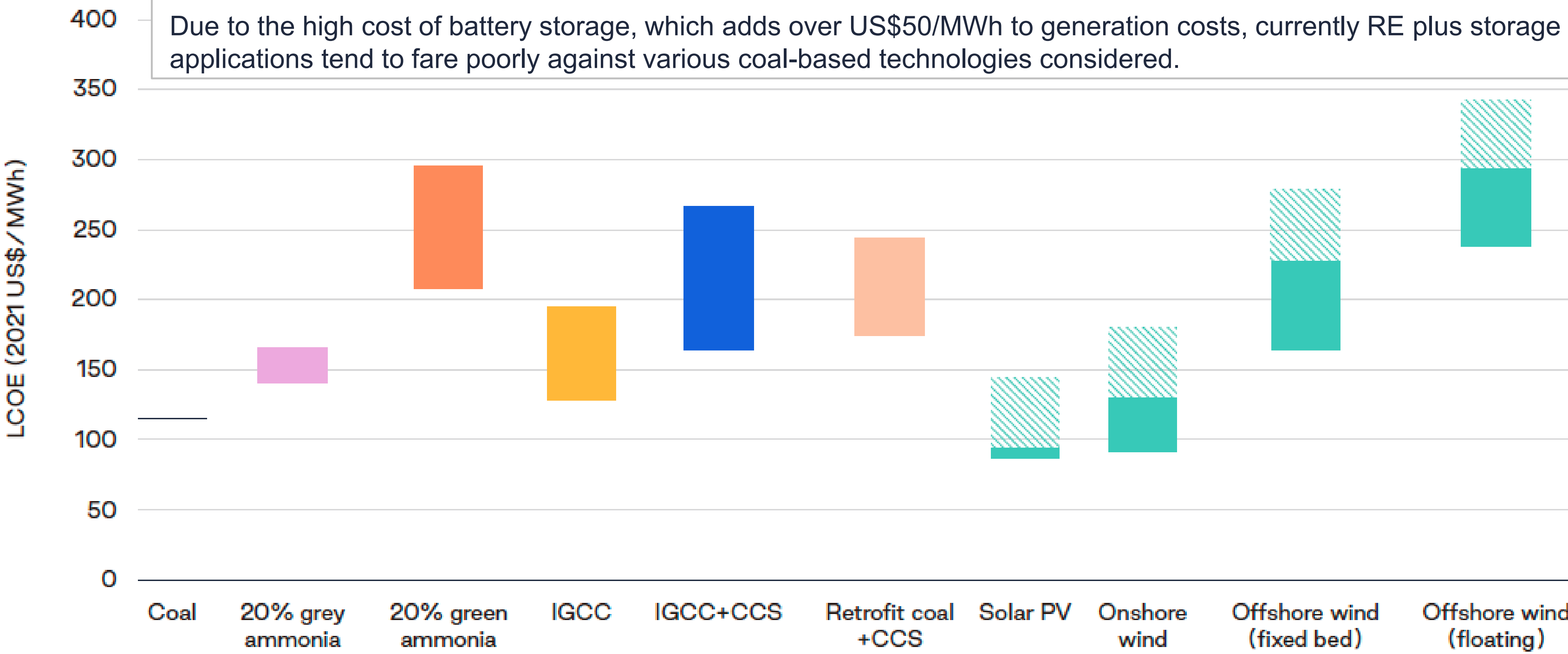
Stand-alone RE cheaper than coal, storage adds steep costs

Figure 6.1 2020 LCOE of advanced coal technologies and renewable energy source in Japan

At present, stand-alone solar and onshore wind projects are cost-competitive against coal—based generation technologies.

Due to the high cost of battery storage, which adds over US$50/MWh to generation costs, currently RE plus storage applications tend to fare poorly against various coal-based technologies considered.



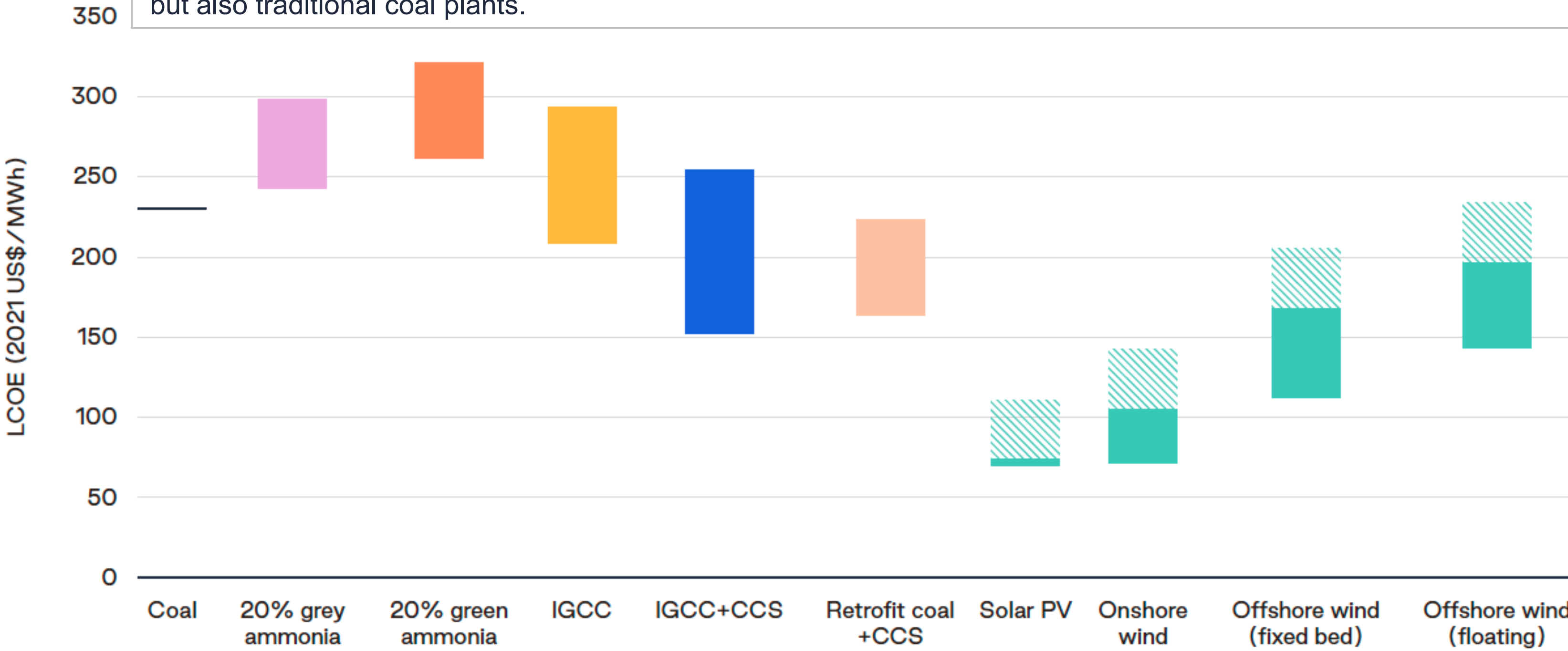
Source: TransitionZero
Note: A carbon price of US$5/t$CO_2$ in 2020. The shaded green bars represent the cost of storage, which is sized using half the power rating of the installed RE capacity, with a 4 hour duration.

Low carbon, least cost alternative: renewable energy

RE+storage gains competitive advantage against coal by 2030

Fig 6.2 2030 LCOE of advanced coal technologies and renewable energy source in Japan

With rapidly declining costs of wind and solar, coupled with a high carbon price, most renewables plus storage options, except floating offshore wind, are strong competitors against not only advanced coal-fired power plants, but also traditional coal plants.



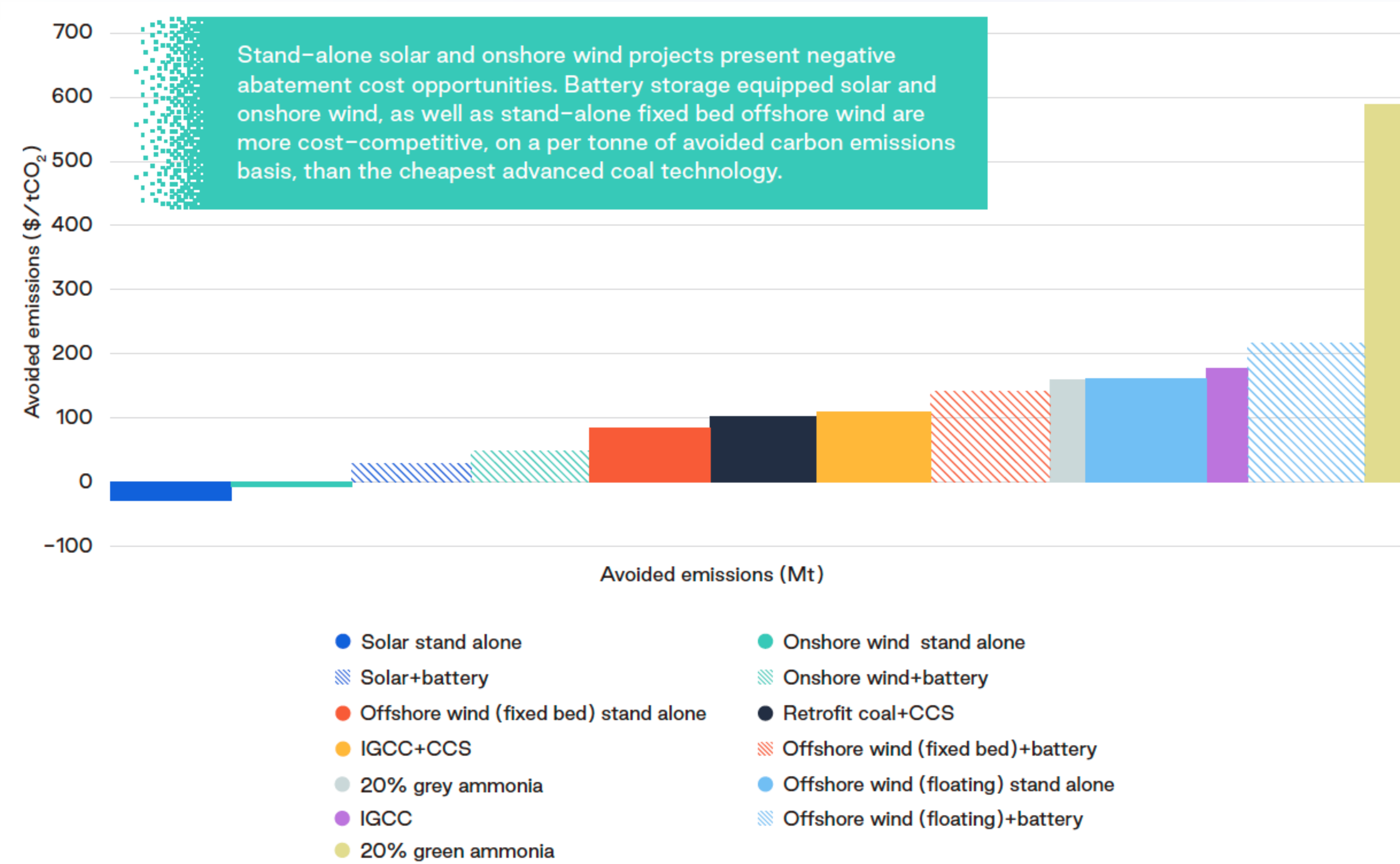
Source: TransitionZero

Note: A carbon price of US\$130/tCO_2 in 2030, which is in line with IEA's NZE scenario, is assumed. The shaded green bars represent the cost of storage, which is sized using half the power rating of the installed RE capacity, with a 4 hour duration.

Low carbon, least cost alternative: renewable energy

2020 Marginal abatement curve in Japan's power sector

Fig 6.3 2020 Marginal abatement curve

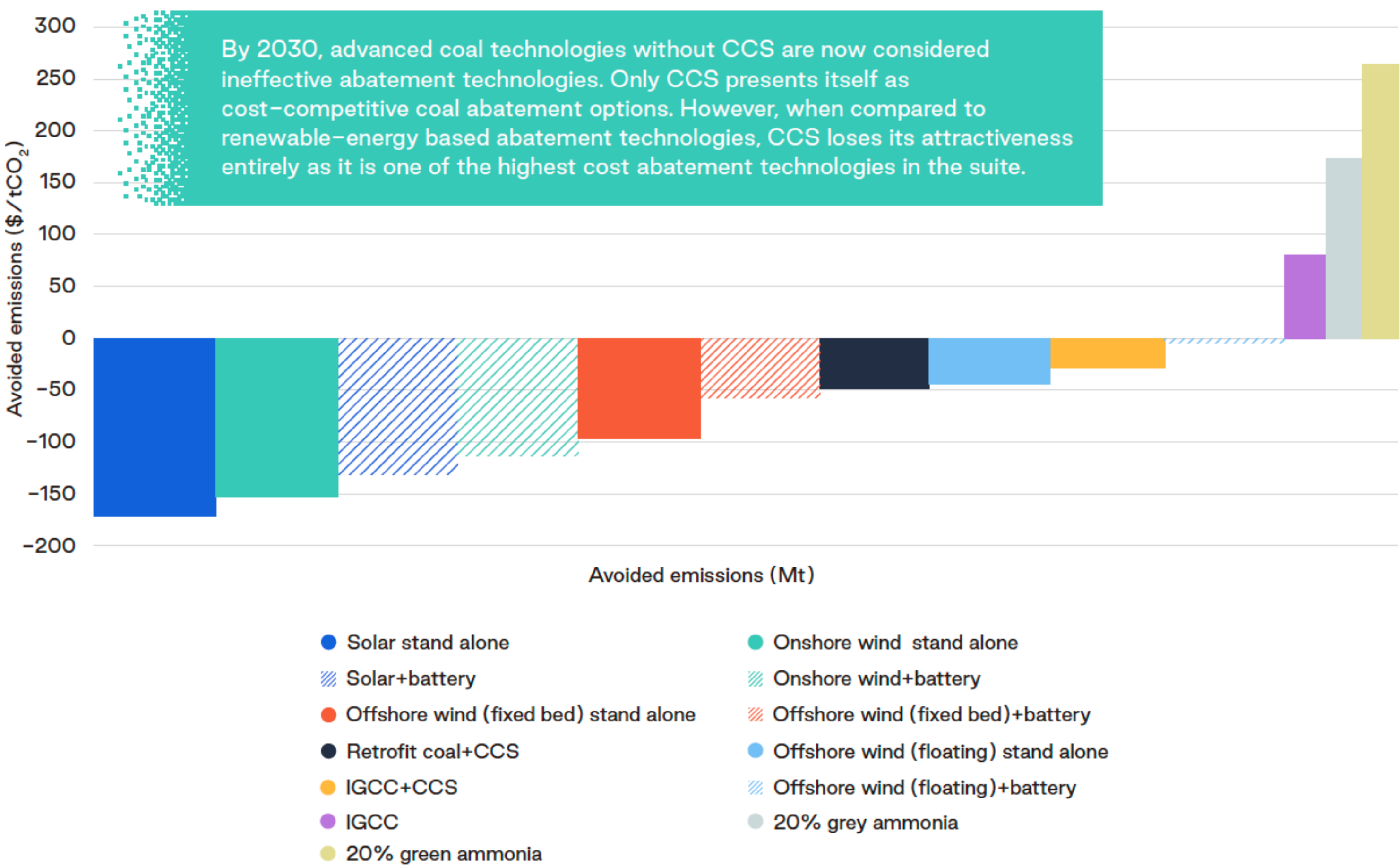


Source: TransitionZero

Low carbon, least cost alternative: renewable energy

2030 Marginal abatement curve in Japan's power sector

Fig 6.4 2030 Marginal abatement curve



Source: TransitionZero

Policy recommendations

Policy recommendations

01

Re-evaluate the role for ammonia co-firing for power generation

- Ammonia co-firing is uneconomical against alternatives, and has a limited role to play in the power sector.
- To be in alignment with global climate goals, only green ammonia should be supported.

02

Prioritise applications of green ammonia in “no-regret” sectors

- Development of a hydrogen/ammonia economy presents multiple co-benefits to Japan.
- Being a front-runner in this space, prioritising ammonia development and deployment in alternative sectors will aid Japan’s decarbonisation and economic goals.

03

Reconsider the role of IGCC in future energy landscape, both domestically and internationally

- IGCC as a technology, holds no clear advantage over competing generation technologies.
- Continued investment into IGCC technologies is unlikely to deliver new economic opportunities for the Japanese economy.

Policy recommendations

04

Invest in CCS capabilities, but be prudent with Japan's limited storage sites

- CCS has a role in global decarbonisation, thus continued investment is necessary.
- With cost-competitive RE, Japan's limited CCS storage capacities needs to be prioritized for harder to abate sectors, such as heavy industry.

05

Adopt an integrated approach to reduce integration cost

- In the near term, Japan can keep integration costs low by eliminating market bias against intermittent RE.
- In the longer term, integration costs are reduced through grid enhancement and reinforcements, facilitated by detailed systems-level planning.

06

Pivot from nascent advanced coal to mature renewables for the short term

- Solar and onshore wind (with/without battery) are competitive against advanced coal.
- These mature renewable technologies suffer less operational and technical issues, compared to advanced coal

Policy recommendations

07

Push for offshore wind to unlock significant RE potential and deliver on steep learning curves

- A vibrant offshore wind industry provides multiple co-benefits for Japan.

- Setting a deployment target provides strong market signals on the scale of offshore wind demand in Japan and reduces investment uncertainties.

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