TransitionZero

Coal-de-sac

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

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TransitionZero

TransitionZero provides credible analysis and insights to accelerate a zero carbon economy in the 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.

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The experts above that contributed to this report are not responsible for any opinions or judgments it contains. Any errors and omissions are solely the responsibility of TransitionZero.

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Foreword

When the former prime minister Yoshihide Suga announced Japan would strengthen its climate target for 2030, alongside a long term goal of becoming net zero by 2050, it was a turning point for the country's energy system. This increase in climate ambition came against a backdrop of challenging economic conditions. On the world stage, Japan faces a turbulent global energy market, with high and volatile commodity prices – exemplified by the recent energy crisis.

The world's third largest economy will need to rapidly decarbonise its power grid in order to become net zero. However, the country's heavy dependence on coal for around one third of its power poses a major challenge. In response, Japanese utilities and policymakers have been keen to promote so called advanced coal technologies such as carbon capture and storage (CCS), ammonia-co-firing, and coal gasification (IGCC).

This comprehensive and timely report from TransitionZero provides a robust analysis of these coal technologies from a technical and economic perspective. The conclusion is clear: they are high cost and incompatible with Japan's net zero target.

The cost for advanced coal technologies ranges from US$128/MWh to US$296/MWh, with an average of around US$200/MWh – double that of stand-alone solar power. Even when including battery storage, solar PV and onshore wind are already cost competitive against most advanced coal technologies, with this trend set to continue in favour of renewables. In climate terms, the average carbon intensity of these advanced coal technologies (without CCS) is five times higher than the Japanese energy grid needs to be in 2030 to align with the IEA's net zero scenario.

Despite the hype around CCS, major economic and technical challenges remain, making it far from a silver bullet solution. Perhaps most notable is the very limited storage potential in Japan – which could run out in just one decade. The climate benefit of CCS in the power sector may ultimately be too little too late, as by the time it becomes cost-competitive over unabated fossil fuels, it will be out-competed by renewables.

This report's detailed analysis is important reading, not just for policymakers who are trying to chart a course through the energy transition, but also for investors who own Japanese utilities. Only with high quality information can investors make smart financial decisions. The quality and impact of TransitionZero's analytics is why I decided to join their board in 2021.

Over-investment in advanced coal technologies that have been shown to be expensive with limited potential – such as IGCC – could result in stranded assets and a costly deadend. The time is now to carefully reconsider the future of advanced coal and redirect investment flows into more promising zero carbon technologies instead.

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Glossary

ASEAN	Association of Southeast Asian Nations
CCGT	Combined cycle gas turbines
CCS	Carbon capture and storage
CCU	Carbon capture and utilisation
CO_2	Carbon dioxide
CRIEPI	Central Research Institute of Electric Power Industry
COP26	UN Climate Change Conference in Glasgow
DAC	Direct air capture
EAGLE	Energy Application for Gas, Liquid, and Electricity project
EOR	Enhanced oil recovery
EPC	Engineering, procurement, and construction
GJ	Gigajoule
GW	Gigawatt
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IGFC	Integrated gasification fuel cell combined cycle
IRENA	International Renewable Energy Agency
J-Power	Electric Power Development Company of Japan
JPY	Japanese yen
kJ	Kilojoule
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelised cost of electricity
MAC	Marginal abatement curve
METI	Ministry of Economy, Trade and Industry
MOEJ	Ministry of the Environment, Japan
MOU	Memorandum of understanding
Mt	Million tons
$MtCO_2$	Million tons of carbon dioxide
MW	Megawatt
MWh	Megawatt-hour
NDC	Nationally determined contributions
NEDO	New Energy and Industrial Technology Development Organization
NO_x	Nitrogen oxides
NZE	Net-zero scenario
OECD	Organisation for Economic Co-operation and Development
PM 2.5	Particulate matter 2.5
R&D	Research and development
RITE	Research Institute of Innovative Technology for the Earth
SO_2	Sulfur dioxide
T&D	Transmission and distribution
TWh	Terawatt-hour
US	United States of America
US$	United States dollar
USC	Ultra-supercritical

Definitions

Advanced coal technologies:
Advanced coal technologies considered in this report include ammonia co-firing, integrated gasification combined cycle (IGCC) and carbon capture and storage (CCS) applications in the power sector.

Ammonia (NH_3):
Is a compound of nitrogen and hydrogen. It can be used directly as a fuel in direct combustion processes, as well as in fuel cells or as a hydrogen carrier. This report refers to various shades of ammonia, based on the different ways ammonia is produced. Brown ammonia is ammonia produced via the Haber-Bosch process using coal as feedstock. Grey ammonia is produced in a similar process but uses hydrogen produced via steam methane reforming using natural gas as feedstock. Blue ammonia is produced when CCS is used to capture emissions from the traditional production of hydrogen using fossil fuel feedstock. Green ammonia is also produced using the Haber-Bosch process, but derives hydrogen from water, with the process powered by renewable energy generation. There are even greener ways to produce ammonia, referred to in the report as "greener ammonia" that aims to bypass the energy intensive Haber-Bosch process. Only blue and green ammonia can be considered low-carbon fuels.

Battery storage:
Energy storage technology that uses reversible chemical reactions to absorb and release electricity on demand.

Carbon capture and storage (CCS):
The process of capturing carbon emissions from fuel combustion, industrial processes or directly from the atmosphere. Captured carbon emissions can be stored in underground geological formations, onshore or offshore in CCS applications, or used as an input or feedstock in manufacturing and other processes in carbon capture and utilisation (CCU) applications. In this report, we refer to CCS and CCU applications collectively as CCS.

Coal:
Includes a variety of coal qualities, such as lignite, coking and steam coal. Thermal coal is also used to refer to steam coal.

Coal gasification:
A process in which coal is partially oxidated by air, oxygen, steam or carbon dioxide to produce synthesis gas (syngas) —a mixture consisting primarily of carbon monoxide, hydrogen, carbon dioxide, methane, and water vapour. As coal gasification is a primary process of coal-based IGCC plants, we use coal gasification and IGCC interchangeably in this report.

Dispatchable generation:
Refers to technologies whose power output can be readily controlled, in order to match supply with demand. In practice, dispatchable generation is seldom turned off due to downtime associated with cold starts. Depending on the technology, the ramp rate, or the rate at which a power plant can increase or decrease output, is also different. In our report, we refer to all generation technologies with the ability to vary output to match demand as dispatchable generation.

IGCC:
IGCC plants convert feedstock into synthesis gas (syngas), which is cleaned before burning in gas turbines to generate electricity. Potential feedstocks for IGCC plants include coal, biomass, refinery bottom residues (such as petroleum coke, asphalt, tar, etc.), and municipal waste. In the report, we exclusively consider coal-based IGCC plants.

Unabated coal:
Consumption of coal in facilities without CCS.

Contents

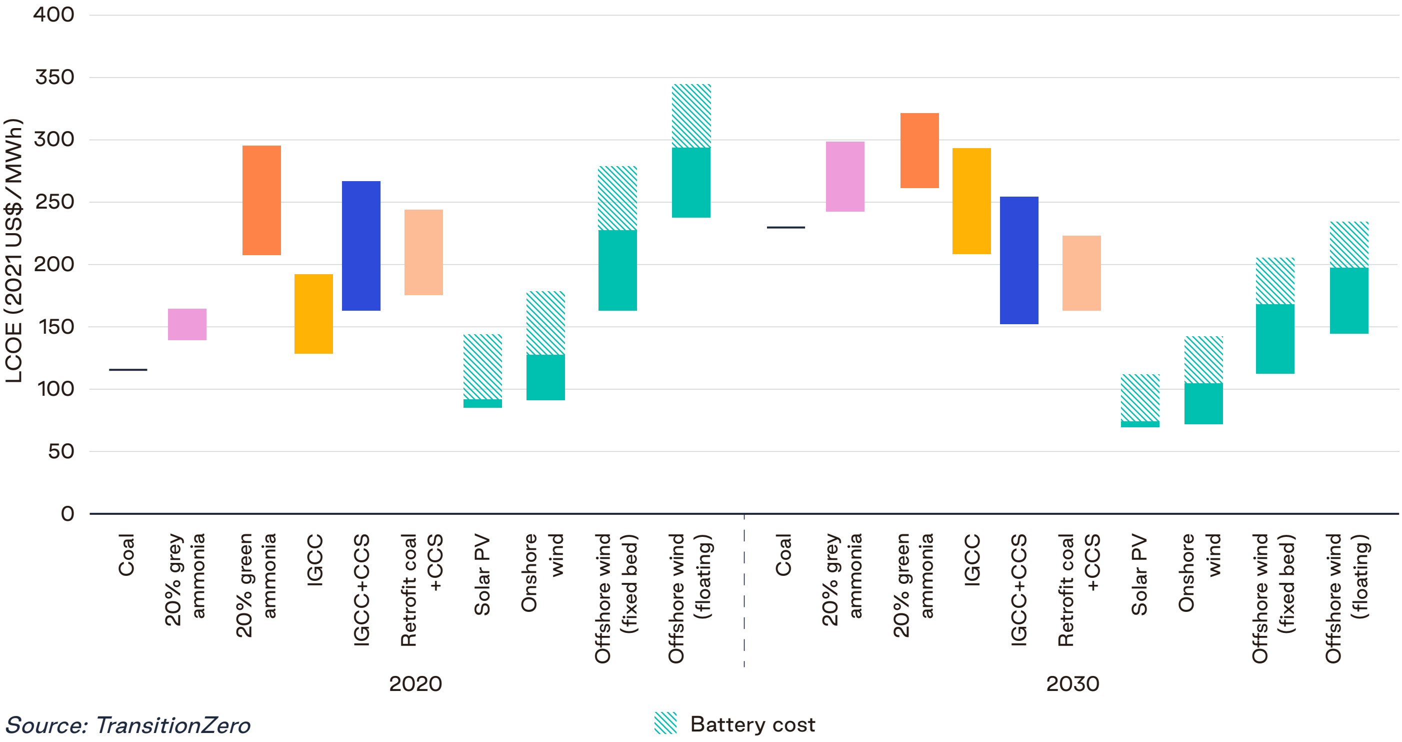
01 Executive summary

The objective of this report is to inform strategies for Japanese power utilities, investors and policymakers, by providing a techno-economic analysis of advanced coal technologies. The advanced coal technologies considered in this report include ammonia co-firing, integrated gasification combined cycle (IGCC) and carbon capture and storage (CCS). In doing so, our hope is to prompt an urgent re-evaluation of the role of these technologies in strategic planning to align Japan with a net-zero outcome.

Independent of climate considerations, advanced coal is high cost

Based on our estimates, the current Levelised Cost of Electricity (LCOE) for advanced coal technologies considered in this report ranges from US$128/MWh for IGCC applications to US$296/MWh for green ammonia co-firing. When compared to other power generation technologies, the average cost of advanced coal technologies is US$197/MWh, which is double that of solar photovoltaics (PV). Even when including battery storage, solar PV and onshore wind are already cost competitive against most advanced coal technologies. This trend is set to continue, and by 2030 solar PV and onshore wind plus battery storage outperforms all advanced coal technologies. Moreover, we expect offshore wind plus storage to also become cost-competitive with coal within the next decade.

Figure 1.1 LCOE estimates across technologies, 2020-2030

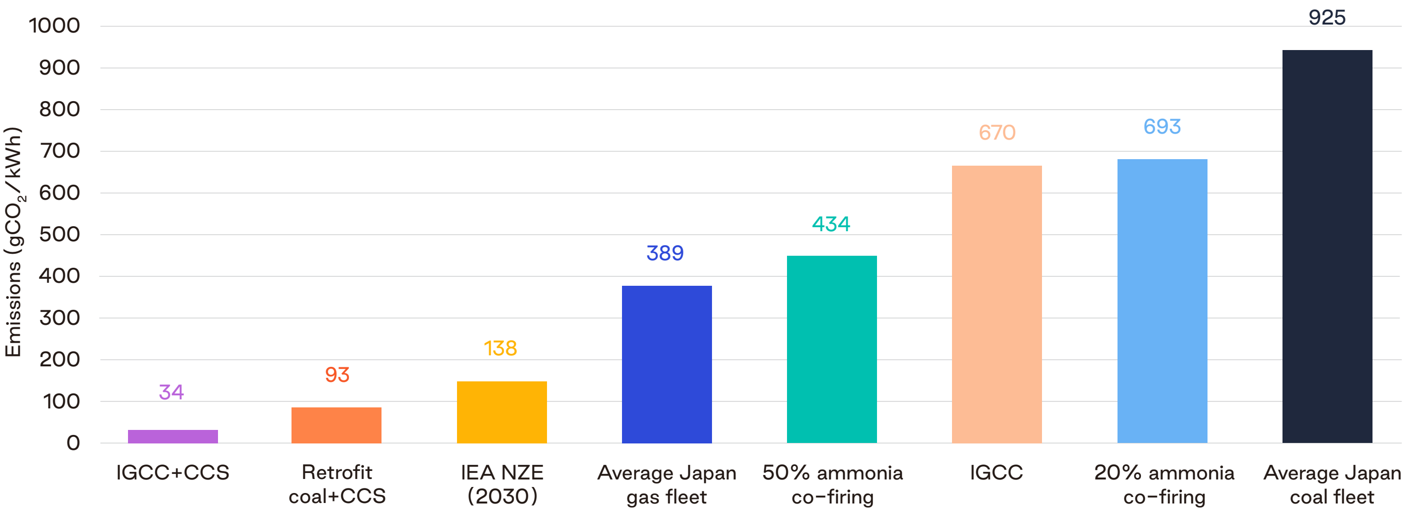


Source: TransitionZero

Advanced coal technologies are inconsistent with a net-zero outcome

While advanced coal technologies will likely outperform coal plants, part of the reason why advanced coal cannot compete with zero carbon technologies in the coming decade is due to their limited emissions reduction potential. Despite superior emissions performance promised by these advanced coal technologies, their emission intensities are inconsistent with a net-zero outcome, which requires all unabated coal to be phased out by 2030 in OECD countries and globally by 2040. Indeed, in the IEA's net-zero emissions (NZE) scenario, the carbon intensity of the grid should be 138 gCO_2/kWh by 2030, which is about one-fifth of non-CCS equipped advanced coal technologies considered in this report.

Figure 1.2 Emissions reduction potential of advanced coal technologies



Source: TransitionZero

CCS in Japan has considerable technical challenges

Beyond the cost and climate limitations of CCS in Japan, there are also considerable technical challenges. Equipping coal plants with CCS comes at a steep trade off, in terms of both financial viability and efficiency advancements. The cost of CCS systems varies depending on the type of capture technologies employed and whether it is a new build or retrofit plant. At the lower end, CCS systems add about $39-65/MWh to the LCOE, with limited room for cost reductions, due to the bespoke nature of projects. The efficiency penalty of CCS-equipped thermal plants may be up to 25%, threatening the financial viability of the plant. With such steep trade-offs, utilities need to seriously reconsider this technology. Moreover, Japan has limited CO_2 storage sites, and absent a globally traded market for carbon, this presents a hard ceiling for CCS applications in Japan. Based on our analysis, Japan's CO_2 storage potential will be depleted in about a decade. As such, Japan has to be prudent with its allocation of storage capacity and prioritise CCS applications for hard-to-abate sectors, such as cement and steel.

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

There is a growing international effort to align coal power with the 1.5°C temperature goal. For example, the Glasgow Climate Pact, references accelerating efforts towards the phase-down of unabated coal power. Based on previous TransitionZero analysis, aligning global coal generation with a 1.5°C goal would require replacing nearly 3,000 coal units between now and 2030[1]. Japan's insistence on leaving the door open for advanced coal looks increasingly divorced from economic, climate and political realities. Japanese utilities need to confront the question on whether current and continued investments in these technologies can ever make financial or economic sense. For this reason, Japanese utilities need to urgently reconsider the role of coal power in today's political climate.

1 TransitionZero (2021).

02 Context

In April 2021, the former Japanese Prime Minister, Yoshihide Suga, announced an increase in climate ambitions, from a 26% emissions reduction under the current nationally determined contributions (NDC) to a 46–50% emissions reduction from 2013 levels by 2030. Since then, Japan has revised its NDC to reflect this increased ambition at COP26, while affirming the increase in commitment in its Sixth Strategic Energy Plan, which was approved by the Cabinet in October 2021.

The increase in climate ambitions comes against a backdrop of challenging economic and energy conditions. Domestically, nuclear restarts are still politically contentious and largely uncertain. Looking outward, Japan faces a turbulent global energy market, with high and volatile commodity prices. As Japan prepares to map out its future power sector trajectory, it will have to carefully consider its options. Alongside the revised 2030 target, Japan has a long-term ambition to be net-zero by 2050. Meeting Japan's net-zero target will require a rapid decarbonisation of its power sector. According to the IEA's NZE scenario, OECD power grids will need to be carbon neutral by 2035.

To support Japanese decision-makers, we have undertaken a comprehensive review of advanced coal technologies being promoted by policymakers and utilities to square the economic and environmental potential of these technologies with Japan's climate ambitions.

Prime Minister of Japan
Fumio Kishida speaking at COP26
Photo credit: 首相官邸ホームページ
(CreativeCommons)

Ammonia co-firing

The report has five sections. The first section analyses ammonia co-firing in power generation. The Japanese government, in coordination with industry, have strongly pushed ammonia co-firing as a key abatement technology for coal in the power sector. As co-firing with ammonia does not require major retrofits in existing coal plants, this strategy appears to be supported by many Japanese utilities, due to the limited capital outlay. Our analysis shows ammonia co-firing is likely to be both high cost and high carbon.

IGCC

The second section explores another advanced coal technology being supported by the Japanese government: IGCC. IGCC plants convert feedstock into synthesis gas, which is cleaned before burning in gas turbines to generate electricity. As climate considerations gained momentum, interest in IGCC has increased due to its compatibility with pre-combustion carbon capture. This section reviews the development of IGCC plants globally and reveals a series of failed experiments, which call into question the technology's ability to be coupled with CCS at scale.

CCS

The third section reviews the potential for CCS in Japan. The commercial viability of CCS projects remains heavily dependent on policy support, which explains the slow deployment of CCS projects globally. Japan's potential for CCS is complicated by storage availability. Moreover, our analysis shows the carbon price required to make CCS viable over the long-term will further improve the relative competitiveness of other zero carbon alternatives, such as wind and solar PV.

The fourth section explores to what extent renewable energy can meet Japan's energy trilemma. Our analysis shows renewable energy and other dispatchable zero carbon technologies are likely to be the lowest cost and least risky option to meet Japan's net-zero aspirations.

The report concludes with high-level policy recommendations to help support Japanese utilities who are trying to navigate the zero-carbon transition while maximising shareholder value. Japan's continued focus on advanced coal technologies could result in an expensive dead end, which could cost utility shareholders and the Japanese society dearly. For this reason, we recommend an urgent rethink of the role of these technologies in net-zero policymaking.

03 Ammonia co-firing

Summary

1 Japanese policymakers and utilities have identified ammonia co-firing as a key decarbonisation technology for its power sector and are deploying large sums of capital to commercialise the technology. Our analysis finds these investments are unlikely to help overcome Japan's energy trilemma challenge.

2 On an energy equivalent basis, grey ammonia, which is the cheapest source of ammonia, currently costs around four times that of thermal coal. The cost gap widens even further when considering green ammonia, which is 15 times the cost of coal.

3 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 carbon price of US$205/t$CO_2$. This results in a LCOE of around US$280/MWh, which is prohibitively expensive.

4 Despite claims, ammonia co-firing does little to reduce emissions. At the current technologically feasible co-firing rate of 20%, the emissions factor remains close to double that of gas-fired combined cycle plants (CCGT), which will need to be replaced or abated by 2035 to be consistent with the IEA's NZE scenario.

5 Due to the carbon and energy intensive nature of conventional methods of ammonia production, unless blue and/or green ammonia is utilised, there is no net emissions reduction from co-firing.

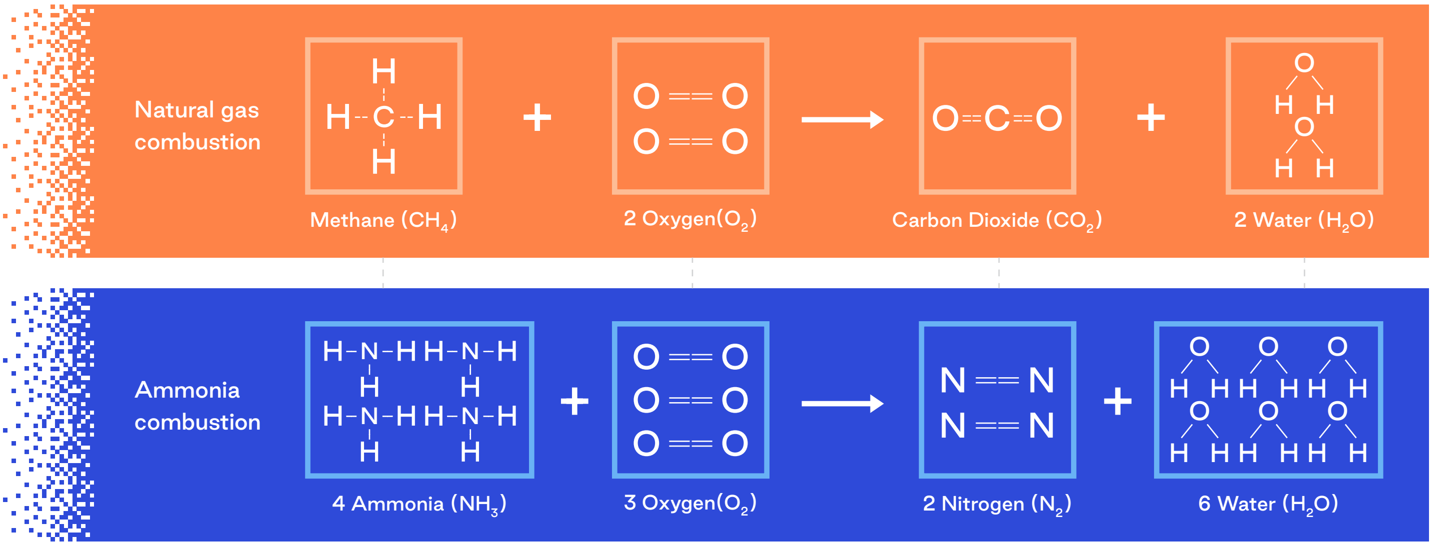
6 The lack of cheap gas as feedstock makes domestically produced ammonia prohibitively costly. This means that Japanese utilities will have to rely on cheaper international imports, further undermining Japan's energy security issues.

7 Despite its poor suitability in the power sector, ammonia has many other uses to support the transition to a zero carbon economy and should be scaled up in hard-to-abate sectors, such as cement and steel.

Background

Ammonia holds similar energy characteristics as fossil fuels, particularly natural gas. Natural gas, consisting primarily of methane, when combusted with oxygen, releases energy through the breaking of carbon-hydrogen bonds, and produces carbon dioxide and water as a by-product. Similarly, the direct combustion of ammonia releases energy through the breaking of nitrogen-hydrogen bonds under heat and produces nitrogen and water as by-products (Figure 2.1).

Figure 2.1 Chemical reactions of natural gas combustion and ammonia combustion



Source: TransitionZero

Ammonia is commonly discussed as a derivative of hydrogen, and as an easy way to capture, store and transport hydrogen to support a zero carbon transition. Its attractiveness stems from its high energy density[2], ability to be stored and transported easily[3] and its well-established supply chain[4]. In recent years, there are also increasing efforts to promote the direct combustion of ammonia as a low-carbon fuel. The combustion of ammonia does not emit any carbon, making it a zero carbon fuel at combustion stage[5]. Furthermore, the relative maturity of the ammonia value chain made it attractive as an interim fuel while the hydrogen economy develops. Hydrogen can be used in its pure form, or through hydrogen carriers such as ammonia etc.

2 Ammonia has a high energy density (22.5 MJ/kg at HHV), making it a suitable storage medium. In fact, liquid ammonia has a higher energy density (15.6 MJ/L) than liquid hydrogen (9.1 MJ/L).
3 Ammonia can be easily refrigerated at -33°C and stored in liquid form, making it a versatile and easy to store energy medium of hydrogen. In comparison, hydrogen must be cryogenically cooled to -253°C for storage. Similar disparities exist when considering pressurised air storage options. Moreover, compared to hydrogen, it is much less flammable, and thus safer to handle.
4 Ammonia is widely used as fertilizer, raw material feedstock and catalytic reactant, with established international trade and supply chain infrastructure (such as transport vessels, specialized terminals, and storage tanks etc).
5 The production of ammonia may be carbon intensive if fossil fuels are used as feedstock. However, there are zero-carbon alternatives available as well. More on the different production techniques of ammonia is discussed in later segments.

However, the direct use of hydrogen has been hindered by transportation challenges, low energy density and high explosion risk.

As a result, ammonia is often explored as an alternative hydrogen carrier. There are several different forms of ammonia: brown, grey, blue, and green. Grey and brown ammonia are produced using fossil fuels as feedstock, with natural gas used in the former and coal for the later. The bulk of the ammonia produced currently is grey ammonia, which uses steam methane reforming (SMR) to produce hydrogen. SMR is a highly energy intensive process due to the harsh operating environments of 500°C and 250 atmospheric pressure, accounting for 80% of the energy demand in the ammonia production process[6]. As concerns about climate change mount, the production of ammonia from fossil fuels has come under pressure to decarbonise due to the high associated emissions. This has resulted in the emergence of two distinct low-carbon alternatives: blue and green ammonia.

Blue ammonia refers to the use of CCS technologies to reduce emissions from the traditional production of hydrogen using fossil fuel feedstock and the Haber-Bosch process. In the best-case scenario, blue ammonia produces 80-90% less direct emissions than grey/brown ammonia, due to leakages during the CCS process[7]. However, the true climate impact of blue ammonia is unclear. Some studies have highlighted that, after accounting for upstream emissions (including the methane slippages from upstream natural gas production), the lifecycle emissions of blue ammonia may be comparable to natural gas fired power plants[8].

Green ammonia, on the other hand, utilizes the traditional Haber-Bosch process to create ammonia, but gets its hydrogen from water electrolysis, powered by renewable energy sources, such as wind and solar PV. An even greener way of producing ammonia would entail using novel methods of ammonia synthesis, such as through electrochemical process and chemical looping[9]. Though accounting for less than 10% of the market share at present, there are various proposed blue/green ammonia plants in the pipeline, indicating strong interest to decarbonise the ammonia value chain. In fact, estimates place the current green ammonia project pipeline at close to 48 million tonnes[10], equivalent to 25% of the global ammonia market in 2020.

Figure 2.2 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 be considered low or zero carbon fuel.

About 96% of the ammonia consumed globally is made through the Haber-Bosch process, using fossil fuels, most commonly natural gas (methane) and coal, and occasionally, oil, as feedstock[11]. This process is highly energy intensive. The use of fossil fuel as feedstock for hydrogen also makes the process carbon intensive as carbon is emitted via both process gas and as combustion emissions[12]. In fact, ammonia production accounts for about 2% and 1.3% of the global energy demand and carbon emissions, respectively[13]. Ammonia synthesis is also considered to be one of the most emissions-intensive chemical industry processes[14]. Therefore, a pivot towards a hydrogen/ammonia economy that is dependent on fossil fuels as feedstock may have no climate benefit, or worse, do more harm than good.

6 The Royal Society (2020)
7 Energy Transitions Commission (2018)
8 Haworth and Jacobson (2021)
9 Smith, Hill and Torrente-Murciano (2020)
10 GCPA (2021)
11 RMI (2020)
12 Energy Transitions Commission (2018)
13 The Royal Society (2020)
14 The Royal Society (2020)

Box 2.1 History of ammonia research and development (R&D) in Japan

Japan first explored the use of hydrogen as an energy carrier back in the 1970s and 1980s, as an alternative energy source to improve energy security. However, interest in hydrogen died down quickly due to the technological and economic hurdles. As part of the broader search for energy alternatives amid large-scale nuclear shutdowns after the Fukushima incident in 2011, the Japanese government revived its research interest in hydrogen with the Energy Carriers technology program. The research covered the three main segments of the hydrogen value chain: production, transportation and utilisation. Under the five-year programme and with US$150 million in government funding, academia, industry leaders and policymakers collaborated to explore the development of a hydrogen value chain, with ammonia being considered as a transport carrier for hydrogen. As part of the programme, a series of tests and demonstrations were conducted to establish the technical viability of coal and ammonia-co-firing.

Laboratory tests

Prior to testing at commercial power plants, a series of laboratory tests were conducted by teams at Osaka University and Central Research Institute of Electric Power Industry (CRIEPI). These initial tests ensured the technical viability of ammonia co-combustion with coal, while also providing key insights on the suppression of NO_x emissions during the process.

Chugoku Electric: 0.6%-0.8% ammonia co-firing

Based on the initial lab test results, Chugoku Electric test-bedded 0.6%-0.8% ammonia co-firing at its 156 MW Mizushima Unit 2 coal plant. The pilot ran for a period of 7 days, from 3 July 2017 to 9 July 2017. Results from the pilot claimed that co-firing coal with 0.6%-0.8% ammonia did not lead to efficiency penalties, nor did it lead to significant increases in NO_x emissions from the plant. In fact, the company claimed that ammonia co-firing with coal is a cheap carbon reduction technology that does not require extensive remodelling of existing coal plants, and thus maximises the use of existing coal fleets[15].

IHI: 20% ammonia co-firing

In December 2017, IHI test-bedded co-firing 20% ammonia at a 10 MW combustion test facility at the Aioi Plant in Hyogo prefecture. This demonstration test was conducted under the Strategic Innovation Promotion Program (SIP) to trial the newly developed coal-ammonia co-firing burner from IHI. This demonstration was the highest level of ammonia co-firing in a practical/commercial setting and paved the way for larger scale demonstrations of ammonia co-firing in Japan.

JERA-IHI: 20% ammonia co-firing with coal at 1 GW Hekinan coal plant

In May 2021, JERA and IHI announced that they are about to embark on the first demonstration project of 20% ammonia co-firing at a commercial coal plant. The demonstration project aims to establish the technological viability of ammonia co-firing at large-scale commercial coal-fired power plants and evaluate both boiler heat absorption and environmental impact characteristics such as exhaust gases. The project will run for approximately four years from June 2021 to March 2025[16], with the test-firing to proceed in 2024/2025.

15 Ammonia Energy Association (2020)

16 Mitsubishi Power (2021)

Cost of ammonia co-firing

While ammonia plays an important role in several industrial processes (see Box 2.2), its use in power generation is likely to be limited. At the current stage, there are no commercial applications of 100% direct ammonia combustion to generate electricity, although large turbine manufacturers and power utilities, such as Mitsubishi[17], IHI[18] and JERA, are investing in research and development of such a clean, carbon-free line. IHI and Mitsubishi Heavy Industries both aim to develop the first 100% ammonia-capable turbine by 2025.

In the meantime, co-firing ammonia with other fuels has been explored as an interim solution. Japan has tested several applications for co-firing ammonia with both coal and gas. Based on current technical constraints, a co-firing ratio of 20% of ammonia with coal (based on energy content) is considered technically feasible. In a scale up of ambitions announced in June 2021, the Japanese government announced that it aims to achieve 50% ammonia co-firing with coal by 2030[19], alongside the goal of importing three million tons of ammonia by the same time frame under their Integrated Innovation Strategy[20].

The Japanese government, with the support of industry players, has strongly pushed ammonia co-firing as a key abatement technology for coal in the power sector. As the co-firing with ammonia does not require major retrofits in the existing coal plants, this strategy is favoured by many Japanese utilities to keep their existing plants running, due to the limited capital outlay. With government backing, a series of demonstration tests were conducted by academia and industry to test the technical and commercial viability of these applications.

The latest among the series of demonstration tests is the 20% ammonia-co-firing at JERA's 1 GW Hekinan power plant. Japan's public research and development arm, the New Energy and Industrial Technology Development Organization (NEDO), has earmarked JPY 110 billion (US$1 billion) for the trial, which is to be conducted at Unit 4 of JERA's Hekinan coal plant[21]. The government funds are expected to contribute to the ammonia procurement, construction of related facilities such as the storage tank and vaporizer, as well as the development of specialised burners for co-firing to be tested at a separate site in Hekinan Unit 5. The tests at Hekinan are Japan's first ammonia co-firing at a commercial plant. If proven commercially and technically viable, Japan aims to progressively refurbish existing facilities for ammonia co-firing from mid to late 2020s, before moving towards higher co-firing/full ammonia combustion by 2050.

IHI has test-bedded co-firing 70% liquid ammonia with natural gas in a 2 MW gas turbine. This demonstration test was conducted between April 2019 and March 2021 and is financed by NEDO. Under this setting, liquid ammonia is sprayed directly into the combustor. The use of liquid ammonia removes the need for a vaporiser, which reduces capital costs. However, this technology is lower on the readiness scale, compared to both ammonia co-firing with coal and hydrogen blending in gas units. Thus, discussions on ammonia's use in the power sector tends to focus on coal-based co-firing. The application of co-firing ammonia with gas has additional challenges due to the corrosive nature of ammonia.


Ammonia in storage tanks

17 Mitsubishi Power (2021)
18 IHI (2021a)
19 Argus Media (2021)
20 Cabinet Office, Government of Japan (2020)
21 NEDO (2021)

Box 2.2 Alternate uses for ammonia

Despite the technical, economic and environmental challenges that ammonia faces in the power sector, it remains an important piece of the wider decarbonisation puzzle. Ammonia is expected to play an important role for decarbonising industrial processes, transport, and to a smaller extent, heating sectors.

Ammonia as feedstock in chemical processes

The use of ammonia as feedstock in the oil refining and petrochemicals industry is considered as one of the key "no regrets" applications, especially since there is currently a lack of zero carbon alternatives in these sectors.

Ammonia in industrial furnaces

Ammonia can also be used in industrial furnaces, through direct combustion. Compared to the power sector, where a variety of alternative power sources are available, decarbonising the industrial sector is considered more difficult, with fewer and often costlier abatement options. Thus, the replacement of fossil fuels by ammonia may be among the best decarbonisation options available, aside from electrification. Potential applications of ammonia co-firing can be explored in the energy intensive iron, steel and cement industries.

Ammonia as a transport fuel

Yet another potential usage of ammonia could be in the replacement of diesel or gasoline in vehicles running on internal combustion engines). Research shows that ammonia-fuelled transport emits less than a third of GHG emissions of a traditional diesel/gasoline vehicle[22]. However, challenges with ignition[23] and safety (with potential ammonia leaks) need to be addressed before the technology can be rolled out widely.

Ammonia in shipping

As emissions standards tighten for the maritime shipping industry, ammonia could emerge as a viable fuel for ships. The benefit of ammonia as a maritime fuel stems from (1) high energy density; (2) safety and (3) low emissions. However, marine engines capable of using ammonia are not yet available. Furthermore, although ammonia is more energy-dense than hydrogen, it pales in comparison to traditional bunker fuels such as diesel and fuel oil. The industry, led by leading engine makers, Wartsila and MAN Energy, is working hard to commercialise ammonia-based engines. Potential challenges ahead for the use of ammonia focuses on emissions (primarily NO_x emissions), corrosion and stability.

Ammonia in aviation

There are also ongoing discussions on the use of ammonia as a jet aviation fuel. The Science and Technology Facilities Council in the United Kingdom has partnered with the private sector to design a prototype that can effectively crack ammonia for use in planes. Following a successful proof of concept, the partners are looking to pilot the technology[24].

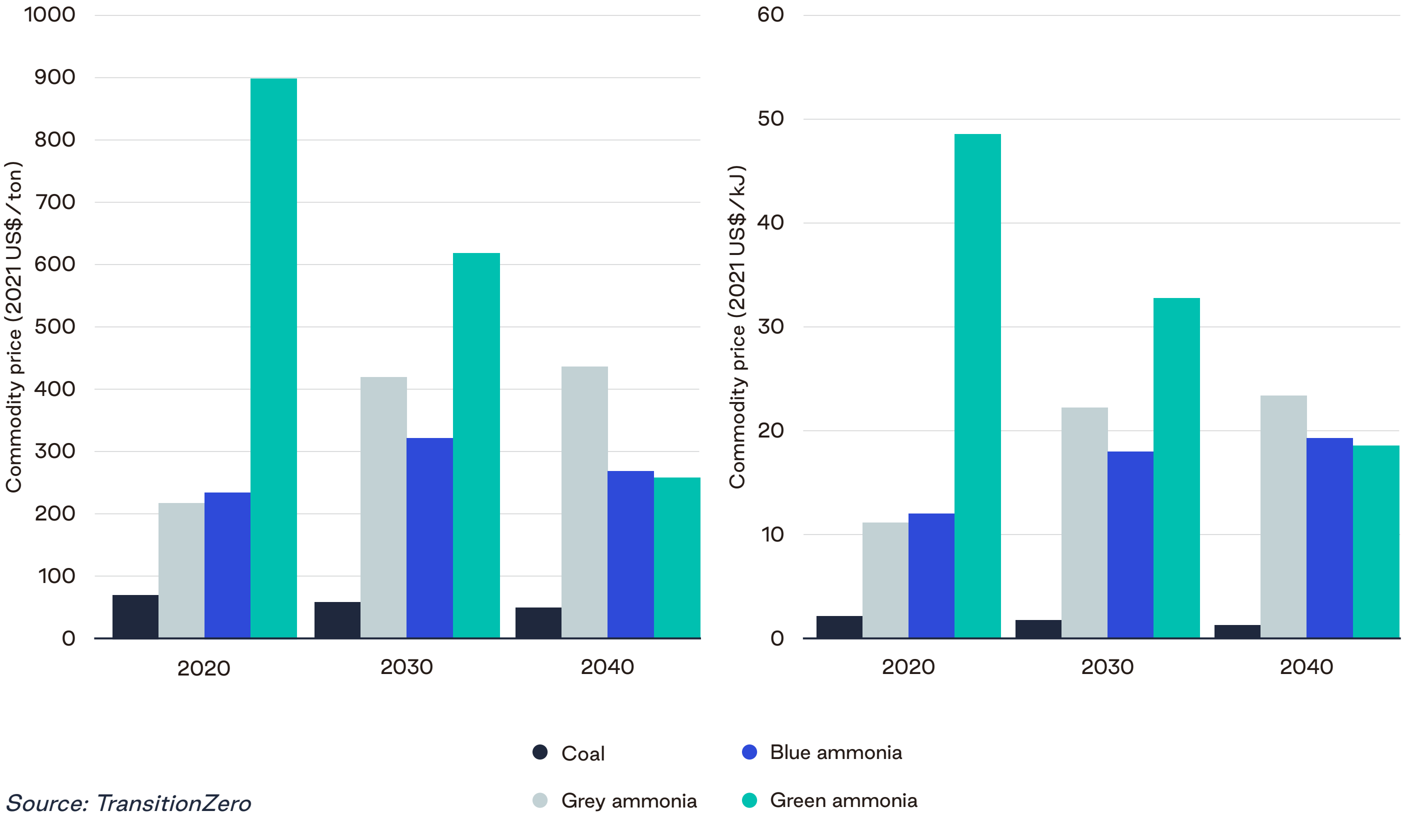
22 Medina et al (2021)
23 Klüssmann et al (2020)
24 UKRI (2020)

Fuel cost assessment

One of the first challenges associated with commercialising ammonia co-firing is cost. On an energy equivalent basis, grey ammonia, which is the cheapest source of ammonia, currently costs around four times that of thermal coal. The cost gap widens even further when considering green ammonia, which is 15 times the cost of coal, on an energy equivalent basis. Assuming carbon prices are instituted globally in line with IEA's NZE scenario, by 2030 the cost of grey ammonia increases substantially, making low-carbon options, such as blue and green ammonia, more competitive.

To support rapid commercialisation of green ammonia, reducing the cost of electrolysers will be a key challenge. Reducing electrolyser costs will depend on breakthroughs in high-temperature electrolysis which reduces electrical energy needs, as well as cost reductions associated with economies of scale and standardisation of system components and plant design. Without these gains, green ammonia may only be competitive in 2040 (Figure 2.3). In addition, on an energy equivalent basis, coal remains the cheapest option, compared to all the shades of ammonia.

Figure 2.3 Ammonia price forecast



Source: TransitionZero

LCOE assessment

Reducing the cost of nascent technologies, such as ammonia co-firing, will be a critical enabler of its adoption. Despite the resurgence of hydrogen related research due to a favourable policy environment, the use of hydrogen in the power sector is being deemphasised compared to other use cases (Table 2.1)[25]. Without widespread international support, ammonia/hydrogen use in power generation is likely to be limited. Other hurdles preventing the uptake of ammonia co-firing stem from the technology itself. The need for customisations for each project limits gains from learning by doing. At the current stage, ammonia co-firing requires the use of specialised burners and stringent control over how and where ammonia is injected into the flame.

Table 2.1 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]

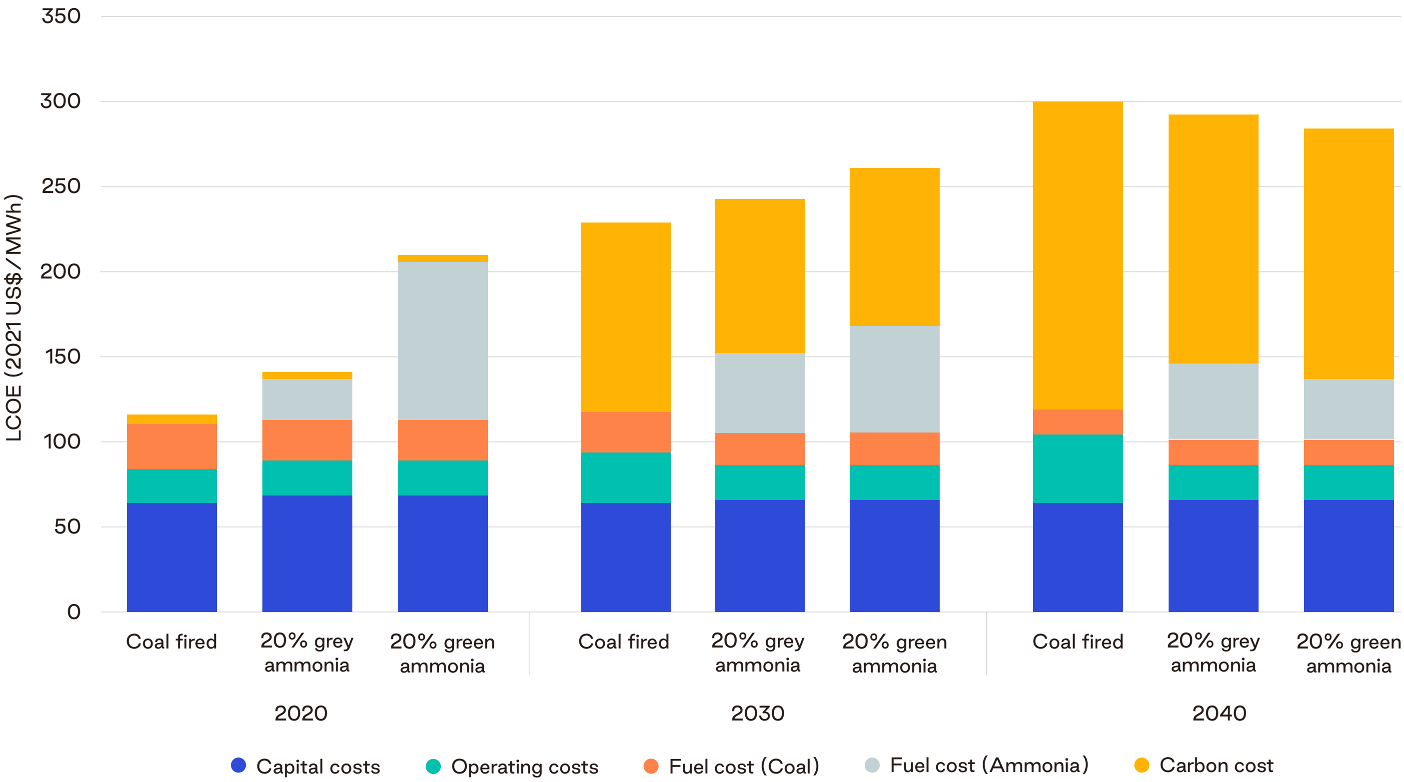
● Immediate ● Medium ● Low/No

25 There has been some discussion on the potential of ammonia as a long-term energy storage option to balance seasonal demand fluctuations. However, the high conversion losses associated with such applications still present technical hurdles for mass deployment. The direct combustion of ammonia in gas turbines as a flexible power generation to support intermittency challenges associated with high RE penetration is also considered. However, its use is hindered by technical challenges with maintaining stable flames due to the slow kinetics of ammonia combustion with air. One potential solution to this is to decompose ammonia into hydrogen and nitrogen and combust hydrogen in the gas turbine. However, the high energy requirements of the cracking process depresses the overall energy efficiency of such applications.

26 World Energy Council (2021)

Even 20% co-firing of the cheapest grey ammonia is set to double the fuel costs compared to coal. The price dynamics shifts slightly in 2030 and 2040 due to the expectation of higher carbon prices being implemented globally. However, due to higher energy equivalent fuel prices, co-blending 20% ammonia triples the total fuel cost, 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$ (Figure 2.4). This results in a LCOE of around US$280/MWh, which is prohibitively expensive.

Figure 2.4 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.

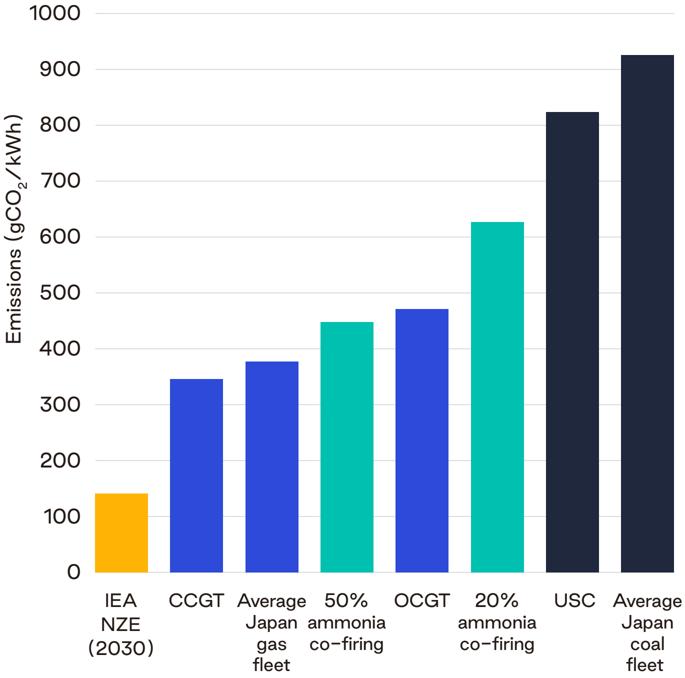
The co-firing of ammonia also comes with additional costs for new plant equipment, such as the supporting ammonia import infrastructure (e.g., storage tanks, pipelines, and vaporisers). The retrofitting and redesigns of existing engines to support ammonia combustion will also contribute to increased capital costs. In the absence of steep increases of carbon costs and/or dramatic cost reductions in electrolysers and CCS technologies, the cost advantage of traditional coal plants over ammonia co-firing plants is expected to last throughout the coming decade.

Carbon reduction potential of ammonia co-firing

Despite claims, ammonia co-firing does little to reduce emissions. At the power generation stage, co-firing ammonia directly displaces emissions associated with coal combustion, with the co-firing rate being a direct proxy for emissions reduction. At the current technologically feasible co-firing rate of 20%, the emissions factor remains close to double that of gas-fired CCGT. A higher co-firing rate of 50% brings the associated emissions per unit of electricity produced close to that of gas generation, which will need to be replaced or abated by 2035 to be consistent with the IEA's NZE scenario[27]. Without significantly higher co-firing rates, ammonia co-firing in coal plants provides only marginal emissions reduction benefits.

> A higher co-firing rate of 50% brings the associated emissions per unit of electricity produced close to that of gas generation, which will need to be replaced or abated by 2035 to be consistent with the IEA's NZE scenario

Figure 2.5 Emissions intensity of different power generation technologies



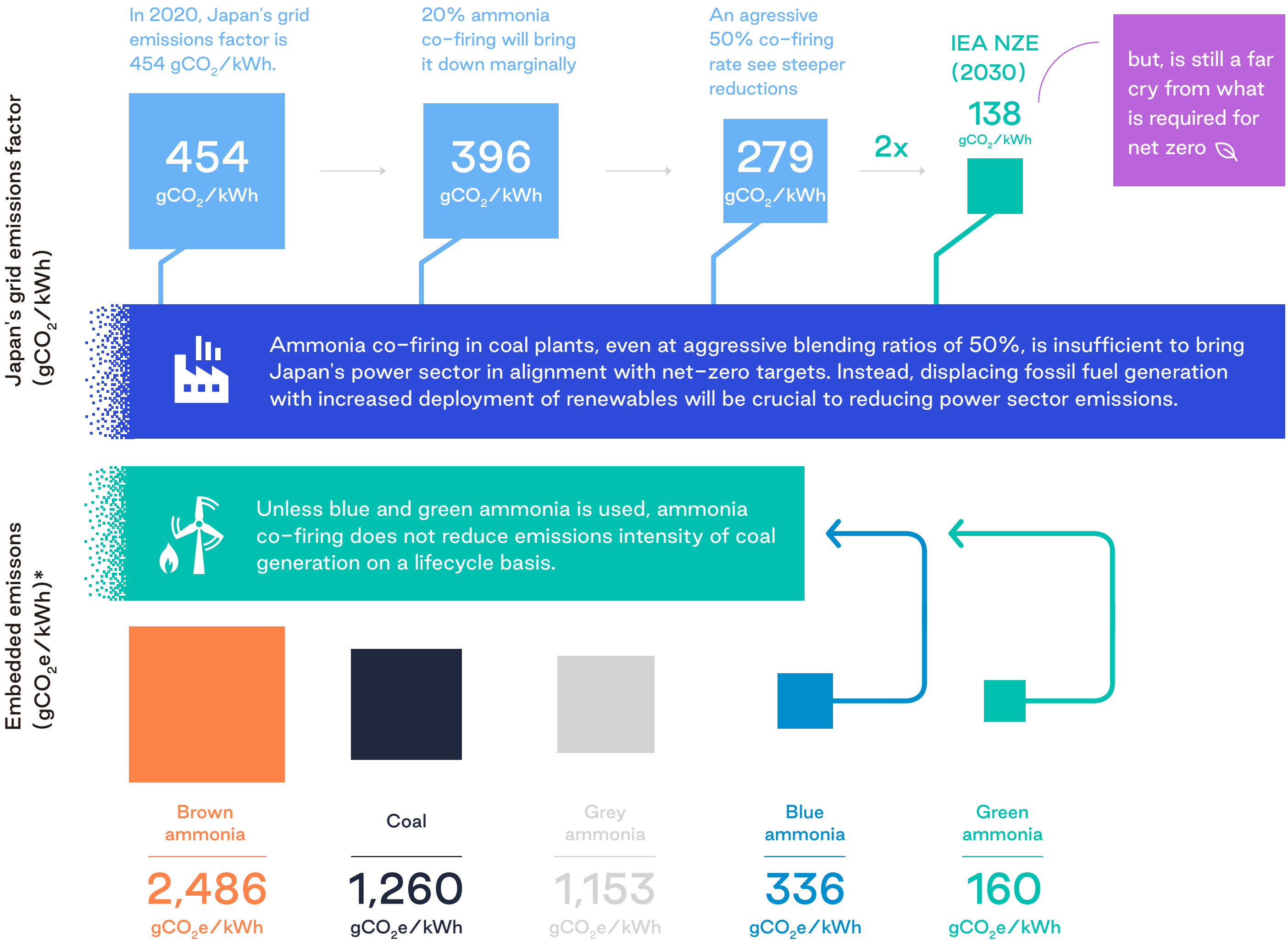
Source: TransitionZero
Note: IEA NZE refers to the carbon intensity of electricity generation referenced in the IEA Net Zero Roadmap. CCGT and OGCT refers to the emissions factor of combined cycle gas turbines, and open-cycle gas turbines, respectively. Both are gas-based generation technologies. USC refers to the emissions factor of ultra-supercritical coal plants. USC plants are considered to be the most efficient of coal-fired power plants.

Ammonia is commonly used as a feedstock in the petrochemical industry

Based on lifecycle analysis conducted by the IEA, grey ammonia produced using unabated fossil fuel contains embedded emissions of 112-249 gCO_2/MJ (1,090-2,423 gCO_2/kWh)[29]. This is equivalent to double the emissions associated with the direct combustion of coal. Unless blue and/or green ammonia is utilised, there is no net emissions reduction from co-firing. While the use of blue and green ammonia can cut upstream emissions to a minimum, potential emissions may also arise from the use of carbon-intensive transport modes, such as the use of heavy fuel oil as fuel for maritime transport, which adds 3-10 gCO_2/MJ (29-97 gCO_2/kWh) to lifecycle emissions[30].

For ammonia co-firing to be consistent with the IEA's NZE scenario, only blue or green ammonia should be considered. However, since green ammonia has a power-to-power efficiency of 22%[31], close to 80% of the energy is wasted during the conversion process. This steep energy efficiency penalty leads to fundamental questions about the use of green ammonia to produce electricity.

Figure 2.6 Japan's emissions factor and lifecycle emissions comparison between coal and ammonia



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.*

29 IEA (2021b)

30 IEA (2021b)

31 IEA (2021b)

Other ammonia co-firing challenges

Technical considerations

There are technical challenges associated with ammonia co-firing. Ammonia has poor flammability, high ignition temperatures, low flame velocity and flame temperature, narrow flammability range and high radiant heat transfer. These challenges make ammonia poorly suited for direct combustion in power plants. Although successful demonstrations have been conducted in a few pilot programmes, the scaling of the technology remains to be seen. Moreover, due to the complexities of coal-fired operations, each power plant is configured differently. As such, the true effect of ammonia co-firing on each plant may be difficult to establish without a wide enough sample pool. Any slight deviation in the power plant set-up may result in high retrofit costs, or lead to efficiency and performance penalties, compromising project economics.

Based on a 20% co-firing rate and an assumed base load operation for the Hekinan plant, we estimate that JERA will need to procure about 500,000 tons of ammonia per year for the demonstration project. However, the company announced that it is only looking to procure 30,000 to 40,000 tonnes for trial at Hekinan Unit 4 and an additional 200 tonnes for the pilot tests at Hekinan Unit 5[32]. This highlights the limited scale of the pilot tests and suggests that the technology is not yet commercially ready.

Air pollution

One of the immediate concerns of ammonia co-firing with coal is air pollution. Due to the presence of nitrogen in ammonia, co-firing ammonia may result in increased NO_x emissions. Simulation studies have shown that NO_x emissions are the highest with low co-firing rates, and gradually decreased with increasing co-firing ratios. However, as a trade-off, unburned ammonia increases once co-firing ratios exceed 40%[33]. The unburned ammonia reacts with NO_x and SO_2 to form secondary PM2.5[34], worsening air pollution. This points to an interesting NO_x-NH_3 dynamic, as ammonia is also often used to control NO_x emissions. Lower flame temperatures and flame instabilities can result in air pollution from NO_x emissions 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 localised air pollution if care is not taken. While air pollution can be controlled, these technologies are often expensive and reduce the efficiency of the boiler.

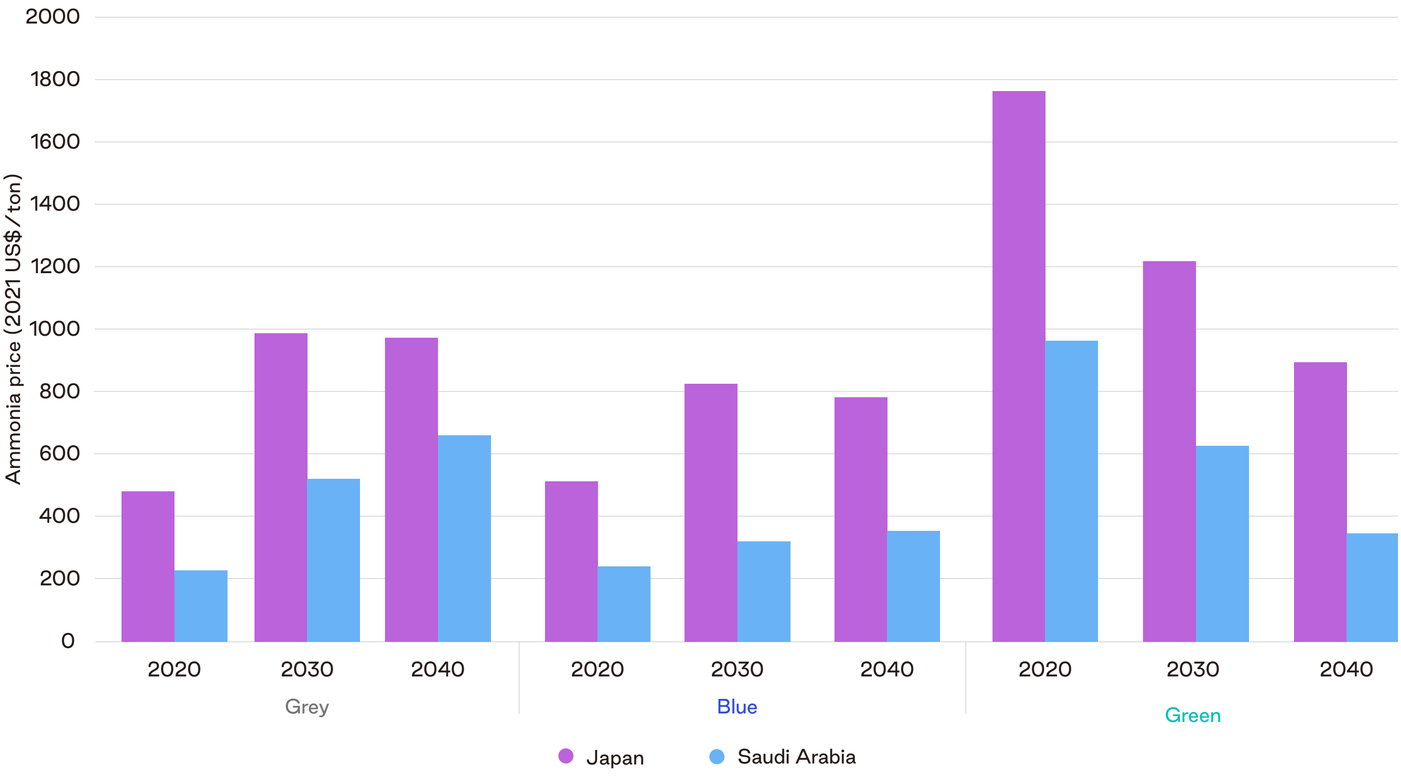
Energy security

Energy security lies at the heart of Japanese energy policy. Japan currently produces about 75% to 80% of its one million tons of ammonia demand domestically. With the growth of the ammonia economy and the increased use of ammonia in power plants, Japan would have to either invest in developing domestic production capacity, or rely on international imports.

Based on our analysis, even accounting for shipping costs, importing from international sources could help Japan save about half of its ammonia costs, across all shades of ammonia. While equipment and other capital expenditure costs are likely to be comparable globally, the presence of cheap natural gas as feedstock and cost-competitive renewable energy is set to widen the pricing gap between domestic production and international imports. The gulf between domestic ammonia and international imports means that Japanese utilities have few options but to rely on cheaper imports.

32 Platts (2021a)
33 Ishihara et al (2020)
34 Oxidised products of NO_x and SO_2 react with NH_3 to form PM2.5 (referred to as secondary PM2.5).

Figure 2.7 Comparison between domestic production versus international imports



Source: TransitionZero
Note: Japan has already imported its first cargo of blue ammonia from Saudi Arabia. The carbon dioxide captured is utilised at a nearby methanol facility, as well as for EOR. Green ammonia production in Saudi Arabia is assumed to be supported by solar PV generation.

This dilemma will worsen Japan's energy security. Assuming a 20% co-firing rate, Japan will require about 20-25 million tons of ammonia every year for use in the power sector, more than 20 times its current demand and about the size of the 2020 globally traded ammonia market. Importing these large volumes of ammonia leaves Japan vulnerable to various sources of uncertainty.

The first source of uncertainty lies in the speed of the energy transition and development of the ammonia market. The rapid scale-up in the global ammonia market will have to be grounded in various transition strategies that are to be determined either at a corporate level or at a national level. If the global economy for low-carbon fuels does not materialise at the speed and scale required, there are significant risks that Japan may be locking itself into obsolete/frontier technologies that remain high cost.

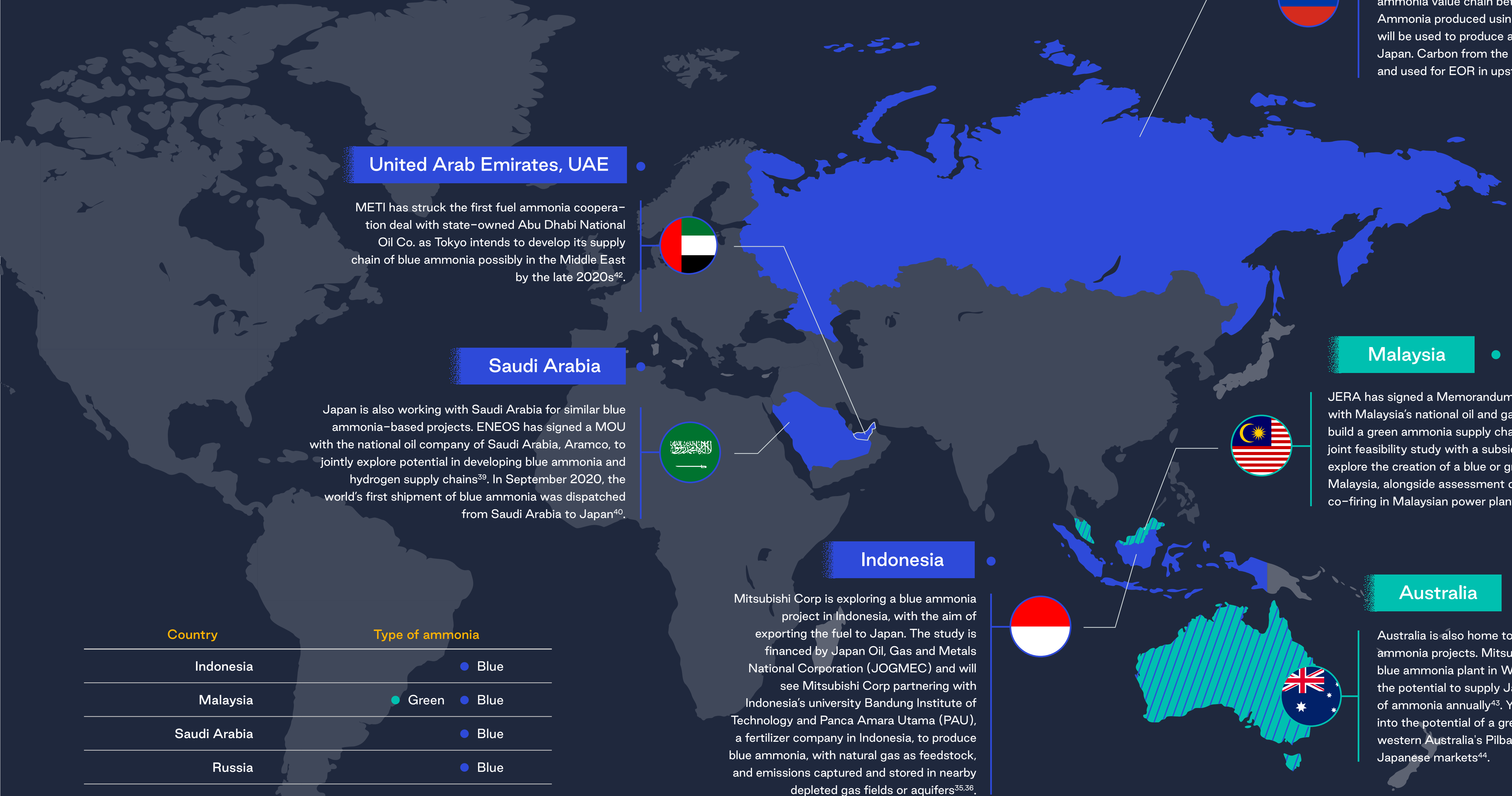
The second degree of uncertainty stems from unanticipated geopolitical shocks across this newly emerging supply chain, leading to concerns surrounding potential price/supply shocks. To mitigate such risks, Japanese companies are looking abroad to develop upstream projects, in a bid to secure dedicated supply for future use. Despite these efforts, it is undeniable that cross-border maritime trade in newly emerging low-carbon fuels such as ammonia and hydrogen, will only serve to increase Japan's energy insecurity.

The last degree of uncertainty arises from the potential sources of ammonia imports. While a diversified group of suppliers may present potential benefits to energy security and resource dependency for Japan, the volatility experienced by gas in 2020/2021 sets up a cautionary tale on how regional and national demand and supply dynamics may introduce unexpected shocks to international markets, to the detriment of resource stability. A high import dependency will leave Japan vulnerable to:

1. uncertainty and price shocks if it relies on the spot market, or
2. pricing premium if Japan chooses to lock in prices for long term stability.

Box 2.3 Map: Japan's ammonia investments globally

Below is a compilation of some of Japan's current partnerships/investments in upstream ammonia supply projects globally.



Russia

Japan's industry ministry signed a memorandum of cooperation (MOC) with Russia's Novatek, Gazprom on hydrogen, ammonia, CCS and CCU. ITOCHU Corporation is also interested in studying the possibilities of establishing a blue ammonia value chain between Eastern Siberia and Japan. Ammonia produced using natural gas from producing oil fields will be used to produce ammonia, which will be transported to Japan. Carbon from the production process will be captured and used for EOR in upstream oil fields[41].

United Arab Emirates, UAE

METI has struck the first fuel ammonia cooperation deal with state-owned Abu Dhabi National Oil Co. as Tokyo intends to develop its supply chain of blue ammonia possibly in the Middle East by the late 2020s[42].

Saudi Arabia

Japan is also working with Saudi Arabia for similar blue ammonia-based projects. ENEOS has signed a MOU with the national oil company of Saudi Arabia, Aramco, to jointly explore potential in developing blue ammonia and hydrogen supply chains[39]. In September 2020, the world's first shipment of blue ammonia was dispatched from Saudi Arabia to Japan[40].

Malaysia

JERA has signed a Memorandum of Understanding (MOU) with Malaysia's national oil and gas company, PETRONAS, to build a green ammonia supply chain[37]. Similarly, IHI also has a joint feasibility study with a subsidiary of PETRONAS to explore the creation of a blue or green ammonia value chain in Malaysia, alongside assessment on the potential ammonia co-firing in Malaysian power plants[38].

Indonesia

Mitsubishi Corp is exploring a blue ammonia project in Indonesia, with the aim of exporting the fuel to Japan. The study is financed by Japan Oil, Gas and Metals National Corporation (JOGMEC) and will see Mitsubishi Corp partnering with Indonesia's university Bandung Institute of Technology and Panca Amara Utama (PAU), a fertilizer company in Indonesia, to produce blue ammonia, with natural gas as feedstock, and emissions captured and stored in nearby depleted gas fields or aquifers[35,36].

Australia

Australia is also home to various proposed upstream ammonia projects. Mitsui & Co. has plans to build a blue ammonia plant in Western Australia, which has the potential to supply Japan with one million tons of ammonia annually[43]. Yara International is looking into the potential of a green ammonia project in western Australia's Pilbara region for export to Japanese markets[44].

Country	Type of ammonia
Indonesia	Blue
Malaysia	Green, Blue
Saudi Arabia	Blue
Russia	Blue
UAE	Blue
Australia	Green, Blue

35 Mitsubishi Corp(2021)
36 Nikkei Asia (2021a)
37 Nikkei Asia (2021b)
38 IHI (2021b)
39 ENEOS (2021)
40 Nikkei Asia (2021c)
41 ITOCHU (2021)
42 Platts (2021b)
43 Nikkei Asia (2021d)
44 Nikkei Asia (2021e)

Conclusion

While the use of ammonia is often cited as a key technology to decarbonise Japan's grid, it currently faces multiple financial, environmental, and technological hurdles. Our analysis shows ammonia will likely remain a prohibitively expensive power generation technology, which will do little to help Japan meet its carbon neutrality ambition. For ammonia to be cost- and climate-effective, there will need to be dramatic cost reductions in electrolysers, technological breakthroughs to allow pure combustion of ammonia in the power sector and the rapid build-up of the globally traded green ammonia market to meet rising demand. There is limited evidence to suggest this will happen in a manner consistent with a 1.5°C outcome. In the absence of a compelling economic and environmental case, the underlying motivation appears to be based on keeping coal plants alive. In doing so, those Japanese utilities who are pursuing ammonia in power generation risk destroying shareholder value unnecessarily.

Ammonia is sometimes transported via trains in tanks

04 Integrated gasification combined cycle (IGCC) plants

Summary

1. Japanese utilities saw renewed interest in advanced coal technologies such as IGCCs, particularly with the start-up of the first commercial IGCC plant in Japan. However, there is little certainty that IGCC can deliver on its financial and climate promises.

2. IGCC has a chequered past, which saw frequent cost blowouts. This has led to cancellations of many planned projects globally. For the projects that went ahead, capital costs often ballooned to double the anticipated outlay.

3. High upfront cost, with significant risk of cost overruns, reduces the financial attractiveness of IGCC plants. Looking into the future, the cost reduction potential for IGCC is also not obvious. IGCC plants face challenges in scaling up installed capacity, with projects seeing the capital cost per unit of installed capacity rise instead of fall, as installed capacity increases.

4. Unless coupled with CCS, IGCC plants do not meaningfully reduce carbon emissions. There are no existing CCS-equipped IGCC plants, pointing to significant financial and technical hurdles to realising the low-carbon potential of IGCC.

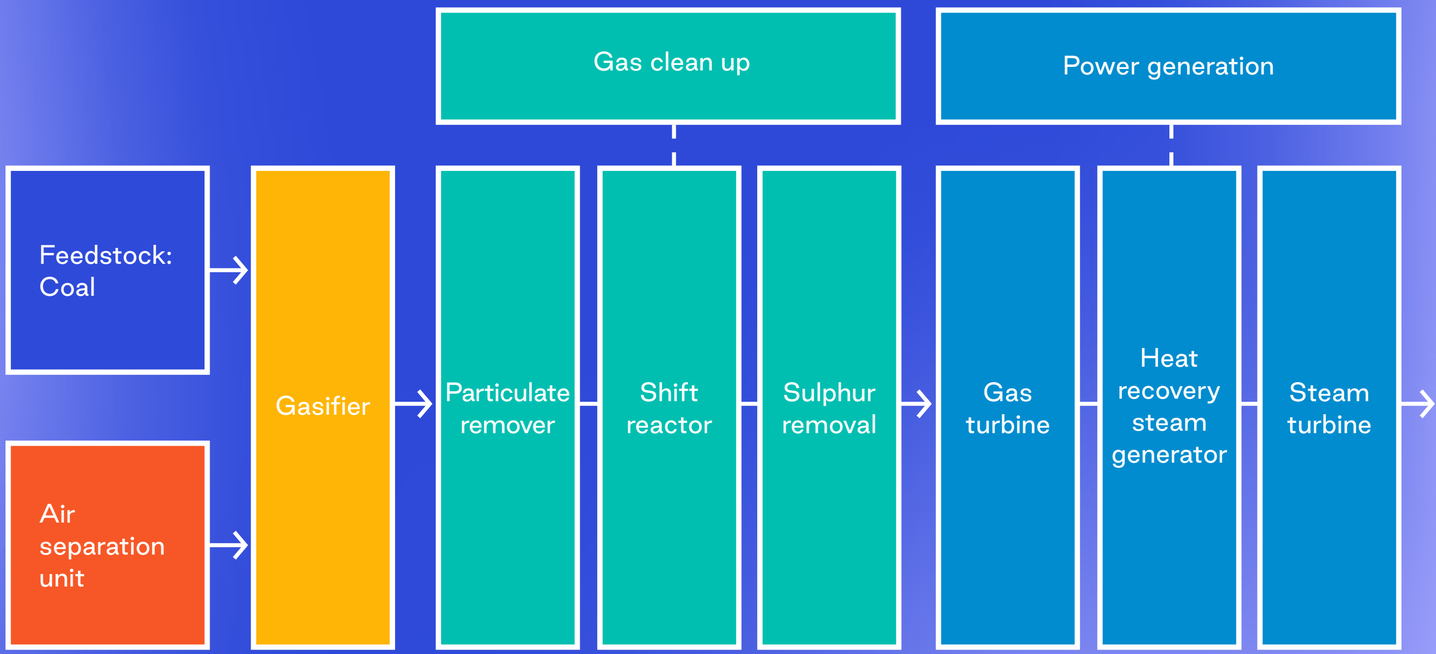
5. Retrofitting IGCC with CCS is technically infeasible, so investing in IGCC means new coal plants, which is inconsistent with Japan's net-zero ambitions, and may lead to stranded assets in the future.

6. IGCCs also face significant technical and operational challenges during the operational phase, among other challenges.

Background

Integrated gasification combined cycle (IGCC) plants convert feedstock into synthesis gas, which is cleaned before burning in gas turbines to generate electricity. Potential feedstocks for IGCC plants include coal, biomass, refinery bottom residues (such as petroleum coke, asphalt, tar, etc.), and municipal waste. A simplified IGCC system comprises three major "systems"—gasification, gas cleanup, and power units (Figure 3.1).

Figure 3.1 Basic set up of an IGCC plant



Source: TransitionZero

Coal-based IGCC plants have several advantages compared to coal plants, including: reduced air pollution, higher thermal efficiency, greater coal quality flexibility and cheaper/easier to integrate with pre-combustion CCS. Although the first IGCC plant was built in Germany in the 1970s, IGCC only gained commercial interest in the 1990s as a potential technology to keep the pollutant-emitting coal plants alive. At that point, IGCC was part of the coal industry's response to the dirty image of coal plants as heavy emitters of harmful pollutants such as sulfur dioxide, nitrogen oxide, mercury, and particulate matter, all of which contributed to localised air pollution. However, due to technological complexities and high costs compared with back-end clean-up alternatives, the technology never really took off. As climate change concerns gained traction in the early 2010s, interest in the technology revived due to its compatibility with pre-combustion CCS. Since then, several new projects have been deployed.

Box 3.1 Global development of IGCC: a series of failed experiments

In the 1990s, a series of IGCC projects were proposed and built across Europe and the US. The rush to IGCC was prompted by air pollution concerns from coal plants. In the US, with the support of the Clean Coal Program through the Department of Energy, three IGCC plants were built: the Wabash River Project, the Polk County IGCC and the Pine IGCC. All three projects ran into operational challenges and failed to achieve their desired outcomes of proving the technical and commercial viability of coal gasification[46]. IGCC was considered a failed experiment.

US: Edwardsport IGCC (2013)

Duke Energy first proposed the Edwardsport IGCC in 2006, with a projected cost of just under US$2 billion for the 618 MW plant. By the time the plant completed construction, the price tag had ballooned to US$3.5 billion, a cost overrun of over 80%. Problems persisted in the operational stage. Plant operations were far from being stable and reliable, as expected of traditional thermal plants. Edwardsport had more than three times the unplanned plant outages compared to a typical gas-fired plant, while also being one of the most expensive plants to run in the US.

China: GreenGen IGCC (2011)

GreenGen IGCC is China's first commercial scale IGCC project. The project was first initiated by China Huaneng Group in 2004. After almost five years of preparatory work, the project finally broke ground in 2009. The initial project plan consisted of three stages:

1 the construction of a 250 MW IGCC plant

2 a demonstration test for carbon capture and

3 the construction of a 450 MW IGCC plant equipped with pre-combustion carbon capture[47].

In 2011, the first phase of the GreenGen project was brought online. However, while phase 2 of the project began in June 2016, the final phase of the project, which was to be the operation of a fully built CCS-equipped IGCC plant, was never completed due to technical and financial challenges.

South Korea: Taean IGCC (2016)

South Korea began its own IGCC experiment in 2006 with support from the Ministry of Knowledge Economy. After years of research and development, a 300 MW demonstration plant within Korea Western Power Co's existing 4 GW Taean power plant was proposed in 2011. During that time, interest in IGCC was growing in South Korea. Due to the purported environmental benefits, IGCC plants were welcomed in South Korea, with ambitious plans to build 15 coal gasification plants producing 10 GW within the decade. However, when the demonstration plant was brought online in 2016, it was grossly over budget and underperformed both on its efficiency and environmental claims. The failure of this demonstration plant significantly slowed down the momentum for IGCC plants in South Korea and there have been no new developments since then.

US: Kemper County IGCC (2017)

The Kemper County IGCC is often referred to as one of the most infamous IGCC failures. The 824 MW project was initially planned to start operating in 2014, at a cost of about US$2.9 billion. However, operational issues with the gasifier system continued to add costs and delay plant commissioning. By 2017, the capital cost of the plant was up to US$7.5 billion, and the decision was made to abandon coal gasification altogether. The facility is now operating as a natural gas plant instead.

46 Pine IGCC failed to achieve stable production, clocking only 128 cumulative hours over the three-year start-up period. Polk IGCC switched to using petroleum coke as feedstock after the five year demonstration period, while the Wabash River project faced significant challenges addressing reliability issues in the early years of operation.

47 Phillips, Booras and Marasigan (2017)

Japan's experience with IGCC in power generation can be divided into two distinct technological tracks: oxygen-blown IGCC and air-blown IGCC. Air-blown IGCCs are known to achieve a thermal efficiency advantage of 2-3% against an oxygen-blown IGCC; the latter requires an additional air separation unit, which consumes high amounts of auxiliary power, incurring high energy penalties for the plant. Existing commercial plants, such as the Nakoso IGCC plant in Japan, operate in the air-blown mode.

In recent years, interest in oxygen-blown IGCC has increased, due to its compatibility with cost-effective pre-combustion carbon capture. Initial studies have indicated that due to the high cost associated with capturing carbon downstream, oxygen-blown IGCC equipped with pre-combustion capture is expected to be commercially attractive going forward. As they had done with other technologies, the Japanese government provided significant seed funding to kick start the technological development of IGCCs in Japan. R&D for IGCC plants first started in 1983 in Japan, followed by a pilot plant test that ran from 1991 to 1996, funded primarily through government subsidies. A summary of Japan's IGCC projects are detailed below.

Air-blown: Nakoso Unit #10 IGCC demonstration plant

In September 2007, Japan conducted demonstration tests for air-blown IGCC at Nakoso Power Station. The capacity of the demonstration plant was 250 MW, half the size of a commercial plant. The 5 year trial proved commercially successful, achieving a net thermal efficiency of 42% and over-achieving on various operational and environmental parameters. The success of the demonstration plant allowed it to continue its operation as a commercial plant from 2013.

Air-blown: Nakoso/Hirono IGCC Power

Following from the success of the Nakoso IGCC demonstration-turned-commercial plant, a further 2x543 MW IGCC facility was built at the same site of the demonstration plant. The Nakoso IGCC plant began operations on April 16, 2021. The power plant claims to be 10% to 15% more efficient than a 600C—class ultra supercritical (USC) coal-fired unit, and targets emissions of 650g carbon/kWh[48].

Oxygen-blown: Energy Application for Gas, Liquid, and Electricity (EAGLE) project

The EAGLE project was an initial research proposal, funded by Electric Power Development Company of Japan (J-Power), in collaboration with NEDO, a testbed for oxygen-blown coal gasification launched in 2002. Demonstration tests started in 2002, centring on IGCC operations. Since then, CCS related tests were also conducted between 2007-2013.

Oxygen-blown: Osaki CoolGen project

Following the EAGLE project, the Osaki CoolGen Project was conceptualised to scale up demonstration tests, and included new elements such as CCS and the production of hydrogen to support the creation of a hydrogen economy. The Osaki CoolGen project consists of the design, manufacturing and operation of a 166 MW oxygen-blown IGCC plant, which will be conducted in three stages.

- Phase 1 (2016-2018): Demonstration tests for the commercialisation of oxygen-blown IGCC
- Phase 2 (2019-2020): Demonstration tests for oxygen-blown IGCC coupled with CCS
- Phase 3 (2021-2022): Demonstration tests for integrated coal gasification fuel cell combined cycle (IGFC) technology

48 Power Magazine (2021)

Cost of IGCC
Chequered past

Table 3.1 Capital cost estimates for IGCC plants

Sources	Original unit	Original value	US$(2021)/kW	Description
Wang and Stiegel (2015)	$/kW (2011 US)	3,339	3,910	
Wang and Stiegel (2015)	$/kW (2011 US)	3,461	4,053	
Wang and Stiegel (2015)	$/kW (2011 US)	3,820	4,474	
NREL (2019)	$/kW (2017 US)	3,893	4,184	
Pichardo et al (2019)	$/kW	5,999	6,182	
Pichardo et al (2019)	$/kW	7,140	7,358	
Xia et al (2020)	$/kW	2,133	2,292	
Xia et al (2020)	$/kW (2017 US)	3,540	3,805	Based on Taean IGCC, South Korea
Rosner et al (2020)	$/kW	5,136	5,228	
Xia et al (2020)	$/kW (2017 US)	5,663	6,086	
Kim (2021)	$/kW (2017 US)	4,820	5,180	Based on actual project: Edward-sport, US
Szima et al (2021)	Euro/kW	2,245	2,657	
Adnan et al (2021)	$/kW (2011 US)	4,872	5,706	

Source: TransitionZero, and the various literature quoted in the table[49]
Note: If the study did not specifically cite the base year for cost estimates, we have assumed that the costs are indexed to the year of publication.

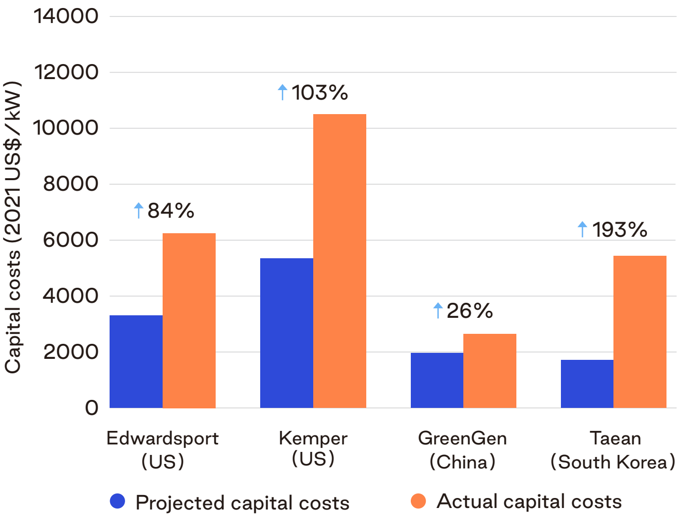
Aside from the high capital costs, the risk of cost blowouts is also significant for commercialising IGCC plants. Due to the technical complexity of IGCC plants, several well-known IGCC plants faced significant budget overruns as the final design specifications are fleshed out, due to factors such as repeated modifications and increased complexity of plant design. The technical complexity for IGCC plants can be largely attributed to the intricacy of individual "systems" and processes, and the need to ensure integration across the multiple systems.

The performance and economic viability of gasifier units are key measures of commercial success of an IGCC plant. However, gasifiers have also been a key problem area for IGCC projects, being the root cause of various well-known IGCC failures. While we refer to a gasifier as one simple unit, there are multiple underlying design parameters that make each gasifier unique. Design considerations such as the choice of technology (i.e. fixed bed gasifier, moving bed gasifier, or circulating fluidised bed), the coal feeding conditions (slurry or dry feed), by oxidising agent (air-blown or oxygen-blown), and many other factors, make each gasifier customised for each plant.

In addition, the need to integrate across multiple systems further enhances the technical challenges associated with IGCC plants. To achieve higher efficiency and ensure smooth plant operations, a high degree of synchronisation is required between the three main subsystems. However, this level of coordination can be challenging to accomplish. If unsolved for, the design flaws may also lead to increased maintenance, reduced availability and degraded reliability for the plant. Such risks should also be considered when evaluating investments into IGCC plants at an early stage. Compared to conventional coal plants, which have achieved a level of technological sophistication to enable simpler plug-and-play project development, a typical IGCC plant will have to undergo rounds of technical design, and even then, face a lead time for synchronisation before stable plant operations.

49 Xia et al (2020); Szima et al (2021); Wang and Stiegel (2016); NREL (2019); Kim (2021); Rosner et al (2019); Adnan et al (2021); Pichardo et al (2019)

Figure 3.2 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. Aside from Kemper IGCC, several now infamous projects, including the US FutureGen project, and Australia's ZeroGen project, were suspended due to unmanageable and escalating costs. Out of the 25 coal-gasification projects that were proposed in the US in early 2000s, only two projects were brought to completion (Edwardsport and Kemper County), and at significantly higher costs (Table 3.2)[50], without ultimately incorporating carbon capture. Most of the projects were suspended, citing challenges due to high costs, significant project lead times and technological challenges. South Korea saw history repeat itself as the ambitious scale-up goals lost momentum after challenges revealed by Taean IGCC.

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

Poor air quality in Seoul, South Korea is regularly blamed on coal. However, Japan seldom faces similar issues due to strict emissions standards at coal power plants.

Table 3.2 Select cancelled IGCC projects

Cancelled IGCC projects	Cancelled year	Country	Size (MW)	Technology
Ashtabula IGCC	2006	US	830	IGCC
Polk Power Station Unit 6	2007	US	630	IGCC
Southern Illinois Clean Energy Center	2007	US	600	IGCC
PacifiCorp Sweetwater Project	2007	US	450	IGCC
Stanton Energy Center	2007	US	285	IGCC
Nueces IGCC Plant	2007	US	600	IGCC
Bowie IGCC	2007	US	600	IGCC
Huntley Generating Station	2008	US	680	IGCC
Buffalo Energy Project	2008	US	1100	IGCC
Future Gen	2008	US	200	IGCC/pre-combustion capture
Kwinana Power Station	2008	Australia	500	IGCC/pre-combustion capture
Great Bend IGCC	2009	US	629	IGCC
Hebei Chaohua IGCC	2010	China	800	IGCC
Goldenbergwerk IGCC	2010	Germany	450	IGCC/pre-combustion capture
Mesaba Energy Project	2011	US	603	IGCC
ZeroGen	2011	Australia	500	IGCC/pre-combustion capture
Magnum IGCC	2011	Netherlands	1311	IGCC
Mountaineer IGCC	2011	US	629	IGCC/pre-combustion capture
Taylorville Energy Center	2013	US	770	IGCC/co-production
Lianyungang IGCC	2014	China	1300	IGCC/pre-combustion capture
Teesside IGCC	2015	United Kingdom	850	IGCC/pre-combustion capture
Texas Clean Energy Project	2017	US	400	IGCC/pre-combustion capture
North Killingholme IGCC	2017	United Kingdom	470	IGCC/pre-combustion capture
Lima Energy IGCC	2018	US	600	IGCC

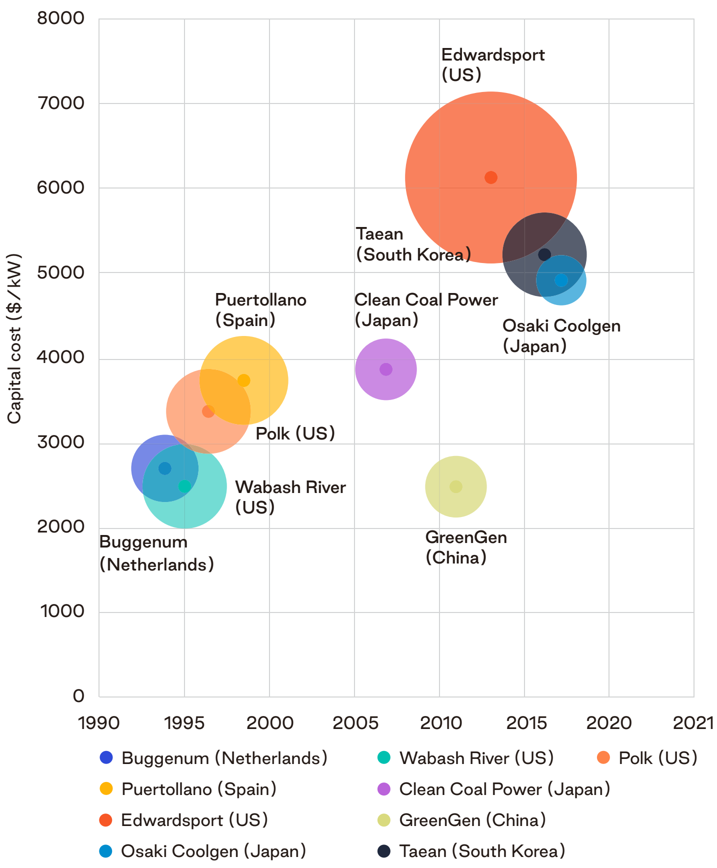
Source: TransitionZero

LCOE assessment

Looking into the future, the cost reduction potential for IGCC is not obvious. With only a handful of existing projects, a robust analysis on the cost reduction potential for IGCC plants is not possible for this report. However, based on the consolidated project costs of commercial IGCC plants, the cost reduction potential for IGCC plants appears limited (Figure 3.3). In fact, from 1990 to 2020, the overall trend for IGCC capital costs seems to be increasing. This is not surprising, due to the technical complexities and bespoke nature of each IGCC project.

In addition, the capital cost estimates of past projects seem to point to another trend: as larger projects are installed over the years, the capital cost per unit of installed capacity does not fall, but actually rises. This poses a significant challenge for large-scale deployment of IGCC plants in the future. Most existing IGCC plants are between 200 MW to 300 MW, significantly smaller than typical coal and gas plant units. The largest IGCC to date is the Edwardsport IGCC project, at 618 MW. It is also the most expensive IGCC plant on a per kW installed capacity basis[51]. The need to ensure seamless integration across various individual systems, discussed above, may have contributed to the difficulty in scaling up IGCC operations.

Figure 3.3 Capital costs 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.

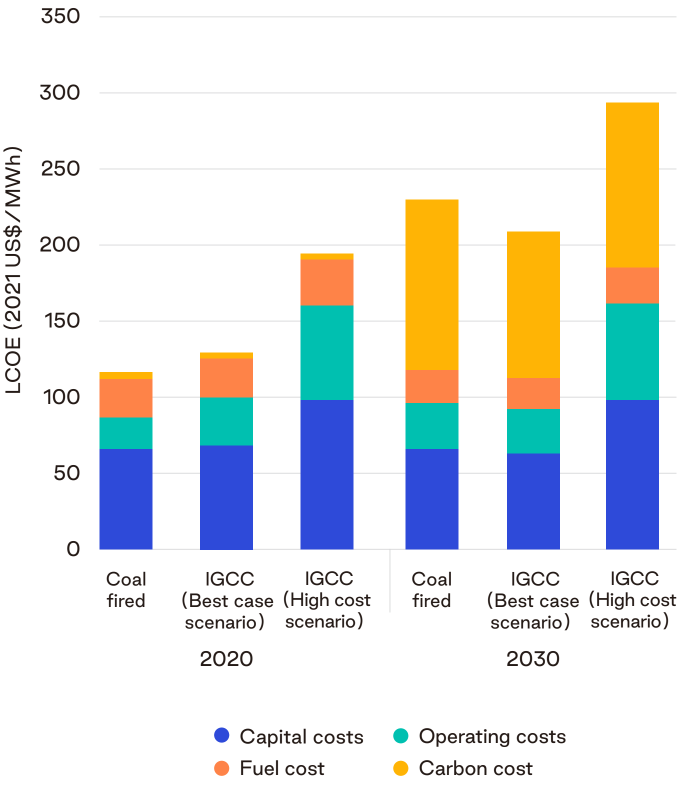
Anecdotal evidence from the ill-fated Edwardsport and Kemper County IGCC plants may also help uncover some of the reasons behind the flat learning curve. Both plants are attempts to scale up from existing prototypes, Edwardsport being a 2:1 scale up of Polk County IGCC and Kemper of a similar demonstration plant in the US. Both projects aimed to gain some learning experience from previous prototypes, including recycling previous project design parameters. However, it was not long before both projects ran into significant design flaws when they realised that significant modifications to the original design was required, leading to additional costs to correct those errors during the construction stage[52]. Developers of both Edwardsport and Kemper County IGCC severely underestimated the complexity of the technology, resulting in both plants failing to reach their design performance. In fact, Kemper County IGCC never ran on coal gasification.

What the Edwardsport and Kemper County IGCC experience illustrates is 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. That being said, some lessons and cost reductions can be achieved on the operational level. According to research by the IEA Clean Coal Centre, several lessons, specifically on the plant management front, can be drawn from existing commercial IGCC plants, which could help to create operational savings[53]. However, the case study above has proven that project developers and investors, alike, should be cautious not to overestimate cost savings from learning curves for IGCC plants.

51 The next largest IGCC plant will be Japan's 540 MW Nakoso IGCC plant. Cost estimates for Nakoso IGCC are not included in this analysis as TransitionZero cannot confirm the actual capital cost, although preliminary estimates place the figure at JPY 150 billion (US$1.3 billion).

52 Xia et al (2020)
53 Barnes (2013)

Figure 3.4 Cost breakdown for IGCC power plants



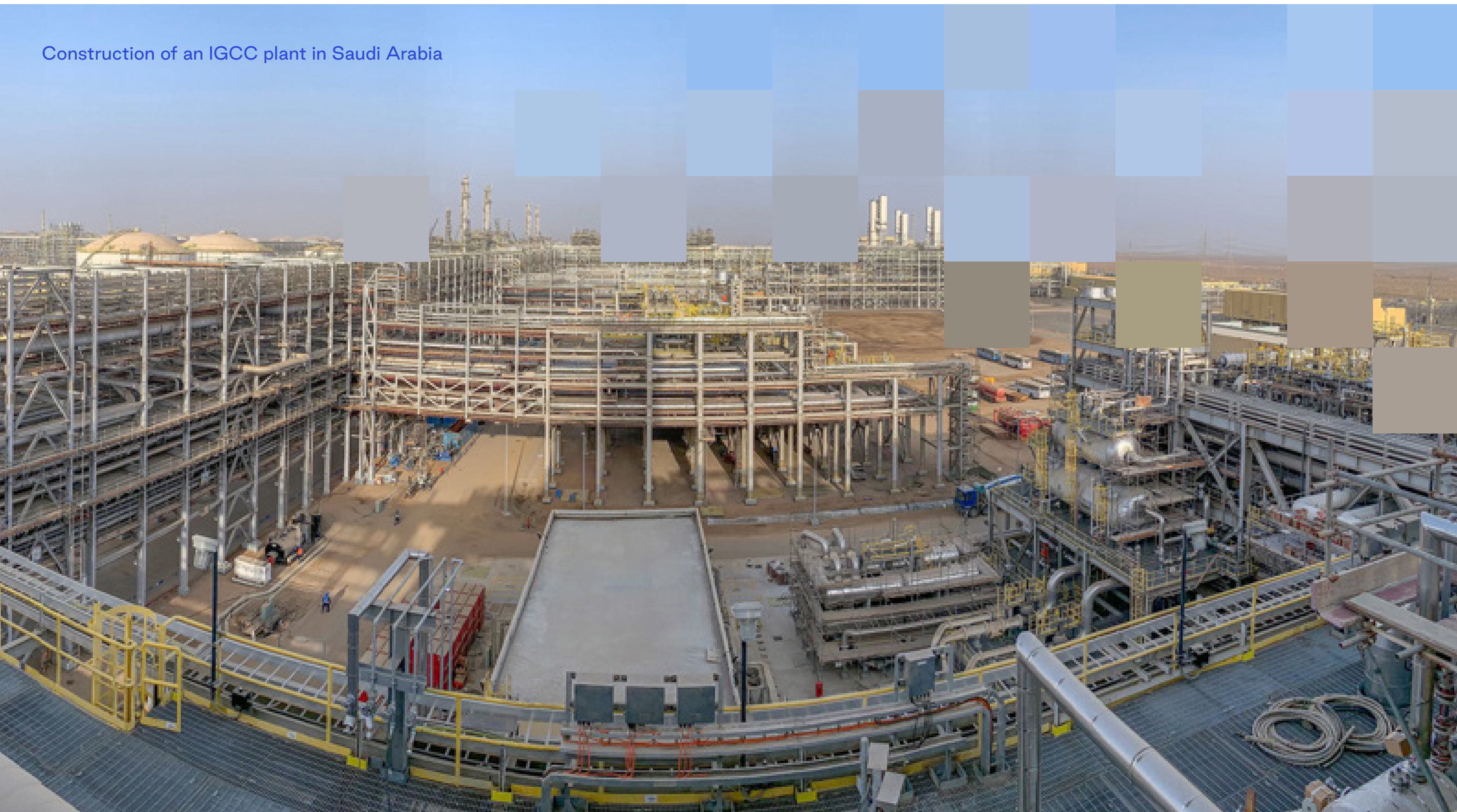
Source: TransitionZero
Note: The carbon cost refers to the carbon costs associated with power generation in Japan, which stands at US$5/ tCO_2 and US$130/ tCO_2 in 2020 and 2030 respectively. The assumed 2030 carbon price is in line with IEA's NZE scenario.

Although commonly overlooked, operating costs hold significant sway over LCOE for IGCC plants. Operating costs make up 24–31% of total LCOE for coal gasification plants, compared to coal plants at 17%. The increased operating costs are the direct result of increased monitoring requirements, particularly from the gasifier and turbine units, which are prone to breakdowns. Such equipment breakdowns lead to plant outages, which drags down plant availability and financial returns on the plant. To counteract these issues, significant investment into monitoring and control systems are required.

Under the best-case scenario, with costs aligned with the lower end of cost estimates, IGCC plants are marginally more expensive than traditional coal-fired power plants. However, for this scenario to occur, there is little margin of error for project development, requiring immaculate plant design, cooperation among engineering, procurement, and construction (EPC) contractors and smooth operations throughout the lifetime of the plant. The likelihood of this is low due to a poor track record, drawn from experience.

When considering a more realistic high-cost scenario, which aligns with the cost estimates of existing plants, the LCOE will skyrocket to above US $190/MWh, which is more than the average 2021 electricity price in Japan, currently standing at US $134/MWh. Compared to the best-case scenario, capital cost premiums are likely to arise from increased equipment costs, EPC contractor risk premiums, as well as other finance and related charges. Realistically, the cost of IGCC plants in Japan is likely to fall somewhere between the best-case scenario and the high-cost scenario.

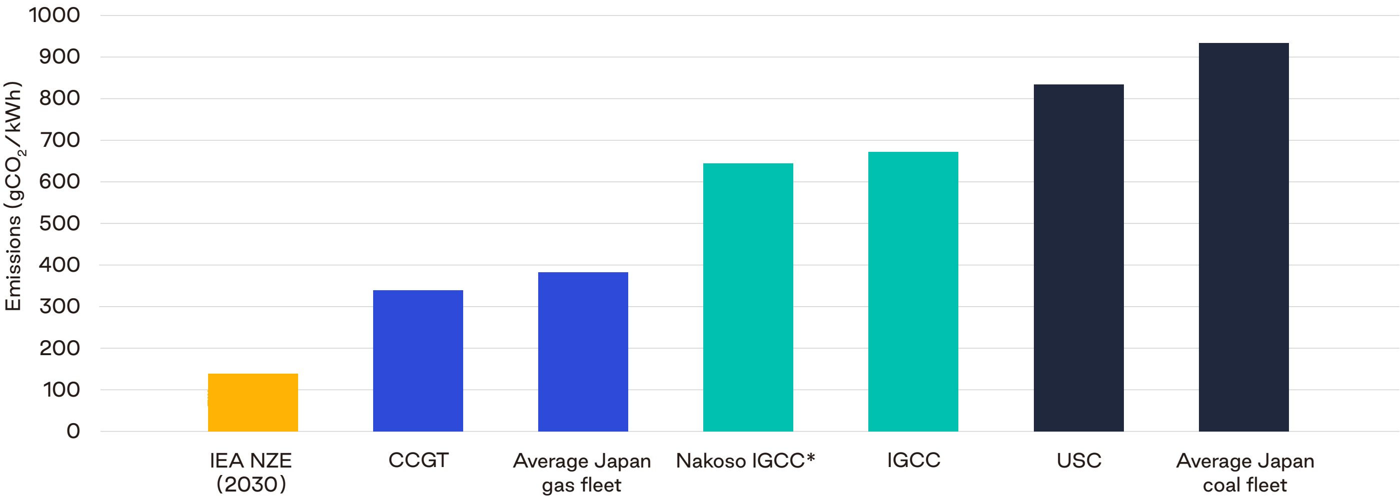
Construction of an IGCC plant in Saudi Arabia



Carbon reduction potential of IGCC

Per the IEA's NZE scenario, unabated coal generation is phased out in advanced countries, such as Japan, by 2030 and globally by 2040. According to existing literature, IGCC plants emit about 670 gCO_2/kWh, or a 22% reduction compared to ultra-supercritical (USC) coal plants. IGCC's abatement potential stems from its higher thermal efficiency, which reduces the coal consumption at coal plants. Compared to the average USC thermal efficiency of 42% at a low heating value (LHV) basis, IGCCs can achieve an efficiency of 46%-50%[54]. This will mean less coal is burned for the same power output, thus reducing the emissions per unit of power generated. Despite potential emissions-cutting benefits, as detailed in Figure 3.5, the emissions of IGCC plants still stand at almost double that of gas-fired power plants and deviate significantly from a net-zero aligned pathway, as envisioned by the IEA NZE scenario. Thus, without pre-combustion CCS, IGCC does not belong on a list of options for decarbonising the power sector.

Figure 3.5 Emissions performance of IGCC plants



Source: TransitionZero

Note: Nakoso IGCC refers to the emissions factor that Nakoso IGCC plant in Japan claims to have achieved, which is lower than industry estimates of a typical IGCC plant. To date, there is no confirmation whether this has been achieved since the plant only started commercial operations in April 2021. CCGT refers to the emissions factor of combined cycle gas turbines. USC refers to the emissions factor of ultra-supercritical coal plants. USC plants are considered to be the most efficient of coal-fired power plants

More critically, existing coal fleets cannot be retrofitted with IGCC technologies. Unlike ammonia co-firing, which can be enabled through the existing coal fleet, retrofitting existing coal plants into IGCC is prohibitively expensive. This means that any additional investment into IGCC will directly translate into new-build coal plants in Japan. This will not only contradict Japan's overall climate ambitions and 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. The stranded asset risk is best illustrated when considering the cost of generation of new build IGCC plants in 2030. Assuming a carbon price of US\$130/tCO_2, consistent with the IEA NZE scenario, the LCOE of IGCC plants lies between U\$200-300/MWh (Figure 3.4), which is close to double the electricity prices in Japan.

The lifecycle impact of IGCC raises even more alarm bells. One of the key benefits of coal gasification lies in its ability to use a variety of coal grades, particularly the lower grade lignite and subbituminous coal. Lignite is largely regarded as the world's most pollutive and energy inefficient fuel. Moreover, lignite also creates concerns around a range of other environmental externalities, including localised air pollution, soil quality concerns near mining sites, upstream methane slippages, among many others. In recent years, with the climate movement gaining momentum, demand for the fuel is declining as end-users seek cleaner alternatives. However, should coal gasification gain mainstream status in the power sector, it could breathe new life into this industry, raising more concerns about emissions across the lignite value chain, a move that would be detrimental to the global climate movement.

54 Estimates place the thermal efficiency of oxygen-blown IGCC at 46%, while air-blown IGCCs can achieve 48%-50% thermal efficiency. The Osaki Coolgen demonstration plant which utilized oxygen-blown technology recorded an efficiency of 42.5% (LHV), while the Nakoso Unit 10 demonstration plant, which employs air-blown IGCC, achieved an efficiency of 42% (LHV). This indicates that there is, in effect, no emissions reduction compared to USC coal plants. The argument is that these demonstration plants see efficiency penalties due to their reduced scale. In fact, Nakoso IGCC claim that their commercial scale oxygen-blown IGCC was able to achieve 48% efficiency at a LHV basis.

Other IGCC challenges

Historically, coal gasification IGCC plants required three to five years to reach a stable level of availability. The prolonged start-up period is required as a "debugging" phase to synchronise power plant parameters before reaching stable operations. During the start-up of the GreenGen project in 2011, the project faced various operational stability issues, which required plant operators to cooperate with equipment suppliers to undergo significant fine-tuning. The issue was resolved after repeated adjustments to the plant system, but it still took three years to reach optimal conditions. While newer plants have been able to reduce the fine-tuning phase to about one to three years, this is still considered long compared to other power generation technologies.

Beyond slow ramp up, IGCC plants also face issues with reliability. The operational challenges with Edwardsport are not unique to the plant. In fact, various other IGCC plants have experienced similar challenges with reliability. As one of the second generation IGCC plants, the Wabash River IGCC faced repeated plant outages due to gasifier problems, while integration issues have weighed down operations at Buggenum IGCC in the Netherlands. Plant outages have a direct impact on the costs of electricity as interruption of electricity generation, as well as high plant repair and maintenance costs, contribute to increased costs of the IGCC projects.

While operational failures at each IGCC plant are unique, some commonalities can be drawn. Equipment failures are common in the gasifier and turbine set-ups. With limited commercial applications of gasifiers globally, the technology has yet to achieve the maturity required for mass deployment. Due to different combustion characteristics of natural gas and syngas, gas turbine manufacturers also have some way to go to ensure stable operations of syngas turbines. To improve availability, some plants have burned natural gas as a backup fuel, or installed additional gasifiers. These additional mechanisms will only serve to prop up costs of IGCC. The addition of new equipment, such as new gasifiers or air separation units, will also increase the own energy consumption of a plant, further reducing plant profitability.

Conclusion

Coal gasification IGCC, despite being around for decades, has yet to establish a proven track record. In its five decades of existence, the IGCC technologies received waves of interest, first in the 1990s for its pollutant control potential, and again in the 2000s, for its emissions reduction pollution potential. However, coal gasification never gained mainstream attention. This is emblematic of the various technical and financial challenges surrounding the technology, highlighted in our discussions in this paper. IGCC is not a new technology. The industry has already given up on the technology, twice. Japan's confidence in pushing forth an outdated technology that did not pass the commercialisation test, twice, is indeed worrisome. Furthermore, stand-alone IGCC only performs marginally better in terms of emissions than coal plants, limiting any meaningful contribution to climate goals. Without an obvious advantage over other power generation facilities, IGCC is unable to compete effectively in Japan's power sector. This will leave IGCC plants technologically obsolete in the face of cost-competitive zero-carbon alternatives, such as wind and solar PV.

05 Carbon capture, utilisation and storage (CCS)

Summary

1 Carbon capture, utilisation and storage (CCS) has a role to play in the net-zero economy. However, despite the hype, the use of CCS in the power sector has been limited, with only one operating project in 2021.

2 Japan has very limited storage capacity for CO_2, which could run out in just one decade. The limited CO_2 storage potential in Japan necessitates careful prioritisation of its use.

3 The energy efficiency penalty of CCS applications range between 23% to 30% for current and previous projects. Such high parasitic loads depress financial returns.

4 Due to a lack of supporting infrastructure, CCS projects in Japan face large hidden costs related to permitting, licensing and other project development costs. This inflates CCS costs to between US$74/t$CO_2$ and US$169/t$CO_2$ for coal plant retrofits.

5 The climate benefit of CCS in the power sector may not be sufficient, as by the time it becomes cost-competitive over unabated fossil fuels, it will be out-competed by renewables.

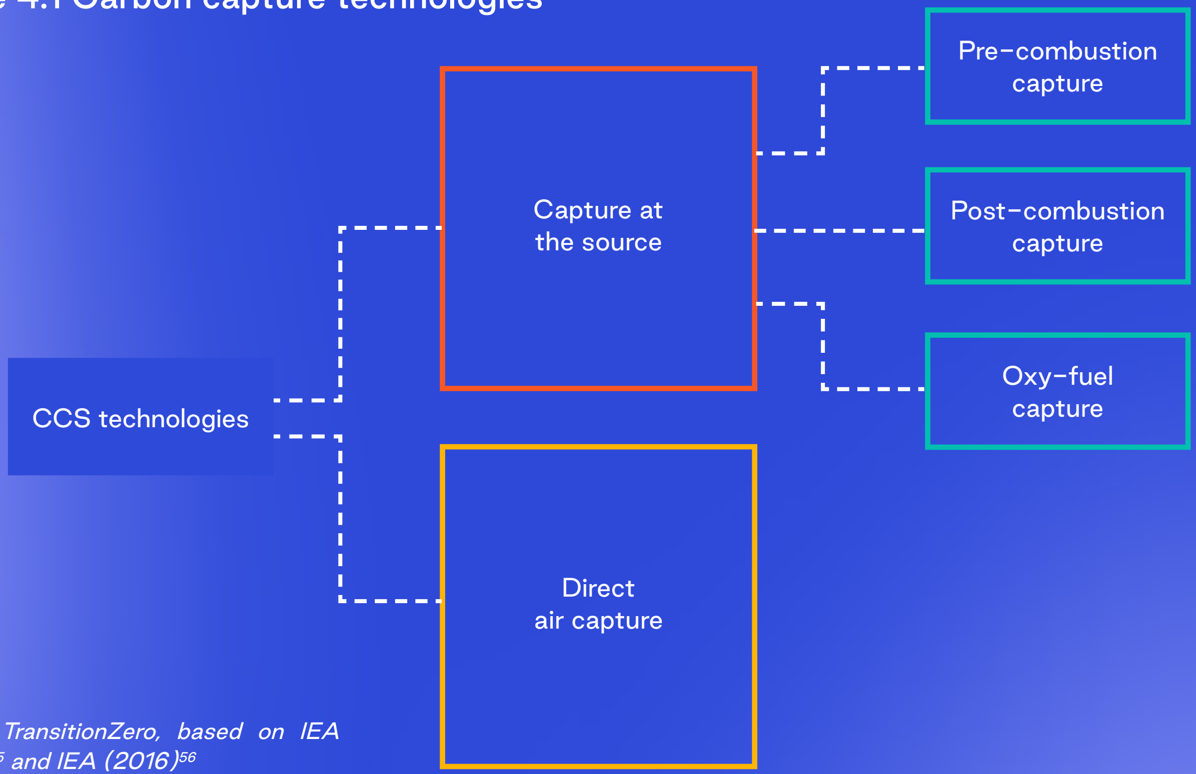
6 Concerns over the integrity of the domestic CO_2 storage sites may hinder the development of CCS value chains in Japan. Carbon leakages could lead to significant and potentially irreparable damage to Japan's marine biodiversity. However, Japan-specific literature on CO_2 storage is scarce. More needs to be done to understand the risks in Japan.

7 Given that there are competitive alternatives in the power sector in the form of mature renewable energy generation, such as solar PV and onshore wind, CCS is not a sustainable solution to keep coal in the energy mix. It is more prudent to use Japan's limited storage capacity for CCS in hard-to-abate industrial sectors.

Background

CCS is used to describe a suite of technologies that aim to capture carbon emissions for permanent storage, primarily in saline aquifers, or in other geological storage sites. There are two main ways to capture carbon emissions: at the source or directly from the air. Compared to direct air capture, which only gained traction in the past few years, conventional CCS applications that capture carbon at the source have been around for decades. As detailed in Figure 4.1, CCS technologies that capture emissions at the facility fall into three categories based on at which stage carbon is captured: pre-combustion carbon capture, post-combustion carbon capture and oxy-fuel capture.

Figure 4.1 Carbon capture technologies



Source: TransitionZero, based on IEA (2020)[55] and IEA (2016)[56]

Post-combustion capture is traditionally used in power plants. In these systems, CO_2 is separated from the exhaust after the fuel (coal or gas) is burnt. Post-combustion capture typically uses an amine-based solvent to separate the CO_2 from the rest of the gas and is considered the most mature of carbon capture technologies. Other approaches using physical solvents, membranes, chemical and physical sorbents are also available. Post-combustion capture is also seen in blast furnaces for steel plants.

Pre-combustion capture involves gasifying the fuel and separating out the CO_2 before the fuel is burnt. Pre-combustion capture is sometimes used in industrial facilities, however, for power applications, pre-combustion capture remains at a test-bedding stage. Similar to post-combustion capture, a variety of solvents and sorbents can be utilised. Pre-combustion capture is often discussed alongside IGCC applications. Under a pre-combustion capture equipped IGCC plant setup, CO_2 and hydrogen can be captured separately, for storage and reuse in the hydrogen economy, respectively.

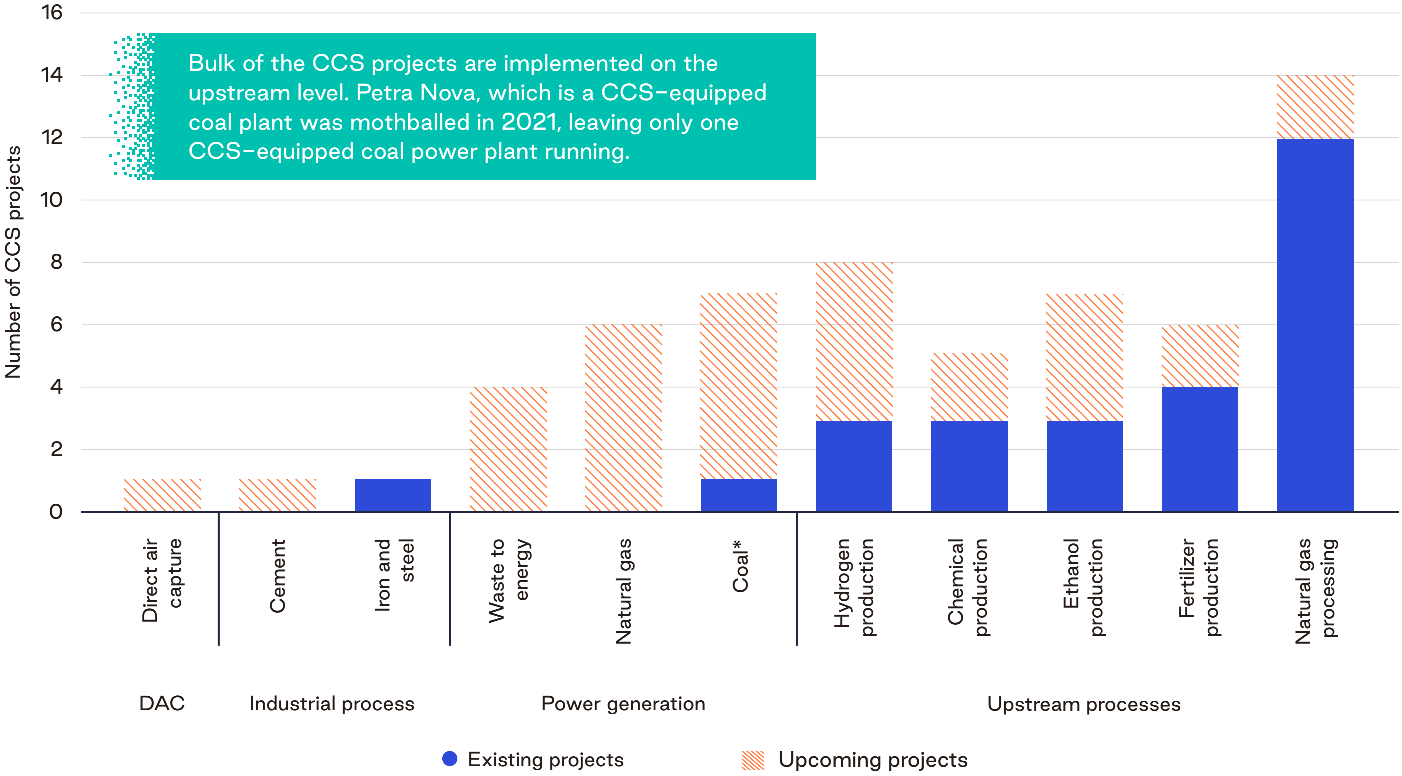
Oxy-fuel capture is the newest addition to the CCS technology suite. Fuel is burnt in a nearly pure-oxygen environment, which results in a more concentrated stream of CO_2 emissions, which is easier to capture.

Direct air capture (DAC), as its name suggests, captures CO_2 directly from the atmosphere. DAC systems can be further classified into liquid capture systems and solid capture systems. In a liquid DAC system, air is passed through a chemical solution, which will strip CO_2 from the air to be stored, prior to release into the atmosphere. Solid DAC systems, on the other hand, utilises solid sorbent filters which will chemically bind with CO_2. The filters are then heated to release concentrated streams of CO_2, which can be easily captured and stored.

55 IEA (2020)
56 IEA (2016)

Currently, about 30% of CO_2 captured in CCS projects is stored, and the rest is utilised in CCU applications. The bulk of the CCS projects utilise CO_2 for enhanced oil recovery, where CO_2 is pumped into oil and/or gas wells to increase well pressure and enhance flow rates. Less than 5% of captured CO_2 is used in industrial processes. Despite the hype surrounding CCS applications in power, there is only one operating CCS-equipped coal plant (Figure 4.2). Most operating CCS projects are focused on upstream production processes.

Figure 4.2 CCS projects in operation



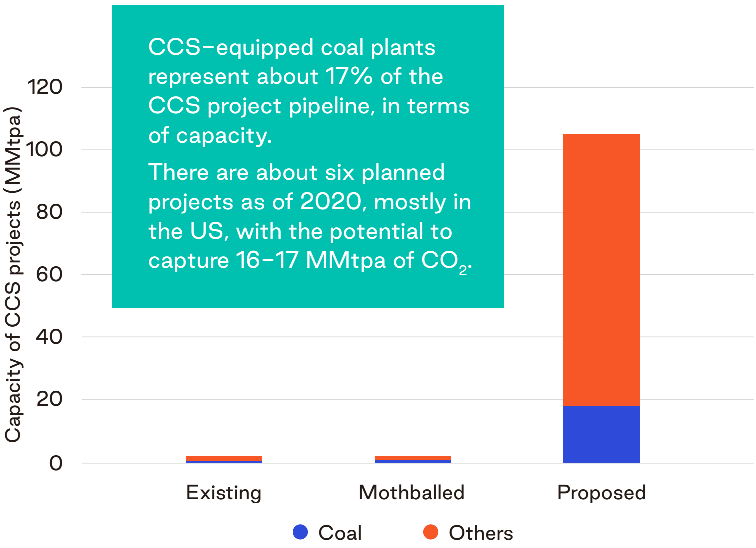
Source: Data from Global CCS Institute[57], TransitionZero analysis
Note: The CO_2 captured in the Petra Nova project was used in EOR operations. Due to the prolonged slump in oil prices, NRG announced that it will permanently mothball the project from June 2021.

The Boundary Dam CCS project in Canada is the only operating CCS-equipped coal project to date. Operating since 2014, the 110 MW coal plant cost more than US$1.5 billion to build, with US$354 million needed for retrofitting and US$1.2 billion for the CCS system. The project utilises the post-combustion CO_2 capture via amine absorption, which is one of the most mature CO_2 capture processes.

57 Global CCS Institute (2021)

There are around six planned CCS retrofits on coal projects, representing about 17% of the CCS project pipeline in terms of capacity (Figure 4.3). All proposed projects aim to utilise amine-based post-combustion capture technologies.

Figure 4.3 CCS-equipped coal-fired power plants



Existing CCS-equipped coal plants
Boundary Dam (Canada, 2014): 0.8-1 MMtpa

Mothballed CCS-equipped coal plants
Petra Nova (US, 2017): 1.4 MMtpa

CCS-equipped coal plants proposed
Guodian Taizhou(China, early 2020s): 0.3MMtpa
San Juan (US, 2023): 5.8-6 MMtpa
Gerald Gentleman (US, mid-2020s): 4.3 MMtpa
Prairie State (US, mid-2020s): 5-6 MMtpa
Project Tundra (US, 2025-2026): 0.5 MMtpa

Bridgeport Moonie (Australia) excluded as it is a mixed development

	Capacity (MMtpa)		Start-up year	Type	Country	Capture type	Storage type
Boundary Dam Unit 3	0.8	1	2014	Retrofit	Canada	Post-combustion amine-based	EOR, injection well
Petra Nova Carbon Capture	1.4	1.4	2017	Retrofit	US	Post-combustion amine-based	EOR
Guodian Taizhou Power Station Carbon Capture	0.3	0.3	Early 2020s	Retrofit	China	Post-combustion amine-based	EOR
San Juan	5.8	6	2023	Retrofit	US	Post-combustion amine-based	Under consideration
Prairie State	5	6	Mid 2020s	Retrofit	US	Post-combustion amine-based	Dedicated Geological Storage
Project Tundra	0.5	0.5	2025-2026	Retrofit	US	Post-combustion amine-based	Dedicated Geological Storage
Gerald Gentleman	4.3	4.3	Mid 2020s	Retrofit	US	Post-combustion amine-based	Under consideration

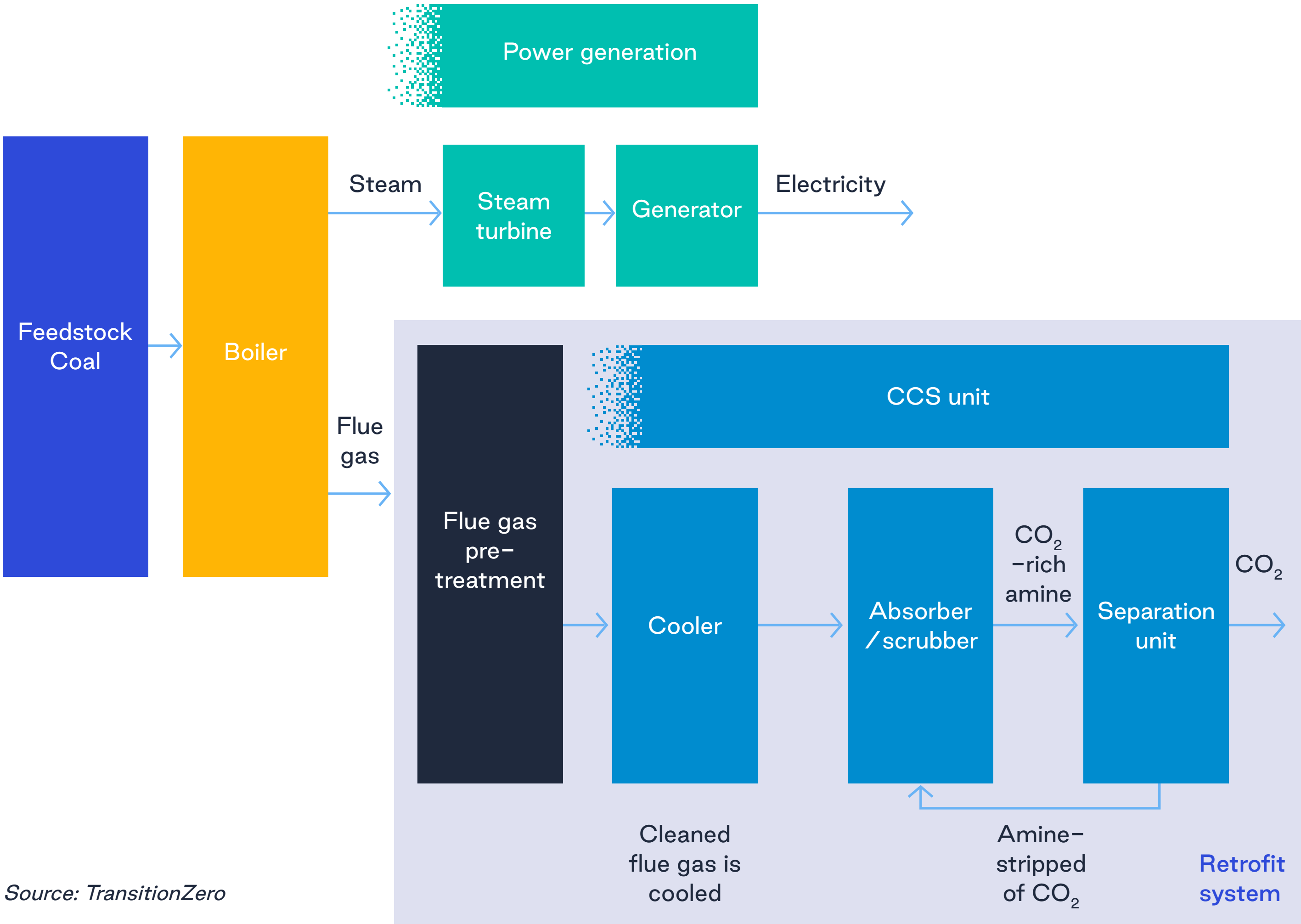
Source: Data from Global CCS Institute[58], TransitionZero analysis
Note: Petra Nova was mothballed in 2020. Bridgeport Moonies CCS (Australia) is not included as part of coal power plant based CCS projects as it is a mixed development project consisting of CCS applications for a variety of power and industrial processes.

58 Global CCS Institute (2021)

Post-combustion CCS

Most of the planned CCS projects for coal plants utilise post-combustion amine-based capture technologies. A typical process schematic of a coal plant equipped with a post-combustion amine-based CCS unit is illustrated in Figure 4.4 Flue gas exiting the boiler system is first passed through a pre-treatment system before it is cooled to about 30°C to 40°C using water in the cooler system. The cooled flue gas will then pass through the absorber or scrubber tower. In the absorber tower, flue gas rises, while amine settles at the bottom of the tower. As CO_2 starts to bind to the amine solution, CO_2-rich amine will collect at the bottom of the tower to be sent to the separation unit. In the separation unit, CO_2-rich amine is heated to about 120°C to release the CO_2. The CO_2-stripped amine is then recycled for use in the absorber tower. One advantage of post-combustion capture systems is its ease of retrofitting. CCS systems can be easily retrofitted onto existing coal plants simply by adding a flue gas pre-treatment unit and the corresponding CO_2 capture units, with minimal impact on the rest of the power plant.

Figure 4.4 Schematic of coal plants equipped with post-combustion amine-based CCS systems



Source: TransitionZero

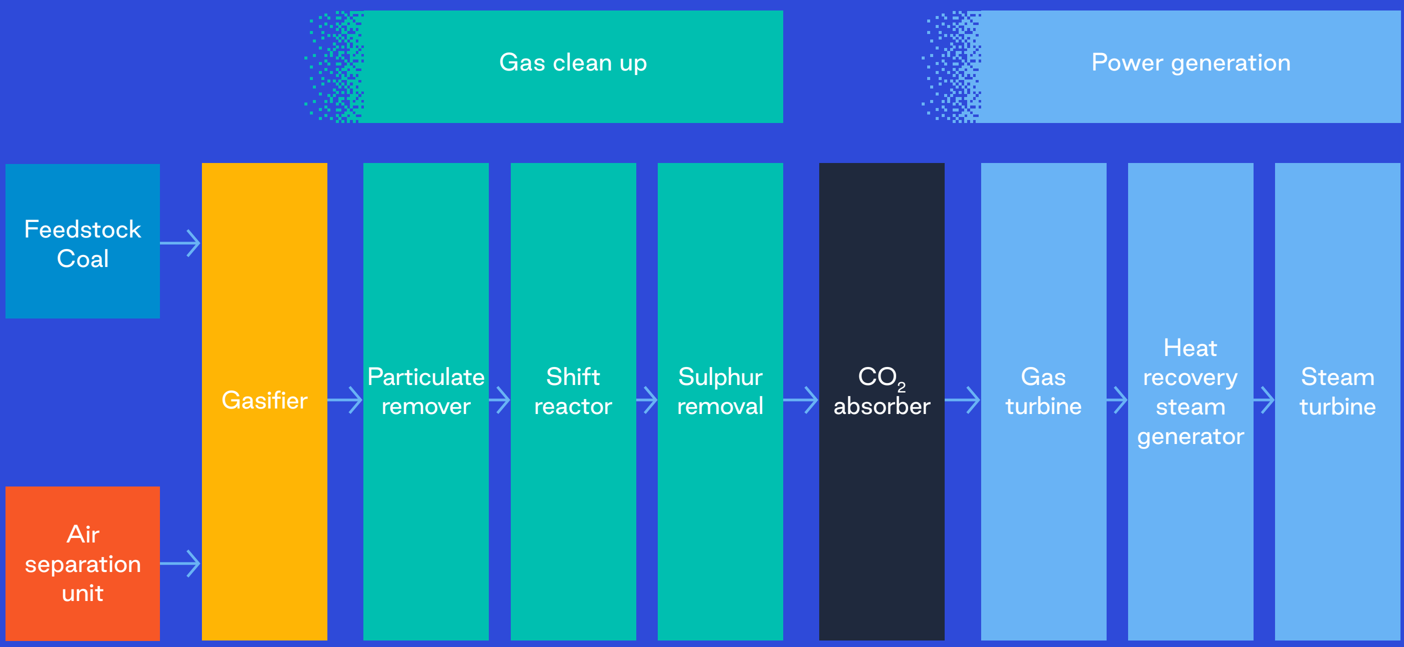
Pre-combustion CCS

Pre-combustion capture is only available in IGCC applications. A CCS-equipped IGCC plant is largely similar to a typical IGCC set-up, except that there is an additional CO_2 recovery unit, similar to one described in Figure 4.4. Cleaned syngas will pass through the CO_2 removal system where CO_2 and hydrogen can be captured separately, for storage and reuse in the hydrogen economy, respectively.

Despite multiple attempts, such as through the Kemper County (US) and GreenGen (China), there has been no successful IGCC+CCS demonstration project. However, based on existing literature, pre-combustion capture is expected to cost less than post-combustion capture due to the concentration of CO_2 at capture. In post-combustion systems, CO_2 has to be captured from a diluted stream of air (5-15% concentration) at low pressure. In comparison, pre-combustion capture in an IGCC set-up has CO_2 being captured at high concentrations and at higher pressure, which increases the efficiency of capture[59]. Thus, a pre-combustion system is expected to achieve a lower CCS cost in terms of dollars per ton of CO_2 captured.

However, due to the need for full integration of pre-combustion CCS into IGCC systems (Figure 4.5), its use is almost always restricted to new-build plants as retrofitting an existing facility for pre-combustion capture is prohibitively costly. Pre-combustion systems also come with added technical complexities that may affect plant performance and impact operational costs. In comparison, post-combustion capture, which has minimal impact on the rest of the power plant, is preferred.

Figure 4.5 Schematic of IGCC plants equipped with pre-combustion amine-based CCS systems



Source: TransitionZero

59 DOE (2021)

Box 4.1 CCS in Japan

Japan has established itself as a frontrunner in CCS research globally, and is home to various CCS demonstration projects, covering both power and industrial applications. In this section, we will cover some of Japan's key CCS demonstration projects.

Nakoso IGCC (Pre-combustion capture, power sector)

After the successful inauguration of the Nakoso IGCC plant, its operators surveyed the site for a pilot CCS project due to its proximity to a depleted gas reservoir below the ocean floor, which is considered as an appropriate site for CO_2 storage. A pre-combustion CCS system using a chemical absorption process was selected. However, the project was suspended following the Great East Japan Earthquake in 2011[60].

Osaki CoolGen IGCC (Pre-combustion capture, power sector)

Under Phase 2 of the Osaki CoolGen project, demonstration tests for pre-combustion CCS are currently being conducted. This project builds on the initial trials of the EAGLE pilot, and aims to achieve a capture rate exceeding 90% using a physical absorption process[61]. Without a dedicated CO_2 storage site, the captured CO_2 will be recycled for use in greenhouses and in coal ash weight blocks[62]. The final phase of this demonstration project will involve the test bedding of syngas based fuel cells.

Tomakomai CCS (Post-combustion capture, industrial sector)

Tomakomai CCS is Japan's first CCS demonstration project covering the entire CCS value chain, including capture, transport and storage. As part of the project, CO_2 was captured at a hydrogen production unit at a refinery complex located in Tomakomai City, Hokkaido, before being piped, compressed and injected into two offshore saline aquifers for permanent storage. CO_2 injection spanned between 2016 to 2019, capturing a cumulative 300,000 tonnes of CO_2 within its three year project run[63]. Monitoring of the CCS site for leakages lasted from the start of the project in 2016 till 2020, through the observation wells and seismic surveys. Despite experiencing a magnitude 6.7 earthquake, the Tomakomai CCS project did not experience any carbon leakages, enhancing confidence in the stability of CCS storage in Japan.

60 Abe et al (2013)
61 Abe et al (2013)
62 J Power (2020)
63 METI (2020)

Other CCS challenges

Storage limitations

Japan suffers from a hard constraint on CCS applications due to limited storage sites, thus careful prioritisation of its CCS application is required to support its decarbonisation journey. Due to the presence of cost-competitive renewables in the power sector, Japan can stand to realise the full potential of its limited CCS capacities by prioritising hard-to-abate sectors, such as heavy industry.

As it stands, there is no real consensus on the CO_2 storage potential in Japan. A 2009 survey identified a technical CO_2 potential of about 146 $GtCO_2$ for Japan[64]. Other figures place Japan's estimated technical storage at between 28 to 197 $GtCO_2$[65]. However, it is important to highlight the difference between technical potential and economic potential. In spite of high technical potential, not all of the technical potential can be tapped due to financial and operational constraints. In its Global Status of CCS 2021 report, the Global CCS Institute estimates that only 3% of the 152 $GtCO_2$ of Japan's technical storage potential can be exploited commercially, with the remaining 147 $GtCO_2$ capacity being various degrees of uneconomical[66].

In their net-zero analysis, RITE used a much more conservative estimate of CCS storage potential, placing the figure at 11.3 $GtCO_2$[67], or close to 8% of the technical potential cited in 2009. Taking a base case assumption of a technical storage potential of 115 $GtCO_2$, and that 10% of the technical potential is economically viable to tap, that will afford Japan a "carbon budget" of around 11.5 $GtCO_2$. If Japan's non-power emissions profile follows that of the IEA's Sustainable Development scenario, Japan's domestic storage sites will be depleted in about a decade, if Japan were to continue on its current emissions trajectory for the power sector. With limited storage facilities and in the absence of CO_2 trading, Japan will need to exercise discretion in its allocation of storage sites. With existing alternatives in the power sector, including wind and solar PV, perhaps the valuable capacity should be better reserved for hard-to-abate sectors instead.

> **Japan's domestic storage sites will be depleted in about a decade, if Japan were to continue on its current emissions trajectory for the power sector.**

Box 4.2 CO_2 recycling and CO_2 trading

Due to the lack of CO_2 storage capacity available, the Japanese government has looked to promote the use of CO_2 as raw material and feedstock for a variety of products through its Carbon Recycling programme. The program is spearheaded by the Carbon Recycling Promotion Office under METI, and is guided by the Roadmap for Carbon Recycling Technologies, which was released in June 2019.

Apart from technological breakthroughs to unlock the use of captured CO_2 in various industrial processes[68], the carbon recycling program can truly gain buy-in only when lower costs of capture can be achieved. At current capture costs of US$40/$tCO_2$, the carbon recycling program is unlikely to develop beyond niche applications. Indeed, Japan has yet to see commercial applications of carbon recycling, with most projects limited in scale, such as the use of CO_2 in agricultural greenhouses.

Another alternative that Japan has looked to is CO_2 trading. Japan has led various regional and international cooperation pacts to drive research, development and investment into commercialising CCS, with the intention to open up new opportunities for Japan to export its CO_2 to overseas projects[69,70]. On that front, Japan has invested heavily into the Association of Southeast Asian Nations (ASEAN) countries, looking to explore the potential of CO_2 transport and storage networks, as well as perform regional source-sink mapping, with the hopes of potentially exporting CO_2 to these nations for storage. However, there have yet to be any formal arrangements or discussions on how such CCS-based trading arrangements would materialise, meaning any commercial projects may be decades away.

64 Kearns et al (2017)
65 Kearns et al (2017)
66 Global CCS Institute (2021)
67 RITE (2021)
68 METI (2021)

Efficiency penalty

Capturing CO_2 always comes with an efficiency/energy penalty as additional energy in the form of electricity, steam or heat, is used for the capture process. This "parasitic" energy consumption will reduce the electricity available to be sold, thereby decreasing plant profitability. Ultimately, the presence of heavy energy penalties may render a CCS project financially non-viable.

The efficiency penalty for CCS applications varies according to technology, ranging from an inordinate 20%[71] to a best-in-class technical potential of 9%[72]. Given the lack of existing power sector CCS projects, it is hard to quantify the expected efficiency penalties for CCS-equipped coal plants. However, experience at the Petra Nova coal plant seem to point to exorbitant penalty of up to 30%[73], while Boundary Dam saw a slight improvement of 23%[74]. These higher than expected energy penalties directly impact plant performance and profitability.

Cost of CCS

Since the first application of CCS for EOR in the early 1970s, its supporters have touted the technology as being on the verge of a commercial breakthrough. Multiple studies have been conducted throughout the past two decades on what needs to be done to commercialise the technology, and yet, as of 2021, there is only one CCS-equipped coal plant operating globally[75].

Due to the high costs, the commercial viability of CCS projects is heavily dependent on policy support, which explains the slow deployment of CCS projects globally. The costs of CCS can be divided into capture costs and storage costs. The capture costs vary by the choice of capture technology used. In Japan, chemical absorption using amine solvents is the most technologically mature and cost-efficient. METI places the current capture costs for post-combustion capture using said technology at JPY 4,000/tCO_2, roughly equivalent to US$36/$tCO_2$. METI's estimates are slightly lower than IEA's capture costs estimates, which stands at US$25/$tCO_2$ and US$40/$tCO_2$ for pre-combustion capture and post-combustion capture, respectively[76].

Estimating storage costs for Japan is much more difficult. Due to geographical limitations, Japan can only consider the storage in offshore saline formations. In such applications, the cost for CCS is highly location-specific as it requires site-specific analysis, thus international averages were used in our analysis.

Using METI and IEA's capture cost estimates and an assumed transport and storage cost of US$20/$tCO_2$ will bring estimated CCS costs to between US$40/$tCO_2$ to US$60/$tCO_2$. This is significantly below TransitionZero's estimated CCS cost, which range between US$74/$tCO_2$ to US$169/$tCO_2$ for retrofitted post-combustion capture and between US$53/$tCO_2$ to US$114/$tCO_2$ for new build IGCC equipped with pre-combustion CCS.

The disparity between METI and IEA figures and our cost estimates stem from a variety of hidden costs of CCS project development. While METI and IEA figures tend to focus on technology specific costs, consisting primarily of technology-specific cost functions, our estimates encapsulate all project-related costs. This includes hidden costs related to efficiency downgrades, additional fuel costs due to the parasitic loads of CCS systems and additional costs associated with permitting, licensing and other project development costs.

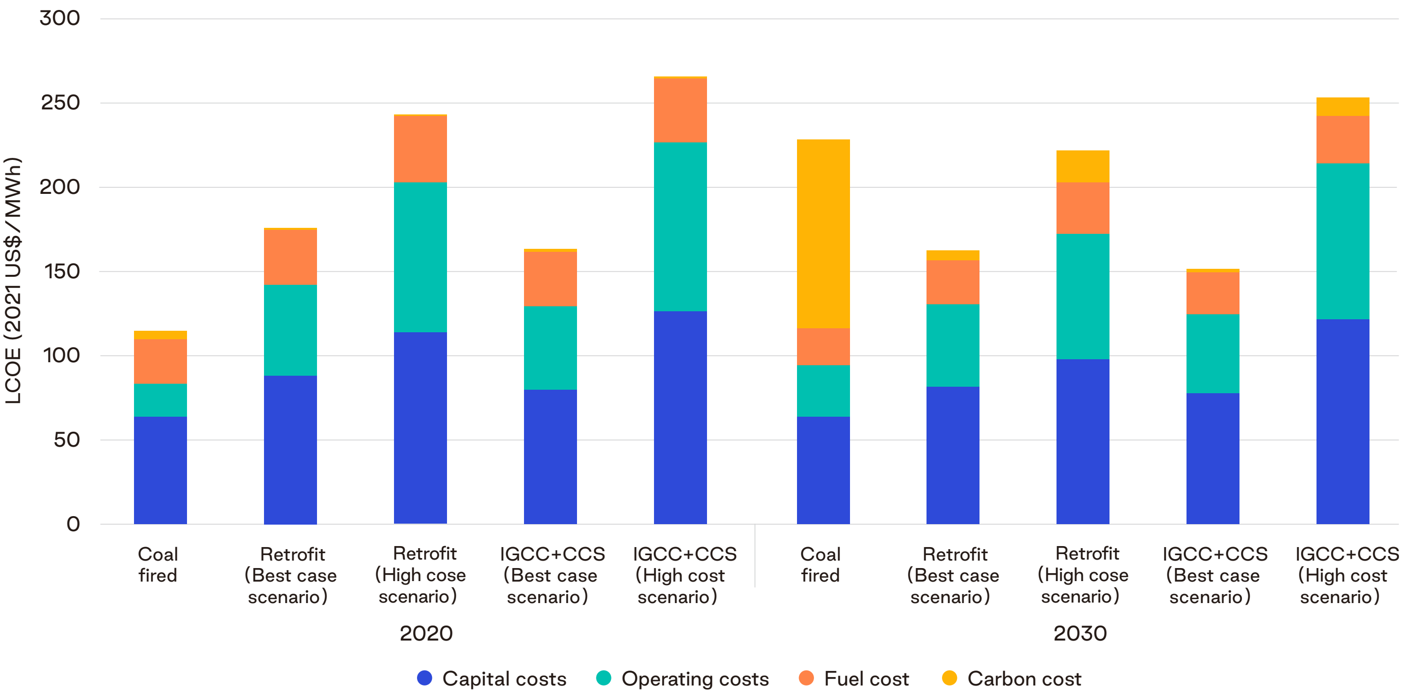
71 CRS (2021)
72 IEA (2016)
73 IEEFA (2015)
74 NETL (2019)
75 Global CCS Institute (2021)
76 IEA (2021c)

LCOE assessment

Drawing on the experience of the 110 MW Boundary Dam and 240 MW Petra Nova projects, which costs US$1.5 billion and US$1 billion respectively, the hidden costs of project development are extensive[77]. Due to high hidden costs, CCS-equipped coal plants have an average LCOE of above US$200/MWh. This clearly shows that CCS applications are far from commercialisation. To put that into perspective, CCS-equipped coal plants will have to see about 5% to 10% cost reduction every year to reach a cost target of US$100/MWh by 2030. This is akin to the steep drop in prices experienced by solar PV in the early 2010s. However, unlike solar PV, CCS applications in the power sector are not scalable and therefore it is unlikely to replicate high deployments rates.

For pre-combustion, the high degree of customisation and system synchronisation limits plug and play opportunities for CCS-equipped IGCC plants, whereas mass deployment of post-combustion capture is constrained by the lack of a CCS infrastructure in Japan. This means that coal plant developers/operators will have to seek out their own solutions for the downstream utilisation of captured CO_2. This includes arranging transportation, storage and/or utilisation options. As such, CCS projects in Japan's power sector will remain a bespoke and niche market segment, at least until a CCS ecosystem develops, allowing CCS projects the downstream accessibility akin to plugging a solar PV panel into the grid. In the meantime, the lack of scalability will continue to leave CCS applications at a cost premium, at least till the next decade.

Figure 4.6 LCOE of CCS applications at coal-fired 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	$/t$CO_2$	$74	$123	$169	$53	$80	$114
2030	Additional cost	$/MWh	$40	$66	$87	$39	$46	$60
	Cost of CCS	$/t$CO_2$	$46	$79	$111	$53	$65	$89

Source: TransitionZero

77 CRA (2021)

Environmental concerns

The Intergovernmental Panel on Climate Change (IPCC) supports claims that CO_2 injected into geological storage sites have a high probability to remain securely stored for centuries[78]. However, there remain serious concerns over the integrity of the CO_2 storage sites and the potential environmental impacts in case of CO_2 seeps, also known as CO_2 leakages. Most of Japan's CO_2 storage sites are in deep offshore subsea areas, where perceived public risks and environmental exposures are low. At present, Japan-specific risk assessment of offshore CO_2 storage sites is lacking. Thus, TransitionZero draws on the existing body of work on offshore CO_2 storage in the North Sea to see if there are lessons for Japan.

In addition to climate concerns, CO_2 leakages in offshore storage sites will have negative impacts on the surrounding seawater, causing it to increase in acidity. The direct impact of a CO_2 leakage to marine biodiversity will be based on various factors including the temperature, depth and existing chemical makeup of the seawater[79]. Thus, the North Sea experience may have limited lessons in the Japanese context. Unless Japan-specific studies are conducted, it is fair to say that ocean acidification will have negative consequences to marine biodiversity[80], although the full magnitude of the impact remains largely unknown.

Based on risks assessment conducted for the North Sea, the potential for CO_2 seepage from caprocks is negligible. However, there is potential for CO_2 leakage from faults and fracturing, whereby the stored CO_2 may flow within the storage site and eventually enter an area with high permeability, allowing CO_2 to escape. The potential leakage rates, based on the UK study, ranges from 1 tCO_2/day to 1,500 tCO_2/day, and may last anywhere between 1 to 100 years[81]. However, the study also qualifies that there are very wide uncertainties on the potential of leakages as the probabilities are highly site-specific.

An added concern for Japan's quest for offshore CO_2 storage sites arises due to the high frequency of seismic activity it experiences. The Japanese archipelago is located at the intersection of various continental and oceanic plates, making it prone to frequent earthquakes. An increased frequency of high magnitude earthquakes increases the risk of CO_2 leakage as it may increase the presence of faults and fractures in the caprock.

As it stands, there are still significant Japan-specific knowledge gaps on the CO_2 storage integrity and the impacts of CO_2 leakage on marine biodiversity. The risk here is primarily one of "we don't know what we don't know." More work needs to be done before calculated risks can be taken on the operations of offshore subsea CCS storage sites in Japan.

Tomakomai CCS test site in Japan

78 IPCC (2005)
79 IPCC (2014)
80 IPCC (2014)
81 Jewell and Senior (2012)

Conclusion

With limited CO_2 storage potential, Japan needs to choose wisely on which sectors to support and ration its available capacity. While CCS can help to reduce emissions in the power sector, its use should be carefully considered against CCS deployment in hard-to-abate sectors, such as industrial processes, to support deep decarbonisation.

Cost will remain a key barrier for the commercialisation of CCS projects in the power sector. While technology-based costs are expected to be modest at around US$40/$tCO_2$, the lack of a CCS ecosystem in Japan means that coal plant operators and developers will have to internalise a variety of project development related costs. These hidden costs include costs related to CO_2 storage site selection, CO_2 transport options, permitting and licensing, among others. These hidden costs may be double the technology-specific costs, thus inflating the LCOE of CCS-equipped coal plants.

Furthermore, due to the long project lead times of seven to eight years and a lack of a CCS ecosystem in Japan, it is unrealistic to expect a rapid scale-up of CCS projects to meet the upcoming 2030 climate 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 a cost advantage.

In particular, the use of IGCC, coupled with pre-combustion CCS systems, should be carefully weighed against alternatives. Due to the need for integration across plant systems, CCS cannot be retrofitted to existing IGCC plants. Continued investments into the technology will have to come in the form of new-build coal plants, which will end up locking in new sources of carbon emissions, especially if the desired capture outcomes are not achieved.

Drax power plant: a CCS-equipped biomass power plant in the UK

06 Low-carbon, least cost alternative

Summary

1 Renewable energy offers a more cost-competitive way of meeting Japan's climate targets and energy needs, compared to advanced coal.

2 Currently, stand-alone solar PV and onshore wind are competitive, and even when combined with expensive battery storage they compete with most of the advanced coal technologies.

3 This trend is set to accelerate, with solar PV and onshore wind plus battery storage beating all advanced coal and even unabated coal by 2030, due to carbon pricing.

4 Though currently more expensive than other renewables, offshore wind holds a lot of promise for Japan. Steep cost reductions are feasible, and there is enough offshore wind potential to theoretically cover Japan's entire electricity demand.

Background

Considering the technological, economic, and environmental challenges with the advanced coal technologies discussed in this report, the question turns to what is a feasible alternative for Japan. Following the series of climate-related policy announcements, starting with the formalisation of Japan's net-zero target in late 2020, overall sentiment in Japan towards renewables has become more optimistic. Commentators are no longer drawing attention to the previous rhetoric on how the unsuitable terrain has hindered solar PV and wind expansions. Policymakers are campaigning on the use of renewables "as much as possible," although stopping short of a 100% renewables commitment. Policies largely in support of renewables, especially for offshore wind, are constantly being rolled out.

For example, Japan has launched its first public tender for the development of offshore wind projects in FY2020, with the goal to scale up wind capacity by 10 GW and 30-45 GW in 2030 and 2040, respectively. In addition, numerous policy revisions to break down barriers against high renewables penetration, such as bureaucratic red-tape, grid-related constraints and financial barriers, are also seen; a prime example is the Act on Promoting Utilization of Sea Areas for Renewable Energy Generation. Policies aimed at supporting the growth of solar PV penetration have focused on continued support of market development through the Feed-in-tariff program and R&D centred on new mounting technologies and increasing conversion efficiency of solar PV panels. Corporations, under the auspices of industry groups such as the Japan Climate Leaders' Partnership, are announcing 100% renewable procurement targets. This widespread optimism emerged as the result of years of groundwork crushing many longstanding misconceptions that stood against renewable deployment.

In 2020, the Ministry of the Environment released a comprehensive study on renewable energy potential, highlighting that Japan has more than double the renewable energy potential it needs to power its economy. The elevated resource potential estimates have spurred both the public and private sector to upsize their renewable energy ambitions, directly contributing to many of the 100% renewable pledges announced recently.

Table 5.1 Revised renewable energy potential in Japan

		Technical potential		Economic potential			
Generation		Capacity (GW)	Generation (TWh)	Capacity (GW)		Generation (TWh)	
Solar PV	Residential	210	253	38	112	47	137
	Industrial	2,536	2,969	0.2	295	0.2	367
	Total	2,746	3,222	38	406	47	504
Onshore wind		285	686	118	163	351	454
Offshore wind		1,120	3,461	178	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[82]

82 MOEJ (2020)

LCOE assessment

Even conservative holdouts, such as the Ministry of Economy, Trade and Industry (METI), are quick to admit renewable energy, in particular solar PV, will emerge as the cheapest source of power generation by 2030, beating out traditional nuclear and coal plants[83]. Our analysis confirms the cost-competitiveness of renewable generation in Japan, with new build stand-alone solar PV and onshore wind projects in Japan already cheaper than coal generation and the more expensive advanced coal technologies considered in this report (Figure 5.1). Even when combined with battery storage, solar PV is cheaper than all of the advanced coal technologies in 2020. The cost gap further widens in 2030, due to higher carbon prices implemented in line with Japan's net-zero ambitions and declining costs for renewable generation (Figure 5.2). Offshore wind, being a nascent industry in Japan, still faces a cost disadvantage against some of the cheaper advanced coal technologies. Offshore wind utilising fixed bed platforms will start becoming competitive in the next decade, although floating offshore wind generation remains costly subject to an unforeseen technological breakthrough.

Opponents of renewable energy have continued to argue that the cost-competitiveness of renewables is built upon a false premise that disregards any additional costs to the overall electricity system, or what is commonly known as "integration costs." Indeed, a discussion on the costs of renewables, including wind and solar PV, can seldom escape a long and noisy debate on the related costs of integrating them into the grid. As the argument goes, as renewable deployment increases in Japan, there will be a greater need to invest in electric storage and adjustment functions to absorb output variations caused by the intermittency and variability of wind and solar PV generation.

To deal with renewables intermittency, cost estimates of wind and solar PV generation are often tied with the use of battery storage as backup, to make the technology firm and/or dispatchable (i.e., you can turn it on or off on demand). In this report, TransitionZero employs a similar methodology to account for integration costs. We have assumed that all renewable generation sources are fitted with battery storage that is half the installed capacity of the renewable generation project itself, with a four-hour duration.

Due to the high cost of battery storage, at present renewables plus storage applications tend to fare poorly against coal and the various advanced coal technologies. Battery storage adds over US$50/MWh to renewable generation costs; therefore, even the mature renewable generation, such as solar PV and onshore wind, find it hard to compete against some of the lower cost advanced coal technologies (Figure 5.1).

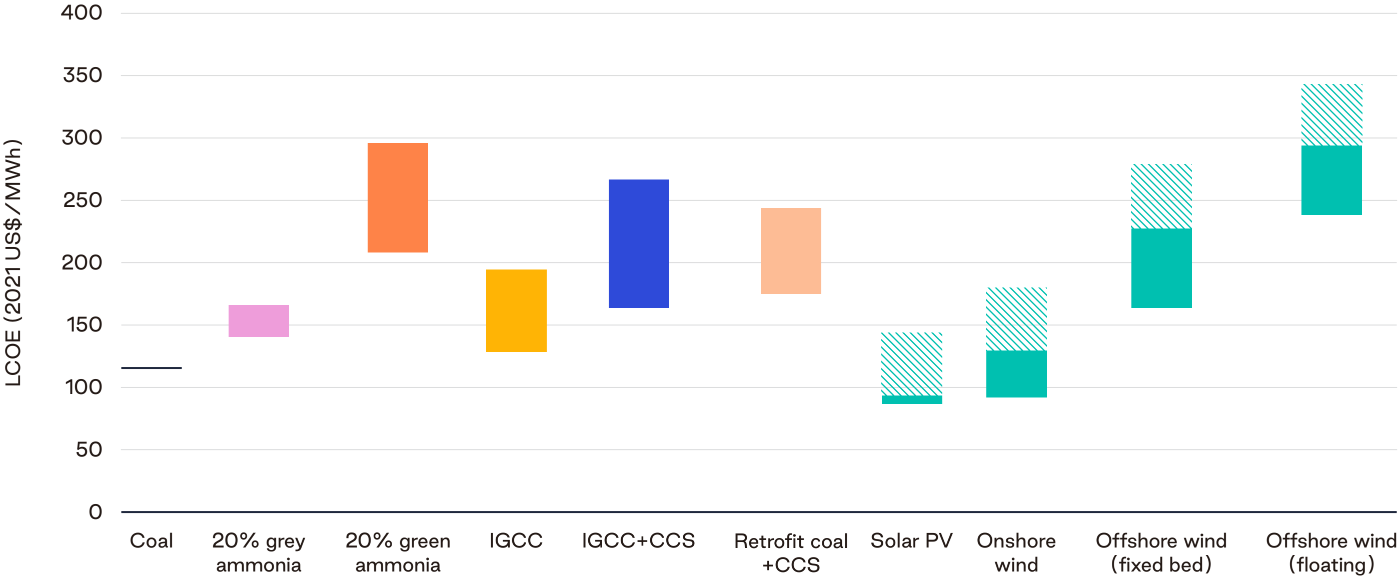
However, the fortunes of coal and renewables plus storage are completely flipped by 2030. With rapidly declining costs of wind and solar PV, coupled with a high carbon price of US$130/t$CO_2$, most renewables plus storage options, except floating offshore wind, are strong competitors against not only advanced coal-fired power plants discussed in this report, but also traditional coal plants (Figure 5.2).

From a LCOE perspective, stand-alone renewable energy projects are already cheaper than coal and advanced coal technologies. Going into the next decade, when faced with inflationary cost pressures due to climate concerns, Japanese coal plants will face stiff price competition from renewable energy projects. By 2030, the majority of renewable generation technologies, with the exception of offshore wind, will be cheaper than coal plants. The cost advantage of renewable energy leaves advanced coal technologies as a distant second in terms of potential technological suites to meet 2030 and 2050 climate goals.

The cost profile for offshore wind that TransitionZero employs in our analysis is a highly conservative one, and is based on the current project pipeline for offshore wind projects in Japan. As it stands, Japan has about 5 GW of offshore wind projects at different stages of planning. With such a weak project pipeline, it may be hard to see cost reductions that can support the financial standing of these projects against fossil fuel plants. However, there is significant offshore wind potential in Japan, and with policy support to drive project development, offshore wind holds significant promise to be a key pillar for Japan's power sector (Pop-out: Japan's offshore wind potential).

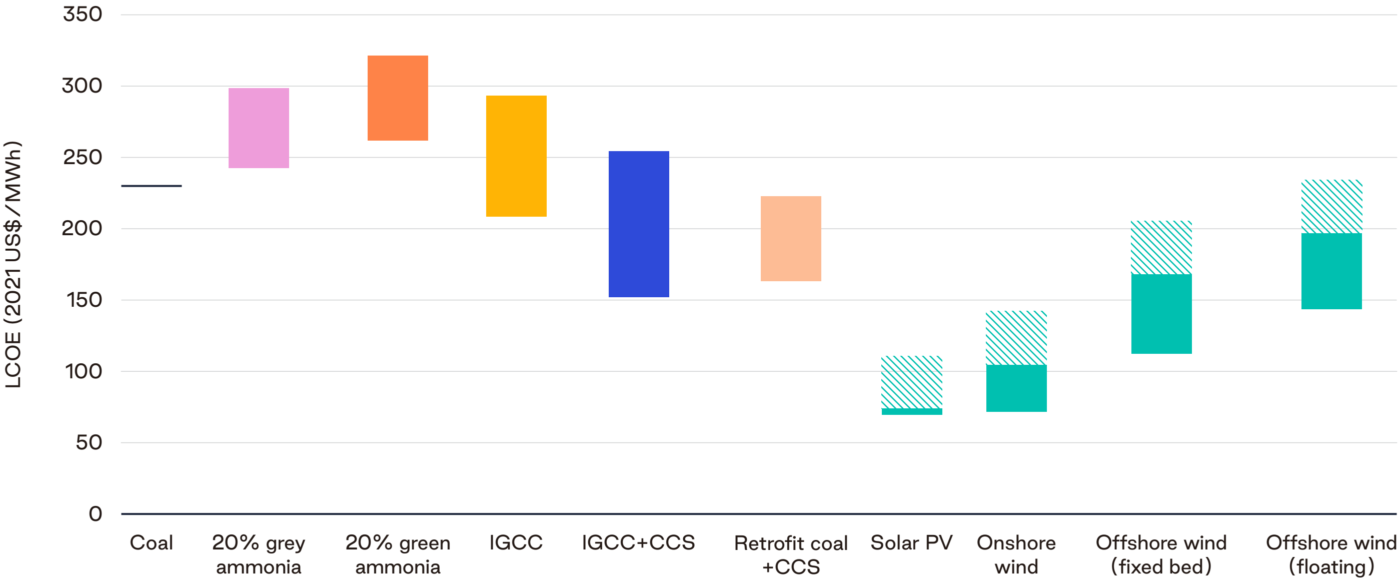
83 METI (2021)

Figure 5.1 2020 LCOE of advanced coal technologies and renewable energy in Japan



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.

Figure 5.2 2030 LCOE of advanced coal technologies and renewable energy in Japan



Source: TransitionZero
Note: A carbon price of US$130/t$CO_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

As a mitigation measure, renewable energy trumps advanced coal technologies

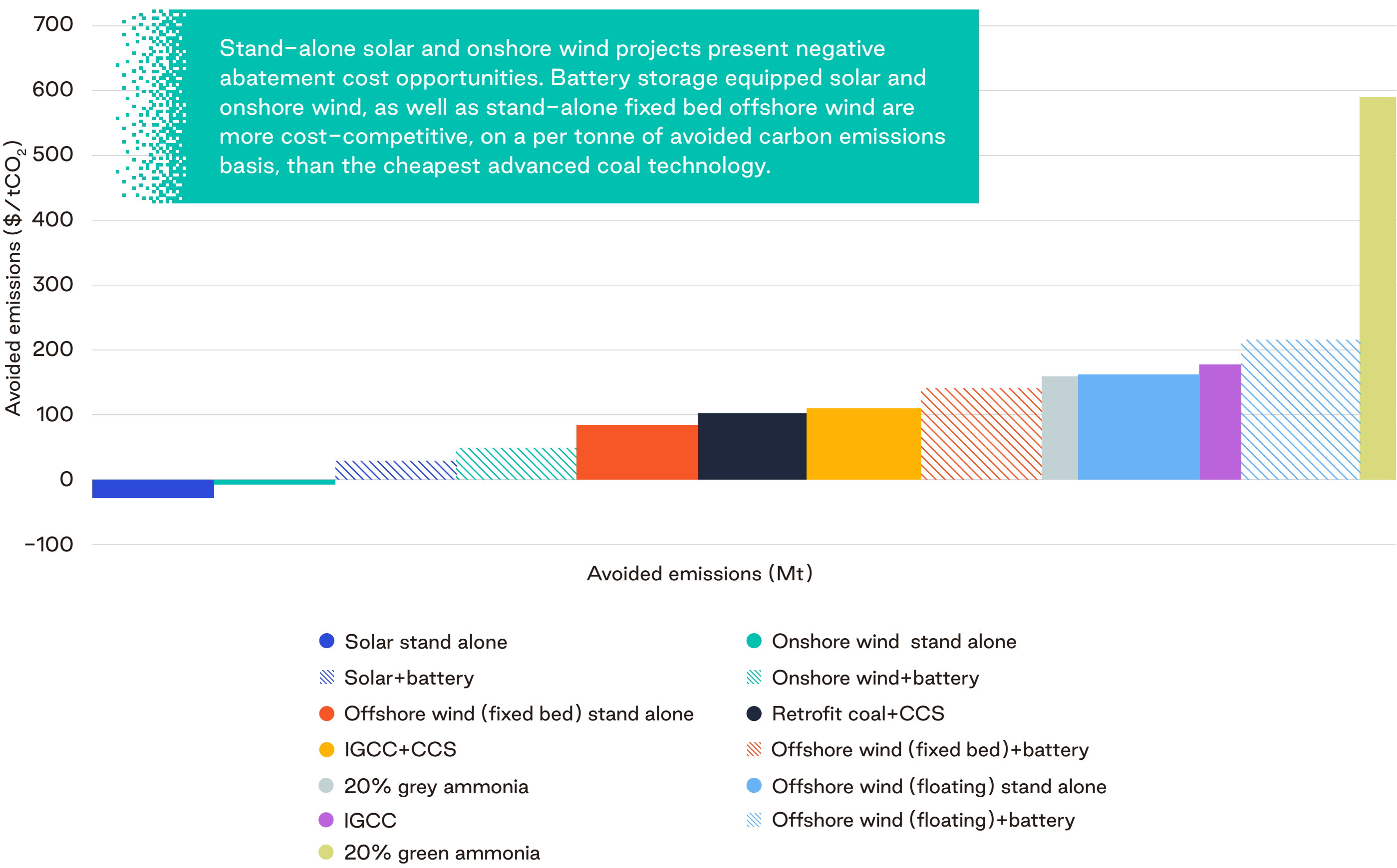
Beyond meeting electricity needs, Japan also needs to consider the cost-effectiveness of technologies in meeting its climate commitments. TransitionZero attempts to quantify these by estimating the marginal abatement cost (MAC) of advanced coal technologies, alongside the renewable energy technologies. The MAC provides an estimate of the volume and costs of opportunities to reduce emissions.

Under this approach, baseline emissions are set as the average emissions of a coal plant. Each block on the MAC presents an alternative to the baseline Japanese coal plant, which can generate the same amount of electricity. For each block, the height estimates the marginal cost of the carbon emissions abatement ($/$tCO_2$), while the width indicates the amount of potential carbon emissions abatement ($MtCO_2$).

At present, stand-alone solar PV and onshore wind projects present negative abatement cost opportunities. Battery storage-equipped solar PV and onshore wind, as well as stand-alone fixed bed offshore wind are more cost-competitive, on a per tonne of avoided carbon emissions basis, than the cheapest advanced coal technology.

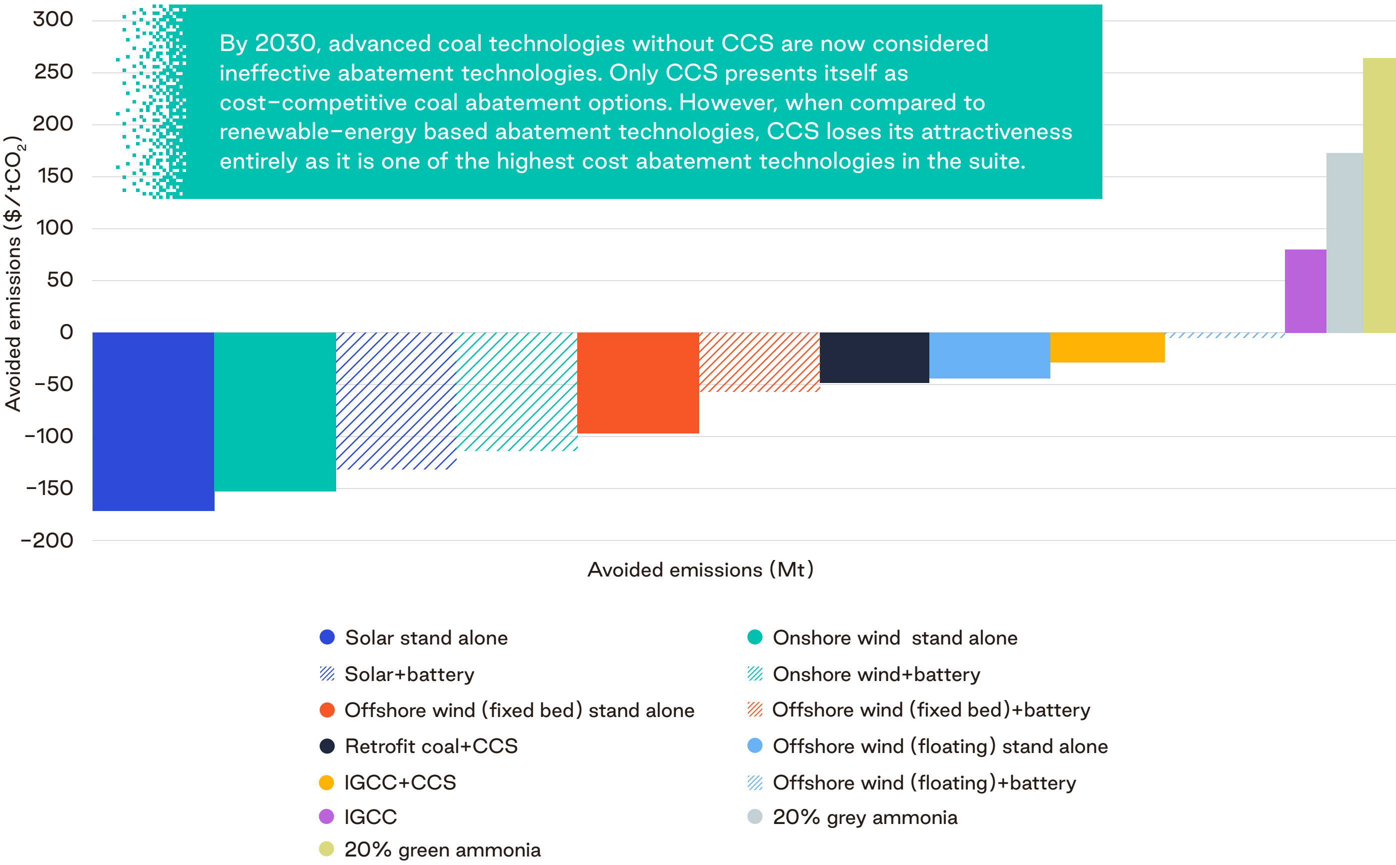
By 2030, advanced coal technologies without CCS are clearly ineffective abatement technologies. Only CCS presents itself as a cost-competitive coal abatement option. However, when compared to renewable-energy based abatement technologies, CCS loses its attractiveness entirely as it is one of the highest cost abatement technologies in the suite.

Figure 5.3 2020 Marginal abatement curves



Source: TransitionZero

Figure 5.4 2030 Marginal abatement curves



Source: TransitionZero

Box 5.1 Japan's offshore wind potential

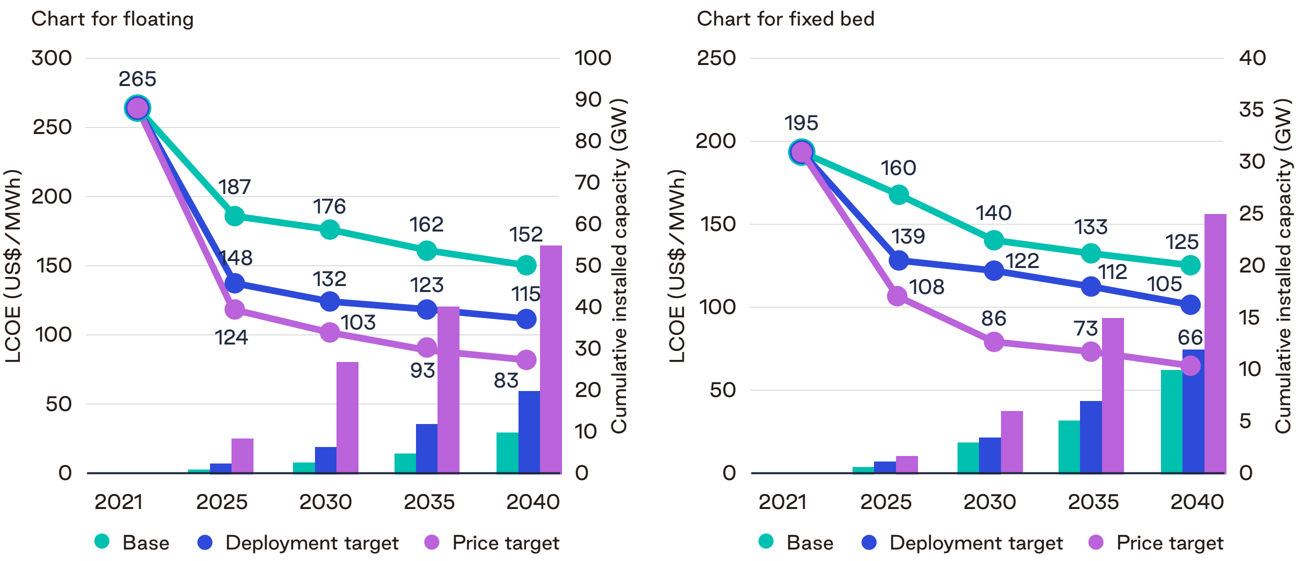
Japan has significant offshore wind potential. According to the latest estimates by the Ministry of the Environment, Japan (MOEJ), electricity produced from offshore wind alone is sufficient to power the Japanese economy. However, Japan's offshore wind potential remains largely untapped, despite generous feed in tariffs (32 JPY/kWh; $291/MWh in 2021[84]), due to a confluence of technical, financial, regulatory and policy challenges.

In recent years, the Japanese government has identified offshore wind as a key priority focus in the power sector. Since then, several favourable policies were released to support the development of offshore wind projects in Japan, alongside a government cost target of 8 to 9 JPY/kWh (US$70-80/MWh) by 2030[85]. Concurrently, a deployment target was set in the Offshore Wind Power Industry Vision document released by the Public-Private Council on Enhancement of Industrial Competitiveness for Offshore Wind Power Generation in December 2020, which calls for a provisional target to award 10 GW of capacity for offshore wind by 2030 and 30-45 GW by 2040[86].

In our analysis, the average cost of stand-alone offshore wind remains above US$100/MWh in 2030. This is higher than IRENA's estimate of the global average LCOE for offshore wind in 2020 at US$85/MWh[87]. A few technical factors inflate cost estimates for Japanese offshore wind plants. Firstly, Japanese offshore wind plants face higher capital cost and lower capacity factors. Japan specific capital cost estimates from IRENA is close to US$5,000/kW, compared to a global average of US$3,184/kW. Bulk of excess capital cost is expected to come from non-equipment based costs, including electrical, installation and soft costs. In addition, Japan's capacity factor for offshore wind projects, as seen in METI's cost estimates, trend on the low end, at about 30%, compared to global averages of 40 to 45%. Both factors can be reduced with mass scale deployment of offshore wind projects.

However, as mentioned earlier, the current project pipeline in Japan, consisting of only 5 GW of named projects, falls short in its ability to steepen learning curves required to make offshore wind competitive. Based on our estimates, to achieve the cost target of 8 to 9 yen/kWh (US$70-80/MWh) by 2030-2035, Japan will have to install 30-35 GW of offshore wind capacity in that timeframe. To align stakeholders and create a local support network, Japanese policymakers will need to both set aggressive annual and long-term capacity targets, as well as guarantee transmission access. This will likely require reducing support for advanced coal projects.

Figure 5.5 Learning curves for offshore wind projects



Source: TransitionZero

Note: Base refers to the base case utilised in this report, which is consistent with the current project pipeline of about 5 GW of projects coming online by 2030. Deployment target aligns with the Offshore Wind Power Industry Vision deployment targets. Price target estimates the cumulative installed capacity required to reach the cost target of 8 to 9 JPY/kWh (US$70-80/MWh) by 2030-2035.

84 METI (2021)
85 METI (2021)
86 METI (2020)
87 IRENA (2021)

Box 5.2 The true cost of integration

Renewables integration is fundamental for Japan's net-zero ambitions. However, there are several inherent challenges for Japan's power grid that present challenges for renewables integration. Due to the fragmented nature of the Japanese power system, with ten regional grids and two frequency levels, the inherent grid flexibility is relatively low. Regional dispatch dominates day to day transmission, with the regional interconnectors severely underutilized. Grid congestion has emerged in places with large renewables penetration, and in places such as Kyushu, solar PV curtailment has occurred.

Moreover, due to the relative inflexibility of nuclear generation, there have been instances, particularly during periods of low load in 2020, when renewable generation, such as solar PV, has been curtailed to allow for continued nuclear generation. Similar prioritization strategies were seen for thermal plants, including coal and gas plants, placing renewables such as solar PV last in the dispatch order. The implicit preference for baseload plants during system dispatch has artificially capped the capacity factor of renewables, racking up renewable generation costs.

In the short run, high integration costs can be largely reduced by eliminating any market bias against intermittent renewable generation sources. In the longer term, integration costs can be better managed by increasing the flexibility of the grid, through optimal grid planning and forecasting, joint grid resource planning, better utilisation of interconnectors and the use of distributed generation, among others. In addition, investing in long-term storage options may also open up opportunities for high RE penetration in the future, without compromising on grid reliability and resilience.

In our report, we have paired renewables with battery storage to improve dispatchability of renewable generation. That said, we also recognise that this methodology may be overly simplistic, and presents an exaggerated cost of integrating variable renewable energy into the grid. This is especially true in present day terms, due to the high cost of battery storage. In reality, the actual impact of renewables on the electricity system is largely dependent on market structure, regulatory practices and grid characteristics[88]. Moreover, battery installations may present more system-related benefits when installed on optimal locations within the grid infrastructure, rather than co-located with RE systems. In summary, accurate estimations of an integration costs will have to be based on a power systems level modelling, which is out of the scope for this report. Before such detailed analysis is available, our estimations of battery storage may provide a ceiling cost estimate for integration costs in Japan.

Solar panels in rural Japan

88 Hirth, Ueckerdt and Edenhofer (2015)

07 Policy recommendations

We offer the following high level recommendation to help stakeholders navigate risk and opportunities associated with the various technological options for Japan's power sector transition.

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

It is clear from this analysis that ammonia co-firing has a limited role to play in the power sector, thus decision makers in Japan must reconsider its current policy support for ammonia co-firing in coal plants. IEA findings further substantiate our analysis, with ammonia making up, on average, a mere 0.5% of global power generation from 2030 to 2050, in the NZE scenario of its latest WEO. Without international traction, ammonia use in the power sector may find it hard to achieve the commercial and technological breakthroughs to allow it to become a zero carbon fuel of the future.

An added complication on the promotion of ammonia use stems from the production methods of ammonia. To be in alignment with global climate goals, only green ammonia should be supported. Due to the high embedded emissions of grey ammonia, and to a lesser extent blue ammonia, a ramp up of ammonia produced from these methods may in fact, lead to an increase in global carbon emissions.

Prioritise applications of green ammonia in "no-regret" sectors

While its applications in the power sector face multiple setbacks, the applications of ammonia in the hard-to-abate sectors, including heavy industry (i.e., cement, steel, and plastics) and long-haul transport (including road freight, maritime shipping and aviation), holds significant promise. Indeed, the development of a hydrogen/ammonia economy may present significant policy co-benefits for Japan, not only in the context of reducing reliance on oil and gas imports, but also potentially improving macroeconomic balance of payments positions while strengthening domestic competitiveness through an industrial transformation towards a net-zero economy. This may put Japan in a favorable position to support low-carbon technology exports internationally, while entrenching Japanese industries at critical nodal points along the global low-carbon fuel supply chain. The potential co-benefits are critical to the policy debate around a hydrogen/ammonia economy.

Riding on the momentum gained in recent months on the creation of a hydrogen/ammonia economy, Japan can benefit immensely from re-focusing its attention on the alternative applications of ammonia in industrial applications and long-haul transport. Prioritising research, development and deployments into these alternative applications of ammonia will not only help Japan's policy makers move closer towards their decarbonisation goal, but also help Japanese industries tap into new areas of competitiveness as the global market for ammonia expands in the coming decades.

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

Continued investment into IGCC technologies is unlikely to deliver new economic opportunities for the Japanese economy. Thus, we recommend a strategic reassessment of the role of IGCC in a net-zero aligned world. Based on our analysis, and decades of commercial failures, it is irrefutable that IGCC as a technology holds no clear advantage over competing generation technologies. IGCC holds no cost advantage over either fossil fuels or renewable energy and, unless coupled with CCS, its emissions performance is subpar.

Even its compatibility with pre-combustion CCS to deliver cost-competitive zero-carbon electricity is built on engineering estimates, with no commercial projects to back up its claims. Underline that with a track record of operational difficulties and we see IGCC for what it truly is – an expensive technology with few benefits.

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

With renewables working out to be effective abatement technologies, it makes more financial and climate sense to allocate Japan's limited carbon storage capacities to hard-to-abate sectors, such as heavy industry.

CCS has an essential role in global decarbonisation, thus continued investment into the technology will undoubtedly expand future options for Japan. However, we must caution against viewing CCS as the silver bullet to indiscriminate investments in advanced coal technologies that would only serve to lock Japan into a carbon-intensive trajectory.

In the absence of a global traded carbon market and a narrow suite of carbon recycling options, the limit on storage locations will likely place a cap on CCS applications in Japan. With such a cap, policymakers and industry players will need to exercise caution on how to allocate CCS capacity responsibly, taking into account the presence of alternatives and costs per abated tonne of CO_2.

Adopt an integrated approach to reduce integration cost

As Japan looks to increase its renewable energy penetration in the coming decades to meet its 2030 and 2050 climate ambitions, it will have to confront the challenge of integrating solar PV and wind generation in a renewables-dominant grid. This will entail a transformation of power systems.

In the short term, Japan can keep integration costs low by revisiting its dispatch rules to eliminate any market bias against intermittent renewable generation sources. Investment in better forecasting tools for renewable energy resources can increase the accuracy for output estimates of wind and solar PV. This increased accuracy will facilitate better system management for the grid operator by keeping short run balancing and frequency control low in addition to reducing last minute curtailments for renewables operators.

In the medium term, integration costs can be reduced through a paradigm shift in the way power systems are viewed in Japan. The perception that the power sector needs large baseload plants to maintain grid stability is outdated. In fact, electricity systems should seek a paradigm shift away from baseload towards installing flexibility in grids. Large baseload coal plants are highly inflexible and pose system costs to the grid due to their inability to fluctuate output to meet varying demand.

In the long term, integration costs can be reduced through grid enhancement and reinforcements, facilitated by government policies. With the new government legislation passed in June 2020 ushering in another round of electricity market reforms, Japan is now on the cusp of change as it seeks to rewrite its rulebook for the transmission and distribution (T&D) networks in the country. Several upcoming developments on the T&D front could help facilitate a transition away from the anarchic way of managing power system flexibility that relies heavily on thermal plants to one that encourages embedded flexibility options. It is timely to reassess the current investments to shift the mix away from inflexible baseload thermal plants to more flexible grid resources.

This shift will require grid investments and upgrades, demand-side management (through virtual power plants, battery storage and electric vehicle integration) and distributed generation. Investment into other demand flexibility solutions, such as long-term energy storage technologies, is also critical to support high renewable energy penetration. These innovations, which enhance flexibility and resilience of the electricity grid without relying heavily on fossil fuels, would be rewarded handsomely as they expand future options to meet Japan's net-zero target. A roadmap to facilitate such a transition would be useful and will have to be supported by detailed systems-level planning.

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

As our analysis has shown, stand-alone solar PV and onshore wind power are significantly cheaper than advanced coal technologies, and even when including the high cost of battery storage they are competitive with most advanced coal options in 2020. This trend is only set to continue in favour of renewables, with solar PV/onshore wind plus battery storage becoming even more competitive than unabated coal by 2030. Solar PV and onshore wind are already commercially mature technologies in widespread global use that are not plagued by the operational and technical issues of the more nascent advanced coal technologies. Additionally, they have a much greater carbon reduction potential. For these reasons, Japan would do well to pivot from investing in advanced coal towards instead scaling up mature renewable energy in the short term as a cost-effective way to meet energy needs while contributing to national climate targets.

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

In the medium term, Japan can take advantage of global technology advancements and cost improvements to unlock its renewable energy potential in offshore wind. A vibrant offshore wind industry provides multiple co-benefits for Japan. It supports local industry, infrastructure, and job creation, which can be ensured through a local content requirement. It also contributes to energy security for Japan by increasing energy sufficiency ratios. More importantly, an energised offshore wind industry affords Japanese companies the chance to become international leaders in a growing international offshore wind market, particularly in Asia, where wind conditions are similar. Investment in Japan's offshore wind sector can help the country unlock tremendous renewable energy potential, while enriching the socio-economic and energy security co-benefits.

In addition to enacting favourable policies to attract offshore wind energy investment, such as supportive environmental regulation, fast-track approval procedures, and financial support, Japanese policymakers can also explore solidifying a deployment target alongside its existing cost reduction target. A deployment target would provide strong market signals on the scale of offshore wind demand in Japan and reduce investment uncertainties. The intended effect of this policy is a strong project pipeline that will help align public and private efforts. In addition, such annual deployment targets can spur investment into supporting infrastructure, including grid upgrades required to support large wind projects, construction of ports and vessels that can build and service offshore wind, among others.

08 Japan’s technological options: investing for the past or the future?

To meet the coming 2030 climate goal, action over the next few years will be vital to deliver the early emissions reductions required. This action will require rapid scale up of emissions reduction technologies, combined with large-scale mobilisation to ensure the required cuts to Japan’s annual emissions. At the same time, current investments need to look to pave the way for technological breakthroughs to unlock additional emissions reduction potential to meet Japan’s net-zero by 2050 target.

As we have demonstrated throughout the report, continued investments into advanced coal technologies, such as ammonia co-firing and coal gasification, can neither contribute to meeting 2030 climate targets nor open up new technological options for Japan. Instead, it will only serve to prolong the life of coal in Japan’s energy mix, lock-in long-term emissions, and narrow Japan’s abatement trajectories, which will ultimately result in deep cuts in emissions further down the road.

Conversely, investment into renewable energy, particularly offshore wind, is set to unlock a suite of new technological options to help Japan deliver on its climate ambitions, while contributing to Japan’s energy security and industry policy objectives.

Lastly, while investing in CCS technology will be essential, it is unlikely to be the “silver bullet” to remedy Japan’s reliance on fossil fuels. Moreover, with a tight budget on available storage capacity, decision-makers need to be prudent with its allocations and target hard-to-abate sectors instead.

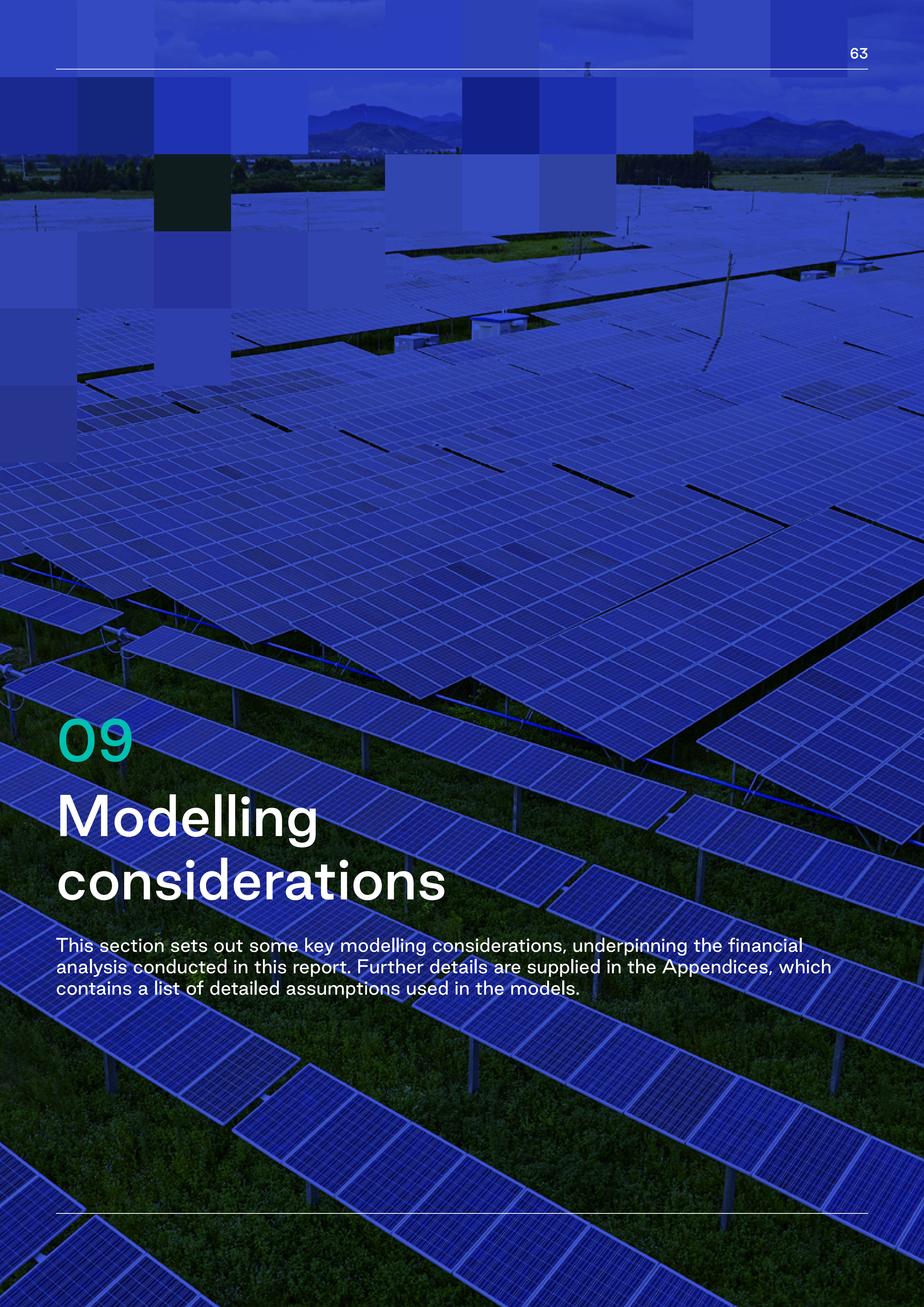
Will Japan be able to continue exporting its advanced coal technologies?

With the growing domestic and international consensus on the threat of climate change, the tide of public opinion is firmly against thermal power generation and, in particular, coal-fired power plants. Even traditional beacons of new coal demand, such as emerging Asian countries, are coming up with their own net-zero targets and coal exit pledges, with the goal to consign coal to history. The stage is therefore set for the eventual retirement of coal.

Japan’s insistence on leaving the door open for advanced coal plants is increasingly pushing the country and its coal industry into a precarious position of promoting a technology that no one truly wants or needs.

In the absence of potential export markets, Japanese utilities need to consider whether the current and continued investments in advanced coal technologies can reap the intended financial returns, or will merely lead to them paying a higher price to rapidly decarbonise in the future. It is now time for Japan to decide: should they place their bets on coal, a fuel of the past, or on the zero carbon technologies of the future?

Japan’s insistence on leaving the door open for advanced coal plants is increasingly pushing the country and its coal industry into a precarious position of promoting a technology that no one truly wants or needs.



09

Modelling considerations

This section sets out some key modelling considerations, underpinning the financial analysis conducted in this report. Further details are supplied in the Appendices, which contains a list of detailed assumptions used in the models.

Ammonia cost modelling

This section sets out some key modelling considerations, underpinning the financial analysis conducted in this report. Further details are supplied in the Appendices, which contains a list of detailed assumptions used in the models.

Ammonia cost modelling

This ammonia cost model is built to estimate the costs of ammonia co-firing in Japan.
The model explores three distinct parameters and its impact on costs of electricity:

1. The different shades of ammonia
2. The different sources of ammonia
3. The different co-firing rates of ammonia

The different shades of ammonia

The model considers three distinct categories of ammonia:

- Grey/brown ammonia: ammonia produced using fossil fuels (primarily natural gas) as feedstock
- Blue ammonia: ammonia produced using natural gas as feedstock, but coupled with carbon capture and storage
- Green ammonia: ammonia produced through the electrolysis of air and water, using renewable energy

The cost and performance assumptions (associated with future cost assumptions) for grey and blue ammonia are drawn from studies from the International Energy Agency (IEA). The cost estimates for green ammonia are drawn from a review of the latest academic journals. All costs and performance estimates are listed in Appendix 1.

The different sources of ammonia

The model considers various sources of ammonia, ranging from domestic production in Japan, to imports from Saudi Arabia, Russia, Indonesia, US and Australia. The countries are chosen to reflect potential costs associated with importing from different regions. Only shipping costs are included in our analysis as shipping costs are understood to be a key cost component for the import of ammonia. Other loading and ancillary costs, such as the presence of ports and dedicated storage and transportation infrastructure, are assumed to be negligible. The cost estimates for the production and transportation of ammonia is retrieved from academic articles.

Varying co-firing rates of ammonia

Lastly, the model considers varying co-firing rates of ammonia at coal plants: 20% and 50%. The model does not include cost inflation associated with varying co-firing rates as it is assumed that cost reductions come alongside technological advancements in co-firing rates. The model includes cost inflation to coal-fired power plants to accommodate for turbine adjustments and increase in balance of plant costs associated with additional storage and transportation infrastructure required for ammonia co-firing. The cost estimates are retrieved from the latest academic articles. The model also includes cost reductions associated with learning curves. The assumptions are based on TransitionZero's internal estimates.

Other assumptions

The model also includes assumptions on commodity prices, power prices and carbon prices. All assumptions are based on internal estimates from TransitionZero, which are guided by estimates from international organizations, consultancies, as well as from other professional sources.

IGCC/CCS cost modelling

The Integrated gasification combined cycle (IGCC)/CCS (carbon capture and storage) cost model is built to estimate the costs of IGCC, IGCC+CCS (carbon capture and storage) plants and CCS retrofits in Japan. The model explores two different IGCC setups and one CCS retrofit setup and its impact on costs of electricity:

1. IGCC
2. IGCC coupled with pre-combustion CCS
3. Coal plant with post-combustion CCS retrofit

IGCC

The cost and performance assumptions of IGCC plants are sourced from a variety of academic and commercial sources. Despite being around for a few decades, the technology has yet to develop itself as a mainstream power generation technology, with only a few projects globally. We have only considered cost estimates provided in the past decade, all earlier cost estimates are omitted from this analysis.

Based on our literature review, we included studies that considered a mix of actual and theoretical plants. We considered three different cost scenarios for this setup: low, base and high cost scenarios. This is to account for differences between actual and theoretical plants, and for potential differences as most of the plants considered in the literature are of 200 MW to 300 MW scale, which is smaller than what our model considers.

IGCC+CCS

The cost and performance assumptions of IGCC plants with pre-combustion CCS plants are sourced primarily from academic sources. Due to a lack of actual plant cost estimates, most of the literature considers only theoretical plants, which underestimates the costs required.

In the past decade, various companies tried to build IGCC+CCS plants, including RWE's Goldberg IGCC+CCS project, Kemper County IGCC+CCS and GreenGen IGCC+CCS project. While some of the projects reached the operational stage for its IGCC systems, none of these proposed projects were able to reach the CCS stage due to the financial, technical and engineering challenges associated with such projects. Thus, the cost and performance estimates for IGCC+CCS plants are entirely based on theoretical estimates and academic studies, which may be more optimistic. Based on literature review conducted by TransitionZero, the lower end of capital cost estimates for IGCC is lower than that coal plants in Japan, which is unrealistic. Therefore, TransitionZero has inflated the cost estimates for these plants based on expert review and feedback to align with Japan-relevant cost estimates for IGCC plants.

Coal+CCS retrofit

The cost and performance assumptions of retrofit coal plants equipped with post-combustion capture is based on actual costs of the Boundary Dam CCS project. This is the only operating post-combustion CCS equipped coal plant that is operating.

Existing academic and commercial estimates for CCS costs tend to focus on technological costs, which underestimate the actual project costs for CCS at the current stage. Thus, TransitionZero aligned with real world project costs for this study.

Renewables cost modelling

The renewables cost model is built to estimate the costs of renewable technologies in Japan. The model explores four different renewable energy technologies and its costs:

1. Solar PV
2. Onshore wind
3. Offshore wind – Fixed bed
4. Offshore wind – Floating

Modelling parameters

The cost and performance assumptions of IGCC plants are sourced from official documents released by METI, as well as the various study groups formed by the Japanese government. Additional resources from international organisations, such as IRENA, and professional advice from industry players were consulted. In addition, TransitionZero considers the integration costs of these renewable power projects by assuming that the renewable energy projects are supported by battery storage, to facilitate easy dispatch.

Battery storage modelling

The battery storage model is built to estimate the costs of integrating variable renewable energy sources to the power system in Japan. The sizing of the power and energy ratings of battery applications is critical to any cost analysis for renewables plus storage applications. The power rating of the battery system, measured in kW, determines how much power can flow in or out of the battery at any given time. The energy rating of the battery system, measured in kWh, is the capacity of the battery system and determines how much energy can be stored in the battery. The battery duration illustrates the number of hours the battery can be discharged for.

Battery sizing decisions are usually project-specific, and vary depending on the function that the battery fulfils. For the purpose of this analysis, TransitionZero has assumed that the power rating for the battery system is half the installed capacity of the renewable energy facility. The model explores five different durations for the battery system:

- 2 hour duration
- 4 hour duration (base case)
- 6 hour duration
- 8 hour duration
- 10 hour duration

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11 Appendices

Appendix 1: Assumptions for cost modelling

Ammonia cost modelling

A. Gas price

	Unit	2021	2030	2040
Japan	US$/MMBtu	7.90	15.00	17.00
Saudi Arabia	US$/MMBtu	1.25	2.19	3.83
Russia	US$/MMBtu	3.40	8.00	7.90
Indonesia	US$/MMBtu	6.00	6.60	7.26
US	US$/MMBtu	3.40	4.00	4.50
Australia	US$/MMBtu	6.01	6.10	6.00

Source: TransitionZero

B. Power price

	Unit	2021	2030	2040
Japan	US$/MWh	156.00	177.00	158.00
Saudi Arabia	US$/MWh	57.01	68.41	75.26
Russia	US$/MWh	93.00	114.00	123.00
Indonesia	US$/MWh	76.00	91.20	100.32
US	US$/MWh	70.00	100.00	108.00
Australia	V$/MWh	86.00	156.00	163.00

Source: TransitionZero

C. Renewable energy costs

	Unit	2021	2030	2040
Japan	US$/MWh	117.39	91	66.51
Saudi Arabia	US$/MWh	41.50	25.95	10.40
Russia	US$/MWh	67.35	53.88	43.10
Indonesia	US$/MWh	65.00	48.75	36.56
US	US$/MWh	34.59	27.67	22.14
Australia	US$/MWh	56.00	44.80	35.84

Source: TransitionZero

D. Carbon price

	Unit	2021	2030	2040
Japan	US$/MWh	5.00	130.00	205.00
Saudi Arabia	US$/MWh	5.00	130.00	205.00
Russia	US$/MWh	0.00	90.00	160.00
Indonesia	US$/MWh	0.00	15.00	35.00
US	US$/MWh	5.00	130.00	205.00
Australia	US$/MWh	5.00	130.00	205.00

Source: TransitionZero

E. Ammonia plant assumptions

	Unit	Value
Capacity	ton	87600
Operating costs	% of capital costs	2.5%
Plant operation	years	25.00
Availability factor	%	95%
Annual degradation	%	1%
Discount rate	%	7.5%

Source: TransitionZero

F. Grey ammonia assumptions

	Unit	2021	2030	2040
Capital costs	US$/t$NH_3$	955.47	955.47	955.47
Gas consumption	GJ/tNH_3	42.00	38.30	32.20
Power consumption	GJ/tNH_3	0.30	0.30	0.30
Emissions factor	tCO_2/tNH_3	2.35	2.14	1.80

Source: TransitionZero

G. Blue ammonia assumptions

	Unit	2021	2030	2040
Capital costs	$/t$NH_3$	1,388.34	1,330.27	1,229.97
Gas consumption (GJ/tNH_3)	GJ/tNH_3	42.00	38.30	32.20
Power consumption	GJ/tNH_3	1.30	1.30	1.30
Emissions factor	tCO_2/tNH_3	0.12	0.11	0.09

Source: TransitionZero

H. Green ammonia assumptions

	Unit	2021	2030	2040
Electrolyser capital costs	US$ million	241	144	107
Haber-Bosch capital costs	US$ million	33	33	33
Hydrogen storage capital costs	US$ million	90	56	26
ASU capital costs	US$ million	12	12	12
Desalination capital costs	US$ million	1	1	1
Annual operating and maintenance costs	US$ million	9	6	5

Source: Al-Breiki and Bicer (2020)

I. Shipping distance

	days	nautical miles
Saudi Arabia	13	6392
Russia	30	13080
Indonesia	6	3069
US	30	10142
Australia	11	5334

J. Ammonia shipping assumptions

Component	Unit	Value
Ship capacity	m3	160000
Capital cost	US$ million	162
Capital cost (allocated each year)	US$ million	8.1
Operating and maintenance costs	US$ million	28.8
Fuel consumption per day	tons	150
Turnaround time for each trip	day	2
Total days in a year	day	365

Source: TransitionZero

Coal plant cost modelling

A. Coal plant assumptions

	Unit	Value
Capacity	MW	1000
Plant operation	years	40.00
Capacity factor	%	60%
Annual degradation	%	1%
Thermal efficiency	%	40%
Coal quality	kcal/kg	6000
Carbon emission	tCO_2/MWh	0.82
Capital costs	US$ million	4031
Operating and maintenance costs	% of capital costs	2.0%
Operating and maintenance costs escalation (2030)	%	3.00%
Operating and maintenance costs escalation (2040)	%	4.00%

Source: TransitionZero

B. Co-firing plant assumptions

	Unit	Value
Capital cost	US$ million	4,031.00
Equipment costs	US$ million	1931
Engineering, procurement and construction costs	US$ million	2100
Steam generator	US$ million	1,148.82
Steam turbine and generator	US$ million	67.04
Feed pumps	US$ million	0.67
Condensate extraction pump	US$ million	0.17
Condenser	US$ million	331.36
Coal handling	US$ million	382.94

Source: TransitionZero

C. Other assumptions

	Unit	2020	2030	2040
Coal price	US$/ton	69.00	58	44
Bunker fuel price	US$/Mt	550.00	550.00	550.00

Source: TransitionZero. IEA WEO (2021)

IGCC/CCS cost modelling

A. IGCC plant assumptions

	Unit	Value
Capacity	MW	1000
Plant operation	years	40
Capacity factor	%	60%
Annual degradation	%	1%
Coal quality	kcal/kg	6000
Discount rate	%	7.50%

Source: TransitionZero

B. 2020 IGCC cost assumptions

	Unit	Low	Base	High
Capital cost	US$/kW	4,193.56	5,123.97	6,112.22
Operating and maintenance cost	% of capital cost	3.0%	3.5%	4.0%
Thermal efficiency	%	46%	44%	40%
Emissions	tCO_2/MWh	0.70	0.74	0.79

Source: TransitionZero

C. 2030 IGCC cost assumptions

	Unit	Low	Base	High
Capital cost	US$/kW	3,858.08	4,867.78	6,051.10
Operating and maintenance cost	% of capital cost	3.1%	3.6%	4.2%
Thermal efficiency	%	46.9%	44.5%	40.3%
Emissions	tCO_2/MWh	0.70	0.74	0.79

Source: TransitionZero

D. 2020 IGCC+CCS cost assumptions

	Unit	Low	Base	High
Capital cost	US$/kW	5,032.27	6,404.97	7,945.89
Operating and maintenance cost	% of capital cost	4%	4%	5%
Thermal efficiency	%	36%	33%	31%
% Capture	%	99%	95%	90%
Emissions	tCO_2/MWh	0.007	0.037	0.074

Source: TransitionZero

E. 2030 IGCC+CCS cost assumptions

	Unit	Low	Base	High
Capital cost	US$/kW	4,931.63	6,084.72	7,707.51
Operating and maintenance cost	% of capital cost	3.9%	4.4%	5.0%
Thermal efficiency	%	37.1%	35.7%	33.3%
% Capture	%	99%	95%	90%
Emissions	tCO_2/MWh	0.007	0.037	0.074

Source: TransitionZero

F. 2020 Coal retrofit cost assumptions

	Unit	Low	Base	High
Retrofit costs	US$/kW	2,735.45	3,218.18	3,540.00
CCS system	US$/kW	2,805.00	3,300.00	3,630.00
Operating and maintenance cost	% of capital cost	3.9%	4.4%	5.0%
Thermal efficiency	%	35.6%	32.4%	29.9%
% Capture	%	95%	90%	85%
Emissions	tCO_2/MWh	0.046	0.093	0.139

Source: TransitionZero

G. 2030 Coal retrofit cost assumptions

	Unit	Low	Base	High
Retrofit costs	US$/kW	2,598.68	3,057.27	3,363.00
CCS system	US$/kW	2,565.00	2,700.00	2,835.00
Operating and maintenance cost	% of capital cost	3.7%	4.3%	4.8%
Thermal efficiency	%	36.0%	33.0%	30.9%
% Capture	%	95%	90%	85%
Emissions	tCO_2/MWh	0.046	0.093	0.139

Source: TransitionZero

Renewables cost modelling

A. 2020 Renewables cost assumptions

	Unit	Solar PV (Low)	Solar PV (High)	Onshore wind (low)	Onshore wind (high)	Offshore wind-fixed bed (low)	Offshore wind-fixed bed (high)	Offshore wind-floating (low)	Offshore wind-floating (high)
Capital cost	US$/kW	1,832.10	1,832.10	2,813.76	2,813.76	4,696.44	4,696.44	5,950.80	5,950.80
Operating and maintenance cost	% of capital cost	2.3%	2.3%	2.5%	2.5%	2.5%	2.5%	3.5%	4.5%
Capacity factor	%	17%	17%	34%	34.0%	39%	36%	40%	43%
Discount factor	%	2%	2%	5%	10%	8%	12%	10%	14%
LCOE (2020)	US$/MWh	86.75	92.56	90.65	127.70	163.14	227.11	249.03	301.65

Source: TransitionZero

B. 2030 Renewables cost assumptions

	Unit	Solar PV (Low)	Solar PV (High)	Onshore wind (low)	Onshore wind (high)	Offshore wind-fixed bed (low)	Offshore wind-fixed bed (high)	Offshore wind-floating (low)	Offshore wind-floating (high)
Capital cost	US$/kW	1,566.44	1,648.89	2,456.41	2,532.38	3,644.44	3,757.15	4,906.43	5,058.18
Operating and maintenance cost	% of capital cost	2%	2.3%	3%	2.5%	3%	2.7%	4%	4.2%
Capacity factor	%	19%	18%	35%	35%	41%	35%	45%	40%
Discount factor	%	2%	2%	4%	9%	7%	10%	7%	10%
LCOE (2030)	US$/MWh	69.85	74.52	72.35	104.74	112.44	168.09	156.59	219.66

Source: TransitionZero

Battery storage cost modelling

A. 2020 battery storage cost assumptions

	Unit	2h duration	4h duration	6h duration	8h duration	10h duration
Capital cost	US$/kW	423.75	765.25	1,099.75	1,432.25	1,769.75
Operating and maintenance cost	% of capital cost	2.5%	2.5%	2.5%	2.5%	2.5%
Capacity factor	%	17%	17%	17%	17%	17%
Discount factor	%	4%	4%	4%	4%	4%
LCOE (2020)	US$/MWh	28.35	51.19	74.43	95.81	118.39

Source: TransitionZero

B. 2030 battery storage cost assumptions

	Unit	2h duration	4h duration	6h duration	8h duration	10h duration
Capital cost	US$/kW	314.50	555.50	790.50	1,020.00	1,591.50
Operating and maintenance cost	% of capital cost	2.5%	2.5%	2.5%	2.5%	2.5%
Capacity factor	%	17%	17%	17%	17%	17%
Discount factor	%	4%	4%	4%	4%	4%
LCOE (2030)	US$/MWh	21.04	37.16	53.50	68.23	106.46

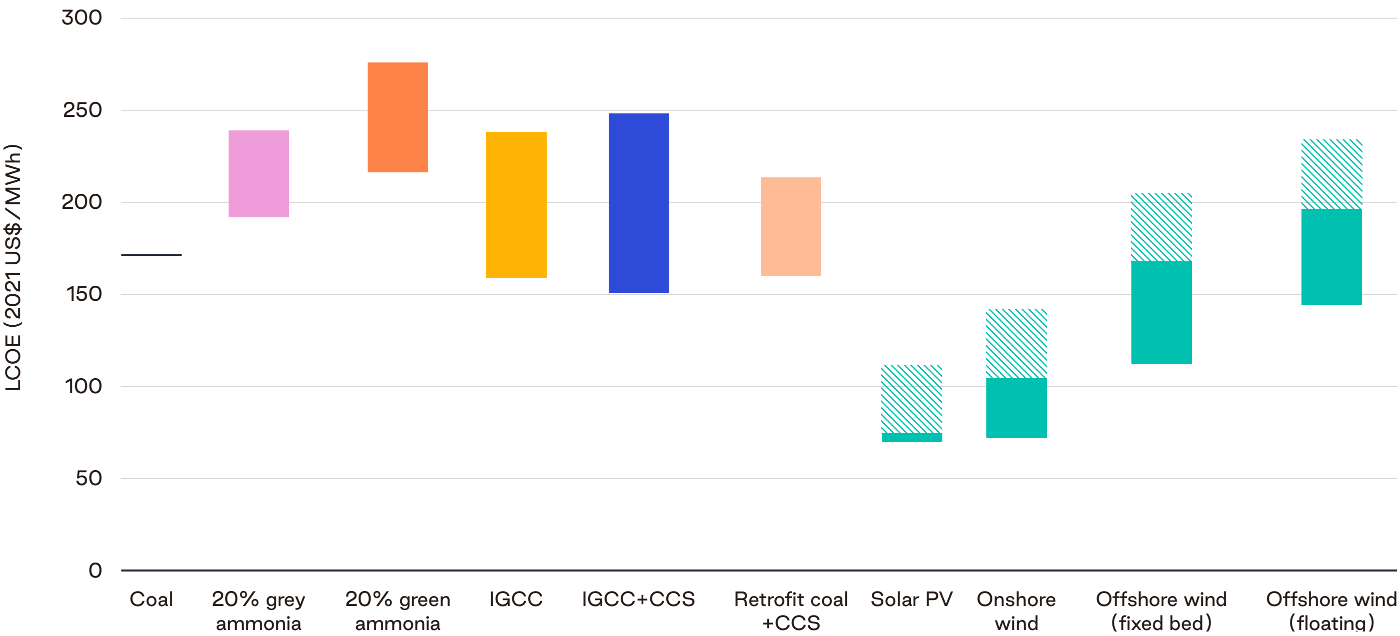
Source: TransitionZero

Appendix 2: Conservative analysis

Our base case analysis relies on a bullish carbon price scenario that sees carbon prices in Japan at US$130/$tCO_2$, in alignment with IEA's NZE scenario for a 1.5C degree world. In IEA's Low carbon fuels of the future report, IEA used a carbon price of US$66-98/$tCO_2$ in 2030 for Japan. Given the outsized impact of carbon prices in cost of generation estimates, we have conducted our analysis again under less vigorous climate targets, with lower carbon price assumptions.

Under a US$65/$tCO_2$ carbon price in Japan, the cost of coal, alongside advanced coal technology, dropped dramatically downwards, averaging US$187-256/MWh in 2030. However, it is still double the costs of solar PV in 2021. Even with a US$65/$tCO_2$, solar PV and onshore wind plus battery storage remains cost-competitive against all coal applications in 2030. Absent large cost reduction breakthroughs (due to the current low deployment rates seen in Japan), floating offshore wind will still face significant cost hurdles at a carbon price of US$65/$tCO_2$, while fixed bed operations fare better. Undoubtedly, a higher carbon price will be the final nail to the coffin for coal in Japan.

Figure 6.1 2030 LCOE of advanced coal technologies



Source: TransitionZero
Note: A carbon price of US$65/$tCO_2$ in 2030, which is in line with IEA's NZE scenario, is assumed. The shaded green bars represent the cost of storage.

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