THE ROLE OF LOW EMISSION COAL TECHNOLOGIES IN A NET ZERO ASIAN FUTURE

GREG KELSALL AND PAUL BARUYA

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INTERNATIONAL CENTRE FOR SUSTAINABLE CARBON

CIAB

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PREFACE

This report has been produced by the International Centre for Sustainable Carbon (ICSC) for the International Energy Agency's (IEA) Coal Industry Advisory Board (CIAB). It is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, nor by our member organisations.

The ICSC was established in 1975 and has contracting parties and sponsors from: Australia, China, Italy, Japan, Russia, South Africa, and the USA.

The overall objective of the International Centre for Sustainable Carbon is to continue to provide our members, the IEA Working Party on Fossil Energy and other interested parties with definitive and policy relevant independent information on how various carbon-based energy sources can continue to be part of a sustainable energy mix worldwide. The energy sources include, but are not limited to coal, biomass and organic waste materials. Our work is aligned with the UN Sustainable Development Goals (SDGs), which includes the need to address the climate targets as set out by the United Nations Framework Convention on Climate Change. We consider all aspects of solid carbon production, transport, processing and utilisation, within the rationale for balancing security of supply, affordability and environmental issues. These include efficiency improvements, lowering greenhouse and non-greenhouse gas emissions, reducing water stress, financial resourcing, market issues, technology development and deployment, ensuring poverty alleviation through universal access to electricity, sustainability, and social licence to operate. Our operating framework is designed to identify and publicise the best practice in every aspect of the carbon production and utilisation chain, so helping to significantly reduce any unwanted impacts on health, the environment and climate, to ensure the wellbeing of societies worldwide.

The ICSC is organised under the auspices of the IEA but is functionally and legally autonomous. Views, findings and publications of the ICSC do not necessarily represent the views or policies of the IEA Secretariat or its individual member countries.

The CIAB consists of a group of high-level executives from coal-related enterprises. It was established by the IEA in July 1979 to provide advice to the IEA on a wide range of issues relating to coal. CIAB Members are currently drawn from 12 countries accounting for approximately 70-80% of world coal production and coal consumption. Members are drawn from major coal producers, electricity producers, other coal consuming industries and coal related organisations. The CIAB provides a wide range of advice to the IEA, through its workshop proceedings, meetings, work programme and associated publications and papers. The IEACIAB commissioned the International Centre for Sustainable Carbon (ICSC), formerly known as the IEA Clean Coal Centre (IEACCC), to undertake this study into the future role of low emissions coal technologies (LECT) in Asia. The study made use of the network and expertise of the CIAB member organisations, particularly relating to China and Southeast Asia.

ABSTRACT

There is a widely held assumption that there must be an end to the use of coal to achieve net zero emissions (NZE). For much of Asia, it is not feasible to phase out unabated coal in the coming decades as it remains the dominant source of energy, because of its low cost and ease of availability. Many Asian countries have relatively fast-growing economies and populations, which are also becoming more urban. Thus, demand for energy, electricity and infrastructure is growing – all of which are carbon-intensive. There is much that Asian countries can do to approach NZE, starting with the deployment of low emission coal technologies (LECT).

Carbon capture, utilisation and storage (CCUS) is a necessary part of Asia's transition to NZE because coal will remain important for many years for existing industry, such as electricity generation and industrial processes that are hard to abate; and new industries, such as bioenergy, hydrogen, ammonia and dimethyl ether (DME). Asia, and in particular China, should become a key focus for the roll-out of commercial CCUS, where large scale projects are underway.

Emissions from coal-fired power plants can be reduced by cofiring biomass with coal and increasing the efficiency of units. Japan is pursuing cofiring low emissions ammonia, produced from fossil fuels with CCUS, or from water electrolysis using electricity. All new, large coal units should adopt high efficiency, low emissions (HELE) ultrasupercritical (USC) conditions and best-available pollutant controls. Alternative power generation systems such as those based on supercritical CO_2 also have potential in the transition to NZE.

A portfolio approach to decarbonise industry and the chemicals sector will be needed, including 'fuel' switching to low emissions fuels of hydrogen and ammonia, biomass as a carbon neutral fuel, improved energy efficiency, and deployment of current best available and future innovative technologies including CCUS.

ACRONYMS AND ABBREVIATIONS

AHEAD	Advanced Hydrogen Energy Chain Association for Technology Development, Japan
ASU	air separation unit
ATR	autothermal reformers
AUSC	advanced ultrasupercritical
BECCS	biomass energy carbon capture and storage
BFB	bubbling fluidised bed
BF-BOF	blast furnace to basic oxygen furnace
BEIS	Department for Business, Energy and Industrial Strategy, UK
CAGR	compound annual growth rate
CCC	Committee on Climate Change, UK
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CFB	circulating fluidised bed
CfD	contract for difference
CHP	combined heat and power
CIAB	Coal Industry Advisory Board, IEA
COP	Conference of the Parties
DAC	direct air capture
DOE	Department of Energy, USA
DRI	direct reduced iron
EAF	electric arc furnace
EOR	enhanced oil recovery
ETS	emissions trading schemes
EU	European Union
FBC	fluidised bed combustor
FCCC	Framework Convention on Climate Change, UN
FCEV	fuel cell electric vehicle
FCH JU	Fuel Cell and Hydrogen Joint Undertaking
FEED	front end engineering and design
GCCSI	Global Carbon Capture and Storage Institute
GHG	greenhouse gases
GNI	gross national income
H2CN	China Hydrogen Alliance
HESC	Hydrogen Energy Supply Chain
HRS	hydrogen refuelling stations
ICSC	International Centre for Sustainable Carbon
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D Programme
IGCC	integrated gasification combined cycle

IPCC	Intergovernmental Panel on Climate Change
LECT	low emissions coal technologies
LCOH	levelised cost of hydrogen
LHV	lower heating value
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MCFC	molten carbonate fuel cell
METI	Ministry of Economy, Trade and Industry, Japan
MHI	Mitsubishi Heavy Industries
NDC	Nationally Determined Contribution
NEA	National Energy Administration, China
NEDO	New Energy and Industrial Technology Development Organization, Japan
NZE	net zero emissions
OECD	Organisation for Economic Co-operation and Development
PC	pulverised coal
PEM	proton exchange membrane
PPP	purchasing power parity
PV	photovoltaic
RAB	regulated asset base (project funding model)
R&D	research and development
SDGs	Sustainable Development Goals, UN
SMR	steam methane reforming
SNG	synthetic natural gas
SOFC	solid oxide fuel cell
TRL	technology readiness level
TPES	total primary energy supplies
VRE	variable renewable energy
UN	United Nations
USC	ultrasupercritical
WGS	water-gas shift

Note: all monetary values are in United States dollars ($) unless otherwise stated.

UNITS

Bt	billion tonnes (10^9 tonnes)
EJ	exajoule (10^{18} joules)
Gt	gigatonnes (10^9 tonnes)
GW	gigawatts (10^9 watts)
gCO_2	grammes of carbon dioxide
GJ	gigajoules
$GtCO_2$	gigatonnes of carbon dioxide
m	metres
Mt	million tonnes (10^6 tonnes)
Mtce	million tonnes of coal equivalent
Mtoe	million tonnes of oil equivalent
$MtCO_2$	million tonnes of carbon dioxide
MW	megawatt
MWe	megawatt electric
MWth	megawatt thermal
t	tonne
TW	terawatt
TWh	terawatt-hour
wt%	weight per cent

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EXECUTIVE SUMMARY

The 26th Conference of the Parties (COP26) to the United Nations Framework Convention on Climate Change (UNFCCC) held in Glasgow in November 2021, was an important moment for global action on the combined challenges of energy and climate. More than 130 countries have pledged to reach net zero emissions (NZE) before 2050. China is aiming for carbon neutrality by 2060 and India has a target date of 2070. Combined, the net zero target covers 88% of GHG emissions, 85% of the population and 90% of GDP (PPP) (Net Zero Tracker, 2021).

The coal industry is a key stakeholder in the UNFCCC process. As an advisory board to the International Energy Agency (IEA) on matters relating to the utilisation of coal, the Coal Industry Advisory Board (CIAB) worked with the International Centre for Sustainable Carbon (ICSC) to produce this report which considers the indispensable role of advanced coal technologies in fulfilling the goals of the Paris Agreement. The CIAB recommends the IEA supports this technology-centred approach to the challenge of reducing emissions in Asia.

There is a widely held assumption that achieving NZE means the end of using coal. Many developed countries have already committed to phase it out. They are generally high-income countries with slow-growing, service-based economies, stable populations and the options of nuclear power, relatively cheap natural gas and renewables. However, much of Asia depends on coal for energy security, where it remains the dominant source of energy as it is relatively cheap and readily available.

Asian countries tend to have relatively fast-growing economies and populations, which are also becoming more urban. This means that demand for energy and electricity is increasing. Urbanisation and industrialisation also raise the demand for infrastructure. These developments require large amounts of steel and cement, the production of which is also still largely coal dependent. Thus, it is much harder for a growing Asian economy to stop using coal than it is for a developed, service-based one in Europe or North America where the population already has 100% access to secure and reliable electricity.

Asia is home to over 60% of the world's population and relies on oil, coal and gas for 90% of its energy needs. It is responsible for more than half of global CO_2 emissions from fossil fuels. Asia has a large, young coal fleet (the average age of units is 13–14 years), which provides 57% of the region's electricity (Asia-Pacific, 2020). This means the region will need to accelerate deployment of low emission coal technologies (LECT) to help the world achieve NZE by 2050.

CARBON CAPTURE UTILISATION AND STORAGE IS VITAL

Carbon capture, utilisation and storage (CCUS) is a necessary, strategic part of Asia's transition to NZE because coal and gas will remain important for years for existing industry, such as electricity generation and industrial processes that are hard to abate, for example steel and cement making; and new industries, including bioenergy, hydrogen, ammonia and dimethyl ether (DME).

CCUS technology is ready for widespread commercial roll-out and its deployment in Asia needs to expand significantly to remain in line with the temperature objectives of the Paris Agreement. There are 30 large-scale CCUS facilities operating globally which store around 40 $MtCO_2$/y; we know it works. The reliability and availability of CCUS plants continue to increase.

The cost of CCUS has fallen significantly; capture currently costs around 65 $/$tCO_2$. 'Learning by doing' will bring costs down further; a 50–75% cut may be achieved as the technology is rolled out commercially. CO_2 capture costs of 43–45 $/$tCO_2$ by 2024-28 are predicted (*see* Figure 1).

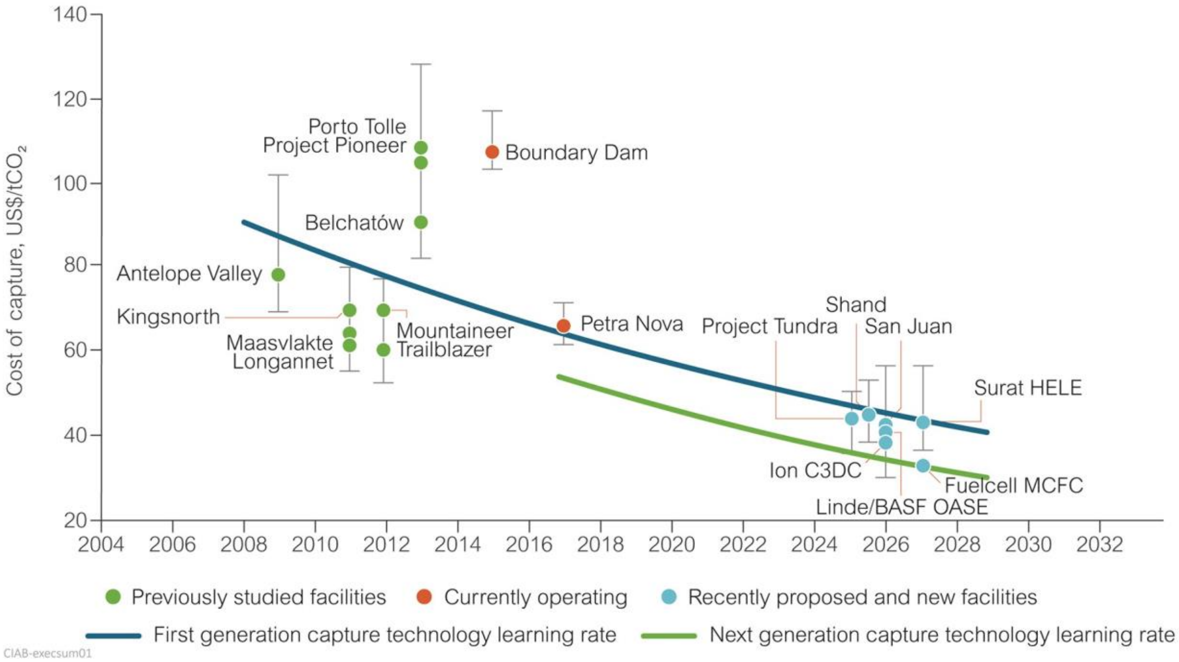

Figure 1 Levelised cost of electricity for large-scale coal power generation plants with post-combustion carbon capture (Zapantis and others, 2019)

Asia, and China in particular, should become a key focus for the wider commercial roll-out of CCUS. A current example in China is the Jinjie project, capturing 0.15 $MtCO_2$/y. Other projects include the Huaneng Longdong Energy Base 2 GW USC plant with 1.5 $MtCO_2$/y capture capacity with a planned completion date of end 2023 and the GreenGen integrated gasification combined cycle (IGCC) (Phase 3) planned to capture 1–2 $MtCO_2$/y by 2025.

The CO_2 captured could be stored permanently in local geological structures deep underground. Regional cooperation is an option for individual countries where this is not possible. For example, countries with limited geological storage could still use hydrogen and other feedstocks from coal (with the storage occurring where the coal is located) as part of attaining NZE.

The business case for CCUS can be boosted by using the CO_2 for enhanced oil/gas recovery and as a carbon source for new, value-adding circular economy activities in cement and chemicals manufacture.

There are no technical barriers to CCUS becoming a key strategic part of the NZE solution for Asia. However, strong financial, regulatory and incentive regimes will be needed to achieve large-scale roll-out.

MORE EFFICIENT POWER GENERATION IS EFFECTIVE

The power generation sector in Asia emits over 8 $GtCO_2/y$, almost half of the total CO_2 emissions of the region. Small, inefficient and unabated coal power plants should be closed. Improved efficiency of power plants can dramatically reduce emissions of CO_2 and other pollutants. Coal power plants with efficiencies of 47% (LHV) (equivalent to ~720 gCO_2/kWh) are in operation, while the global average is 37.5%. Each percentage increase in efficiency reduces CO_2 emissions by 2–3%, plus high efficiency, low emissions (HELE) power plants are more suitable for CCUS. There is the potential to lift efficiencies to almost 50% in the near term (reducing emissions by another ~10%, to around 680 gCO_2/kWh). Thus, all new, large coal units should adopt HELE ultrasupercritical (USC) conditions and best-available pollutant controls, while in the longer term all coal-fired units will need to be abated with CCUS.

Several alternative high-efficiency pathways are based on an IGCC, offering potential additional benefits of fuel flexibility, generation of high-value products, and good compatibility with carbon capture. The integration of fuel cell technology, particularly solid oxide fuel cells and molten carbonate fuel cells into IGCC coal-fired power plant, has the potential to further increase the efficiency of LECT. In the long term, efficiencies of around 60% LHV basis have been projected for such power plants. Supercritical CO_2 (sCO_2) cycles such as the Allam-Fetvedt Cycle hold great potential to provide advanced power generation systems that can achieve higher plant efficiency and close to full carbon capture at lower costs.

COFIRING WITH LOW CARBON FUELS REDUCES EMISSIONS

Cofiring coal with agricultural and forestry wastes as well as low-emissions hydrogen and ammonia reduces GHG emissions from power plants and may offer a cheaper option to achieve NZE at a power plant, for example with 90% capture and 10% cofiring. The role of cofiring is increasing in Asia: China, Japan and Indonesia have specific policy tools to support biomass cofiring, either in place or planned. There are substantial agricultural and forestry waste resources suitable for cofiring with coal. Such action would also improve local air quality if the waste was no longer burnt in the field.

In Japan, the option to cofire low emissions ammonia, produced from fossil fuels with CCUS, or from water electrolysis using electricity, is being pursued. Work is underway to develop a global supply chain to provide the required levels of low emissions ammonia.

COAL SUPPORTS MORE RENEWABLE ENERGY ON THE GRID

As the proportion of variable renewable energy (VRE) supplying the grid increases in Asia, dispatchable coal-fired power plays an important role in the overall grid response to demand When there is little wind or sunshine, coal-fired power plants can be ramped up to maintain stable supplies of electricity. Even when high levels of VRE are achieved >50–70%, coal power will remain key to ensuring security of supply. Thus, an increase in VRE capacity lowers the output from coal plants but does not necessarily mean their closure. Coal power plants do not compete with VRE. Instead, they facilitate the increased penetration of VRE into Asian power networks by maintaining a stable grid while producing low emissions power when necessary.

However, as investments and policies for power sector transformation focus on VRE, inefficient coal power plants continue to operate, instead of being replaced by HELE plant with CCUS. This is exacerbated by the flight of international finance and technology providers from the coal sector. While coal remains fundamental to many Asian electricity grids, the sector should be supported in a rapid transition to HELE technologies through appropriate valuation of dispatchable capacity to make the grid reliable, with continued support for R&D, and greater international collaboration.

COAL HAS A MASSIVE, HARD TO REPLACE ROLE IN ASIAN INDUSTRY

Industry already produces about 8 GtCO_2/y of direct emissions, 70% of which are from the cement, iron and steel, and chemical sectors. Almost 2 GtCO_2/y of industrial emissions are a by-product of chemical reactions within the production process and currently cannot be avoided. Demand for products is forecast to continue to grow, driven by population and economic growth.

China is responsible for 50–60% of the global production of cement, steel and aluminium, where coal is the dominant feedstock and source of process heat. This means that coal accounts for 70% of steel, 83% of cement and 75% of aluminium production in China (*see* Figure 2).

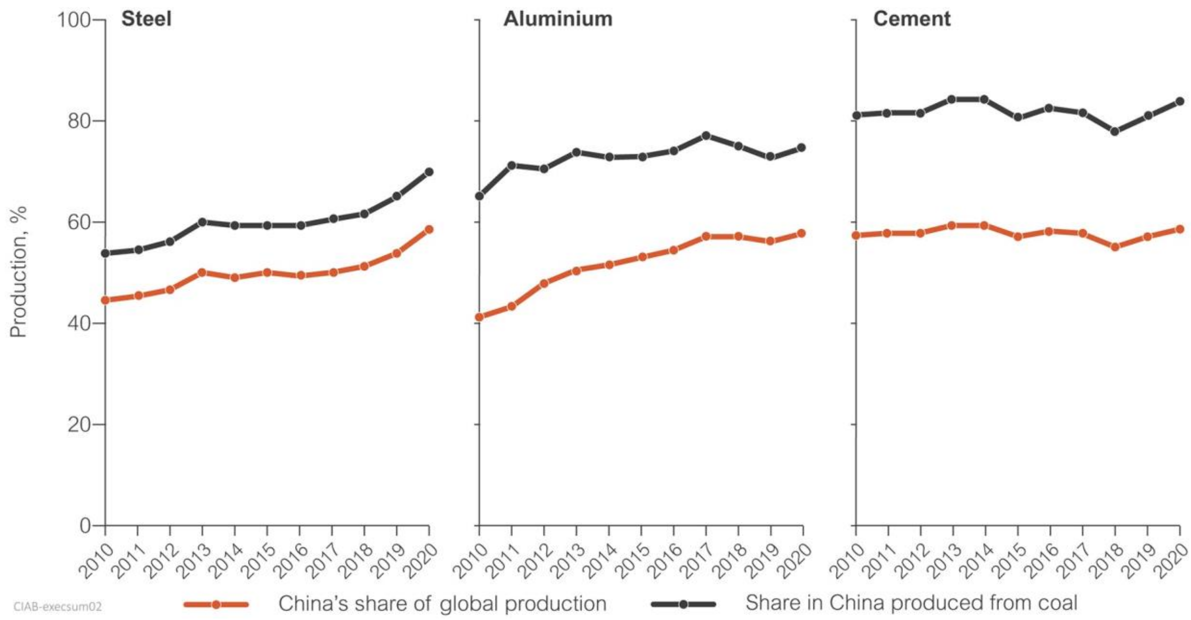

Figure 2 Proportion of steel, aluminium and cement production in China derived using coal as a feedstock and energy source (Yang, 2020)

A portfolio of approaches will be needed to achieve NZE from industry, including:

- deployment of CCUS;
- 'fuel' switching to hydrogen, biomass and electricity where available at a competitive price; and
- improved energy efficiency and increasing the use of scrap steel and aluminium.

Coal will continue to be key through the transition to NZE, with CCUS retrofit essential to decarbonise industry.

GROWING CHEMICALS SECTOR RELIES ON COAL

For chemicals and fuel production from coal, gasification can offer the best production route in Asia and has a strong track record in China. The chemical and fuel sectors are growing and are likely to expand through the transition. The use of methanol as an intermediate, substitute natural gas, coal-to-liquids and coal-to-tar, deep processing and hydrogenation, and lignite upgrading are all expected to grow strongly. Process optimisation can improve conversion efficiencies, but again CCUS must be adopted for this industry to develop in a way consistent with NZE.

LOW-CARBON EMISSIONS HYDROGEN INCREASING IN IMPORTANCE

Hydrogen is a very versatile fuel, with a potential role in all sectors; global demand in 2050 may be up to 650 MtH_2/y, a 560% increase from 2018. It is likely to be used for industrial feedstock and energy supply, transportation, heating and power in buildings, and power generation usage including hydrogen buffering.

The preferred method of hydrogen production depends on local factors. In China, low emissions hydrogen production via gasification from coal with CCUS is lower cost than low emissions hydrogen based on water electrolysis, typically by a factor of almost 3. This economic advantage of coal gasification with CCUS means it will probably continue to be a low-cost source of large-scale hydrogen in Asia. The Sinopec Qilu CCUS retrofit to the existing coal gasification plant in China could lead the way to a wider roll-out of low-carbon hydrogen technology in Asia.

The addition of CCUS to coal gasification for hydrogen production can reduce the carbon intensity of hydrogen to 0.4–0.6 $kgCO_2/kgH_2$, at a 98% rate of carbon capture. This is 2% of the CO_2 compared to hydrogen production from the global average electricity mix. Cofiring biomass or ammonia with the coal, increasing the capture rate, or using advanced technology such as the Allam-Fetvedt Cycle, could all reduce the CO_2 emissions closer to net zero, or even below, in the case of cofiring with CCUS.

MEETING THE CHALLENGE IN ASIA

Achieving NZE will require an increase in the level of VRE in Asia and a reduction in the emissions traditionally associated with fossil fuels. Coal will continue to be used in Asia in the coming years because: security of energy supply is vital; coal provides dispatchable power to help maintain a stable power grid as the level of VRE increases; natural gas is relatively expensive; and coal is difficult to replace as a feedstock in many industries.

Thus, Asian countries reliant on coal now will need low emissions technologies for power generation and especially for the foundation industries of steel, cement and aluminium, for the chemicals industry and for the hydrogen sector which can contribute to power generation, industry, building and transport.

CCUS, together with HELE power plants, biomass and waste cofiring with coal will be key enabling technologies to help large parts of Asia approach NZE while maintaining economic growth. There are low emission technologies available and others close to commercialisation that are vital to enable Asia to approach NZE.

Investment in advanced coal technologies is an essential part of global action to meet emissions objectives and achieve the intended outcomes of the Paris Agreement. This study aims to accelerate the transition.

1 INTRODUCTION

The Paris Agreement on climate change was adopted at the 2015 Conference of the Parties to the United Nations Framework Convention on Climate Change (COP21). The central aim of the Agreement is to strengthen the global response to the threat of climate change by keeping global temperature rise by 2100 to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C. It seeks to balance greenhouse gas (GHG) sources and sinks in the second half of this century, effectively requiring net zero GHG emissions (IPCC, 2018). Recognition is growing that GHG emissions need to be reduced to net zero by around 2050 to limit the global temperature rise this century to the 1.5°C target and to mitigate the more severe impacts of climate change (IPCC, 2021). This is reflected in the latest updates to the Nationally Determined Contributions (NDCs) of the Parties to the Agreement and recent government announcements, particularly at COP26 in November 2021. More than 130 countries have pledged to reach net zero emissions (NZE) before 2050. China is aiming for carbon neutrality by 2060 and India has a target date of 2070. Combined, the net zero target covers 88% of GHG emissions, 85% of the population and 90% of GDP (purchasing power parity, PPP) (Net Zero Tracker, 2021). Other countries such as Indonesia are exploring opportunities to rapidly progress towards NZE in 2060 or sooner (UNFCCC Indonesia, 2021).

Achieving NZE will require an increase in the level of renewable energy sources, particularly solar and wind, together with a reduction in the use of fossil fuels, among other measures. According to the IEA's net zero emissions scenario (IEA, 2021a) the resulting energy mix could be as shown in Figure 1. This scenario is one potential pathway to achieve net zero global GHG emissions; alternative routes have also been developed, such as that defined by the Intergovernmental Panel on Climate Change (IPCC, 2019).

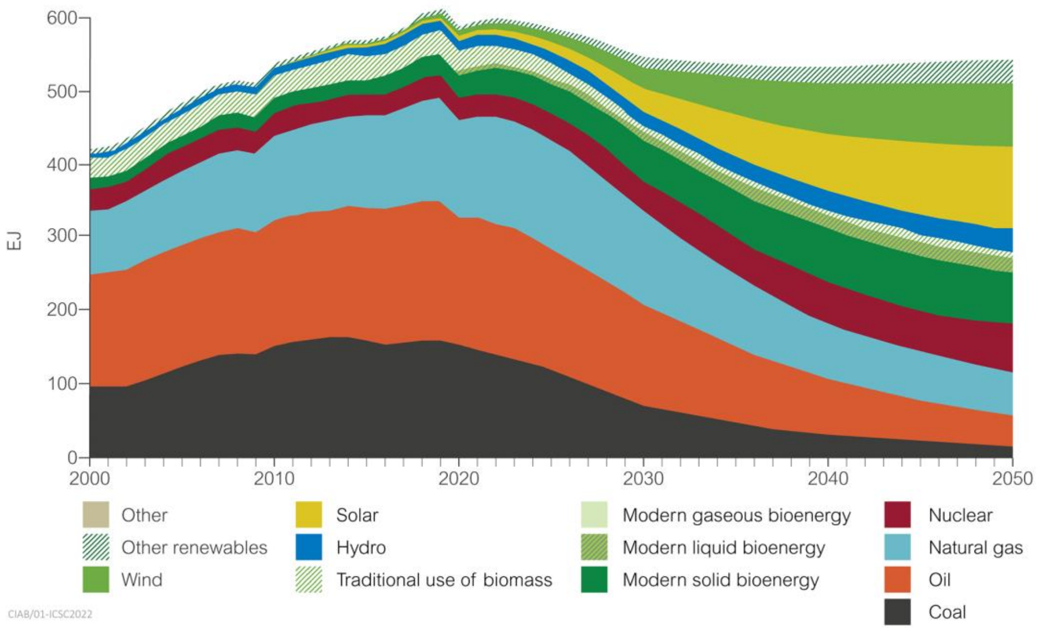

Figure 1 Global energy mix in the IEA's net zero emissions pathway (IEA, 2021a)

Impact on coal

In the IEA NZE scenario there is a dramatic reduction in the use of fossil fuels; its share of total energy supply falling from 80% in 2020 to a little over 20% in 2050. In this scenario coal consumption for energy would reduce from over 5 billion tonnes (Bt) in 2020 to below 0.6 Bt in 2050, representing an average annual reduction of 7% per year. Despite the ambitions of this scenario, significant quantities of coal would still be used in 2050 for:

- non-energy goods, in plants with carbon capture utilisation and storage (CCUS) (*see* Chapter 2 for a description of this technology);
- heavy industries such as steel, cement, aluminium and chemicals manufacturing where emissions are difficult to abate, again using CCUS technology together with low emissions hydrogen, ammonia and methanol derived from coal; and
- power generation where low emissions electricity can be produced, again using CCUS.

However, it should be noted that coal demand worldwide was expected to grow by 6% in 2021 and to rise to 8025 Mt in 2022, the highest level ever seen, and to remain at this level to 2024 (IEA, 2021e).

Cofiring coal with biomass, waste, hydrogen or ammonia could be used to deliver low emissions, and when coupled with CCUS, this could deliver negative CO_2 emissions to offset GHG emissions from other sectors. As a fully dispatchable source of low emissions power, coal-based power generation with CCUS can complement the increased penetration of renewables by providing reliable back-up to operate flexibly around the variability of solar and wind power. A further advantage is that the large rotating turbo-machinery associated with fossil fuel power generation, both steam and gas turbines, provide spinning inertia to help maintain stable grid frequencies as wind and solar based power generation increases. Low emissions coal technologies (LECTs) can therefore be an enabler to support the increased level of renewables penetration in the 2050 energy mix as part of a resilient energy system.

Regional variations

There will be considerable regional variations in how NZE can be achieved. In Asia, there are various priorities which must be balanced. As well as reducing emissions of GHG and other air pollutants, there is a need to provide universal access to affordable, reliable electricity, to meet the energy demands of an increasingly urbanised society and of fast-growing economies, and to maintain some energy independence. These requirements are shown in the wider context of the United Nation's Sustainable Development Goals (SDGs), particularly:

- SDG 7 Affordable clean energy for all;
- SDG 8 Decent work and economic growth;
- SDG 9 Industry innovation and infrastructure;
- SDG 1 Sustainable cities and communities; and
- SDG 13 Climate action.

Thus, in much of Asia, coal use is forecast to increase, mainly for the reasons listed below (Mills, 2021):

- use of indigenous energy resources;
- ease of availability;
- enhancing national energy security and reducing energy imports;
- diversification of sources of energy;
- growing electricity demand or shortages of supply;
- generates cheaper, more affordable electricity than alternatives;
- drives economic and/or social development; and
- can be instrumental in providing universal access to electricity.

In China for example, there was an overall increase in coal consumption of over 1% in 2019. Across Southeast Asia, coal use increased by around 15% in 2019, mainly reflecting demand growth in Vietnam and to a lesser extent, in Indonesia (IEA, 2020a). This shorter term analysis shows that by 2025, global coal demand is forecast to level out at around 7.4 Bt/y, or around 5200 million tonnes of coal equivalent (Mtce) with China's coal demand reaching a plateau of around 4 Bt (around 2800 Mtce). India and some other countries in South and Southeast Asia are also forecast to increase coal use to 2025 as industrial production expands and new coal-fired capacity is built.

A further factor is that more than half of the global 2 terawatts (TW) of coal capacity has been built in the last 20 years, and coal power plants can have a life of 40–50 years. Over 90% of this expansion has taken place in Asia, primarily in China, but also India, and increasingly in Southeast Asia, including

Indonesia and Vietnam. These recently built plants will probably continue to be operated for at least the next decades; the challenge is to ensure that they are operated in a low emissions manner consistent with the transition to NZE emissions.

This study assesses the role of coal as an energy source to support the transition to a NZE future. The focus is on Asia where there are countries with fast growing economies that have ready access to relatively cheap coal, either domestically produced or from imported sources, which is fundamental to supplying reliable energy for their economic expansion and development. This includes both coal for power, as well as for heavy industrial manufacturing including steel, cement, aluminium and a range of chemicals. Coal will also have a sizeable role in affordable, low emissions hydrogen, ammonia and methanol production, both as intermediaries in chemicals manufacture and as energy vectors in their own right. These sectors, supported by coal, are important in terms of urbanisation and other aspects of economic development in Asia. The challenge is that this development needs to be achieved in parallel with reducing GHG emissions to meet climate commitments.

Therefore, the report covers CCUS as a key enabling technology for low emissions coal, together with the cofiring of coal with biomass, waste fuels or low emissions fuels such as ammonia, as an alternative to deliver low emissions. By utilising CCUS and cofiring together, low emissions coal could actually become a negative emissions technology to effectively remove GHGs from the atmosphere. LECTs for power generation, together with flexible operation as part of resilient grids with high embedded renewable energy are discussed. Coal based technologies in industrial manufacturing and to produce chemicals and hydrogen are also assessed. Finally, the report includes case studies from China, India, Indonesia and Vietnam as major coal users, but with very different perspectives and resources. Japan is also assessed as a country pursuing regional solutions to meet national targets, particularly relating to the nature of geological storage opportunities and carbon dioxide/hydrogen transport networks to support CCUS initiatives.

The report primarily addresses technology issues relating to low emissions coal use to complement the IEA's world roadmap to NZE by 2050 (IEA, 2021a).

2 CCUS – KEY TO ASIA'S TRANSFORMATION TO NET ZERO

2.1 KEY MESSAGES

CCUS as a technology is understood and proven.

- The various elements of the CCUS technology chain are in place for commercial deployment.
- Barriers to widespread large-scale CCUS deployment are not technical.
- Several other next generation technologies that could provide step change cost reductions and increase efficiency are being researched and developed and could, in time, reach the market.

There are 30 operational large-scale CCUS facilities globally, with the potential to store around 40 $MtCO_2/y$; the majority relate to natural gas processing applications.

CCUS projects are spreading around the globe and increasing in diversity.

- Over the past three years the number of new projects has risen from 28 in 2019 to 102 in 2021 with facilities in development in power generation, liquefied natural gas (LNG), cement, steel, waste-to-energy, direct air capture and storage and hydrogen in Europe, the Middle East, North America and China.
- North America remains an important region, but several countries now have commercial CCUS facilities under development, including Belgium, Denmark, Hungary, Indonesia, Italy, Malaysia and Sweden.
- Asia, and in particular China, should become a key focus for the roll-out of commercial CCUS.

The cost of CCUS has reduced significantly, with a current cost of capture of around 65 $\$/tCO_2$ (2021). Further cost reductions can be expected through 'learning by doing' where perhaps a 50–75% cut could be achieved as the technology is deployed commercially.

There are no technical barriers to increasing capture rates beyond 90% in the three generation capture routes post-, pre- and oxyfuel combustion.

- CCUS capture levels will need to increase from the current 90–95% to closer to 100%, or other options such as cofiring with biofuels utilised, to allow power plants to continue to operate in a NZE future. This is because any residual CO_2 emissions from CCUS facilities will not be compliant without being offset from negative CO_2 emissions elsewhere.

The hub and cluster approach is increasingly being adopted to enable the sharing of transport and storage infrastructure. This can improve the economics of CCUS due to economies of scale and overall de-risking of storage liability and cross-chain risk. Fossil fuel power plants with CCUS could form the anchor for these clusters with local industries feeding in their captured CO_2.

- There are already four hubs operating in Brazil, Canada, Norway and the United Arab Emirates.
- CCS hubs are evolving to become the dominant operating model for CCUS in North America and Europe.
- The Asia CCUS Network provides a platform for policymakers, financial institutions, industry and academia to work together to develop and deploy CCUS in Asia.

Irrespective of the policy scenario, technology and innovation will be the key driver to achieving the goals of the Paris Agreement. In particular, CCUS fitted to power generation, industrial manufacturing plant and low emissions hydrogen production facilities will be needed to help secure Asia's transformation to a NZE future at least cost. According to the IPCC (2019), between 350 and 1200 gigatonnes of CO_2 ($GtCO_2$) will need to be captured and stored this century to limit the global temperature rise to the 1.5°C target (IPCC, 2019). Most climate models indicate that without CCUS it becomes nearly impossible and significantly more costly to keep the temperature increase within the target. Moreover, the risk of overshooting would be increased by limiting the potential for large-scale CO_2 removal or 'negative emissions' using bioenergy with CCS (BECCS) (Stechow and others, 2016; Consoli, 2018).

The latest analysis from the IEA (2021a) shows that to achieve the NZE pathway, 7.6 $GtCO_2$/y needs to be captured by 2050, almost 50% of which would be from fossil fuel combustion, 20% from industrial processes and around 30% from BECCS and direct air capture (DAC) (IEA, 2021a). The use of CCUS with fossil fuels provides almost 70% of the total growth in CCUS to 2030 in the NZE scenario. Clearly, to help the world achieve NZE, CCUS will need to be a prominent feature in Asia, home to over 60% of the population. Moreover, the roll-out of commercial CCUS and other low emission technologies will empower Asian economic growth and increasing urbanisation without the attendant growth in emissions.

The following sections explore the technical status of CCUS globally.

2.2 CCUS TECHNOLOGIES

CCUS prevents CO_2 from being released to the atmosphere. It involves capturing CO_2 produced by large power and industrial plants, compressing it for transportation and then either injecting it into rock formations underground, using it for enhanced oil recovery (EOR), or to form useful products. CCUS as a technology is understood and proven. Carbon capture equipment has been used commercially to purify natural gas and other gases since the 1930s. CO_2 was first injected underground in commercial-scale operations in 1972 and it is transported daily by pipelines and, to a lesser extent, trucks, trains and ships in many parts of the world. CCUS is of strategic value for climate change abatement. It can be applied to fossil fuel power plants (both coal- and natural gas-fired) to provide low emissions generation capacity to complement intermittent renewable power sources. It is a solution for hard-to-abate industries such as cement, steel, aluminium and chemical production, as well as a platform for the hydrogen economy. CCUS will also become important in removing carbon from the atmosphere (for example BECCS and DAC with CCUS) to balance emissions that are challenging to avoid (IEA, 2020e; IChemE, 2018). The ICSC has published many reports on CCUS; see for example Kelsall (2020), Lockwood (2016, 2018a,b) and Minchener (2019).

CO_2 CAPTURE TECHNOLOGIES

There are four principal types of capture process:

Post-combustion capture – CO_2 is removed from the flue gas after the main process conversion step (typically combustion). The remaining flue gas is primarily nitrogen together with other minor components. Most post-process capture technologies used in projects today are amine-based absorption systems of the post-combustion capture type. Additional technologies that fall into the post-process capture category include adsorption onto a solid sorbent, fuel cells including molten carbonate fuel cells (MCFC) and membrane separation.

Oxyfuel combustion – Fuel is burned with oxygen in a stream of recycled CO_2. By excluding the nitrogen from the process, CO_2 separation becomes a relatively easy process of condensing out the water from the flue gas. However, it requires an air separation unit (ASU) to produce the oxygen for the oxyfuel combustion process which adds to the system cost.

Pre-combustion capture – In an integrated gasification combined cycle (IGCC) power plant in which the fuel is gasified/reformed to a $CO/H_2/CO_2$ mixture, typically incorporating a water-gas shift (WGS) reaction step to increase the concentration of hydrogen by reacting the carbon monoxide with steam. The CO_2 is then captured from the pressurised fuel gas stream. The IGCC system combines chemical processing with power generation, with the flexibility of being able to produce hydrogen. The typical separation technologies that fall into this category include solvent separation processes such as Rectisol and Selexol, pressure swing adsorption and water enhanced gas-shift.

Calcium and chemical looping – A further approach with calcium or chemical looping technologies involves the use of metal oxides or other compounds, as regenerable sorbents to transfer either CO_2 or oxygen from one reactor to a second reactor. Circulating fluidised beds, which are available commercially, can be used as one or both reactors. Both calcium and chemical looping technologies are second-generation CO_2 capture technologies utilising high-temperature streams to significantly reduce the energy penalty associated with CO_2 capture.

Post-combustion capture is the most widely deployed approach and most of these projects use chemical absorption through amines. This capture technology has been used commercially in industrial settings in chemicals production and to purify natural gas and other gas streams for over 80 years.

2.2.1 CCUS component readiness levels

The Technology Readiness Level (TRL) of a component or system qualitatively assesses the maturity of technology through the different stages of research and development (R&D). Of the different CCUS technologies at varying stages of development (*see* Figure 2) several are readily deployable at commercial scale (TRL9) and most are at the pilot plant stage (TRL6) or higher (IChemE, 2018). Various other technologies that can reduce costs and increase efficiency are at TRL7–8 and most should, in time, move to TRL9.

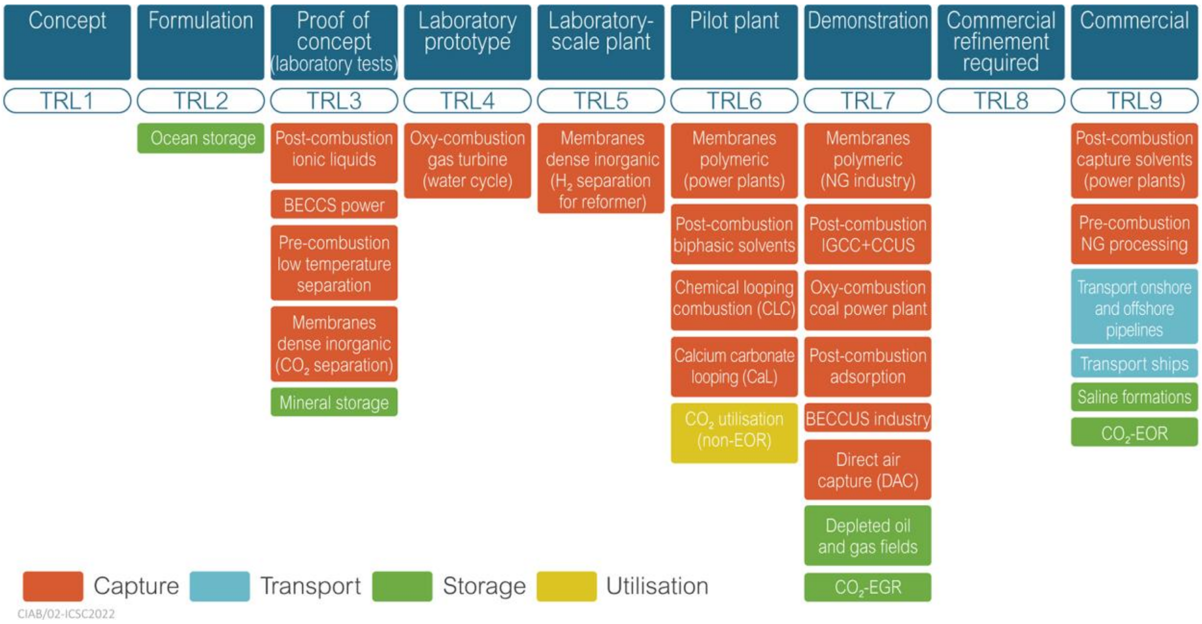

Figure 2 CCUS components in terms of Technology Readiness Level (IChemE, 2018)

Thus, the elements of the CCUS technology chain are in place for commercial deployment and their safety and operability has been confirmed in various pilot demonstrations and large-scale commercial operations. The barriers to widespread large-scale deployment of CCUS are not technical and there is potential for future cost reductions through next generation technologies and through 'learning by doing'.

2.2.2 CCUS R&D priorities

A recent study sponsored by the UK Government's Department for Business, Energy and Industrial Strategy (BEIS), sought to identify the key innovation needs to help prioritise investment in low-carbon innovation. Part of the study focused on CCUS (EINA, 2019) and defined the following as key R&D priorities:

- **For pre-combustion** – advanced reformer technologies to unlock the potential to combine hydrogen production with CCUS for power, which opens further opportunities across the energy system. Cost reduction is possible using cheaper and more energy-efficient materials and processes.

- **For post-combustion** – R&D into new solvent and absorption processes aimed at lowering cost and improving capture performance, whilst also having the potential to reduce regeneration costs, corrosion effects, environmental impacts, and product degradation.

- **For oxyfuel combustion** – new technologies for lower-cost air separation in oxycombustion, including ion transport membranes (ITMs). Ceramic materials that conduct oxygen ions at elevated temperatures are an early-stage technology with significant potential for a step-change cost reduction in air separation.

A selection of next generation technologies showing how they could progress through the TRL levels is shown in Figure 3. They could offer benefits (either through innovation in materials, processes or equipment) for reduced capital and operating costs and improved capture performance.

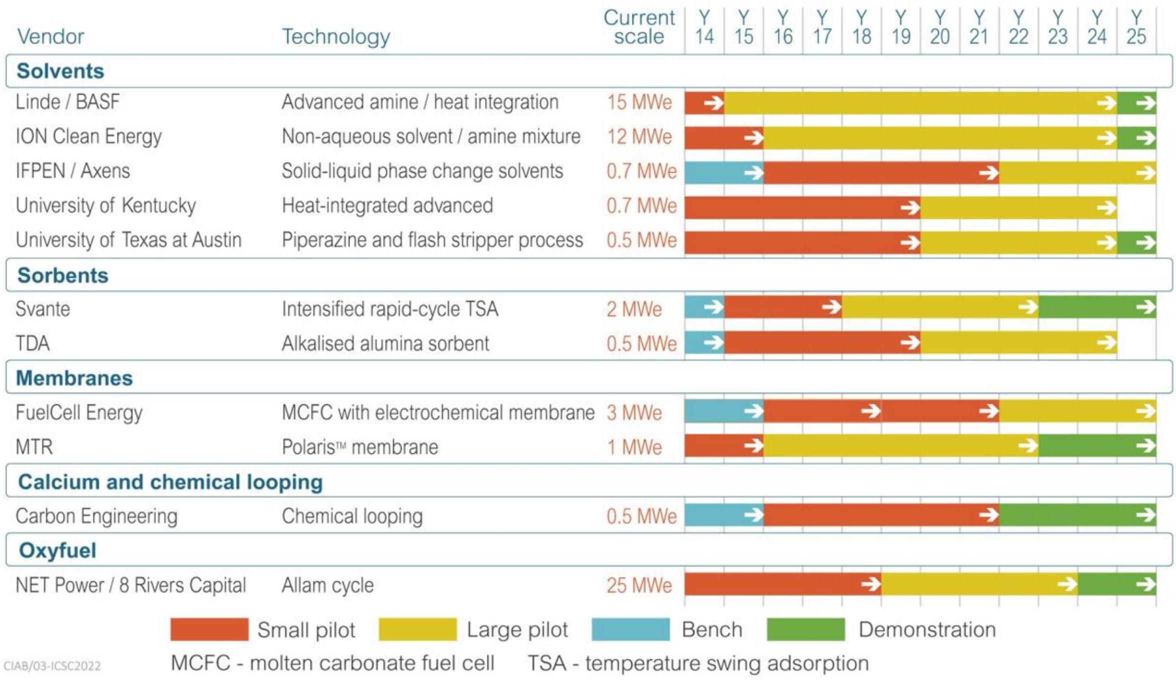

Figure 3 Selection of next-generation CCUS technologies being tested at >0.5 MWe (Kearns and others, 2021)

2.3 CCUS TECHNOLOGY STATUS

There are a total of 30 operational (October 2021) CCUS facilities globally (*see* Appendix, Table A-1) (GCCSI, 2020, 2021b). The majority of these facilities relate to natural gas processing applications, together with chemicals production such as ethanol and fertilisers, hydrogen for refinery applications, steel production and power generation. Together, they provide the potential to store around 40 $MtCO_2$/y. In addition, six facilities are in construction and due to be completed in the 2020s (*see* Appendix). Two of them relate to chemicals production in China, namely Sinopec Qilu Petrochemical CCS and Guodian Taizhou Power Station Carbon Capture.

There are also a significant number of projects in advanced development using a predominantly front end engineering design (FEED) approach, or in the early stages of development (*see* Appendix, Table A-2).

In terms of power generation, CCUS currently plays a relatively small role with one operational and one in suspended operation providing a combined 350 MWe capability. Both are retrofits of coal-fired power plants located in North America, namely:

- 110 MW Boundary Dam power plant in Canada, which was retrofitted with CO_2 capture in 2014 and is rated at 1.0 $MtCO_2/y$ captured;
- 240 MW side-stream at the Petra Nova power plant in Texas, USA, which started operation in January 2017, rated at 1.4 $MtCO_2/y$ captured. Operation of this facility was suspended in early 2020 due to the global economic downturn caused by the Covid-19 pandemic, together with a reduction in oil prices affecting the plant's revenue from EOR. Petra Nova's operator, NRG, has indicated that CO_2 capture will resume when economic conditions improve (GCCSI, 2020).

The key regions in terms of CCUS installations are North America, Europe, the Middle East and Asia Pacific.

2.3.1 CCUS projects becoming widespread and more diverse

Eighteen of the 30 commercial scale CCUS operating facilities are in North America, with 14 of them in the USA, due in large part to supportive national policy frameworks, a focus on low emission technology innovation, the history of oil and gas exploration/operation, accessible CO_2 storage sites although the use of the captured CO_2 for EOR has been a stronger driver, and strong stakeholder support including the private sector.

Looking ahead to 2030, CCUS projects are becoming increasingly diverse, with development projects in a broad range of sectors including power generation, LNG, cement, steel, waste-to-energy, direct air capture and storage and hydrogen production. North America continues to be the leader in CCUS deployment with 41 new large-scale commercial CCUS projects announced in 2021. Importantly, several new countries have commercial CCUS facilities under development, including Belgium, Denmark, Hungary, Indonesia, Italy, Malaysia and Sweden.

2.3.2 Lessons learned from CCUS projects

Several studies have been carried out to identify the potential to reduce the costs of CCUS (*see* Irlam, 2017; Bruce and others, 2019; IEA 2020; Kearn and others, 2021). Generally, they point to cost reduction through increased deployment at pilot demonstration and subsequently commercial scale – so-called 'learning by doing'. There is growing knowledge, based on Boundary Dam, Petra Nova and the more recent pipeline of FEED studies, that provide the initial practical understanding to drive cost reduction and improve performance of next generation CCUS facilities. In addition, pilot and early TRL research projects are underway to develop the potential for innovating existing technologies and developing new ones which could bring step change cost reduction.

2.3.3 Cost reduction

Technology costs fall in real terms as a result of innovation and learning by doing. Examples include the costs of manufacturing solar cells and offshore wind, which have fallen significantly and are projected to fall further. Another example is the development of wet desulphurisation scrubbers for coal-fired power plants in the USA where capital costs fell by about half as the deployment of the technology increased.

Capture forms the bulk of total CCUS costs. The cost of CO_2 capture is much lower for concentrated sources (such as in hydrogen production, coal to chemicals and natural gas processing) than for power generation, cement and iron and steel production. Over the past 15 years the cost of capture from coal-fired power flue gas has fallen by about 50% following R&D, demonstrations and learning by doing. Diverse technologies, platforms and innovations developed outside the energy sector are being transferred into this sector to reduce costs, risks and timescales for CCUS projects.

Current carbon capture costs for coal-fired power plants with post-combustion CO_2 capture using amine-based solvents are in the range of 105 $/t$CO_2$ captured at Boundary Dam, to 65 $/t$CO_2$ captured at Petra Nova (GCCSI, 2020). The US Department of Energy (DOE) has noted that carbon capture costs need to come down to around 30 $/t$CO_2$ for CCUS to be commercially viable (USDOE, 2018). These costs will naturally decline in the future as CCUS technology becomes more commercialised through economies of scale. Based on a typical learning rate of 8–13% for coal related technologies (Zapantis and others, 2019) and assuming a target capacity of 220 GWe of coal-fired power plant fitted with CCUS to achieve the IEA's NZE scenario (IEA, 2021a), a cost reduction in the range of 50–75% could be achieved by 2050 for amine-based post-combustion CO_2 removal. If the current cost of CCUS is taken as the more recent Petra Nova price of 65 $/t$CO_2$ captured, the price for future CCUS plant could therefore fall to 18–30 $/t$CO_2$, depending on final capacity and the actual learning rate. This number could be even lower with the additional learning from industrial applications of CCUS.

It is interesting to compare the projected cost for the proposed Shand Power plant FEED study (Bruce and others, 2018a; Int CCS KC, 2018) with the existing Boundary Dam project. The cost reduction projected for the single 300 MWe Shand coal power plant with an assumed 90% CO_2 capture is 57% relative to Boundary Dam, resulting in a capture cost of 45 $/t CO_2. Capital cost and variable operating and maintenance costs are the key areas for achieving this cost reduction. This level of cost reduction is higher than that predicted by the learning rate-based cost reduction, indicating that the learning rate is steeper at this relatively early stage of commercialising demonstration technologies (Kelsall, 2020).

The Shand FEED study fits into a cluster of more recent project studies at around the 43–45 $/t CO_2 cost level, within a proposed timescale for commencement of plant operations by 2024-28 (*see* Figure 4). This figure also indicates the potential for further cost reduction by moving to advanced capture systems within a similar timescale, where costs below 35 US$/t$CO_2$ could be expected based on pilot plant tests.

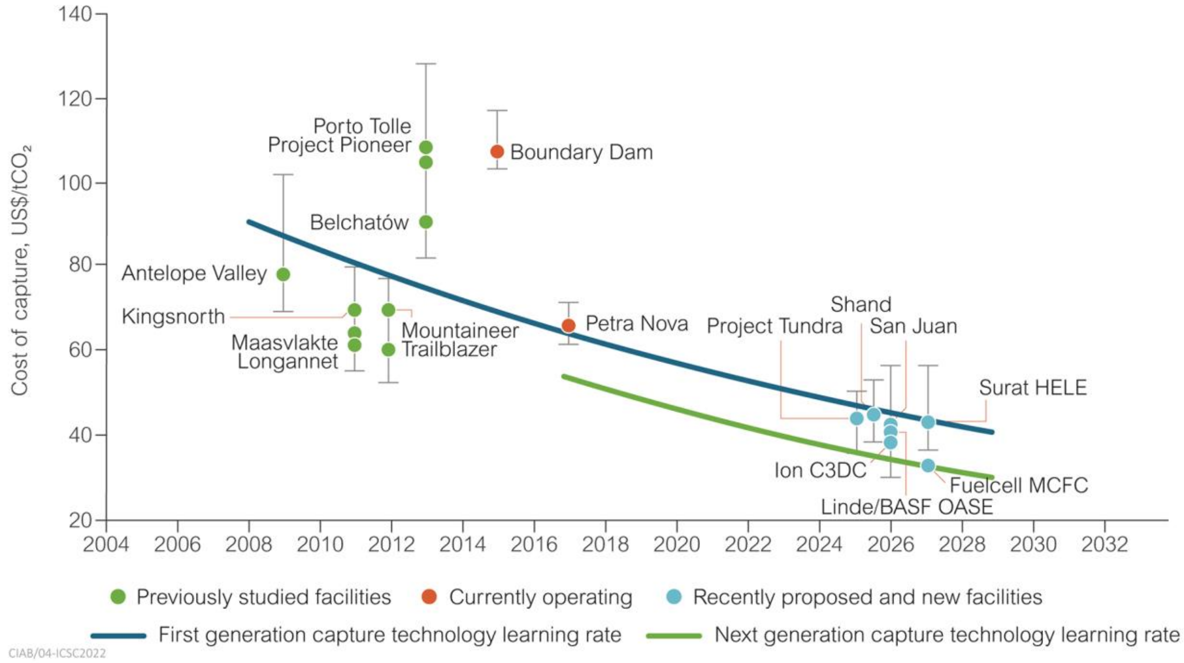

Figure 4 Levelised cost of electricity for large-scale coal power generation plant with post-combustion carbon capture (Zapantis and others, 2019)

GCCSI analysis based on an 8% discount rate, 30 years project life, 2.5 years construction time, capacity factor of 85%. Fuel prices were based on the reported data in the project feasibility and FEED reports. Cost data normalised to 2017 values.

Considering geographic variability, Ferrari and others (2019) assessed location specific economic factors to assess global locations for CCUS relative to a base case plant costing in the Netherlands. In terms of total plant costs, China had the greatest cost reduction at around 35% less than the Netherlands base case, due to significant savings in material and construction labour costs. Indonesia and Eastern Europe were next lowest with around a 20% cost reduction (*see* Figure 5). It is not surprising that the lowest cost of CO_2 avoided is in China with a value of around 50 €/tCO_2 (about 55 $/t$CO_2$) avoided, as this cost correlates primarily with plant capital cost.

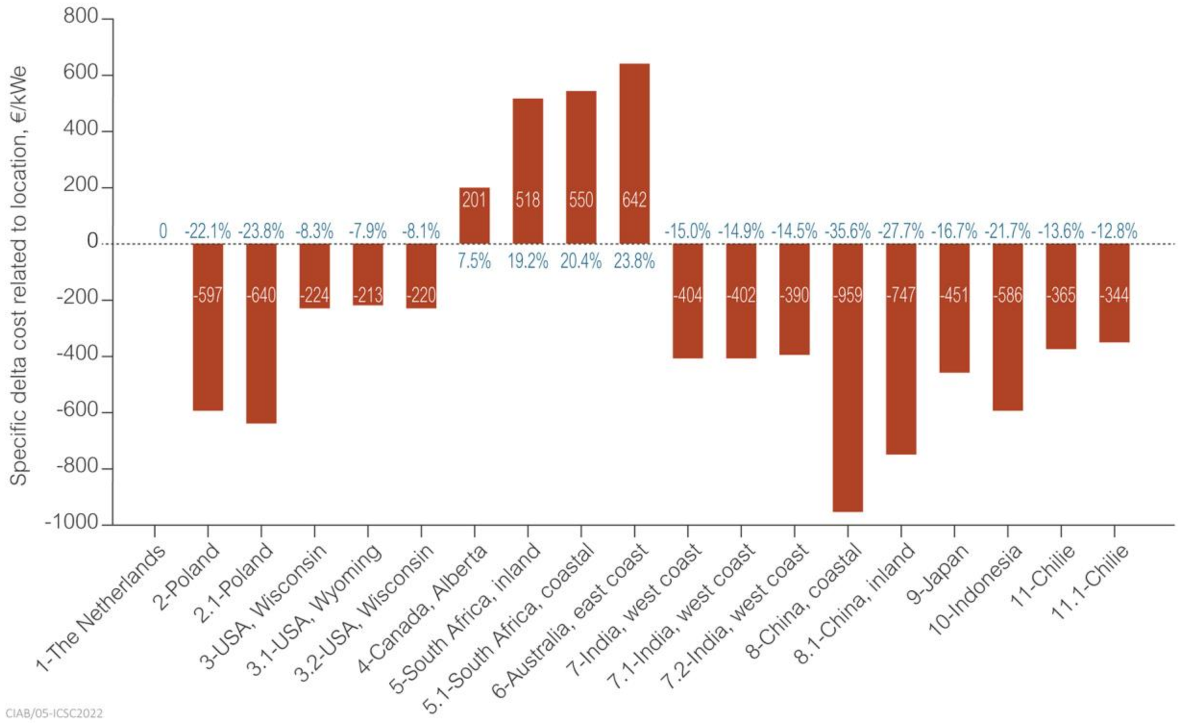

Figure 5 Supercritical coal power plant with post-CO_2 capture: specific total plant cost difference due to plant location compared to reference Netherlands base case (Ferrari and others, 2019)

2.3.4 Capture level

In its NZE modelling the IEA (2021a) assumes capture rates from fossil fuel power plants are capped at 90%. However, this is an artificial limit and in fact has been exceeded at Petra Nova. Today CCUS based on post-combustion CO_2 capture typically aims for a 90–95% capture level. In the longer term, as near zero emissions power plants will be needed to contribute to a NZE future, higher capture efficiencies will be required. Feron and others (2019) have shown that from a technical perspective, there is no limiting factor to increasing capture rates. A fossil fuel power station could be made effectively CO_2 neutral by capturing 99.7% of the CO_2, utilising intercooling in the CO_2 absorption tower for example. (At this capture rate the power station is CO_2 neutral as the only emitted CO_2 is that in the incoming combustion air.)

This increases the capital cost of the CCUS facility due to the requirement for larger sized equipment (absorber/desorber columns, heat exchangers and CO_2 compressor), as well as increased energy consumption. For an ultrasupercritical (USC) coal-fired power plant the efficiency (based on lower heating value, LHV) is reduced from 44.4% to 34.5% for 90% capture, and to 33.0% for 99.7% CO_2 capture, representing an additional drop of 1.5 percentage points in efficiency. The cost per tonne of CO_2 avoided increases from 55.0 €/tCO_2 ($62) at 90% capture level to 56.9 €/tCO_2 ($64.5) at 99.7% capture level, which is an increase of 3.5%.

It should be noted there are other possibilities to achieve NZE in a coal-fired power plant. These include cofiring coal with biofuels or potentially ammonia. For example, the co-combustion of 10% biomass in a coal-fired power plant with 90% CO_2 capture can be more economic than 99% and 99.7% capture, with a 2% increase in electricity generation cost over the usual 90% capture rate and only 1.5% increase in CO_2 avoided cost (IEAGHG, 2019). This study showed that the CO_2 avoided cost of 99% capture was 58.3 €/tCO_2 ($66) for a standard plant, compared with 55.8 €/tCO_2 ($63.5) for 90% capture and 10% biomass cofiring in a pulverised coal combustion unit. Similar costs have been shown by Feron and others (2019). This is important for Asia where the average age of coal-fired generation units is 13–14 years and biomass cofiring is potentially less expensive than 99.7% capture.

A 90-95% capture level should not be seen as an obstacle to a power station continuing to operate in the transition to net zero as it can take alternative approaches and/or buy reputable offsets to achieve the final reduction.

2.3.5 Hub and cluster approach

CCUS hubs, in which multiple emission sources share transport and storage infrastructure, are evolving to become the dominant operating model for CCUS in North America and Europe. The technologies to develop CO_2 hubs exist and are mature but experience and learning from their operation are still limited (Carbon Sequestration Leadership Forum, 2021). To address this, the Global CCS Institute has developed a database of major hubs, including four in operation and thirty under development (*see* Appendix, Table A-3). The establishment of the Asia CCUS Network underscores the interest in learning from these hub infrastructure developments and applying them in the Asia Pacific.

Shared transport and storage networks can improve the economics of CCUS due to economies of scale and overall de-risking of storage liability and cross-chain risk (IEA, 2020d; Zapantis and others, 2019; CCUS Cost Challenge Task Force, 2018). Heavy industries often exist in clusters close to local resources, power generation supply and port or rail infrastructure. These industrial clusters can be supported by providing CO_2 transport and storage network infrastructure which multiple CO_2 sources can access. This reduces the unit cost of CCUS as the CO_2 network capital cost is spread out across an increased quantity of CO_2. It also reduces cross-chain risk by creating multiple customers for the operators of the CO_2 transport and injection business and multiple CO_2 storage service providers for industrial CO_2 sources. This provides greater levels of operational flexibility than single source and sink facilities and reduces the operational risk.

The hub and cluster approach is driving the way CCUS projects are being carried out in several locations, particularly those associated with industrial carbon capture. Capturing CO_2 from clusters of industrial installations and using shared infrastructure for the subsequent CO_2 transportation and storage network, is the preferred approach to drive down unit costs across the CCUS value chain.

Examples include the Port of Rotterdam, the Netherlands (Porthos, 2019), the Northern Lights project, Norway (Northern Lights, 2019) and the nine UK industrial decarbonisation FEED projects (UKRI, 2021). The hub and cluster approach was also used in the Shand FEED study (Int CCS KC, 2018) where the CO_2 is used for EOR. EOR operators require reliable sources of CO_2 to avoid interruptions in oil production, so connecting two or more CO_2 sources to an EOR operation reduces the potential operating risk. A further example of this CO_2 hub concept is the Alberta Carbon Trunk Line (ACTL) in Canada which is large enough to transport 14.6 $MtCO_2/y$ in its 240 km pipeline with the transported CO_2 utilised for EOR and geological storage.

The initial investment in the hub and cluster model could also be a barrier, unless revenue guarantees are provided during the early stages of development. In the UK for example, the Regulated Asset Base (RAB) model has been used to enable private investment in infrastructure (CCUS Cost Challenge Task Force, 2018). RABs use a legally binding license with a periodic regulatory review of long-term tariffs.

Where the balance of risk and return is still insufficient for initial private sector investment in the CO_2 transport and storage network, the relevant government should consider taking this role. In this way, governments can kickstart a hub and cluster development with the option of privatising the business after it has gained sufficient CO_2 source and sink 'customers'. Alternatively, the government could invest in establishing a regulatory framework that provides the private sector with the right incentives to invest in transport and storage networks, which may be preferable in regions where this is already common practice for infrastructure projects (Zapantis and others, 2019).

3 COFIRING COAL

3.1 KEY MESSAGES

Achieving NZE in Asia hinges on an unprecedented low emissions technology push to 2030 and beyond. Cofiring biomass, ammonia and other products with coal can assist in reducing emissions by 2030 and, together with CCUS, offers a net zero solution for the longer term.

- Several Asian countries have good agricultural and forestry waste resources increasing the potential for biomass cofiring to reduce emissions;
- Direct cofiring of biomass and coal in pulverised combustion (PC) boilers is a mature technology applied in Japan, South Korea and elsewhere; and
- Another approach, preferred in China, is cogasification indirect cofiring as it is easier to measure the amount of biomass used.

For coal-fired power stations, the option of using biomass co-combustion (for example at 10%) combined with a standard PC process (such as 90% CO_2 capture) may be a lower cost option to achieve NZE compared with a 99.7% capture rate, depending on the region of deployment.

Ammonia has several desirable characteristics that suggest it could be an effective energy carrier for the efficient, low-cost transport and storage of hydrogen. In addition, it can be used as a transition fuel in its own right, including in thermal power generation, provided appropriate safety standards, successful demonstration and cost competitiveness are achieved.

- Ammonia does not emit CO_2 when burned and is expected to offer great advantages in reducing GHGs (in an internal combustion engine for example, or fuel cell where final use produces no CO_2);
- Central production of ammonia from fossil fuels provides opportunities for CO_2 capture. Collaborative work is underway in Japan with Australia and Saudi Arabia to develop a global supply chain to provide the required levels of ammonia with CCUS;
- Transportation and distribution of ammonia would be simpler and cheaper than for hydrogen;
- In Japan the option to cofire low emissions ammonia, produced from fossil fuels with CCUS or from water electrolysis using renewable electricity is being pursued. The aim is to utilise 3 $MtNH_3$/y for power generation by 2030 equating to around 7 GW of power produced; and
- In a world-first demonstration, Japanese power generator JERA and its partner IHI Corporation are developing cofiring burners to be used with about 20% ammonia in the 1 GWe Hekinan unit 4 coal-fired power station in Japan.

Asian countries including China, Japan and Indonesia, have specific policy instruments in place or planned to support biomass cofiring. Japan also has them to support low emissions ammonia.

The second approach to delivering low emissions coal-based energy is to cofire the coal with 'carbon neutral' biomass fuels or fuels containing no carbon such as ammonia. This could offer a relatively quick and cost-effective way to partially decarbonise energy from coal in the short to medium term, potentially extending the life of coal-fired power plants during the transition to NZE. It has been estimated that solid biomass could be used to reduce emissions in both the electricity and industrial sectors, which are projected under the NZE scenario to increase from 32 EJ (2020) to 55 EJ in 2030 and 75 EJ in 2050, offsetting a large portion of the potential decline in coal demand noted in the introduction (IEA, 2021a). There are potential issues with the use of biomass for energy related activities, largely concerning the sustainability of the biomass, competition with alternative land use for food production, water scarcity, soil quality and biodiversity. These factors should be included when considering the options for biomass cofiring and the choice of the biomass feedstock.

3.2 BIOMASS FUELS

The major types of biomass fuels that have been cofired with coal are wood and grassy- or straw-derived herbaceous materials. The feedstocks include forestry residues such as tree thinnings, sawdust or bark, tree trimmings and waste wood; agricultural by-products such as straw, corn stover, rice husks, olive pits, oilseed residues, palm kernel expeller and nutshells; and energy crops grown as biofuels such as switchgrass, eucalyptus, willow and poplar trees (Gil and Rubiera, 2019). The properties of biomass fuels are significantly different from coal and there is also variation among the types of biomass, which has an impact on technology selection, fuel selection, deactivation of catalysts, corrosion, ash deposition and the utilisation of ash when cofiring (Zhang, 2020).

Generally, biomass feedstocks have the following characteristics compared with coal (Madanayake and others, 2017):

- higher moisture content;
- lower bulk density;
- more fibrous composition;
- higher organic volatile matter;
- less fixed carbon;
- lower nitrogen and sulphur content;
- higher concentration of chlorine and phosphorus;
- higher concentrations of alkali and alkaline earth elements;
- lower ash fusion temperature;
- lower energy density;
- lower ash content; and
- a higher proportion of oxygen and hydrogen, and less carbon, resulting in a lower heating value and higher thermal reactivity.

The higher moisture content and lower bulk density create constraints for biomass handling, transportation and storage. The more fibrous composition impedes grindability in existing coal pulverisers and results in larger and more irregularly shaped particles. Biomass typically has a volatile matter: fixed carbon ratio greater than 4.0, whereas the ratio for coal is often less than 1.0. Thus, biomass undergoes pyrolysis earlier than coal and the predominant form of biomass combustion is via the gas-phase oxidation of the volatile species. A higher concentration of chlorine and phosphorus, and alkali and alkaline earth elements, especially in agricultural residues, results in slagging in combustors, fouling of heat transfer surfaces and bed agglomeration in fluidised bed combustors. The presence of chlorine and sulphur also results in the formation of acidic products, which accelerate the corrosion of metal surfaces within the combustion system. As biomass has a low nitrogen and sulphur content, emissions of nitrogen and sulphur oxides are also low.

Asia has a large and wide range of potential biomass resources for cofiring. Both Indonesia and China are among the top 10 forested countries in the world, making them well placed for forestry residue related biomass products (Baruya, 2015). Indonesia has a capacity in the form of palm kernel shells of almost 1.7 Mt, almost all of which is exported to Japan and Korea (PwC, 2021a). In Vietnam, agriculture produces almost 70% of the total solid biomass; the remainder is from firewood and wood residues. Around 60–90% of rice straw is burned in the field (Truong and others, 2015), indicating the potential 'un-tapped' biomass resource for cofiring. Studies indicate that China could provide an estimated 3.04 Gt/y dry matter of ligno-cellulosic biomass, comprising 0.79 Gt/y from agricultural residues, 0.31 Gt/y from forestry residues, 0.32 Gt/y of energy crops grown on marginal lands and 1.62 Gt/y of energy crops grown on grasslands. The production of this amount of biomass equates to capturing 5.24 GtCO_2/y and 58 EJ/y of primary energy (Xing and others, 2021).

3.3 AMMONIA

Low emissions ammonia (NH_3) can be produced from coal and natural gas with the addition of CCUS, or by the electrolysis of water using electricity produced by wind, solar or nuclear power. These ammonia production processes typically involve a hydrogen intermediary step (*see* Section 8.4 for further details). Ammonia is used as a medium to store hydrogen because it can be liquefied under mild conditions and stored easily, while having a large weight fraction of hydrogen.

Where natural gas is available at a competitive price, natural gas with CCUS is generally the lowest cost production route for low emissions ammonia. Cost estimates for 2030 are generally in the range of 12–24 $/GJ, equating to 230–440 $/t$NH_3$ in regions with access to low-cost natural gas as well as CO_2 geological storage. Production costs for the electrolytic route are decreasing due to reductions in the cost of renewable electricity and economies of scale in manufacturing. By 2030, costs are estimated to be in the range of 22–33 $/GJ, equating to 400–620 $/t$NH_3$ in regions with good wind or solar resources (IEA, 2021c).

A well-developed transport and storage infrastructure is needed to establish global supply chains and connect low-cost regions of ammonia production with demand centres for the low emissions ammonia. As an existing bulk commodity product, pipeline transmission of ammonia is a mature technology and global transport using chemical and liquefied petroleum gas (LPG) tankers is also well-developed. Transporting fuels via shipping over a distance of 10,000 km is estimated to cost 2–3 $/GJ for ammonia compared with 14–19 $/GJ for liquid hydrogen (IEA, 2021c). This lower cost of transport is one of the main reasons why the IEA considers ammonia to be the preferred hydrogen energy carrier, or as a fuel itself. For example, ammonia can be burned directly in an internal combustion engine, converted to electricity in an alkaline fuel cell or cracked to provide hydrogen for non-alkaline fuel cells producing no carbon dioxide.

In the medium term, low emissions ammonia is likely to remain an expensive energy carrier for power generation. However, analysis by the IEA (2021c) indicates that cofiring 60% of low emissions ammonia in a Japanese coal power plant in 2030 would lead to a generation cost 30% higher than the energy market value in baseload, but just 15% higher in peak load conditions. By contrast, using the same low emissions ammonia in Indonesia would lead to a four-fold increase in generation costs compared with the variable operating costs of a coal power plant.

3.4 COFIRING TECHNOLOGIES

3.4.1 Biomass and waste fuels

The three principal configurations for cofiring biomass at coal-fired power plants are direct, indirect and parallel cofiring, as summarised in Figure 6.

In direct cofiring coal and biomass are fired in the same boiler. Biomass is pre-mixed with coal in the existing coal handling and conveying system, at modest cofiring ratios (typically less than 10% biomass on an energy basis), then co-milled and cofired in the existing coal-firing system (option 1 in Figure 6). This has been the most popular approach to cofiring because it can be implemented relatively quickly with minimum capital investment and minimal modifications. The main investments are the biomass storage and handling systems. In option 2, the biomass is milled in a separate, modified existing coal mill and cofired with coal in the existing coal combustion system. Alternatively, the biomass could be milled in a new dedicated mill to increase the cofiring ratio, typically up to 50% on an energy basis. After this, there are several ways in which to cofire the biomass. In option 3 biomass is injected into pipework that conveys coal to the burner. In option 4 biomass is injected into modified coal burners. In option 5 biomass is injected into a new dedicated biomass burner. These options involve higher levels of capital investment than options 1 and 2.

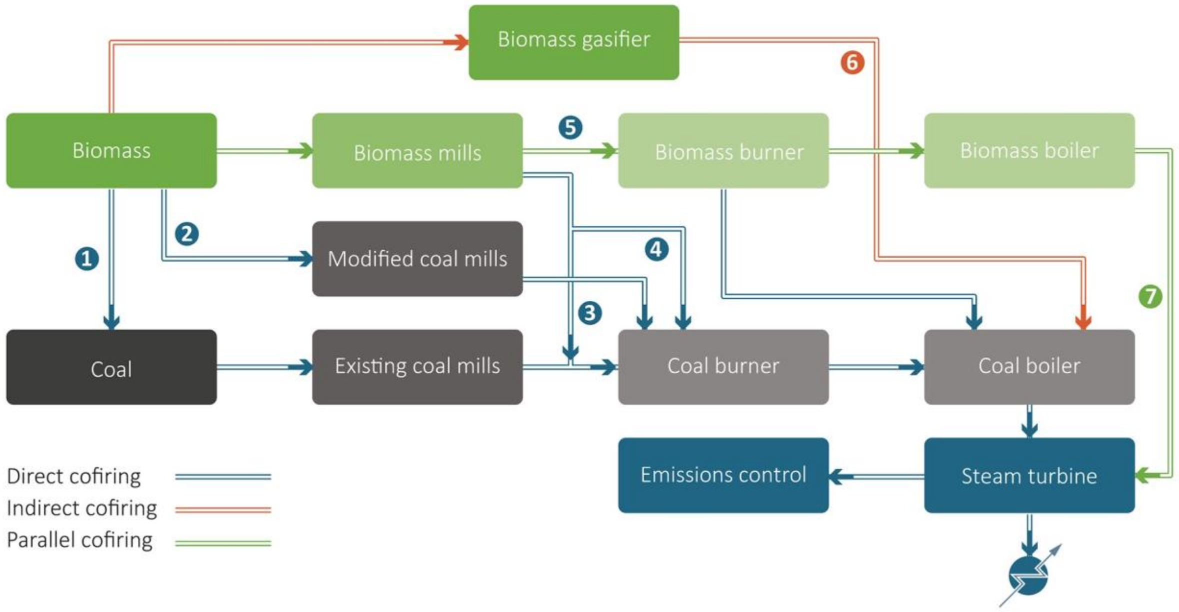

Figure 6 Options for cofiring biomass (Livingston and others, 2016)

In indirect cofiring, represented as option 6, biomass is gasified in a separate gasifier, and the fuel gas is burned with coal in the same coal boiler. The parallel cofiring system (option 7) has separate boilers for coal and biomass. Both indirect and parallel cofiring can allow for high ratios of biomass to be cofired and have greater fuel flexibility (Livingston and others, 2016).

Madanayake and others (2017) summarised cofiring technologies (*see* Table 1) based on the furnace, to include grate furnaces, fluidised bed combustors (FBC) and pulverised coal (PC) combustors. FBC includes bubbling fluidised bed (BFB) combustion and circulating fluidised bed (CFB) combustion boilers, both of which are used commonly for cofiring.

TABLE 1 FURNACE BASED COFIRING TECHNOLOGIES (MADANAYAKE AND OTHERS, 2019)

Combustion system	Advantage	Disadvantage
Grate furnace	Low investment costs for plants <20 MWth and low operating costs Can use almost any type of wood Appropriate for biomass fuels with high moisture content (10–60 wt%) Suitable for fuels with high ash content and varying particle sizes (with a limit on the amount of fine particles)	Mixtures of wood fuels can be used, but combinations of fuels with different combustion behaviour and ash melting points (for example, blends of wood with straw or grass) are not possible Increase of temperature may cause ash melting and corrosion
Fluidised bed	Large fuel flexibility in calorific value, moisture content, and ash content, enabling fuel diversification and increasing the scope of fuels in existing power plants Combustion temperature in bed is low, resulting in low NOx emissions Provides an option to directly inject limestone to remove sulphur cost-effectively (instead of flue gas desulphurisation equipment) Maximised combustion efficiency even with low-grade fuels Environmental performance of FBC installations is good, with low emissions of CO, NOx and high boiler efficiencies (about 90%) Fluidised bed technology can be converted from coal to biomass/coal cofiring with relatively little investment	Despite the flexibility of fuel specifications, it is not always possible to use the existing feeding system for biomass by premixing the fuels (the cheapest option). Where the feeding characteristics of the cofired fuels varies too much from the primary fuel, a separate feeder needs to be installed Slagging and fouling on boiler walls and tubes when burning fuels with high alkali content Bed agglomeration when burning fuels of high alkaline and/or aluminium content Cl-corrosion on heat transfer surfaces (for example, superheater tubes) High investment costs Low flexibility in particle size, high dust load in the flue gas, loss of bed material with the ash Incomplete combustion of fuels and high unburnt carbon content in the ash, especially in CFB
Pulverised coal	Increased efficiency due to low excess oxygen, high NOx reduction possible when appropriate burners used	Particle size of biomass is limited to <10–20 mm Low moisture content required for pneumatic feeding and decreased efficiency for high moisture fuels
Gasification	Gaseous syngas provides flexibility for co-firing in the boiler Wide range of potential biomass fuels and high cofire ratios possible	Cofiring requires modification of the heat transfer in the boiler Relatively expensive due to gasification plant

Direct biomass cofiring

Most coal-fired power plants use PC combustion. Some of them are large, modern USC plants, such as Uniper's 1.1 GW Maasvlakte MPP 3 plant and Engie's 730 MW Rotterdam plant. There are also a few power plants built with FBC boilers. Cofiring in Europe and Canada mainly occurred in PC boilers and the technologies were developed over the last 20 years and have been reviewed in previous ICSC reports (Zhang, 2020). However, in general, FBC boilers can cofire higher levels of biomass than PC boilers.

There are 46 FBC cofiring units (>50 MW) worldwide, with 43 in operation and three planned. Most of these units are less than 300 MW and work under subcritical steam conditions with efficiencies of around 38–40% (S&P Global, 2019). The largest USC FBC power plant is KOSPO's 2 x 1100 MW Green Power Plant in Samcheok, South Korea; unit 1 came online in December 2016 and unit 2 in June 2017. The plant is designed to fire up to 5% biomass by heat input with the possibility of increasing the biomass ratio (Proctor, 2018). The 112 MWe plus 265 MWth Kushiro power plant planned in Japan has been designed to cofire 30% wood pellets and palm kernel shells in a CFB boiler. Valmet, with its local Japanese partner JFE Engineering, supplied the multifuel boiler and flue gas cleaning system (Valmet, 2017).

A study by Indonesian generator PJB concluded that cofiring 20% sawdust biomass could reduce a subcritical coal plant's CO_2 emissions by up to 32% (to 696 gCO_2/kWh) (Parama and Harsono, 2020).

Indirect cofiring of biomass with coal

Parallel cofiring involves installation of a separate biomass handling and firing system. The steam generated from the biomass-fired boiler is then mixed with steam from the coal-fired boiler. Although it has a lower operational risk, allows a high ratio of biomass cofiring, and means the ash can be handled independently, this technology is more expensive and may have space constraints for existing plant since additional infrastructure is needed (Gil and Rubiera, 2019).

Perhaps the best known indirect cofiring technology involves coupling a biomass gasifier with a coal boiler. In addition to the similar advantages and disadvantages of parallel cofiring, cogasification cofiring requires modification of the heat transfer in the boiler. However, cogasification is preferred in China as the method makes it easy to measure the amount of biomass being cofired. The first pilot test was carried out at Guodian Jingmen Power plants with a 10.8 MW gasifier in 2013 (*see* Figure 7). The CFB gasifier feedstock was rice straw with a gasification efficiency greater than 70%, gas output of 14,000–18,000 m^3/h, calorific value of the combustible gas was 4–5 MJ/m^3 and the overall thermal efficiency of the gasifier exceeded 85%. High temperature gas was sent by the induced draught fan to be burnt in the 600 MW coal-fired power boiler via two special gas burners at the two sides of the boiler after passing through the circulation separator, dust separator and the heat exchanger for proper cooling (He, 2016). The same 10.8 MW CFB gasification design was applied to the 640 MW SC unit 6 of Xiangyang power station. Here, the gasification process uses agriculture and forestry waste in briquette form which are converted to fuel gas before being transported via pipeline to the Xiangyang Plant's 640 MW SC power plant to be cofired with coal. The main key technologies and advantages of the project are (Chuanrong, 2021):

- wide fuel flexibility to include agricultural and forestry waste using CFB gasification technology based on ash sintering temperature control, to prevent slag conglomeration issues due to the high potassium and chlorine content of straw feedstocks;

- integrated two-stage cyclone separation, high-temperature gas temperature-controlled cooling, medium-temperature pressurised conveying, gas reburning with special burners and other technologies suitable for large-scale PC power generating units; and
- measurement of gas chemical energy and sensible heat through online gas components monitoring, together with gas flow and temperature, as an online automatic measurement method of biomass power generation.

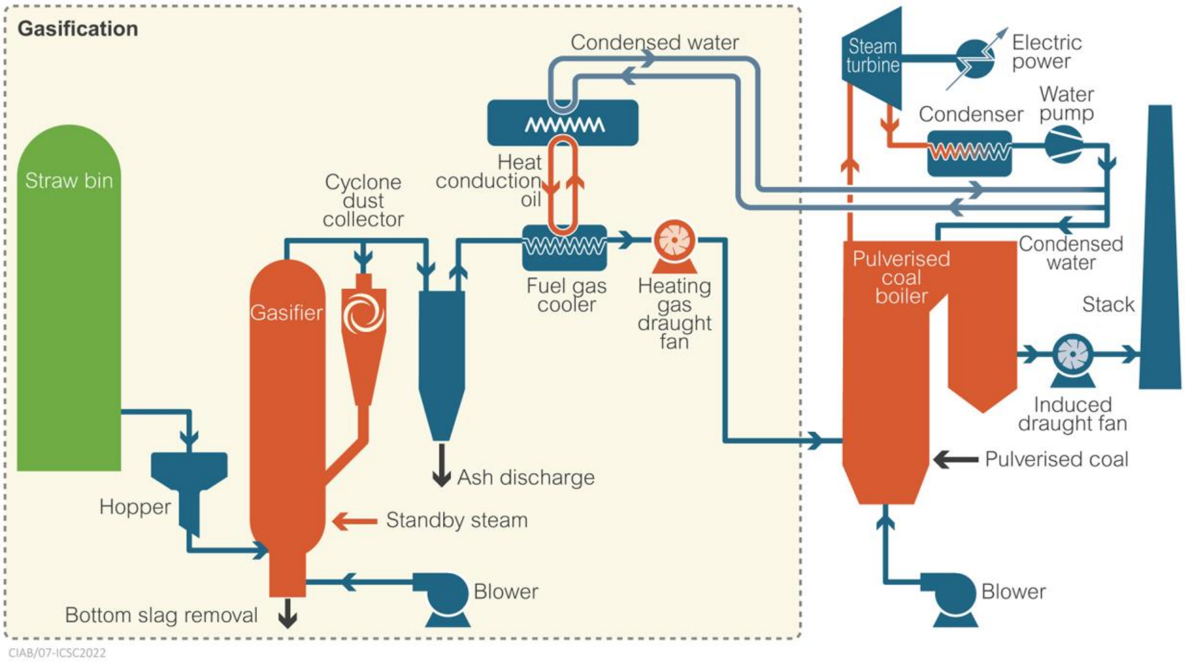

Figure 7 Guodian Jingmen gasification cofiring (He, 2016)

A second CFB gasification unit has been installed at Huadian Xiangyang number 5 unit, again based on briquetted agricultural and forestry waste feedstock. Here, the process produces a biochar from the first stage cyclone separator, with the syngas piped to the plant's number 5 SC unit to be cofired with coal.

The advantages of these two CFB gasification units are described as:

- **Low fixed investment** – by using the existing coal-fired power plant, investment is only required for the gasification equipment and related auxiliary equipment;
- **High efficiency** – the high temperature syngas produced by biomass gasification is directly burned in the boiler of a 640 MW supercritical unit;
- **Flexible operation** – the project can determine the investment method according to the fuel price and benefit. The gasifier can be directly connected to, or shut-off from, the main boiler through the gas quick shut-off valve. The operation of the main equipment is not affected in any way, and the operation and management are flexible;

- **Power metering** – the biomass derived syngas properties can be measured separately with electrical output based on measured calorific value; and
- **Diversified management** – the number 5 unit project can reduce the risk of project operation and policy changes by producing biochar through multi-condition adjustment.

In addition, a larger CFB gasifier was coupled with a 600 MW supercritical unit at Datang Changshan coal-fired power plant in 2019 (Sina News, 2019).

In general, cofiring has positive impacts on emissions of SOx, NOx, particulate matter and trace metals such as mercury due to the inherent properties of biomass. However, there is evidence that cofiring can de-activate selective catalytic reduction catalysts for NOx control. Some strategies have been established to reduce the poisoning of catalysts.

Although the overall volume of ash produced from cofiring is reduced, cofiring biomass changes the chemical properties of the fly ash and bottom ash and impacts ash utilisation (Zhang H, 2019). The issues resulting from the chemical composition of biomass can be reduced by leaching and washing. Those related to the transport of biomass, its handling and combustion characteristics can be substantially improved by modifying the resource through steam explosion, torrefaction, densification and pelletisation. Pelletisation is the most widely used pretreatment and torrefaction has substantial potential if commercialised. Steam explosion is an increasingly popular method to improve the energy density of biomass and make it more brittle to increase its grindability (Zhang, 2020).

Technology status

There are two leading cofiring projects in China. One of the 660 MW units at Guodian Jingmen coal-fired power plant was attached to a 10.8 MW gasifier to gasify straw for cofiring. From 2013 to July 2016, the system ran for about 20,000 hours and supplied approximately 200 GWh electricity to the grid. The biomass power sold for 0.75 yuan/kWh (0.1 €/kWh). The part which exceeded the local coal-fired power generation price was paid by the National Renewable Development Fund. The unit was profitable (Sun and Li, 2017). Huadian Shiliquan power plant has a 140 MW unit with two 30 MW straw combustors installed near the upper secondary air combustors to cofire less than 20% biomass (Sun and Li, 2017). The nation's first government supported cofiring biomass pilot project started operation at Xiangyang power station in 2018. China Hefei Debo Bioenergy Ltd supplied the 10.8 MW fluidised-bed gasifier. Also, on the NEA list of 58 pilot projects, the 660 MW SC unit 1 at Datang Changshan power plant will be coupled with a 20 MW gasifier produced by Haerbin Power Co Ltd to cofire locally grown straw (Zhang, 2020).

In India, the largest power producer, NTPC has announced plans to start biomass cofiring in all its coal-fired power stations (Economic Times, 2018), but the extent of activity following this announcement is unclear. However, as part of this effort, NTPC carried out a successful trial using agricultural residues at its 1820 MW Dadri coal-fired power plant in 2017 (Zhang 2020).

3.4.2 Ammonia

Changes to existing coal thermal plants to cofire ammonia are relatively straight forward, requiring boiler modifications and investment in additional facilities including ammonia tanks and vaporisers. As ammonia combustion is characterised by a low flame temperature and narrow flammability limits, it can cause flame stability issues during co-combustion. Cofiring also reduces the amount of soot and coal powder particles in the furnace, leading to lower radiative heat transfer but also to reduced ash deposition on heat transfer surfaces and improved boiler performance. Gas turbine systems are also being developed for low emissions ammonia. These can either combust hydrogen derived from ammonia, that is using the ammonia as a hydrogen carrier, blends of ammonia and hydrogen or ammonia directly. The technology currently has a lower TRL than hydrogen cofiring. However, gas turbine manufacturers, including MHI have announced plans to offer commercial ammonia-fired gas turbines at the multi-megawatt scale by around 2025 based on the company's H25 gas turbine at over 40 MWe output (Kakaras, 2021).

3.4.3 Technology status

Japan's Ministry of Economy, Trade and Industry (METI) has proposed a new target to finalise development of a coal burner that can cofire ammonia at more than 50% in the fuel mix and for a fully ammonia-fired gas turbine by 2030. The aim is to complete a demonstration project for the ammonia cofired burner and ammonia-fired gas turbine at operating power units by 2029-30, ready to start commercial installation from 2030.

In support of this target, Japanese power generator JERA and partner IHI have started to utilise a small amount of ammonia in unit 5 of its Hekinan Thermal Power Station (Walton, 2021; Shinden, 2021). The Hekinan plant was built by Chubu Electric and commissioned in 1991, and has been operated since 2019 by JERA, a joint venture between Chubu and TEPCO Fuel and Power (*see* Figure 8). Two of the 48 burners at unit 5 have been replaced with test burners. Their performance will be assessed until March 2022 to examine the effects of different burner materials and combustion times to identify the required conditions for cofiring burners. The longer term aim of the testing is to develop cofiring burners to be used at around a 20% cofiring ratio (heating value basis) in 2024 at Hekinan. JERA is in charge of ammonia procurement and construction of related facilities (such as the storage tank and vaporiser) while IHI's role is to develop the burners to be used in the demonstration. This is the world's first demonstration project in which a large amount of ammonia will be cofired in a large-scale commercial coal-fired power plant.

Development of the required boiler and burner technology is being undertaken by Mitsubishi Power which has conducted combustion tests at the MHI Research & Innovation Centre using basic combustion test furnaces that can simulate the combustion conditions of coal-fired boilers. These tests were used to compile basic data on ammonia and coal cofiring and 100% ammonia firing. The company has also identified optimal systems and conditions for combustion based on its knowledge of ammonia firing characteristics. These include the generation of NOx which is a concern for ammonia firing, and the potential for unreacted residual ammonia to be released outside the power generation system. Earlier tests by MHI confirmed that the flames remained stable during combustion, NOx emissions were in line with the combustion test target and there was no residual ammonia (MHI, 2021b).

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Figure 8 Hekinan coal-fired power plant (Shinden, 2021)

Japan is also cooperating with energy producing countries including Australia and Saudi Arabia, to establish a stable, low cost and flexible low emissions ammonia supply chain (IEEJ, 2020; HESC 2018, 2021). With strong market signals from Japan, the Energy Council of the Australian government published the National Hydrogen Strategy in 2019, and a new chapter of the ammonia fuel association was opened, aiming to work closely with the hydrogen fuel community and increase awareness of the use of ammonia for energy storage and power generation (Zhu, 2021). A further example of supply chain development is the Japanese trading house Itochu's collaboration with Petronas Energy Canada and a Canadian infrastructure company to produce ammonia for export to Japan. A 1 MtNH_3/y plant is due to begin construction in 2022, using natural gas from Petronas' fields in Alberta as a feedstock, with CO_2 captured during the manufacturing process. Itochu is also working on a feasibility study for a similar low emissions ammonia production plant in Russia, in conjunction with Irkutsk Oil, whilst Mitsui and CF Industries are exploring the possibility of developing low ammonia projects in the USA (Burgess, 2021; Oki, 2021).

3.5 BIOENERGY WITH CCS (BECCS)

Where cofiring is combined with CCUS, net zero or negative emissions could be achieved. For example, 10% biomass cofired with 90% coal combined with CCUS at 90% capture level will deliver notional net zero emissions, although this does not allow for CO_2 emissions released during the harvesting or transport of the biomass fuel. Increasing either the capture rate above 90% or increasing the cofiring level above 10% will result in negative CO_2 emissions, effectively removing CO_2 from the atmosphere. Although cofiring of coal with biomass has been used primarily for power generation applications, the same approach could be extended to industrial manufacturing and the production of chemicals and hydrogen. Cofiring coal with biomass could therefore provide a useful means to achieve reduced emissions, although this would need to be supported by a suitable policy framework. Various studies have shown that BECCS is necessary as part of an overall systems approach to deliver NZE at the lowest cost (Pratama and Mac Dowell, 2019).

A further opportunity for the technology is for waste-to-energy (WtE) plants, which could be a significant growth area in Asia as both population growth and urbanisation increase. WtE plants use sorted municipal solid waste as a fuel for thermal power generation and low-grade heat for nearby homes and businesses. A significant fraction of the incoming waste-based fuel will be of biogenic origin, including paper, cardboard, wood, food waste and garden trimmings. If a WtE plant can capture and store a higher proportion of its CO_2 than is produced from the combustion of fossil-fuel origin waste (such as plastics), then the plant's overall emissions become negative. This makes the plant a net reducer of atmospheric GHGs, a source of useful heat and power, and reduces the burden on limited landfill space. Thousands of WtE plants are operating worldwide. Most are a modest size, making the need for economic small-scale capture plants vital for increasing deployment of CCUS (GCCSI, 2020).

An example of a BECCS system configuration based on coal gasification that could find application in China is shown in Figure 9. Studies show the potential of BECCS in China and Asia more widely, to deliver low emissions energy based on the supply of 19 ligno-cellulosic biomass feedstocks from agricultural and forestry residues (excluding grains) and dedicated energy crops such as miscanthus or high yield crops (Xing and others, 2021).

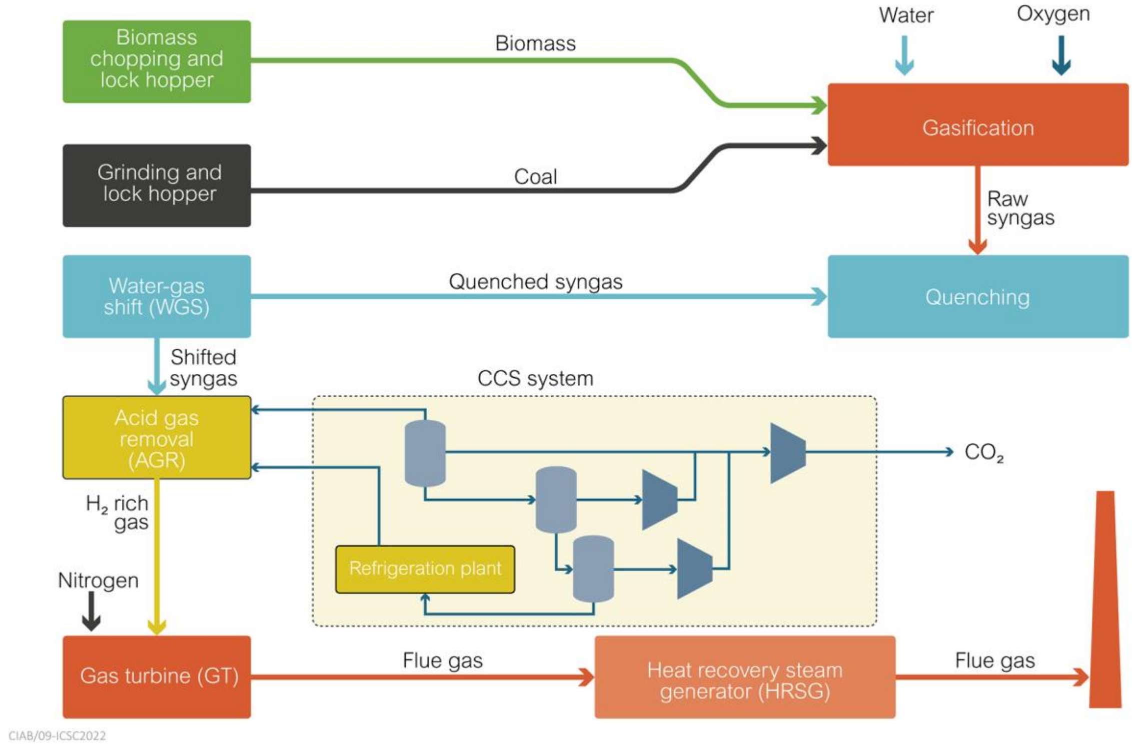


Figure 9 Process flow diagram for a BECCS system based on IGCC technology with CCS, proposed for China (Lu and others, 2019)

3.6 NECESSITY FOR COFIRING

The cofiring of biomass in Asia is expanding quickly with China, Japan, South Korea, India, Indonesia, Vietnam and Malaysia actively cofiring. Of the countries studied in this report, China, Japan and Indonesia either have policy measures and frameworks in place to support cofiring, or are in the process of doing so (Zhang X, 2019). To support the use of low emissions fuels in the power sector, electricity markets should be redesigned to reward flexibility, capacity and other system service contributions provided by low emissions ammonia cofired thermal power plants. This could be accompanied by support measures such as carbon pricing and/or other complementary policies, as well as regulatory frameworks to further decrease the remaining cost gap with incumbent generation (IEA 2021c).

3.6.1 China

By 2030, China aims to increase the share of non-fossil fuels in its primary energy consumption to around 20% and cut CO_2 emissions per unit of GDP by 60–65% from the 2005 level. The *Renewable Energy Law*, enacted in 2006 and amended in 2009, facilitates the energy sector to achieve this goal. It gives biomass power generation the benefit of several tax breaks, including a 10% reduction in corporate income tax and exemption from value added tax and equipment import tax. Furthermore, a benchmark premium of 0.75 yuan/kWh (0.1 €/kWh), including tax, is provided for electricity generated using agricultural or forestry biomass. However, the price premium has only been available to power plants in which the boiler heat input from biomass is no less than 80% of the total heat input. This, in effect, excluded cofiring projects from receiving the premium (Sun and Li, 2017).

In December 2016, China's National Energy Administration (NEA) announced that a *Coal Coupling Power Demonstration Programme* would be established, as part of the Clean Power Plan in China's 13th Five-Year Plan. The aim of the programme is to reduce air pollution from the scattered burning of agricultural and sludge wastes as well as to reduce CO_2 emissions from coal-fired power plants. It includes a series of large-scale demonstration projects with coal-fired power plants to determine the applicability of various techniques to cofire coal with biomass (agricultural and forestry wastes especially straw), sludge, and residential wastes (Zhu, 2019).

China's top-down engineering-oriented approach means that it can set ambitious goals and achieve them quickly. In December 2017, the Ministry of Environmental Protection, restructured as the Ministry of Ecology and Environment in 2018, and the NEA jointly issued a *Notice for Implementation Pilot Project on Technological Innovation of Coal-Biomass Cofiring Generation*. The Notice stressed that the aim of setting up these pilot projects was to use existing high efficiency coal-fired units and their emission control equipment to utilise agricultural and forestry waste and sludge. Cofiring sludge and residential waste projects will be carried out in combined heat and power (CHP) generation plants from 36 major cities where huge quantities of wastes are produced.

Of the 58 NEA announced projects on cofiring agricultural and forestry wastes, 56 will use indirect gasification. The Chinese government aims to learn from these pilot projects and then to establish their policy and incentive scheme on coupling biomass with coal at their existing coal-fired power plants (Zhang X, 2019).

3.6.2 Japan

Cofiring biomass in coal-fired power plants has been considered as a short- to medium-term solution by Japan to deliver its NDC requirement of reducing GHG emissions by 46% in 2030 from the 2013 level and to meet the renewable energy share target.

The *Strategic Energy Plan* is a comprehensive energy policy for future new energy which is reviewed every three years. The latest publicly available version was enacted in October 2021. The new plan notes that coal-fired power plants will remain at a reduced level to 2030 and beyond due to the low cost, low geopolitical risk and role as a substitute for nuclear power since the 2011 earthquake (METI, 2021). Prior to the Strategic Energy Plan, METI released Japan's *Energy Mix 2030*, which includes 19% coal-fired power and 36–38% renewable energy. Biomass is projected to account for nearly 14% of the renewable energy in 2030 (Lin and others, 2019). The Outlook requires thermal generation efficiency to rise to 44.3% or more by March 2031. About two-thirds of Japan's current coal-fired power plants will find it hard to achieve this standard. The power plant efficiency is calculated by dividing energy output by fuel input. As METI has allowed biomass input to be deducted from fuel input, only coal is counted as fuel input for a cofiring power plant. Consequently, a high cofiring ratio would increase the calculated efficiency, helping the plant to meet the efficiency target (Uno and Kikuchi, 2017). However, METI is considering changing the calculation formula as part of the plan to reduce dependence on coal (Aikawa, 2019).

In addition, Japan's feed in tariff (FIT) scheme is the main instrument to promote electricity generation from renewable sources. Under the FIT scheme electricity providers supply a portion of their electricity generation from renewable energy sources for a fixed period at a fixed price. The cost of producing this new energy is distributed among all energy providers in the form of a nationwide surcharge, with utility companies paying part of the cost. The purchase price is reviewed and published every year by METI (Zhang X, 2019).

Japan's Strategic Energy Plan is being revised and the plan is for the electricity generation mix in 2030 to contain low-emissions ammonia and hydrogen, but at a relatively low level. Hydrogen is expected to comprise 6.7 TWh and ammonia 8.2 TWh, based on fuel supply volumes of 0.3 MtH_2/y and 3 $MtNH_3$/y respectively. Based on 20% ammonia cofiring at 75% capacity factor in coal-fired power plant by 2030, this would equate to around 7 GW of power produced. The aim is to increase the amount of ammonia used in power generation to 30 $MtNH_3$/y by 2050. The Cross-ministerial Strategic Innovation Promotion Program (SIP) of Japan set up hydrogen and ammonia related technology roadmaps, the Strategic Plan for Hydrogen Utilisation in 2017, and promoted R&D of ammonia direct combustion/co-combustion and utilisation. A 22-member Green Ammonia Consortium led by Tokyo Gas was created in 2017, which seeks to demonstrate hydrogen, ammonia and hydrides as building blocks of a hydrogen economy and to develop an ammonia value chain. At the end of 2020, METI announced that it had chosen the fuel ammonia industry as one of the prioritised areas in its 'Green growth strategy' action plan.

However, since the power produced from ammonia cofiring will be more expensive than other conventional fossil fuels, FITs or carbon pricing might be necessary for the commercial usage of ammonia beyond the current demonstration phase (Yabumoto, 2021; IEA, 2021c).

3.6.3 Indonesia

Indonesia plans to make the cofiring of biomass in power stations mandatory as part of its efforts to phase out coal power plants, which account for more than 60% of its electricity supplies (Reuters, 2021b). The government is preparing a regulation to this effect, which would apply to state electricity utility PT Perusahaan Listrik Negara (PLN) as well as independent power producers. The timing and other details, such as the ratio of biomass to be used in cofiring were not known at the time of writing (November 2021). The state power company plans to start cofiring at 52 of its largest coal power plants and has estimated it could replace 9 Mt/y of coal with biomass. In the longer term, Indonesia plans to add CCUS to its coal/biomass cofired power plant, delivering negative emissions (Indonesia LTR, 2021).

3.6.4 India

In India, the *Electricity Act 2003* requires the State Electricity Regulatory Commissions (SERCs) to determine and implement Renewable Purchase Obligations (RPOs). To achieve the target set by India's *National Action Plan on Climate Change* (NAPCC), the Government of India launched the Renewable Energy Certificate (REC) mechanism in November 2010. The NAPCC aims to derive 15% of India's energy requirements from renewable energy sources (non-solar) by 2020. India's intended NDC, submitted to the UNFCCC before COP21, states that it plans to increase the installed capacity of biomass to 10 GW by 2022 from the current capacity of 4.4 GW as part of the overall goal of increasing the share of non-fossil fuel electricity generation capacity to 40% in the country's electricity mix by 2030 (Purohit and Chaturvedi, 2018). India has yet to submit its second NDC.

3.6.5 Vietnam

Cofiring biomass in coal-fired power plants to reduce GHG emissions and improve air quality, could be a good choice for Vietnam as it has substantial biomass resources. Agriculture produces almost 70% of the total solid biomass with the remainder coming from firewood and wood residues. Around 60–90% of rice straw is burnt in the field (Truong and others, 2015). Recent research has found that even without incentives, cofiring rice husks is cheaper than firing coal alone in coal power plants. The rice husk supply in Vietnam means that it could only be cofired at a 15% cofiring ratio in 14 out of a total of 96 coal power plants in 2030 if all planned power plants are deployed (Truong and others, 2019).

4 POWER GENERATION

4.1 KEY MESSAGES

State-of-the-art USC coal power plants currently achieve up to around 47% efficiency (LHV, net), equivalent to around 720 gCO_2/kWh. As this performance limit is largely set by the steam temperatures achievable with advanced steels, efforts to go beyond have centred on developing an 'advanced USC' plant based on nickel alloys. This technology could see demonstration in the next decade, but it is likely that more incremental technology development will have more impact in a risk-averse power sector. Smaller increases in steam temperature using new steels, together with advanced steam cycle designs, have the potential to raise efficiencies to approaching 50% (around 680 gCO_2/kWh). Several alternative high-efficiency pathways are based on gasified coal, offering potential additional benefits of fuel flexibility, generation of high-value products, and good compatibility with carbon capture.

The integration of fuel cell technology, particularly solid oxide fuel cells (SOFCs) and molten carbonate fuel cells (MCFCs) into IGCC coal fired power plants, offers the potential to further increase the efficiency of low emissions coal technology (LECT). In the long term, efficiencies of around 60% LHV basis have been projected for power plant at the multi-100 MWe size range.

While less efficient subcritical coal units will be progressively phased out and replaced, several options must be considered for the >240 GW capacity with a significant remaining lifetime. Existing upgrading technologies can raise efficiency by up to 5 percentage points, or they may be converted to biomass cofiring, cogeneration units, or highly flexible plants with limited operation.

CCUS remains the key technology to deliver very low emissions from coal-fired power plant; the Jinjie CCUS project is already in place in China and further projects such as the Huaneng Multi-energy project at the 1 $MtCO_2/y$ scale and above are in construction.

Most large-scale CCUS installations to date have been undertaken in sectors outside power generation. For Asia to achieve NZE it is essential to expand the opportunities for CCUS into the coal-fired power generation sector. Learning from CCUS projects provides significant lessons for future CCUS design and development. This will lead to capital and operating cost reductions.

Supercritical CO_2 cycles such as the Allam-Fetvedt Cycle hold great potential for providing alternative power generation systems that can achieve higher plant efficiency and close to full carbon capture at lower costs. There are some outstanding technical issues that need to be addressed. Some small, low temperature sCO_2 Brayton Cycle power systems are starting to emerge in the commercial market.

More than half of the global 2 TW of coal capacity has been built in the last 20 years. Over 90% of this expansion has taken place in Asia, primarily in China, but also India, and increasingly Southeast Asia (Lockwood, 2021). There are several reasons why rapidly growing economies, particularly in Asia, will continue to use coal in the transition to a NZE future, especially where access to natural gas is limited. For power generation, these reasons are summarised in Table 2.

The options available for LECT in power generation applications are explored in this chapter. The focus is on more efficient power plants which generate less CO_2 per kWh of energy generated.

TABLE 2 DRIVERS FOR COAL DEPLOYMENT IN CASE STUDY REGIONS (S&P GLOBAL, 2020; BP, 2020)

Country	Coal capacity under construction, GW	Coal in 2020 power generation mix, %	Coal power capacity targets/ government projections	Electricity generation growth per year in 2019 and (2008-18), %	Drivers for coal power growth
China	44.3	61	1.1 TW cap for 2022 (could be increased to 1.3 TW for 2030)	4.7 (7.4)	Extensive domestic coal reserves and limited gas – coal expected to peak as China seeks to diversify energy mix
India	40.6	73	266 GW expected in 2030, up to 400 GW in 2040	0.5 (6.5)	Extensive coal reserves and limited gas – coal expansion slows in the near-term but expected to continue to 2040
Vietnam	9.97	53	In the latest draft of its power development plan, coal-fired power generation will be reduced to 39.7 GW by 2030, down from 46.4 GW	8.7 (11.4)	Steady coal growth since 2000 relied on domestic anthracite, but turning to imported bituminous coal
Indonesia	11.6	60	Coal power to grow in absolute terms but decline to 54% of generation in 2028	4.5 (6.0)	Extensive coal reserves – aims to diversify energy mix while retaining domestic coal as a key element
Japan	8.63	29	Proportion of coal in electricity mix to decrease to 26% – phase out non-USC/IGCC	-1.9 (1.1)	Reliant on fossil fuel imports – maintaining coal's role in a diverse mix to limit dependence on LNG imports or nuclear

4.2 LOW EMISSIONS COAL TECHNOLOGY POWER PLANT

4.2.1 Supercritical

Most coal-fired power plants are based on pulverised coal (PC) combustion in which finely ground coal is combusted in a furnace and the resulting heat is used to raise steam. PC plant technology progressed since its first appearance in the 1920s, primarily through increases in steam temperature and pressure, which directly relates to an increase in thermal efficiency. In the late 1950s, a significant step was the design of power plant with supercritical (SC) steam conditions, at pressures greater than 22 MPa and temperatures greater than 374°C. As there is no sharp transition between water and SC steam when water is heated at these pressures, SC power plants operate with once-through steam cycles rather than the circulating boilers used by many subcritical units. SC plants operating at around

540–565°C (with lower temperatures associated with higher pressures up to 35 MPa) became more standard from the 1960s to 1980s (*see* Table 3) (Lockwood, 2021).

TABLE 3 TYPICAL OPERATING PARAMETERS FOR COAL FIRED POWER GENERATION TECHNOLOGIES (LOCKWOOD, 2021)

	Subcritical	Supercritical	Ultrasupercritical
Main steam temperature, °C	<540	538–566	593–610
Steam pressure, MPa	16–18	>22	25–30
Cycle efficiency-LHV basis, %	30–39%	39–43	<47.5
CO_2 emissions intensity, g/kWh	>870	800–870	720–870

4.2.2 Ultrasupercritical

In the 1980s, a new 9% chromium steel for power plant applications was developed in the USA and Japan. Known as P91 when deployed in steam pipes, this material enabled a practical return to steam temperatures above 590°C, giving rise to the term 'ultrasupercritical' (USC) plant. (Di Gianfrancesco, 2017). The first such plants were commissioned in Japan in the early 1990s, and in the 2000s, USC technology was embraced by South Korea and in particular China, where it has formed the backbone of rapid power capacity growth since 2006. The steam parameters of USC plant do not have a strict definition, but are generally considered to include plant with main steam temperatures of at least 593°C and pressures of at least 24 MPa (Sloss, 2019). The development of new steels such as P92 (for steam pipes) and T23 and T24 for waterwalls, has led to further increases in steam parameters. State-of-the-art USC plants now typically employ main steam temperatures of 600°C and reheat temperatures of up to 620°C, with some examples in China of plants with parameters of 610/630°C. Pressures are usually in the range 25–29 MPa (Wiatros-Motyka, 2020).

Shanghai Shenergy's 2 x 1000 MW Waigaoqiao 3 plant claims to be the most efficient plant in China, having reached around 47% efficiency (LHV, net) primarily by employing several key innovations developed on site, including better use of waste boiler heat and reduced auxiliary power consumption (Feng, 2017).

The next most widespread form of utility coal plant is based on circulating fluidised bed (CFB) combustion in which more coarsely ground coal is combusted at lower temperatures of typically 800–900°C in a fluidised bed reactor. This technology is generally more tolerant of poor or variable coal quality and is often applied to lignite, high ash coal, or biomass cofiring. The first USC CFB units were commissioned at Sam Cheok (4 x 550 MW) in South Korea in 2016, and 350 MW SC units have been widely deployed in China in the last decade (Zhang H, 2019). CFBC represents around 5% of the global coal fleet (S&P Global, 2020).

4.2.3 Upgrading existing plant efficiency

Over 60% of coal plants in operation use subcritical steam cycles and therefore achieve efficiencies well below the current state-of-the-art. While much of this capacity is over 30 years old and could potentially be phased out, 246 GW of subcritical plant has been built since 2010 and will likely remain operational for at least another 15 years. For these units, as well as less efficient SC units (236 GW of SC capacity has been installed since 2010), there is a vital need to minimise CO_2 emissions intensity for their remaining lifetime. This can be achieved by performing various measures to upgrade their efficiency, particularly given the tendency for plant performance to deteriorate over time. There are many options available to achieve incremental efficiency improvements throughout a coal power plant, including:

- steam turbine refurbishment;
- improved boiler heat recovery;
- digitalisation and smart process control systems;
- reducing auxiliary power consumption; and
- raising the steam temperature.

4.2.4 Integrated gasification combined cycle (IGCC)

An alternative vision for coal power is to exploit the high efficiency of gas turbines by first converting the coal to syngas (primarily a mixture of carbon monoxide and hydrogen) in a gasifier. This can then be used to fuel a combined cycle gas turbine in an arrangement known as IGCC. Once the energy penalty of the gasification process is accounted for, such plants are expected to be capable of up to 48% net efficiency. Several demonstration IGCC plants were deployed in the 1990s and early 2000s in the USA, Europe, and Japan, but owing to unexpectedly high costs, complexity of operation, and the concurrent improvement in PC plant efficiency, IGCC plant failed to gain wider popularity (Sloss, 2019). From the late 2000s, the technology has experienced renewed interest due to its potential application in the pre-combustion capture of CO_2.

Japan is taking the lead in IGCC technology development, following the successful 250 MW, air-blown demonstration project at Nakoso power plant, which began operating commercially in 2013. In 2014, the technology was selected by Mitsubishi Power for two 540 MW units at Nakoso and nearby Hirono power plants, as part of an initiative to provide power and an economic boost to the Fukushima region in the aftermath of the 2011 nuclear accident. These units, which are now operational, use the same air-blown gasification technology developed for the first Nakoso unit, with a design efficiency of 48% (LHV, net), placing them just above the current state-of-the-art for USC units. The gasification process is more accommodating of various coal types than PC boilers, particularly those with low melting point ash; Mitsubishi Power emphasises this fuel flexibility as a primary benefit of using the technology.

Successful operation of the Nakosa and Hirono units could lead to a new wave of IGCC deployment around the world, as Japan seeks to export the technology to emerging economies.

In China, the 250 MW GreenGen IGCC was completed in 2015, but planned phases to introduce CCUS and construct a larger scale unit have stalled (Lockwood, 2021).

4.2.5 Advanced ultrasupercritical

Since the late 1990s, there have been coordinated research efforts to develop a new generation of high efficiency coal plant known as advanced ultrasupercritical (AUSC). As advanced steels such as P92 are not suitable for use at temperatures much above those encountered in state-of-the-art USC plant, this next stage of efficiency improvement requires extensive use of nickel-based superalloys in place of steels for the hottest sections of the plant, including superheaters, headers, steam pipes and turbines.

An AUSC plant would aim to significantly increase steam temperatures to at least 700°C to maximise the benefit of these expensive, high-performance materials. However, while nickel alloys are already used for gas turbines and jet engines, their application in coal plants requires development of modified alloys which can meet application-specific challenges including fabrication of larger components, welding to other materials, and longer in-service lifetimes (Wiatros-Motyka, 2020). Currently, there are indications that major Japanese manufacturers such as Mitsubishi and IHI have the technical capability to commission a full-scale AUSC plant, should the economics be suitable and supportive policies in place (Wiatros-Motyka, 2020).

In the past decade, China and India have become significant players in this field. China established an industrial research consortium, and has operated a large-scale component test facility, where several domestically developed alloys have been tested alongside internationally established materials. However, a full-scale demonstration of AUSC technology is not anticipated in China before 2030. While India's nationally coordinated research initiative only began in earnest in 2016, the country currently has the most ambitious schedule for deployment of a demonstration plant, and it has been considered that construction could potentially begin as early as 2022. The Indian plant design draws on relatively established materials developed and tested under the European and US research programmes (Pande, 2017; Edkie and Chetal, 2017).

Given the high upfront cost of commissioning a new AUSC plant, there is some interest in using AUSC materials for retrofit applications. In Japan, various designs have been proposed for retrofitting existing plant with nickel alloys in key areas of the steam cycle to raise the main steam temperature towards 700°C (Fukuda, 2019).

While international efforts have been relatively slow to realise a 700°C plant based on nickel alloys, the efficiency of state-of-the-art USC plant continues to increase incrementally, through the use of new materials and other design innovations. In particular, the development of higher performance steels has emerged as a co-benefit of AUSC research programmes, enabling plant designs with main steam temperatures from 630°C to 650°C. One example is martensitic steel ‘MarBN’, which could be employed in high pressure components to reach main steam temperatures of up to 650°C and is progressing towards commercial application (Lockwood, 2021).

In China, where the majority of new USC plant are under construction, there is also a greater focus on a more progressive increase in steam temperatures, with a 650°C plant expected to be developed by 2025 (Ye, 2019). High temperature plant designs in China generally employ double reheat steam cycles, in which the steam leaving the intermediate pressure turbine is returned to the boiler for reheating, before being used to power a second intermediate-pressure turbine stage. The revival of double reheat USC in China began with its application to the 660 MW Huaneng Anyuan in 2015, shortly followed by a 1000 MW unit at Guodian Taizhou, where steam parameters of 31 MPa/600°C/610°C/610°C enabled an efficiency of 46.2% (LHV, net), which is 2 percentage points higher than a single reheat unit with the same parameters. Around 14 double reheat units are now operating or under construction in China, mostly with reheat steam temperatures of 620°C. Dongfang Turbines have developed a double reheat design with the parameters 615°C/630°C/630°C, to be used at Datang Yuncheng plant, using the domestically developed G115 steel for steam pipes (Dongfang, 2017).

A notable double reheat unit undergoing commissioning in China is the 1350 MW unit known as Pingshan Phase 2. This unit is designed to use the highest steam parameters applied in coal plant to date, at 31.1 MPa/610°C/630°C/623°C. Developed by Shanghai Shenergy, a key innovation at this plant is a split-level turbine design, in which the length of the main steam pipe is greatly reduced by raising the high pressure turbine to the level of the superheaters. In addition to reducing the cost of the pipe, this reduces pressure losses and combined with the other optimisation approaches used by Shenergy at Waigaoqiao, Pingshan 2 is expected to reach efficiencies of 49.8% (Feng, 2018).

4.3 CO_2 EMISSIONS REDUCTION

Efficiency improvements for thermal plant are inversely related to CO_2 emissions, as shown in Figure 10. The IEA (2020a) estimated the average efficiency of the global coal fleet in 2018 to be 37.5%, which corresponds to over 900 gCO_2/kWh for combustion of a standardised hard coal. This can be compared with below 690 gCO_2/kWh as efficiencies approach 50%, as expected for Pingshan 2 or future AUSC plant. If the global coal fleet were to be brought to efficiency levels of the current state-of-the-art, it would correspond to a CO_2 saving of roughly 2 $GtCO_2$/y, or around 20% of the total emissions from coal power.

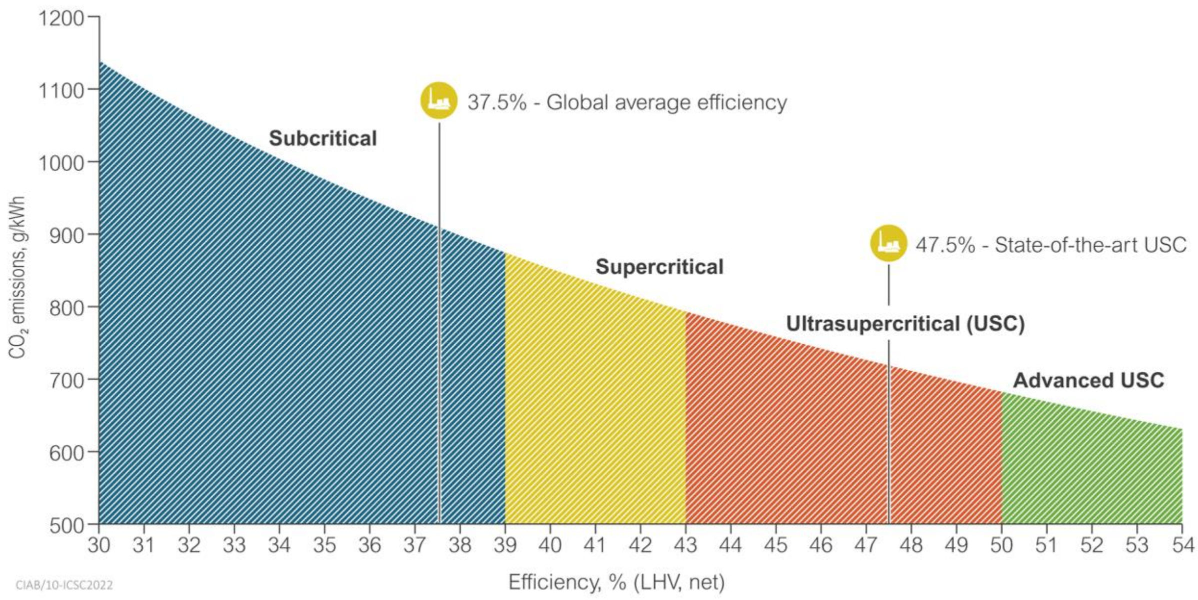


Figure 10 CO_2 savings available from coal plant efficiency improvement (ICSC, 2020)

4.4 EXAMPLES OF COAL CCUS POWER PLANT

Coal power plant efficiency improvements through the adoption of state-of-the-art steam cycle conditions are important to reduce CO_2 emissions, but to deliver emissions consistent with net zero, they should be used in conjunction with CCUS (*see* Chapter 2). Leading examples of CCUS applied to coal power plant include Boundary Dam in Canada and from an Asian perspective the Jinjie CCUS project, together with the Huaneng Multi-Energy under construction in China.

4.4.1 Boundary Dam CCUS project

The Boundary Dam 3 project in Saskatchewan, Canada, was the world's first fully integrated CCUS facility at a coal-fired power plant. The nominal capture rate of the facility is 1 $MtCO_2$/y and includes capture, compression and transport elements for CO_2. Further, the CCUS facility is fully integrated with the coal power plant which provides all its steam and power requirements. The facility produces CO_2 primarily for EOR, but it is also provided for injection and permanent geological storage at Aquistore. This is an onsite CO_2 measurement, monitoring and verification project, which involves the injection and storage of CO_2 in a saline aquifer at a depth of 3400 m.

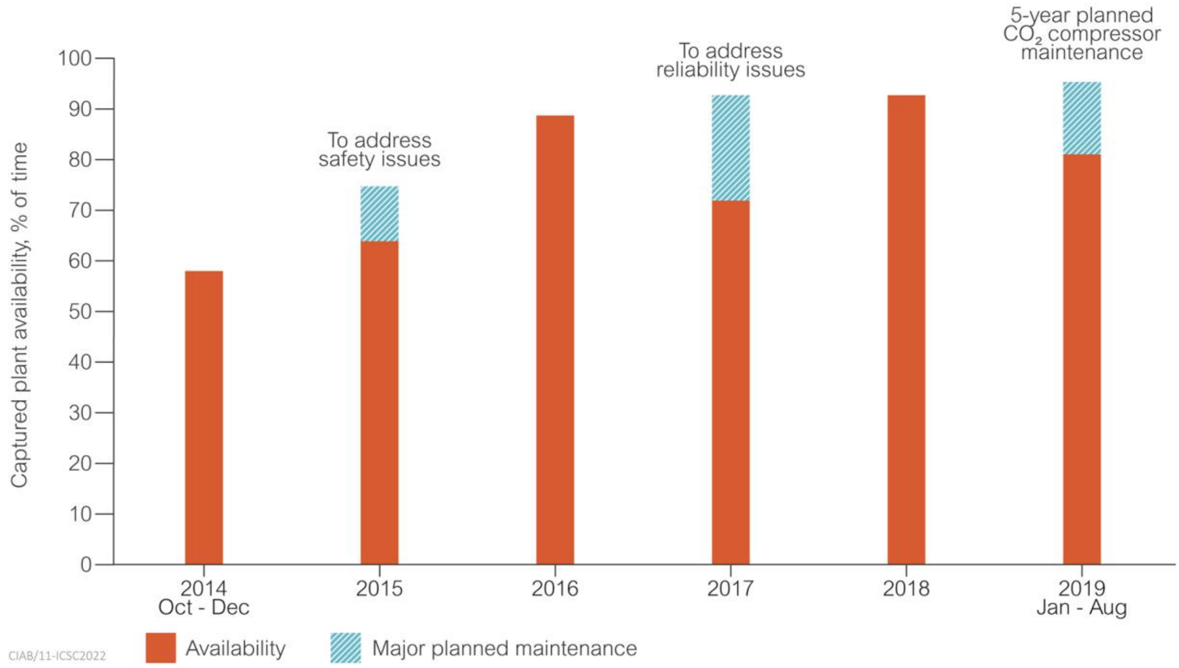
Key characteristics of the coal-fired power plant are shown in Table 4. The plant uses Shell's Cansolv post-combustion solvent-based CO_2 capture technology to remove about 85–90% CO_2 from the flue gas stream from unit 3 of the plant. This unit was repowered to increase its efficiency prior to installing the CCUS facility, producing 160 MWe gross power output (110 MWe net power output with CO_2 capture). The main parasitic load for the CCUS facility's regeneration unit is supplied by low-pressure steam diverted from the main power plant steam cycle, which leads to a derating of the steam turbine power output.

TABLE 4	KEY DATA FOR BOUNDARY DAM CCUS DEMONSTRATION FACILITIES (MANTRIPRAGADA AND OTHERS, 2019)
Parameter	**Boundary Dam**
Location	Saskatchewan, Canada
New build/retrofit	Retrofit
Gross capacity, MW	160
Net capacity, MW	110
Coal type	Lignite
Design capture rate, %	85–90
CO_2 use	EOR
$MtCO_2/y$	1.0
Solvent	Cansolv
Regeneration energy	Steam from coal plant primary steam cycle
Project capital cost, US$ millions	1300–1500 (800 for CCUS)

The CCUS facility faced technical challenges, particularly in the early years, including some process complications relating to fly ash and other contaminants. Significant levels of amine degradation also occurred as a result of high temperatures due to poor steam temperature control, leading to amine reaction with flue gas contaminants and particulates. Major work was undertaken to address these issues between October 2015 and August 2017, including replacing some of the carbon steel infrastructure with stainless steel and the introduction of anti-fouling measures. As a result, analysis carried out by the International CCS Knowledge Centre on behalf of the IEA Coal Industry Advisory Board (Bruce and others, 2019) indicates that the facility has been able to achieve 85% availability levels since the end of 2017 (*see* Figure 11). This compares with a design availability for the CCUS facility of 85%, showing that, disregarding those plant outages outside the scope of the CCUS facility itself, the availability is now close to the target level.

This level of availability continued into 2020, where the leading causes of derates are described as fouling of the CO_2 lean rich heat exchangers and high pressure losses through the CO_2 absorber flue gas path. These will be addressed towards the end of 2021 by increasing the number of plates on the lean rich heat exchangers as well as the capacity of the pumps to these heat exchangers to provide a level of redundancy, together with the replacement of fouled packing and increased utilisation of activated carbon and antifoam treatments to mitigate foaming (Janowczyk and others, 2021).

In terms of CO_2 captured, the cumulative amount continues to increase and totalled 4.2 $MtCO_2$ at the time of writing (October 2021).



Capture plant availability is the percentage of time the capture plant is capturing CO_2 while the power plant is operating at 50% load and above. The calculations include both the original planned maintenance durations as well as any unplanned extensions.

Figure 11 Availability of carbon capture facility at Boundary Dam 3 power plant (Bruce and others, 2019)

4.4.2 Jinjie CCUS projects

Jinjie Energy's 0.15 $MtCO_2$/y CCUS project is a national R&D project in China and a key project in Shaanxi Province (*see* Figure 12). The aims of the project are to carry out:

- research on CO_2 capture technologies for coal-fired power plants;
- conduct industrial demonstration; and
- establish an innovative, efficient and low energy technology system for coal-fired power plants in China to capture CO_2 from flue gas.

Located in the Shenmu High-tech Industrial Development Zone of Yulin City, construction started in November 2019, and was completed in January 2021. The overall planned capacity for the project includes four 600 MW coal-fired units, two 660 MW coal-fired units, two 1000 MW coal-fired units and a supporting coal mine with capacity of 18 Mt/y.

The CCUS project uses chemical absorption to carry out research on carbon capture technologies for coal-fired power plants and is integrated with the plant's No.1 600 MW subcritical unit. The facility is equipped with several efficient and energy saving technical components including inter-stage cooling as well as efficient heat exchangers with low terminal difference and a high gravity reactor and modified plastic fillers (SASAC, 2021). The captured CO_2 will be injected into the existing CO_2

injection site from the Ordos project in Chenjiacun field in Inner Mongolia for dedicated geological storage. At the time of writing (October 2021), the Jinjie Energy project is the largest post-combustion CCUS full chain demonstration facility applied to a coal-fired power plant in China.

In June 2021, the project was commissioned, passing a continuous 168 hour full-load trial operation. During the trial operation, a CO_2 capture rate of 90% was achieved, producing industrial-grade liquid CO_2 products with a purity of 99.5% (China Shenhua, 2021; Sheng, 2021).

Figure 12 Jinjie Energy's 0.15 MtCO_2/y CCUS facility (SASAC, 2021)

4.4.3 Huaneng 10 GW multi-energy project

China Huaneng Group (CHG) is constructing a 10 GW multi-energy power plant in Qingyang, Gansu Province, China (*see* Figure 13). The power plant comprises 2 GW of low emissions coal-based power generation using two 1 GW USC power generation units equipped with CCUS (Liu, 2021). The steam operating conditions for the USC units will be 28 MPa main steam pressure and 605°C, with a single reheat temperature of 623°C. This plant will be an air-cooled unit with a gross thermal efficiency of 46.6% and coal consumption of 264 g/kWh.

The remaining 8 GW of power will be derived from the renewable sources of wind and solar, with around 10% of energy storage provided using battery-based technology. Assuming a 2–4 hour energy storage capacity, this would equate to 1600–3200 GWh of energy storage. The plant is described as a national key project, with the large-scale CCUS project supported by the main project as one of the top ten Chinese science and technology demonstration projects of 2021. The plant, owned by Huaneng

Longdong Energy Co Ltd, has been issued an investment project record certificate by Gansu Province and is scheduled to complete construction and commissioning by 2023. When fully operational, the power plant will generate more than 100 billion yuan ($15.7 billion) of investment, create more than 28,000 jobs, produce more than 18 billion kWh/y of new energy power, use more than 95% of clean energy and reduce CO_2 emissions by about 20 $MtCO_2$/y.

Two units on the left under construction with two units on the right planned as future expansion.

Figure 13 Artist's impression of 10 GW Huaneng Longdong multi-energy power plant (Lianbo, 2021)

The CCUS element of the project is described as a 'megaton-level CCUS Research and Demonstration Project'. The preparation of a feasibility study report is in progress, including schemes of public works for gas extraction, steam use, water and electricity use and optimisation of the layout scheme. The CCUS system is based on post-combustion capture technology using a proprietary third generation solvent developed within CHG, which aims to reduce energy consumption to 2.2–2.3 GJ/tCO_2, in line with state-of-the-art solvent based systems. It is targeted to capture 1.5 $MtCO_2$/y at a capture rate of 90–95% on an approximately 35% side-stream from one of the 1 GW USC systems. This capture level therefore represents one-third of the CO_2 emissions from the unit and hence one-sixth of the total power plant emissions. A site survey has been completed for pipeline transportation of the CO_2 and preliminary studies on geological conditions have been conducted for underground storage. There is also the potential to use a portion of the CO_2 for EOR to support the CCUS plant business case in the near term.

Overall, the Huaneng Multi-Energy project with its 20% of power from coal-based power generation with CCUS, coupled with 80% power from variable renewable energy, is an excellent example of how coal can support the increased penetration of renewables in Asia, to move towards NZE. The coal power generation element provides dispatchable power to help maintain grid stability, as discussed further in Chapter 5. However, in the near term, the USC coal plus CCUS element of the project will be operated at baseload to provide much needed power to help meet China's energy demand.

These Chinese CCUS projects and other power sector applications (including Boundary Dam, Petra Nova, CS Energy's Callide Oxyfuel demonstrations and the Shand CCS feasibility study of a post-combustion CCUS retrofit) provide significant lessons for future CCUS design and development. They will assist in securing capital and operating cost reductions. Work to date has successfully demonstrated favorable economies of scale and other factors to reduce the cost of CO_2 capture. Technological advances and learning by doing will lead to further cost improvements.

4.5 SUPERCRITICAL CO_2 POWER CYCLES

CO_2 exists in a supercritical state above critical point conditions of 31.1°C and 7.38 MPa. This has several beneficial properties for use as a working fluid for power generation. Various coal-based power generation cycles based on driving turbines with supercritical CO_2 (sCO_2) have been developed and are reviewed by Zhu (2017). These can be divided into direct-fired and indirect-fired cycles, according to whether the CO_2 in the cycle is produced by the combustion process itself, through oxyfuel combustion, or operates in a closed loop, as in a conventional steam cycle. The most advanced supercritical CO_2 technology is the Allam-Fetvedt Cycle process developed by 8 Rivers Capital, which was demonstrated at the NET Power plant in Texas. While this plant is fuelled by natural gas, the company has also developed a design for a process based on coal-derived syngas. This promises an efficiency of close to 48% (LHV, net) and inherently produces a pure stream of CO_2 ready for storage or utilisation.

4.5.1 Allam-Fetvedt Cycle

The Allam-Fetvedt Cycle is an innovative natural gas, or syngas from gasification of coal, fired power generation technology with inherent CO_2 capture (Lu, 2020). It involves oxyfuel combustion with the CO_2 produced used as the working fluid, as shown in Figure 14. The core process is a gas-fired, high-pressure, low-pressure ratio cycle, operating with a single turbine that has an inlet pressure of approximately 30 MPa and a pressure ratio of 10. The cycle uses a turbine running on sCO_2 instead of the steam used in conventional power generation plants. An advantage is that the high energy density of sCO_2 means the components are relatively small, reducing the size of the overall plant footprint (Zhu, 2017). The high efficiency, small size and simple layout of sCO_2 power cycles coupled with other technology attributes could result in potentially large reductions in capital and fuel costs and decreased

GHG emissions from coal-fired power generation. This technology can produce electricity with more than 97% CO_2 capture without the need for additional carbon capture equipment.

NET Power is currently commercialising the Allam-Fetvedt Cycle in the natural gas industry while 8 Rivers Capital is leading an industrial consortium in North Dakota and Minnesota to apply the Allam-Fetvedt Cycle to syngas from coal/biomass/petroleum coke gasification. Nearly all components of an Allam-Fetvedt Cycle plant are commercially available, except the turbine and combustor. Toshiba developed, manufactured and supplied a hybrid turbine and combustor for use in the gas-fired 50 MWth (25 MWe) pilot project in Texas (GCCSI, 2020). Toshiba has developed and built the sCO_2 turbine and the high-pressure oxyfuel combustor for the Allam-Fetvedt Cycle demonstration plant, which started operation in 2018. The demonstration process will match the operating conditions of the core Allam-Fetvedt Cycle and the expected commercial plants.

The design of a commercial-scale 280-300 MW Allam-Fetvedt Cycle natural gas plant is also underway. 8 Rivers Capital plans to begin operating a 280 MW, natural gas-fired NET Power plant within the Southern Ute Indian Reservation in southwest Colorado by 2025. Known as the Coyote Clean Power Project, it will be a near zero emissions plant with the capability to capture and store CO_2. A final investment decision on the Coyote facility is expected to be made in 2022 with production targeted to begin by 2025 (Patel, 2021). In addition, a pre-FEED study for an Allam-Fetvedt Cycle power production facility for potential deployment at multiple locations in the UK has also been announced, for co-production of power and hydrogen using natural gas feedstock (Kelsall, 2021; Sembcorp, 2021).

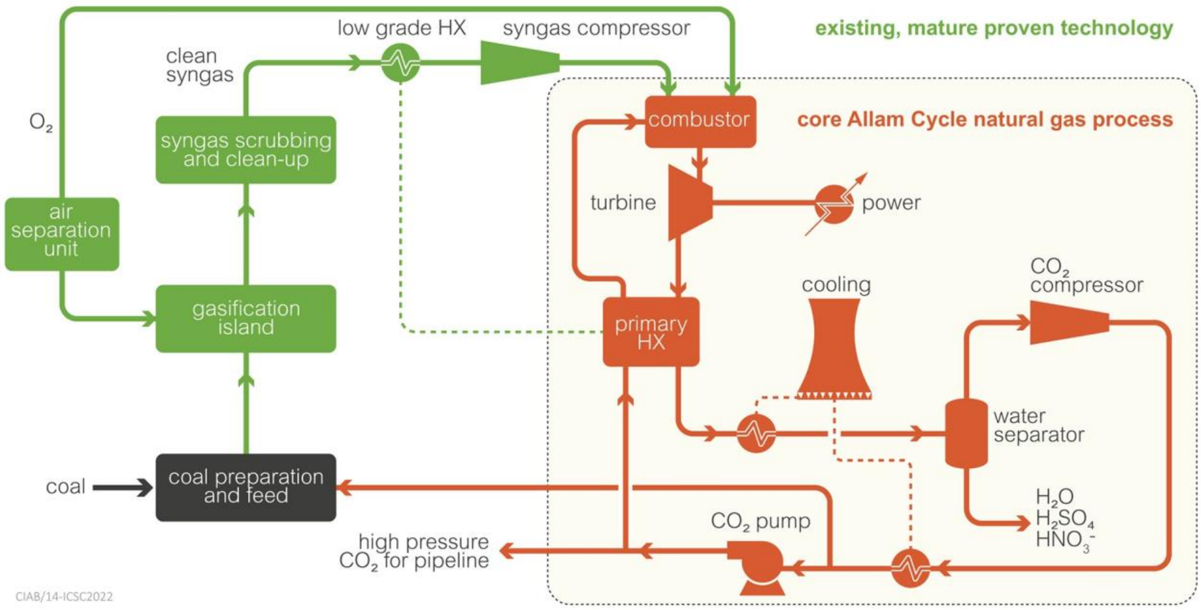


Figure 14 Simplified block flow diagram of the Allam-Fetvedt Cycle coupled with a coal gasification system (Lu, 2020)

4.5.2 Echogen sCO_2 cycle

Supercritical CO_2 can be used to directly replace steam as the working fluid in the power plant Rankine cycle. One example is the Siemens Energy/Echogen system which has potential application for waste heat applications such as solar, geothermal power and bottoming cycles and some Brayton Cycle gas turbine applications. It appears to have an advantage at relatively small scale, typically 0.1–10 MWe. For large coal-fired power generation systems, the more conventional steam Rankine cycle seems better suited.

In 2014, the first 8 MWe closed sCO_2 cycle heat engine EPS100, developed by Echogen Energy Systems, was brought to the market. It turns waste heat from various industrial processes to electricity and operates at relatively low temperatures. Echogen Energy Systems now offers heat engines of 1–9 MWe and has extended the application from waste heat recovery to solar and geothermal power. Extensive R&D is ongoing to develop indirectly heated, closed-loop high-temperature sCO_2 cycle for power generation from nuclear, solar and fossil fuel combustion (Zhu, 2019).

4.6 FUEL CELLS

An innovative variant of IGCC plant is to use coal-derived hydrogen in a fuel cell, which is an electrochemical device similar to a battery, but which uses a continuous supply of fuel to one electrode of the cell rather than oxidising a finite quantity of material. The solid oxide fuel cell (SOFC) is a widely used variety which operates at high temperatures and can be fuelled by natural gas, which is steam-reformed to hydrogen and CO_2 in situ, or by coal derived syngas from an IGCC system (*see* Section 4.2.4).

Sponsored by the New Energy and Industrial Technology Development Organization (NEDO), the Osaki CoolGen project in Japan aims to develop an SOFC fuelled by coal-derived hydrogen (Zhang, 2018). The 166 MW demonstration plant progresses the oxygen-blown gasification technology developed under NEDO's 'EAGLE' project. It consists of an IGCC component as well as the integrated gasification fuel cell (IGFC) and a pre-combustion CO_2 capture pilot (*see* Figure 15). The IGCC unit was successfully commissioned in 2017, and the CO_2 capture process in 2019. The fuel cell which began operation in 2021, operates on a slipstream of pure hydrogen produced by the CO_2 separation process. The whole plant is designed to achieve 42.7% efficiency (LHV, net), including CO_2 capture, with the fuel cell component targeting an efficiency of 55%.

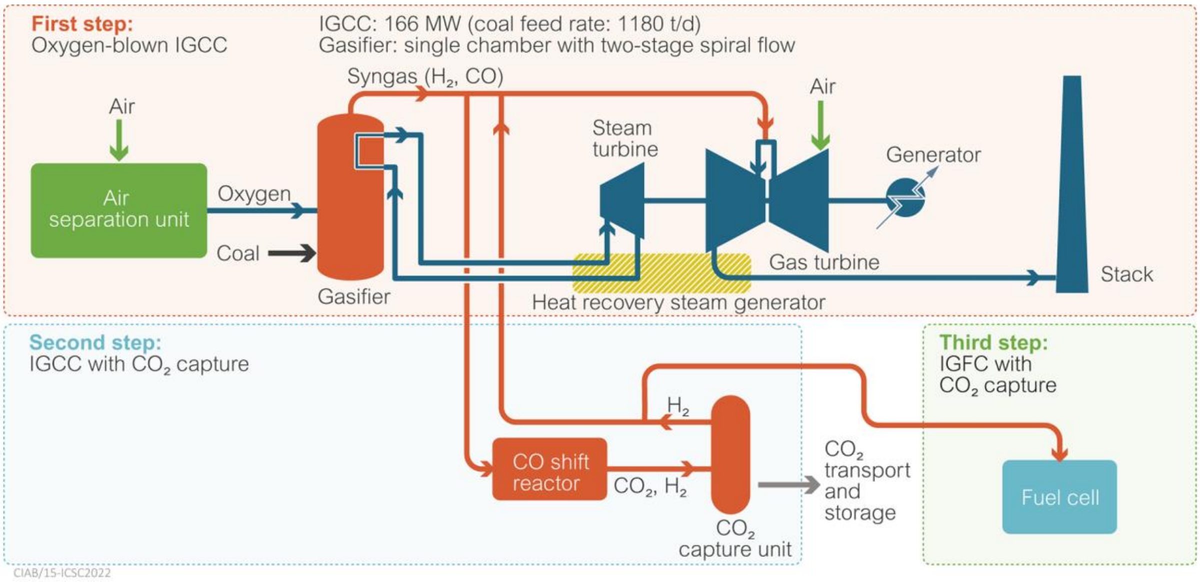


Figure 15 The Osaki CoolGen IGCC and IGFC demonstration project (Matsuda, 2020)

Mitsubishi have been working on a version of this since around 2004, referred to as a 'triple cycle' (Kobayashi and others, 2011). The cycle is projected to have electrical efficiencies firing coal derived fuel of potentially up to 60% (LHV) basis in the longer term, when utilised at the multi-100 MWs scale (*see* Figure 16). CO_2 capture could again be incorporated in the cycle, although this would reduce the cycle efficiency.

Due to the modular nature of fuel cells and to drive down the cost of SOFC units through mass production, the roadmap will first develop a product, called Megamie, at the 250 kWe–1 MWe scale based on an SOFC combined with a recuperated micro-gas turbine. Here, efficiencies of around 55% LHV are targeted when firing natural gas. The market is distributed power generation and small to medium business and industrial applications (Irie and others, 2017). The first commercial use of the Megamie system commenced operation in February 2019 as an in-house cogeneration facility for Mitsubishi Estate Co Ltd's Marunouchi Building in Tokyo, Japan where it continues stable operation. The second Megamie system was installed at Hazama Ando Technical Research Institute in Tsukuba, Ibaraki Prefecture, Japan (Mitsubishi Power, 2020).

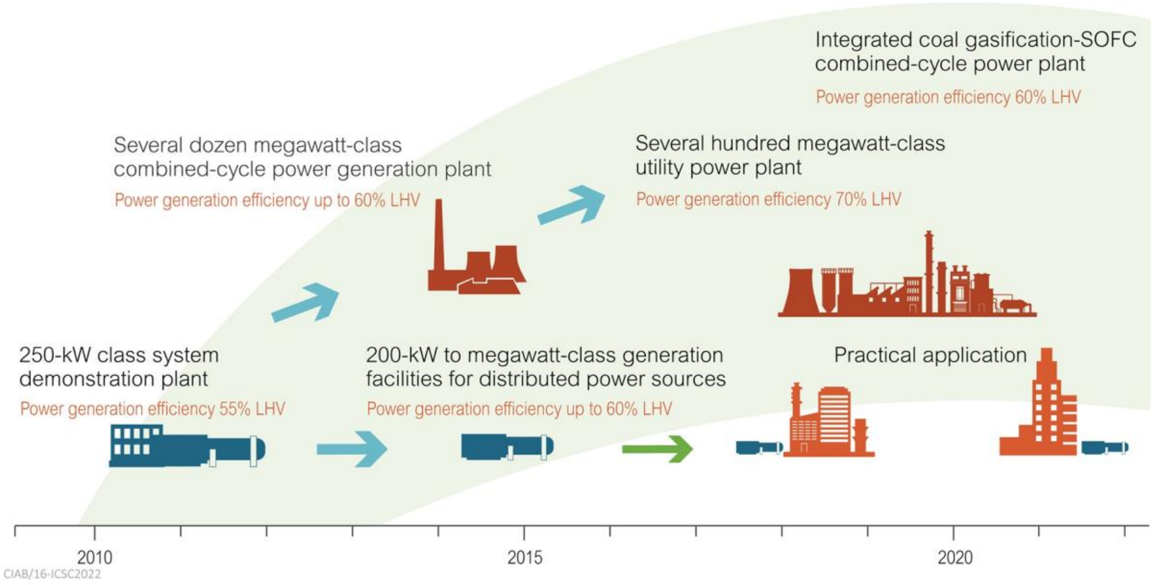


Figure 16 Roadmap to high efficiency triple cycle based on SOFC and Brayton/Rankine Cycles (Kobayashi and others, 2011)

A thorough review of fuel cell integration with coal-based power systems has been provided by the ICSC (Zhang, 2018), which also covers molten carbonate fuel cells (MCFC) and direct carbon fuel cells (DCFC). The latter technology offers high electrical efficiencies of around 70% and CHP efficiency of around 90%. The by-product is highly concentrated CO_2 requiring no gas separation which can be stored directly, avoiding cost and efficiency penalties. Fuel utilisation can be almost 100% as the fuel feed and product gases are distinct phases and thus can be easily separated. There is no requirement for water usage in the process, an advantage in areas of water scarcity. However, despite the significant promise of DCFC, the development of the technology remains at an early TRL stage.

4.7 DIGITALISATION

The large number of coal power plants deployed in the past decade, adding to the already significant coal-based power fleet, means that ensuring that these existing plants run as cleanly as possible is a priority. To this end, the power sector, including coal-fired power plant, is making increasing use of 'digitalisation' based on five key functions of connection, monitoring, analysis, prediction and optimisation. The increased connectivity provided by the industrial internet of things (IoT), increased computing power and artificial intelligence (AI) for increased analytics and data handling, together with remote sensors and improved near real-time modelling of power plant system components are all used. Figure 17 shows how the various digital components build up to form a model of the real plant asset – the 'digital twin'. These digital twins can be used for:

- Remote condition monitoring of power plant assets to assess actual component performance in the field as a basis for maintenance. This can optimise scheduled maintenance to include only those components assessed as requiring replacement and help to reduce unscheduled outages by implementing preventative maintenance.

- Digital twins with near real-time performance prediction using a combination of historic data, neural networks or mathematical model based process simulation can optimise plant performance. For example, this could optimise system parameters to produce lowest emissions whilst achieving long component life.
- Coupled with financial modelling, the digital twin could optimise power plant performance with revenue. For example, this could involve offering grid services such as frequency response set against reduced component life, or in the case of multi-product systems like IGCC, switching between producing electricity, hydrogen and chemicals to maximise financial return.
- Use big data from plant fleets to inform the design of the next generation of plant.

Whilst the power industry has been the driver for the digital twin approach to a large extent, it would be equally applicable in the context of heavy industry and chemicals/hydrogen production from coal. This use of digitalisation sees the coal technology business behaving increasingly as a service industry.

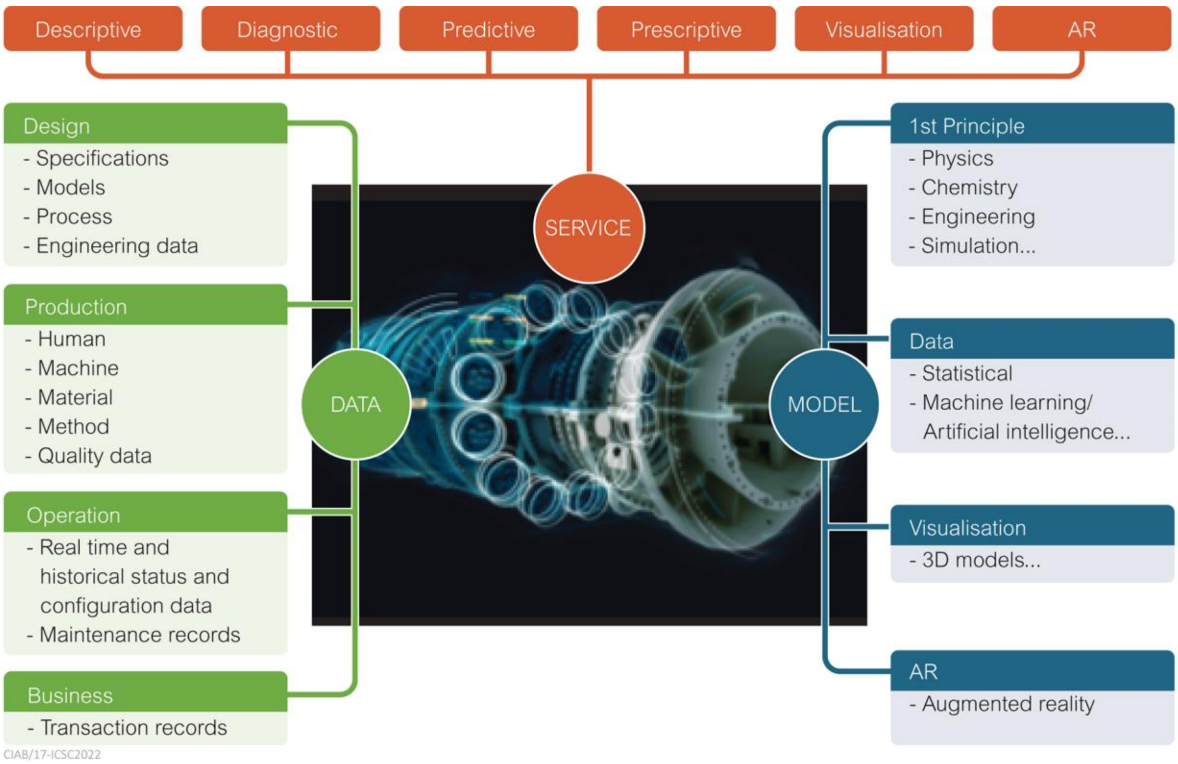


Figure 17 Constituents of a digital twin (Malakuti and others, 2020)

As digitalisation advances, plant operation becomes increasingly dependent on the IoT, which increases the risk of cyber-attack. Hardware and software have been developed and implemented to protect energy infrastructure from such attacks. Digital solutions adopting AI and machine learning, and/or blockchains for enhanced cyber security are under development. A more in-depth review of digitalisation in the coal sector has been undertaken recently by the ICSC (Zhu, 2020).

5 THE ROLE AND VALUE OF LOW EMISSION TECHNOLOGIES IN BALANCING THE GRID

5.1 KEY MESSAGES

The primary electricity service required by consumers (active power) is only of value if it is complemented by 'ancillary services', which are key to managing the grid power system safely, securely and reliably. These services maintain key technical characteristics of the system and include:

- maintaining system frequency;
- maintaining system voltage, both system strength and voltage control;
- restarting the system after a total or partial shutdown; and
- reserve capacity to ensure power supply meets demand at the exact time the demand signal is received.

Dispatchable generation, where power can be dispatched on demand at the request of power grid operators based on 24/7 market requirements, delivers these ancillary services. It comprises the thermal power systems of coal-fired, gas-fired and nuclear power, as well as hydroelectricity.

Coal power plants will remain important in Asia for the coming decades. Given the young average age, 13–14 years, of these assets, they offer the best option to provide the ancillary services and system flexibility to support increasing levels of variable renewable energy including wind and solar power.

Dispatchable power provides high levels of inertia for maintaining system frequency. This plays an important role in overall power grid response, including frequency disruptions and power factor correction.

Even when high levels, in excess of 50–70% VRE are achieved, coal fired power generation technology will remain key to ensure security of supply in Asian economies.

Consequently, an increase in variable renewable generation capacity does not necessarily allow for significant closures of competitive, dispatchable plants, although the coal plants will typically need to operate at lower capacity factors.

For the most modern USC power plant with high turndown capability, the opportunity must be taken to retrofit CCUS technology so that the dispatchable power provided can do so with very low CO_2 emissions.

Thus, it is not a case of coal competing with VRE but coal enabling increased penetration of VRE into Asian power networks to support the transformation to NZE.

Electric power systems are undergoing radical changes in both supply and demand technologies. On the demand side, there is a growing number of distributed and variable generation resources. In addition, entities that used to be exclusively consumers now require the grid to be able to purchase, or otherwise accommodate, the excess power they produce. On the supply side there is a shift from large, synchronous (baseload) generators to smaller generators and variable resources (notably wind and solar). As power systems around the world transform, power system flexibility becomes a priority. The renewable power sources of wind and solar photovoltaic (PV) differ from thermal power plant, including coal electricity generation, in that their maximum instantaneous output depends on how much wind or sunlight are available at any given moment, which makes their output variable. Forward prediction of when this variable renewable energy (VRE) is available, even on a short-term time scale, is only partially available. In addition, the technical response characteristics of VRE, especially during grid disturbances, are determined by control software settings rather than by inherent technical design. These properties of variability, partial predictability and response characteristics can make it difficult for power systems to accommodate higher amounts of VRE (IEA, 2020b). Power system flexibility is needed to manage system integration. This flexibility encompasses all system components that facilitate the reliable and cost-effective management of variability and uncertainty in both supply and demand.

Analysis by the IEA (2020b) has identified different phases of VRE integration which are characterised by the specific penetration level, and by the main integration issues and challenges, covering technical, regulatory, market and institutional aspects (*see* Figure 18).

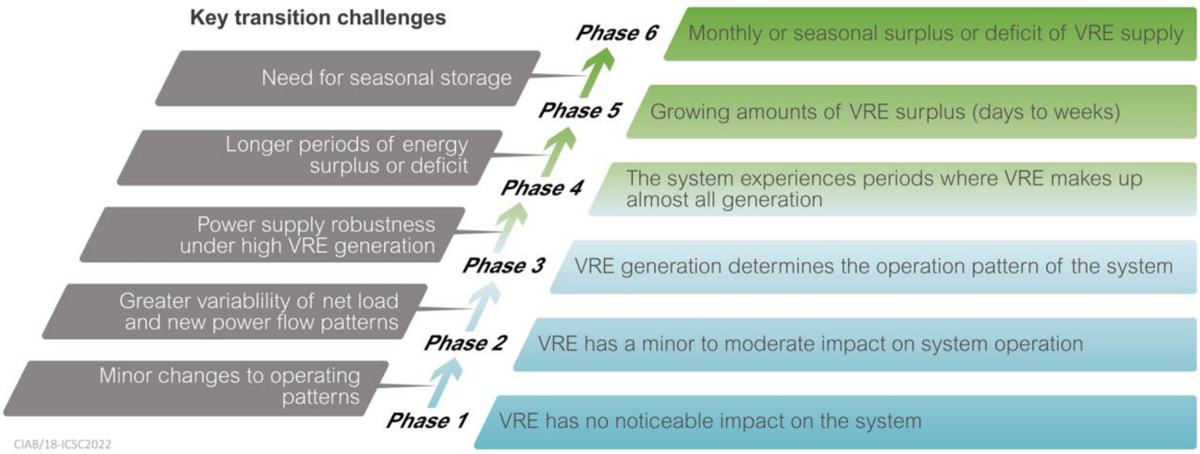


Figure 18 Phases of VRE integration in power systems (IEA, 2020b)

Increasing VRE penetration levels to move from one phase to the next require that measures become more interrelated and complex. Ultimately, a systematic transformation of the electricity system, and the wider energy system overall, is needed. Further VRE deployment beyond Phase 4 is possible, but requires the electrification of other end-use sectors, seasonal storage and the use of synthetic fuels such as hydrogen. Most countries are presently at Phase 1 or 2 but are striving towards higher phases; China, India and Japan are characterised as being in Phase 2 (IEA, 2020b).

There are several options to deal with this variability in terms of providing a flexible power system (*see* Figure 19). They include flexibility on the supply side, energy storage, demand side response and the design of the grid network (Deloitte, 2019). Demand side response is perhaps the easiest option to implement through reducing the magnitude and frequency of instances of unmet demand. However, analysis by Imperial College London, UK indicates that demand side response alone would not be sufficient to consistently ensure security of supply (Pratama and Mac Dowell, 2019). Flexibility in the power system supply side provided by dispatchable thermal power technologies such as natural gas combined cycle and coal-fired power plant are very important to allow the increased penetration of VRE. As VRE penetration increases to higher levels, the need for energy storage, both on the inter-day time scale through pumped hydro and batteries, and inter-seasonal storage through technologies such as power-to-hydrogen, will become increasingly necessary. However, the extent to which this can be relied upon is attenuated by the cost and round-trip efficiency of storage, in addition to the requirement for adequate capacity to generate sufficient power (Pratama and Mac Dowell, 2019).

The next sections look at the flexibility that coal-fired power plants can provide, together with an assessment of the geographic variability, specifically in Asia.

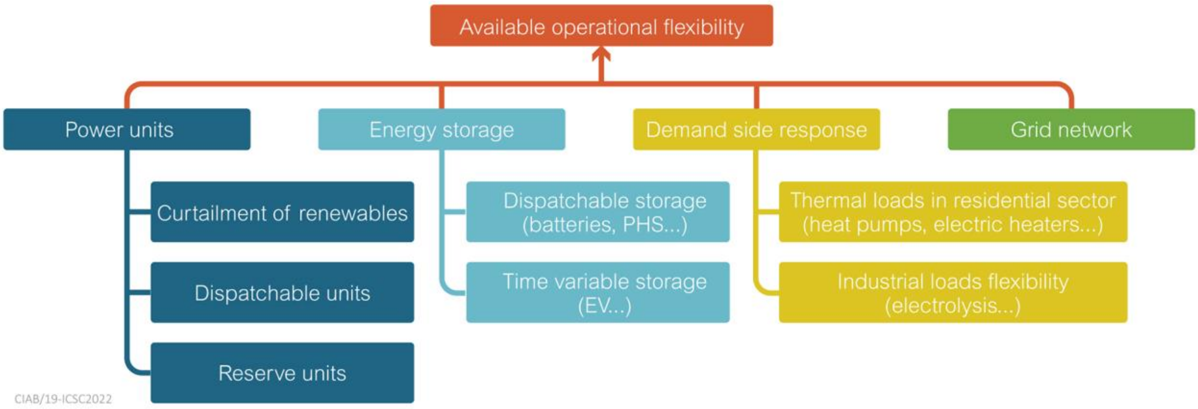


Figure 19 Potential options to provide flexibility in power systems (Deloitte, 2019)

5.2 COAL POWER PLANT FLEXIBILITY

Dispatchable technologies including coal power plant are highly valuable in electricity systems with significant variability in energy demand. Coal power plants around the world are increasingly required to operate more flexibly, ramping output up and down according to the variation in output from VRE sources. Characteristics of more flexible operation include faster ramp rates and start-up, lower minimum load, and the ability to maximise efficiency of both power generation and pollutant control measures while operating in this manner. This operational flexibility includes the speed at which output within an operating range can be adjusted and the time needed to be ready to start feeding into the grid from standstill. The technical constraints defining these features can generally be summarised by the following parameters:

- **Minimum up and down times**: the time to start-up from idle until reaching the minimum load point when grid synchronisation status is achieved, and to shut-down from an operating point;

- **Cost of start-up and shut-down**: costs are associated with additional fuel use and wear-and-tear costs due to mechanical and thermal stress;
- **Maximum load capacity**: often referred to as the nominal capacity of the plant;
- **Minimum load capacity**: given as a percentage of nominal capacity; and
- **Ramp-up and down rates and costs**: refers to the steepness of an increment or decrease of output per unit of time, often given as a percentage of the nominal capacity per minute. Ramping costs refer mainly to wear-and-tear costs due to flexible plant operation.

Coal power plants can also play an important role during cold spells coinciding with meteorological conditions that result in limited output from wind and solar plants. Their role for providing 'mid-term' flexibility, becomes more important with an increasing share of renewables. Analysis of such 'winter doldrum' periods with durations of one to three days in Germany, which has a relatively high level of renewables, found that coal-fired power plants generate twice as much power than on an average day if the renewable energy share is 50%, and three-and-a-half times more power if the renewable energy share is 70%. Another finding is that the weather conditions leading to 'dark cold doldrums' also affect neighbouring countries to a degree, so the scope for energy balancing via importing higher levels of electricity is constrained. Coal-fired power plants contribute, as other dispatchable plants, to system security via flexible adjustments of their output and through the provision of firm capacity. Thus, dispatchable power plants remain key for ensuring security of supply of the system even if most of the annual electricity generation comes from renewable sources. Consequently, an increase in variable renewable generation capacity does not necessarily allow for significant closures of dispatchable plants (Deloitte, 2019), although the coal plants will typically operate at lower capacity factors.

A further advantage offered by coal-fired power plant, or other large thermal or hydro plant, is the high level of inertia which plays an important role in overall power grid response, including frequency disruptions and power factor correction (Bruce and others, 2019). This forms part of a portfolio of services including maintaining system frequency, maintaining system voltage (both system strength and voltage control), restarting the system after a total or partial shutdown and reserve capacity to ensure power supply meets demand at the exact time the demand signal is received.

Overall, it should not be a case of coal competing with VRE, but more that coal enables the increased penetration of VRE into global energy systems. Placing a financial value on the provision of the range of ancillary services offered by coal power plant, as discussed above, is needed to ensure that coal can continue to support increasing levels of VRE in the transition to a NZE future.

As many existing coal plants were designed to operate as baseload generation, adapting to more flexible modes of operation can require plant modifications, particularly to instrumentation and control systems, which are essential for optimising combustion at all levels of output. Fundamental changes to plant operating protocols and staff training may also be necessary. Recent advances in plant flexibility were reviewed in detail by the ICSC (Wiatros-Motyka, 2019).

New USC plants are generally designed to take flexible operation into account, employing features such as sliding pressure boilers, advanced materials which allow for lower mass high-pressure components, and more flexible turbines with condensate throttling and steam-cooling of inner casings. Such developments have allowed state-of-the-art USC plant to achieve stable operation at as low as 10–15% of their maximum output, and ramp rates of up to 8% of their maximum output per minute. However, some efficiency penalty during unit cycling is inevitable, relative to baseload operation. As coal milling can be a major limiting factor in achieving rapid load changes and low minimum loads, a promising technology is the use of indirect firing, in which coal is temporarily stored following pulverisation, allowing mills to operate steadily at high loads, regardless of plant output (Wiatros-Motyka, 2019). Faster start-ups can be achieved through heating thick-walled plant components during offline periods, usually using external steam or electric heaters. Burners are now often equipped with plasma ignition to eliminate costly auxiliary fuel consumption during start-up (Lockwood, 2021). Flexible operation and extended offline periods can lead to accelerated degradation of plant components, so enhanced monitoring and maintenance protocols are required, using digitalisation techniques as described in Section 4.7.

5.3 SITUATION IN ASIA

There are several reasons why the case study countries will continue to use coal-fired power generation in the transition to NZE, including the use of indigenous coal resources, enhancing national energy security, and driving economic and/or social development. Almost all the coal capacity built in the last 20 years is in Asia, primarily in China, but also India, and increasingly in Southeast Asia, including Indonesia and Vietnam. The region has a high demand growth rate meaning that dispatchable thermal power plants have a critical role in providing security of supply, which is needed to meet the rapidly increasing demand.

The flexible use of coal-fired thermal power plant to support the increasing level of VRE penetration is therefore the best way forward in this region. It may require some modifications to the power plants to provide flexibility levels closer to natural gas-fired combined cycle plant, together with the retrofit of CCUS to those power plants that will continue to operate to 2050 and beyond.

Taking China, the world's largest wind and solar market, as an example: China's power systems face significant challenges in integrating large-scale renewable energy and reducing the curtailed renewable energy, particularly in the northern provinces (Ku and others, 2020; Na and others, 2019). The power systems need significant flexibility to avoid this curtailment. In regions still heavily reliant on coal for generating electricity, the flexible operations of coal power units will be the most feasible option to face these challenges.

Overcapacity in the coal fleet, and its relatively young average age, suggests that CCUS retrofits will be important, but greenfield coal installations may be an option for coal dominated provinces such as Shaanxi, Hebei and Inner Mongolia (Ku and others, 2020).

6 INDUSTRIAL APPLICATIONS

6.1 KEY MESSAGES

Industry is central to Asia's continued economic development and prospering society.

Industry produces about 8000 MtCO_2/y of direct emissions, with the cement, iron and steel, and chemical sectors being responsible for around 70% of these. The Asia-Pacific region accounts for around two-thirds of these emissions at around 5600 Mt/CO_2/y. If indirect emissions are added, industry accounts for almost 40% of global man-made CO_2 emissions.

Given the limited alternatives currently available, industries such as cement, steel and aluminium will continue to rely on coal and gas for years to come. Because of this they are referred to as 'hard to abate industries'. They represent the source of around 40% of Asia's CO_2 emissions. Almost 2000 MtCO_2/y of industry emissions are a by-product of chemical reactions within the production processes. These process related emissions cannot be avoided using feasible production technologies.

Various technology solutions are being explored with the potential to make deep cuts to their emissions. But they will take time to develop and deploy. In addition, these industries are typified by young assets, with perhaps two-thirds or more of their lives still to operate. Accordingly, CCUS must play a critical role if these sectors are to transition to NZE.

A portfolio of approaches is likely to be necessary to reduce CO_2 emissions, including

- 'fuel' switching to hydrogen;
- biomass and electricity via electrification;
- improved energy efficiency; and
- deployment of current best available and future innovative technologies including CCUS.

China will need to play a key role in the effort to reduce industrial emissions, as it accounts for over 50% of global cement, steel and aluminium industry related CO_2 emissions.

Industry produces about 8000 MtCO_2/y of direct emissions, of which the cement, iron and steel, and chemical sectors are responsible for around 70%. The Asia-Pacific region including China and India accounts for around two-thirds of these emissions at around 5600 Mt/CO_2/y. If indirect emissions are added, industry accounts for almost 40% of global man-made CO_2 emissions. Demand for industrial products is forecast to continue to grow, at least through to 2050, driven by a population growth of two billion people, where growing affluence, particularly in developing economies, will see hundreds of millions of people able to afford goods and services for the first time (IEA, 2020d; GCCSI, 2020).

Almost 2000 MtCO_2/y of industry emissions are a by-product of chemical reactions within the production process. These process related emissions cannot be avoided using feasible production technologies. For example, 55–65% of emissions from cement production are created when calcium carbonate (limestone) is converted to calcium oxide (lime); these CO_2 emissions are produced as an inherent part of the cement manufacture process. Other examples of industrial processes with significant CO_2 emissions include:

- natural gas processing;
- production of iron and steel;
- ammonia/urea and biofuels; and
- various petrochemical processes that produce chemicals, plastics and fibres.

A portfolio of approaches is likely to be necessary to reduce CO_2 emissions, including

- 'fuel' switching to hydrogen (*see* Chapter 8), biomass (*see* Chapter 3) and electricity via electrification:
- improved energy efficiency; and
- deployment of current best available and future innovative technologies including CCUS.

The most feasible option for mitigation in various industrial manufacturing processes is to use CCUS to remove the CO_2 after production. It is particularly useful in several chemical production processes that produce almost pure streams of CO_2 with a very low capture cost (IEA, 2020d).

6.2 REGIONAL IMPACT

China will need to play a key role in the effort to reduce industrial emissions, as it accounts for a large share of production and CO_2 emissions (McKinsey 2018). In 2015, facilities in China produced around 58% of global cement, 50% of global iron and steel, 36% of ammonia and 16% of ethylene (*see* Figure 20). Production has continued to increase; global steel production in 2020 was 1680 Mt/y, over 56% of which was produced in with China (Worldsteel, 2020) and global cement production increased to 4100 Mt/y of which around 54% was made in China (Statista, 2021b). Aluminium production is another important area where China was responsible for 57% of global production of 65.3 Mt/y in 2020 (Int Aluminium, 2021). While Chinese facilities account for 30% of the energy used in these sectors, their extensive use of coal as a primary source of energy increases their emissions footprint.

Efforts to decarbonise these sectors in Asia will need to include retrofit of the significant number of existing production sites, together with potential new production sites across China, India, Japan, Vietnam and Indonesia. The key industrial sectors of iron and steel, cement and aluminium are covered in more detail below, with chemicals production covered in Chapter 7.

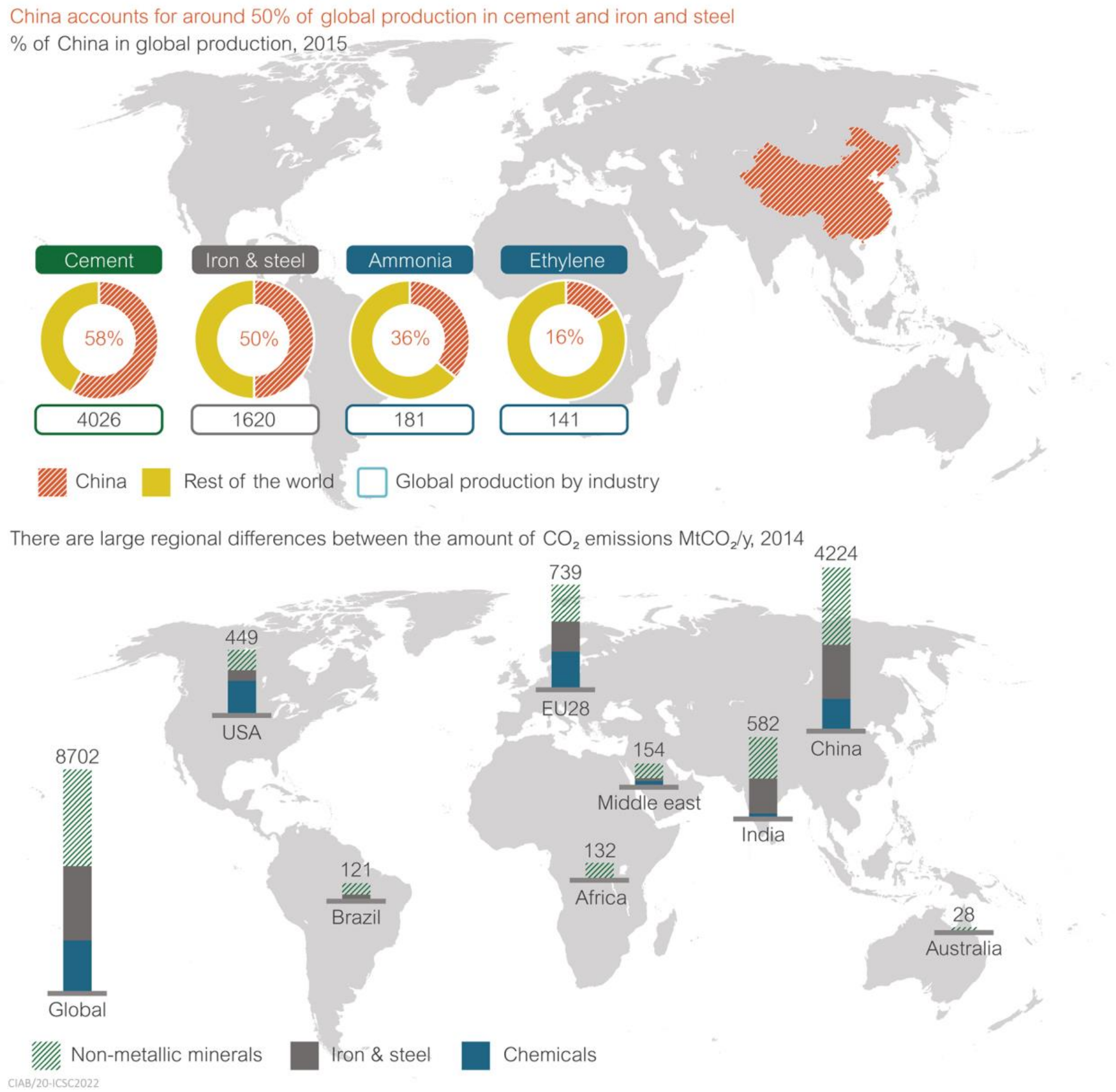


Figure 20 Regional variations in industrial manufacturing (McKinsey, 2018)

In terms of the energy source for industrial manufacturing, coal as feedstock and for process heat dominates in China, accounting for 70% of its steel, 83% of cement and 75% of aluminium production, as shown in Figure 21. Taking steel as an example, in 2019 global consumption of coal in this industry was around 900 Mtce, equating to around 15% of global primary demand for coal. This illustrates the importance of coal in industrial manufacturing and the scale of the challenge to move to NZE in the industrial sector.

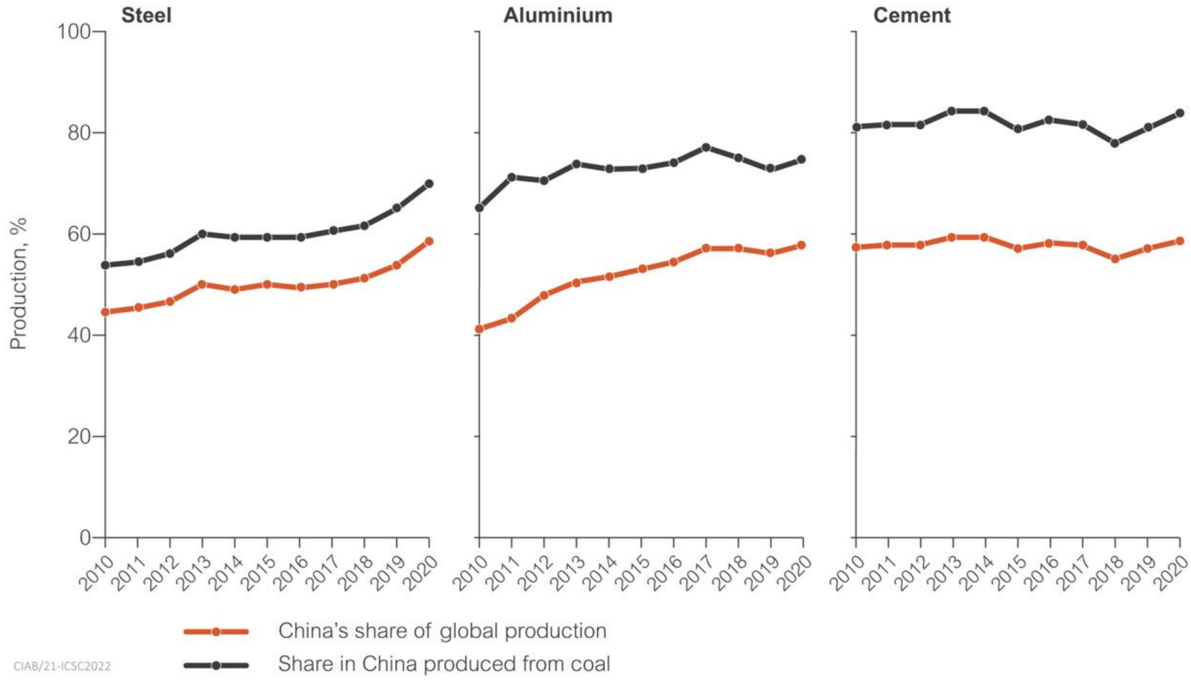


Figure 21 **Proportion of steel, aluminium and cement production in China derived using coal as a feedstock and energy source (Yang, 2020)**

6.3 IRON AND STEEL

The leading technologies for iron and steel production globally are shown in Figure 22. They have been described in full by the ICSC (Baruya, 2020) and are summarised below:

Blast furnace to basic oxygen furnace – The blast furnace to basic oxygen furnace (BF-BOF) process accounts for about 95% of the world's virgin steel and some 70% of total steel production. In the process iron ore is reduced and melted at temperatures of around 1200°C. Metallurgical coal is used as a source of heat, as a reducing agent for the iron ore and it also provides permeability to the blast furnace burden. Coal and/or gas can also have a role. The resulting pig iron is then reacted with oxygen in a basic oxygen furnace (converter) to remove excess carbon content from the iron and to generate liquid steel.

Electric arc furnace – This process is used to produce recycled steel and the remaining fraction of virgin steel. In this case, electric arc furnaces (EAF) are either fed scrap steel to make recycled steel or fed direct reduced iron (DRI) to produce virgin steel. Syngas produced from coal or natural gas is usually used as the reducing agent to reduce iron ore at temperatures below the melting point of steel. Recycled steel produced in an EAF tends to be of lower quality than virgin steel because it retains the contaminants that were present in the scrap steel, such as copper.

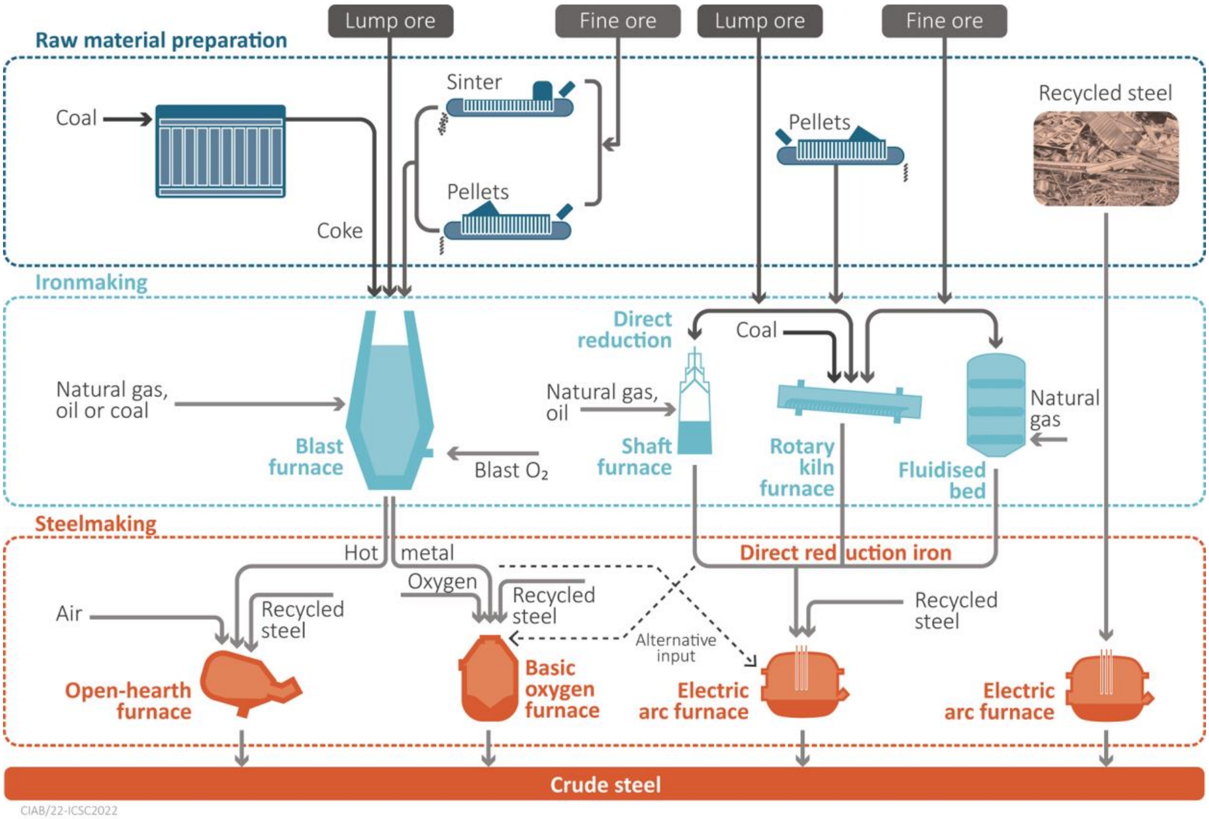


Figure 22 Primary steel production methods (Worldsteel, 2019)

Global CO_2 emissions from iron and steel production were 2.8 Gt in 2017 and are growing. Making greater use of recycled steel, where it is available, and replacing older BF-BOF plants with EAF plants reduces emissions as EAF production emits 0.4 tCO_2/t of crude steel, compared with the BF-BOF process which emits 1.7–1.8 tCO_2/t of crude steel, and DRI which emits 2.5 tCO_2/t. Emissions from integrated BF-BOF steel plant come from several sources during coke making and iron ore reduction, including the reaction of coke with oxygen and further reaction with CO_2, reduction of iron ore with carbon monoxide and limestone decomposition to produce slag from the impurities in iron ore. These are inherent to the BF-BOF process.

Emissions from BF-BOF plants themselves can be reduced by the greater use of scrap metal, further energy efficiency measures and productivity improvements throughout the plant. Such productivity and performance improvement measures will reduce CO_2 emissions by typically 20%, but the following approaches are generally required to fully decarbonise steel production:

- applying CCUS to BF-BOF production sites, most likely in combination with improved steel manufacture technology;
- using biomass derived charcoal instead of coal as a feedstock and fuel in BF-BOF production, or cofiring biomass derived charcoal with the coking coal, potentially in combination with CCUS;

- using biogas or hydrogen instead of natural gas or coal derived gas as the reductant in DRI production; and
- using electricity derived from low emissions energy sources in an EAF.

Based on the lower emissions of the EAF process, it seems likely that the share of steel production from the EAF method will increase, but this will ultimately be limited by the availability of scrap steel. The amount of scrap steel available globally was estimated to be around 750 Mt in 2017, of which 630 Mt was recycled by the global steel and foundry casting industries. Global scrap availability is forecast to reach about 1000 Mt by 2030 (Worldsteel, 2018).

6.3.1 Steel production in Asia

Asia dominates global steel production (*see* Table 5), as China, India and Japan are the top three steel producing countries. Vietnam is growing with a 12% increase in the amount of steel produced from 2019 to 2020, despite the impact of Covid-19.

In Asia as a whole, BF-BOF accounts for 80.2% of steel production, with the proportion being higher at 88.4% in China and lower at 45.2% in India. There is scope to increase the proportion of steel produced by EAF from scrap steel, but this is limited by the near-term availability of scrap steel in developing Asian countries. The quantities of scrap steel will increase in the medium term as the Asian economies develop, facilitating an increased use of EAF. India in particular, is forecast to increase steel produced by this method. The level of scrap steel could increase from around 10% in China and the wider Asia currently to closer to 45% by 2050 (IEA, 2020c). However, a key approach, certainly in China in the medium term, will be to introduce low emissions technologies into the BF-BOF process. This is because EAF can only fully decarbonise steel production where the electricity used is from low carbon sources. Due to the volume of steel produced, grid electricity would need to be used which in the near to medium term will be coal-dominated. In addition, DRI which is often used to supplement scrap steel to increase the quality of the steel produced, predominantly uses natural gas as fuel, which is not cost competitive in China.

TABLE 5 STEEL PRODUCTION IN THE CASE STUDY COUNTRIES (WORLDSTEEL, 2021)

Country	Global rank	Steel, Mt/y (2020)	Steel, Mt/y (2019)	Share of global market, % (2020)	Share of global market, % (2019)
China	1	1053.0	1001.3	56.5	53.3
India	2	99.6	111.4	5.3	5.9
Japan	3	83.2	99.3	4.5	5.3
Vietnam	14	19.5	17.5	1.0	0.9
Indonesia	22	7.6	7.8	0.4	0.4
Global total		1864.0	1880.1		

6.3.2 Technology options to decarbonise steel

Hydrogen, CCUS, bioenergy and direct electrification are all potential routes to reduce CO_2 emissions from the steel sector. The cost of energy and technology, the availability of raw materials and regional policies and drivers are all factors which determine the route to NZE. Access to low-cost renewable electricity could provide a competitive advantage to the hydrogen-based DRI route, whereas innovative smelting reduction, gas-based DRI and innovative blast furnace concepts equipped with CCUS are likely to be utilised in areas where local factors favour fossil fuels. Hydrogen and CCUS related technologies will be necessary to fully decarbonise steel manufacture by 2050, potentially contributing around 25% of the global emission reductions required in the steel industry. The concentration of CO_2 in the exhaust gases from iron and steel manufacture, typically in the range of 21–27%, are favourable for the economic application of CCUS (IEA, 2020d).

It should be noted that the fleet of BF-BOF furnaces in Asia and in particular in China are relatively young; the majority of plant in China is around 12 years old, which is less than one-third of their typical operating life (IEA, 2020c). This suggests that technology solutions with CCUS and hydrogen will be particularly important in the region, certainly during the transition period of the next 20–25 years.

Some of the most promising solutions can be split into two leading technology streams, namely the adaptation of existing iron and steel plants and new builds. Investments in existing plants can include using biomass as a feedstock instead of coal, retrofitting CCUS onto BF-BOF and DRI plants, and finally top gas recycling. Technologies better suited for greenfield investment include using DRI with hydrogen, natural gas, Finex® reduction, and direct electrolysis of iron ore, all of which avoid the use of coking coal (Baruya, 2020).

Biomass feedstock

Biomass in the form of charcoal can either replace coal or be cofired with it as a feedstock for BF-BOF plants. This approach has been applied in Brazil at a commercial scale. A potential alternative approach is to use lignocellulosic biomass directly rather than converting it to charcoal, as is being explored by Rio Tinto. Here, biomass is blended with iron ore and heated by a combination of gases released by the biomass and high efficiency microwaves that could be powered by renewable energy. If this and larger-scale tests are successful, there is the potential over time for this technology to be scaled up commercially by the company (Rio Tinto, 2021).

Given the relatively high level of indigenous biomass available in Asia from forestry and agricultural waste (*see* Section 3.2), cofiring with biomass and waste fuels could be an attractive option, particularly in China, Vietnam and Indonesia.

Carbon capture, utilisation and storage

CCUS retrofitted to existing BF-BOF plants avoids the capital cost of replacing the existing plant. A key challenge is capturing CO_2 from a series of multiple processes, such as the sinter plant, the coke batteries, the blast furnace, the BOF, and an onsite power generator. Flue gases can be treated individually at each point source before being combined for transport. Alternatively, the CO_2 can be processed centrally onsite. The drawback of adding capture facilities for each process is the requirement for land adjacent to the capture point and the provision of electricity and solvent supplies for separate units. A centralised facility would require large ducts to be installed across the entire site to collect flue gases for transport to the capture unit facility. There is little experience of CCUS in steel plants and so taking the technology forward carries some risk; it may be more cost-effective to select the most carbon-intensive processes (Worldsteel, 2019b). The cost of capturing CO_2 from steel furnaces will be site specific but could fall within the range of 65–70 $/t$CO_2$, potentially falling to 55 $/t$CO_2$ over time (Amelang, 2019). CCUS is likely to be used in combination with BF-BOF related technologies as outlined below.

Oxyfuel top gas recycled blast furnace (TGRBF) with CCUS

One of the most promising technologies for retrofitting older iron and steel plants is oxyfuel top gas recycled blast furnace (TGRBF) with CCUS. This process can mitigate up to 65% of the process CO_2 emissions. TGRBF replaces some of the coke in the BF with gaseous by-products created during the BF process. The main benefits include lowering the throughput of coke by up to 35%, thus reducing CO_2 and energy costs while extending the life of the coke ovens through less wear and maintenance. However, by-products that were formerly fed to the onsite power generator need to be replaced by natural gas procured externally or more power is required from the grid. The addition of oxyfuel technology mirrors that of oxyfuel combustion cycles used with CCUS. Pure oxygen eliminates nitrogen from the process and leads to an exit stream of more concentrated CO_2 that is better suited to capture (McQueen and others, 2019).

DRI using hydrogen reductants

Hydrogen already plays a role as a reducing agent in conventional DRI steel plants. The conventional process starts with natural gas as a source, which is converted to a syngas of hydrogen and carbon monoxide, which acts as the reducing agent for iron ore. Existing DRI facilities could be converted to operate on lower concentrations of natural gas and higher amounts of hydrogen. Some of the most advanced technologies aim to eliminate fossil fuel use in iron and steelmaking to decarbonise the entire process of manufacturing crude steel effectively. It should be noted that using hydrogen as a fuel in steelmaking would require a near complete overhaul of the steel production process. Hence, hydrogen based steel production processes will generally be more economic for regions where new facilities are to be built (McKinsey, 2018).

Hisarna Technology

TATA Steel is developing the Hisarna DRI process in the Netherlands under the Ultra-low CO_2 Steelmaking (ULCOS) initiative (TATA Steel, 2020). Typically, the DRI process requires passing natural gas through iron ore pellets at temperatures below the melting point of the ore to produce sponge iron. However, the Hisarna process melts iron ore using pure oxygen to combine with the resident carbon monoxide in the reactor to sustain temperatures at 1200°C. The process eliminates the stages of iron ore processing (sintering) and coke production and could reduce CO_2 emissions by 20%. The high concentration of CO_2 is also suited to CCUS, which could reduce emissions from the integrated steel plant by 80%. The pilot-scale Hisarna plant has a capacity of 60,000 t/y. During operations, researchers estimated that the technology would not be industrially available for at least 10–20 years (McQueen and others, 2019). TATA Steel has announced plans for a larger-scale Hisarna pilot facility to be built at the Tata Steel site in Jamshedpur, India.

Finex® Technologies

The Finex® technology was developed as a joint venture between Primetals Technologies (Austria) and POSCO (South Korea). In this process, iron ore fines and limestone flux are blended in a fluidised bed reactor and then fed into a melter-gasifier unit where the iron ore reduces to molten iron with the use of non-coking coal and oxygen as the reductants. The system avoids the need for the sinter and coke plants and replaces the BF stage, avoiding some key energy-intensive stages of the steelmaking process. Another key benefit is the creation of a concentrated stream of CO_2 as a waste gas that is suitable for CCUS (POSCO, 2017; McQueen and others 2019).

BF off-gas to fuels and chemicals

The first commercial plant began operation in 2018 in China, by LanzaTech, Shougang Group and TangMing, producing 30 million litres of ethanol for sale in the first year of operation. The second large-scale plant was constructed in Ghent, Belgium under the Steelanol/Carbalyst project by ArcelorMittal and LanzaTech, completed in 2021 and with a capacity of 80 million litres of ethanol (IEA, 2020c).

Direct electrolysis

Electrolysis reduces the need for coke as a reductant and instead passes a current through a suspension of iron ore in a solution of alkaline electrolytes. Sodium hydroxide can be used with the solution electrolysed at 110°C. Iron precipitates at the cathode while oxygen forms at the anode. Initial test results are not encouraging due to the scale of production at just 5 kg/day iron, although iron purity levels were high at 99.98% (McQueen and others, 2019).

COURSE50

In Japan the CO_2 Ultimate Reduction in Steelmaking Process by Innovative Technology for Cool Earth 50 (COURSE50) aims to reduce CO_2 emissions from blast furnaces by replacing part of the coke with hydrogen and using CCUS. The technology is positioned as an example of innovative technology development under the initiative 'Cool Earth 50' on global warming announced in May 2007, and R&D has been conducted as a NEDO commissioned project since 2008. After five years of development, the project has been developing practical applications since 2018 (COURSE50, 2021) and aims to have a commercial system ready by 2030 (IEA, 2020c).

Salcos

The Salzgitter Low CO_2 Steelmaking (SALCOS) project in Germany uses a 2.2 MW demonstration scale proton exchange membrane (PEM) to produce hydrogen to feed into a DRI system that produces sponge iron (Salzgitter, 2020; Forster, 2020). Other areas of SALCOS research aim to introduce low emissions hydrogen from water electrolysis using renewable electricity, and an economic feasibility study of adapting steelworks to the SALCOS. The plan is to mix the sponge iron with scrap steel at the EAF stage, which would be powered using renewable energy sources. Theoretically, this could eliminate fossil fuels from the steelmaking process, but it is unlikely to be deployed before 2035. Implementation would double the cost of producing steel compared with BF-BOF (Baruya, 2020).

HYBRIT

A Swedish consortium, SSAB, comprising Vattenfall and LKAB, has developed a hydrogen-based system that could also eliminate coal as a feedstock called Hydrogen Breakthrough Ironmaking Technology or HYBRIT (Åhman and others, 2018). The SSAB pathway started in 2016-17 with a pre-feasibility study. Construction of a pilot-scale hydrogen plant commenced in 2018 to test DRI with hydrogen and produced the first fossil fuel free steel in August 2021 (Loughran, 2021).

The commercial-scale rollout of HYBRIT will depend on the cost and method of hydrogen production. In Asia, reformed natural gas or coal gasification may be the most affordable source of low emissions hydrogen while the preferred route in regions such as Europe may be the electrolysis of water using renewable energy to produce low carbon hydrogen. To ensure that the electricity used is fully renewable, such projects would need sufficient hydrogen storage capacity to balance the hydrogen demand for the DRI process. Otherwise, the grid electricity used would have the carbon intensity of the local electricity generating mix, typically fossil fuel dominated in regions of high steel production such as China.

Trials are underway to combine the use of biomass pellets as a heat raising fuel with the HYBRIT system, and construction of a test facility started in 2019. In 2021, an onsite hydrogen storage facility will start construction near the hydrogen DRI test facility in Luleå, Sweden and is expected to operate from 2022-24 (SSAB, 2020).

Electrolysis

Another approach to iron ore reduction is electrolysis, a method already used to reduce aluminium ore (bauxite) to metallic aluminium. The process involves dissolving iron ore in a mixture of calcium oxide, aluminium oxide, and magnesium oxide at temperatures of 1600°C, and an electric current is then passed through the solution. This technology is still at the pilot scale. Part of the pathway to decarbonise the steel sector will again involve partially replacing coking coal with hydrogen in BF-BOF plants within blast furnaces. The hydrogen-based methods of steel production are a promising replacement for BF-BOF without requiring extensive replacement of blast furnaces, but the process will increase the cost of steel by 20–30% from 400 \$/t of crude steel to 480–520 \$/t. The cost of electricity is critical to the economic viability of the hydrogen process compared with the cost of CCUS. The desired cost range is 25–40 \$/MWh depending on whether the project is a brownfield or greenfield project (Amelang, 2019; Baruya, 2020).

Technology summary

The overall potential impact of the technologies on achieving NZE targets is shown in Figure 23. This shows the TRL of a technology against the expected date of commercial availability, with the size of the bubble reflecting, at a qualitative level, the impact of the technology on achieving NZE (IEA, 2020c; Draxler and others, 2021). As noted earlier, secondary steel production from scrap steel will increase, requiring the increased use of DRI based on low emissions hydrogen, which can be produced by water electrolysis, natural gas reforming with CCUS, or in the case of China, from coal gasification with CCUS. A range of technologies based on CCUS, including HIsarna, Top Gas, COURSE50 and Finex®, will become commercially available in the 2025-35 timescale and could be deployed in Asia to significantly decarbonise steel production whilst continuing to use coal.

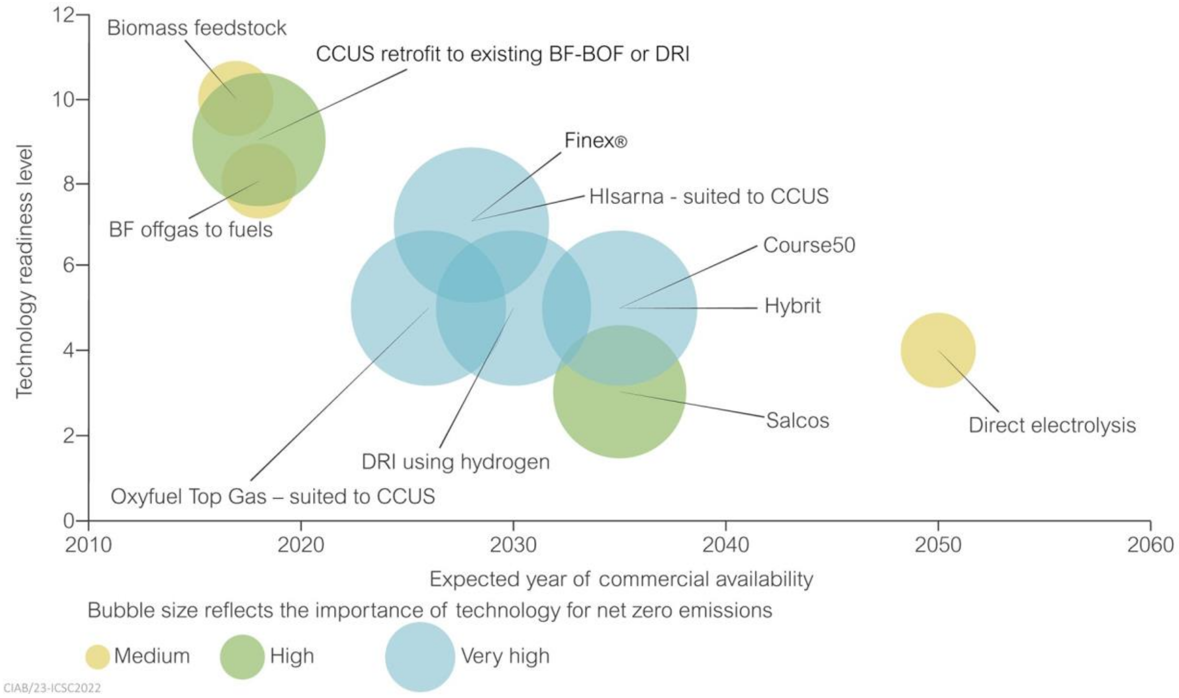


Figure 23 Technology readiness level as a function of time for range of potential CO_2 reduction technologies (author based on IEA, 2020c; Draxler and others, 2021)

6.4 CEMENT

Concrete is the single most widely used material in the world and it has a carbon footprint to match. About 80% of cement is used as a binder in concrete, which is a mixture of sand and gravel, cement and water and is a key building material. Cement is typically composed of several materials, dominated by around 65% cement clinker together with around 30% supplementary cementitious materials (SCMs) (Fennell and others, 2021; GCCSI, 2020). The cement manufacture process is relatively efficient in terms of CO_2 emissions. A typical cement plant uses around 3.3–3.5 GJ/t of clinker (a mixture of calcium silicates) produced, compared with a thermodynamic minimum energy of 2.8 GJ/t (IEA, 2018). This compares favourably with the energy demand of manufacturing steel, aluminium and chemicals. However, due to the large volume of cement produced at around 4.1 Gt/y, CO_2 emissions are high at 3 GtCO_2/y, around 7% of global CO_2 emissions (Statista, 2021b).

Cement production is expected to increase by perhaps 25% by 2050, and most of the new production will occur in developing regions, including India and Southeast Asia. This is because the cement trade is highly localised with limited international movement. As a bulky, relatively low value commodity, it is typically uneconomic to transport cement for more than around 250 km from the site of production to the point of use.

The main feed constituent of cement is limestone (calcium carbonate, $CaCO_3$), which is first ground together with other minor constituents. It is then calcinated which involves heating the ground limestone to temperatures of more than 1600°C in a kiln so that the calcium carbonate in the limestone turns into calcium oxide (CaO) and CO_2. This process produces around 55–65% of the CO_2 emissions from cement production (*see* Table 6). The substance that results from the kiln firing process, known as clinker, is ground and sometimes blended with other minerals to form cement. CO_2 emissions are therefore inherent to the calcination process, making CCUS one of the limited options to abate these emissions.

TABLE 6 SOURCES OF CO_2 EMISSIONS FROM THE CEMENT MANUFACTURE PROCESS (TYRER, 2021)

Process step	CO_2 emissions,%	Comment
Calcination	55	Determined from the composition of the clinker
Fuel for process heat	38	Coal, petcoke, waste-derived fuels
Primary electricity	7	All site electricity including grinding, blending and conveyors

The cement sector is therefore one of the most challenging to decarbonise as traditional cement manufacture using clinker emits high levels of process emissions and requires substantial amounts of heat. Fossil fuels are the main source of heat, particularly coal in the Asian context (*see* Figure 21 on page 80). No alternative production technologies exist that combine technological maturity and economic cost-competitiveness, while ensuring similar output quality as traditional cement making, as of 2020 (Nilson and others, 2020).

However, there are some potential technical options to decarbonise cement manufacture (*see* Figure 24), including:

- Improving energy efficiency by deploying existing state-of-the-art technologies in new cement plants and retrofitting existing facilities to improve energy performance levels when economically viable.
- Switching to alternative lower carbon intensity fuels such as biomass and waste materials in cement kilns. Wastes include biogenic and non-biogenic waste sources, which would otherwise be sent to a landfill site or burnt in incinerators.
- Reducing the clinker/cement ratio by increasing the use of blended materials and the market deployment of blended cements, to decrease the amount of clinker required per tonne of cement or cubic metre of concrete produced. Some of these substitutes are in wide use, with fly ash and slag routinely mixed with clinker in current processes. In some regions, regulations limit or prevent the use of alternative cement rather than conventional Portland cement.
- Using emerging and innovative technologies that contribute to the decarbonisation of electricity generation by adopting excess heat recovery technologies to generate electricity from recovered thermal energy, which would otherwise be wasted, and support the adoption of renewable-based power generation technologies, such as solar thermal power.
- Integrate CCUS into the cement manufacturing process for long-lasting storage or sequestration.
- Capturing CO_2 in concrete that is produced from cement represents an innovative method of carbon capture and utilisation (CCU). In this process, the CO_2 gas from clinker production is captured in concrete while the concrete is setting. As an example, a joint venture between Korea Advanced Institute of Technology and Aramco CCU is developing a process to lock CO_2 into concrete using calcium metasilicate (Seo and others, 2018).

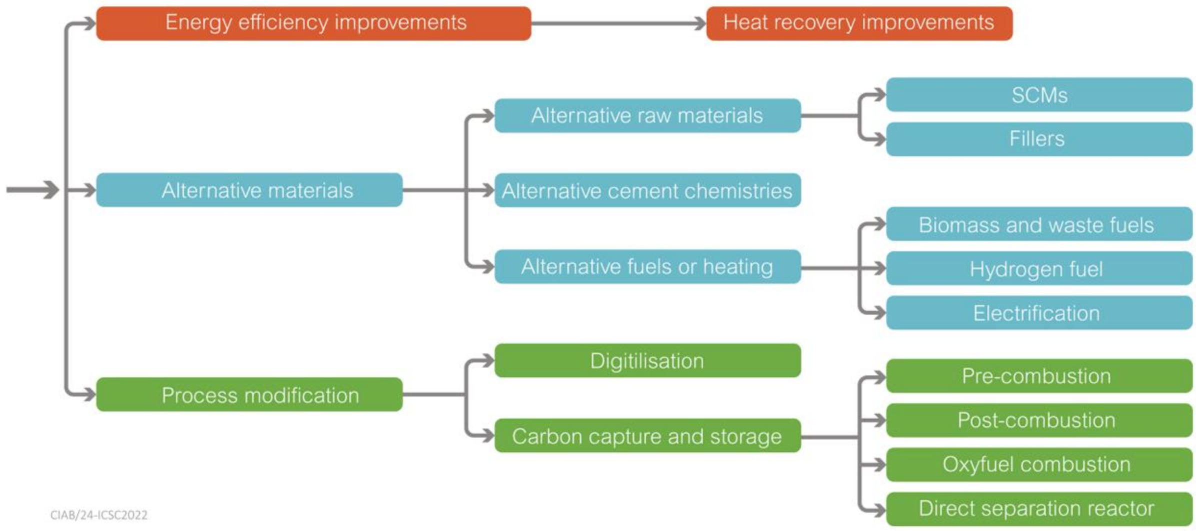


Figure 24 Decarbonisation options in cement production (Fennell and others, 2021)

Analysis by the IEA (2018) has indicated that the integration of CCUS and reduced clinker content in cement through the increased use of SCMs can have the largest impact on CO_2 emissions reduction, contributing 48% and 37% respectively to move from the reference scenario to the 2°C scenario. Achieving NZE by 2050 is likely to require an even greater share of CCUS technologies. Further analysis by the New Climate Institute looking at the EU's cement sector roadmap shows that even with a CO_2 reduction strategy based on reduced clinker content, CCUS is still needed to achieve NZE (Nilson and others, 2020).

Additional demand side options to reduce the quantities of cement can also be followed, although this will not in itself achieve NZE. These measures include:

- design buildings to have a longer service life;
- increase the proportion of old building stock that is refurbished rather than replaced; and
- optimise building design to use less cement in concrete to better match the strength required.

6.4.1 Cement production in Asia

Asia dominates the production of cement, producing around 70% of the global total in 2020 (*see* Table 7) (Statista, 2021b). China is the largest producer by far at 2200 Mt/y cement in 2020, with India second largest at 340 Mt/y followed by Vietnam at 96 Mt/y. All of the Asian countries studied are in the top 10 of global cement producing countries, driven by the local demand for cement to fuel increasing urbanisation. The lack of international trade and hence competition in the cement industry means that there is an opportunity for regional cooperation through knowledge sharing to implement CO_2 reduction measures, which would have minimal impact on individual company financial performance.

The high availability of blending agents including blast-furnace slag from the region's iron and steel industries (*see* Section 6.3), pulverised fuel ash (PFA) from coal-based power generation and agricultural wastes such as rice hulk ash are all beneficial in terms of reducing clinker content in cement and therefore reducing CO_2 emissions. In China, as the level of clinker in cement is already relatively low at 0.58 compared with a global average of 0.65, there may be a preference for CCUS as the primary means of achieving NZE in this region (IEA, 2018). In the case of blast-furnace slag and PFA, these are the by-products of CO_2 intensive iron and steel and power generation sectors, but as the material is available, the marginal impact on reduced clinker production is still positive in terms of overall CO_2 emissions.

TABLE 7 CEMENT PRODUCTION IN ASIAN CASE STUDY COUNTRIES (STATISTA, 2021B)

Country	Global rank	Cement, Mt/y (2020)	Cement, Mt/y (2019)	Share of global market % (2020)	Share of global market, % (2019)
China	1	2200	2300	56.1	53.7
India	2	340	340	8.3	8.3
Vietnam	3	96	97	2.3	2.4
Indonesia	5	73	70	1.8	1.7
Japan	10	53	53	1.3	1.3
Global total		4100	4100		

6.4.2 CCUS-related technology options to decarbonise cement

In general technology roadmaps for several leading cement manufacturers point to the need for CCUS technology, particularly in the 2030-50 timeframe (Heidelberg Cement, 2020; Balch, 2021). Examples of technologies under development for CCUS are highlighted below.

Lehigh Cement with CCUS study

Lehigh Cement, International CCS Knowledge Centre and Mitsubishi Heavy Industries America, part of the MHI group, are carrying out a CCUS feasibility study for Lehigh Cement's plant in Edmonton, Alberta, Canada. The study will assess the viability of 90–95% CO_2 capture, equating to around 0.6 $MtCO_2$/y from the cement plant's flue gas (MHI, 2021a). It will use the amine-based post-combustion capture knowledge gained through the design, construction, operation, and subsequent enhancements/modifications of SaskPower Boundary Dam 3 CCUS Facility (*see* Section 4.4.1), together with the Shand CCS Feasibility Study (Int CCS KC, 2018).

Due to the similarities in flue gas composition, the expertise acquired at the Boundary Dam facility will be adapted to the cement sector in the study. The Lehigh CCS feasibility study will consider an engineering design that tailors the KM CDR Process owned by MHI, for integration with Lehigh's plant and output specifications, such as a flue gas pre-treatment system and the carbon capture and compression process. The Lehigh CCS feasibility study will explore the value of CCUS for the cement industry, by encompassing engineering designs, cost estimation and an in-depth business case analysis.

Norcem CCUS project

Norcem, a subsidiary of Heidelberg Cement, has assessed solutions to capture 0.4 $MtCO_2$/y from its cement plant in Brevik (Petroleum and Energy, 2016). Norcem aspires to achieve zero CO_2 emissions from its concrete products from a lifecycle perspective by 2030 through a combination of CCUS and fuel switching to biofuels. Norcem has found that amine based post-combustion capture is the most suitable technology and has chosen Aker Solutions as its technology provider. Aker Solutions has conducted more than 8000 hours of testing on Norcem's flue gas with its mobile test unit, and the technology was thus considered sufficiently qualified by Norcem to remove CO_2 from Norcem's flue gas. A key part of the development has been the optimal use of residual heat from the cement production process for use in the CCUS plant. This available heat was a main factor in sizing the facility at 0.4 $MtCO_2/y$, corresponding to around 50% of the cement plant's total CO_2 emissions. The CCUS facility is targeted to be operational by 2024, with the technology potentially applicable to cement plants globally, including the Asian target countries.

Heidelberg Cement has also been developing an oxyfuel based cement kiln. Oxyfuel based systems could increase the CO_2 concentration in the flue gas to over 70%, making downstream CO_2 capture more energy efficient, significantly reduce the flue gas volume to be treated and hence reduce capital costs (GCCSI, 2020).

Project LEILAC – (Low emissions intensity lime and cement)

Calix, an Australia based company is trialling its calcination reactor technology in the LEILAC project. This will achieve a fourfold scale up of its earlier pilot plant testing. In conventional rotary kilns for cement and lime manufacture, combustion air is used to burn fuels at very high temperatures. The nitrogen left over from this process mixes with the CO_2 produced through calcination. Nitrogen lowers the purity of CO_2, increasing the energy and cost involved in carbon capture. Calix's technology separates the CO_2 produced through calcination from the heat source by using a separate fired heater or electrical heating source. CO_2 produced from the calcination process is therefore kept separate from any air or nitrogen from the combustion used to provide process heat. As a result, the inherent process-related CO_2 from the Calix calciner is dry, capture-ready and close to 100% concentration.

To achieve full decarbonisation, this approach would require the Calix reactor to be heated using low emission electricity, fired with biofuels or low emissions hydrogen to provide low emissions heat. An advantage of the system is that the Calix calciner could be retrofitted into conventional cement plant making a potential technology to contribute to the decarbonisation of Asia's existing cement plant fleet (GCCSI, 2020).

6.5 ALUMINIUM

Aluminium is sometimes referred to as the 'green metal', due to its high specific strength, corrosion resistance and recyclability. Almost 80% of scrap aluminium is reused without loss of quality, making it one of the most recycled metals. Recycled aluminium constitutes around 33% of aluminium demand currently and its production uses around 5% of the energy needed for primary aluminium production. Replacing primary aluminium with recycled aluminium will therefore be key to reducing overall emissions from the aluminium industry.

The demand for aluminium is anticipated to grow by more than 50% by 2050 to 298 Mt. This increase cannot be achieved by recycled post-consumer scrap aluminium alone. An additional 90 Mt of primary aluminium production will be required by 2050, assuming no change in recycling rates, or 75 Mt with an increased level of perhaps 50–60% recycled aluminium content by 2050. (WEC, 2020). This compares with primary aluminium production of 65.3 Mt/y in 2020 (Int Aluminium, 2021). Several factors contribute to the anticipated growth of the aluminium sector, including:

- global population growth;
- increased urbanisation requiring new construction and expanded transportation;
- growth of the electric vehicle industry where aluminium is an important lightweight material;
- expansion of the electrical grid, especially in developing countries;
- greater use in packaging of consumer goods to replace single-use plastics; and
- construction of renewable (solar, wind, energy storage) power equipment; for example aluminium accounts for more than 85% of most solar PV components.

6.5.1 Production process and CO_2 emissions

Aluminium is the most abundant metal in the earth's crust comprising around 8% content. Due to its high reactivity it is found as stable compounds, typically potassium aluminium sulphate, and aluminium oxide. Of these, bauxite is the most common raw material used to produce aluminium. The top five bauxite producing nations are Australia, Guinea, Jamaica, Brazil and China, while the countries with the largest reserves are Guinea, Australia and Vietnam (US Geological Survey, 2021).

Approximately 70% of global bauxite production is refined to alumina (Al_2O_3) through the Bayer chemical process, which is a wet chemical caustic leach method operated at between 140–280°C and a pressure of approximately 3.5 MPa. Most of the resulting alumina produced from this refining process is then used as the feedstock for the Hall–Héroult electrolytic smelting process, in which the alumina is reduced electrolytically in a molten bath of natural or synthetic cryolite (Na_3AlF_6) operated at 960-980°C. These are the two main CO_2 emitting process steps (*see* Figure 25); relatively few emissions are generated during the post-smelting steps of casting and fabrication. The primary aluminium smelting process has a high energy intensity of 14.3 MWh/t aluminium as a global average, while the value in China is 13.5 MWh/t aluminium. For the alumina refining step, the energy usage, which is mainly process heat, is 10.5 GJ/t alumina as a global average, and 10.3 GJ/t alumina in China (Int Aluminium, 2021).

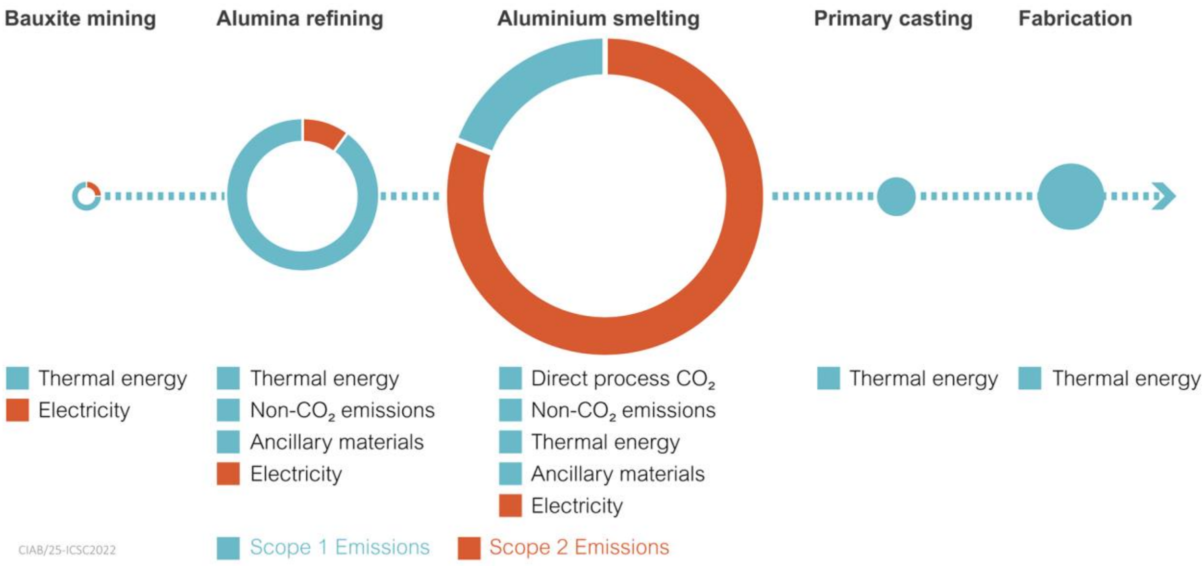


Figure 25 CO_2 emissions in primary aluminium production (WEC, 2020)

The aluminium sector generates around 1.1 $GtCO_2$/y, around 2% of global CO_2 emissions. The aluminium smelting process is responsible for around 77% of the overall CO_2 emissions from the aluminium production chain, of which 64% on a sector wide emissions basis are due to electricity usage. Around one-third of the aluminium industry is reliant on grid power for electricity, while two-thirds use dedicated power sources. It is the dedicated plants, most notably coal-fired power plants in China, that drive emissions across the sector (WEC, 2020).

The second largest source of CO_2 emissions is the direct emissions from aluminium processing which account for a combined 25–30% of sectoral emissions. They are principally caused by the electrolysis of alumina using a carbon anode during smelting, as well as fuel combustion during refining in the Bayer process to produce heat and steam.

Using an inert material in place of carbon in the anodes could eliminate direct emissions from electrolysis and several aluminium producers are working to develop anodes that produce oxygen instead of CO_2 (WEC, 2020). The capital costs of inert anodes are projected to be 10–30% less than carbon-based equivalents. However, this cleaner form of electrolysis is more energy intensive, increasing further the need for low emission sources of power.

Heat and steam, needed to convert the raw material bauxite into alumina in the Bayer process, are primarily generated using fossil fuels. Low emissions electricity generation therefore offers the biggest opportunity to reduce emissions in the sector to near zero by 2050. As aluminium is a traded commodity with relatively narrow profit margins, this low emissions electricity will need to be from a low cost source which will depend on local factors. It could be from solar, wind, hydropower or nuclear sources, or in the case of Asian countries from coal fitted with CCUS, or cofired with low emissions fuels such as ammonia or hydrogen, or carbon neutral fuels including biomass and wastes (*see* Chapter 3 for further details on cofiring).

6.5.2 Alumina and aluminium production in Asia

China dominates both alumina (67.5 Mt, 2020) and primary aluminium (37.3 Mt, 2020) production representing 53.7% and 57.2% of global production respectively (Statista, 2020a; Int Aluminium, 2021), as shown in Table 8. India is the second largest producer of primary aluminium, together with Russia, producing 3.6 Mt in 2020, representing 5.5% of global production. Vietnam does not feature significantly in the list of top alumina or aluminium producing countries, but it does have significant bauxite reserves, estimated to be around 3.7 Gt (US Geological Survey 2021). This suggests that Vietnam could become a major alumina producer in the medium term as the country develops economically.

TABLE 8 ALUMINIUM PRODUCTION IN ASIA (INT ALUMINIUM, 2021)

	Primary aluminium, Mt (2020)	Global share, %	Metallurgical alumina, Mt (2020)	Global share, %
China	37.3	57.2	67.5	53.7
Asia and Africa (excluding China)	5.7	8.8	12.9	9.5
Global total	65.3		125.5	

Coal as a source of electricity for the electrolytic aluminium smelting process and as process heat for the alumina refining process dominates in China, providing around 75% of the combined energy input as shown in Figure 21 on page 80. This is likely to continue in the medium term, requiring CCUS or cofiring with low carbon fuels. There will however be opportunity to switch to renewable energy sources. As an example, China Hongqiao Group, the largest global private aluminium manufacturing company, is relocating around 2 Mt/y of aluminium manufacturing capacity from Shandong in eastern China to Yunnan's Wenshan prefecture in the southwest to allow easier access to cleaner hydropower electricity (Daly, 2021). The Huaneng Multi-Energy project is another example of how increased renewable electricity supported by USC coal power with CCUS can decarbonise power generation (*see* Section 4.4.3).

6.5.3 Technology options to decarbonise aluminium

Additional innovation is needed to develop new technologies, as well as to improve existing ones and to adjust them to suit the unique needs of the aluminium industry. Some potential opportunities for the aluminium industry to collaborate on research, design and development solutions include:

- improved scrap sorting and purification to retain the value of high-quality scrap aluminium;
- the continued development of inert anode technology;
- application of CCUS technologies to refining and smelting to capture process emissions;
- supporting the integration of renewables to meet the vast power demands of the aluminium industry, including storage solutions to manage intermittency; and
- optimisation and efficiency improvements for process technologies to reduce energy consumption.

7 COAL GASIFICATION TO CHEMICALS

7.1 KEY MESSAGES

The chemical industry emits 1.1 $GtCO_2$/y, making it equal third with the aluminium industry, behind the steel and cement sectors. Over 30% of these CO_2 emissions are process-related, meaning they are difficult to reduce.

China is the leading producer of ammonia with 36% of the global 181 Mt/y market and is an important producer of ethylene and methanol. Coal is the primary feedstock for the chemicals industry in China using gasification related technology.

Although much carbon is locked into chemical products, carbon intensity is a prime concern for the coal gasification industry, with methanol production for example taking 2.5 t of coal to make 1 t of methanol.

A portfolio approach to decarbonise the sector will be needed, including 'fuel' switching to low emissions fuels of hydrogen and ammonia, biomass as a carbon neutral fuel, improved energy efficiency, and deployment of current best available and future innovative technologies including CCUS.

The chemical industry emits 1.1 $GtCO_2$/y, making it equal third highest with the aluminium industry, behind the steel and cement sectors, in terms of industrial CO_2 emissions. The Asia-Pacific region, dominated by China, accounts for around two-thirds of these emissions. Over 30% of the CO_2 emissions are process related, so are difficult to reduce. According to the IEA (2020d), CCUS is the most important lever in terms of reducing emissions from the chemical sector. The IEA's Clean Technology Scenario (CTS) estimates that CCUS could make a potential contribution of 38% of CO_2 emissions reduction required through to 2060.

Coal gasification is a very important process involved in the production of chemical fertilisers, energy and many intermediate chemical products. Currently China dominates coal gasification and is a global leader in terms of chemicals manufacture. It is the leading producer of ammonia with 36% of the global 181 Mt/y market and an important producer of ethylene and methanol. Coal is the primary feedstock for the chemicals industry in China using gasification related technology. This versatile technology is also important to produce liquid fuel products using coal to liquid processes and synthetic natural gas (SNG). The first section of the report therefore focuses on coal gasification.

7.2 COAL GASIFICATION PROCESS

There are three main coal gasification routes to produce chemicals and fuels (Reid, 2021):

- using a methanol intermediate and applying the methanol to olefins (MTO) technology to make polymers;

- using syngas based Fischer-Tropsch technology; and
- direct coal liquefaction to produce fuels.

The technology underpinning coal gasification is mature although there are developments to improve the efficiency and operation of syngas generation with a gradual shift away from established designs. Figure 26 shows two designs in use currently, namely the General Electric/Texaco single burner slurry gasifier used in over 70 installations particularly in early plants, and the Shell dry feed pressurised entrained flow reactor that is now deployed by Air Products and intended for a recently announced Indonesian project (Jasi, 2020). Other reactor designs include Siemens dry entrained flow reactor, the Sasol Lurgi reactor deployed in South Africa, U gasifier from Synthesis Energy, and more significantly the HT-L single burner, entrained flow reactor, designed in China, which competes in China's pulverised coal gasification sector (Reid, 2021; Minchener, 2019).

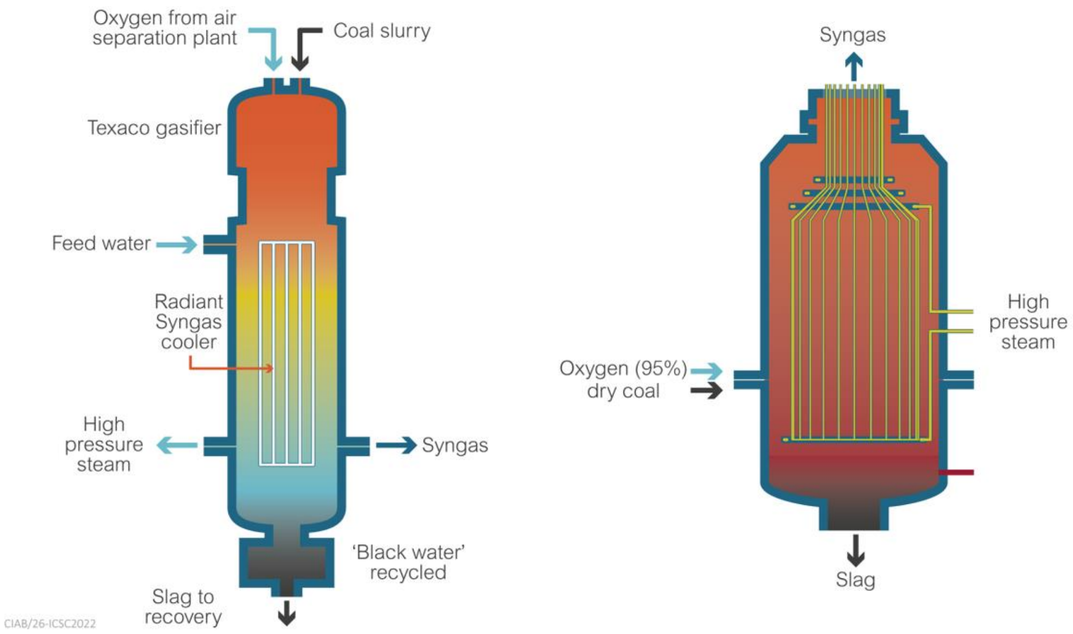


Figure 26 GE's coal slurry gasifier (left) and Shell's dry pressurised entrained flow reactor (right) (adapted by author)

As part of the Chinese National Energy Administration's priority of energy security, China is seeking to reduce the import of raw materials. Coal chemicals will therefore compete directly with natural gas and oil derived chemicals. The relatively low price of indigenous coal compared with imported gas and oil is a further factor in favour of coal gasification.

Since 2018, a substantial construction programme has been underway to expand and build new coal chemical facilities that will maintain or even increase the share of chemicals production from coal. Although much carbon is locked into chemical products, carbon intensity is a prime concern of the coal gasification industry. It will attract more international scrutiny over the coming years given the large number of coal chemical plants under construction and in development. Typically, it takes 2.5 t of coal to make 1 t of methanol, as much of the carbon is effectively rejected as CO_2, noting also that a modern methanol plant produces around 1 Mt/y of methanol (Chatterjee, 2020). Similarly, for synthesised methane, over half the carbon in the coal is rejected as CO_2, with the production of 1t of SNG requiring about 2.5 t of coal, equivalent to CO_2 emissions approaching 8 t allowing for ash (Reid, 2021).

China dominates coal gasification but new plants for coal-based chemicals and fuels production have been constructed in Africa and Asia, partly associated with the Belt and Road Initiative (Metzger, 2021). Most recently there are plans for a $10 billion investment in coal gasification facilities in India to make chemicals, particularly urea and fuels using Air Products technology (Chatterjee, 2020). The coal to chemicals and fuels sector is expanding at an unprecedented rate, influenced in part by the transition away from coal in many geographic locations in the power sector. This may subdue coal feedstock prices in the medium to long term.

7.2.1 New coal chemicals facilities – gasification and liquefaction

Table 9 summarises Chinese facilities under construction in terms of key products produced. There are 150 plants in the first phase with an additional 220 projects announced and expected to begin construction before the end of 2023.

TABLE 9 CHINA COAL CHEMICAL AND FUEL PLANTS ANNOUNCED IN 2019: PLANNED, UNDER DEVELOPMENT AND UNDER CONSTRUCTION AND COMMISSIONING (ASIACHEM, 2019; AIZHU, 2020)

Product	2019-21	2020-24
	Under construction or commissioning, Mt/y	Planned and under development, Mt/y
Methanol	19.2	32.2
Mono ethylene glycol (MEG)	8.3	17.3
Polyester		9
Methanol/coal to olefins (MTO/CTO)	7.7	13
Polyethylene	1.8	2
Polypropylene	2.9	2.5
Ethanol	0.5	2.1
Formaldehyde	0.4	
Dimethyl ether (DME)	0.9	
Methanol to gasoline (MTG)	0.9	4.8
Acetic acid	1.6	1.2
Coal to liquids (CTL) or gasification by Fischer-Tropsch (FT)	1.2	33
Tar deep processing, coal tar hydrogenation and lignite upgrading	15.8	86.8
Synthetic natural gas (SNG)	6.5	95.2
Ammonia	10.2	6.9
Urea	11.7	7.4

Methanol derived from syngas forms the basis of MTO processes for polymer production. There are plans for 52 Mt capacity requiring gasification of over 125 Mt of coal by 2024, largely sourced from indigenous mines in the region. In effect, 10 Mt of methanol capacity will be added each year with the products directed primarily to olefins and the production of mono-ethylene glycol (MEG) for polyester fibres. Of the olefins produced, a significant proportion will be converted to polyethylene and polypropylene, adding a total of 10 Mt/y of new capacity by 2023 which would double current production (Reid, 2021).

The scale of coal to fuel conversion is also gathering pace with 1 Mt/y of methanol to gasoline (MTG) scheduled for 2021 with a further 5 Mt/y to be added in subsequent years. In total, Fischer Tropsch and coal liquefaction related products are set to increase by 33 Mt/y.

For heavier components, coal hydrogenation and tar processing are scheduled to increase capacity by an additional 100 Mt by 2023. There is growing interest in the use of coal tar for new materials and the addition of these new plants indicates that tar from coking coal plants will be insufficient to meet demand for coal tar pitch.

China's coal chemicals strategy also includes facilities to manufacture polyvinylchloride (PVC), purified terephthalic acid (PTA), polyethylene terephthalate (PET, styrene, aromatics, nitric acid, melamine (made from urea) and propionic acid, among others (Reid, 2021).

By the end of 2019 China had invested $85 billion in coal chemicals and this is set to increase. For example, Hengli has recently announced a $20 billion investment in an operation to convert 20 Mt coal to 9 Mt of polyester via an ethylene glycol intermediary. It includes mining operations and chemical facilities and aims to be operational by 2025 (Aizhu, 2020). Other leading companies in the coal to chemicals sector include the Shenhua Group and Sinopec. There is a list of reference plant for Sinopec in the Appendix, Table A-4.

A Sinopec flagship project is the 1.7 Mt/y coal-based MTO project of Zhong'An United Coal Chemical Company (*see* Figure 27). The project is a joint venture between Sinopec and Anhui's Wanbei Coal-Electricity Group. As the EPC contractor, Sinopec delivered the syngas plant with a capacity of 505,563 m^3/h (as $CO+H_2$) and the methanol plant with a capacity of 1.8 Mt/y, as 100% methanol.

Figure 27 Coal-based 1.7 Mt/y methanol-to-olefins (MTO) project (Sinopec, 2021)

7.3 SYNTHETIC NATURAL GAS AND HYDROGEN

The demand for natural gas in China is rising with the modernisation of domestic heating and cooking methods and the new Russian 'Power of Siberia' pipeline to China supplying imported gas for domestic use. Coal to SNG production capacity will reach 6.5 Mt/y in 2021 but is set to ramp up to perhaps 100 Mt/y before 2024, with a list of some of the earlier coal to liquid and SNG projects in China shown in Table 10.

TABLE 10 A SUMMARY OF MAJOR CTL/SNG RESEARCH AND DEVELOPMENT PROJECTS IN CHINA (XU, 2015)

Coal to liquid/SNG projects	Capacity	Commission date	Location	Gasifier licensor	Synthesis technology licensor
ICC slurry bed reactor pilot test	750–1000 t/y	2000-02	Taiyuan		ICC MFT
Yankuang industrial test plant	4500 t/y	2003-04	Lunan	ECUST-OMB	Yankuang Fe-LTFT
Yitai ICTL Demonstration	160 kt/y	2009-11	Dalu	Texaco	Synfuels China MTFT
Luan ICTL Demonstration	160 kt/y	2009	Tunliu	Lurgi	Synfuels China MTFT
Shenhua ICTL Demonstration	180 kt/y	2009-10	Majiata	Shell	Synfuels China MTFT
Shenhua-Ningmei	4 Mt/y	2016	Yinchuan, Ningxia	Siemens-GSP	Synfuels China MTFT
Shanxi Luan High Sulphur Coal Co-production	1 Mt/y	2015	Changzhi	Lurgi	Synfuels China MTFT
Yankuang Shaanxi Yulin ICTL	1Mt/y	2015	Yulin	ECUST	Yankuang ICTL
Yitai Xinjiang ICTL	2 Mt/y		Xinjiang		Synfuels China MTFT
Yitai Yili ICTL	1 Mt/y		Yili		Synfuels China MTFT

TABLE 10 CONTINUED					
Coal to liquid/SNG projects	**Capacity**	**Commission date**	**Location**	**Gasifier licensor**	**Synthesis technology licensor**
Datang International Power Keqi SNG	4 billion m^3/y	2012	Hexigten	Lurgi	Lurgi
Datang International Power Fuxin SNG	4 billion m^3/y		Fuxin, Liaoning Province		Lurgi
Huineng Coal Power Erdos SNG	1.6 billion m^3/y		Erdos, Inner Mongolia		
Qinghua Yili SNG	1.4 billion m^3/y		Ili, Xinjiang		Haldor Topsoe TREMP™
Sinopec Zhundong SNG Demonstration	30 billion m^3/y		Zhundong, Xinjiang		

The conversion of coal to hydrogen and subsequently to ammonia will mean an additional 10.2 Mt of capacity by 2021 but then a more gradual increase to give a total of perhaps 20 Mt by 2024. Urea is formed from ammonia and CO_2 to be used as fertiliser, and as such offers an outlet for CO_2 captured from the gasification plant as a potential circular economy solution.

A new project aims to recover CO_2 from Shaanxi industrial facilities and manufacture 3.5 Mt/y methane applying Hitachi Zosen methanation technology that uses hydrogen obtained from renewable generation. As CO_2 may be more easily recovered from coal gasification plants than power plants, this could offer an alternative to storage for a portion of the CO_2 (Ng, 2020).

7.4 COAL TO CHEMICALS AND FUELS BEYOND CHINA

Some gasification projects outside China are partly associated with China's Belt and Road Initiative promoting coal technologies to developing nations, as shown in Table 11. More generally the logic of using domestic feedstock rather than importing oil and gas is the driving force for developing these plants.

TABLE 11 COAL CHEMICAL AND FUEL PLANT DEVELOPMENTS OUTSIDE CHINA (REGIUS SYNFUELS, 2020; ARGUS. 2020A,B; NS ENERGY, 2020; JASI, 2020; HARSONO, 2020; RIVERVIEW ENERGY, 2020)

Location	Product	Scale
India	Fuel	100 Mt/y coal to be gasified with an investment of $55 billion over 10 years (Argus, 2020a,b)
Dankuni, Bengal, India	Methanol (hybrid blend with petrol)	0.6 Mt/y (NS Energy, 2020)
East Kalimantan, Indonesia	Methanol	2 Mt/y requiring gasification of 6 Mt/y coal (Jasi, 2020)
Sumatra, Indonesia	DME	$2 billion coal to methanol and DME (Harsono, 2020)

Air Products plans to invest $2 billion in a 2 Mt/y coal to methanol plant (6 Mt/y feedstock) located in East Kalimantan, Indonesia, reducing oil imports and countering an anticipated decline in coal exports from Indonesia. The facility will sell methanol to produce thermosetting polymers derived from formaldehyde (Jasi, 2020), although it should be noted that these projects are still under review (PwC, 2021b). The production cost of DME is currently still around 490 $/t. This amount does not include the cost of carbon capture that is predicted to reach around 20–40 $/t$CO_2$ (Reid, 2021).

Coal India is planning to install a 0.6 Mt/y coal to methanol plant at Dankuni, Bengal. The methanol will form a hybrid blend with petrol (15:85 ratio) as a mixed fuel, which avoids the safety issues associated with 100% methanol. In all, India has earmarked 100 Mt/y of coal specifically for coal gasification to provide fuels, fertiliser, and chemical feedstocks, with a total investment of $55 billion envisaged over the next 10 years to establish a new coal to chemicals sector (Argus, 2020b).

7.5 CHEMICALS FROM COAL TAR DISTILLATES AND PITCH

The broad range of chemicals obtained indirectly from coal tar distillate and pitch includes over 1000 products, many in everyday use. Established tar distillate derivative products have a solid customer base. Some are listed in Table 12, which provides details on each product sector to illustrate the breadth of consumer products involved. It is divided into two sections, the upper part covers distillate derived products and the lower section pitch products (Reid, 2021).

TABLE 12 COAL TAR PRODUCTS AND THEIR USE (ADAPTED FROM REID, 2021)

PRODUCTS FROM TAR DISTILLATES				
Town gas with new interest in hydrogen	Insecticides (creosote)	Carbolic acid (phenol now produced mainly from petroleum)	CO_2 (fire extinguisher, soda water)	Fungicide (lice shampoo)
Mothballs (restricted countries)	Food preservative (tartrazine yellow used in certain countries)	Acetylene (China only, competes with calcium carbide hydrolysis)	Solvents (benzene)	Sulphur
Synthetic rubber from naphtha	Paint pigments	Wood preservative	Perfume fixative	Dispersants
Naphtha derivatives (concrete additives, agrochemicals, and detergents)	Medicine (keratoplastics for skin conditions)	Fibres (artificial silk, rayon, nylon	Shampoo and creams (eczema cream, tar shampoo, anti-dandruff shampoo	
Disinfectants	Baking powder	Ammonia	Varnish	Rubber cement
PRODUCTS FROM TAR PITCH				
Carbon black	Pitch oil	Wash oil	Pitch CF	Batteries (electrodes)
Insulation (carbon foams)	Pitch CF (insulation and structural materials)			

There is also rising demand for some distillate products such as naphtha derivatives in use as concrete additives.

7.6 TECHNOLOGY OPTIONS TO DECARBONISE COAL GASIFICATION

Coal gasification is an important technology in China and increasingly in wider Asia, so options to reduce CO_2 emissions in the chemical sector and particularly in coal gasification to chemicals are vital if NZE targets are to be achieved. The options are broadly as described earlier for the steel, cement and aluminium industrial sectors, based on a portfolio of approaches including:

- 'fuel' switching to low emissions fuels of hydrogen and ammonia, biomass and electricity via electrification for aspects of the gasification process;
- improved energy efficiency; and
- deployment of current best available and future innovative technologies including CCUS.

In the short-term, developing advanced gasification technologies, eliminating reduced production capacity and optimising industrial infrastructure should be the focus to increase the energy efficiency of the coal chemical industry, which could reduce emissions by 120–240 $MtCO_2$/y (Huang and other, 2019). In the medium term, fuel substitution, CCUS and international energy cooperation will become increasingly important. Due to the higher concentration and partial pressure of CO_2 in the syngas stream of the gasifier, pre-capture systems using Selexol and Rectisol™ type technologies are likely to be preferred over post-capture amine based technologies.

Other opportunities more specific to chemicals production include:

- **Ammonia**: The 0.5 $GtCO_2$/y produced by the ammonia sector is typically converted into urea as a common fertiliser. The issue is that CO_2 is released into the atmosphere when the urea is used. To prevent these emissions, urea could be replaced with nitrate-based fertilisers produced from ammonia with no CO_2. Alternatively, the process of producing hydrogen, the first step in the ammonia production process, could use low emissions hydrogen (*see* Section 8.6). Some additional innovative strategies include methane splitting and high-temperature electrolysis, but these methods are still in the research phase (McKinsey, 2018).
- **Ethylene**: The production of ethylene, a base chemical used to make plastics, emits CO_2 when the fuels used to make it are heated during the steam cracking process. Recycling used plastics would not only lower the carbon emissions associated with ethylene production but would lessen the demand for producing virgin ethylene. In addition, plastics manufacturers could use low emissions hydrogen or biomass to heat pyrolysis furnaces (McKinsey, 2018).

8 LOW EMISSIONS PRODUCTION OF HYDROGEN AND SOME OTHER CHEMICALS

8.1 KEY MESSAGES

The total global hydrogen demand in 2018 was around 115 MtH_2/y. This hydrogen was produced local to the point of use, almost entirely from fossil fuels and was used primarily as feedstock in the refinery and chemical industries.

Global demand for hydrogen is forecast to increase to perhaps 78 EJ, or 650 MtH_2/y, representing around 14% of the expected total energy demand in 2050. It would be used primarily for industrial feedstock and energy, together with transportation, heating and power in buildings, and power generation usage of hydrogen including hydrogen buffering.

Hydrogen is seen as a necessary feature of the energy transformation required to achieve a NZE future, where it could play an important role as part of a broader strategy.

- There will be regional variations in future demand for hydrogen, depending on local factors including resource availability, political support, existing gas infrastructure and GHG emission reduction targets.

In general, low carbon hydrogen production from coal gasification with CCUS and natural gas reforming with CCUS are lower cost than low carbon hydrogen based on water electrolysis, typically by a factor of approaching 3.

- In regions of the world with access to relatively low cost renewable electricity, based on high wind or solar incidence, low emissions hydrogen produced using water electrolysis could in time become a competitor with low emissions hydrogen from coal or natural gas. Hydrogen from low cost wind could start to be competitive with the upper range of fossil fuel based hydrogen prices in less than five years, perhaps competing with the lowest cost fossil fuel based technologies by 2035.

The number of reference plants for low emissions hydrogen produced from coal gasification with CCUS is relatively limited. However, there is a long track record of successful operation in fertiliser plant in the USA provided by the Great Plains and Coffeyville plants. The Sinopec Qilu CCUS retrofit to the existing coal gasification plant in China could lead the way to a wider roll-out of low carbon hydrogen technology in Asia.

8.2 CURRENT HYDROGEN DEMAND

Hydrogen has the potential to play a significant role in tackling climate change and address poor air quality. For this reason, after various false starts, there is much interest in hydrogen's potential contribution to a NZE future. The demand for hydrogen increased by around 400% between 1975 and 2018 (IEA, 2019c). Hydrogen production is almost entirely based on fossil fuels (Muradov, 2017), and uses 6% of global natural gas and 2% of global coal. Based on the energy input required to produce the hydrogen, coal accounts for around 27% of hydrogen demand, natural gas accounts for over 70%, while electricity as an energy input for electrolysis, accounts for less than 1% (*see* Figure 28). Fossil fuels still indirectly account for the majority of the electricity used for electrolysis.

In energy terms, the total annual hydrogen demand worldwide is around 330 million tonnes of oil equivalent (Mtoe), equating to 70–73 million tonnes of hydrogen per year (MtH_2/y). The hydrogen is produced in dedicated facilities, primarily local to the point of use. Its main uses are (*see* Figure 28):

- 38 MtH_2/y, or 52% of hydrogen demand for refinery applications; and
- 31 MtH_2/y, or 42% of hydrogen demand as a feedstock for ammonia production.
- Other important uses of pure hydrogen include food and drug production, crystal growth, glass manufacturing, chemical tracing, metal fabrication, polysilicon and semiconductor manufacturing, metal production, and thermal processing (USDOE, 2020). In addition to this dedicated hydrogen demand, there is a further 45–48 MtH_2/y produced as a by-product from other processes (*see* Figure 28). It was used as follows (in 2018):12 MtH_2/y for the manufacture of methanol; 4 MtH_2/y in the manufacture of steel using the DRI process (IIMA, 2018); and 26 MtH_2/y for other applications such as synthesis gas for fuel or feedstock and process heating.

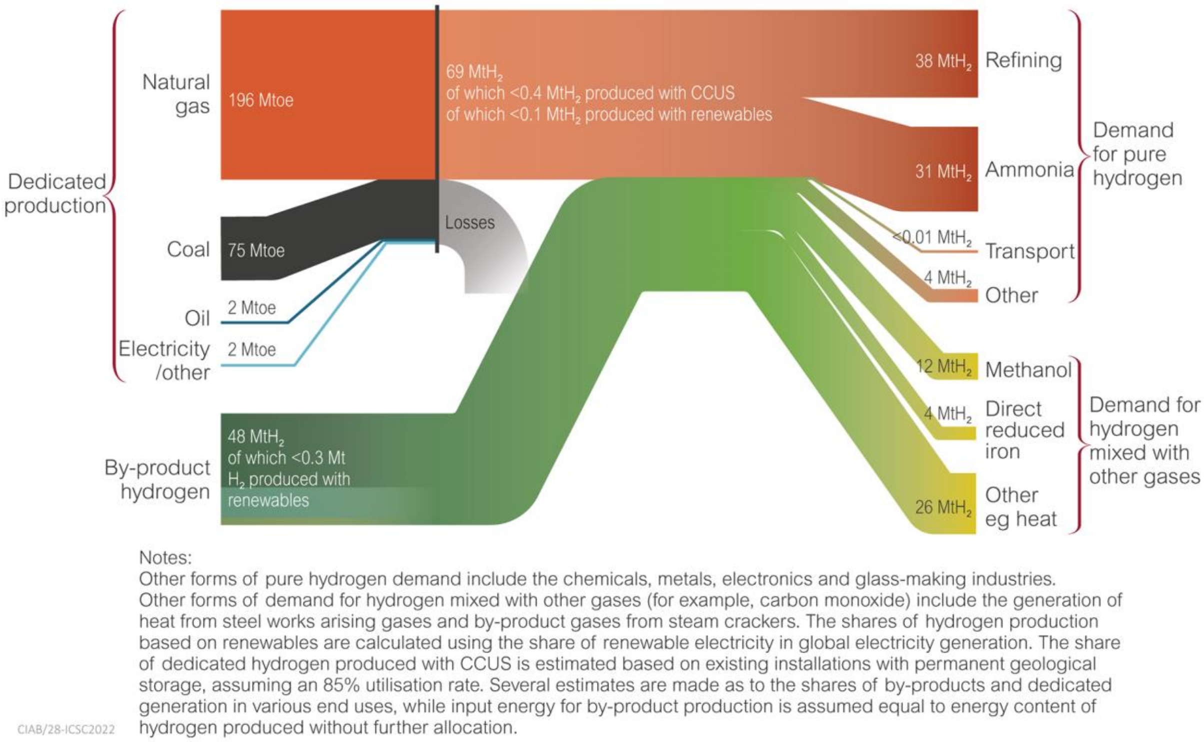


Figure 28 Sankey diagram showing hydrogen value chains in 2018 (IEA, 2019c)

8.3 FUTURE HYDROGEN DEMAND

Several forecasts have been made of potential future hydrogen demand (Hydrogen Council, 2017b; IEA, 2019c; IRENA, 2019; DNV GL, 2018; FCH JU, 2019). The forecasts vary significantly (De Blasio and Pflugmann, 2020) and a selection are presented in Table 13. The Hydrogen Council study estimates global demand at approximately 650 MtH_2/y in 2050, representing around 14% of the expected world total energy demand at that time. Studies by DNV GL are more conservative, with estimates of between 180–275 MtH_2/y in 2050, or 28–42% of the Hydrogen Council estimate. These compare with the current demand for hydrogen of 115 MtH_2/y, corresponding to a potential five- to six-fold increase based on the highest forecast.

Analysis by IRENA shows that hydrogen demand could be 158 MtH_2/y in 2050. It should be noted that for this case, the hydrogen is classed as low carbon hydrogen, produced by electrolysis of water using renewable electricity, representing around 8% of the electrification share of final energy consumption in 2050.

In terms of financial value, the hydrogen market is expected to grow to around $200 billion by 2030 from the current $136 billion in 2019, at a 4.3% compound annual growth rate (CAGR) between 2020 and 2030.

TABLE 13 FUTURE DEMAND FOR HYDROGEN IN 2050 RELATIVE TO 2018 LEVELS (AUTHOR BASED ON DATA FROM IEA, 2019C; IRENA, 2019B; DNV GL, 2018; HYDROGEN COUNCIL, 2017B)

Forecast hydrogen demand	Base case				
	2018*	2050†	2050‡	2050§	2050¶
MtH_2/y	115	158	179	275	650
Mtoe	330	454	513	788	1863
TWh	3833	5278	5967	9167	21667
EJ	13.8	19	21.5	33	78

Note: EJ to MtH_2/y conversion based on Hydrogen LHV of 120 MJ/kg

* IEA, 2019c; † IRENA, 2019b; ‡ DNV GL, 2018 (reference uptake);
§ DNV GL, 2018 (high uptake) ¶ Hydrogen Council, 2017b

In all these assessments, hydrogen is seen as a necessary feature of the energy transformation required to achieve a NZE future.

The breakdown of the forecast use of hydrogen in 2050 is shown in Figure 29. Hydrogen would be used primarily for industrial feedstock and energy, together with transportation, heating and power in buildings, and power generation including hydrogen buffering (Staffell and others, 2019). The spread of hydrogen usage across these sectors is reasonably uniform, with significant quantities of hydrogen used in each. A full analysis of the use of hydrogen in these sectors is available in an ICSC report (Kelsall, 2021).

Analysis by the USDOE (2020) has shown similar strong potential for hydrogen use across a range of sectors. In terms of market share, hydrogen use for industrial feedstocks will continue to be a key sector, providing almost 100% of the feedstock for ammonia and methanol and 80% of refinery feedstock.

There will be regional variations in this future demand for hydrogen, depending on local factors including resource availability, political support, existing gas infrastructure and GHG emission reduction targets. In terms of locations, the IEA (2019c) recommends turning existing industrial ports into hubs for lower cost, lower carbon hydrogen, with areas around the North Sea coastline of Europe, the Gulf Coast of North America and the south eastern coast of China set to become important centres. This hub and cluster approach is covered in Section 2.3.5.

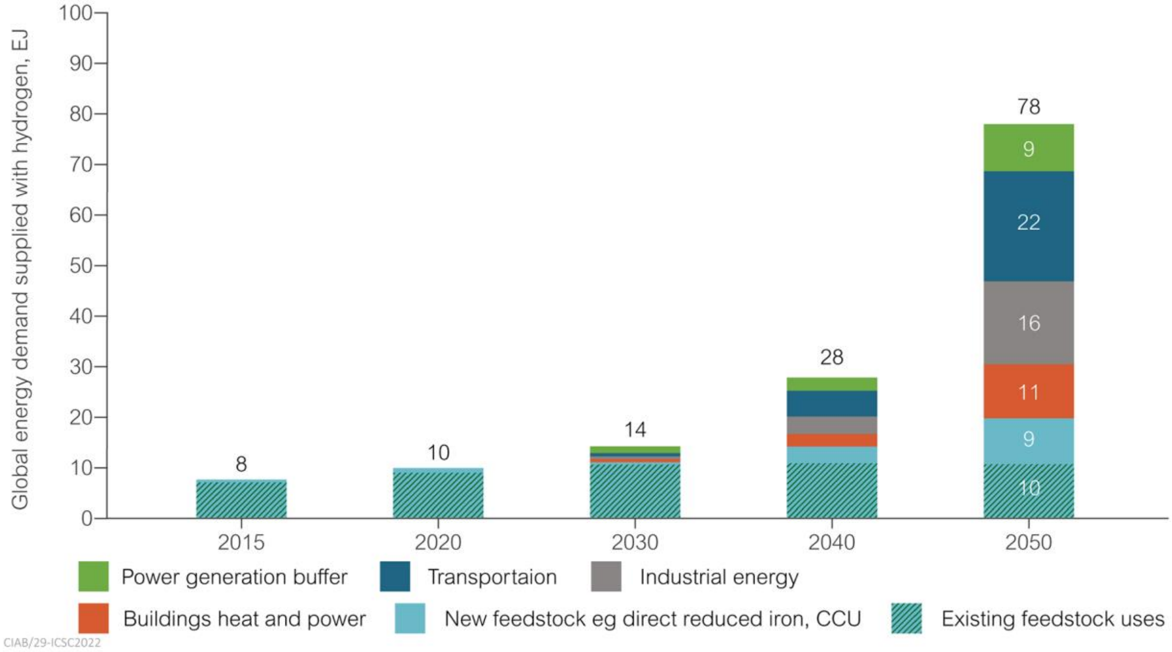


Figure 29 Forecast increase in global hydrogen demand (EJ) through to 2050 (Hydrogen Council, 2017b)

Asia represents the fastest growing market for hydrogen use and it is expected to witness the fastest industry growth in the near future. Hydrogen consumption is rising in the region due to economic growth and expansion of the chemical, refining, metal processing, petrochemical and electronics sectors.

8.4 HYDROGEN PRODUCTION

There are three main routes available for hydrogen production depending on the fuel feedstock:

- reforming of natural gas, primarily steam methane reforming (SMR);
- gasification of coal; and
- electrolysis of water.

These primary hydrogen production methods can be expanded to include the following (Muradov, 2017):

- partial oxidation and autothermal reforming;
- refinery and chemical plant off-gases (including chlor-alkali process); and
- other minor sources such as plasma pyrolysis, residual oil and biomass gasification.

Electrolysis is inherently low in GHG emissions, provided that the source of electricity is renewable, whereas fossil fuel sourced hydrogen requires the addition of CCUS to reduce GHG emissions. The USDOE has identified additional fuel feedstocks which can be used instead of, or in combination with, fossil fuels to reduce GHG emissions, potentially producing negative GHG emissions when CCUS technology is utilised (USDOE, 2020):

- producing hydrogen from diverse resources, including coal, biomass, natural gas, petroleum, petroleum products, waste plastics and other recyclable materials with CCUS; and
- cogasification of blends of coal, biomass, waste plastics, and other recyclable materials with CCUS which can result in hydrogen produced with net negative GHG emissions and other environmental benefits when CCUS is integrated with the gasifier.

An overview of the main hydrogen production processes is provided by Zapantis and Zhang, 2020; Olabi and others, 2020; and Muradov, 2017. Here, only the coal gasification production route is discussed.

8.4.1 Coal gasification

Various coal gasification commercial concepts have been described previously by the ICSC (Minchener, 2019). In gasification, a hydrocarbon-rich feedstock such as coal is heated at high temperatures to produce a syngas rich in hydrogen, which also contains carbon monoxide (CO) and CO_2. The syngas can then be upgraded by converting the CO to CO_2 and more hydrogen using the water-gas shift (WGS) reaction and then separating the hydrogen (Committee on Climate Change, CCC, 2018). This allows the carbon to be separated and sequestered, which means that coal gasification can be a low carbon, hydrogen production technology. The process can produce a stream of hydrogen of around 99.8 % purity, similar to that from SMR.

Hydrogen production from coal using gasification is a well-established technology, used for many decades by the chemical and fertiliser industries to produce ammonia, particularly in China. Globally around 130 coal gasification plants are in operation, more than 80% of which are in China (IEA, 2019c). In terms of gasification with carbon capture, there are currently three facilities producing hydrogen from coal, coke or asphaltene with a combined capacity of around 0.6 MtH_2/y (GCCSI, 2020) (shown in Section 8.8). These facilities demonstrate that large-scale production of low emissions hydrogen using carbon capture can already be technically and commercially feasible.

There are some challenges to using coal gasification combined with CCUS. Primarily, this is because coal produces hydrogen with a relatively low hydrogen/carbon ratio of around 0.1:1 from coal compared with 4:1 for SMR using natural gas as fuel, together with the higher level of impurities in the feedstock such as sulphur, nitrogen containing compounds and minerals (Muradov, 2017). As noted, the existing commercial applications of coal gasification, both with and without CCUS, mean that there are technical solutions available.

Figure 30 is an example of the coal gasification process including carbon capture, which is achieved using acid gas removal. This can be an integral part of the coal gasification process using relatively mature physical absorption technologies such as Selexol and Rectisol™ (Zapantis and Zhang, 2020). CO_2 capture option C1 requires an additional process of CO_2 compression and dehydration. Since a large proportion of CO_2 is separated via acid gas removal, the amount of CO_2 entering the additional CO_2 capture (option C2) is relatively small. The same process would be applicable to petroleum coke and biomass gasification.

Further examples of coal gasification concepts are available in the literature, for example the ash agglomerating fluidised bed gasification cycle (Li and others, 2019) and coal direct chemical looping (Li and others, 2020).

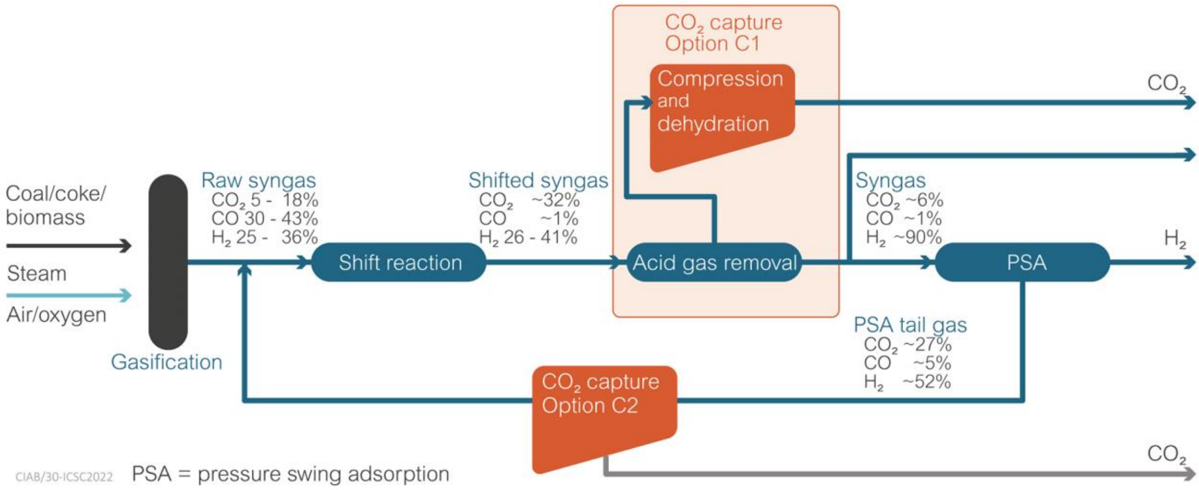


Figure 30 Hydrogen/syngas production using coal gasification with CCUS (Zapantis and Zhang, 2020)

The CO_2 capture and emissions information during coal gasification with CO_2 capture options C1/C2 are compared with coal gasification without CO_2 capture in Table 14.

TABLE 14 COMPARISON OF COAL GASIFICATION CCUS OPTIONS (ZAPANTIS AND ZHANG, 2020)

	Base case	CCUS, option C1	CCUS option C2
Case	Gasification without CO_2 capture	Gasification with CO_2 capture on syngas stream	Gasification with additional CO_2 capture after acid gas removal
CO_2 concentration at capture inlet, %	n/a	25–42	5–6
Pressure at capture inlet, MPa	n/a	3.5–5.7	5.3
CO_2 capture efficiency, %	n/a	90–95	90
Proportion of CO_2 captured, %	0	90	98
CO_2 emissions during syngas/ hydrogen production, kg/kg	19–25	2.1–2.7	0.4–0.6
CO_2 emissions including life cycle emissions from electricity, %	20–26	4.7–5.3	3–3.2
n/a = not applicable			

The performance of individual CO_2 capture technologies and methods for integrating them differ in terms of CO_2 removal rate as well as hydrogen and CO_2 purity levels. Hydrogen purity requirements largely depend on the end use application. While most fuel cells require high purity levels, lower levels are sufficient for gas turbines, refinery processes and industrial boilers. Few technologies exist that produce both high purity hydrogen and CO_2 that is pure enough for other uses or storage, since gas separation technologies focus on either hydrogen removal or CO_2 removal. The optimal combination of hydrogen production route and capture technology therefore depends on what the hydrogen is going to be used for, as well as on the production costs (IEA, 2019c).

8.5 COSTS OF HYDROGEN PRODUCTION

Many analyses have been carried out to assess the costs of hydrogen production (IEA, 2019c; IRENA, 2019a; CCC, 2018; Hydrogen Council, 2017a, 2020; Bruce and others, 2018b; USDOE, 2020). Hydrogen costs vary as a function of the production technology used together with the additional factors shown below (De Blasio and Pflugmann, 2020):

- local factors due to the geographic region considered;
- fuel prices;
- renewable electricity price, either wind or solar PV;
- capacity/load factors;
- learning rates for CCUS and water electrolysis systems; and
- carbon tax for residual CO_2 emissions.

The varying assumptions mean that it is difficult to make direct comparisons of the above studies. However, a high-level comparison is made in Table 15 with a further comparison provided in Figure 31. In general, this shows that the low carbon hydrogen-based production routes of coal gasification with CCUS and natural gas SMR with CCUS are lower cost than low carbon hydrogen based on water electrolysis, typically by a factor of approaching 3. This indicates that with a large existing unabated fleet of gas and coal based hydrogen production, the transition to large scale low carbon hydrogen will require significant deployment of CCUS plant.

TABLE 15 COMPARISON OF HYDROGEN PRODUCTION COSTS (ZAPANTIS AND ZHANG, 2020; GCCSI, 2020)

Source of costs	Hydrogen cost from renewable electricity, $	Natural gas SMR with CCUS, $	Coal gasification with CCUS, $
CSIRO (Bruce and others, 2018b)	7.7	1.7–2.1 (85% capacity factor)	1.9–2.4 (85% capacity factor)
IEA, 2019c	2–4 (renewable electricity cost of 40 $/MWh, 4000 h/y operation, best location)	1.5-2.4	1.5–2.0
IRENA, 2019a	2.7–6.8 (lower cost is wind at 48% capacity factor. Higher cost is solar PV at 26% capacity factor)	1.6–2.3	2.0
Hydrogen Council, 2020	6	1-2	2.1
USDOE, 2020	6.0	1.5-2.3	1.6
Averaged cost from the above five sources	5.6 with range of 2.0–8.3	1.8	1.9, with range of 1.6–2.4

Given the economic advantage of coal gasification and natural gas reforming with CCUS, it is likely that these will continue to be the lowest cost source of large-scale hydrogen in the near and medium term. Reforming of natural gas for hydrogen production costs vary from 1.5 $/kg$H_2$ to 2.3 $/kg$H_2$, including CCUS and are very sensitive to the natural gas price (*see* Figure 31). This analysis is based on studies that show the cost of hydrogen from coal gasification with CCUS at around 1.6 $/kg$H_2$ for coal and around 2.1 $/kg$H_2$ for coal/biomass/waste plastic with CCUS. These processes are, of course, highly dependent on the delivered feedstock price.

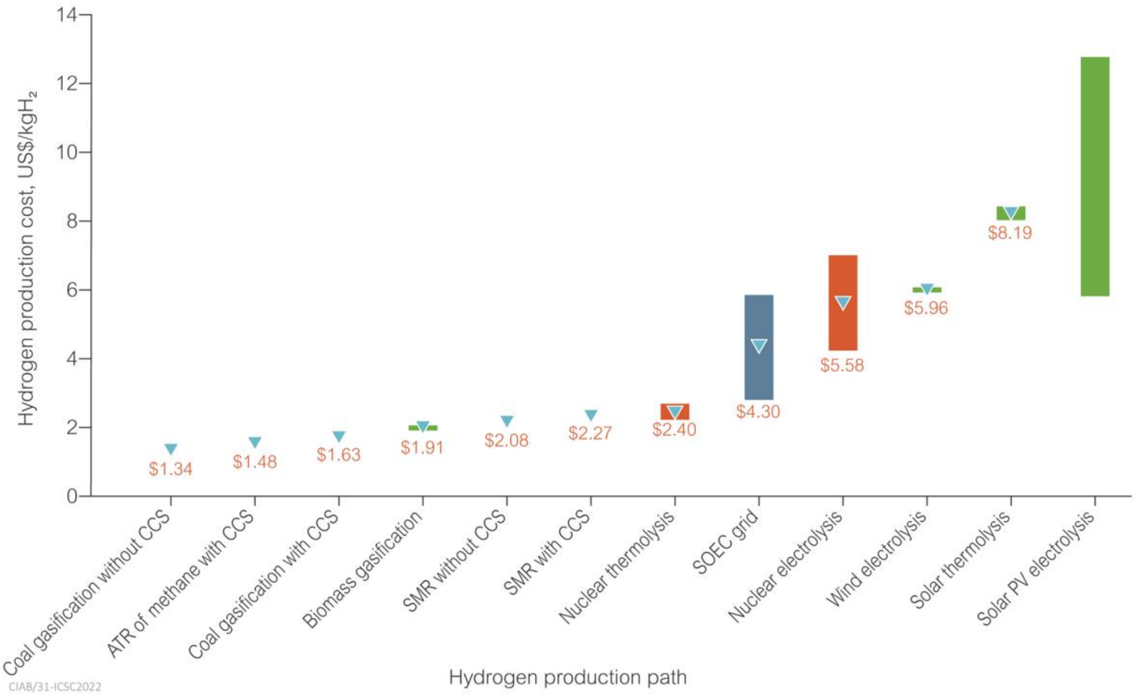


Figure 31 Comparison of hydrogen production costs (USDOE, 2020)

Regional variations due to specific local factors are a key variable in the relative costs of hydrogen production, illustrated in Figure 31 for China. Coal gasification costs with CCUS in China are around 1.6 $/kgH$_2$ (IEA, 2019c), consistent with Figure 32. Indeed, since the IEA was a key source of data for the USDOE analysis, it is likely that the coal gasification cost presented is based on the case in China.

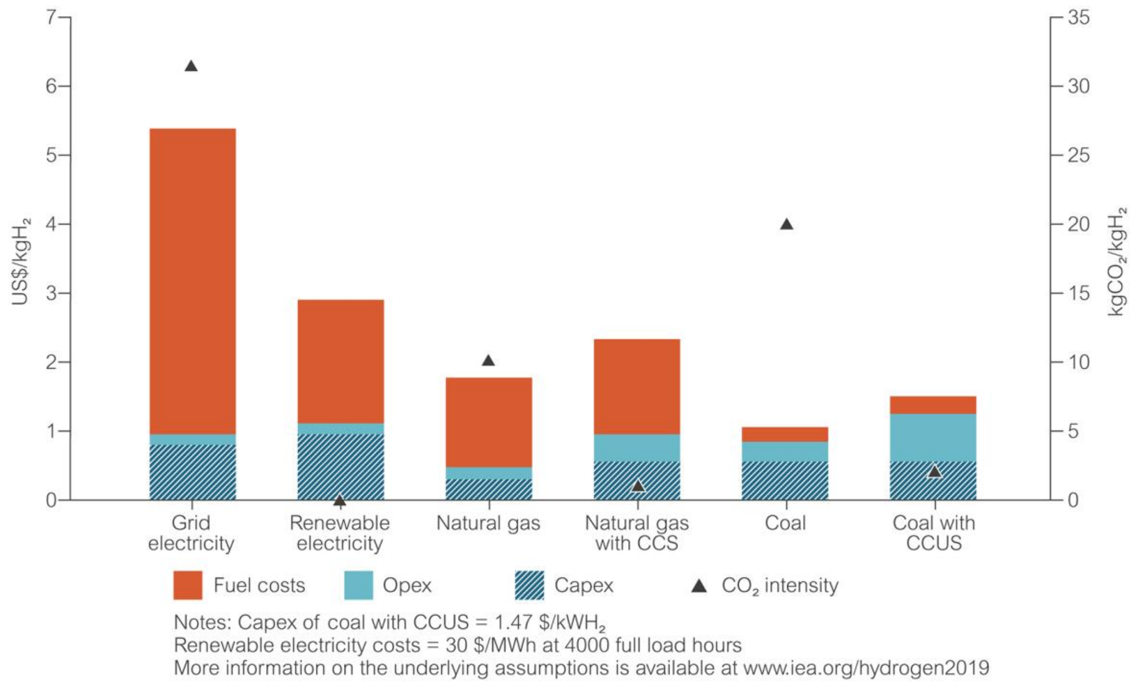


Figure 32 Hydrogen production costs in China in 2019 (IEA, 2019c)

The next sub-sections look at the costs of coal-based gasification and electrolysis in more detail and how the relative cost positions between the two could vary moving towards 2050.

8.5.1 Hydrogen costs from coal

In China, the cost of hydrogen production from coal can be broken down into capital expenditure (Capex) and operating costs (Opex) requirements which account for around 80–85% of the cost, with fuel accounting for 15–20% (*see* Figure 32). This reflects the relative complexity of the coal gasification-based approach compared with SMR and electrolysis, as shown earlier in Section 8.4. However, the availability and cost of coal as fuel still plays an important role in determining the viability of coal-based hydrogen projects.

The addition of the CCUS system contributes to around a 5% increase in Capex, with the largest cost addition being a 130% increase in Opex (that is, the difference between the 'coal' and 'coal with CCUS' bars in Figure 32).

Analysis by the Committee for Climate Change shows that for a new build case in the UK, gasification plant would cost around 70 £/MWh (96 $/MWh), including the costs of CCUS (CCC, 2018). Future savings from economies of scale could reduce this, lowering the cost of future coal gasification with CCUS by around 10–15%, to closer to 60 £/MWh (82 $/MWh) by 2050. This cost assumes a 95% carbon capture rate and a carbon tax of 227 £/tCO_2 (311 $/t$CO_2$) by 2050, such that carbon costs account for 25% of the cost of hydrogen production. The value of future carbon taxes is therefore a significant variable in the analysis of future hydrogen production costs and a potential risk to any investment decision. The potential for very high capture rates to approach 100% (Feron and others, 2019), as well as cofiring coal with a portion of biomass or other carbon-based waste materials, was identified as a potential direction of development for coal based CCUS plant (Kelsall, 2020).

In terms of Capex and Opex costs, the Committee for Climate Change analysis shows that they are again the most significant part of the overall cost, contributing around 55–60% of the total cost of hydrogen production. Since coal gasification is a relatively mature technology, the opportunity for further cost reduction through technology development was assumed to be relatively limited. Analysis for the UK Government by Element Energy however, points to good technology development opportunities on the major flowsheet sections that have potential to reduce Capex and Opex of gasification-based hydrogen (Element Energy, 2018). Based on the Element Energy study, it is predicted that capital cost of coal gasification will decrease, with perhaps a 45–50% reduction in Capex being possible by 2050 relative to the 2018 value.

8.5.2 Water electrolysis

In regions of the world with access to relatively low cost renewable electricity, based on high wind or solar incidence, low carbon hydrogen produced using water electrolysis could in time become a competitor with low carbon hydrogen from coal or natural gas. Areas with potential include Mongolia and parts of China (IEA, 2019c). This suggests that China could be a region where water electrolysis-based hydrogen production using renewable electricity could impinge on hydrogen production from coal gasification.

The potential cost reduction for water electrolysis is shown in Figure 33, in comparison with hydrogen from fossil fuels with CCUS. However, it should be noted that in this analysis by IRENA, the cost of hydrogen production from fossil fuels was assumed to be constant over the period through to 2050, resulting in an increase in the levelised cost of hydrogen (LCOH), due to the assumed increase in carbon tax over the period (IRENA, 2019a). As a result, the cost of hydrogen from fossil fuels increases over time due to the assumed increase in CO_2 cost from 50 \$/tCO_2 in 2030 through to 200 \$/tCO_2 in 2050, which is not offset by any reduction through technology development or learning by doing. This is unlikely to be the case.

Focusing on the water electrolysis aspect of the study, the forecast is for hydrogen from low cost wind to start to be competitive with the upper range of fossil fuel based hydrogen prices in less than five years, perhaps competing with the lowest cost fossil fuel based technologies by 2035. Low cost solar PV shows a similar cost reduction profile to wind, although this would be achieved slightly later in time. For regions where wind and solar PV resources are closer to the global average, water electrolysis-based technologies may not become competitive with the upper range of fossil fuel based technologies until after 2030-35.

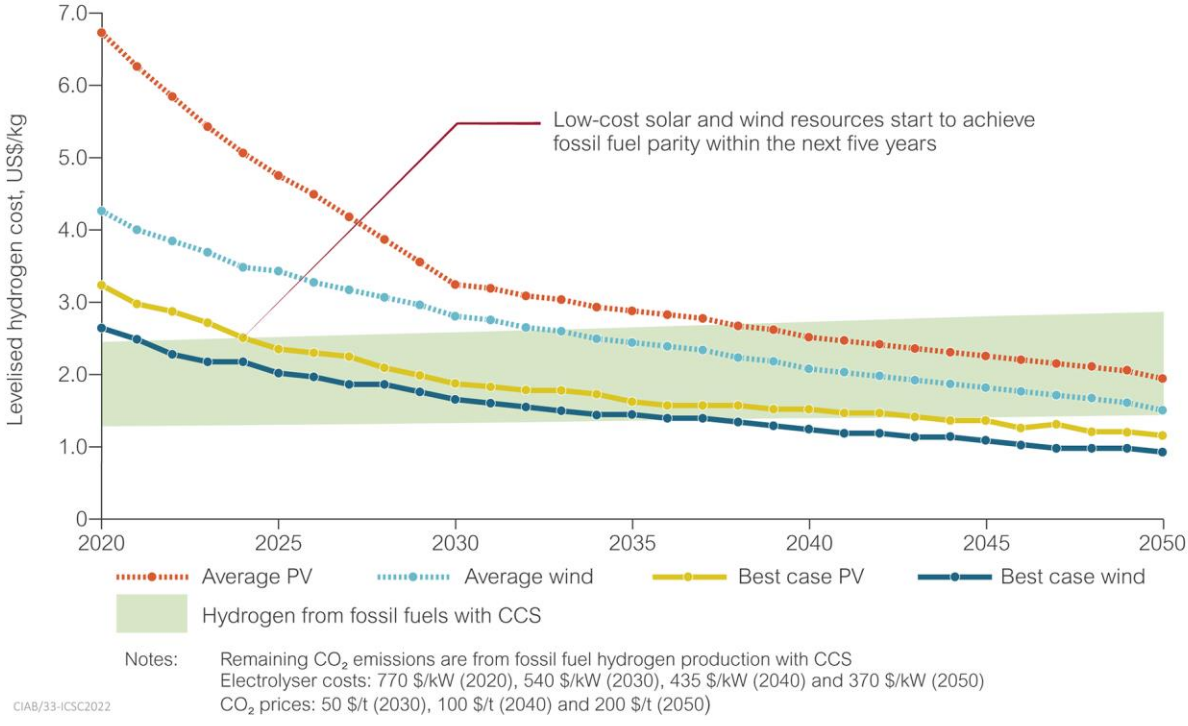


Figure 33 Cost comparison of low carbon hydrogen (IRENA, 2019a)

8.6 EMISSIONS FROM HYDROGEN PRODUCTION

In general terms, increasing the proportion of hydrogen use in the energy mix can have a positive impact on CO_2 emissions reduction. Based on the future forecast demand of hydrogen (*see* Section 8.3), hydrogen could deliver a CO_2 reduction potential of around 6 $MtCO_2/y$ by 2050 globally (Hydrogen Council, 2017b).

The estimated CO_2 emissions per kilogram of hydrogen produced are shown in Figure 34 where the CO_2 impact of different hydrogen production technologies varies widely. The carbon intensity of hydrogen from unabated coal gasification is 19 $kgCO_2/kgH_2$, which is around double the value of the carbon intensity from SMR of natural gas. This is of course an inherent feature of coal due to its higher carbon/hydrogen ratio relative to natural gas. However, when CCUS is added, this carbon intensity can be reduced to below 3 $kgCO_2/kgH_2$, based on 90% CO_2 capture. The hydrogen production process using coal gasification can be configured to capture 98% of the CO_2 emissions, which would reduce the carbon intensity of hydrogen down to 0.4-0.6 $kgCO_2/kgH_2$, as noted in Table 15 (Zapantis and Zhang, 2020). There is also the option to cofire coal with biomass and/or waste materials which can again reduce the carbon intensity. At a CO_2 capture level of 99.7%, the CO_2 emissions will be essentially compliant with zero emissions.

The CO_2 intensity of electrolysis depends on the CO_2 intensity of the electricity used to produce it. Where this is entirely from renewable electricity sources such as and wind and solar, the carbon intensity is close to zero. However, for cost of electricity reasons, or to match demand side hydrogen requirements, the electrolyser may be operated at higher load factors by using grid supplied electricity at the prevailing carbon intensity level of the local grid. As there is often a high proportion of fossil fuel, the conversion losses during electricity generation mean that using electricity from natural gas or coal power plants results in higher CO_2 intensities than directly using natural gas or coal for hydrogen production. This means that for electrolysis to have similar or lower CO_2 intensity than hydrogen production from natural gas without CCUS, the CO_2 intensity of electricity must be below 185 grammes of carbon dioxide per kilowatt hour (gCO_2/kWh), which is around 55% of the CO_2 intensity from a state-of-the art CCGT and less than 40% of the global average. Consequently, for the global average energy fuel mix, the carbon intensity of water electrolysis based hydrogen production could be as high as 26 $kgCO_2/kgH_2$ (IEA, 2019c).

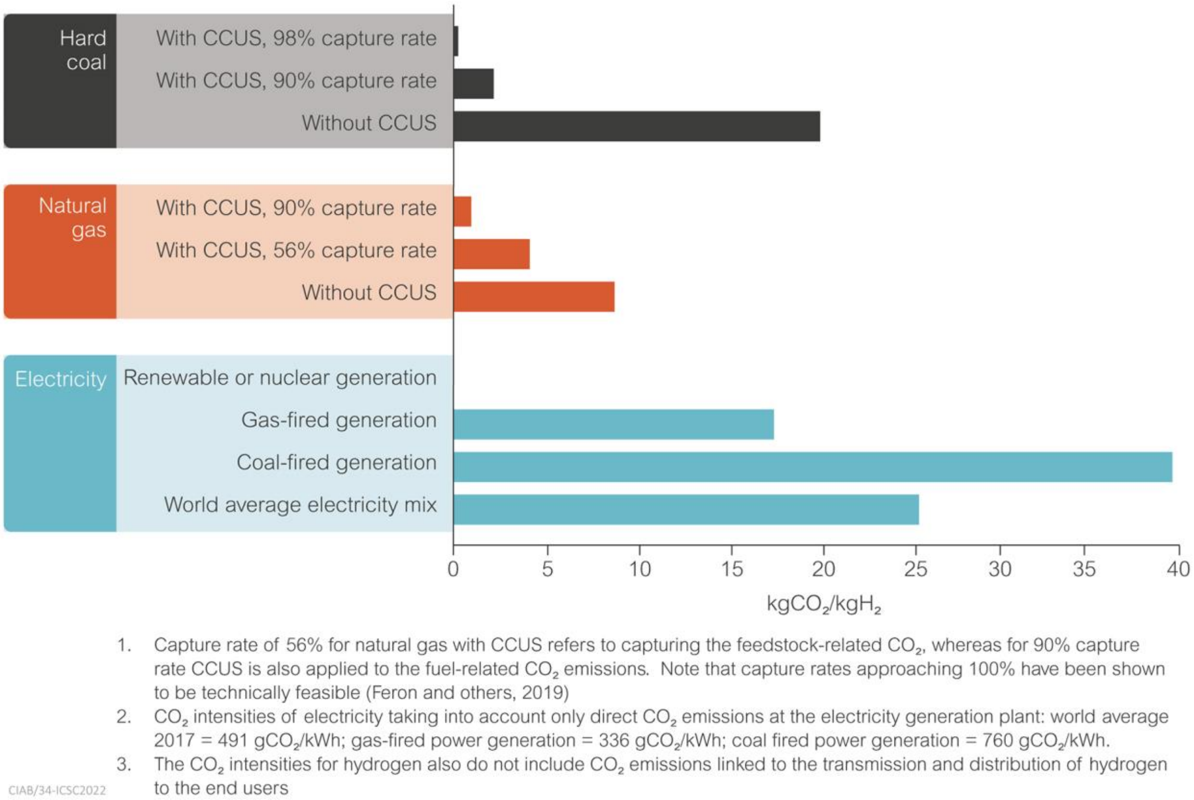


Figure 34 CO_2 intensity of hydrogen production (IEA, 2019c)

In comparison, coal or natural gas production pathways with CCUS produce around 2–3 $kgCO_2/kgH_2$ including electricity emissions from the production of the coal or gas, consistent with the IEA analysis shown above.

In terms of moving towards NZE, the outcome is that the impact of using water electrolysis could be detrimental unless the water electrolysis process is used at low capacity factor with mainly renewable electricity, or until the penetration of renewables in a region's energy mix increases significantly such that the carbon intensity of grid electricity is reduced to a very low level. The approach could be for the hydrogen producer to secure a 'green' electricity mix through real time power purchase agreements or perhaps real time green certificates. The producer would then use the higher proportion of renewable based electricity as a basis for calculating the carbon intensity of the hydrogen produced (Aarnes and others, 2018). However, Aarnes and others (2018) showed that in order for water electrolysis based hydrogen production to deliver lower CO_2 emissions than fossil fuels with CCUS, the carbon intensity of the energy mix would need to be lower than 75 gCO_2/kWh. Similar results have been presented by Gardarsdottir and others (2019) where at least 95% of the electricity used in the electrolyser should come from renewable sources to be able to deliver lower emissions than fossil fuel based hydrogen production with CCUS. From a systems level consideration, it is difficult to envisage how such high levels of renewables could be achieved without entailing significant cost or impacting on grid stability (*see* Chapter 5).

A further consideration is that electricity from wind or solar based hydrogen production may displace the use of green electricity in the rest of the electricity system. This would indicate that reductions in carbon emissions from production and use of low carbon hydrogen from fully renewable electricity, at mid-merit capacity factor, could potentially be offset by an increase in overall power sector emissions. As noted by the GCCSI, using renewable energy to replace fossil fuel based generation, provides three to eight times as much abatement benefit as can be achieved by using renewable energy to make low carbon hydrogen. Their conclusion is that the most effective support for moving towards NZE is to produce hydrogen from natural gas or coal with CCUS, while using renewables predominantly for electricity generation (GCCSI, 2020).

8.7 OTHER CONSIDERATIONS IN THE CHOICE OF HYDROGEN PRODUCTION TECHNOLOGY

Other considerations which impact on the choice of coal gasification-based hydrogen production relative to natural gas reforming and water electrolysis technologies are listed below (CCC, 2018):

Land footprint – Coal gasification technologies typically require more land than gas reforming technologies or for water electrolysis, due to the higher number of process steps/unit operations and the need for onsite coal storage. The area required is typically 0.8–2.5 m^2/kW hydrogen produced from coal gasification, compared to 0.05–0.16 m^2/kW hydrogen produced from natural gas reforming and 0.07–0.14 m^2/kW hydrogen produced from water electrolysis. This land footprint for water electrolysis does not include the potentially significant land area for renewable electricity production to power the water electrolysis based hydrogen production systems. A study in Australia carried out by GCCSI, estimated the land area for water electrolysis to be almost fifty times larger than for coal gasification to produce the same hydrogen output, where the area for renewable electricity production is also included (Zapantis and Zhang, 2020).

Water footprint – Coal gasification and natural gas reforming technologies require around 0.1–0.3 litres of non-potable water per kWh of hydrogen produced as a direct part of the gasification/ reforming process. In addition, both require around 0.1–30 litres of water for cooling, although this could be reduced by using air or hybrid cooling technologies (Carpenter, 2018; Barnes, 2019; Kelsall, 2020; Int CCS KC, 2018). Water electrolysis, on the other hand, requires around 0.5 litre of potable water per kWh of hydrogen. This could be a constraint for water electrolysis, particularly in areas where potable water is scarce, although desalination of sea water could be used in coastal locations for an additional cost. This has a minor impact on the total costs of water electrolysis, increasing total hydrogen production costs by around 0.01–0.02 \$/kgH_2. Research is also being carried out on the direct use of sea water in electrolysis in the future (IEA, 2019c).

Air quality – Coal gasification produces air pollutant emissions of nitrogen oxides (NOx) and particulate matter. However, these can be mitigated by fitting conventional filtration technology to the plants, such as selective catalytic reduction technologies and electrostatic precipitators.

8.8 EXAMPLES OF HYDROGEN PRODUCTION FROM COAL/PETROLEUM COKE UTILISING CCUS

Key global projects relating to the production of low carbon hydrogen focusing on coal/coke as feedstock are shown in Table 16. They are generally covered in the GCCSI CO_2RE projects database (GCCSI, 2021). The Pouakai project in New Zealand based on the Allam-Fetvedt Cycle is natural gas-fired, but the cycle could also be fired with petroleum coke or coal (Lu and others, 2020; Zhu, 2017).

TABLE 16 HYDROGEN PRODUCTION FROM COAL/COKE INCLUDING CCUS (AUTHOR BASED ON ZAPANTIS AND ZHANG, 2020)

Facility	H_2 production capacity	Process	H_2 use	Operation date (with CCUS)
Great Plains Synfuel, USA	1300 t/d in syngas	Lignite gasification	SNG and fertiliser production	2000
Coffeyville, USA	200 t/d	Petroleum coke gasification	Fertiliser production	2013
Sinopec Qilu, China	100 t/d	Coal/coke gasification	Fertiliser production	2021 (planned)
Latrobe Valley, Australia (CCUS not included in pilot phase)	3 t/y (<0.1 t/d)	Lignite gasification	Export to Japan for power generation	2021
Pouakai, New Zealand	600 t/d (proposed)	Natural gas fired oxyfuel/supercritical CO_2	Fertiliser production	2024

The projects with direct relevance to Asia are discussed below.

8.8.1 Sinopec Qilu

Sinopec Qilu petrochemical plant is in the process of retrofitting a CCUS system to an existing coal/coke water slurry gasification unit at a fertiliser plant in Zibo City, Shangdong Province, China. The initial phase of the facility under construction is capable of capturing almost 0.4 $MtCO_2$/y. The longer-term target is to capture 0.5 $MtCO_2$/y, with the captured CO_2 transported by pipeline to the Shengli oilfield for EOR. EOR is seen as a potential way of utilising the significant quantities of CO_2 from China's power and chemical manufacturing industries to enhance oil production from indigenous oil fields (Hill and others, 2020).

Sinopec Qilu was licensed initially in 2006 and uses three GE gasifiers, allowing two to run while one is on standby for planned maintenance. Operation of the plant began in October 2008 to produce a synthesis gas consisting of hydrogen and carbon monoxide, used as feedstock to produce butyl alcohol and methanol.

8.8.2 Hydrogen Energy Supply Chain (HESC)

The Hydrogen Energy Supply Chain (HESC) project is being developed in Victoria State, Australia with the support of Japan (HESC, 2018 and IRENA, 2019a). The project aims to develop and demonstrate technologies for the production, storage and transportation of clean hydrogen from lignite fuel in the Latrobe Valley and to establish a supply chain through to utilisation in Japan in the Kobe CHP plant in Japan (KHI, 2019). The pilot phase encompasses a gasification plant in the Latrobe Valley and a liquefaction facility at the Port of Hastings. The liquefaction, storage and loading facility at Port Hastings will convert hydrogen gas to liquefied hydrogen using existing commercial technology. HESC will be the first initiative to transport mass quantities of liquefied hydrogen across open waters and will use an innovative, world first hydrogen carrier. The first shipment is planned for October 2021 - March 2022. The liquefied hydrogen will be unloaded at a specially designed base in Kobe, Japan.

The AUS$500 million ($390 million) project is supported by the Japanese government and Japanese industry, together with the Australian and Victorian governments which have each contributed AUS$50 million (around $39 million) in funding. The project is being carried out by CO_2-free Hydrogen Energy Supply-chain Technology Research Association and an Australian consortium consisting of Iwatani, Marubeni, Kawasaki Heavy Industries, J-Power, Sumitomo and AGL Energy Ltd.

CCUS is not included in the initial pilot phase of the project due to the relatively small amount of CO_2 produced during the pilot phase. Carbon offsets have therefore been purchased for the CO_2 emitted in this phase, although it is recognised that for the subsequent commercial phase, CCUS will be needed. The captured CO_2 will be stored in a geological storage site offshore in the nearby Gippsland Basin, in cooperation with the CarbonNet storage project which aims to develop a CCS transport and storage hub in Gippsland (HESC, 2021).

J-Power is leading the coal gasification and hydrogen refining facility which started construction in November 2019 and began producing hydrogen in January 2021 (HESC, 2021).

In terms of project challenges, the key technical issue would appear to be demonstration of the supply chain to ship hydrogen to Japan, where cryogenic hydrogen transport is proposed, based on KHI technology (KHI, 2019).

8.9 OTHER HYDROGEN CARRIER FUELS

Hydrogen containing compounds which are liquid at temperatures and pressures relatively close to ambient conditions include ammonia (NH_3), methanol (CH_3OH), dimethyl ether (CH_3OCH_3), and methylcyclohexane (C_7H_{14}). They have attracted significant attention as a means of transporting and storing hydrogen, as fuels in their own right and as chemical reagents in industrial manufacturing processes. In assessments of these hydrogen carrying fuels, ammonia is recognised generally as the leading fuel (Styring and others, 2021; Aziz and other, 2019). The IEA for example recognises that ammonia is much cheaper to transport and store and thus, the most economically competitive alternative to hydrogen for distribution. In Japan, METI announced that it has chosen the fuel ammonia industry as one of the prioritised areas in its 'Green growth strategy' action plan (Zhu, 2021).

8.9.1 Ammonia

Ammonia as a fuel and in terms of technologies to utilise it, mainly in the context of Japan, was discussed in Section 3.3. The particular advantage of ammonia is that it is the only carbon-free hydrogen carrier and has a hydrogen content of 17.7% by mass with an energy density of 18.6 MJ/kg LHV basis, or 12.7 MJ/L for liquid ammonia. Although ammonia has a narrow flammability range and its toxicity is a concern, its strong smell can be advantageous in terms of leak detection. It can be liquefied at pressures of 1 MPa or temperatures of -33°C, which make it attractive from a storage and distribution viewpoint (El-Kadi and others 2018; RSC, 2020). In comparison, hydrogen needs to be cooled to below -240°C and 1.2 MPa to be liquefied.

8.9.2 Methanol

In a similar way to ammonia, methanol provides a potential medium as an energy carrier for hydrogen. Methanol is a liquid at ambient conditions and has an energy density of 0.79 MJ/l or 19.9 MJ/kg LHV basis. It is also relatively easy to convert to hydrogen through a catalytic fuel reformer, at relatively low temperatures of 200–300°C (Danish Technology Institute, 2009). One potential issue with methanol as a hydrogen carrier fuel is that its toxicity is high and its infrastructure is not well developed (Styring, 2021). It is however an internationally traded commodity product with a number of potential uses in the chemical industry as discussed in Chapter 7.

Methanol is a potentially viable fuel in the context of power-to-fuels, where excess renewable electricity could be converted to hydrogen using water electrolysis and then reacted with CO_2 to form methanol. Coal power plant exhaust or industrial process flue gases could provide a relatively concentrated CO_2 stream for this reaction.

8.9.3 Methylcyclone hexane

Methylcyclone hexane (MCH) has an energy density of 43.4 MJ/kg, or 33.4 MJ/L and is a liquid at room temperature, since its boiling point is 100°C. Together with ammonia, it is being actively investigated as a hydrogen carrier in Japan. Examples of MCH use include the Advanced Hydrogen Energy Chain Association for Technology Development (AHEAD) project which has begun operation of the world's first international hydrogen supply chain. This involves producing hydrogen from natural gas and converting it to MCH. The MCH is then shipped to Japan where it undergoes dehydrogenation to release the hydrogen (AHEAD, 2020). Hydrogen regenerated from the MCH is supplied to a gas turbine in Mizue Thermal Power Plant for power generation (Chiyoda Corp 2020).

8.9.4 Dimethyl ether

Dimethyl ether (DME) can be produced directly from synthesis gas produced from natural gas, coal, or biomass. It can also be produced indirectly from methanol via a dehydration reaction. With an energy density of 28.7 MJ/kg (LHV basis) or 19.03 MJ/L, it is particularly rich in hydrogen, with six hydrogen atoms in each DME molecule. It can be liquefied at temperatures and pressures of around 20-60°C (near room temperature) and 0.5–1.5 MPa, making it easier and less expensive to transport than liquid hydrogen and giving handleability similar to LPG.

DME is an alternative diesel fuel characterised by relatively low emissions of CO_2, NOx and particulate matter. Its high cetane number means it can be used in compression ignition engines with minimal modifications (Styring and others, 2021). Although it produces lower emissions of CO_2, they are not zero and so DME should be considered as part of a circular economy solution, or part of one that forms the transition to NZE. In the medium term, it could be used as a hydrogen carrier and energy storage medium, as it can be readily converted to hydrogen via a catalyst based steam reforming process. There is also the option to manufacture DME from CO_2 and low emissions hydrogen, where coal power plant exhaust or industrial process flue gases could provide a relatively concentrated CO_2 stream for the process, as highlighted above for methanol.

9 THE CHALLENGE IN ASIA

9.1 KEY MESSAGES

- Trends in Asia are shaping the global energy picture as the region retains a greater share of world GDP, energy consumption, and CO_2 emissions.
- While industry and manufacturing are still vital components of GDP, the services sector has emerged as the leading share of Asian GDP.
- The distribution of industrialisation and economic wealth are uneven across Asia. Economic development could increase energy consumption in economies outside OECD Asia and China. Access to electricity has improved, and demand for modern grid electricity will increase as infrastructure expands to serve increasingly urbanised populations.

Coal remains the leading fuel for all primary energy and electricity generation; NZE targets will require the decarbonisation of fossil fuel use. The Asian power sector has modernised, but could improve further. The region has pushed for a more significant role for SC and USC technology for coal plants, leapfrogging older coal technologies still operating in Europe and North America.

Having reviewed the technologies that are vital to achieve NZE, with a focus on Asia, this chapter explores Asia in more detail and highlights the challenges for the continent in reducing GHG emissions to near zero.

9.2 ECONOMIC OUTLOOK

Asia is a diverse and economically dynamic region comprising some 50 economies at various stages of industrialisation which are following a variety of economic, political and economic models. Asia has grown from 13% of global GDP in 1960 to 33% in 2020 (*see* Figure 35). The economic outlook for Asia is for more growth which will reflect in the region's demand for modern energy supplies. While the economies of most Asian countries have expanded, much of the wealth has been generated in China. The opening up of the Chinese economy to freer trade and foreign investment in the early 2000s has resulted in a rapid development of economic activity. No other Asian economy has experienced such growth in absolute US dollar terms although similar rates of growth are occurring across Asia. In 2020, China was reported to have a $15 trillion economy, accounting for one sixth of global GDP. China's GDP is almost six times the size of India's, with a broadly similar population, 14 times the size of Indonesia's, and 54 times that of Vietnam's.

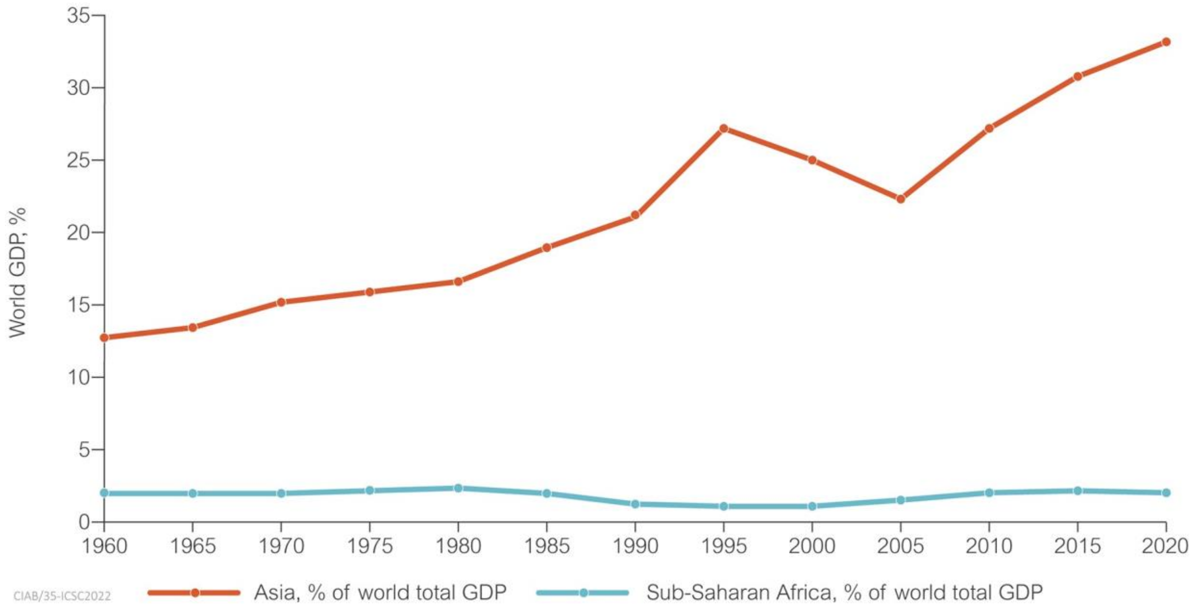


Figure 35 Asian share of world GDP 1960-2020, % (author based on World Bank, 2021a)

There is a consensus that emerging economies in Asia will displace more developed ones in the world rankings for GDP in the coming decades. In 2020, the IEA estimated that GDP growth in 2019-40 in the Asia Pacific will average 4%/y while that in Europe and North America will grow at just 1.5%/y. The Chinese economy could overtake the USA by 2028 to become the largest in the world (CEBR, 2020). During 2020-35, it is expected that India will move from sixth place to third overtaking the UK, Germany and Japan. Indonesia will become the eighth largest, while Vietnam will jump from 38th to 19th, just behind the Netherlands. These findings are consistent with research by PwC (2017), where several lower-middle income Asian countries such as India, Indonesia and Vietnam move up the rankings in order of GDP through to 2050 (*see* Table 17). Some high to upper-middle income Asian countries are forecast to move down the ranking, notably Japan, South Korea, Malaysia and Thailand (World Bank definitions of income are available at: www.worldbank.org).

TABLE 17 GDP OUTLOOK TO 2030 AND 2050 BY COUNTRY IN $ AT MARKET EXCHANGE RATES (MER) (PWC, 2017)

GDP at MER rankings	2016 rankings		2030 rankings		2050 rankings	
	Country	GDP at MER	Country	Projected GDP at MER	Country	Projected GDP at MER
1	USA	18562	China	26499	China	49853
2	China	11392	USA	23475	USA	34102
3	Japan	4730	India	7841	India	28021
4	Germany	3495	Japan	5468	Indonesia	7275
5	UK	2650	Germany	4337	Japan	6779
6	France	2488	UK	3530	Brazil	6532
7	India	2251	France	3186	Germany	6138
8	Italy	1852	Brazil	2969	Mexico	5563
9	Brazil	1770	Indonesia	2449	UK	5369
10	Canada	1532	Italy	2278	Russia	5127
11	South Korea	1404	South Korea	2278	France	4705
12	Russia	1268	Mexico	2143	Turkey	4087
13	Australia	1257	Russia	2111	South Korea	3539
14	Spain	1252	Canada	2030	Saudi Arabia	3495
15	Mexico	1064	Spain	1863	Nigeria	3282
16	Indonesia	941	Australia	1716	Italy	3115
17	Turkey	830	Turkey	1705	Canada	3100
18	Netherlands	770	Saudi Arabia	1407	Egypt	2990
19	Saudi Arabia	638	Poland	1015	Pakistan	2831
20	Argentina	542	Netherlands	1007	Spain	2732
21	Poland	467	Iran	1005	Iran	2586
22	Nigeria	415	Argentina	967	Australia	2564
23	Iran	412	Egypt	908	Philippines	2536
24	Thailand	391	Nigeria	875	Vietnam	2280
25	Egypt	340	Philippines	871	Bangladesh	2263
26	Philippines	312	Thailand	823	Poland	2103
27	Malaysia	303	Pakistan	776	Argentina	2103
28	Pakistan	284	Malaysia	744	Malaysia	2054
29	South Africa	280	Bangladesh	668	Thailand	1995
30	Colombia	274	Vietnam	624	South Africa	1939
31	Bangladesh	227	Colombia	586	Colombia	1591
32	Vietnam	200	South Africa	557	Netherlands	1496

Even as the Asian economies expand, few outside the OECD will reach a high-income status, defined by the World Bank as a per capita gross national income (GNI) of more than $12,695 (in 2021). China and Malaysia are currently in the upper-middle band of 4096-12,695 $/capita and approaching the high-income band (*see* Figure 36), while India, Indonesia and Vietnam are substantially poorer in the lower-middle income band of 1046–4095 $/capita.

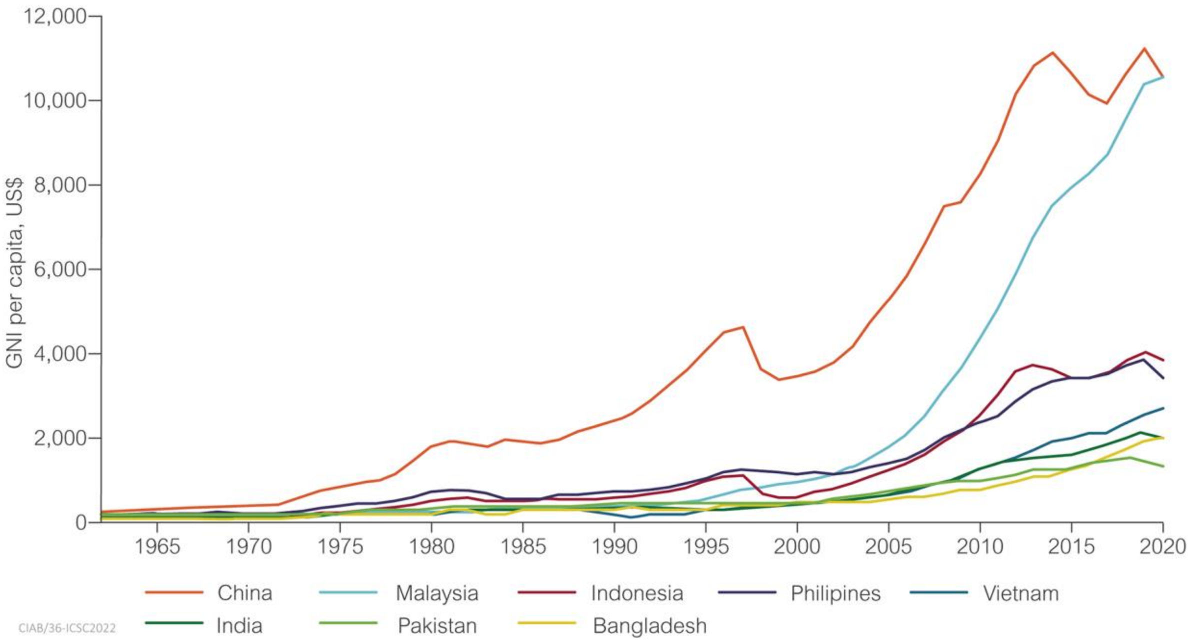


Figure 36 GNI per capita in developing Asia 1960-2020 (World Bank, 2021a)

Thus, although there will be some changes for Asia in the overall rankings they are relative. All the economies are expected to grow suggesting greater wealth and development. This increases the demand for infrastructure, which requires steel and cement among other commodities and more electrification and modern energy supplies. Part of the expansion will stem from long-term population growth.

9.3 POPULATION GROWTH

Asia's population is expected to increase from 4.6 billion in 2020 to 5 billion by 2030, and reach 5.2 billion by 2050 (UN, 2018a). However, the rate of growth will slow, from just under 2%/y in 2015-20 to 0.8%/y by 2050. Exceptions include Japan, China, and South Korea, where the trends indicate a population decline during 2020-50.

Until 2015-20 the population of Asia was more rural than urban. However, the region has now reached an inflexion point, after which the majority of the population will be urban and rural populations will decline (*see* Figure 37). These trends have implications for planning future sustainable energy supplies as serving urban populations will become increasingly important (Dijkstra and others, 2021).

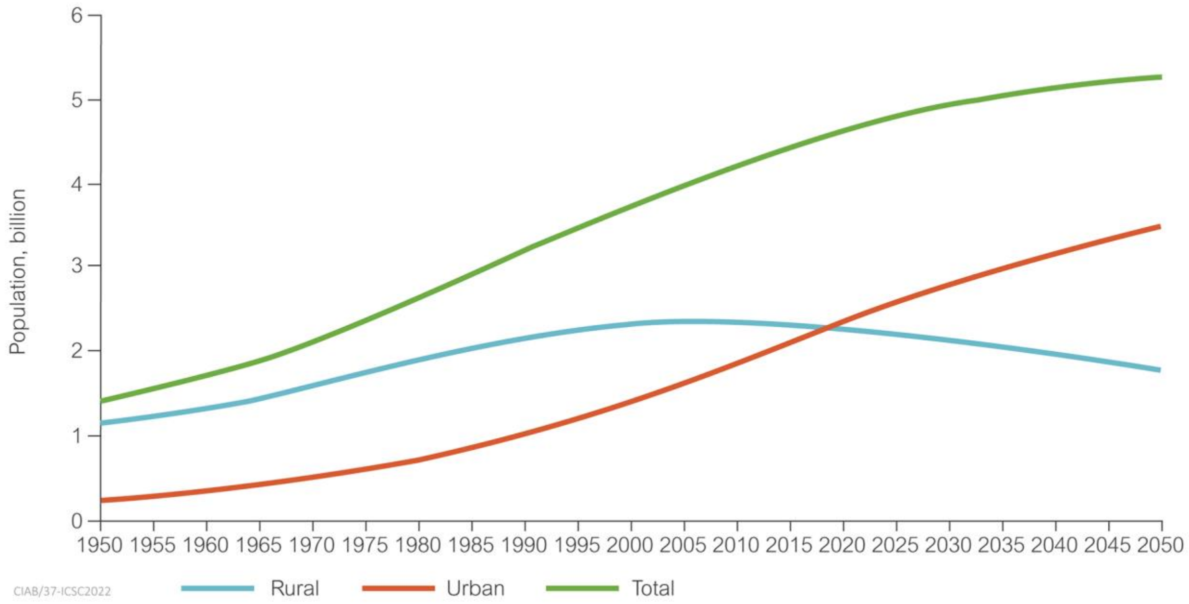


Figure 37 Forecast of Asian population growth to 2050 (author based on UN, 2018b)

The movement of people to urban areas is due to a range of factors that attract economic migrants, such as better employment opportunities, education, and higher incomes. Industrialisation and urbanisation are often linked; for example, manufacturing as a percentage of GDP correlates directly with urbanisation, especially in Asia. Elsewhere, GDP might have a stronger correlation with natural resource development, such as in Africa (Vollrath and others, 2016). Figure 38 illustrates the decline in rural activities such as agriculture and forestry when measured as a percentage of GDP. The transition in South Korea, Taiwan, China, Malaysia, and Indonesia followed a classical model of structural economic change, from agriculture to manufacturing and then to services. India, Thailand, Bangladesh, Sri Lanka and Vietnam instead shifted from agriculture to manufacturing or mining while the service sector developed more gradually. Urbanisation brings a transfer of skills and labour as industry modernises and labour productivity and resource efficiency improve (Nayyar, 2021). An effect of urbanisation is an increased demand for new construction, transport infrastructure, energy demand, and other municipal services. These requirements of urbanisation are reflected in demand for steel, cement, electricity and other commodities, which have been discussed in earlier chapters.

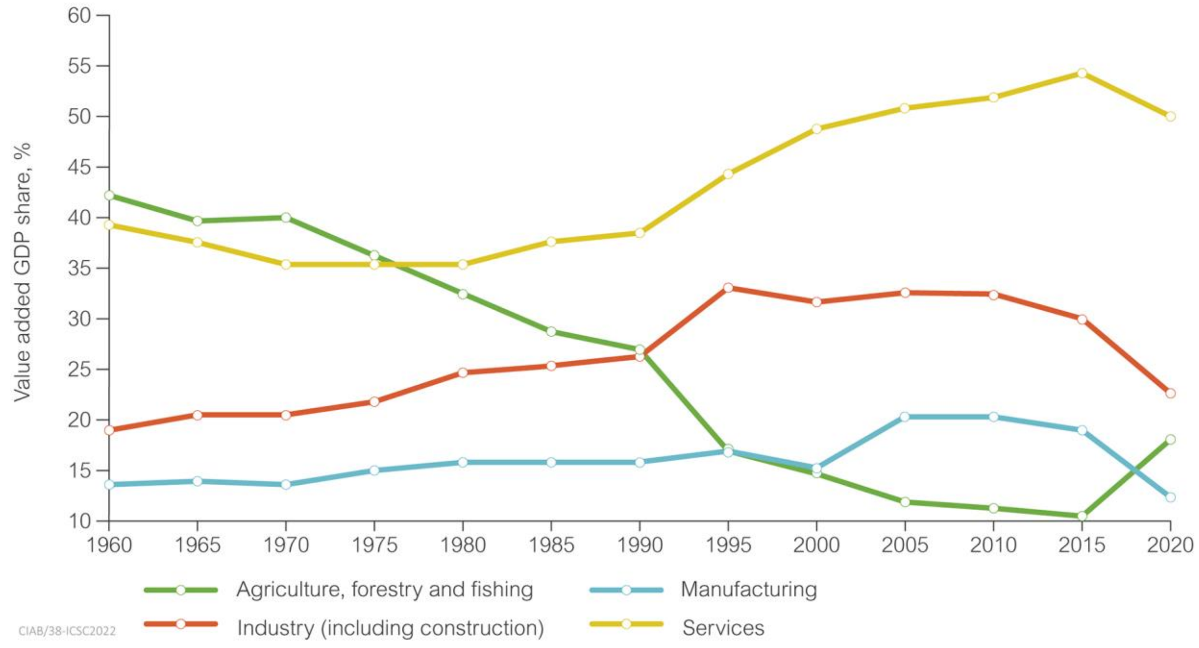


Figure 38 Share of GDP by economic sector in Asia, % (author based on World Bank, 2021a)

During industrialisation, economic growth is considered to grow synchronous with energy demand (Sharma and others, 2019). This was evident throughout the 20th century in the growth in fossil fuel consumption, but as advanced economies became service-led, GDP has become more decoupled from energy demand. According to the IEA (2020c), the phenomenon of energy and GDP decoupling could mean that total primary energy demand per unit of GDP halves between 2019 and 2040 from 0.1 toe/$ (PPP) to 0.04 toe/$.

Energy is an essential strategic economic sector that supports development in Asia. However, development and growth will occur at different rates across the region due to the multiple factors involved, including different political and economic models. Capitalist-style market economics has been adopted by both democratic and centrally controlled economies. For example, China has fused capitalism with its centrally controlled ideals and Vietnam is adopting a similar model. India and Indonesia also encourage private sector involvement to varying degrees in the energy sector, from mining to power generation. Still, the state retains a significant influence in leading power utilities in these countries.

9.4 THE ENERGY TRILEMMA

Throughout Asia, policymakers across different countries have intensified efforts to develop a secure, affordable, and more sustainable pathway for their energy sectors. These policies include expanding the energy sector by facilitating investment in fuel and power supplies and energy infrastructure while fostering efficiency (IEA, 2019). Access to electricity has increased dramatically in developing Asia, from 67% of the population in 2000 to 96% in 2019 (99% in urban and 94% in rural regions). However, 155 million people were still without access to electricity in 2019 (IEA, 2020b).

The energy trilemma is a concept developed by the World Energy Council (WEC) which sets out the three key energy challenges and the tension between them, for the provision of secure and sustainable energy in an equitable manner. The trilemma is the need to balance the following objectives (WEC, 2020):

- **energy security** – where a nation should create an energy system that has the ability to meet current and future energy demand while withstanding system shocks;
- **energy equity** – where there is universal access to reliable and affordable energy as an enabler of economic prosperity such as basic electricity and clean cooking fuels; and
- **environmental sustainability** – a diverse energy system that mitigates against all adverse environmental impacts but does so efficiently.

Sloss (2020) describes how middle-income countries, such as those selected as case studies (*see* Chapter 10) have prioritised economic growth and improving access to affordable electricity in the past, when poor access to electricity and clean cooking fuels exacerbated health issues and economic poverty. Addressing environmental sustainability concerns is becoming a stronger theme in the energy strategies of Asian countries and therefore the balance of the trilemma may shift.

The World Energy Trilemma Index ranks countries for each trilemma goal (*see* Figure 39). The range of grades are A (best) to D (worst) for energy security, environmental sustainability, and energy equity which account for 90% of the score. The grading for each country also has a fourth component, Country Context, which accounts for 10% of the score and applies to issues such as the rule of law, good governance, economic and political stability and the ease of doing business.

Despite the progress that has been made, energy security has been an issue for many Asian countries and scores are generally below the global average especially for economies that are heavily reliant on energy imports while demand grows; this adds pressure during times of high energy prices. The fragmentation of energy markets and a lack of grid interconnection between different countries adds to the difficulties for countries to meet their electricity needs. According to the WEC (2021), there appears to be relatively poor progress in terms of environmental sustainability to date, but more countries have recently announced NZE targets.

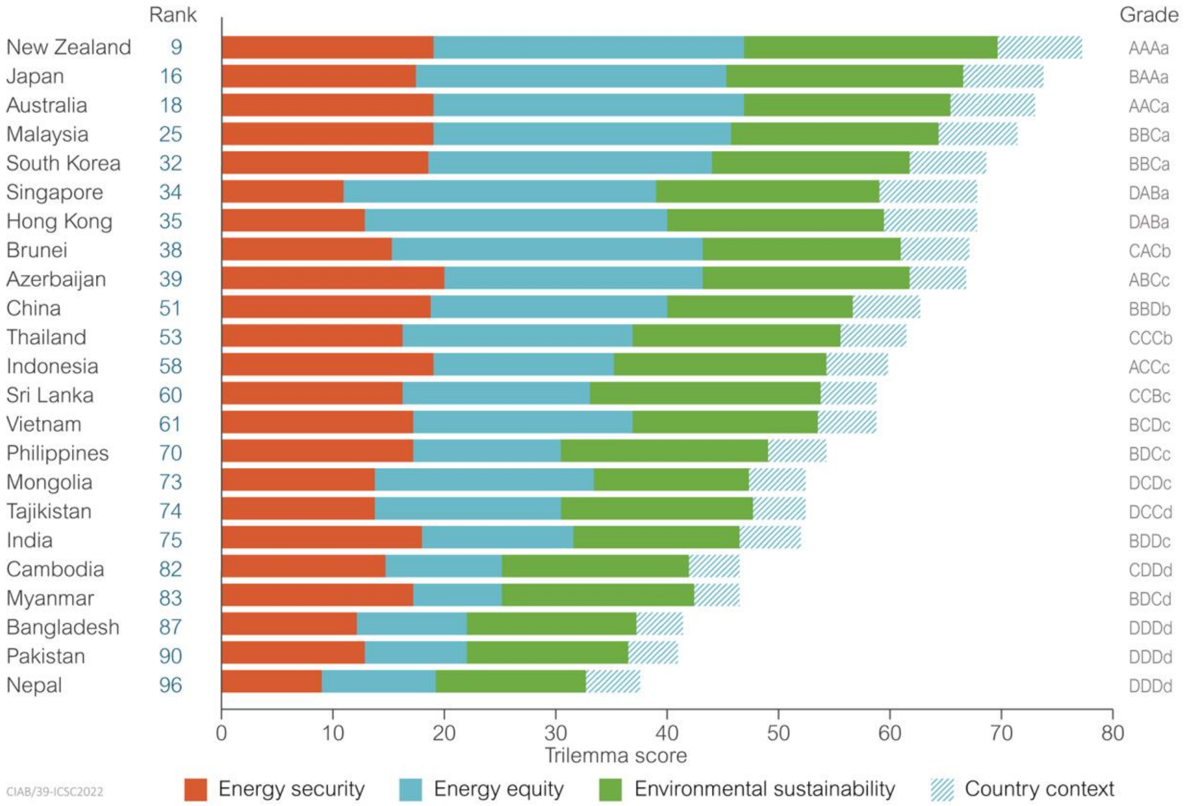


Figure 39 Energy trilemma performance by country (WEC, 2021)

Figure 39 presents the Energy Trilemma Index grades by country for 2021. With respect to energy security, the case study countries score in the range A-B. China, India, Indonesia and Vietnam have an abundance of one or more energy resources, particularly coal. This helps secure fuel supplies for the power sector thus strengthening a component of energy security over the long term, although fuel shortages in the short term are still possible. With the exception of Indonesia, which has abundant coal, oil, and gas, China, India and Vietnam are deficient in oil and gas resources and rely more on imports for one or both of these fuels (IEA, 2021). China is rated relatively well for energy equity due to good energy access and affordable supplies.

The four case study countries scored C-D for environmental sustainability which is partly attributed to the relatively low proportion of electricity coming from low carbon sources. This summary of the energy trilemma highlights that energy security and energy equity are still the dominant concerns the trilemma in much of Asia. The sustainability requirement is starting to become more important.

9.5 CURRENT ENERGY TRENDS IN ASIA

Fossil fuels dominate Asia's total primary energy supplies (TPES), but investment in renewable energy is increasing. Figure 40 shows that almost half of the region's TPES are coal. Coal use in 2020 decreased by 2% due to the Covid-19 pandemic, but its share of TPES increased from 42% to 48%. China accounts for almost 3500 Mtoe of Asia Pacific's TPES, of which coal is 2100 Mtoe and represents 70% of the coal component shown in Figure 40.

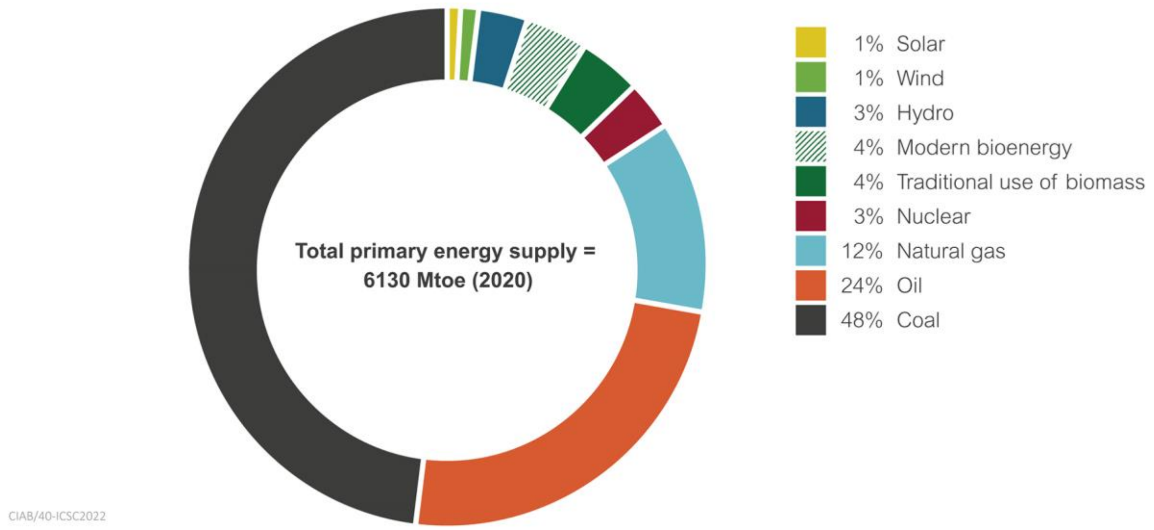


Figure 40 Total primary energy supply in Asia Pacific by fuel in 2020 (author based on IEA, 2021f – World Energy Outlooked extended data)

Coal supplies 42% of industrial energy demand, comprising coking coal for steel production (*see* Section 9.9) and thermal coal for cement production and other industrial processes (*see* Figure 41).

Demand for energy in the buildings sector is met by electricity and other solid fuels such as traditional biomass which account for 35% and 26% respectively; coal supplies just 6% of energy for buildings.

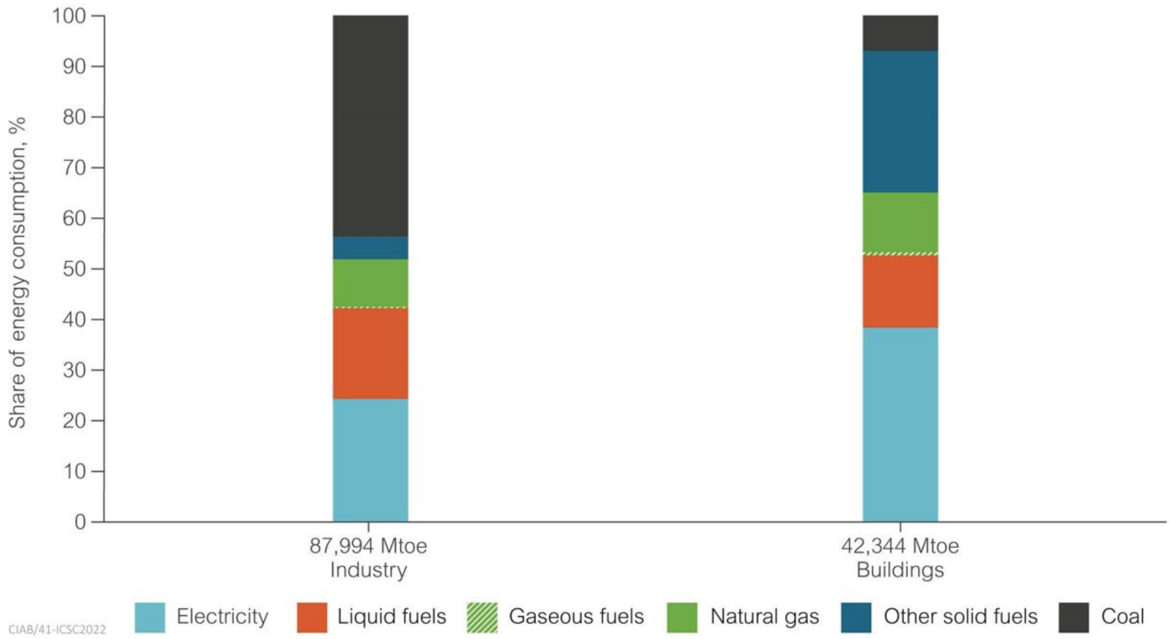


Figure 41 Share of energy consumption in industry and buildings in the Asia Pacific by fuel (author based on data from the IEA World Energy Outlook, 2021f)

The power sector is dominated by coal which supplied 57% of Asia Pacific's electricity in 2020. Coal power generation was 7406 TWh, of which almost 5000 TWh came from China and India generated 1130 TWh. Combined, these two countries account for 83% of the coal power shown in Figure 42. China and India made pledges at COP26 in 2021 to shift the focus of power generation away from coal. However, Chapter 10 discusses these countries' current trajectory of CO_2 emissions which highlights the need for the technologies discussed in earlier chapters.

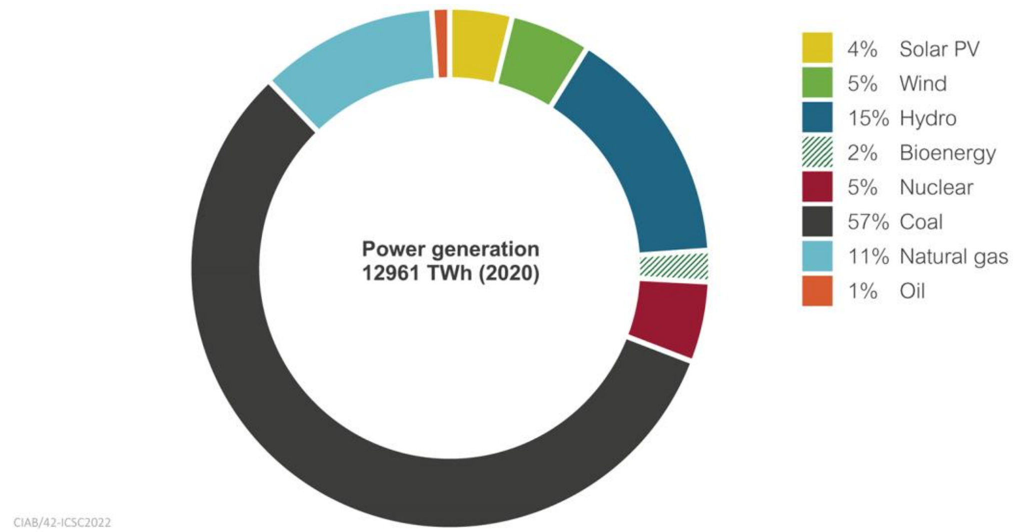


Figure 42 **Power generation by fuel in Asia Pacific, 2020 (author based on data from the IEA World Energy Outlook, 2021f)**

As China consumes more than half of the coal that is used, the actions taken there will drive future global coal trends. More than 90% of coal demand in China is supplied from domestic production, but China is also the second largest importer of coal, importing 205 Mt in 2020 (SSY, 2021). There have been major efforts to restructure the coal mining sector in China in recent years through the closure of unsafe and hazardous operations, and the consolidation of the sector has led to a considerable level of rationalisation (IEA, 2021). Consequently, the role of imports to supplement domestic production will ebb and flow, impacting the international markets. India is the largest importer of coal at almost 220 Mt, but the Indian government has prioritised boosting domestic production and reducing imports to promote self-sufficiency.

9.6 EMISSIONS OF CO_2

Figure 43 illustrates the share of CO_2 emissions by country in Asia and the scale of the challenge in reaching net zero. Global CO_2 emissions from oil, gas and coal combustion reached 31,980 Mt in 2020, of which Asia accounted for more than half at 16,350 Mt (BP, 2021). Almost 90% of Asia's emissions are from five countries: China (9900 Mt), India (2300 Mt), Japan (1030 Mt), South Korea (580 Mt), and Indonesia (540 Mt). This is followed by Vietnam, Thailand and Taiwan, each of which emitted approximately 280 $MtCO_2$.

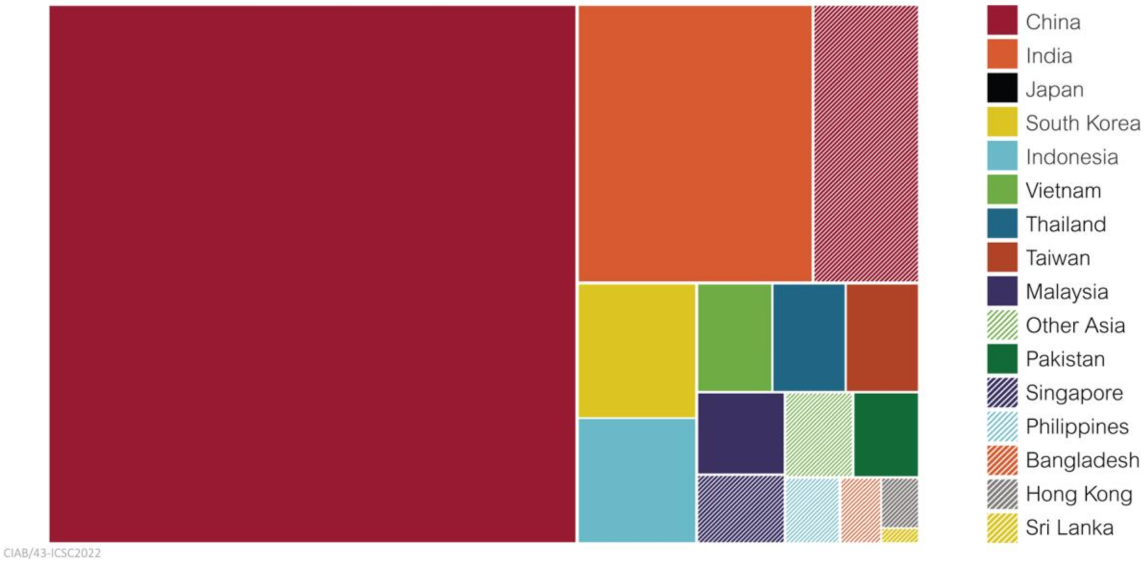


Figure 43 Share of CO_2 emissions by country in Asia (excluding Pacific) in 2020, total of 16,350 $MtCO_2$ (BP, 2021)

Most CO_2 emissions are from a fleet comprising predominantly SC and USC power plants built within the last 20 years. Figure 44 and Figure 45 show the age profile of the Asian fossil fuel fleet, showing that coal accounts for most plants built since the 1970s. In 2021, the average age of an Asian coal plant was 13–14 years. These data are dominated by the Chinese coal fleet, which accounts for 70% of Asia's coal fleet in terms of MW capacity (author's estimates based on S&P Global, 2021). The author's estimates suggest a similar age profile for the rest of Asia.

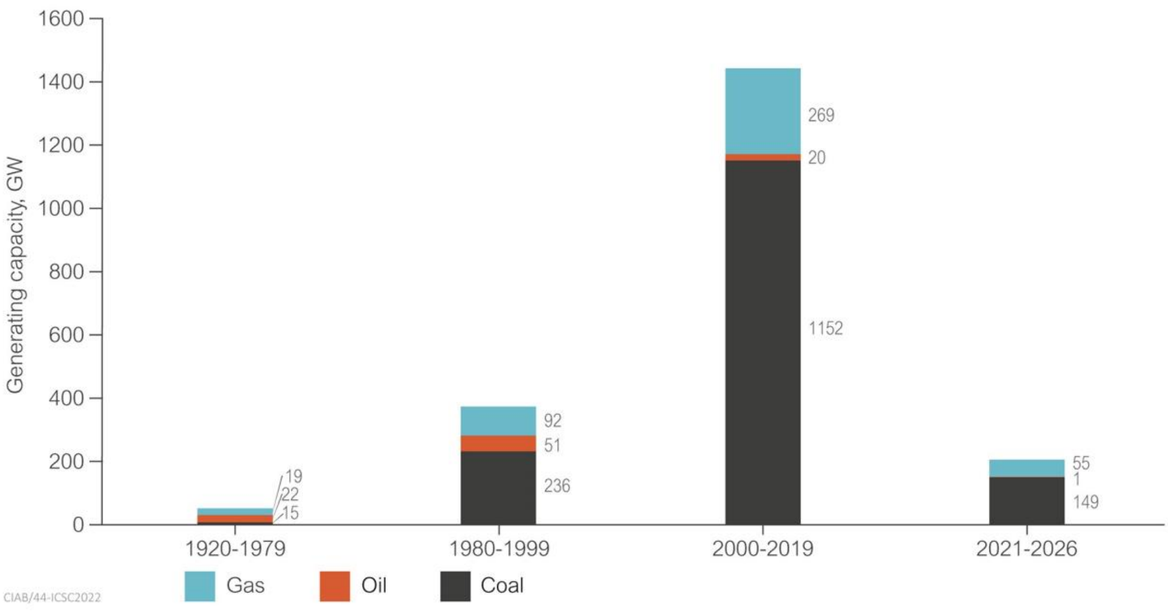


Figure 44 Age profile of coal, gas and oil generating capacity in Asia – post-2020 are under construction, and does not include planned units (author's estimates based on S&P Global, 2021)

As Figure 45 shows, USC plants are the dominant technology of plants under construction. Subcritical plants are no longer built on a large scale, but instead are reserved for smaller projects of around 300 MW or less. Since the mid-2000s, China has commissioned more than 150 very large USC units with a minimum capacity of 1000 MW each. The challenge of decarbonising Asia's coal fleet must address these young generating assets.

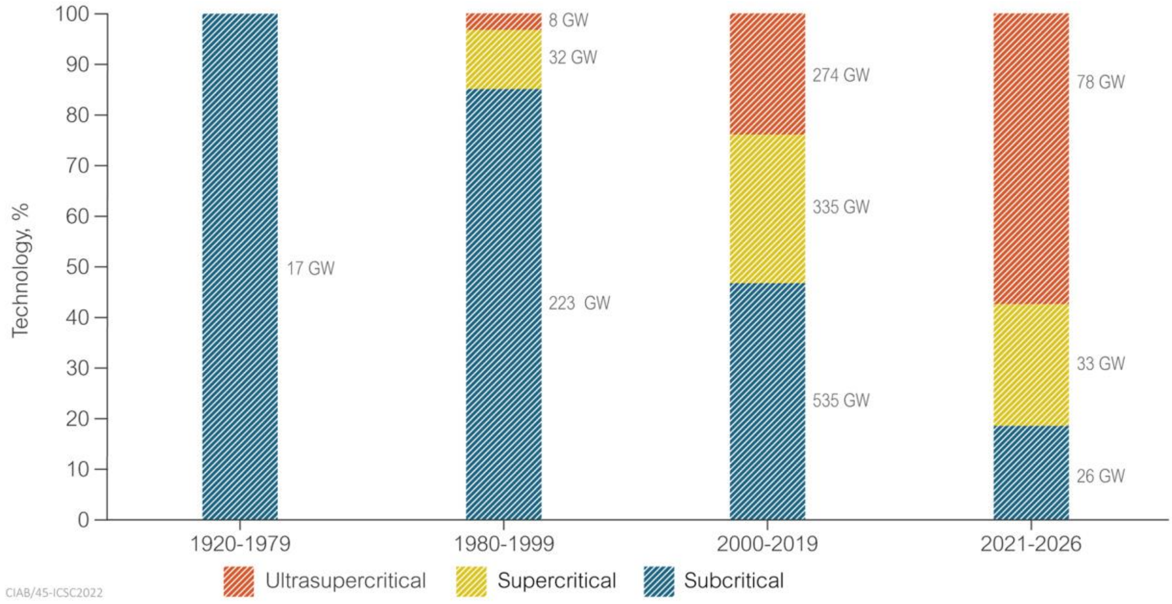


Figure 45 Coal power plants by steam technology in Asia (author's estimates based on S&P Global, 2021)

9.7 ASIAN ENERGY OUTLOOK

Investment in renewable power is increasing in Asia, but fossil fuels still dominate total primary energy supplies (TPES). Recent work on long-term projections for energy is presented in the IEA World Energy Outlook (IEA, 2021a). It uses several scenarios including the Stated Energy Policies Scenario (STEPS) the Announced Pledges Scenario (APS), and the Sustainable Development Scenario (SDS). STEPS illustrates the consequences of pursuing existing and stated energy policies that are backed up by legislation and regulatory measures including NDCs; few NZE pledges are enshrined in law and are not included in STEPS. APS assumes national NZE pledges are realised in full and on time, and therefore goes beyond STEPS.

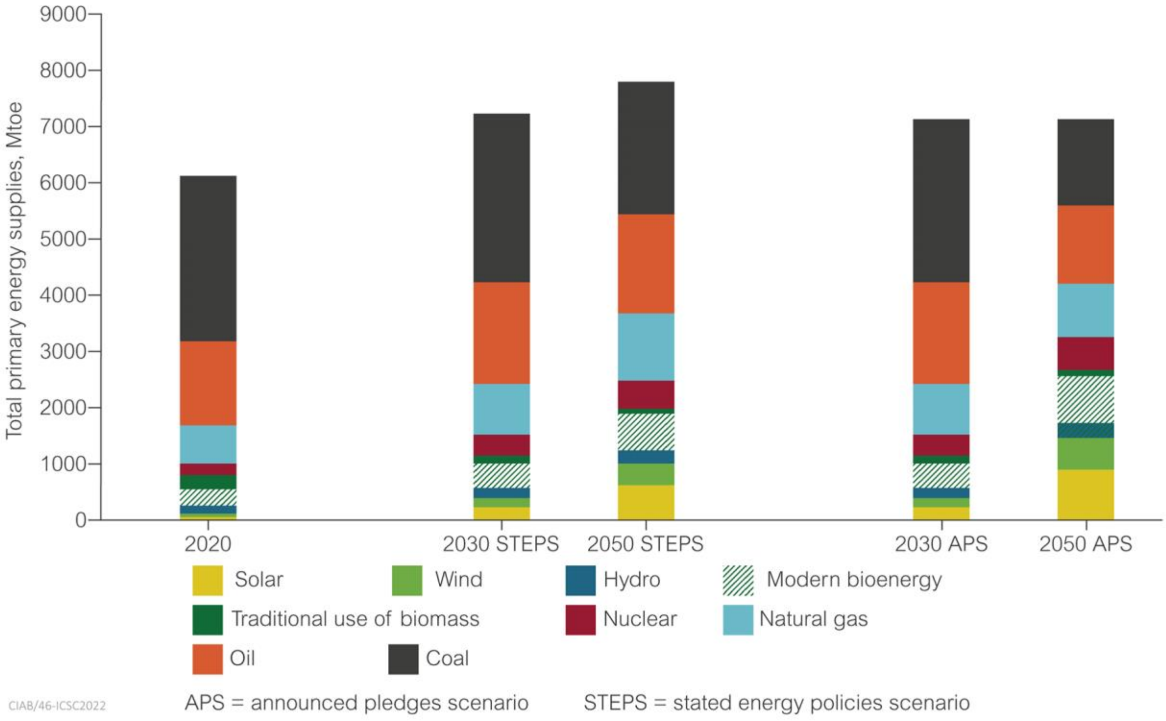


Figure 46 Asia Pacific TPES outlook to 2030-50, Mtoe (author derived from IEA, 2021f)

The various IEA scenarios model a decline in coal demand based on halting construction of new unabated power plants and reducing the emissions from 2100 GW of operating plants (*see* Figure 46). The slowdown in new coal plants has been evident in recent years. The STEPS and APS show coal having a smaller share of the generation mix between 2030-50 due to the region relying more heavily on solar and wind power. This is in general agreement with scenarios from the US Energy Information Administration (EIA).

In the STEPS, between 2020-50, generation from unabated coal decreases from 7406 TWh to 5504 TWh (*see* Figure 47). This reduction is due to a contraction of the fleet from 1524 GW to 1431 GW and plant utilisation dropping from 56% to 44% in the same period. In addition, 2 GW of CCUS capacity is in place in 2030. While the APS models a more drastic cut in coal-fired power than the STEPS, it also has a greater deployment of CCS fitted to the fossil fuelled fleet in Asia (*see* Figure 48). Under the SDS, CCS is developed at a faster rate bringing 32 GW online onto fossil fuelled plants. The unabated coal fleet is reduced by 80% in 2020-50 and the utilisation drops to less than 0.5%. Thus, under the SDS more fossil-fuelled plants are equipped with CCS, but the amount attributed to coal power is not revealed in the IEA results.

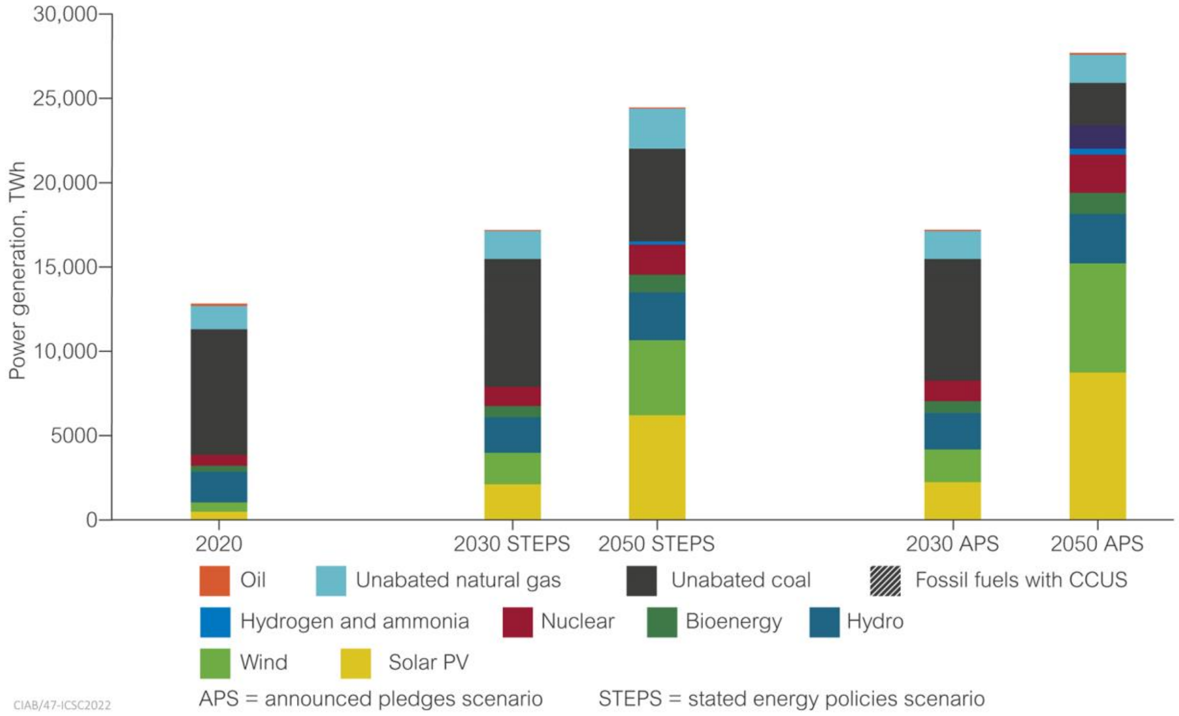


Figure 47 Outlook for power generation in the Asia Pacific under the STEPS and APS to 2050 (author derived from IEA, 2021f)

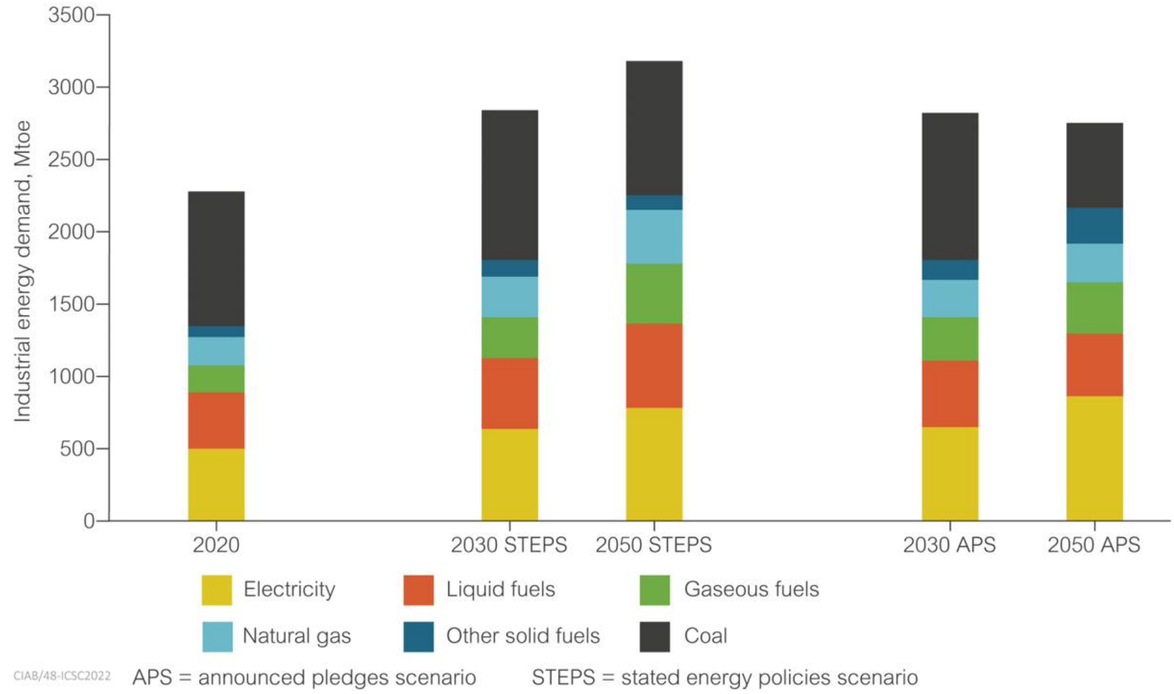


Figure 48 Asia Pacific industrial energy demand outlook to 2030-50 (author derived from IEA, 2021f)

The industrial sector derives 40% of its energy from coal, and the share of energy consumption remains significant in 2050, accounting for 21–29% depending on the scenario. Hydrogen does not feature greatly in the STEPS or APS but becomes an extremely important fuel when considering policies to achieve NZE.

9.8 NET ZERO EMISSIONS SCENARIO

Achieving NZE will require an extreme set of measures, all of which must be actioned to reach the goal, according to the IEA (2021a) (*see* Figure 49). Their scenarios for reaching net zero require a massive 80% decline in fossil fuel consumption globally by 2050.

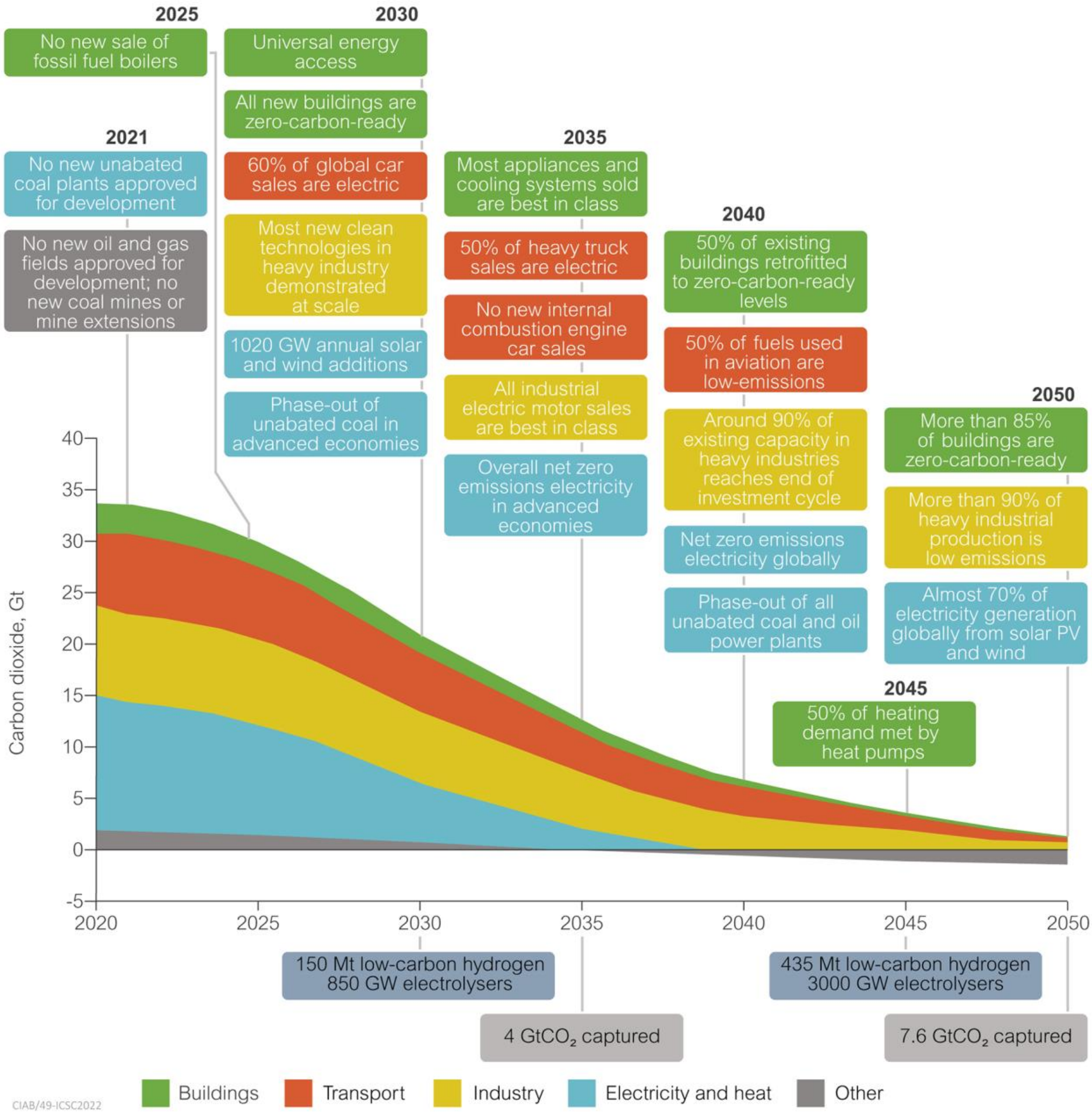


Figure 49 Key milestones in the pathway to NZE (IEA, 2021a)

The key technologies identified by the IEA include a fourfold increase in solar PV and wind capacity for power generation in 2020-30, electric vehicle (EV) sales to increase 18 times, and a reduction in global energy intensity of 4 %/y. The IEA acknowledge that the NZE ambition requires the deployment of both existing technologies and those that are not yet on the market, such as for decarbonising heavy industry. Many industrial facilities that are difficult to decarbonise will be equipped with CCUS, as well as fossil fuel power plants. However, achieving NZE means that electricity will need to account for

50% of total energy consumption, 90% of which is assumed to be supplied by VRE. Electricity already plays a crucial role in transportation, buildings and industry, and becomes essential for hydrogen production. Unabated coal power plants will be phased out, the least efficient of which come offline by 2030. All remaining coal plants will be fitted with CCS by 2040.

The critical challenge for Asian countries is to manage such sweeping cuts in emissions from economies that are relatively poor, dependent on coal, and also anticipate decades of continued economic growth, urbanisation and industrial development. By November 2021, more than 130 had set or were considering a NZE target by 2050. Eight countries had self-declared they have achieved net zero, a further 16 had a pledge in law, 59 in a policy document, 21 another kind of declaration or pledge and 72 countries were discussing or proposing a pledge (Net Zero Tracker, 2021). Eight Asian countries have pledged to reach NZE: Bangladesh (2050), Bhutan (achieved), Cambodia (2050), China (2060), Japan (2050), Myanmar (2050), Nepal (2050), Pakistan (2050), and Singapore is under discussion (NPUC, 2021).

9.9 STEEL OUTLOOK

The non-power sector accounts for 30% of coal consumption and is dominated by the manufacture of steel and cement. Steel is one of the most widely used materials with an immense variety of applications, including consumer goods, transport, construction, and infrastructure. Steel production has more than doubled this century from 850 Mt in 2000 to 1880 Mt in 2020. Coking coal is a vital component of most steel production (*see* Section 6.3). Around 70% of world steel production relies on the blast furnace and basic oxygen (BF-BOF) process that has raw materials such as iron ore and coal as the main components (Baruya, 2020). The remaining 30% is based on the electric arc furnace (EAF) process, whose feedstock requires large amounts of scrap steel and smaller amounts of BF-BOF crude steel.

Almost three-quarters of the steel produced in 2020 was in Asia, and more than 0%% of this was produced using the BF-BOF method; the rest came from EAF plants (Worldsteel, 2021). Four of the top ten steel-producing countries are in Asia (*see* Table 5 on page 82); they are China (1053 Mt), India (99.6 Mt), Japan (83.2 Mt), and South Korea (67.1 Mt). Other Asian steel producers include Taiwan (21 Mt), Vietnam (19.5 Mt) and Indonesia (7.6 Mt). Coking coal and steel production are discussed in detail in the ICSC report by Baruya (2020).

The outlook for steel production is uncertain due to a lack of publicly available data. However, there is some evidence to suggest that a slowdown and decline in steel output from China is expected due to the rationalising of redundant steel mill capacity to improve efficiency in the sector. This could be partly offset by an increase in output from countries such as India (Marcus and Villa, 2020). The Indian National Steel Policy published in 2017 expected steel production capacity to grow from 140 Mt/y to 300 Mt by 2030-31 to meet the expected rise in demand. In 2022, actual steel demand in India could increase by 17% to 110 Mt due to recovery in construction activity. By 2030-31, this demand could double to 230 Mt. The Indian steel sector is undergoing consolidation and there is an increasing role for foreign companies. For example, Nippon Steel (Japan) is joining ArcelorMittal of India in projects that could add 30 Mt/y of new steel mill capacity worth $11 billion. Other steel companies from Japan and South Korea aim to boost investment by engaging with Indian steel companies such as Tata Steel and Vijayanagar (IBEF, 2021).

In 2019, the ASEAN region operated with 89.5 Mt of steel mill capacity; a further 61.5 Mt is planned in anticipation of rising demand (*see* Figure 50) (Jin, 2020). Indonesia and Vietnam plan to increase their respective mill capacity by 13 Mt and 19 Mt. According to the IEA (2021) it will take longer for industry, transport and buildings achieve NZE than other sectors:

> *...cutting industry emissions by 95% by 2050 involves major efforts to build new infrastructure. After rapid innovation progress through R&D, demonstration and initial deployment between now and 2030 to bring new clean technologies to market, the world then has to put them into action. Every month from 2030 onwards, ten heavy industrial plants are equipped with CCUS, three new hydrogen-based industrial plants are built, and 2 GW of electrolyser capacity are added at industrial sites.*

Asia is undergoing a mix of expansion in steel production and rationalisation and modernisation. With a NZE target, investment in conventional steel mills could be shelved unless CCUS is included.

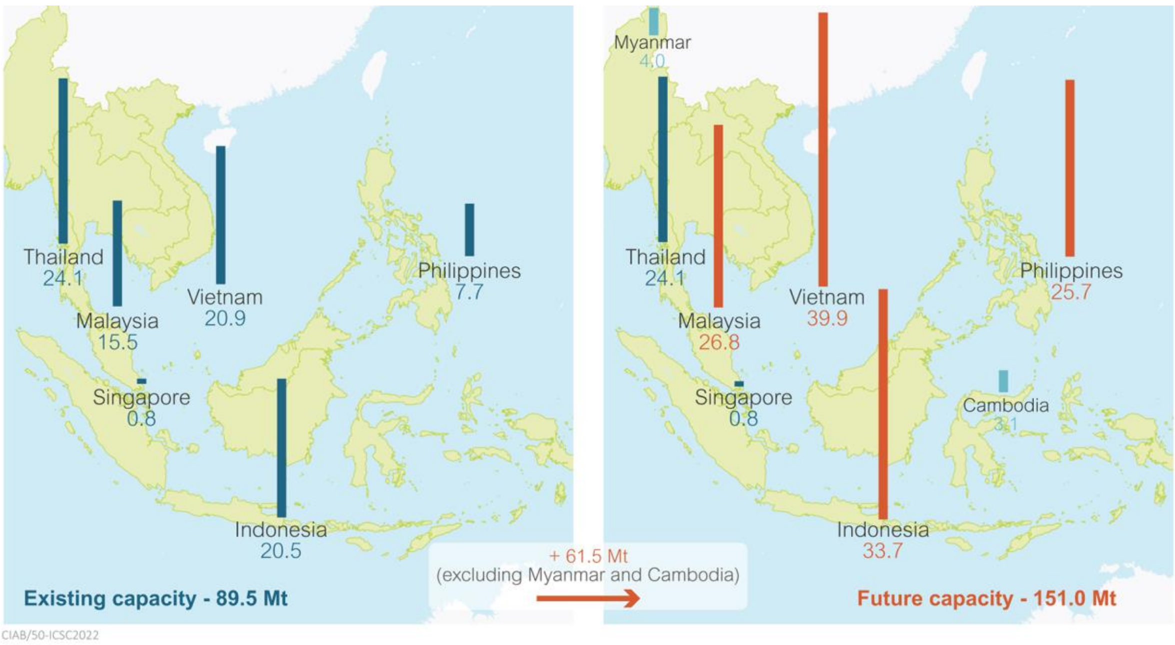


Figure 50 Steel mill capacity outlook in Southeast Asia (Jin, 2020)

9.10 CONSEQUENCES OF NET ZERO EMISSIONS IN ASIA

Many countries have announced NZE pledges at the time of writing (October 2021 but most have not published clear pathways on how they will achieve this goal. The work by the IEA (2021a) acknowledges that the NZE scenario relies on technologies that are commercially available today, but also on many that are yet to reach the market. The challenges of achieving NZE for various Asian nations are discussed in the case studies in Chapter 10.

According to the IEA (2021a), national NZE strategies remain in the early stages of implementation:

> *Governments need to provide credible step-by-step plans to reach their net zero goals, building confidence among investors, industry, citizens and other countries.*

Behavioural change and technological solutions are some of the measures needed. Electrification of transport, heating, and industrial processes is essential (*see* Table 18). The share of steel production using EAF needs to increase from 24% in 2020 to 37% in 2030 and 53% in 2050, to fit the IEA scenarios (IEA, 2021). As a result, electricity demand will increase much faster, at 3%/y in 2020-50 compared with 2%/y over the past decade (IEA, 2021). By 2050, the IEA concludes that renewables must supply 88% of generation. Global hydrogen use expands from less than 90 Mt in 2020 to more than 200 Mt in 2030, of which 70% will come from low carbon sources such as electrolysis and the remainder from coal and natural gas with CCUS.

TABLE 18 KEY GLOBAL MILESTONES FOR ELECTRIFICATION IN THE IEA NZE SCENARIO

Sector	2020	2030	2050
Electricity sector			
Renewables share of generation	29%	61%	88%
Annual capacity additions (GW): Total solar PV	134	630	630
Total wind	114	390	350
of which: Offshore wind	5	80	70
Dispatchable renewables	31	120	90
End-uses sectors			
Renewable share in total final consumption (TFC)	5%	12%	19%
Households with rooftop solar PV (million)	25	100	240
Share of solar thermal and geothermal in buildings	2%	5%	12%
Share of solar thermal and geothermal in industry final consumption	0%	1%	2%
Key global milestones for electrification in the NZE			
Share of electricity in total final consumption	20%	25%	49%
Industry			
Share of steel production using electric arc furnace	24%	37%	53%
Electricity share of light industry	43%	53%	76%

Chapter 10 presents four case studies for further investigation: China, India, Indonesia, and Vietnam. These countries were chosen because they have ample coal reserves and an established value chain from mining to power generation. In the four countries, the development of modern coal-fired power plants has increased over the last 20 years or so, with the installation of newer and cleaner coal technologies. China and India have been dominated by coal-fired power for some time. Indonesia and Vietnam have previously relied on non-coal sources, and since the mid-2000s, have embarked on a programme to reduce their reliance on hydroelectric power, oil- and gas-fired power, and have diversified their generation mix with coal. Economic growth has also stimulated infrastructure and industrial development, creating the drivers for energy demand in heavy industry and construction which has been partly met by coal, or coal-based electricity.

10 CASE STUDIES

10.1 KEY MESSAGES

The case studies summarised in Table 19 illustrate that a range of solutions, both local and regional, may be optimal to reach a country's net zero goal at least cost:

- Local – where cost effective storage is available taking into account CO_2 point sources, transport options and geological storage capacity;
- Regional – some countries have limited or costly storage. But they could still use hydrogen and other feedstocks from coal, with the carbon storage occurring where the coal reserves are located as part of attaining net zero.

CO_2 emissions will continue to increase in the four Asian case studies in the medium term. This is largely due to growing populations, expanding economies and increasing urbanisation.

All sectors need to reduce emissions dramatically in a pathway towards net zero emissions. This includes power generation and hard to abate heavy industry sectors. China and India are leading manufacturers of cement and steel. China is also a leader in the production of alumina, aluminium and chemicals. Southeast Asia is one of the fastest growing regions of the world with key growth centres in Indonesia and Vietnam, both of which have expanding heavy industry sectors. They are already among the largest cement producers in the world and their requirements for aluminium and steel are forecast to grow strongly as these are all nation building commodities.

To accommodate economic development and balance the three requirements of energy security, energy equity and environmental sustainability, the efficiency of the coal-fired fleet should be improved where possible in the period to 2030. There are also opportunities for cofiring, which are being promoted, particularly in Indonesia. Japan is developing cofiring ammonia and coal.

To ensure longer term sustainability, support is needed to make a business case for CCUS so that it can develop at scale. In particular, countries need to identify geological storage then develop links between emission sources and storage sites and pursue the deployment of CCUS.

For CCUS deployment to remain in line with the temperature objectives set out in the Paris Agreement, CO_2 capture in all case study countries will need to expand significantly.

Thus, collaboration is to be encouraged and national and international hub networks explored. These hubs will assist in lowering the cost of deploying CCUS at industrial plants and coal-fired power assets. It is particularly prudent to apply CCUS to Asian coal plants as most of them are only a third of the way through their 30–40 years lifespan. Retiring them early to switch to alternative technologies would incur substantial costs. Alternatively, applying CCUS recognises the societal value of the sunk investment in the asset.

Japan is developing innovative bilateral collaborations, including coal gasification in Australia to produce hydrogen for importation into Japan and ammonia supplies from various countries with geological storage in the producing country.

Japan is also leading development of the multilateral Asia CCUS Network, which aims to share information on CCUS technologies and development options, including a shared international hub infrastructure in ASEAN and possibly Australia. This will enable production of much needed low emission chemicals and other products for use in Japan as it transitions to a net zero future.

TABLE 19 SUMMARY OF THE FIVE CASE STUDIES (STATISTA, 2021A; INT ALUMINIUM, 2021)

Country	Global ranking of emissions, 2020	Established coal-fired capacity, GWe	Established hard to abate industries (world ranking)	National CCUS activity	Geological storage	Regulatory and policy interest in CCUS	Alternatives to fossil fuels
China	1	1009	No 1 producer of steel, cement, alumina, aluminium, and No 4 for chemicals	Yes	Yes	Yes Included for first time in current Five-Year Plan	Hydrogen, ammonia and other coal to liquid products, nuclear, renewables
India	3	220	No 2 producer of steel and cement, No 9 chemicals	No, member Asia CCUS network	Unknown but potential	No	Renewables, nuclear
Indonesia	10	21.9	No 22 steel producer No 5 cement producer	Yes, member Asia CCUS network	Positive potential	Yes	Geothermal
Vietnam	23	20.7	No 14 steel producer No 3 cement producer	No, member Asia CCUS network	Positive potential	Limited	Renewables
Japan	5	48	No 3 steel producer No 10 cement No 5 chemicals	Yes, member Asia CCUS network	Limited	Yes	Pursuing bilateral and multilateral hydrogen and ammonia supply chains

Several Asian countries have pledged to achieve NZE; Bhutan has already achieved NZE while South Korea has proposed to enshrine a NZE target into law. China and Japan's NZE plans exist as policy documents but are not yet legally binding. Asian countries where a NZE target is under discussion include Bangladesh, Cambodia, Laos, Myanmar, Nepal, Pakistan, Singapore, and Timor-Leste. India announced a NZE target of 2070 at the COP26 in November 2021 (Reuters, 2021a). The overall challenge to achieve NZE in Asia is discussed in Chapter 9. In this chapter case studies of China, India, Indonesia, and Vietnam are examined in more detail. Each country study briefly describes the scale of decarbonisation required in comparison with CO_2 emission trends and the nationally determined contributions (NDCs) to achieving the goals of the Paris Climate Agreement. The challenges of meeting NZE targets and sustainable pathways are investigated further in the context of rising energy demands due to economic and population growth and the scale of existing coal power assets currently operating in these countries.

The case studies illustrate how low emission technologies can provide a pathway to support national NZE targets while accommodating ongoing industrialisation and urbanisation. Importantly the case studies also show that Asian countries may expand their local solutions into regional ones by building transport and storage hub infrastructure. Japan is used as a case study to illustrate this.

10.2 CHINA

10.2.1 Challenges of achieving NZE

In 2020, GDP in China reached $14.7 trillion making it the second largest economy in the world after the USA (World Bank, 2021a). According to Price Waterhouse Coopers, China's GDP could become the largest before 2030, when measured in terms of purchasing power parity (PPP), where PPP adjusts GDP to account for the cheaper price of goods and services in less developed countries (PwC, 2017). In 2009, 100% of China's population gained access to electricity and gross national income per capita (GNI) reached $10,600. Thus, China is approaching the status of a high-income country, defined as having a minimum GNI of $12,695, putting it ahead of almost any other non-OECD Asian economy.

The population of China is expected to peak in 2029-33 at 1.46 billion and decrease to 1.44 billion by 2050 (*see* Figure 51). The population will also become more urban, increasing from 60% of the total population in 2018 to 80% urban in 2050. Urbanisation typically brings about an increased demand for energy and infrastructure that requires cement and steel. However, forecasts suggest that Chinese steel demand is expected to decline approaching 2050 (*see* Figure 52). In 2020, China was the largest producer of crude steel in the world at 1053 Mt, almost 90% of which was produced using the coal-based (BF-BOF) method of steel production which is a challenge to decarbonise (*see* Section 6.3) (Worldsteel, 2021). The proportion of global cement production originating in China will diminish as other countries increase production at a faster pace (WCA, 2021).

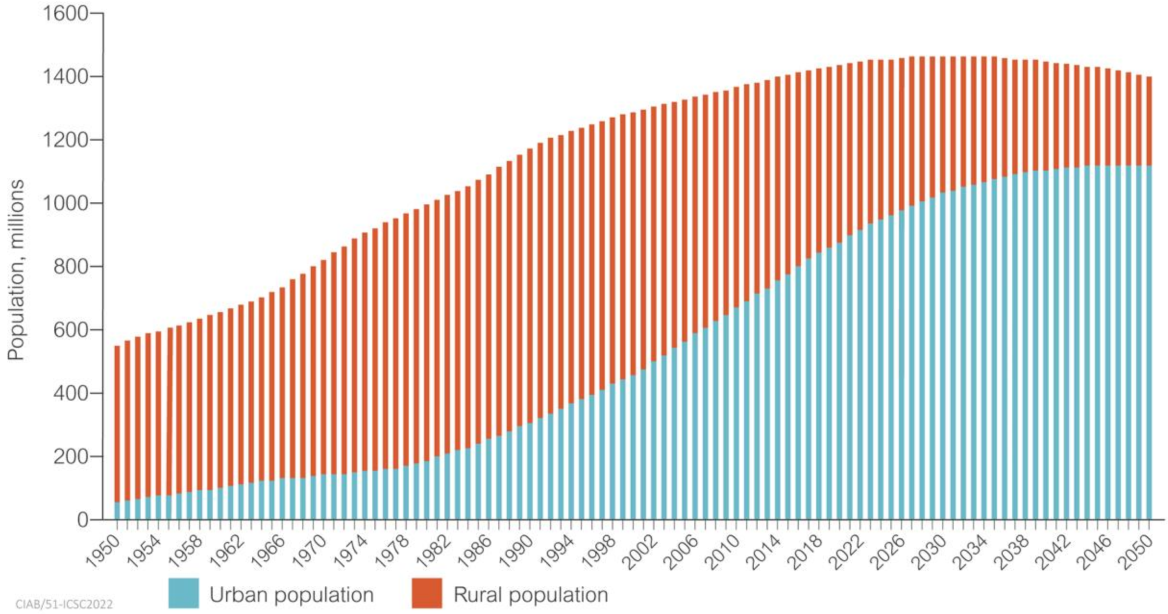


Figure 51 China's population outlook to 2050 (UN, 2018)

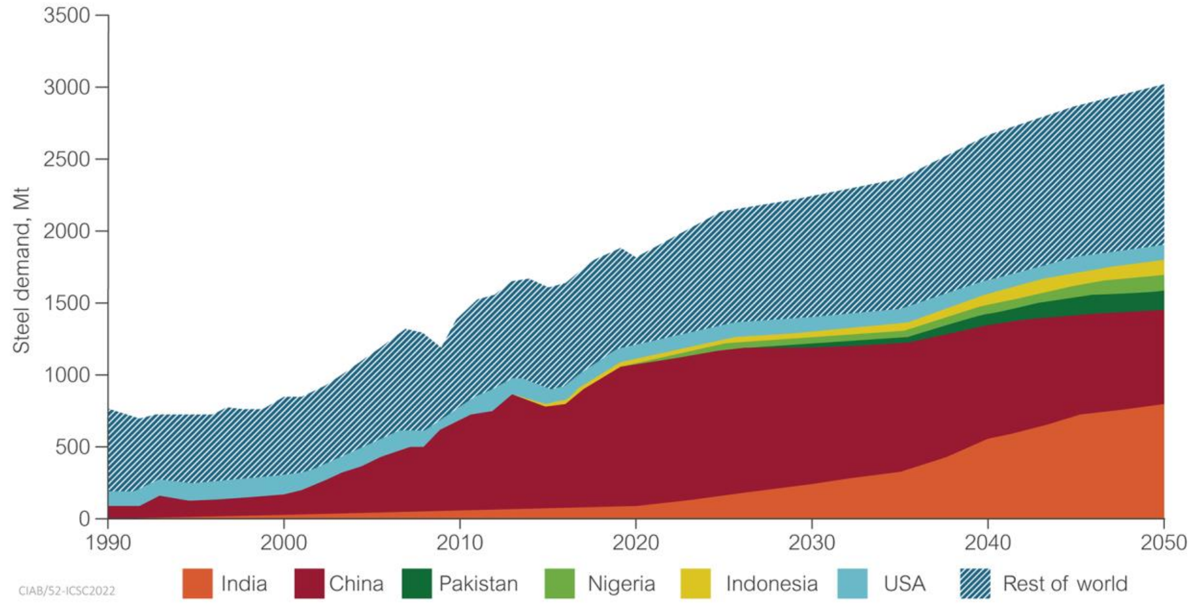


Figure 52 Global steel demand forecast to 2050 (Morgan, 2021)

10.2.2 Emissions, policies and targets

China is responsible for half of Asia's emissions of CO_2. Carbon dioxide emissions from fossil fuels in China have trebled every 20–25 years over the last 50 to reach 11.5 Gt in 2019 (*see* Figure 53). Forty per cent of emissions come from the power sector, 29% from industry, 16% from non-combustion sources, and a further 15% is split between transport and buildings (*see* Figure 54).

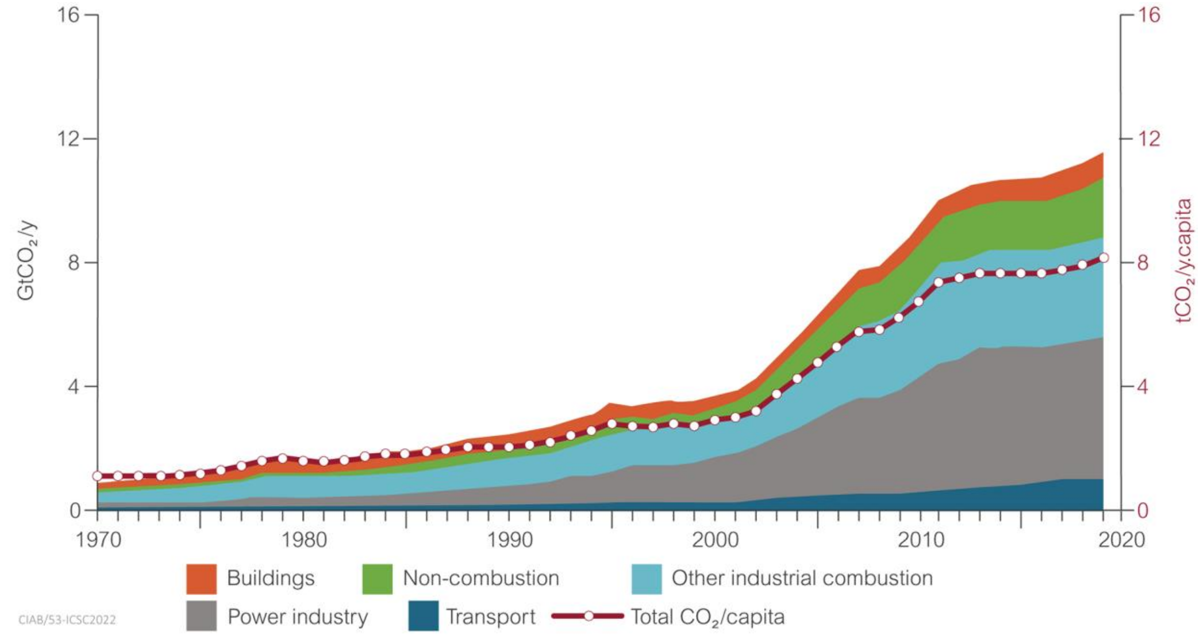


Figure 53 China's CO_2 emissions by sector, 1970-2019 (EDGAR, 2021a)

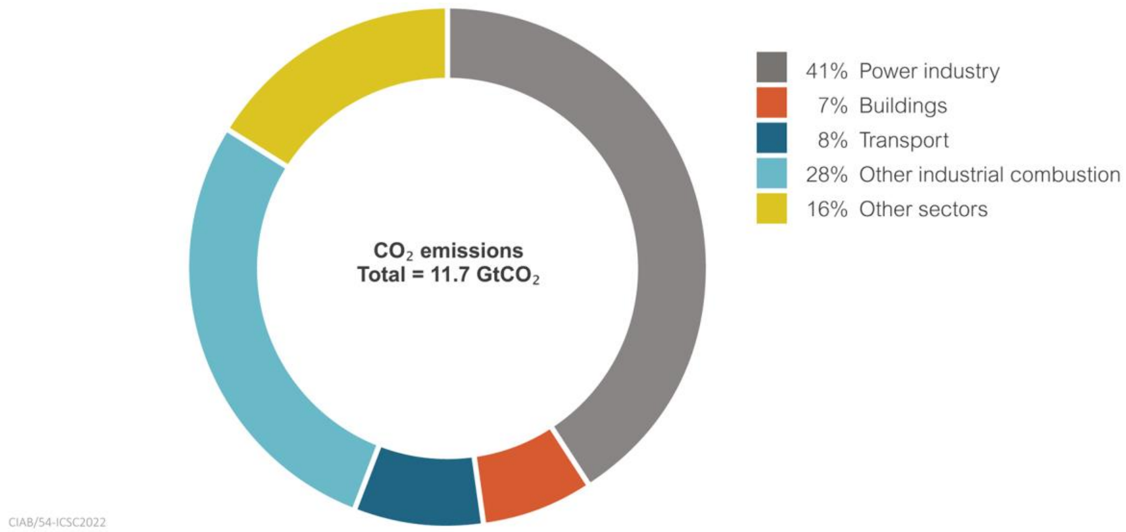


Figure 54 China's CO_2 emissions by sector, 2020 (EDGAR, 2021e)

Pledges made to the UN General Assembly by President Xi Jinping in September 2020 to achieve peak emissions by 2030 and carbon neutrality before 2060 signalled China's intention to go beyond its earlier commitment to the Paris Climate Agreement (Volcovici, 2020). Two documents set out the energy strategy for China. They are the *14th Five-year Plan (FYP) for National Economic and Social Development* and the *Objectives Toward 2035* which aim to divert the energy economy towards peak emissions in 2030 and set legally binding targets to reduce CO_2 intensity per unit of GDP by 18%. One of the most important features of this plan is the role of regional governments and industry sectors (Min, 2021). Thus far, China is set to meet its 2030 goals, but the trajectory of emissions thereafter remains uncertain. Figure 55 illustrates the task of reaching NZE compared with emissions in 2020, expected emissions in 2030, and the NDC targets. The columns illustrate the degree of compliance with the strictest emissions levels needed to limit the temperature increase to 1.5°C, with green being on track or 'role model' and black as 'critically insufficient'. As China's policy states, the country aims for emissions to peak, which will then require a precipitous drop to reach the dark green 1.5°C. The impact of Covid-19 on the Chinese economy reduced CO_2 emissions in 2020 to an estimated 13.8 $GtCO_2$ but they increased again in 2021. Even with a rebound in emissions projected to reach 12.3–14.5 $GtCO_2e$ by 2030, they may remain below the NDC target (CAT 2021a). However, President Xi Jinping announced China's intention to strictly control coal generation until 2025, and after emissions peak in 2030, a gradual phasing out of coal power is planned (IHS, 2021).

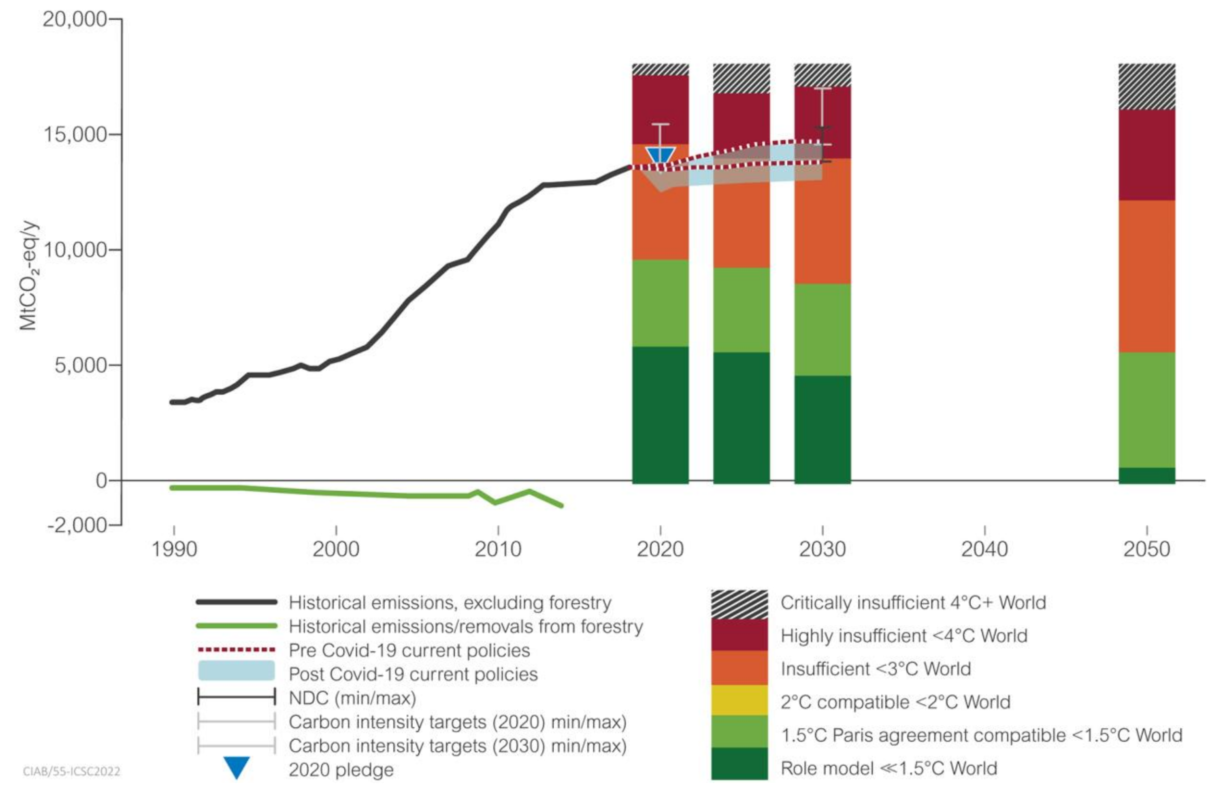


Figure 55 China's CO_2 emissions and NDC targets (CAT, 2021a)

China relies on coal for more than half of its primary energy yet aims to reduce fossil fuel usage across several sectors, such as transport, buildings, and industry. To achieve carbon neutrality by 2060 the electricity from net zero sources would need to more than double to 15,034 TWh. These sources would include renewables and CCUS fitted to an estimated 850 GW of coal capacity (Mallapaty, 2020). The 14^{th} FYP suggests China will continue the 'clean and efficient use of coal' as well as developing renewables, gas, and nuclear power (Cooper, 2021). However, the form in which the continuation of coal power will take is unclear.

10.2.3 Upgrading the existing fleet

As of mid-2021, China operated 1009 GW of coal-fired capacity which represented 63% of China's total generating capacity (*see* Figure 56). A further 40 GW are under construction and 66 GW are in the planning stages (S&P Global, 2021). SC and USC plants make up approximately two thirds of the capacity that will come online in the next few years.

The average efficiency of China's coal fleet has increased considerably since the 1970s from 25.8% to 37.8% during 2011-19. This improvement in average plant performance is due to the installation of higher efficiency SC and USC plants this century and the closure of smaller and less efficient units (*see* Figure 57). Eighty-five per cent of the coal fleet, equivalent to 830 GW, is around 20 years old or younger and comprises almost 500 GW of SC and USC units.

Subcritical coal plants still play an important role, although China has closed the most polluting ones and raised performance and emissions standards across the remainder of the fleet. China's emissions standards for new and existing coal plants are stricter than the EU for PM, SOx, NOx, and mercury emissions (Roberts, 2017; ICSC, 2021). Around 150 GW is more than 20 years old, of which 140 GW uses subcritical technology (*see* Figure 57). Upgrading subcritical plants to SC and USC offers efficiency gains and emission reductions. Further emission reductions could be achieved by cofiring with biomass and adding CCUS. There are examples of novel upgrade options that maintain subcritical steam conditions yet achieve efficiencies matching SC conditions (Varley, 2019).

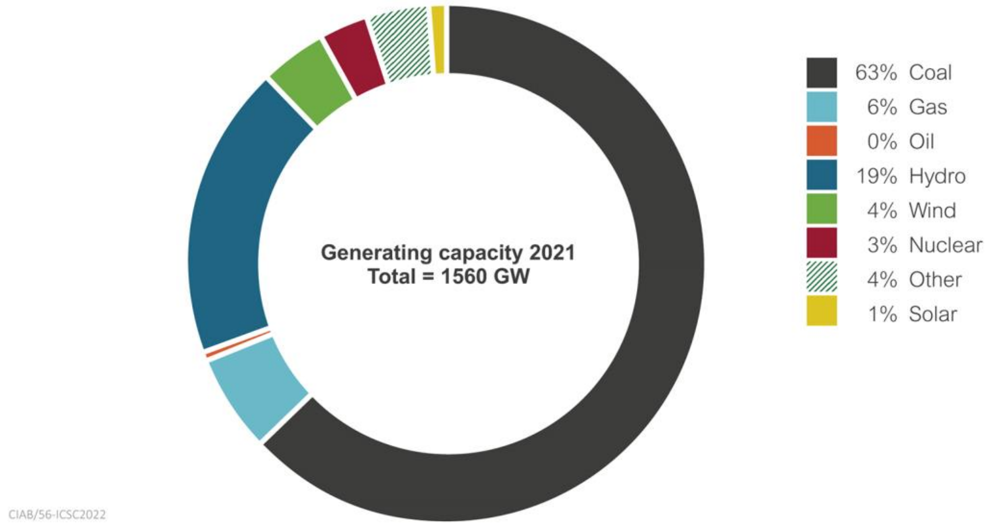


Figure 56 China's power generating capacity by source in 2021 (author's estimates based on S&P Global, 2021)

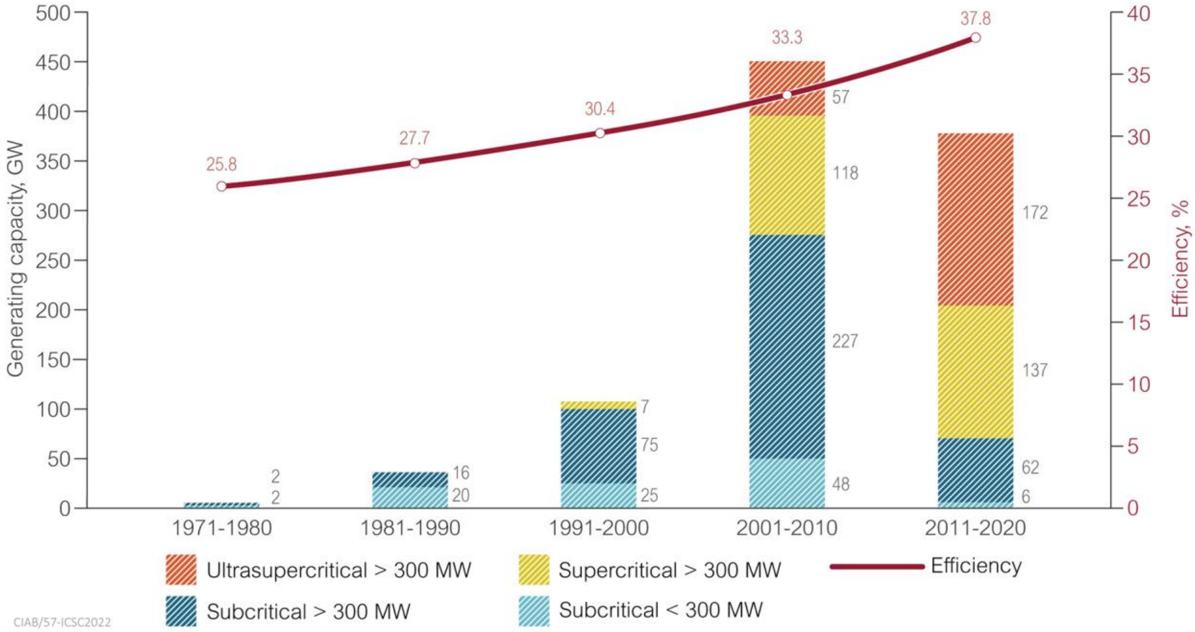


Figure 57 China's coal fleet by age, technology and efficiency (author's estimates based on S&P Global, 2021)

10.2.4 Current status of CCUS

China leads the region's CCUS activities with four large-scale commercial facilities in operation (South China Sea Offshore CCS, CNPC Jilin Oil Field CO2 EOR, Karamay Dunhua Oil Technology and Sinopec Zhangyuan CCUS for gas processing and chemicals production) and a further two large scale plant in construction (Sinopec Qilu and Guodian Taizhou Power Station Carbon Capture). There are several other CCUS projects in China as shown in Table 20, either in operation at smaller scale, or in the planning stage due for operation in the 2020s. Following the 2018 restructure, the Chinese Government focused on a more coordinated approach to general environmental management, combining emissions reductions with air pollutant controls, to stimulate new industries and employment (Kelsall, 2020). Their new National CCUS Professional Committee provides the government with support and advice, aiming to enhance international cooperation on CCUS. In May 2019, the latest roadmap for CCUS in China was published (Guo and Huang, 2020). It clarified the strategic position of CCUS and proposed mid- to long-term targets and priorities for achieving a low carbon transition through affordable, feasible and reliable CCUS technologies. While the GCCSI expects these policy commitments to advance the deployment of CCUS (GCCSI, 2019a), a previous comprehensive study of CCUS in China (Lockwood, 2018b) concluded that from a cost perspective, China could realistically proceed to retrofit a significant portion of the country's coal fleet by 2035, provided that adequate policy incentives were introduced. However, more recent analysis (Jiang and others, 2020) indicates that China's CCUS policy is insufficient for further development of CCUS technology, citing lack of an enforceable legal framework, insufficient information for the operation of projects, weak market stimulus and a lack of financial subsidies. A further analysis (Fan and others, 2020) indicated that CCUS retrofit of coal-fired power plant could only become viable from an investment viewpoint if the decarbonised electricity price increased to 0.75 ¥/kWh (around 0.1 $/kWh), equal to the FIT of solar PV and biomass power, when the investment value could exceed that of wind power generation projects in China.

TABLE 20 MAIN CCS FACILITIES IN CHINA (XU AND OTHERS, 2021)

	Facility name	Category	Status	Date of operation	Industry	Capture capacity, Mt/y
1	Daqing Oil Field EOR Demonstration Project	Pilot and demonstration CCS facilities	Operational	2003	Industrial applications	0.2
2	Sinopec Zhongyuan Carbon Capture Utilization and Storage Pilot Project	Pilot and demonstration CCS facilities	Operational	2006	Chemicals	0.1
3	Huaneng Gaobeidian Power Plant Carbon Capture Pilot Project	Utilisation facilities	Operational	2008	Power generation	<0.1
4	Shanghai Shidongkou 2nd Power Plant Carbon Capture Demonstration Project	Utilisation facilities	Operational	2009	Power generation	0.1
5	Chongqing Hechuan Shuanghuai Power Plant CO_2 Capture Industrial Demonstration Project	Utilisation facilities	Operational	2010	Power generation	<0.1
6	Sinopec Shengli Oilfield Carbon Capture Utilization and Storage Pilot Project	Pilot and demonstration CCS facilities	Operational	2010	Power generation	<0.1
7	Karamay Dunhua Oil Technology CCUS EOR Project	Pilot and demonstration CCS facilities	Operational	2015	Methanol	0.1
8	PetroChina Changqing Oil Field EOR CCUS	Pilot and demonstration CCS facilities	Operational	2017	Coal-to-liquids	0.1
9	Beijing Shougang LanzaTech New Energy Technology	Utilisation facilities	Operational	2018	Iron and steel	0.1
10	Haifeng Carbon Capture Test Platform	Test centres	Operational	2018	Power Generation	<0.1
11	CNPC Jilin Oil Field CO_2 EOR	Large-scale CCS facilities	Operational	2018	Natural gas processing	0.6
12	Sinopec Qilu Petrochemical CCS	Large-scale CCS facilities	Construction	2019	Chemicals	0.4
13	Guohua Jinjie CCS Full Chain Demonstration	Pilot and demonstration CCS facilities	Advanced development	2019	Power Generation	0.2
14	Sinopec Eastern China CCS	Large-scale CCS facilities	Early development	2020-21	Fertiliser	0.5
15	Yanchang Integrated Carbon Capture and Storage Demonstration	Large-scale CCS facilities	Construction	2020-21	Chemicals	0.4
16	Chinese-European Emission Reducing Solutions (CHEERS)	Pilot and demonstration CCS facilities	Advanced development	2022	Oil refining	-
17	China Resources Power (Haifeng) Integrated Carbon Capture and Sequestration Demonstration	Large-scale CCS facilities	Early development	2020s	Power generation	1.0
18	Huaneng GreenGen IGCC Demonstration-scale System (Phase 2)	Pilot and demonstration CCS facilities	Construction	2020s	Power generation	0.1
19	Huaneng GreenGen IGCC Large-scale System (Phase 3)	Large-scale CCS facilities	Early development	2020s	Power generation	2.0
20	Huazhong University of Science and Technology Oxy-fuel Project	Pilot and demonstration CCS facilities	Construction	2020s	Power generation	0.1

TABLE 20– CONTINUED

	Facility name	Category	Status	Date of operation	Industry	Capture capacity, Mt/y
21	Shanxi International Energy Group CCUS	Large-scale CCS facilities	Early development	2020s	Power generation	2.0
22	Shenhua Ningxia CTL	Large-scale CCS facilities	Early development	2020s	Coal-to-liquids	2.0
23	Sinopec Shengli Power Plant CCS	Pilot and demonstration CCS facilities	Early development	2020s	Power generation	1.0
24	Australia-China Post Combustion Capture (PCC) Feasibility Study Project	Pilot and demonstration CCS facilities	Advanced development	–	Power generation	1.0

Accelerating CCS in China – incentives and regulation are at the forefront

Operational CCUS capacity in China is no more than 2 Mt/y of CO_2 capture. This needs to increase by many magnitudes over the next fifteen years. The Paris Agreement and COP26 has refocused attention on emissions reduction and CCUS is becoming a more prominent part of that conversation in China.

CCUS is proven in use at various scales and across a range of industries in China, highlighting its versatility. The challenge for CCUS deployment is not technology. A supportive business case must be made for CCS to be widely deployed in China, as in the rest of the world. At its heart, this involves three intertwined factors: the setting of national emission reduction targets consistent with the aims of the Paris Agreement, the inclusion of CCUS in national climate action plans, and the establishment of policies that reward emission abatement through CCUS.

The storage element of CCUS also needs attention and the development of CO_2 storage resources beyond EOR in China must be prioritised; not to do so raises the risk of CCUS deployment being slowed by lack of data on storage potential. An important component of storage 'availability' in China is progressing the establishment of CCUS-specific legal and regulatory regimes that will support the many hundreds or thousands of facilities that will emerge over the course of the next few decades.

10.2.5 Hydrogen

The China Hydrogen Alliance (H2CN) released a landmark White Paper on China's hydrogen and fuel cell industry in June 2019, which is regarded as a key publication in support of Chinese governmental decision-making regarding hydrogen (Tu, 2020). Key targets recommended by H2CN are provided in Table 21. The number of stationary power projects and fuel cell systems should grow from 200 and 10,000 in 2019 to 20,000 and 5.5 million in 2050, the equivalent of 16% and 23% CAGR respectively.

TABLE 21 OVERALL TARGETS FOR HYDROGEN AND FUEL CELL DEVELOPMENT IN CHINA (TU, 2020)				
Development target	**Status in 2019**	**Target: 2020-25 Near term**	**Target: 2025-35 Medium term**	**Target: 2035-50 Long term**
Hydrogen as proportion of primary energy, %	2.7	4.0	5.9	10.0
Sector revenue, yuan billions	300	1000	5000	12,000
Number of refuelling stations	23	200	1500	10,000
Number of FCEVs	2000	50,000	1,300,000	5,000,000
Number of stationary power projects	200	1000	5000	20,000
Number of fuel cell systems	10,000	60,000	1,500,000	5,500,000

Most hydrogen production from coal takes place in China using gasification technology, mainly to produce ammonia (IEA 2019c). China is exploring the role of hydrogen in its economy, and using coal is currently the cheapest way to produce it, with costs without CO_2 capture of around 0.6-0.7 RMB/m^3 (around 1 \$/kgH_2). CHN Energy, China's largest power company, is also the world's largest hydrogen production company. Its 80 coal gasifiers can produce around 8 MtH_2/y, which is equivalent to 12% of global dedicated hydrogen production. The continued use of coal with CCUS therefore appears to be the lowest cost method of producing low carbon hydrogen in China, being some 30% cheaper than hydrogen production from natural gas (De Blasio and Pflugmann, 2020).

The interest in hydrogen to date has been primarily for the industrial manufacture of ammonia and methanol, as noted in Chapter 7, with the use of hydrogen to achieve decarbonisation being a lower priority. However, President Xi Jinping's 2020 announcement that China aims to achieve carbon neutrality before 2060, with emissions peaking before 2030, marks a significant change to this position (Tu, 2020). Given the scale of CO_2 emissions reduction that this implies, hydrogen will need to play an increasingly important role. A particular strength of China will be its ability to reduce the unit manufacturing cost of hydrogen economy technologies and components through industrial network clustering and economies of scale. This could result in a move towards the use of hydrogen from electrolysis in addition to hydrogen from fossil fuels. In this respect, it should be noted that in 2019, China had more than one third of global wind and solar energy, which could start to provide the level of renewable energy necessary to support the increased use of water electrolysis-based hydrogen production.

10.3 INDIA

10.3.1 Challenges of meeting NZE

India is the world's largest democracy with a population of 1.4 billion; by 2027, India could overtake China as the most populous country (*see* Figure 58). India is the sixth largest economy with a GDP of

$2.6 trillion, equal to that of France (World Bank, 2021a). According to PwC (2017), India could become the third largest economy by 2030 after the USA and China.

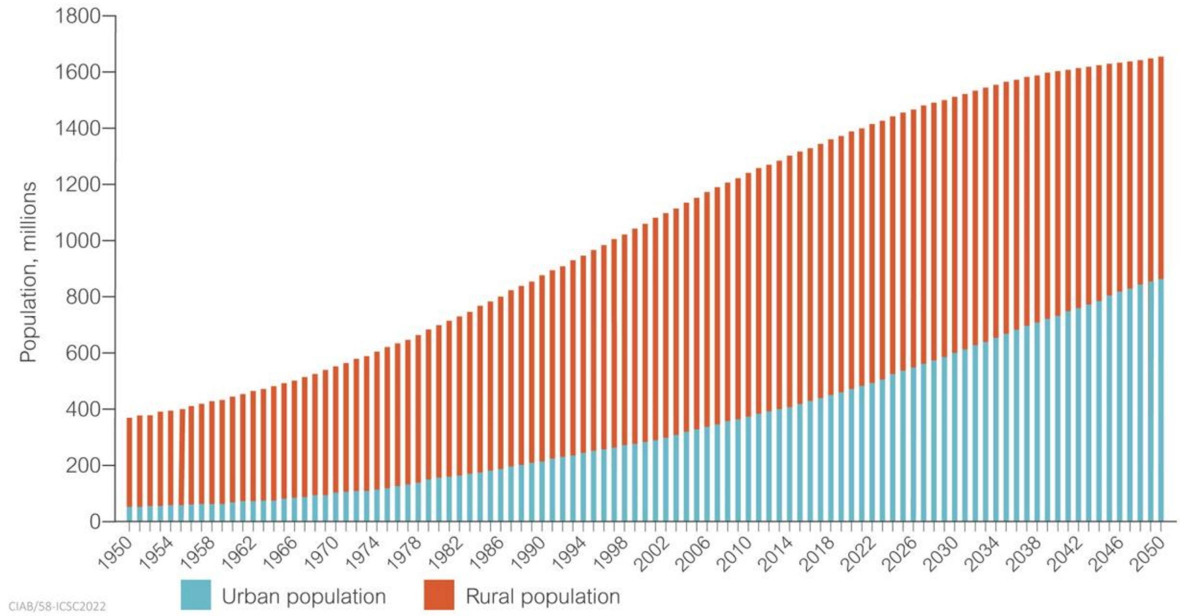


Figure 58 India's population outlook to 2050 (UN, 2018)

However, India's GNI per capita is only $1900 (2020), compared with China at $10,610 and below that of Indonesia ($3900) and Vietnam ($2660). Some 35% of India's urban population lives in slum housing compared with China at 25% and Vietnam at 14% (World Bank, 2021a). In 2020, the urban population in India was just above 480 million; by 2050, it could be 866 million (World Bank, 2021b). India has taken immense steps to increase access to electricity for its population. The proportion with access has increased from 59% in 2000 to 98% by 2019 (World Bank, 2021b).

Improved housing, electrification and infrastructure for the growing urban population could lead to India's steel consumption more than doubling from 93 Mt in 2020-21 to 230 Mt by 2030-31 (IBEF, 2021; Worldsteel, 2021b). In 2020, India was the second largest steel producer in the world at nearly 100 Mt of which 55.5% was produced from the electric arc furnace (EAF) method, and 44.5% from the BF-BOF. Figure 59 illustrates the rising share of Indian steel production according to the IEA SDS which could compensate much of the reduction in demand expected in China.

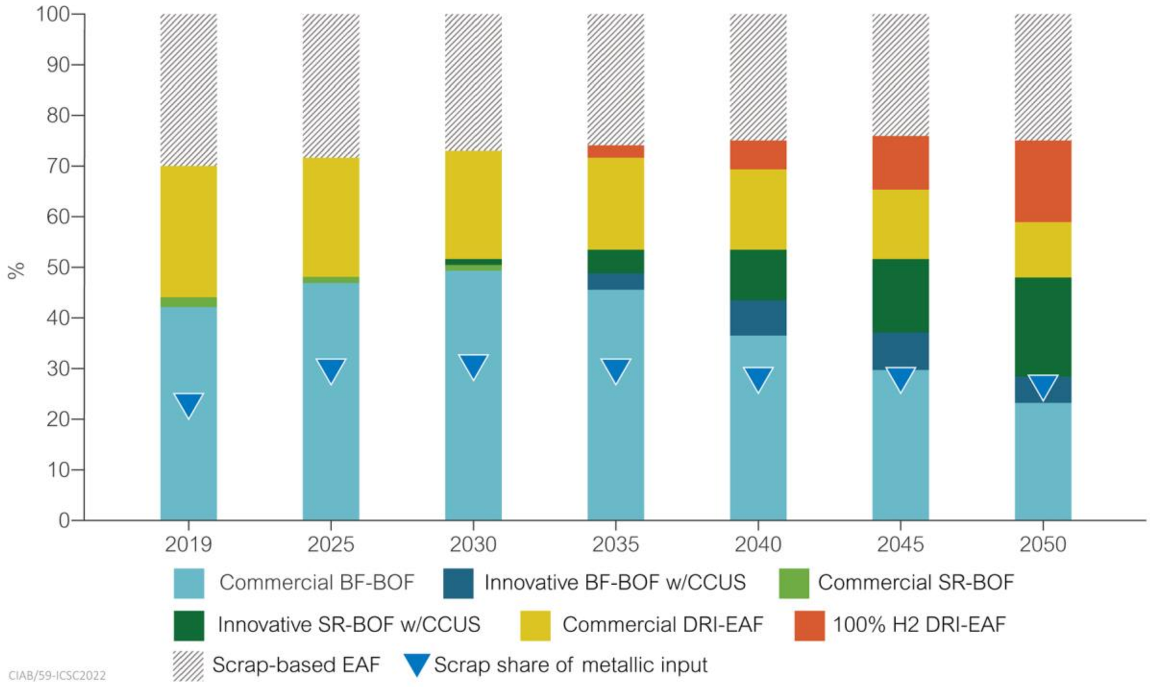


Figure 59 Production of steel by route in India in the IEA Sustainable Development Scenario 2019-50 (IEA, 2020c)

As described in Section 6.3, emissions from steel production can be reduced. Potential solutions include using CCUS or replacing the BF-BOF processes with production capacity using the electric arc furnace (EAF), and direct reduced iron (DRI) (Baruya, 2021).

Cement production capacity is being increased by 80 Mt/y by 2024 from just under 300 Mt/y in 2021 to meet rising demand. According to the World Cement Association, India is expected to double its share of global cement production from 8% in 2018 to 16% in 2030 (WCA, 2019). Again, there are methods to reduce emissions from this sector (*see* Section 6.4).

Power generation in India is dominated by coal. During the last 30 years, there has been a major shift from traditional biomass to more modern energy supplies, notably electricity, which has increased the role of coal in the economy, from 30% of TPES in 1990 to 44% in 2020 (387 Mtoe) (IEA, 2021). Around two-thirds of the coal was used for utility power generation (IEA, 2020). India's success in expanding the reach and capacity of its electricity supply capabilities has been essential to alleviate poverty and extend economic prosperity (Adams and others, 2021).

Between 2009-18 alone, power generation grew at 6.1%/y, adding 640 TWh to India's annual production; the equivalent to adding the entire output from the German power sector in 2018. Provisional estimates for 2018-19 show India's generation output reached 1547 TWh (*see* Figure 60). Coal-fired power has increased its share of total generation from 68% to 75% between 2009-19 reaching 1163 TWh (MOSPI, 2020).

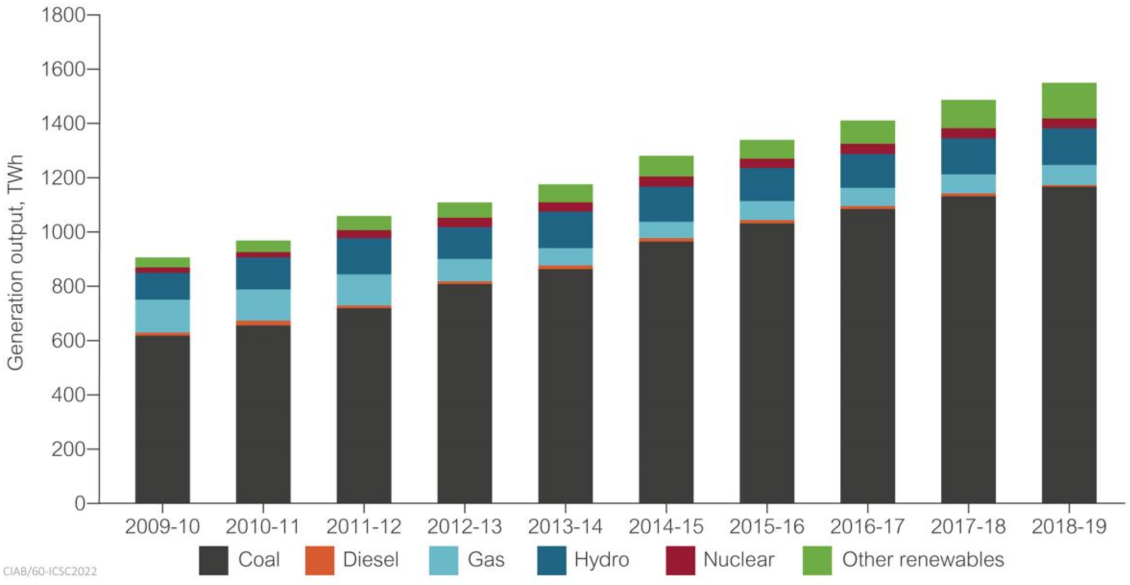


Figure 60 Electricity generation by fuel in India, 2009-19 (MOSPI, 2020)

India has a wide range of energy pathways based on ambitious plans to expand non-hydro renewables by 450 GW by 2030 and beyond, four times the renewable fleet that was reported in July 2021 (CAT, 2021). It is argued that falling auction prices for wind and solar will hasten the adoption of renewables at the expense of coal power which has recently faced fuel shortages. However, coal is expected to continue to supply a significant proportion of future energy demand as it remains at the core of the Indian energy system and its coal communities (Vaidyanathan, 2021). The Central Electricity Authority suggests that India will need 64 GW of new coal power although the National Electricity Plan 2018 identified some 48 GW of plants that are more than 25 years old which could be phased out (CAT, 2021).

10.3.2 Emissions, policies and targets

Forty-five per cent of primary energy consumption in India comes from coal, almost all of which is produced domestically. It is viewed as a strategic energy source providing employment throughout the entire mine-to-power supply chain (Vaidyanathan, 2021). Consequently, the Indian government is a significant stakeholder in the energy sector through its state-owned coal mining and power generation enterprises, although private sector participation is also encouraged (Adams and others, 2021).

In 2020, India was the third largest emitter of CO_2 in the world at 2.3–2.4 $GtCO_2$ (2019) behind China (10.3 Gt) and the USA (4.9 Gt) (*see* Figure 61 and Figure 62). The size of India's population means that per capita CO_2 emissions are low at just 1.8 tCO_2 compared with China at 7.4 tCO_2, Indonesia at 2.4 tCO_2, and Vietnam at 2.7 tCO_2 (IEA, 2021). India's growing population and economy means that demand for energy will increase. The current energy mix means that CO_2 emissions will also grow as the government has introduced economic stimulus packages to restore growth in the economy post Covid-19, despite intentions for a green recovery including investment in solar and battery technology (Kazmin, 2020).

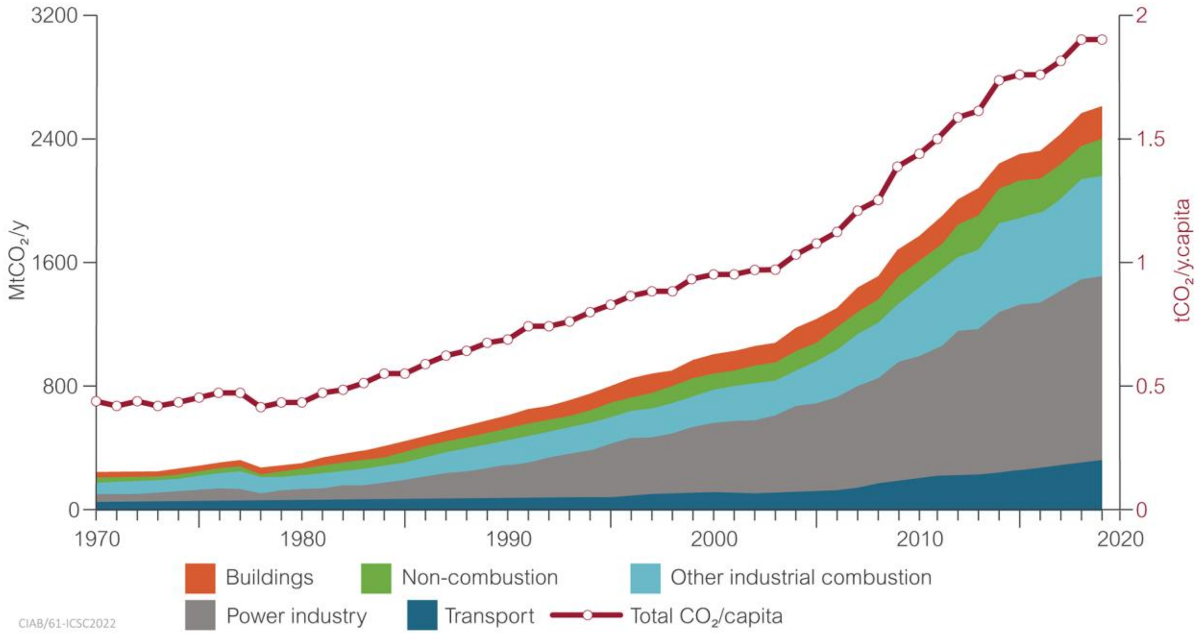


Figure 61 India's CO_2 emissions by sector, 1970-2019 (EDGAR, 2021b)

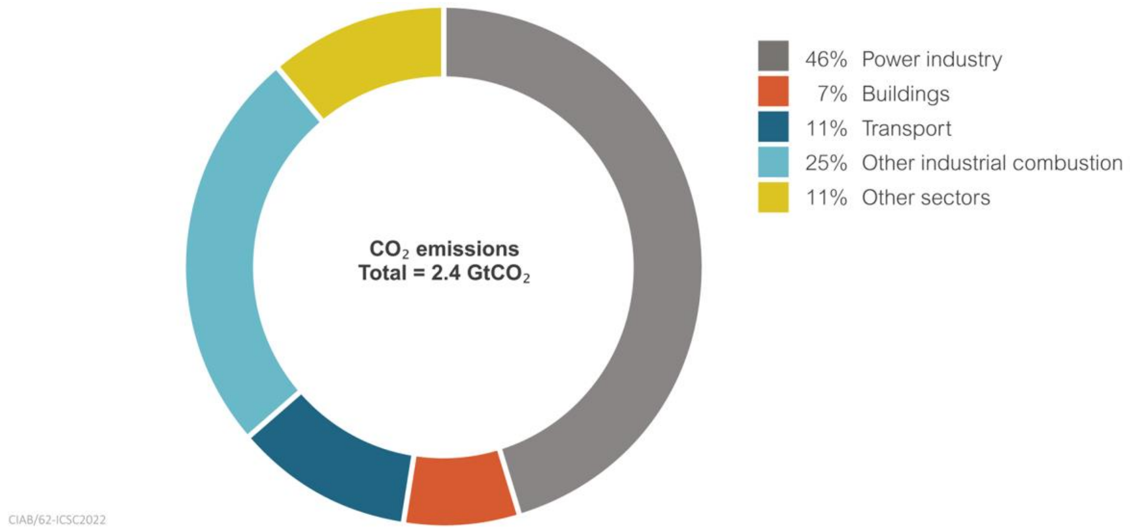


Figure 62 India's CO_2 emissions by sector, 2020 (EDGAR, 2021e)

Figure 63 shows that emissions in India are still increasing and are not yet compatible with achieving the Paris Agreement target.

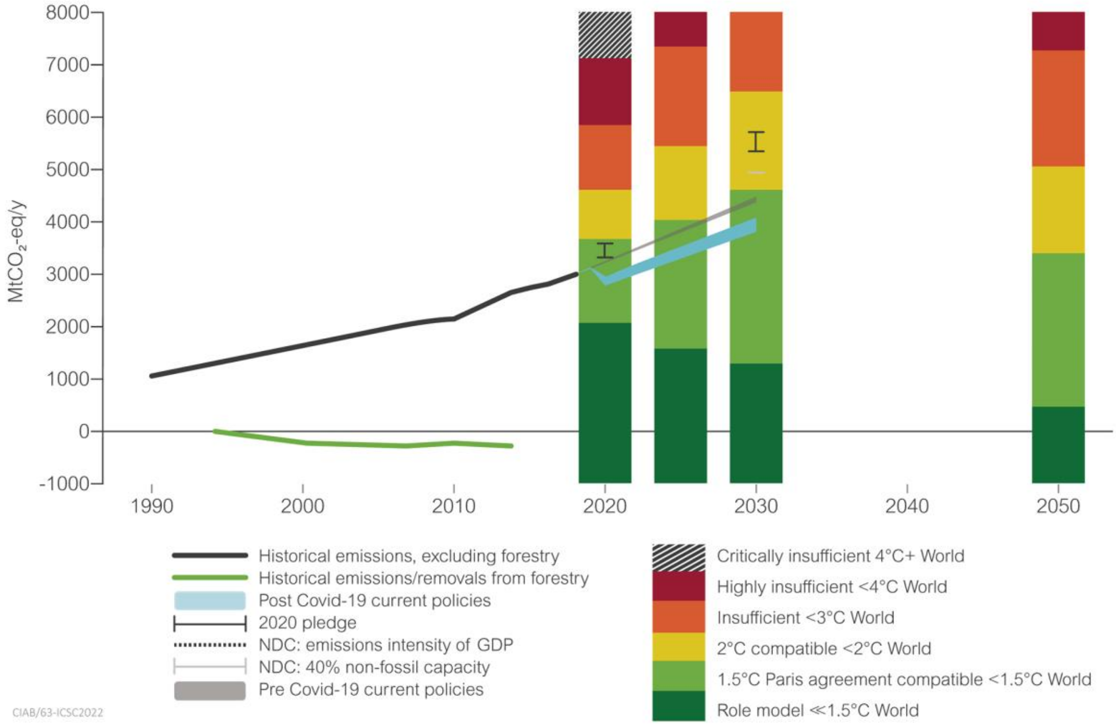


Figure 63 India's CO_2 emissions and NDC targets (CAT, 2021a)

Under the Copenhagen Accord, India agreed an emissions intensity (tCO_2 per $ GDP) reduction of 20–25% below the 2005 level. Between 2005 and 2020, a doubling of CO_2 emissions coincided with a more than doubling of GDP leading to a reduction in emissions intensity of 22% (*see* Figure 64). The stricter Paris Agreement target requires a reduction of 30% and so India should reduce the CO_2 emissions intensity further although Figure 64 shows how India's emissions pathway is almost consistent with its NDC.

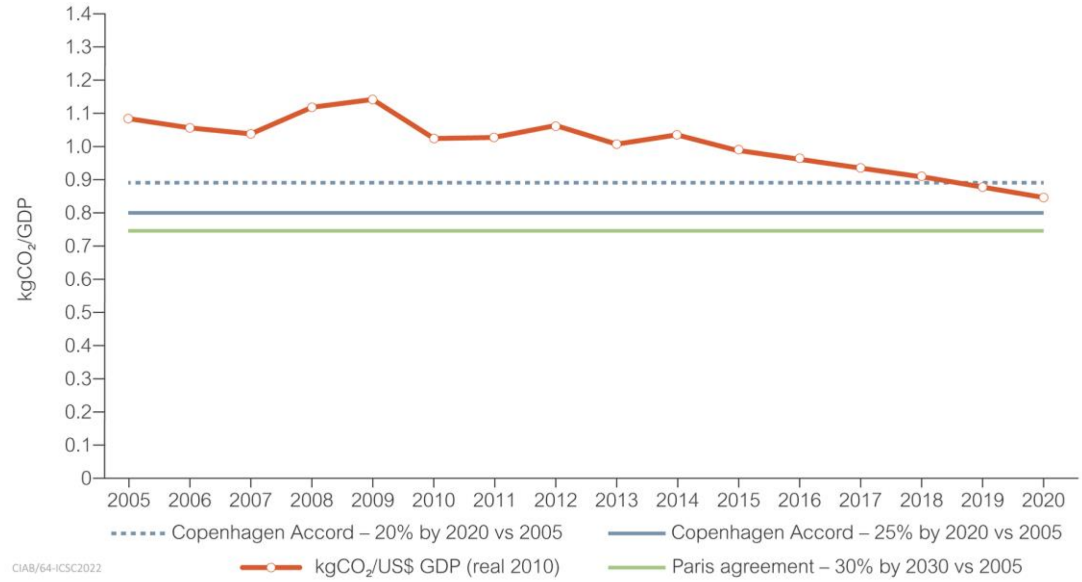


Figure 64 CO_2 intensity of GDP in India 2005-20 compared with climate targets (author's estimates based on World Bank, 2021a; ICOS, 2020; Levin and Lebling, 2019; IEA, 2020; Economic Times, 2020; Orr, 2019)

Going beyond its original NDC and achieving NZE will mean a massive task of replacing output from India's unabated coal fleet with zero emissions power technology while emissions from the steel and cement sectors will also prove challenging as production relies heavily on coal. The lack of oil and natural gas resources in India provides the energy sector with few alternatives with respect to fossil fuel sources. A large amount of CCUS and cofiring will be required.

10.3.3 Upgrading the existing coal fleet

The current fleet of 220 GW comprises mainly subcritical plants (160 GW); the first SC units came online after 2011. Before 2000, India's coal units were mainly smaller <300 MW, accounting for 70–80% of all new coal capacity. Due to rising demand for electricity, smaller units have given way to units of >300 MW and an increasing role for SC (*see* Figure 65). Fifty-five per cent of the capacity under construction uses SC or USC technology. India is also working on advanced USC with the aim of developing new units that will operate at efficiencies approaching 50% (net LHV).

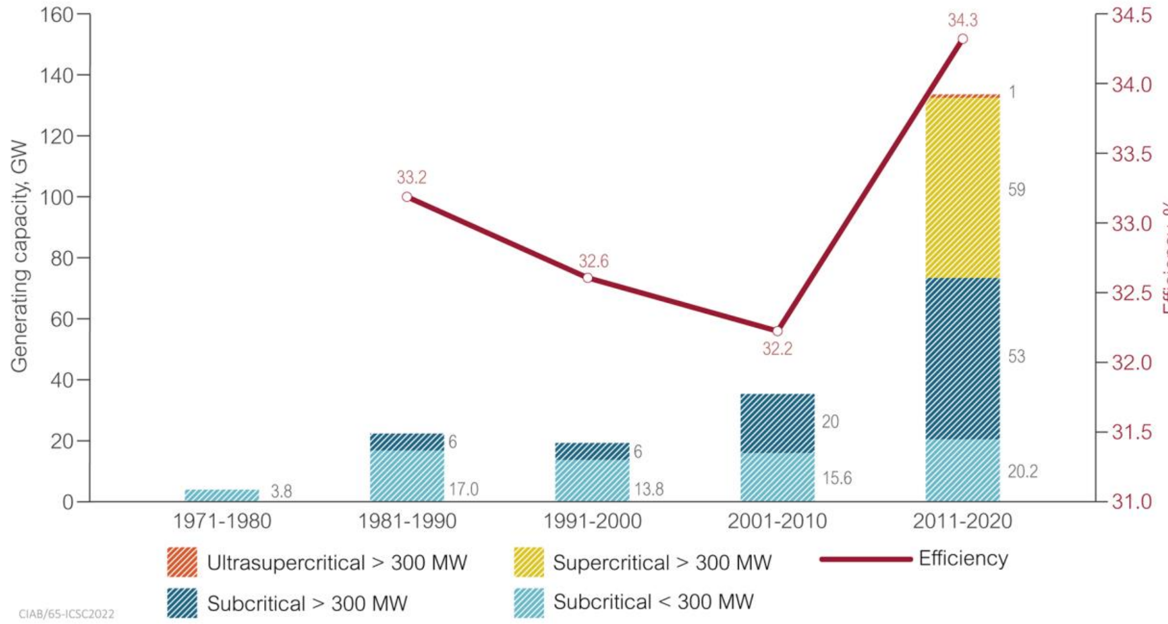


Figure 65 India's coal fleet by age, technology and efficiency (author's estimates based on S&P Global 2021)

In 2018, the Central Electricity Authority identified approximately 48 GW of coal capacity that could be retired after 25 years of service in the period 2017-27. Although this would still leave a significant amount of subcritical capacity, it offers the opportunity to modernise and renovate the less efficient units. Examples of unit upgrades are reported in Adams and others (2021) and demonstrate how plants burning Indian coals can adopt various measures including coal washing, optimised combustion, steam turbine upgrades, heat recovery and digitalisation of plant operations. For example, steam turbine retrofits in Indian subcritical stations are reported to achieve more than 5 percentage points increase in efficiency, while also improving plant flexibility, reliability and increasing the output capacity of existing units. Currently, operators of Indian power plants are contending with financial stress and delays in installing pollution control equipment to reduce emissions of NOx, SOx and PM.

10.3.4 Current status of CCUS

In 2018, India's emissions rose by 4.8%, due to a strong increase in energy demand, with coal use increasing by 5%. It has the world's third largest coal fleet, with an average unit age of 16 years. However, despite the significant potential for India to contribute to global CO_2 emissions reduction, there are no projects in India listed in the GCCSI database of current and planned projects. A recent analysis of CCUS in India (Gupta and Akshoy, 2019) noted that there is marginal interest in the domestic demonstration of CCUS technology in India, due mainly to concerns over public reaction to underground CO_2 storage.

However, the Government of India has supported CCUS since the early 2000s, but little has been invested beyond R&D. Areas of R&D include algae-based capture at gas plants, oxyfuel combustion, and solvent-based research at pilot scale. India has been active in several international initiatives including funding for EU- and US-based programmes (Lockwood, 2018a). The most likely progress will occur in Indian-owned industrial facilities in Europe such as Tata Steel, which has committed to becoming carbon neutral by 2050, but there is currently little interest in deploying CCS in its steel facilities in India. However, India has a large fertiliser industry which needs CO_2 as a feedstock for production of urea and soda ash (sodium bicarbonate) which derives CO_2 from natural gas.

There is currently limited knowledge of India's CO_2 storage potential, and most current estimates are based on studies conducted in 2008. It should be noted that the Damodar Valley basin, which covers a major coal producing area in northern Jharkhand, is considered potentially favourable for storage, subject to further investigation (Adams and others, 2021).

10.4 INDONESIA

10.4.1 Challenges of meeting NZE

Indonesia is one of the largest economies in Southeast Asia with a GDP of $1.1 trillion (World Bank, 2021a). In terms of GDP (PPP) Indonesia could overtake several OECD European nations to become one of the top ten largest economies by 2030 and then the fourth largest economy by 2050 (PwC, 2017; Orlik and Roye, 2020). Economic growth in Indonesia will drive the demand for energy, housing and infrastructure. Indonesia has a population of around 272 million across more than 17,500 islands and despite its geography access to electricity in Indonesia is very good at 99% (2019), compared to 86% in 2000 (MEMR, 2021). This still leaves more than three million people without electricity, who are mainly on remote islands in the east (author's estimates based on World Bank, 2021b).

Indonesia's population could grow by 27 million to 299 million in 2030, and 330 million in 2050 (*see* Figure 66). The urban population could increase by 155 million, from 57% in 2020 to 73% of the total in 2050 (UN, 2018). The corresponding growth in construction will lead to a rise in demand for steel and cement, although the rate of construction is expected to slow from 6.8 %/y in 2019 to 5.7%/y by 2020 (Sebastian 2021). A lack of infrastructure means Indonesian economic growth tends to fall short of its potential (ITA, 2021). Even at a lower rate of growth, the demand for construction materials will require decarbonisation measures for industrial processes for cement, chemicals, steel production, and other metal smelting such as nickel (MEF, 2021).

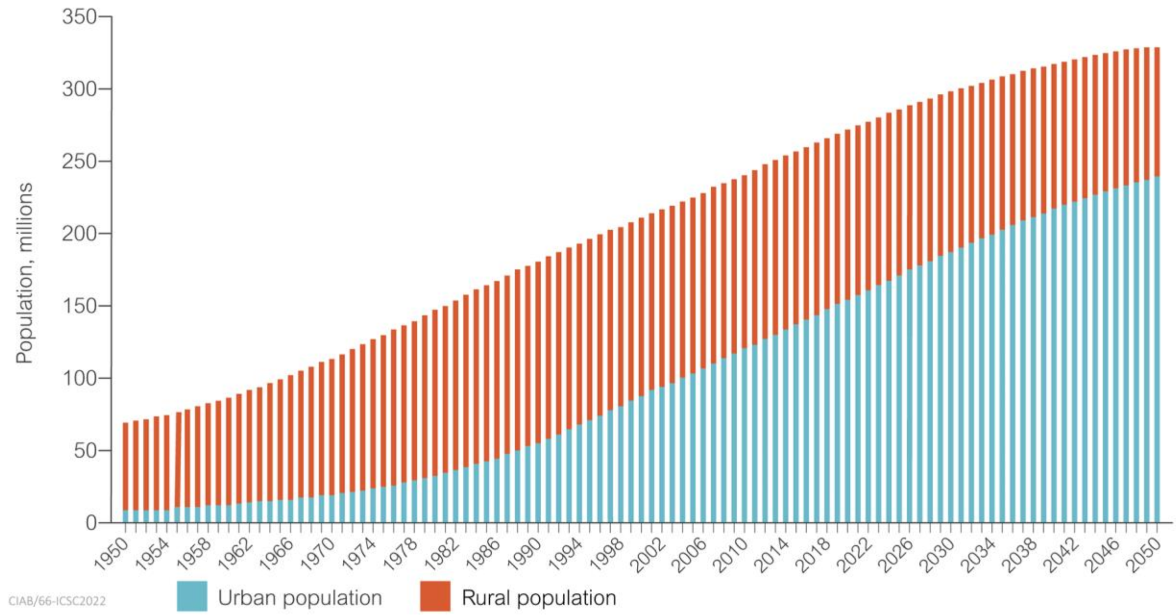


Figure 66 Indonesia's population outlook to 2050 (UN, 2018)

10.4.2 Emissions, policies and targets

Carbon dioxide emissions in Indonesia have doubled since 2000 making it the fifth largest emitter in Asia at 0.6 $GtCO_2$. Per capita emissions are similar to India's at 2.4 tCO_2/capita. Growth in emissions has been driven by the power sector which has increased fourfold between 2000 and 2020. Power generation accounted for 42% of CO_2 emissions from fossil fuel combustion in 2020, industry accounted for almost a quarter of emissions, and the remaining third was from other sectors (*see* Figure 67 and Figure 68).

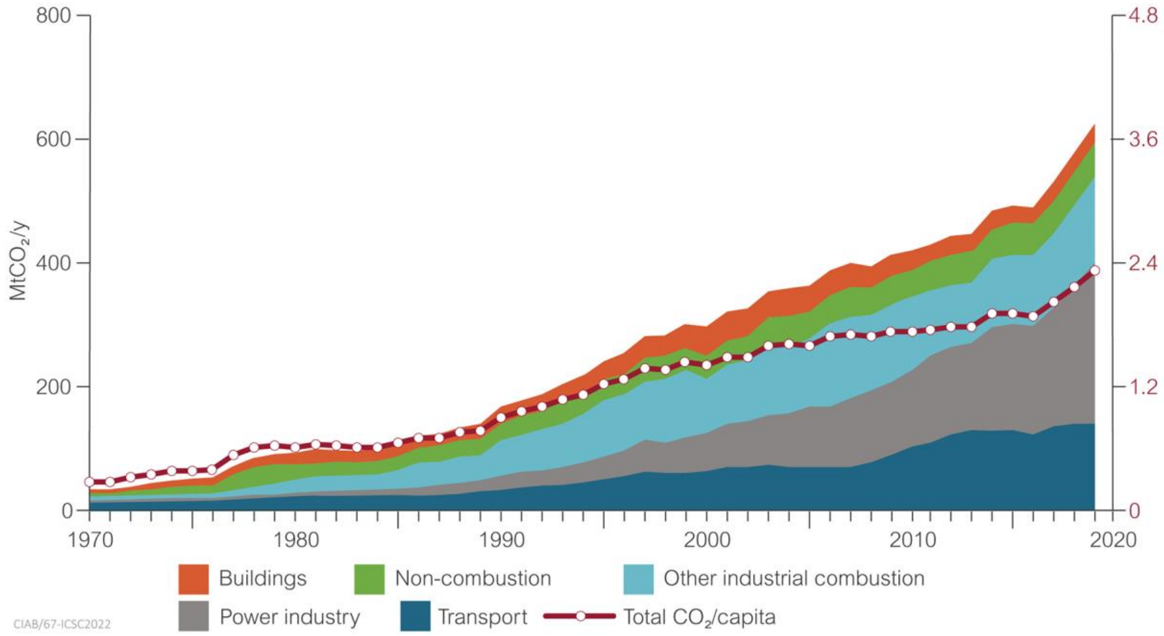


Figure 67 Indonesia's CO_2 emissions by sector, 1970-2019 (EDGAR, 2021d)

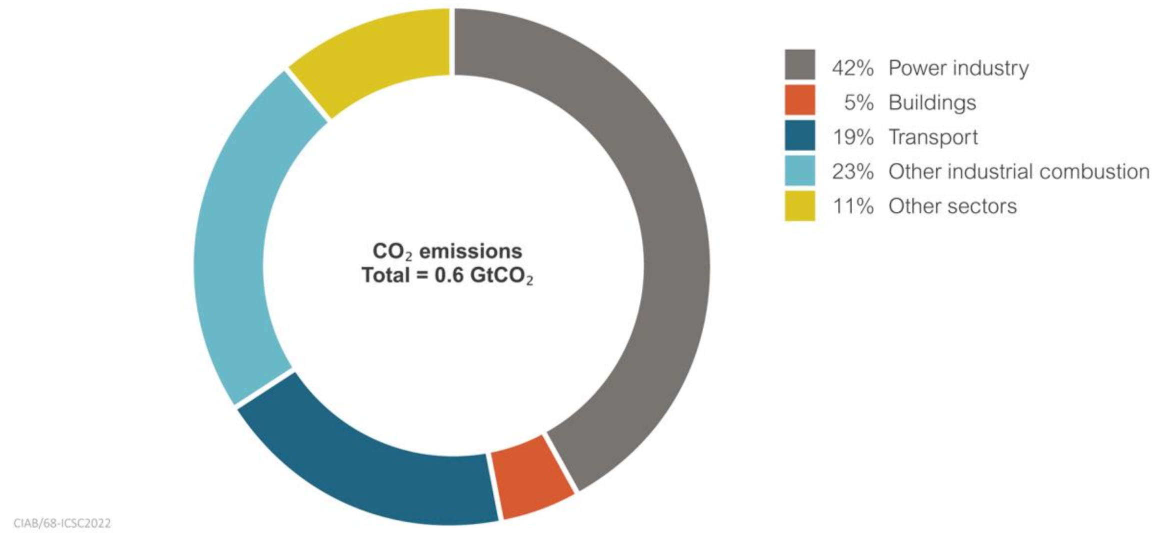


Figure 68 Indonesia's CO_2 emissions by sector, 2020 (EDGAR, 2021e)

Indonesia's NDC submission to the Paris Agreement pledges a 29% (unconditional) reduction in GHGs by 2030 compared to the business-as-usual scenario (*see* Figure 69); a further 40% (conditional) could be achieved subject to the availability of international support for finance, capacity building and technology transfer. There are also targets to obtain 23% of energy from renewable sources by 2025 and 31% by 2050 (CAIT, 20210).

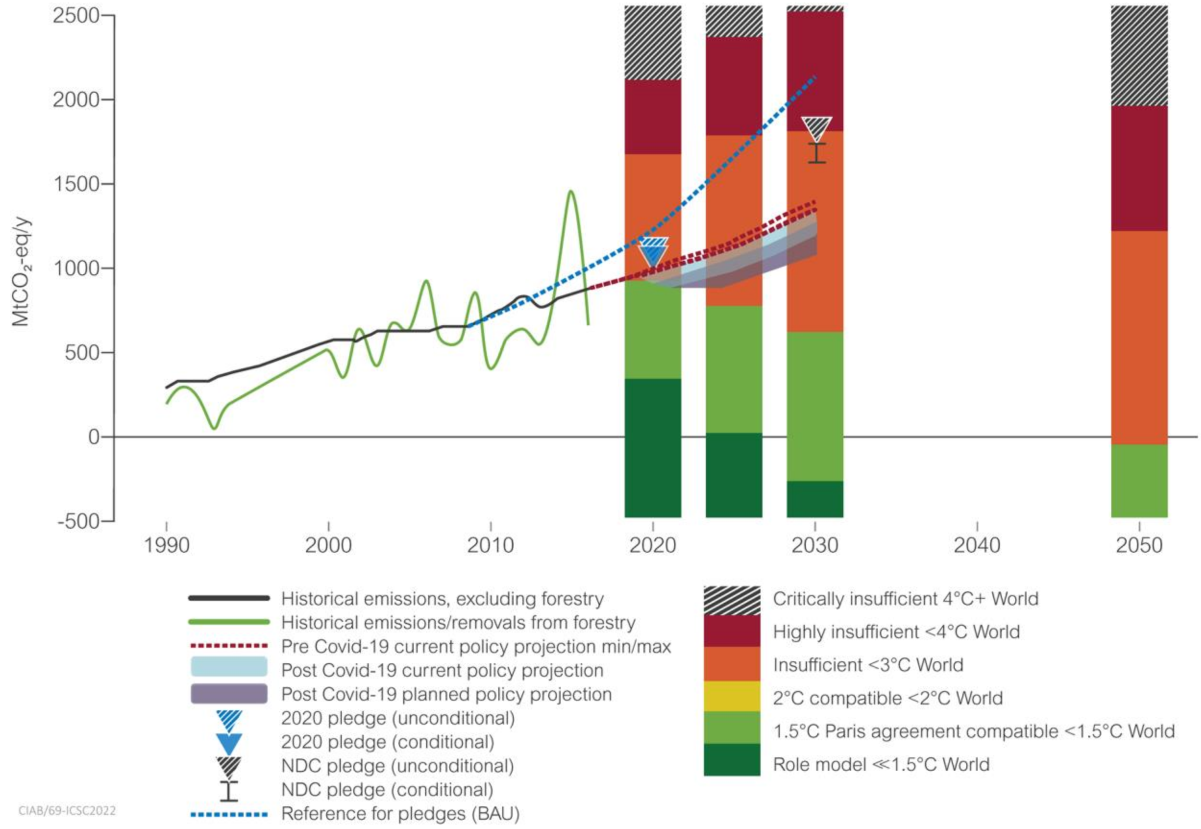


Figure 69 Indonesia's CO_2 emissions and NDC targets (CAT, 2021a)

The Long-term Strategy for Low Carbon and Climate Resilience 2050 outlines three pathways including a 'low carbon scenario compatible with the Paris Agreement' (*see* Figure 70). Even under this pathway, the most ambitious of the three, the amount of coal used for primary energy will continue to grow until at least 2050. While renewables share of electricity generation will increase under this pathway to 43% by 2050, coal will still provide 38% of the country's growing electricity needs. Methane gas (10%) and biofuels (8%) make up the rest (UNFCCC, 2021). In this scenario the government projects that 76% of coal-fired power plants will be equipped with carbon capture technology, making them low emissions plant. Despite this, the low carbon scenario still projects Indonesia's GHG emissions will be 540 $MtCO_2e$ by 2050, equivalent to 1.6 tCO_2/capita. The preface to the strategy document, signed by environment minister Siti Nurbaya, indicates that Indonesia is *'exploring opportunity to rapidly progress towards net zero emission in 2060 or sooner'*.

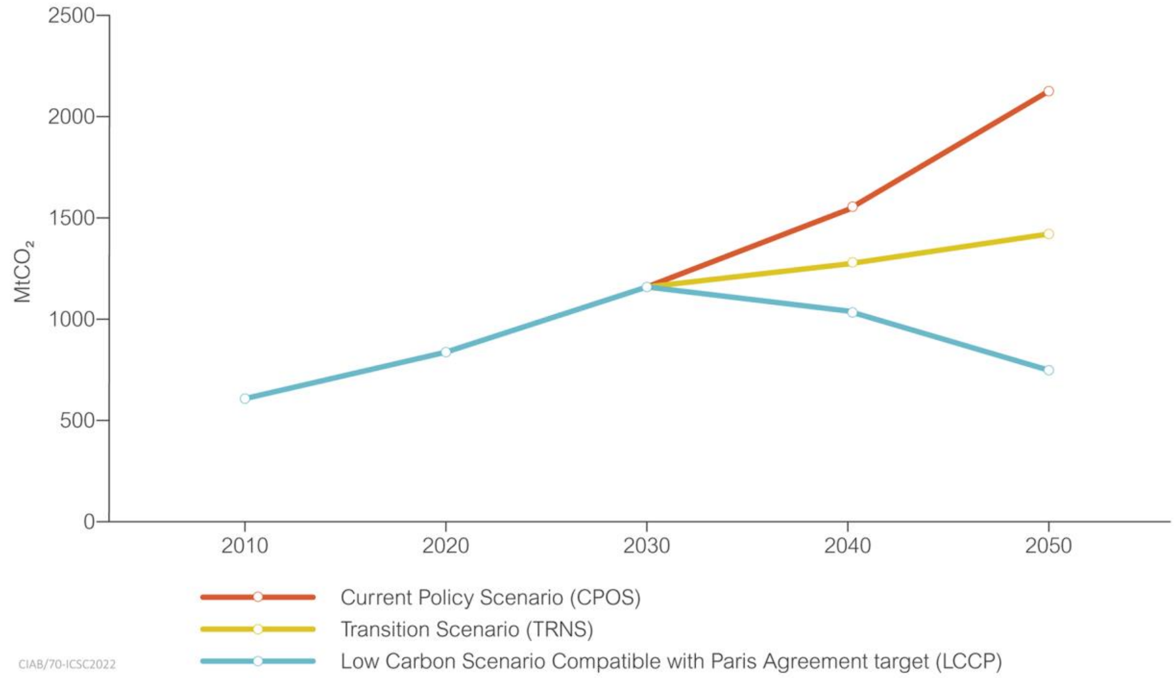


Figure 70 Projection of Indonesia's energy sector emissions by emitting sector under Current Policy Scenario (CPOS), Transition Scenario (TRNS) and Low Carbon Scenario Compatible with Paris Agreement target (LCCP) (UNFCCC, 2021b)

The reduced demand from international markets and Indoensia's ambitions to decarbonise have resulted in the Indonesian government considering developing coal to chemicals production, particularly dimethyl ether, as an alternative use of its indigenous fossil fuel reserves. The state-owned coal company Bukit Asam is working with Air Products and Chemicals Inc to develop a 1.4 Mt/y coal gasification plant to be operational by 2024, at a cost of $2 billion (€1.75 billion).

The new National Electric Generation Plan (RUPTL) for 2021-30 forecasts that electricity demand in Indonesia will grow 4.9%/y to reach 443 TWh by 2027. One of the plans to decarbonise the electricity sector is to replace 0.2–1.3 MW of diesel power with solar capacity (IDA 2021). However, as emissions grow in the medium to long term, the task of decarbonising an expanding economy of the scale of Indonesia will require a broad set of measures.

The Covid-19 pandemic caused a major interruption in Indonesia's CO_2 emissions growth, pushing the forecast output to 2030 well below the unconditional NDC targets, although emissions will increase during a period of post-Covid-19 recovery (*see* Figure 69). The expected emissions in 2030 could be half those expected under the business-as-usual scenario. The CO_2 emissions and uptake from forestry activity are an important adjustment to Indonesia's emissions balance but could be a major contributor to achieving NZE. However, based on past trends, future contributions from forestry remain uncertain.

10.4.3 Upgrading the existing coal fleet

As of mid-2021, Indonesia was operating 21.9 GW of coal-fired capacity, almost two thirds of which was built after 2010. A further 10.7 GW are under construction and 17 GW are in various stages of planning (author's estimates based on S&P Global, 2021). Indonesia is therefore committed to a large increase in coal-fired generation. Around 6 GW of the 30 GW coal fleet is smaller units of <300 MW, which are generally not suitable for ugrading to SC or USC. The nation's first SC plants came online in 2012 but the young age of the fleet means upgrading prospects are limited to just a few units, such as the four subcritical units at the Suralaya power complex that were built in the 1980s (*see* Figure 71). The possibility of converting the plant to an IGCC is being investigated. This would provide Indonesia with a plant that could produce electricity and liquid hydrocarbons to secure alternative forms of energy from the country's abundant coal reserves (Sloss and others, 2021). Nonetheless, 23 GW of the coal fleet is subcritical. However, the emergence of larger units (>300 MW) since 2010 reflects the overall rise in coal-fired power as part of a strategy to increase energy security and to meet the rising demand for electricity.

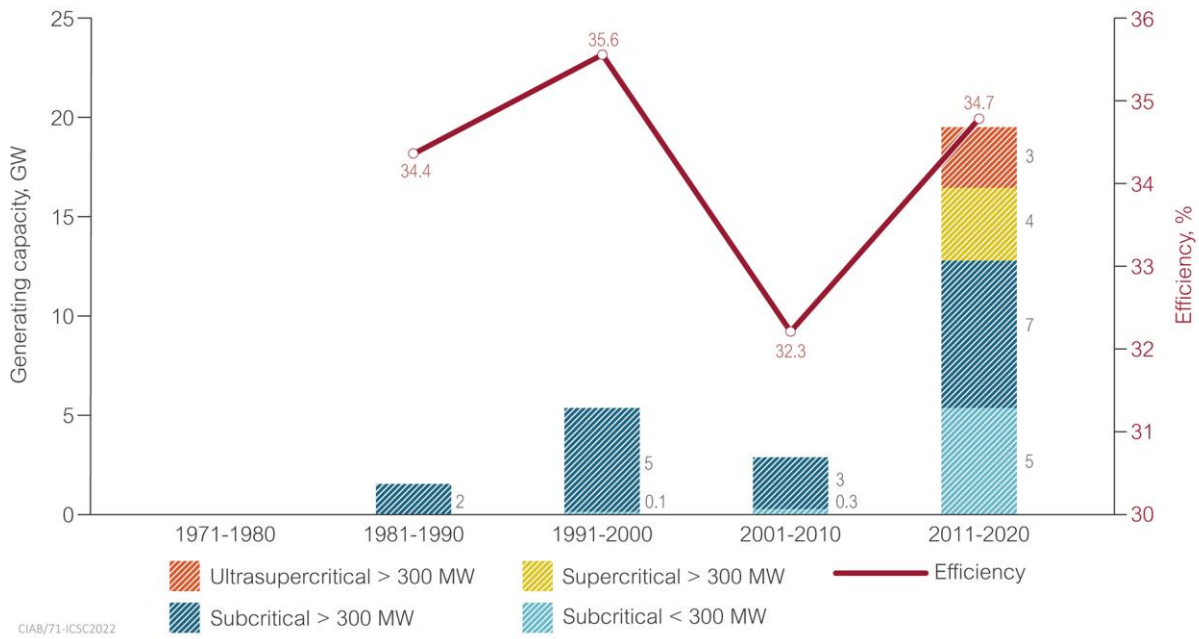


Figure 71 Indonesia's coal fleet by age, technology and efficiency (author's estimates based on S&P Global 2021)

As part of its low carbon strategy, Indonesia plans to make the cofiring of biomass in power stations mandatory as coal power plants account for more than 60% of its electricity supplies. *"This cofiring programme is an intermediate solution as we determine how to phase out coal power plants,"* according to Chrisnawan Anditya, a renewable energy director at the Energy and Mineral Resources Ministry (Reuters Indonesia, 2021). He said the government is preparing a regulation to implement mandatory cofiring, which would apply to state electricity utility PT Perusahaan Listrik Negara (PLN) as well as independent power producers. The timing and other details, such as the ratio of biomass used in cofiring, were not disclosed. PLN has said it is planning to gradually retire its coal power plants as part of its ambition to reach carbon neutrality by 2060. The state power company plans to start cofiring at 52 of its biggest coal power plants and has estimated it could replace 9 Mt/y of coal with biomass.

10.4.4 Current status of CCUS

Regulations to deploy CCUS in Indonesia were drafted in 2019 but have yet to be endorsed by the government. Similarly, carbon pricing has also been put forward by the Presidential Regulation on Carbon Economic Value but has not yet been issued. In time the Ministry of Energy and Mineral Resources may set up CCUS-specific regulations to foster development. The potential for CCUS in Indonesia has been recognised by foreign corporations; a feasibility study for PAU Central Sulawesi Clean Fuel Ammonia Production with CCUS was instigated by a Japanese-Indonesian consortium. This is an example of how technical and economic cooperation among different Asian economies could foster a more effective development programme for CCUS by identifying the best storage and utilisation opportunities across the whole region.

Several Japanese corporations are also looking to the upstream oil and gas sector by collaborating with Indonesia's national oil company Pertamina and the Bandung Institute of Technology to launch a feasibility study for enhanced gas recovery at the Gundigh onshore gas field in Central Java. The storage potential in Gundigh is 0.3 $MtCO_2/y$ and gas production would also be boosted. The stored CO_2 is intended to raise carbon credits to be shared between the governments of Indonesia and Japan. CCUS is endorsed by the Asian Development Bank (ADB) which sees it as central to emissions reduction from Indonesia's energy and industrial sectors. It could reduce power sector GHG emissions by 40%. The Japan International Cooperation Agency (JICA) also supports the feasibility study by conducting subsurface surveys while the ADB investigates a legal and regulatory framework for CCS. A Southeast Asia Regulators' Network has been established by the GCCSI and the Association of Southeast Asian Nations Centre for Energy to broaden the understanding of CCUS-specific legal and regulatory issues (Battersby, 2021).

10.5 VIETNAM

10.5.1 Challenges of meeting NZE

Economic growth in Vietnam has been consistently high for many years; GDP has increased ninefold between 2000-20 to $271 billion (World Bank, 2021a). Vietnam was one of the few countries, including China, which saw growth in 2020 of GDP of 2.9% (World Bank, 2021a).

As a socialist-market economy, much of Vietnam's strategic industries such as power generation and coal mining remain under state control, but the government invites foreign investment which has been instrumental in its economic success. Unemployment is low at around 2% (2018) and the workforce is increasingly skilled. Forty per cent of manufactured exports in 2019 were based on high technology goods, compared with 31% for China, 10% for India, and 8% for Indonesia (World Bank, 2021a). Currently, Vietnam is ranked 44th in terms of global GDP at $271 billion, but over time, GDP could expand tenfold, moving Vietnam up the rankings to overtake other nations such as Thailand and Malaysia, when measured in terms of PPP (World Bank, 2021a; PwC, 2017). The Power Development

Plan 8 (PDP 8) assumes Vietnam's GDP will increase by 6.6 %/y in 2021-30 and 5.7 %/y in 2031-45. As part of the PDP 8, the country needs to invest 12.8 billion $/y for generating capacity and 3.3 billion $/y for electricity grids in 2021-45 (Burke and Nguyen, 2021).

Part of this demand will be driven by population growth which will be relatively modest. It is forecast to increase 12.6% from 97 million in 2020 to 109 million in 2050. During this period, the urban population will rise from 36 million to 63 million, an increase from 37% of the total population to 57% (*see* Figure 72) (UN, 2019). More than 99.4% of the population has access to electricity (World Bank, 2021b). Urbanisation in Vietnam will give rise to more construction of housing and infrastructure that will drive the demand for cement and steel.

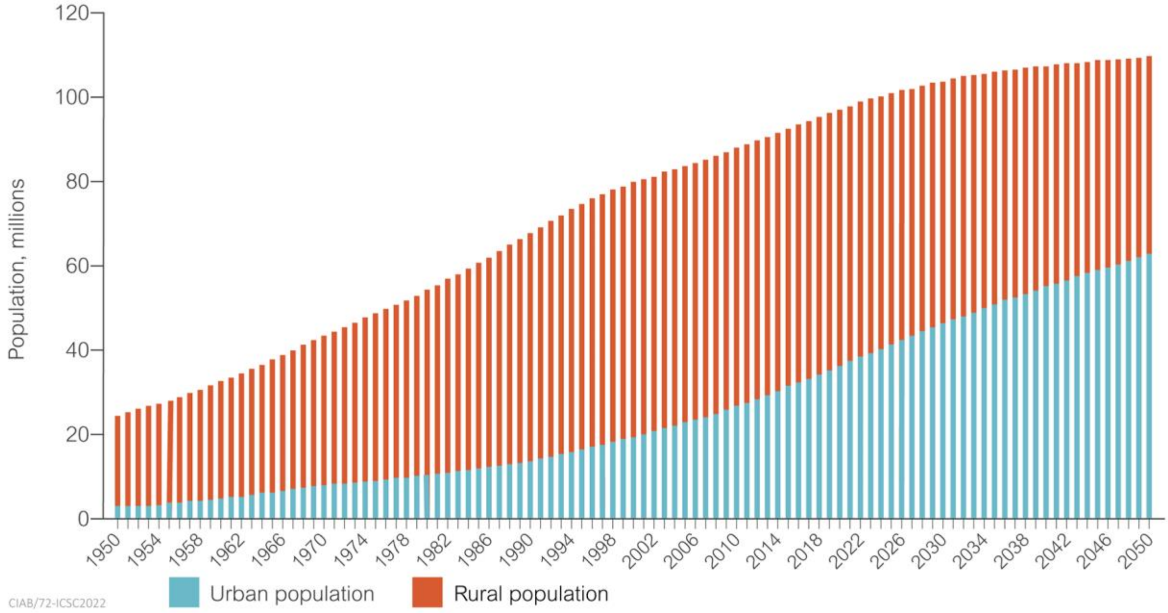


Figure 72 Vietnam's population outlook to 2050 (UN, 2018)

Vietnam lacks integrated BF-BOF steel mill capacity. Instead, high value steel products are made from imported steel and from EAF capacity that uses recycled steel. In 2016, more than 90% of Vietnam's steel demand came from the construction sector which was expected to grow at a rate of 7 %/y in 2018-2022. However, rising electricity costs could add cost pressure on electricity-based steel production, while a slowdown in the real estate market could dampen demand for steel and cement (Jeon, 2019).

10.5.2 Emission policies and targets

Vietnam is the sixth largest emitter of CO_2 in Asia at 0.3 $GtCO_2$ accounting for less than 1% of global CO_2 emissions from fossil fuels (EDGAR, 2021e). The power generation and industrial sector each account for roughly a third of Vietnam's emissions (*see* Figure 73 and Figure 74). The NDC for Vietnam has an unconditional target of an 8% reduction by 2030 compared to the BAU scenario (*see* Figure 75);

a further conditional target of 25%. In Vietnam's growth projection to 2030 CO_2 emissions are well below those set in the NDC.

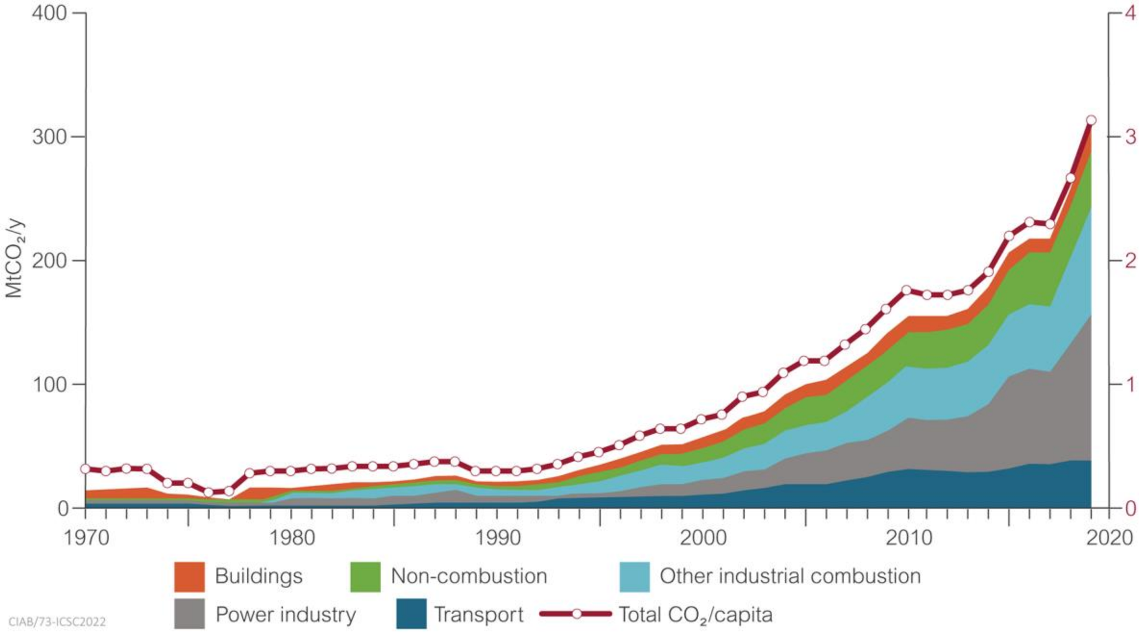


Figure 73 Vietnam's CO_2 emissions by sector, 1970-2019 (EDGAR, 2021d)

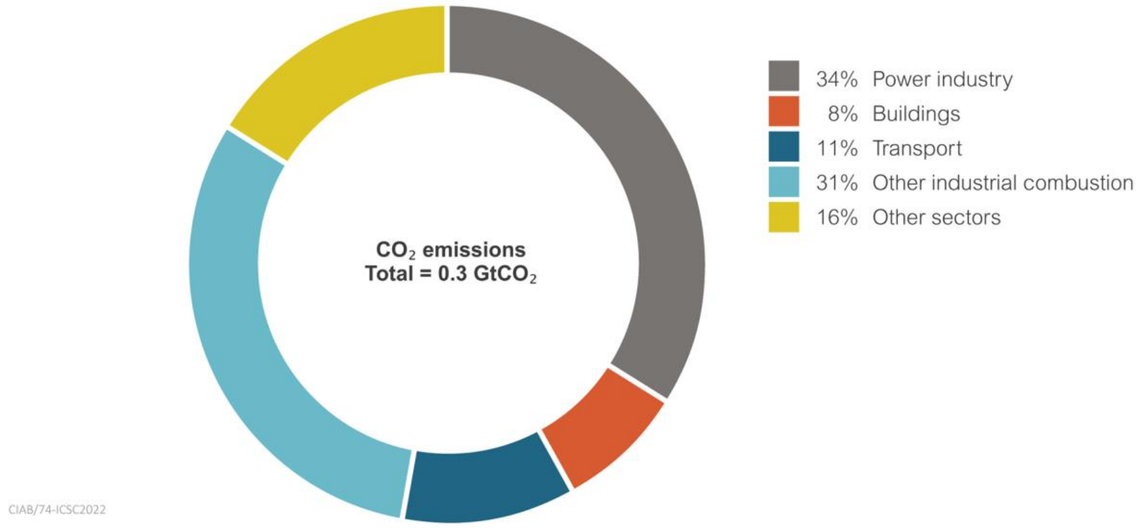


Figure 74 Vietnam's CO_2 emissions by sector, 2020 (EDGAR, 2021e)

The government's PDP 8 issued in February 2021 affirms their commitment to maintain coal-fired power, but at a smaller share of capacity, falling from 34% in 2020 to 27% in 2030 and 18% by 2045. In terms of electricity generation, coal and gas will each provide 30%. However, under the current strategy, there will be no new coal-fired power projects other than those under construction or in the financial investment stage due for commissioning before the end of 2025 (Burke and Nguyen, 2021). As of mid-2021, Vietnam was operating 20.7 GW of coal-fired capacity, 8.8 GW was under construction, while 20 GW were at various stages of planning. Ninety per cent of Vietnam's coal fleet was built within the last decade less than a third of which comprised SC and USC technology (author's estimates based on S&P Global, 2021).

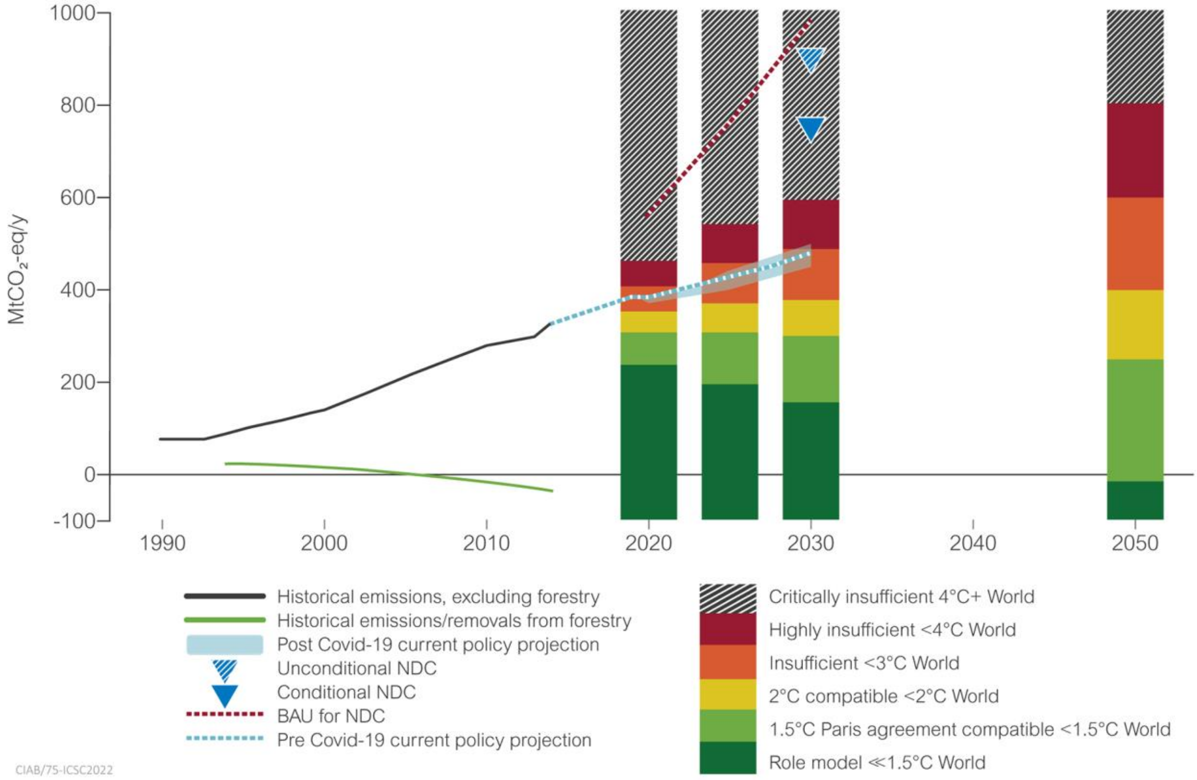


Figure 75 Vietnam's CO_2 emissions and NDC targets (CAT, 2021a)

According to Reuters (2021c), the PDP 8 means that there could be 41 GW of coal power by 2030, roughly a third of the national generating capacity. Gas power will increase from 7 GW in 2020 to 13.5 GW in 2025 and 28–33 GW in 2030. There will also be large investment in wind and solar, but their share of capacity will be either the same or smaller than current levels. Beyond 2030, renewable power will be developed to reach 53% of capacity by 2045; 42% of which will be wind and solar.

10.5.3 Upgrading the existing fleet

Vietnam's coal fleet is young and modern with most additions coming online after 2011 (*see* Figure 76). The surge in coal power construction in the 2010s was the result of a strategy to diversify the nation's generating fleet, previously dependent on hydropower and gas. Some 15 GW out of a total coal fleet of approximately 21 GW are subcritical and could be eligible for upgrades to high efficiency technology. Despite the prevalence of subcritical capacity, 90% of new coal capacity planned and under construction comprises SC and USC technology, marking a shift to HELE coal power in the country. The rising efficiency of the fleet is set to continue.

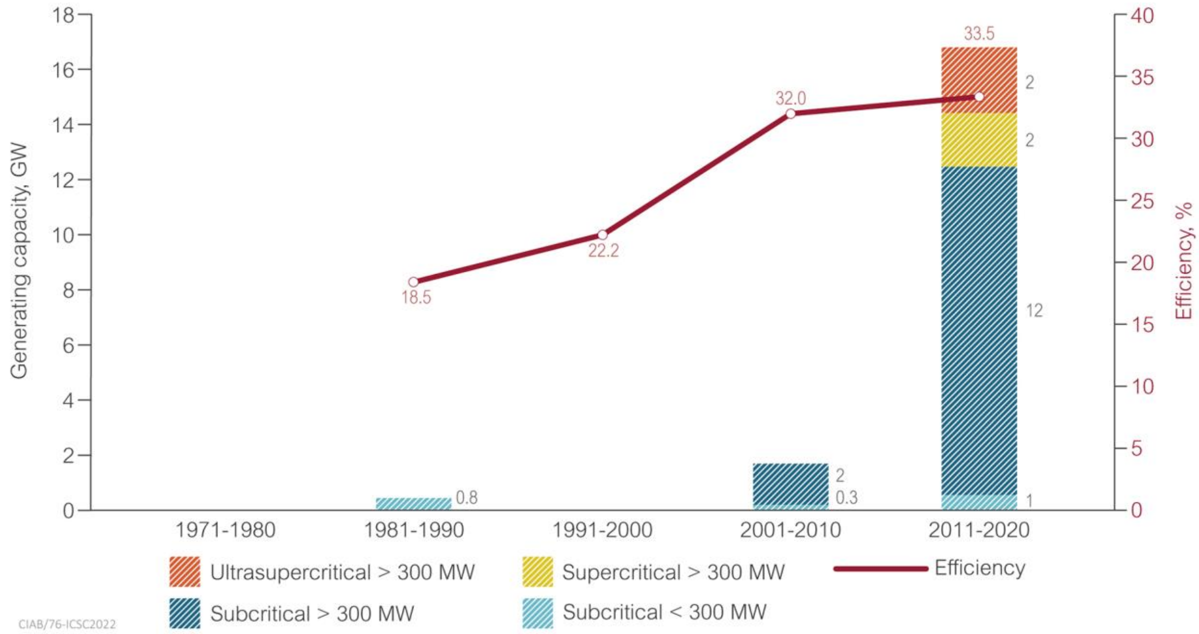


Figure 76 **Vietnam's coal fleet by age, technology and efficiency (author based on S&P Global 2021)**

10.5.4 Current status of CCUS

There has been limited progress on CCUS in Vietnam. The strategy to diversify the nation's power sector to include coal and reduce dependency on hydroelectricity and gas power means that the rise in CO_2 emissions from power generation is inevitable. Thus, CCUS will be important in decarbonising the economy. According to early reports, CCUS is unlikely to happen before 2035 and is not yet a priority for the country. Nonetheless, storage potential was investigated in 2009 by the Bureau des Recherches Géologiques et Minières BRGN of France and Vietnam's counterpart KVN. The studies identified depleted oil and gas fields, deep saline aquifers, and other geological formations related to coalbed methane in domestic coalfields as possible storage sites. However, current regulations are inadequate to promote CCUS as other environmental regulations have taken precedence. CCUS is only feasible with financial assistance as the funds allocated for environmental projects are insufficient. The Environmental Protection Fund and commercial banks in Vietnam lack financial resources to support CCUS and lending is constrained by a lack of certainty in the policy framework (Ha-Duong and Nguyen Trinh, 2017).

10.6 JAPAN, A CASE STUDY OF REGIONAL COOPERATION FOR NATIONAL GOALS

This section shows how regional cooperation can facilitate the achievement of national goals to reduce emissions of CO_2. The examples are taken from Japan's work on both hydrogen and CCUS.

10.6.1 Japan's cooperation on hydrogen

Japan was the first country to adopt a hydrogen strategy in 2017, (*see* Table 22) which is summarised by Chaube and others (2020). Primarily the strategy aims to achieve cost parity with competing fuels such as gasoline in the transportation sector or liquefied natural gas (LNG) in power generation and covers the entire supply chain from production to downstream market applications (METI, 2020). In support of this aim, the Japanese government began investing in R&D in around 2014, for low cost, zero emission hydrogen production, an expansion of the hydrogen infrastructure for import and transport abroad within Japan and an increase of hydrogen use in various areas such as mobility, CHP, as well as power generation.

TABLE 22 TARGETS DEFINED IN JAPAN'S BASIC HYDROGEN STRATEGY (CHAUBE AND OTHERS, 2020)

Benchmark factor	Mid-term target, 2030	Long-term target, 2050
Source of supply	Developing international hydrogen supply chains and domestic power-to-gas	CO_2 free hydrogen, including fossil fuels with CCUS and power-to-gas
Hydrogen volume, MtH_2/y	0.3	5–10
Cost of H_2,US$/t	3	2
Power generation cost, JP¥/kWh	17	12
Mobility • Hydrogen refuelling stations (HRS) • Fuel cell electric vehicles (FCEVs) • Fuel cell buses • Forklifts	900 800,000 1200 10,000	Replace gasoline stations Replace gasoline vehicles Introduce large FCEVs
Fuel cells (stationary power), where Ene-Farm is a fuel cell based domestic CHP system	5,300,000	Replace traditional energy systems

Japan proposes to pioneer a global supply network for hydrogen production, shipping and applications in various economic sectors (Nagashima, 2020). The majority of hydrogen and other derivative fuels for Japan are expected to be imported. Examples include the Advanced Hydrogen Energy Chain Association for Technology Development (AHEAD) project which has commenced operation of the world's first international hydrogen supply chain. This involves producing hydrogen from natural gas and converting it into methylcyclohexane (MCH). The MCH is then shipped to Japan where it undergoes dehydrogenation to release the hydrogen (AHEAD, 2020). Hydrogen, which was transported from Brunei Darussalam by sea and regenerated from the MCH was supplied to a gas turbine in Mizue Thermal Power Plant for power generation (Chiyoda Corp, 2020). A further example is the Hydrogen Energy Supply Chain (HESC) (*see* Section 8.8.2).

The Hydrogen Energy Supply Chain (HESC) project is a significant example of Japanese government collaboration with the private sector and other governments to build international supply chains (HESC, 2018). This project is being developed by Kawasaki Heavy Industries, Electric Power

Development Co (J-Power), Iwatani Corporation, Marubeni Corporation, Sumitomo Corporation and AGL, with the support of the Governments of Japan, Australia and the State of Victoria. It will produce liquefied hydrogen from brown coal in the Latrobe Valley. The liquid hydrogen will be shipped to the Kobe liquid hydrogen storage and unloading terminal in Japan. In the pilot phase around half a billion dollars will be invested in Australia and Japan. If successful, an investment decision to construct a commercial scale clean hydrogen production facility with CCUS in the Latrobe Valley, to supply Japan could be made in the mid-2020s.

The CO_2 would be captured and transported via pipeline for geological storage in CarbonNet's offshore storage area in the Gippsland Basin. In this way low emission hydrogen would be produced in Australia from lignite with CCUS and shipped to Japan for domestic use, thus assisting Japan achieve its NZE target (Figure 77).

Figure 77 Hydrogen Energy Supply Chain pilot project (KHI, 2021)

Overall, the hydrogen market in Japan is expected to grow more than 50 fold by 2030 to reach over JP¥ 400 billion (around $4 billion), with a particular focus on hydrogen refuelling stations (HRS) for transport applications (Chaube and others, 2020). This market is expected to increase by around seven fold to JP¥37 billion (around $350 million) by 2030. The number of HRS will increase from 111 in 2020 to 580 by 2025, and then to over 1300 throughout Japan by 2030.

As mentioned in Section 3.4.3, Japan is also cooperating with energy producing countries including Australia and Saudi Arabia, to establish a stable, low cost and flexible low emissions ammonia supply chain. Ammonia can be consumed directly in various industry applications and/or converted to hydrogen for use in the Japanese economy.

Thus, areas of focus include hydrogen production, carrier technologies and international supply chains, hydrogen use in fuel cells, mobility and power generation. The industrial sector, while recognised as a potential area for hydrogen use, is not a priority in the near term.

10.6.2 Japan's cooperation on CCUS

The Japanese Ministry of Economy, Trade and Industry (METI) and the Ministry of the Environment (MOEJ) continue to drive Japan's CCUS programme (Suzuki, 2018). The programme addresses the full CCUS value chain including the development and demonstration of capture technologies, investigating regulatory models, exploring policy options for commercial deployment, identifying and characterising storage reservoirs and CO_2 transport options, together with understanding CCUS business models. The Japanese Government recently submitted its Long-Term Strategy under the Paris Agreement, to the UNFCCC. The strategy identifies CCUS among other technologies to reduce emissions, including the production of clean hydrogen. It states the Government of Japan's intention to collaborate with the private sector and other governments on a range of initiatives designed to reduce barriers to the deployment of CCUS (GCCSI, 2019a).

Japan is looking beyond its borders for regional solutions to assist it achieve its NZE target, to supplement its own limited geological storage options. This includes joint ventures to explore CCUS hubs, in which multiple emission sources share transport and storage infrastructure in other countries or regions. The idea is for Japan to encourage development of CCUS hubs in Asia and then be a guaranteed key customer for the resulting low emission chemicals and feedstocks produced. In this way, Japan can import much needed products for its own energy needs but with geological storage of the associated emissions being either local in the producing country or use being made of regional hub storage options. The benefit for other countries is that a leading customer for valued energy products will help underwrite development of the hubs and supply chains.

Section 2.3.5 explained how CO_2 infrastructure hubs are evolving to be the dominant CCUS model as they provide a cost-efficient transition to a low-carbon economy. There are already four hub networks in operation and 30 in development, mostly in Europe and North America.

This suggests development of shared transport and geological storage assets in Asia could underpin a regional solution for countries that have limited CO_2 storage potential, such as Japan, or would reap economies of scale by working together, such as ASEAN member countries. This could follow the example currently being pursued in the Northern Lights project in Europe, where multiple countries plan to transport CO_2 to Norway for offshore storage. Northern Lights is the world's first open-source CO_2 transport and storage infrastructure project and it has the express aim of making it easy for other infrastructure hubs to follow (Northern Lights, 2019).

Indeed, technologies to develop CO_2 hubs exist and are mature but experience and learning from their operation is still limited, with more investment required (Carbon Sequestration Leadership Forum, 2021). Thus, Japan is playing a leading role in promoting regional recognition and support for CCUS technology and CCUS hub infrastructure. In November 2020, various Asia Pacific Energy Ministers held discussions regarding a proposed Asia CCUS Network initiated by Japan. This subsequently led to the launch of the Asia CCUS Network. Its members include Australia, India, Japan, USA and nine of the ten ASEAN member states. Its aim is to provide a platform for policymakers, financial institutions, industry players and academia to work together to ensure the successful development and deployment of CCUS in the Asia region. Key milestones for the Network's work plan are:

1. Studies on the CCUS value chain; common rules and procedures for CCUS deployment; financial analysis of CCUS development and deployment; carbon trading/Joint Credit Mechanism activity
2. Joint workshops, conferences, seminars among members and supporters of the Asia CCUS Network
3. Capacity building and training to be conducted in countries in ASEAN and East Asia.

This means the initiative will assist in the development of regional Asian approaches to CCUS deployment. For example, opportunities to use offshore storage options in Malaysia, Indonesia and northern Australia could form the basis of new CCUS hubs involving both capture and CO_2 storage development as shown in Figure 78.

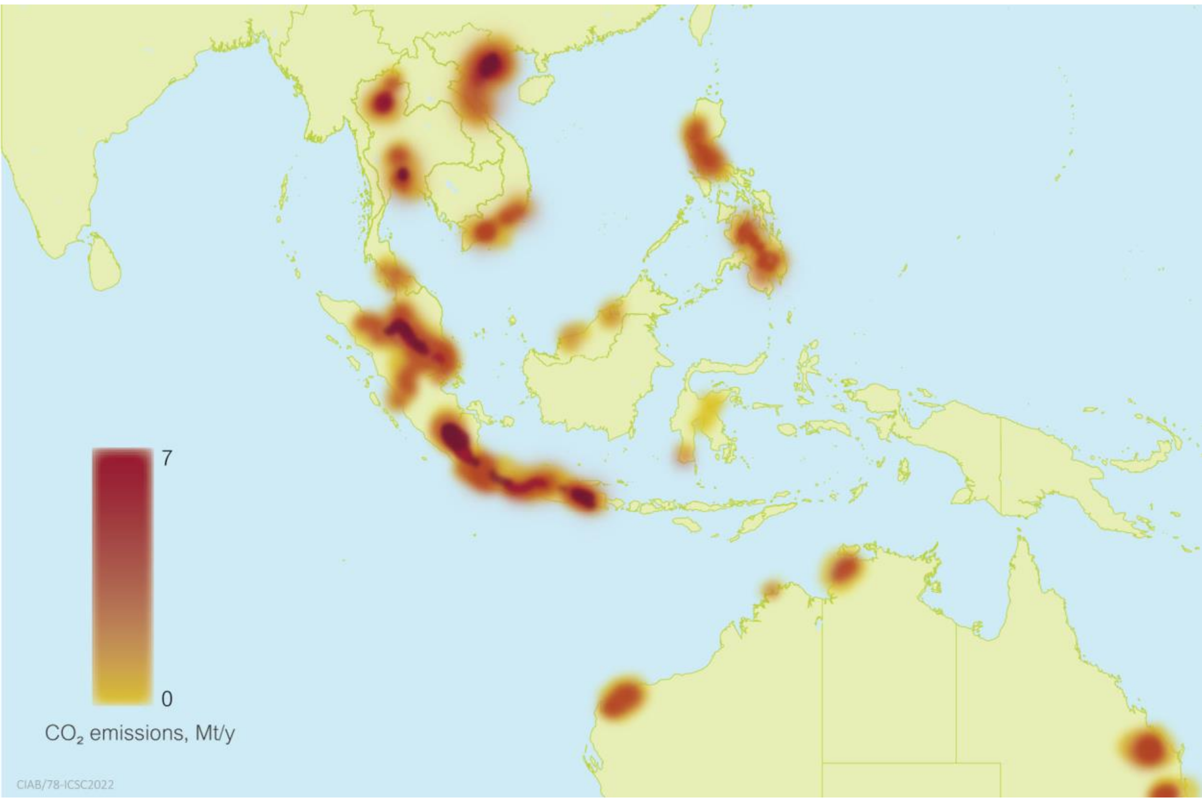


Figure 78 CO_2 sources in Southeast Asia (IEA, 2021b)

In addition to local CO_2 storage solutions, regional approaches to CO_2 transport and storage infrastructure could enable faster and widespread uptake of CCUS in Southeast Asia. Storage options include depleted oil and gas wells in Malaysia and Indonesia and in the Petrel Basin offshore from Australia's Northern Territory (IEA 2021b).

In these ways, Japan is illustrating the value of bilateral and multilateral CCUS collaborations aimed at promoting international trade in clean energy products produced from fossil fuels. These world leading initiatives should encourage more regional hub solutions to complement national ones so as to achieve NZE in Asia.

Japan's strategy, which has a strong element of international cooperation, could have a positive global impact and contribute to the creation of new synergies regarding international energy trading and business cooperation. These will be crucial to drive development and make technologies more affordable.

11 POLICIES AND CHARACTERISTICS SUPPORTING CCUS ROLL-OUT

11.1 KEY MESSAGES

More positive carbon price signals in Asia would drive growth in CCUS. Whether the carbon price is effectively valued through carbon emitted, emissions trading schemes or tax credits on the amount of CO_2 stored, the value needs to be around 40–80 \$/tCO_2 in 2020, increasing to 50–100 \$/tCO_2 by 2030.

The availability of debt financing for CCUS projects needs to increase significantly and banks have a critical role to play. To qualify for debt financing, CCUS projects will need to provide assurance that key risks are identified with mitigations in place and that hard to manage risks are allocated to governments in the short term.

CCUS capture levels will need to increase from the current 90-95% to closer to 100% to allow the power plants to continue to operate in a NZE future as any residual CO_2 emissions from CCUS facilities will not be compliant without being offset by negative CO_2 emissions elsewhere.

The hub and cluster approach should be adopted to enable the sharing of transport and storage networks. This can improve the economics of CCUS due to economies of scale and overall de-risking of storage liability and cross-chain risk. Fossil fuel power plants with CCUS could form the anchor for these clusters with local industries feeding in their captured CO_2.

11.2 DRIVERS SUPPORTING CCUS

CCUS is a proven technology with costs on a strong downwards trajectory. It is a key part of Asia's transformation to a net zero CO_2 emissions future. However, it now needs a strong financial and regulatory regime to achieve commercial roll-out.

Whilst a comprehensive framework to support the widescale roll-out of CCUS remains to be established, supportive policy measures and project conditions are in place in some regions, which have supported the establishment of the current and proposed large-scale CCUS projects as shown in Figure 79 (Havercroft, 2018; Havercroft and Consoli, 2018).

Figure 79 Policies and characteristics supporting CCUS projects (GCCSI, 2019a)

For the early CCUS plants, a proportion of the increased operating costs may be absorbed by the project developer as part of a wider business strategy to improve their environmental image; for example, to ease government approval for a particular project, or help promote their own CCUS technology (Lockwood, 2018a). This type of longer-term investment strategy has played a role in the early development of CCUS, particularly in projects led by oil and gas sector companies such as the In Salah project (BP, Sonatrach, and Statoil), Shell's Quest project, and Chevron's Gorgon project (Herzog, 2016). A further example of this longer-term vision of technology providers and key stakeholders is the Oil and Gas Climate Initiative (OGCI). With thirteen oil and gas company members (as of 2019), the organisation invests in innovative, commercially viable and scalable technologies and solutions. OGCI Climate Investments is a $1 billion-plus-fund set up by the OGCI member companies to lower the carbon footprint of the energy and industrial sectors (OGCI, 2019).

The primary financial mechanism supporting CCUS has been through the value placed on the captured CO_2 for EOR, as highlighted in Figure 79, where around 75% of the operating facilities are supported by revenues derived from sale of the CO_2 for EOR. With revenues in the range of 10–35 $/t$CO_2$, EOR is generally insufficient to cover the costs of CCUS alone, certainly for coal-based power plant applications. At the higher end of the range, it can however cover the costs of capturing and transporting CO_2 in sectors where the cost of capturing CO_2 is relatively low, such as natural gas processing, fertiliser and bioethanol production (Zapantis and others, 2019).

Many national governments recognise the need to provide funding support for CCUS projects, particularly for the transport and storage infrastructure. Grant programme funding for CCUS has tended to be top-down and focused on handpicked projects, such as Norway's commitment to Longship or Australia's to CarbonNet. In the USA, the expansion of the 45Q tax credit plus complementary policies, such as the California Low Carbon Fuel Standard, have encouraged many new investment plans. Importantly, 45Q puts a value on CCUS and helps unleash the innovation and business acumen of the private sector (IEA, 2020f).

Policy mechanisms to stimulate investment in CCUS have been proposed by the IEA and others and are summarised in Figure 80, with some additional information provided below.

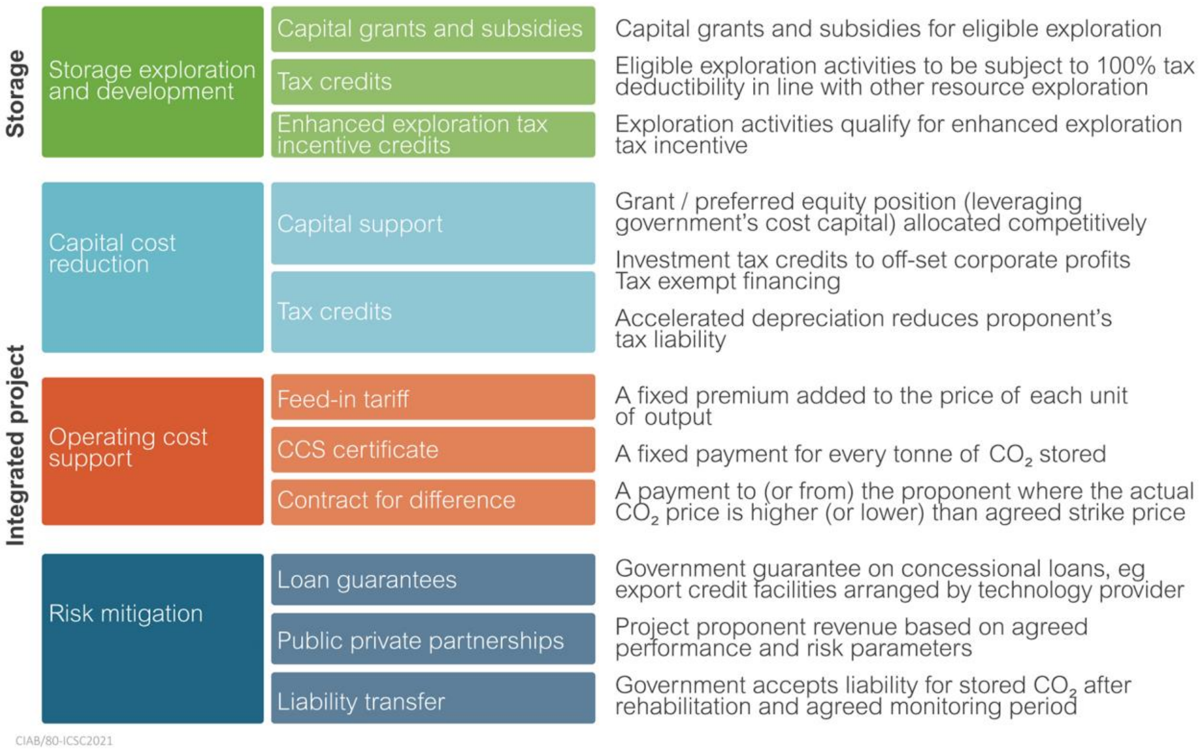


Figure 80 Policy incentives for CCUS (IEA, 2016)

11.2.1 Tax credits

Tax credits are a policy instrument which reduce the tax liability of a taxpayer for fulfilling a defined criteria, in this case storing CO_2. A key feature of tax credits is that they are performance based, in that they are only awarded when CO_2 is captured and stored. The credits can be used to reduce a company's tax liability or, if they have no tax liability, be transferred to the company that disposes of the CO_2, or traded on the tax equity. Tax credits have the benefit of being well established in the context of climate change mitigation in the USA, having been used to drive significant investment in renewables over the past two decades.

45Q tax credits in the USA have supplemented the revenues from EOR projects and have also provided an incentive for the geological storage of CO_2. They seek to link directly the financial compensation to the amount of CO_2 stored. Tax credits have been recognised as an enabler of the six large-scale facilities in the USA that have come on stream since 2011, including Petra Nova, Century Plant, Air Products SMR, Coffeyville, Lost Cabin and Illinois Industrial (*see* Appendix, Table A-2 for project details).

Section 45Q underwent a major reform in 2018 so that now the tax credit increases linearly each year to a maximum of 50 $/t$CO_2$ for saline aquifer-based geological storage or 35 $/t$CO_2$ for EOR by 2026, tracking inflation thereafter. Under the current arrangements, 45Q provides tax credits worth 20 $/t$CO_2$ for CO_2 used for EOR and 32 $/t$CO_2$ for CO_2 held in dedicated geological storage. The reform removed a cap on how much money could be paid out under the system, which was equivalent to 75 MtCO_2 captured in total for the tax credit scheme. It also retains the 45Q eligibility threshold for a minimum annual CO_2 volume per project of 500,000 t for power plants, but lowers it for industrial sources and DAC to 100,000 t. The legislation makes the tax credit available for non-EOR utilisation and geological storage of CO_2 with the minimum eligibility threshold set at 25,000 tCO_2/y. The CCUS projects must commence construction before 2024 to be eligible and can receive the credits for up to 12 years.

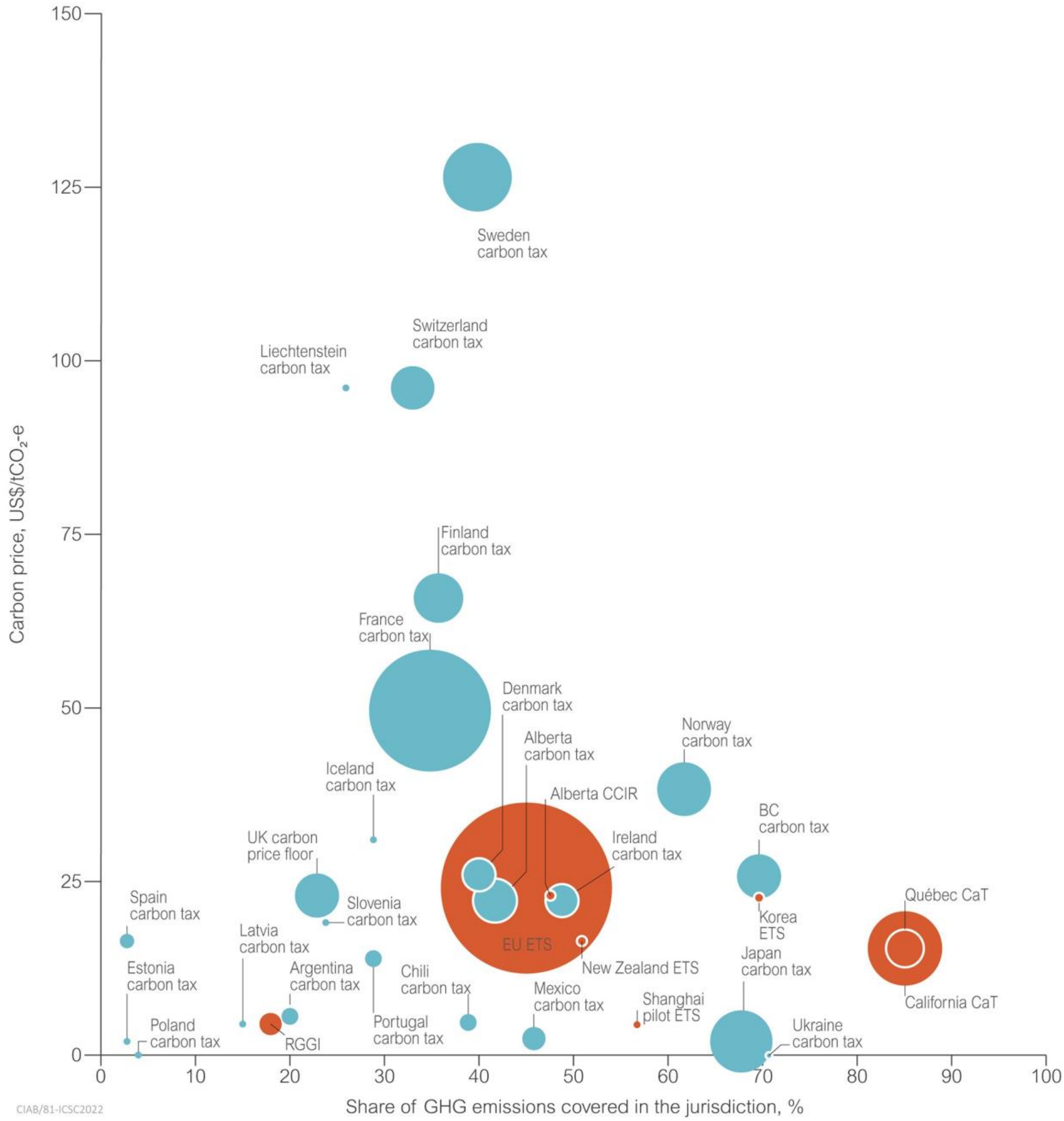
Similar tax credit-based incentives are being considered in other countries such as China and Canada. Studies show that CCUS costs are still high for coal-fired power plants in China, and 45Q tax credit type provisions could effectively improve the investment benefits of CCUS projects (Fan and others, 2018, 2019). However, from the perspective of large-scale CCUS deployment, the incentive effect of the tax credit depends on the application. For a full chain CCUS system including CO_2 capture and geological storage, the 45Q tax credit provisions would need to be combined with CO_2 trading to enable a coal-fired power plant to capture 90% CO_2 emissions continuously over its typical 40-year lifespan. This is because the 45Q tax credit income timeframe is assumed to be 12 years in the study, as is the case in the USA. Where the captured CO_2 could be exploited for EOR, the coal plant could maintain an income stream beyond the initial 12 year tax credit timeframe. As a result, the Chinese government can learn from the 45Q mechanism, but it would also need to encourage coal power generators to explore further CO_2 utilisation approaches such as EOR to increase the economic value of CO_2.

11.2.2 Carbon pricing

According to the World Bank (2019), 57 carbon pricing initiatives have been implemented, or are scheduled for implementation. They consist of 28 emissions trading schemes (ETSs), spread across national and subnational jurisdictions and 29 carbon taxes, primarily implemented on a national level. These carbon pricing initiatives account for around 11 $GtCO_2e$, or about 20% of GHG emissions. More positive carbon price signals would help to drive the growth in CCUS necessary to achieve the required reductions in global CO_2 emissions. Whether the carbon price is effectively valued through carbon emitted or ETSs, the value needs to be around 40–80 $/$tCO_2$ by 2020, increasing to 50–100 $/$tCO_2$ by 2030 (World Bank, 2019). Currently, less than 5% of global CO_2 emissions have a carbon pricing regime which is consistent with this value.

Carbon tax – A carbon tax is one directly linked to the level of CO_2 emissions, providing certainty with regards to the marginal cost faced by emitters. It does not guarantee a maximum level of emission reductions, unlike an ETS. Norway introduced a carbon tax in the oil and gas production sector in 1991 which has been successful in incentivising the development of the Sleipner and Snøhvit CCUS projects. The cost of injecting and storing CO_2 for the Sleipner project at 17 $/$tCO_2$ was less than the 50 $/$tCO_2$ tax penalty levied at the time for CO_2 separated from natural gas and vented to the atmosphere (Herzog, 2016). This was complemented by a commercial need to separate the CO_2 from natural gas to meet gas quality requirements, providing a clearer business case to invest in CCUS.

Carbon taxes have been introduced in several countries (World Bank, 2019), although there are typically exemptions for the different types of emitters, particularly those which participate in ETS. These range from as low as 2 $/$tCO_2$ up to 125 $/$tCO_2$ as shown in Figure 81.



The size of the circles is proportional to the amount of government revenues except for those with revenues below US$100 million in 2018

Figure 81 Carbon tax prices introduced globally (World Bank, 2019)

In general, carbon tax systems have not led to CCUS, other than the Norwegian projects noted above. CCUS power plants derive additional revenue from the system only in so much as the carbon tax penalty increases the marginal power prices through unabated fossil fuel plants setting the price. This has typically driven fuel switching from coal to gas, but it could be interesting in countries such as China where there is limited natural gas infrastructure.

Emissions trading schemes – Regulation of emissions has also played a role in supporting the deployment of CCUS by placing an implicit value on emissions. A mandatory condition for the approval of the Gorgon project in Australia was the injection of at least 80% of the CO_2 vented by natural gas processing operations. As one of the largest natural gas projects in the world, the additional costs of compressing and storing CO_2 were manageable in the context of the project as a whole, adding less than 5% to the total project costs. The expectation of a future tax on carbon is an additional reason for CCUS being adopted for the Gorgon project, highlighting the point that it is not just current policies but also expected future ones that drive CCUS investment.

In Europe, the latest EU ETS review in 2018 strengthened the Market Stability Reserve (the mechanism to reduce the surplus of emission allowances) and increased the pace of emissions cuts. The overall number of emission allowances will decline at an annual rate of 2.2% from 2021 onwards, compared to 1.74% currently. This review has delivered a stronger carbon price, which has exceeded 55 €/tCO_2 for the majority of May-November 2021.

According to the International Monetary Fund (Dabla-Norris and others, 2021), a modest carbon tax of 25 \$/tCO_2, tailored to each country's energy mix and implemented over a 10-year period, could reduce the region's GHG emissions by 21%. The study, however, noted that such a tax would still leave a significant gap compared with the target of NZE. Dabla-Norris and others (2021) estimated that the carbon tax would have to be 75 \$/tCO_2 by 2030 for the region to be on a trajectory to limit global warming to 1.5°C. At present, the only countries in the region with carbon taxes are Japan and Singapore, and they are relatively modest at around 3 \$/tCO_2 in Japan and 4 \$/tCO_2 in Singapore. China, Indonesia, Japan, and Vietnam all have carbon emissions trading programmes.

11.2.3 Capital grants

CCUS facilities represent large capital investments. Several CCUS facilities have received capital grant support from governments to bridge funding deficits. Bringing new energy technologies to market is challenging because of the so-called 'valley of death' where financing is difficult to obtain for innovations that are not technically proven at high TRL levels (Sloss, 2019). Funding from government grants helps to address this, by rewarding early projects for the knowledge they create which can be used later by subsequent project developers, and by making investments more attractive to private sector investors.

Grant support has also been used to fund the construction of transport and storage networks, to address cross-chain risks. This was the approach used for the Alberta Carbon Trunk Line, which has received CAN$558 million (US$400 million) from the Alberta and Canadian governments.

11.2.4 State ownership of CCUS facilities

Some governments have overcome the need to attract private sector investment by supporting the construction of CCUS facilities through state-owned enterprises (SOE). In effect, the governments of Saudi Arabia and the UAE have adopted a strategy of state ownership of CCUS facilities to supply CO_2

for EOR, at least in the early stages of deployment. China has supported CCUS in this way through the state-owned China National Petroleum Corporation for the Jilin project, although it has also implemented other policy measures to support CCUS deployment in China. Sponsoring projects through SOE has several advantages:

- It is a way of directly supporting the development of new industries such as CCUS, particularly in countries that have less developed regulatory frameworks or where outsourcing to the private sector is difficult;
- Governments can generally borrow at relatively low interest rates, helping to bring down the effective cost of capital for projects; and
- The development of transport and storage infrastructure is particularly suited to this funding approach due to its naturally monopolistic characteristic.

Additional measures

To date, CCUS has been deployed in relatively few countries and in general has relied on the revenue stream from EOR, although there have been a few exceptions including Sleipner, Snøhvit, Quest, Gorgon, and In Salah (*see* Appendix, Table A-2 for project details).

While this has enabled the initiation of projects, the policies currently in place are insufficient to enable CCUS deployment to scale-up at the rates required to meet global climate targets requiring additional measures as described below.

11.2.5 Debt and equity financing

For capital intensive investment projects such as CCUS facilities, the cost of debt and equity can have a significant impact on financial viability. Banks have a critical role in providing debt finance which must increase significantly to achieve the necessary growth in the number of CCUS projects. To qualify for debt financing, CCUS projects will need to provide assurance that key risks are identified with mitigation measures in place and that hard to manage risks are allocated to government in the short term. This is because equity investors require higher rates of return on higher risk investment loans.

The different sources of financial instruments and their advantages and disadvantages are shown in Table 23, noting that project financiers will typically use a range of financial instruments to reduce project risk exposure. Some of these institutions specialise in high-risk environments, including in developing countries.

The cost of equity is also affected by risk. Typically, an investment is made if the expected internal rate of return (IRR) is equal to or greater than the required rate of return, known as the hurdle rate, where it will generally be set higher for more risky investments. For CCUS, with a perceived high risk, this represents a problem.

The key risks identified as 'hard to reduce' which should be addressed in the near term by transferring them to governments include:

Cross-chain risk – While the separation of the capture, transport, and storage elements of CCUS is considered the most likely model, it introduces challenging 'cross-chain' risks, where there is a chance that one party in the supply chain defaults on its obligation to supply or take CO_2, affecting the other parties in the chain (CCSA, 2016; IEA, 2016). A greater role for government in taking on the risk could alleviate this problem, or at least provide a clear structure to allocate risks between the various entities.

TABLE 23 FINANCIAL INSTITUTIONS AND INSTRUMENTS (ZAPANTIS AND OTHERS, 2019)

Source	Description	Advantage	Disadvantage
Commercial debt	Asset-backed loans that can be secured over the medium to long-term Commercial debt has been an important source of finance for both fossil fuel and renewable energy projects	Flexible and capable of providing a significant proportion of funding (high liquidity)	Time consuming and uncertain execution Not attracted to new technologies and will tend to perceive them as risky
Green banks	Banks specifically targeting green or low carbon investment	Deep liquidity Able to provide policy and technical support	Limited in scope and may not have support for CCS Region specific
Investment insurance agency or export credit agency	Government or private financial institutions that can offer financing to domestic company international operations. They help to resolve risks such as export and political risks of overseas investments	Reduces risks	Backed by assets Requires a well-defined strategy employed during the early stage of project design
Multi-lateral banks/ international financial institutions	This includes multilateral development banks (serving developing countries) and multilateral financial institutions (specialising in types of projects rather than regions). They play a significant role in Climate Finance as many of them serve as accredited entities to the Green Climate Fund. They have a long history of providing direct lending to projects	Deep liquidity Typically better than commercial bank's lending conditions as they are often able to provide concessional financing Able to provide substantial technical and policy support	Region specific and may not support CCS based on eligibility criteria

Policy risk – The potential for changes in political support pose a risk for any CCUS investment which is directly dependent on government policy for its commercial viability. Changing incentives for renewables in some countries has damaged investor confidence in this sector and investors may perceive an even greater risk for CCUS where there has been a history of changing political support (Lockwood 2018a). Many projects have been started under supportive conditions only to see waning political backing before they have proceeded to a final investment decision (FID). The history of CCUS in the UK presents a clear example of how political uncertainty can harm investor confidence (CCSA, 2016; Lockwood, 2018a).

Storage liability – While the risk of CO_2 leaking from geological storage is low, the impact is a cost to the project which is difficult to quantify. Leakage risks could feasibly be covered by government, as recognition of the broader value of CCUS to society. The IEA have proposed that national governments are best placed to bear 'climate related leakage risks' while project operators retain responsibility for any local environmental impacts or health and safety issues relating to a potential leak (IEA, 2016). This is based on the rationale that only the government has the means to instigate 'climate compensation' tools beyond the sphere of the project, such as increased deployment of renewables. One model adopted by the Australian Government is where the storage operator retains the risk of short-term liability during the operational period of the project and for a specified post-closure period (Dixon and others, 2015). This approach has been replicated elsewhere including the EU and Alberta, Canada. The basis is that the risk of leakage is highest during the CO_2 injection phase, which reduces the post-injection phase risk and continues to reduce over time. Consequently, the long-term risk accepted by government should be low.

To date, to help overcome the barrier, governments have typically provided capital grants as well as other mechanisms to aid financing such as loan guarantees and tax exemptions (Lockwood, 2018a). These funds are usually made available during the construction phase. As the market matures, with the steps identified already in this section increasingly in place, the hurdle rate will fall from 17.5% towards 8%, with the cost of debt falling from 14% towards 4%.

As the CCUS industry matures, risk reduction is making lower cost finance more available, which in turn reduces the cost of investments. In the mature market stage, projects tend to comprise equity and debt capital exclusively (Zapantis and others, 2019).

11.2.6 Potential business models

Several potential business models that incorporate the features described earlier in this section have been proposed (Element Energy, 2018; CCUS Cost Challenge Task Force, 2018). The preferred business model for the UK case as proposed by the CCUS Cost Challenge Task Force is shown in Figure 82.

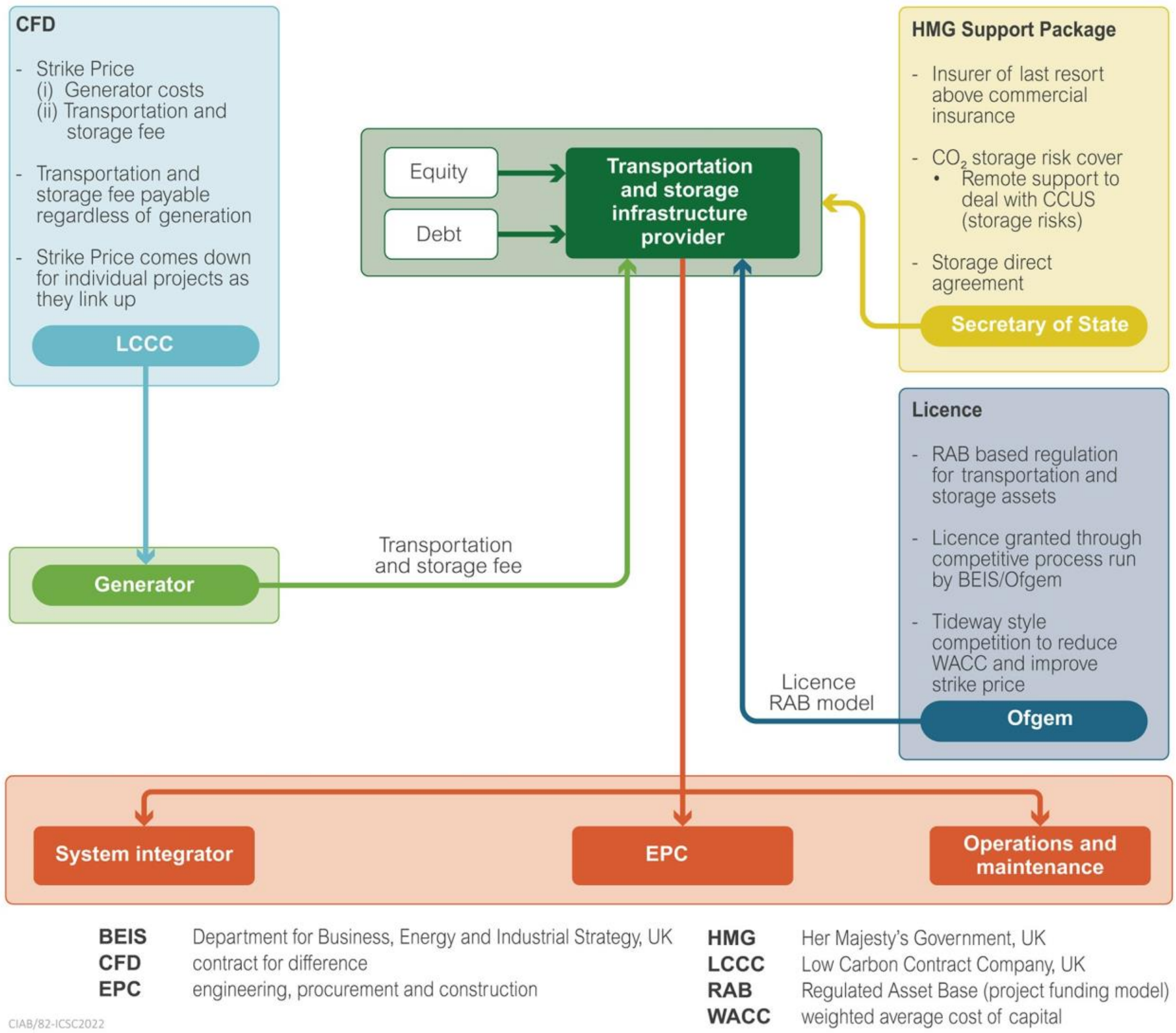


Figure 82 Potential business model for CCUS as proposed in the UK (CCUS Cost Challenge Task Force, 2018)

Transport and storage (T&S) – the model is based on the use of the RAB for the T&S component of the CCUS project. The RAB model gives the flexibility to enable future development as the need for further infrastructure increases and is potentially attractive to investors with a longer-term time horizon. RAB models have low volatility in returns, a stable regulatory regime and the potential for future growth and deployment of further capital. RAB models therefore command a lower cost of capital which helps drive down the overall costs of delivery.

Capture for electricity generating projects – the model proposes that CO_2 capture-related projects which generate electricity could be supported using the existing UK Contract for Difference (CfD) mechanism, or any successor mechanism that may be introduced in the future. CfD is the Government's main mechanism for supporting low-carbon electricity generation. CfDs incentivise investment in energy projects by providing developers of projects with high upfront costs and long lifetimes with direct protection from volatile wholesale prices. At the same time, they protect consumers from paying increased support costs when electricity prices are high.

The CfD strike price for CCUS would need to reflect the cost of capture and generation as well as the relevant project's proportion of the CO_2 transport and storage fee. However, the transport and storage fee could be a separate pass-through element of the overall revenues and not part of the CfD strike price (CCUS Cost Challenge Task Force, 2018).

The UK's CCUS Advisory Group (CAG) proposed a variant of the CfD to take account of the dispatchability of CCUS (CAG, 2019). Referred to as 'dispatchable CfD', this would include fixed and variable payments designed to bring forward investment in dispatchable low-carbon generation capacity, including electricity generation with CCUS. The model is an adaption of the standard CfD mechanism which aims to enable CCUS to play both a baseload and mid-merit role in meeting electricity demand.

12 CONCLUSIONS

There is a widely held assumption that there must be an end to the use of coal if we are to achieve net zero emissions (NZE). Many countries, particularly in Europe, have already committed to phase out coal. These are generally developed countries with slow-growing, service-based economies, stable populations and the options of nuclear power, relatively cheap natural gas and renewables. However, for much of Asia, phasing out coal is not currently a feasible option. Energy security in Asia depends on coal where it remains the dominant source of energy as it is relatively cheap and readily available.

Asian countries tend to have relatively fast-growing economies and populations, which are also becoming more urban. This means that demand for power and electricity is growing. Urbanisation and industrialisation also increase the demand for infrastructure. These developments require large amounts of steel and cement, the production of which is also still largely coal dependent. Thus, it is much harder for a growing Asian economy to stop using coal than it is for a developed, service-based European or North American economy which already has 100% access to electricity.

Asia, home to over 60% of the world's population, relies on oil, coal and gas for 90% of its energy needs. It is responsible for more than half of global CO_2 emissions from fossil fuels. However, while maintaining reliance on coal, there is much that Asian countries can do to approach NZE. The deployment of low emission technologies should be accelerated as a start.

Many countries, particularly those across Southeast Asia, have young fleets of fossil fuel power stations with 352 GW of coal-fired power plants under construction or in planning. In 2017, the Asia-Pacific region was responsible for 72% of global coal consumption, with China alone contributing 48%.

CARBON CAPTURE, UTILISATION AND STORAGE (CCUS) TECHNOLOGY IS READY FOR COMMERCIAL DEPLOYMENT. STRONG FINANCIAL, REGULATORY AND INCENTIVE REGIMES WILL ENABLE ITS LARGE SCALE DEPLOYMENT ACROSS ASIA.

CCUS is a necessary, strategic part of Asia's transition to NZE because coal and gas will remain important over many years for existing industry, such as electricity generation and industrial processes that are hard to abate; and new industries, such as bioenergy, hydrogen, ammonia and dimethyl ether (DME).

The CO_2 captured could be stored permanently in local geological structures deep underground. Regional cooperation is an option for individual countries where this is not possible or where collaboration provides a less costly pathway. Regional cooperation on CCUS can also lead to increased international trade in low emission energy products from coal that are needed in the home country, where it is produced with local geological storage and in the importing countries. The business case for CCUS can be boosted by using the CO_2 for enhanced oil/gas recovery and as a carbon source for new, value-adding circular economy activities in cement and chemicals manufacture.

The cost of CCUS has reduced significantly and further cost reductions can be expected through 'learning by doing' where perhaps a 50–75% cut could be achieved as the technology is rolled out commercially. More positive carbon price signals would drive growth in CCUS. The value needs to be around 40–80 $/tCO_2$ in 2020, increasing to 50–100 $/tCO_2$ by 2030. The availability of debt financing for CCUS projects needs to increase significantly and banks have a critical role to play.

Asia, and in particular China, should become a key focus for the roll-out of commercial CCUS. Commercial scale projects in place in China include the Jinjie CCUS projects; further projects such as the Huaneng Multi-energy project at the 1 $MtCO_2/y$ scale and above are in construction.

The phasing in of abatement technologies such as CCUS and cofiring biomass can have similar results in terms of emissions reductions to the phasing down of coal.

Cofiring biomass with coal is increasing in Asia as a means to reduce GHG emissions. Several Asian countries have substantial agricultural and forestry waste resources, further increasing the potential for biomass cofiring.

Japan is pursuing cofiring low emissions ammonia, produced from fossil fuels with CCUS, or from water electrolysis using electricity. Work is underway to develop a global supply chain to provide the required levels of ammonia.

All new, large coal units should adopt high efficiency, low emissions (HELE) ultrasupercritical (USC) conditions and best-available pollutant controls. Small, inefficient unabated coal power plants should be closed. State-of-the-art USC coal power plants currently achieve up to around 47% efficiency (LHV, net), equivalent to around 720 gCO_2/kWh, where the average efficiency globally is 37.5%. In the long term, efficiencies of around 60% LHV have been projected for power plants at the multi-100 MW size.

LOCAL AND REGIONAL SOLUTIONS WILL BE REQUIRED TO REACH A COUNTRY'S NET ZERO GOAL AT LEAST COST.

Specifically:

Local – CCUS solutions can help individual nations reach net zero. The four country case studies illustrate how this can achieved.

Regional – Some countries with limited storage and/or where the cost is high could still use hydrogen, ammonia and other feedstocks from coal as part of attaining net zero, with the storage occurring where the coal reserves are located.

INCREASING LEVELS OF RENEWABLE ENERGY WILL BE PURSUED IN ASIA, BUT COAL WILL CONTINUE TO BE USED FOR YEARS BECAUSE: SECURITY OF ENERGY SUPPLY IS VITAL; COAL PROVIDES DISPATCHABLE POWER TO HELP MAINTAIN A STABLE POWER GRID AS THE LEVEL OF VARIABLE RENEWABLE ENERGY (VRE) INCREASES; NATURAL GAS IS RELATIVELY EXPENSIVE IN ASIA; AND COAL IS DIFFICULT TO REPLACE AS A FEEDSTOCK IN MANY INDUSTRIES.

Dispatchable power, including coal-fired power provides high levels of inertia which plays an important role in overall power grid response, including frequency disruptions and power factor correction. Even when high levels, >50–70% VRE are achieved, coal-fired power generation technology will remain key to ensure Asia's security of supply. Consequently, an increase in variable renewable generation capacity does not necessarily allow for significant closures of dispatchable plants, although the coal plants will typically operate at lower capacity factors.

Coal power plants offer the best option to provide system flexibility in the near term to support the increasing levels of VRE in many Asian countries.

Industry globally produces about 8000 $MtCO_2/y$ of direct emissions, with the cement, iron and steel, and chemical sectors being responsible for around 70% of them. Asia dominates steel production as China, India and Japan together produce 65% of the material. Almost 70% of global cement production is also in Asia. Demand for industrial products is forecast to continue to grow, at least through to 2050.

Almost 2,000 $MtCO_2/y$ of industrial emissions worldwide are a by-product of chemical reactions within the production processes. These process related emissions cannot be avoided using feasible production technologies. China will need to play a key role in the effort to reduce industrial emissions, as it accounts for over 50% of global cement, steel and aluminium industry related CO_2 emissions. The chemical industry emits 1100 $MtCO_2/y$, making it equal third with the aluminium industry, behind the steel and cement sectors. Over 30% of these CO_2 emissions are also process-related.

A portfolio approach to decarbonise industry and the chemicals sector will be needed, including 'fuel' switching to low emissions fuels of hydrogen and ammonia, biomass as a carbon neutral fuel, improved energy efficiency, and deployment of current best available and future innovative technologies including CCUS.

Hydrogen is seen as a necessary feature of the energy transformation.

Currently, most hydrogen is produced local to the point of use, almost entirely from fossil fuels and is used as feedstock in the refinery and chemical industries. Global demand for hydrogen is forecast to increase to around 14% of the expected total energy demand in 2050. It will be used primarily for industrial feedstock and energy, together with transportation, heating and power in buildings, and power generation usage of hydrogen including hydrogen buffering.

In general, low carbon hydrogen production from coal gasification with CCUS and natural gas reforming with CCUS are lower cost than low carbon hydrogen based on water electrolysis, typically by a factor of approaching 3. The Sinopec Qilu CCUS retrofit to the existing coal gasification plant in China could lead the way to a wider roll-out of low-carbon hydrogen technology in Asia.

As investments and policies for power sector transformation focus on VRE, inefficient coal plants continue to operate as backup, instead of being replaced by HELE plant with CCUS. This is exacerbated by the flight of international finance and technology providers from the coal sector. While coal remains fundamental to many electricity grids, the sector should be supported in a rapid transition to HELE technologies with CCUS through appropriate valuation of dispatchable capacity to make the grid reliable, continued support for R&D, and greater international collaboration. This study aims to accelerate the transition.

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14 APPENDIX

TABLE A-1 GLOBAL CCUS INSTALLATIONS IN COMMERCIAL OPERATION (GCCSI, 2020, 2021B)

No	Title	Status	Country	Date	Industry	Capture capacity, Mt/y	Capture type	Storage type
1	South China Sea Offshore CCS	Operating	China	2021	Natural gas processing	0.3	Industrial separation	Dedicated geological storage
2	Alberta Carbon Trunk Line (ACTL) with Sturgeon Refinery CO_2 Stream	Operating	Canada	2020	Hydrogen for oil refining	1.4	Industrial separation	EOR
3	Alberta Carbon Trunk Line (ACTL) with Nutrien CO_2 Stream	Operating	Canada	2020	Fertiliser production	0.3	Industrial separation	EOR
3	Gorgon Carbon	Operating	Australia	2019	Natural gas processing	4.0	Industrial separation	Dedicated geological storage
4	Qatar LNG CCS	Operating	Qatar	2019	Natural gas processing	2.1	Industrial separation	Dedicated geological storage
5	CNPC Jilin Oil Field CO_2-EOR	Operating	China	2018	Natural gas processing	0.6	Industrial separation	EOR
6	Illinois Industrial Carbon Capture and Storage	Operating	USA	2017	Ethanol production	1.0	Industrial separation	Dedicated geological storage
7	Petra Nova Carbon Capture	Operation suspended due to the pandemic	USA	2017	Power generation	1.4	Post-combustion capture	EOR
8	Abu Dhabi CCUS (Phase 1 was Emirates Steel Industries)	Operating	UAE	2016	Iron and steel	0.8	Industrial separation	EOR
9	Karamay Dunhua Oil Technology	Operating	China	2015	Chemical production-methanol	0.1	Industrial separation	EOR
10	Quest	Operating	Canada	2015	Hydrogen for oil refining	1.2	Industrial separation	Dedicated geological storage
11	Uthmaniyah CO_2-EOR Demonstration	Operating	Saudi Arabia	2015	Natural gas processing	0.8	Industrial separation	EOR
12	Boundary Dam CCS	Operating	Canada	2014	Power generation	1.0	Post-combustion capture	EOR
13	Petrobras Santos Basin Pre-Salt Oil field CCS	Operating	Brazil	2013	Natural gas processing	4.6	Industrial separation	EOR
14	Coffeyville Gasification Plant	Operating	USA	2013	Fertiliser production	1.0	Industrial separation	EOR

TABLE A-1 – CONTINUED								
No	**Title**	**Status**	**Country**	**Date**	**Industry**	**Capture capacity, Mt/y**	**Capture type**	**Storage type**
15	Air Products Steam Methane Reformer	Operating	USA	2013	Hydrogen for oil refining	1.0	Industrial separation	EOR
16	Lost Cabin Gas Plant	Operation suspended due to a fire	USA	2013	Natural gas processing	0.9	Industrial separation	EOR
17	PCS Nitrogen	Operating	USA	2013	Fertiliser production	0.3	Industrial separation	EOR
18	Bonanza Bioenergy CCUS EOR	Operating	USA	2012	Ethanol production	0.1	Industrial separation	EOR
19	Century Plant	Operating	USA	2010	Natural gas processing	5.0	Industrial separation	EOR
20	Arkalon CO_2 Compression Facility	Operating	USA	2009	Ethanol production	0.3	Industrial separation	EOR
21	Snøhvit CO_2 Storage	Operating	Norway	2008	Natural gas processing	0.7	Industrial separation	Dedicated geological storage
22	Sinopec Zhangyuan CCUS	Operating	China	2006	Chemical production	0.1	Industrial separation	EOR
23	Core Energy CO_2-EOR	Operating	USA	2003	Natural gas processing	0.4	Industrial separation	EOR
24	Great Plains Synfuels Plant and Weyburn-Midale	Operating	USA	2000	Synthetic natural gas	3.0	Industrial separation	EOR
25	Sleipner CO_2 Storage	Operating	Norway	1996	Natural gas processing	1.0	Industrial separation	Dedicated geological storage
26	MOL Szank field CO_2	Operating	Hungary	1992	Natural gas processing	0.2	Industrial separation	EOR
27	Shute Creek Gas Processing Plant	Operating	USA	1986	Natural gas processing	7.0	Industrial separation	EOR
28	Enid Fertilizer	Operating	USA	1982	Fertiliser production	0.2	Industrial separation	EOR
29	Terrell Natural Gas Processing Plant (formerly Val Verde)	Operating	USA	1972	Natural gas processing	0.4	Industrial separation	EOR

TABLE A-2 GLOBAL CCUS INSTALLATIONS IN CONSTRUCTION AND DEVELOPMENT (GCCSI, 2020; 2021B)

No	Title	Status	Country	Date	Industry	Capture capacity, Mt/y	Capture type	Storage type
30	Sinopec Qilu Petrochemical CCS	Construction	China	2020-21	Chemical production	0.4	Industrial separation	EOR
31	Guodian Taizhou Power Station Carbon Capture	Construction	China	Delayed to 2020s	Power generation	0.5	Industrial separation	0.3 $MtCO_2$/y for EOR
32	The ZEROS Project	Construction	USA	Late 2020s	Power generation	1.5	Oxyfuel	EOR
33	Louisiana Clean energy complex	Construction	USA	2025-26	Hydrogen/ Various	5.0	To be announced	Dedicated geological storage
34	Norcem Brevik	Construction	Norway	2024	Cement	0.4	Post combustion	Dedicated geological storage
35	Santos Cooper Basin CCS	Construction	Australia	2023	Gas Processing	1.7	Industrial separation	Dedicated geological storage
36	Wabash CO_2 Sequestration	Advanced development	USA	2022	Fertiliser production	1.5–1.8	Industrial separation	Dedicated geological storage
37	Port of Rotterdam CCUS Backbone Initiative (Porthos)	Advanced development	The Netherlands	2023	Various	2.0–5.0	Various	Dedicated geological storage
38	San Juan Generating Station	Advanced development	USA	2023	Power Generation	6.0	In evaluation	EOR
39	Santos Cooper Basin CCS Project	Advanced development	Australia	2023	Natural gas processing	1.7	Industrial separation	Dedicated geological storage
40	Fortum Oslo Varme-Langskip	Advanced development	Norway	2023-24	Waste-to-energy	0.4	Post combustion capture	Dedicated geological storage
41	Brevik Norcem-Langskip	Advanced development	Norway	2023-24	Cement production	0.4	Industrial separation	Dedicated geological storage
42	Cal Capture	Advanced development	USA	2024	Power Generation	1.4	Post-combustion capture	EOR
43	Lake Charles Methanol	Advanced development	USA	2025	Chemical production	4.0	Industrial separation	EOR
44	Abu Dhabi CCS Phase 2 – Natural Gas Processing Plant	Advanced development	UAE	2025	Natural gas production	2.3	Industrial separation	EOR
45	Dry Fork Integrated Commercial CCS	Early development	USA	2025	Power generation	3.0	Post-combustion capture	Dedicated geological storage & EOR
46	Carbonsafe Illinois-Macon County	Advanced development	USA	2025	Power generation and ethanol	2.0–5.0	Post-combustion capture and industrial separation	Dedicated geological storage & EOR
47	Project Tundra	Advanced development	USA	2025-26	Power Generation	3.6	Post-combustion capture	Dedicated geological storage

TABLE A-2 – CONTINUED

No	Title	Status	Country	Date	Industry	Capture capacity, Mt/y	Capture type	Storage type
48	Integrated Mid-Continent Stacked Carbon Storage Hub	Advanced development	USA	2025-35	Ethanol, power generation &/or refinery	1.9	Various	Dedicated geological storage & EOR
49	CarbonNet	Advanced development	Australia	2020s	In evaluation	3.0	In evaluation	Dedicated geological storage
50	Mustang Station of Golden Spread Electric Cooperative	Advanced development	USA	Mid-2020s	Cement Production	1.5	Post-combustion capture	In evaluation
51	Prairie State Generating Station	Advanced development	USA	Mid-2020s	Power Generation	6.0	Post-combustion capture	Dedicated geological storage
52	Gerard Gentleman Station	Advanced development	USA	Mid-2020s	Power Generation	3.8	Post-combustion capture	In evaluation
53	Plant Daniel	Advanced development	USA	Mid-2020s	Power Generation	1.8	Post combustion capture	Dedicated geological storage
54	Project Interseqt-Hereford Ethanol Plant	Early development	USA	2021	Ethanol production	0.3	Industrial separation	Dedicated geological storage
55	Project Interseqt-Planview Ethanol Plant	Early development	USA	2021	Ethanol production	0.3	Industrial separation	Dedicated geological storage
56	Hydrogen 2 Magnum (H2M)	Early development	Netherlands	2024	Power generation	2.0	In evaluation	Dedicated geological storage
57	Project Pouakai	Early development	New Zealand	2024	Hydrogen production/power generation	1.0	Industrial separation	In evaluation
58	Caledonia Clean Energy	Early development	UK	2024	Power generation	3.0	Post-combustion capture	Dedicated geological storage
59	Velocys' Bayou Fuels Negative Emission	Early development	USA	2024	Chemical production	0.5	Industrial separation	Dedicated geological storage
60	Dry Fork Integrated Commercial CCS	Early development	USA	2025	Power generation	3.0	Post-combustion capture	Dedicated geological storage
61	Net Zero Teesside	Early development	UK	2025	Various	0.8–10.0	Various	Dedicated geological storage
62	Oxy and Carbon Eng Direct Air Capture and EOR Facility	Early development	USA	Mid 2020s	–	1.0	Direct air capture	EOR
63	South West Hub	Early development	Australia	2025	Fertiliser production & power generation	2.5	Industrial separation	Dedicated geological storage
64	Red Trail Energy BECCS project	Early development	USA	2025	Ethanol production	0.2	Industrial separation	Dedicated geological storage

TABLE A-2 – CONTINUED

No	Title	Status	Country	Date	Industry	Capture capacity, Mt/y	Capture type	Storage type
65	Illinois Clean Fuels Project	Early development	USA	2025	Chemical production	2.7	Industrial separation	Dedicated geological storage
66	HyNet North West (HyNet, 2019)	Early development	UK	Mid--2020s	Hydrogen production	2.0	Industrial separation	Dedicated geological storage
67	LafargeHolcim Cement Carbon Capture	Early development	USA	Mid-2020s	Chemical production	0.7	Industrial separation	In evaluation
68	ECO2S: Early CO_2 Storage Complex in Kemper County	Early development	USA	2026	In evaluation	3.0	In evaluation	Dedicated geological storage
69	Northern Gas Network (H21, 2016), UK	Early development	UK	2026	Hydrogen production	1.5	Industrial separation	Dedicated geological storage
70	H2H Saltend (H2H, 2020)	Early development	UK	2026-27	Hydrogen production	1.4	Industrial separation	Dedicated geological storage
71	Drax BECCS	Early development	UK	2027	Power generation	4.0	Post-combustion capture	Dedicated geological storage
72	Ervia Cork CCS	Early development	Ireland	2028	Power generation and Hydrogen production	2.5	In evaluation	Dedicated geological storage
73	China Resources Power (Haifeng) Integrated CCS Demo	Early development	China	2020s	Power generation	1.0	Post-combustion capture	Dedicated geological storage
74	Huaneng GreenGen IGCC (Phase 3)	Early development	China	2020s	Power generation	2.0	Post-combustion capture	In evaluation
75	Korea-CCS 1&2	Early development	S Korea	2020s	Power generation	1.0	Post-combustion capture	Dedicated geological storage
76	Sinopec Shengli Power Plant CCS	Early development	China	2020s	Power generation	1.0	Post-combustion capture	EOR
77	Acorn Scalable CCS	Early development	UK	2020s	Oil refining	4.0	Industrial separation	Dedicated geological storage

TABLE A-3 MAJOR GLOBAL HUBS AND CLUSTERS (GCCSI, 2021B)

No	Name	Country	Facility industry	Transport type	Storage type
1	Abu Dhabi Cluster	United Arab Emirates **Operating**	Natural gas processing, hydrogen production, iron and steel production	Pipeline	EOR
2	Acorn	Scotland	Hydrogen, natural gas power, natural gas processing, direct air capture (DAC)	Pipeline	Dedicated geological storage (saline formations)
3	Alberta Carbon Grid	Canada	To be determined	Pipeline	To be determined
4	Alberta Carbon Trunk Line (ACTL)	Canada **Operating**	Fertiliser, hydrogen, chemical	Pipeline	EOR
5	Antwerp@C	Belgium	Hydrogen, chemical, oil refining	Pipeline	Dedicated geological (saline formations)
6	ARAMIS	Netherlands	Oil refining, hydrogen, waste incineration, chemical, steelmaking	Pipeline, ship	Dedicated geological storage (saline formations)
7	ATHOS (Amsterdam CO_2 Transport Hub & Offshore Storage)	Netherlands	Hydrogen, iron and steel, chemical production	Pipeline	Various options
8	Barents Blue	Norway	Chemical, hydrogen, waste incineration	Ship	Dedicated geological storage (saline formations)
9	C4 Copenhagen	Denmark	Waste incineration, natural gas power	Pipeline	Dedicated geological (saline formations)
10	Carbon Connect Delta (Port of Ghent)	Belgium & Netherlands	Steelmaking, chemical production	Pipeline, ship	Under Evaluation
11	CarbonNet	Australia	Natural gas processing, coal-fired power, hydrogen, ammonia, fertilisers, waste to energy, DAC	Pipeline	Dedicated geological (saline formations)
12	CarbonSAFE	USA	Coal-fired power, ethanol	Pipeline	Various options
13	Dartagnan	France	Aluminium production, steelmaking	Pipeline, ship	N/A
14	Carbon Transport and Storage Company	Australia	Coal-fired power initially, cement, chemical production	Pipeline	Dedicated geological storage (saline formations)
15	Edmonton Hub	Canada	Natural gas power, hydrogen, oil refining, chemical production, cement	Pipeline	Dedicated geological (saline formations)
16	Greensand	Denmark	Waste incineration, cement	Pipeline, ship	Depleted oil and gas reservoirs
17	Houston Ship Channel CCS Innovation Zone	USA	Various	Pipeline	TBD
18	Humber Zero	UK	Hydrogen production, natural gas power	Pipeline	Dedicated geological storage (saline formations)

TABLE A-3 – CONTINUED					
No	**Name**	**Country**	**Facility industry**	**Transport type**	**Storage type**
19	HyNet North West	UK	Hydrogen	Pipeline	Dedicated geological (saline formations)
20	Illinois Storage Corridor	USA	Coal power, bioethanol	Pipeline	Dedicated geological storage (saline formations)
21	Integrated Mid-Continent Stacked Carbon Storage Hub	USA	Coal-fired power, cement, ethanol production, chemical production	Pipeline	Various options
22	Langskip	Norway	Waste incineration, cement	Pipeline	Dedicated geological storage (saline formations)
23	Louisiana Hub	USA	Hydrogen, iron and steel, oil refining, chemical, ethanol	Pipeline	Dedicated geological (saline formations)
24	Net Zero Teesside	UK	Natural gas power, fertiliser, iron and steel, chemical production	Pipeline	Dedicated geological (saline formations)
25	North Dakota CarbonSAFE	USA	Iron and steel	Pipeline	Various options
26	Petrobras Santos Basin CCS Cluster	Brazil **Operating**	Natural gas processing	Direct injection	EOR
27	PORTHOS (Port of Rotterdam CO2 Transport Hub and Offshore Storage)	Netherlands	Hydrogen, chemical	Pipeline	Depleted oil & gas reservoirs
28	Ravenna Hub	Italy	Hydrogen, natural gas power	Pipeline	Depleted oil and gas reservoirs
29	South Wales Industrial Cluster	UK	Natural gas power, hydrogen, oil refining, chemical	Pipeline, ship	Dedicated geological storage (saline formations)
30	Summit Carbon Solutions	USA	Bioethanol	Pipeline	Dedicated geological storage (saline formations)
31	Valero Blackrock	USA	Bioethanol	Pipeline	TBD
32	Wabash CarbonSafe	USA	Coal-fired power, natural gas power, hydrogen, chemical, cement, biomass power	Direct injection	Various options
33	Xinjiang Junggar Basin CCS Hub	China **Operating**	Coal-fired power, hydrogen, chemical	Pipeline, tank, truck	EOR
34	Zero Carbon Humber	UK	Hydrogen, iron and steel, chemical, cement, ethanol	Pipeline	Dedicated geological storage (saline formations)

TABLE A-4 SINOPEC REFERENCE COAL AND NATURAL GAS TO CHEMICALS PLANT (SINOPEC, 2021)

No	Project	Year
1	1.2 Mt/y coal-to-methanol project, Sinopec Great Wall Energy & Chemical (Ningxia) Co Ltd.	2019
2	Syngas debottleneck and acetic acid revamp and upgrade project, Sinopec Great Wall Energy & Chemical (Ningxia) Co Ltd. This is China's first big coal chemical upgrade and revamp project, with a capacity expansion by 40%. The coal slurry concentration is increased to 64.1%, and the effective gas volume is up to 216,854 m^3/h. SNEI delivered this EPC project based on a revamp solution developed in-house.	2017
3	1.7 Mt/y coal-based methanol-to-olefins (MTO) project (purification, methanol synthesis, SRU, ASU, air compressor station, etc), Zhong'an United Coal Chemical Co Ltd. The project is a joint venture between Sinopec and Anhui's Wanbei Coal-Electricity Group. SNEI delivered as EPC contractor the syngas plant with a capacity of 505,563 m^3/h (as $CO+H_2$), and the methanol plant with a capacity of 1.8 MMTPA (as 100% methanol).	2015
4	100,000 m^3/h coal-based hydrogen production unit, Sinopec Jiujiang Company. SNEI delivered this EPC project based on Sinopec's low-temperature methanol wash semi-lean solution circulation technology and coal slurry gasification at 4.0 MPa. SNEI earned the National Quality Project Award, Sinopec Quality Project Award, and the second prize of the National Excellent Project Engineering Award.	2014
5	1.8 Mt/y MTO, Henan Hebi Integrated Coal Project	2013
6	1.8 Mt/y methanol project, Sinopec Great Wall Energy & Chemical Co Ltd	2012
7	2 billion m^3/y coal to natural gas project, Sinopec Great Wall Energy & Chemical Co Ltd	2011
8	90 kt/y coal-based hydrogen production unit and associated air separation unit (ASU), Sinopec Nanjing Chemical Industrial Corporation. This project is based on a licensed coal slurry gasification technology, with a hydrogen production capacity of 126,000 m^3/h, Φ3200 gasifiers (2 running and 1 standby), coal feed of 1000 t/d per gasifier; with an associated ASU of 56,000 m^3/h	2011
9	100 kt/y acetic anhydride project, Yankuang Lunan Fertiliser Factory (earned 'Sun Cup' award and 'Quality Project Award' in 2011)	2010
10	1 billion m^3/y natural gas purification plant of Songnan gas field, Sinopec Northeast Oil and Gas Company	2009
11	CO plant for 500 kt/y acetic acid plant, Sinopec Yangzi Petrochemical Co Ltd	2008
12	Coal slurry gasification unit for 300 kt/y ammonia plant, Sinopec Nanjing Chemical Industrial Corporation	2005
13	Syngas project, BASF-YPC Company Limited	2004
14	300 kt/y ammonia, 520 kt/y urea project, Sinopec Nanjing Chemical Industrial Corporation	2002