Energy Technologies for Low-Carbon Development in Middle-Income Countries: Assessment and Implications

Yaroslav Melekh, Michael Grubb, and James Dixon*

Abstract

This paper investigates the implications of growing energy demand and industrialization in middle-income countries and the role of low-carbon technology options in the green transition. It emphasizes the importance of the transition to low-carbon electricity systems, and the benefits of electrification to reduce energy consumption and emissions. It underscores the economic and environmental challenges of transitioning from coal to gas, noting the vulnerability of gas to geostrategic perturbations and methane leakage, which undermines its potential climate benefits. It finds carbon capture and storage (CCS) for power generation to be impractical for most middle-income countries due to significant costs, high infrastructural barriers, and crowding-out investments in electricity storage which has demonstrated significant cost reductions. It concludes that the transition to natural gas and CCS will inevitably lead to carbon lock-in in the power sector. However, CCS can play a role in hard-to-abate sectors in middle-income countries that account for a significant share of the young fleet of blast furnaces and cement kilns. It finds that commissioning new blast furnaces will expose global net-zero targets, and instead, explores the role of hydrogen as a potential solution in the steel sector. Finally, it discusses how high financing costs delay the transition in middle-income countries and addresses the issues of carbon leakage and the need for international cooperation on manufacturing standards and the terms of trade.

Keywords: energy transition; coal transition; electrification; variable renewable energy; electricity storage; hydrogen; carbon capture and storage; industrial decarbonization; technology readiness levels; energy innovation; climate finance

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Acronyms

BECCS	bioenergy with carbon capture and storage
BF	blast furnace
BOF	basic oxygen furnace
CAPEX	capital expenditures
CBAM	carbon border adjustment
CCS	carbon capture and storage
CCUS	carbon capture utilization and storage
CDR	carbon direct removal
CO_2	carbon dioxide
DRI	direct reduced iron
EAF	electric arc furnace
ES	electricity storage
EU	European Union
EUR/tCO_2	euros per tonne of carbon dioxide
GHG	greenhouse gas
$GtCO_2$	gigatonnes of carbon dioxide
GW	gigawatt
GWh	gigawatt hour
GWP	global warming potential
HBI	hot briquetted iron
H-DRI	hydrogen-based direct iron ore reduction
H-DRI-EAF	hydrogen-based direct iron ore reduction with the electric arc furnace
HtA	hard to abate
kg	kilogram
kW	kilowatt
kWh	kilowatt hour
LCA	life-cycle assessment
LCOE	levelized cost of electricity
LCOS	levelized cost of storage
LDES	long-duration electricity storage
LUC	land use change
MDES	medium-duration electricity storage
Mt	megatonne
MWh	Megawatt hour
O&M	operation and maintenance
OECD	Organisation for Economic Co-operation and Development
OPEX	operating expenditure
PCC	post-combustion capture
PV	photovoltaics
t	tonne (metric ton, 1000 kilograms)
TGR	top gas recycled
TRL	technology readiness level
USD/kg	US dollars per kilogram

USD/tonne CO_2	US dollars per tonne of carbon dioxide avoided
VRE	variable renewable energy
WACC	weighted average cost of capital

Executive Summary

Economic development, along with population and urbanization trends in many middle-income countries, is likely to lead to rapidly rising demand for energy. Choices about how to meet these demands will affect not only the pace and ultimate scale of climate change, but also the economic future of these countries and the resilience of their energy supplies.

PART A. Electrification and the transition toward low-carbon electricity systems

Electrification. Multiple factors point to increasing electrification of energy systems overall, especially given the need for decarbonization. Among other potential benefits, electrification can reduce primary energy by 40 percent to 60 percent due to the higher conversion efficiency of electricity, and hence achieve greater reduction of greenhouse gas (GHG) emissions, even if the generation mix depends heavily on fossil fuels. Many analyses and models suggest that at least 60 percent of final energy demand can be met by electrification, compared to about 20 percent today.

In transport, electrification of cars, vans, and other light vehicles (including 2- and 3-wheelers) is increasingly attractive due to recent and potential future cost reductions, primarily of batteries. In the industrial sector, decarbonization involves increasing electrification in place of more carbon-intensive industrial processes, along with some direct input of low-carbon fuels such as "blue" or "green" hydrogen,[1] and possible niche roles for carbon capture and storage (CCS), discussed later.

Power generation: renewables. Following large cost reductions in the past decade, solar and wind are often the cheapest generating sources on a levelized cost of electricity (LCOE) basis, before accounting for system/integration costs, and contingent on financing costs. This may remain true with small amounts of local battery storage (such as for a few hours of evening lighting and cooking). At low penetrations, the wider system/integration need for "balancing" is mostly implicitly available from fossil fuel or pumped hydro power plants,[2] along with general transmission and distribution needs. At moderate contributions of variable renewable energy (VRE), potentially of up to 40 percent of electricity demand, the cost of system balancing is unlikely to change LCOE substantially and grid costs (beyond direct connection) may in many cases not be directly attributable to new renewables. At larger deployments and over time, balancing needs and costs may increase, with innovation required to expand the scope for long-duration electricity storage (LDES) at scale.

However, because renewables are capital-intensive but have very low operating costs, their cost advantage relative to fossil fuels depends heavily on the cost of capital and the business environment. Higher country risks in many middle-income countries mean that project

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[1] Blue hydrogen is produced from fossil fuels through steam reforming, mixing natural gas or coal with heated water, and using carbon capture to reduce emissions. Green hydrogen is produced without emitting carbon dioxide through electrolysis by splitting water into hydrogen and oxygen, using clean electricity to power this process.

[2] "Balancing" refers to ensuring that electricity supply meets electricity demand at any moment in the grid.

financing costs can sometimes account for as much as 50 percent of lifetime costs, increasing unit costs and impeding deployment. Across middle-income countries, countries with better business environments and electrification (including stronger grids) tend to benefit more than others, thus attracting more investments in renewables. The implication is a path-dependency in investment flows to more advanced middle-income countries that, consequently, benefit from lowering project financing risks and cheaper renewables. Other middle-income countries may be disproportionately disadvantaged in terms of access to capital and financing costs. Underwriting real and perceived risks may not only cheapen renewable energy projects but also, more broadly, reduce the amount of public finance needed to support those projects and make renewable energy more affordable.

Coal versus gas. The transition from coal to gas can provide some benefits, such as reducing local pollution and direct carbon emissions from power generation. This shift has significantly reduced direct carbon dioxide (CO_2) emissions in some countries.[3] However, the climate benefits of a transition to gas are questionable due to methane leakage throughout the supply chain that often erodes point-of-emission benefits; methane is a potent greenhouse gas, with global warming impact per unit far higher than CO_2 over a 20-year time span, and is thus potentially a major contributor to breaching medium-term climate goals, including the Paris Agreement targets.[4] In addition, gas has become demonstrably exposed to geopolitics, and its price stability remains hugely uncertain, thus undermining its possible benefits. Investing in new gas infrastructure risks exacerbating greenhouse-gas lock-in[5] for decades to come and in most cases will impede achievement of the Paris goals.

Many emerging economies have fueled their rapid growth mainly with cheap coal (though this has also proved to be exposed to international commodity prices) and so have a relatively new stock of coal power plants (10 to 12 years old). Continued construction would worsen the risk of asset-stranding,[6] partly as the rapid growth of renewables reduces their load factor, as well as explicit retirement associated with decarbonization. Middle-income countries without developed gas infrastructure have potential to move more rapidly ("leapfrogging") by accelerated deployment of renewables, if grid balancing, access to capital, and financing costs are addressed.

The analysis for this paper finds no evidence that carbon capture and storage (CCS) for power generation is a plausible option for most middle-income countries. It requires substantial additional capital investment, which necessarily adds to generation costs and degrades efficiency, while its deployment is constrained by limited options of plausible disposal sites.

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[3] Coal to gas switching has occurred particularly where there was existing developed gas infrastructure, especially at the time when renewables were still an immature technology and where coal infrastructure was aged. Often, this was facilitated by the introduction of carbon pricing and binding climate targets.

[4] Paris Agreement targets envision limiting the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

[5] Greenhouse gas, or carbon, lock-in means that once built, new fossil-fuel infrastructure is intended to be utilized for prolonged period of time (decades), hindering a transition to zero-carbon alternatives.

[6] Stranded assets are the assets that are exposed to policy and/or technological change, and/or climate change, which entails premature loss of their value, as the asset can no longer provide anticipated returns.

In terms of sustainability, CCS has limited efficiency at the point of emission, while energy penalties and pipeline leakages can result in net capture of as low as 50 percent, depending on the exact technology. There is no business case for private investment in CCS in the absence of a high carbon price,[7] for which there is little prospect in most middle-income countries, without large public subsidies. Despite ongoing efforts since the mid-1990s, technology readiness levels (TRLs) of most niche carbon capture technological options are at the demonstration stage (TRL 6 and TRL 7) at most. For power generation, there seems no investment case for new CCS-coal/gas power plant projects compared to new renewables projects. Unrealistic hopes for CCS risk encouraging continued investment in both upstream (extraction) and downstream (generation) fossil fuel assets, thus exacerbating carbon lock-in and the risk of stranded assets, ultimately jeopardizing the prospects for "net zero."[8] The role and prospects for CCS in hard-to-abate (HtA) domains like steel and cement seems more plausible (discussed later).

Running a next-generation power sector with a high level of variable renewables will rely on balancing capabilities, which will require significant public investments, including potentially in research, development, and demonstration (RD&D) and niche subsidies to bring the costs down. Given limited funding, technology pathways—especially for power generation—would appear best to focus on a variety of electricity storage and other balancing technologies to complement renewables; this is likely to be more productive than seeking to expand fossil fuel power generation. Various forms of flow batteries can extend storage well beyond those of lithium-ion batteries, and there are multiple options for long-duration electricity storage (LDES) including green hydrogen, potentially in varied forms. Further deployment efforts should focus on medium-duration electricity storage (MDES) and long-duration electricity storage needed to meet the exponential growth of renewables in the coming years. MDES and LDES scale-up can reduce electricity system costs in the long term, including by decreasing demand for further expansion of short-duration solutions (such as lithium ion batteries).

Overall, there is now no reason to believe that low-carbon electricity systems are in general more expensive than high-carbon systems, even after accounting for the needs of storage and other balancing in the light of the variability of wind and solar energy, though getting to zero emissions involves larger uncertainties. Electrification is also increasingly attractive, notably for much transport and some industry. The challenges are to migrate away from the old systems, and to ensure that all countries have adequate access to finance, including private finance at interest rates that support low-carbon investments in generation, balancing, and network technologies.

[7] Carbon pricing refers to a policy instrument of imposing a fee, either in an emission trading scheme or as a tax, on carbon dioxide emitted into the atmosphere, aimed to induce greenhouse gas emissions reduction.
[8] "Net zero" refers to means to abate carbon emissions to a small amount of residual emissions that can be absorbed or removed from the atmosphere. The Net Zero Emissions Scenario is a normative scenario developed by the Internal Energy Agency that shows a pathway for the global energy sector to achieve net zero CO_2 emissions by 2050, and is consistent with limiting the global temperature rise to 1.5 °C (with at least a 50 percent probability), in line with emissions reductions assessed in the Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report.

PART B. The role of CCS and hydrogen in decarbonizing hard-to-abate sectors: steel and cement

Industrial production accounts for about one-third of global energy-related and industry-related GHG emissions; thus, its decarbonization is essential to achieving net zero emissions. CCS and hydrogen are likely to be more significant in industry than in power generation or transport sectors. Each industrial sector is different and may require tailored solutions. This paper reviews two major cross-cutting options—CCS and hydrogen. To avoid overgeneralization while illustrating the range and complexity of options, the discussion focuses on the decarbonization of steel and cement, the biggest industrial emitting sectors, which account for about 15 percent of global emissions.

Due to the industrialization and urbanization of middle-income countries, steel and cement demand are projected to continue growing rapidly until 2050. Decarbonizing steel and cement will require dealing not only with combustion emissions, but also with process—that is, non-combustion— emissions. However, the young and growing fleet of industrial facilities in middle-income countries means GHG emission profiles must be addressed in the near term, alongside accelerating the low-carbon requirements for future installations.

A large opportunity exists to integrate demand-side responses, such as energy efficiency, demand reduction, and alternative materials, offering substantially untapped potential. Improvements—such as insulation upgrades, boiler improvements, the use of heat exchangers, and optimizing processes through measurements and control—can reduce energy usage of production stages by 10 percent to 26 percent each. Approaches such as material-efficient design, waste reduction, alternative materials, and circular economy interventions may reduce demand by up to about 25 percent. However, deep decarbonization of industry will also require more extensive supply-side measures.

Iron and steel

Current global steel production is dominated by fossil fuel blast furnaces (BFs). More than 60 percent of all BFs are younger than 12 years old, with most of these in China and India. Retrofitting this capacity is a near-term priority, with options such as changing processing routes, utilizing higher rates of recycling and scrap, and adopting CCS. The lowest cost option will depend on local and site-specific factors, but literature indicates that CCS can potentially offer the cheapest abatement cost and the highest rate of GHG emission reduction, at nearly 50 percent, for existing blast furnace-basic oxygen furnace (BF-BOF) capacity where CO_2 storage is accessible. The role of hydrogen as a substitute for coal or gas is very limited in BFs, reducing up to 20 percent of GHG emissions.

Direct reduced iron (DRI), producing iron from the ore generally to feed in to an electric arc furnace (EAF), is the other major production route for primary steel at present. For existing DRI capacity, CCS again offers the lowest abatement cost where feasible, but deep decarbonization requires alternative technologies. Hydrogen alone can reduce CO_2 by up to 60 percent, but currently at extremely high abatement costs: 700–1100 US dollars per tonne of carbon dioxide (USD/tonne CO_2) avoided for green hydrogen (from renewables) and 120–380

USD/tonne CO_2 avoided for blue hydrogen (from natural gas with CCS). To achieve higher decarbonization rates, the combination of hydrogen with low-carbon electric arc furnaces can provide reductions of more than 80 percent. While retrofits are crucial in the near term, the development of low-carbon technologies such as hydrogen direct reduction will be crucial for future deep decarbonization.

In principle, green hydrogen can become an integral part of steel decarbonization, while the role of blue hydrogen is questionable or transitional due to high life-cycle GHG emissions, given evidence on methane leakage, and exposure to fossil fuel prices. The cost of green hydrogen depends on the cost of electricity (30 percent to 60 percent), the cost of electrolyzers,[9] and any opportunity costs from carbon pricing. While renewable energy auctions have demonstrated the cheapening of renewables in recent years, the low technology maturity of electrolyzers is still a significant barrier to potential production cost reduction until 2030. The economics of green hydrogen is also multifaceted and depends on the availability of industrial hubs, infrastructure for transportation, or onsite generation and consumption. Unlike CCS, the current policy environment suggests the need to impose extremely high levels of carbon pricing, at about 300 USD/tCO_2 avoided for steel, which is not likely to be a politically plausible option. The cost range for low-carbon (blue and green) hydrogen is currently too wide, in the range of 4–10 US dollars per kilogram (USD/kg), to draw conclusions with confidence about future competitiveness. More direct monetary or fiscal support to the industry, along with public research and development (R&D), is required.

Cement

Nearly 60 percent of GHG emissions from cement come from non-combustion emissions that are currently hard to abate, and viable low-carbon technologies are limited. Therefore, except for potential substitution by alternate construction materials, the major option to address decarbonization is CCS. Post-combustion CCS is more effective than for steel (due to higher CO_2 concentrations), with close to 90 percent capture, and is more suited toward retrofitting the existing fleet of cement kilns, which are mostly young in middle-income countries. Avoidance costs per tonne of CO_2 range between 63–94 USD/tCO_2 avoided for near-term commercialized technologies, potentially reaching 44–46 USD/tCO_2 avoided for other CCS technologies in the long term.

There is potential to provide low-carbon heating options to address the remaining 40 percent of combustion-related emissions. Electrification of kilns is possibly, but relatively expensive, at nearly 100 euros per tonne of carbon dioxide (EUR/tCO_2) avoided, depending on the cost of electricity. As it stands, hydrogen has limited technical potential in cement kilns. However, the other byproduct of electrolysis—oxygen—can be used to reduce GHG emissions through oxy-combustion, with abatement costs of about 150 USD/tCO_2 avoided, or 50 USD/tCO_2 if coupled with CCS.

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[9] An electrolyzer is a device used for electrolysis, a chemical process of using direct electric current to split water into hydrogen and oxygen.

Many industrial decarbonization options are not yet fully commercialized, with many still at the low to middle stages of technology readiness levels (TRLs). Twelve industrial CCS facilities were in commercial operation as of 2021, and the scale of deployment and current learning rates do not provide confidence about the scale-up required for climate targets. However, the abatement costs of CCS in industry are more economically justified than in the power sector, where renewables seem likely to prevail.

Conclusion: Decarbonizing industry

Unlike the electricity transition that is under way, decarbonizing industry will impose significant additional production costs before low-carbon alternatives reach parity with current production processes. This transition is likely to take another decade or two (maybe more, without adequate carbon pricing or equivalent subsidies). Given the capital intensity of steel plants and cement kilns, retrofitting will likely be slow and marginal unless strong incentives are in place. Therefore, there is a need for policy support to produce low-carbon steel and cement through the mix of different interventions such as direct subsidies, "green" procurement policies, and carbon prices.

The cost of low-carbon materials will vary depending on the availability of cheap renewable energy resources and/or CO_2 disposal sites, as well as ores. Due to such disparities, as well as the costs incurred when transporting hydrogen, the global order of steel trade in particular has the potential to shift significantly, bringing costs and opportunities.

Given the trade dimensions and related concerns about carbon leakage, policy options include a trend toward low-carbon investment subsidies in developed countries, or carbon border adjustments to "level" the carbon price paid by consumers on products between domestic production and imports. This may well still have international distributional consequences. Developing countries may be able to gain significant roles in the value chain of emergent low-carbon industries, but there remains a pressing need for international cooperation on manufacturing standards, and relevant aspects of the terms of trade, finance, and consumption-oriented carbon pricing, to ensure that less developed countries in particular bear the least possible adjustment costs in the transition to low-carbon industrial production.

PART A. Electrification and the Transition toward Low-Carbon Electricity Systems

1. Introduction

1.1. The incumbent fossil fuel system

Economic growth in developing countries is traditionally associated with industrialization, urbanization, and rapid population growth. Subsequently, energy needs increase. Conservative projections suggest that more than 80 percent of new electricity demand will come from developing countries by 2040 (EIA 2021). The question, therefore, is how to meet this demand with carbon-neutral and low-carbon energy technologies, while maintaining objectives of economic growth and development.

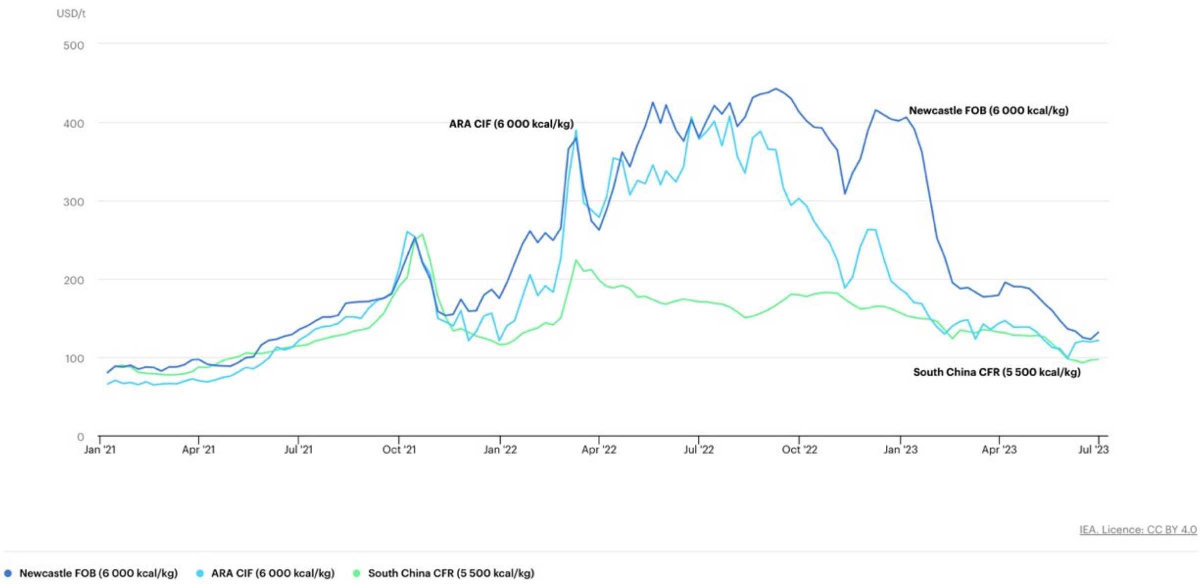
Historically, poverty eradication and economic development have been facilitated by a wide use of fossil fuels in the power sector and industry. This had been true for almost two centuries, especially in what are now known as industrialized nations. More recently, such an industrial development paradigm has been embraced by many developing countries, some of which have transformed into emerging economies and account for a young and significant fleet of fossil fuel–powered electricity and industry (IEA 2020a; Kalkuhl et al. 2019).

Our economic dependence on fuel-fed systems has created technological lock-ins. Hydrocarbons are used in power plants to generate electricity, and our vehicles consume oil, refined and converted into gasoline and diesel. Nuclear power also depends on fuel, in the form of radioactive materials. In the electricity sector, these systems have a common technological denominator—heat, steam, and turbines that generate electricity. Fossil fuel systems traditionally prefer centralized systems and grids (Skovgaard and van Asselt 2018), with large power plants in several areas contributing significantly toward powering the entire system. The cost of fossil fuel systems also matches classic supply chain models, meaning that energy pricing is calculated at the time of generation (Helm 2017). A reliance on fossil fuel energy comes with significant caveats. Combusting coal and gasoline results in local pollution, affecting human health and the environment. Emitted greenhouse gases (GHGs) warm the atmosphere and drive climate change, leading to flooding, droughts, forced migration, and loss of productivity (IPCC 2021).

Fossil fuel energy costs are largely dominated by fuel costs (EIA 2022)—meaning that although there are upfront capital investments, once these financing needs have been met, the cost of energy is reliant on coal and gas prices (Partridge 2018). Even though those extracted resources had been considered cheap, and prices were seemingly flat, before the oil shocks of the 1970s (FRED 2023), the experience of recent decades demonstrates their price volatility in international commodity markets (IRENA 2023c). Such price uncertainty can be beneficial in times of oversupply, but can also backfire during crises, exposing households and industry to surging energy prices (IEA 2022a), putting pressure on governments to cushion negative impacts, and, in many cases, increasing public debt (IEA 2022a).

Geostrategic tensions have also significantly contributed to volatility and uncertainty in the fossil fuel trade, and so too in the stability of economies. The most notorious recent example has been the enormous cut-offs of natural gas supply as a consequence of Russia's invasion of Ukraine. Such developments resulted in gigantic price spikes and cascaded within and across the economies until energy importers adjusted to new supply chains (IEA 2023d). The cascade effect also reached coal. Even though it used to be, and still is in some cases (Zhang et al. 2019), a "protected" commodity through domestic price regulation, coal has been exposed to international price fluctuations (figure 1).

Figure 1. Thermal coal price markets, January 2021–July 2023



Source: IEA 2023b.
Note: ARA = Amsterdam, Rotterdam, Antwerp; CIF = cost, insurance, and freight; CFR = cost and freight; FOB = free on board; kcal/kg = kilocalories per kilogram.

Commodity price turbulence in fossil fuel markets, geostrategic tensions, and associated interventions to mitigate negative impacts often lead to subsidizing the fossil fuel industry. Subsidies can occur either directly or indirectly (Rentschler, Kornejew, and Bazilian 2017), aggravating the impact on human health, the environment, and climate, and thus economic development. These financial flows and policies also crowd out strategic investments in low-carbon options that can offer the low-cost energy necessary for economic development and the associated industrialization of middle-income countries, and the social and environmental co-benefits such as clean air and green jobs**.**

1.2. Renewables and electrification

Until the 2010s, few technological alternatives existed to provide the low-carbon energy generation that meets baseload power and can be easily ramped up or down to meet variable energy demand. Mature technologies such as hydro- and biomass power plants have been widely used in many countries; however, they remain partly controversial due to environmental footprints, limited sites, land use competition, and exposure to physical climate risks.

Solar photovoltaic (PV) and wind power plants, as a new generation of renewable energy technologies, can be widely dispersed due to the abundance of solar irradiation and wind velocity. These technologies are also more resilient to geostrategic perturbations. The highly recyclable raw materials are traded more widely globally, as compared to the concentration of supply in a limited number of countries endowed with fossil fuels. At the same time, international connections and electricity storage are needed to facilitate the smoothing of supply of variable renewable energy (VRE). Temporal and spatial variability of renewables entails "give and take" bidirectional and multidirectional relationships of electricity flows between countries, rather than dependencies associated with the import of depleting fossil fuels.

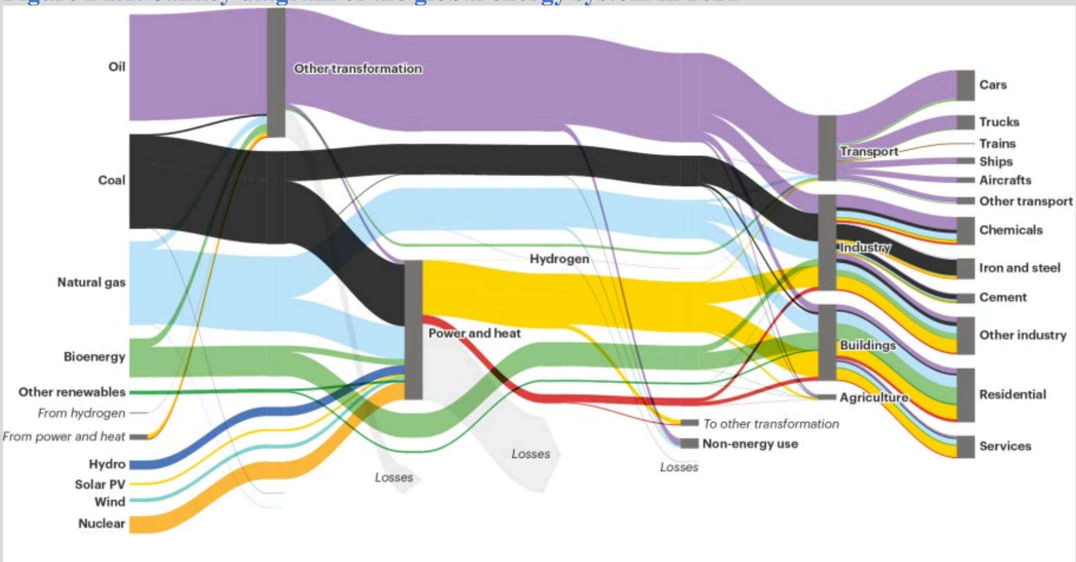
Further decarbonization will require not only carbon-neutral energy, but also electrification, as most global greenhouse emissions come from energy end-use in buildings, transport, and industry rather than from the power and heating sectors (Fortes et al. 2019; IPCC 2023a). Therefore, significantly reducing emissions and energy demand further in the power sector alone will not be sufficient to achieve deep decarbonization (Garvey and Taylor 2020). This imperative comes with challenges. First, achieving even 50 percent electrification in end-use sectors in a Net Zero Emission Scenario will more than double final electricity consumption by 2050 (IEA 2022b). Second, this transformation requires mobilizing capital to fund electrification, often associated with high upfront costs and capital-intensive investments, especially in industry (Nurdiawati and Urban 2021), as discussed further in Part B of this paper.

Decarbonization is being enabled by the cost revolution in wind and solar energy, which has triggered accelerated deployment across the globe over the last decade. More recently, the levelized cost of electricity (LCOE) of these renewables has fallen into and below the fossil fuel range (Grant et al. 2021; IRENA 2022), while balancing costs are minimal at low penetration levels (Heptonstall and Gross 2021; NEA 2019). One of the main advantages of electrification derived from renewables is the increase in efficiency because electricity can be generated directly, reducing the energy input required to address end-use demand (Luderer et al. 2022). This greater efficiency contrasts with conversion from fossil fuel power generation, which results in energy losses of 40 percent to 65 percent (IEA 2020a; IPCC 2023a). Hence, decarbonization will be facilitated by the development of renewable energy sources for electrification. Box 1 further discusses how a climate-compatible system differs from current energy flows, and presents a visualization of the increased efficiency due to electrification.

Box 1. The Role of Electrification in the Net Zero Transformation of the Global Energy System

The Sankey diagrams that follow display energy transfers from primary sources through to end-use demand. Figure B1.1 depicts the global energy system in 2021, with large roles for oil, coal, and natural gas. The first narrow light grey band depicts the energy losses encountered when refining oil; these losses are larger still when generating power and heat with fossil fuels, as shown in the second wider light grey band.

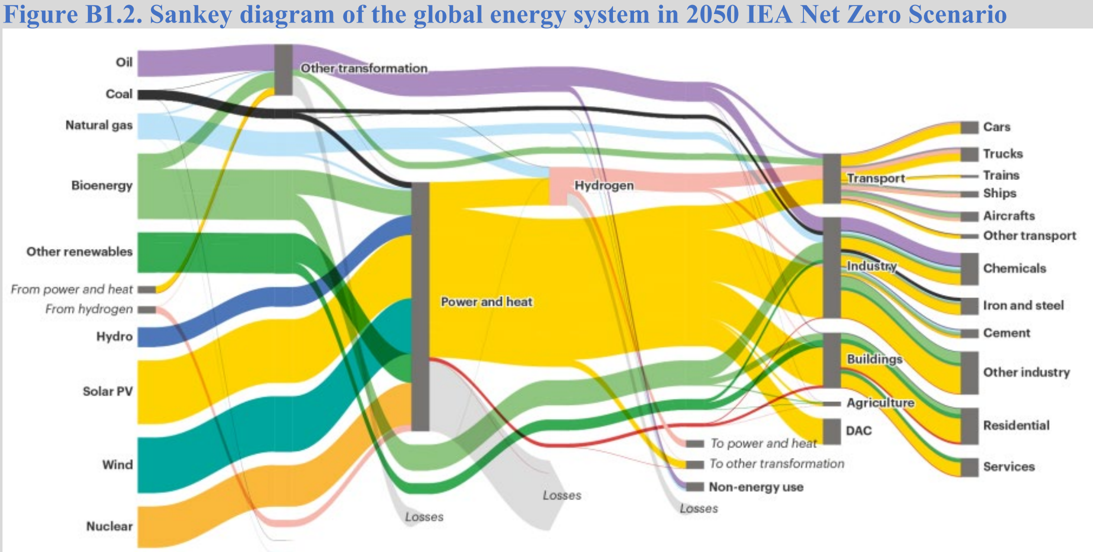
Figure B1.1. Sankey diagram of the global energy system in 2021



Source: IEA 2023c.
Note: PV = photovoltaics.

Figure B1.2 shows an energy system in 2050 compatible with the International Energy Agency's Net Zero Scenario. Power and heat generation has grown significantly, visualized by the expansion of the yellow band. The magnitude of energy loss in electricity generation remains similar between energy systems, even though the size of "power and heat" increases significantly, due to the efficiency gains from renewables.

Figure B1.2. Sankey diagram of the global energy system in 2050 IEA Net Zero Scenario



Source: IEA 2023c.
Note: PV = photovoltaics.

The energy infrastructure choices that countries make now will have extremely significant ramifications for their future, regarding infrastructure lock-ins (Grubb, Poncia, and Pasqualino 2024). Countries with developed energy infrastructures are already feeling this, as previous technologies, institutions, and behavioral norms that have "locked in" GHG emissions (Seto et al. 2016) are targeted for decarbonization. Developing countries and emerging economies must also consider these lock-ins when making decisions related to coal and gas-based power plants and fossil fueled–vehicles (Erickson et al. 2015), as well as critical infrastructure (Erickson and Tempest 2015). However, when it comes to access to capital and financing costs, there is a significant divide between high-income countries and middle-income countries (Rickman et al. 2023). The latter often have weaker institutions, which are reflected in higher investment risks (Ameli et al. 2021), making even the cheapest technologies like solar or wind more expensive.

The rest of Part A on electrification and the transition toward low-carbon electricity systems is organized as follows. Section 2 provides an analysis of switching from coal to gas and possible caveats, including discussions around the role of carbon capture as an abatement option in the power sector and associated long-term infrastructure risks. Section 3 discusses the future of flexibility in the power sector, and the role of emerging electricity storage. Section 4 delves into the challenges of financing the energy transition in middle-income countries. Section 5 presents conclusions to Part A.

2. The Role of Gas and Carbon Capture in Transition from Coal

2.1. Switching from coal to gas

The Rationale

For almost two centuries, coal has been central to economic development. Initially, it was the energy-dense resource that enabled the industrial revolution of the nineteenth century. It is also a comparatively cheap fuel in many cases, at least when neglecting environmental costs. Since the 1990s, when the global community first acknowledged the need for tangible actions to address climate change, coal has been considered the most "feasible" fossil fuel to phase out due to significant GHG emission contributions. For example, the United Kingdom moved from a share of nearly 72 percent of coal in its electricity generation in 1990 to less than 2 percent in 2020 (UK Department for Business, Energy and Industrial Strategy 2021). First, this was achieved in part by the additional carbon pricing on the high pollution levels of coal, bringing the commodity close to market price parity with natural gas in the 2010s. Second, decommissioning coal power plants (CPPs) was made low-hanging fruit by the high age of plants, meaning a major decision on their future was due to be made regardless, as well as the availability and underutilization of domestic gas infrastructure (Brauers, Oei, and Walk 2020). However, such policies may not work when infrastructure is scarce. For instance, more than 80 percent of power plants in Poland depend on solid fuels; hence, imposing a higher price on carbon would not facilitate the phase-out of coal in the near to medium term, as new infrastructure for natural gas needs to be developed (Wilson and Staffell 2018).

Especially before the recent global energy crisis, literature pointed out the need for a "transition fuel" or a "bridge technology" between the phase-out of coal and a low-carbon energy system. This need was driven by the still low immaturity of renewables—and thus their high costs, lack of carbon-free balancing capacity (such as electricity storage), and technical limitations of the electricity grid to absorb the intermittency of renewables, suggesting the need to transition to gas while renewables develop further (Kemfert et al. 2022). Gas was seen as a way to substitute for the "dirtier" baseload power, and provide ancillary services, such as through gas peaking power plants (van Foreest 2010; Von Wald et al. 2022). Energy system needs and corresponding low-carbon balancing options are further explored in section 3.

More recently, the world of rapidly decreasing capital and operational costs of variable renewables,[10] which can feed the grid at almost zero marginal costs, along with advancements in novel electricity storage technologies, implies a shrinking utilization rate (capacity factor) for gas power plants (Heptonstall and Gross 2021). This, in turn, limits their revenues and the return on capital for newly installed gas capacities (Robertson and Mousavian 2021), exposing such investments to the risk of becoming stranded assets. Since 2010, capacity factors for coal and gas have widely fallen. For example, in Australia, coal and gas capacity factors fell by nearly 20 percent and 40 percent, respectively, between 2010 and 2020 (Robertson and Mousavian 2021). Additionally, deployment at scale of emerging storage technologies can outcompete gas-fired peaking plants in capacity markets,[11] further undermining their investment case (Schmidt and Staffell 2023). One limitation of this argument is that total power system value is often omitted in LCOE estimations, leaving out system needs that fossil fuel generation can address. This aspect is further discussed in section 3.

The further increasing competitiveness of renewables and shrinking capacity factors of fossil fuel power plants means the risk of gas infrastructure becoming stranded is increasing, potentially becoming more salient in the coming decade. Investment decisions to develop fossil fuel infrastructure may lead to significant losses due to the premature writing-off of coal and gas assets. Such losses are expected to amount to $90 billion by 2030 and more than $250 billion by 2050 (Hansen 2022). These debates are often expanded to incorporate carbon capture and storage (CCS) as a way to keep existing fossil fuel infrastructure investments active, while achieving an arguably lower carbon footprint. However, there is mixed evidence in the literature regarding whether this is a plausible way forward with respect to the economics of CCS, the political economy, and sustainability. Finally, investments in natural gas may also

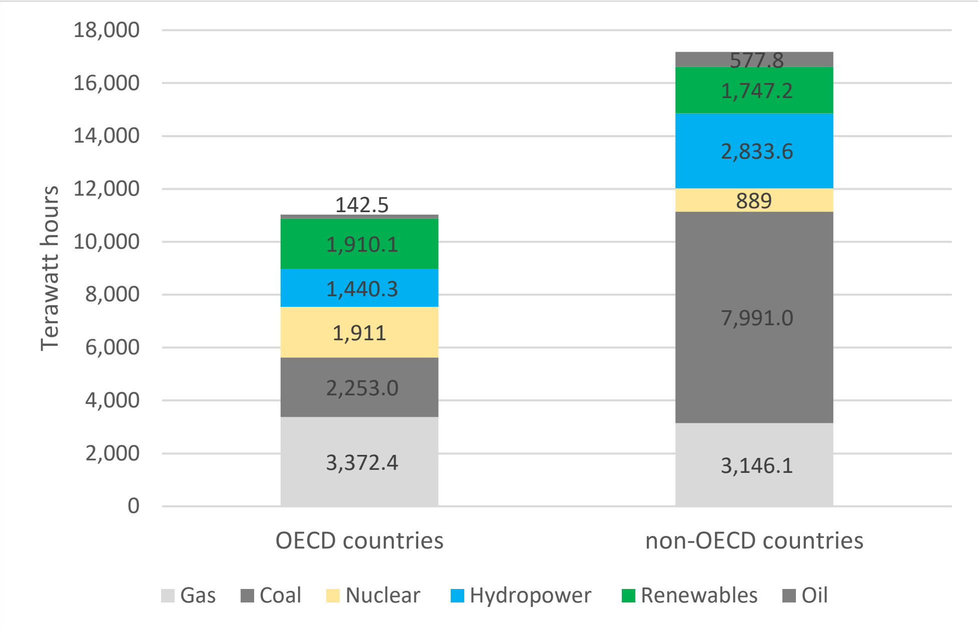
[10] That is, capital and operational costs have been rapidly decreasing before financing costs are taken into account. Financing costs are discussed further in section 4.

[11] Capacity markets envision power capacity reverse auctions to deliver electricity at times of system stress when the electricity price is the most expensive or faces penalties, ensuring that electricity system needs are met at least possible costs to consumers.

crowd out further investments in low-carbon grid balancing technologies, especially in electricity storage (Hekkert et al. 2007; Unruh 2000).

Economic development in many developing and emerging economies has relied on inputs of cheap energy, mainly from coal, at times when most renewables were enormously expensive (Kalkuhl et al. 2019). Based on the experience of developed countries, decommissioning a fleet of coal power plants and substituting them with natural gas—a less carbon-intense fuel—may look like an attractive decarbonization option for middle-income countries. However, switching to natural gas means almost tripling current demand (figure 2) for a more expensive and geopolitically volatile energy commodity. In addition, many middle-income countries possess a relatively new stock of coal power plants (box 2), impeding a possible transition from coal to gas and rapid emission savings, unless early decommissioning occurs and developed and underutilized gas infrastructure are in place.

Figure 2. Power generation by fuel in OECD and non-OECD countries, 2021



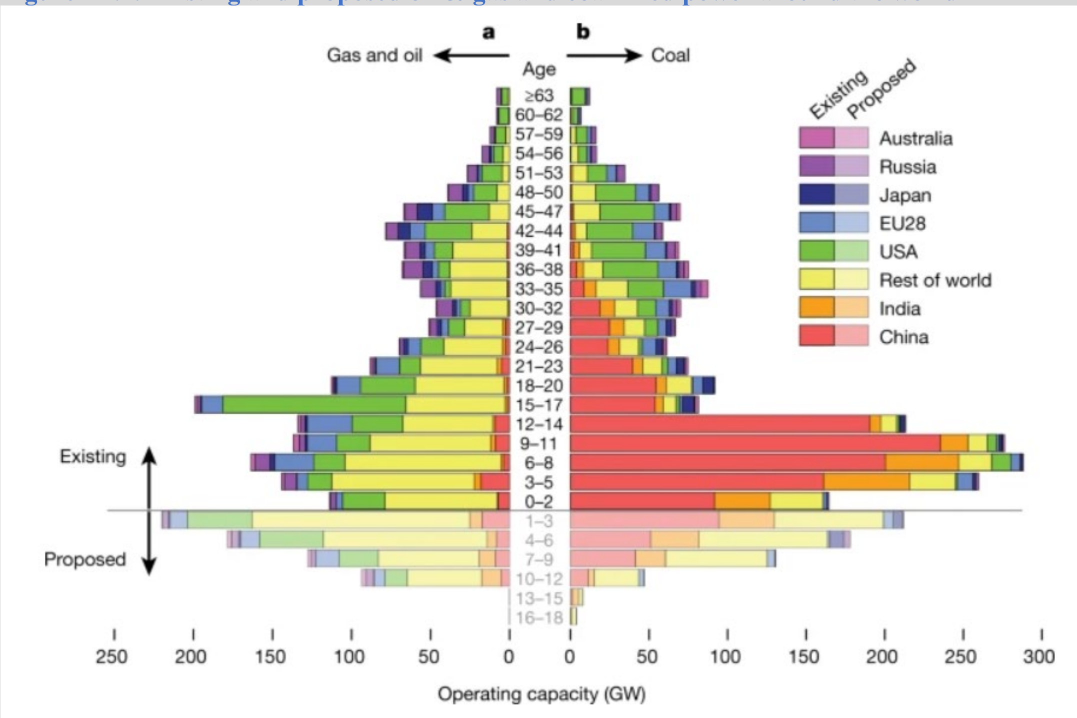
Source: Original calculations for the *World Development Report 2024* based on BP 2022.
Note: OECD = Organisation for Economic Co-operation and Development.

Shifting to natural gas will require arguably enormous adjustment costs to retrofit young coal power plants with gas turbines or, in many cases, build new ones. Such a fuel shift also requires building new gas infrastructure that, in many middle-income countries, is not well penetrated, leading to infrastructure and carbon lock-ins (Wilson and Staffell 2018). The need to develop a new and complex infrastructure traps the country because these investments, once made, must generate returns that must be extracted, increasing the risk of accumulating stranded assets.

Box 2. Global Stock of Oil & Gas and Coal-Fired Power Plants and Their Age

Major emerging economies, which possess most of the newly commissioned coal power generation, might face large losses due to the early retirement of fossil fuel power plant assets; such losses are estimated at $358 billion for China and $169 billion for India (Kefford et al. 2018). This is due to the relatively young fleet of fossil fuel plants in these countries, illustrated in figure B2.1. Additionally, older coal plants (30+ years) are typically situated in more developed economies, such as the United States and European Union, making policies and debates around the early decommissioning of such facilities much more straightforward. The bottom of the figure depicts the pipeline of new projects. These new investments must be carefully analyzed for both future environmental risks and the financial risks of early decommissioning or retrofitting costs. The wealth loss due to stranded fossil fuel assets could reach $1 trillion to $4 trillion globally (Mercure et al. 2018), with the risk to facilities rising when carbon pricing is incorporated into investment decisions (Mo, Cui, and Duan 2021).

Figure B2.1. Existing and proposed oil & gas and coal-fired power around the world



Source: Tong et al. 2019.
Note: The dominance of recently constructed coal plants in China and India is illustrated by large size of the red and orange bars. Lightly colored bars indicate a pipeline of projects. GW = gigawatts; EU28 = 28 member-countries of the European Union; USA = United States.

Environmental sustainability of switching to natural gas

From a life-cycle perspective, research suggests that the total GHG emissions of gas may be comparable to those of coal when analysis includes pipeline leaks. A recent study (Gordon et al. 2023) found that gas emissions could be even exceed emissions from coal, with methane leak rates ranging from 0.65 percent to 66 percent in extremely leaky systems. Even the lowest leakage rate detected in this remote sensing study is much higher than the 0.2 percent rate required to meet coal's overall GHG emission profile. Thus, it is very unlikely that, even with the improvement of measurements, the global warming potential (GWP) of gas will be lower than the GWP of coal (Gordon et al. 2023).

Methane leakage contributes significantly to the GWP of gas power. For instance, reducing leakage in the United States from 3 percent to 0.2 percent would equate to a GHG emission saving of retiring 40 percent of the existing stock of internal combustion engine vehicles in the country (Gordon et al. 2023). The recent research on methane life cycles provides evidence that previous estimates of its GWP have been underestimated by 20 percent to 60 percent (Kemfert et al. 2022; Schwietzke et al. 2016). This underestimation is mainly attributed to the disproportionally higher GWP of methane over a 20-year timespan compared to coal. Once accounted for, the higher GWP of methane makes significant differences to available carbon budgets until 2050 (Kemfert et al. 2022; Schwietzke et al. 2016). Consequently, a switch from coal to gas may not, in fact, have the climate change benefits that have often been touted.

Dispute about the objective (whether long-term stabilization or delivering the Paris goals—which will be exceeded in one to three decades on current trends) and associated indexes (20-year or 100-year GWP) are sources of uncertainty. The other, central fact is that methane monitoring and reporting remains inadequate to resolve ongoing disputes about methane leakage. This challenge demands a far more robust response from industry if a credible case is to be made for overall climate benefits in switching from coal to gas (Stern 2022).

2.2. Rationale for CCS and its limitations

From a purely theoretical perspective, CCS allows fossil fuel power generation the potential to be carbon-neutral, and thus remain a part of the technology mix in Net Zero Scenarios. Key rationales for CCS are that thermal power plants (except for nuclear plants) can be easily ramped up or down; therefore, CCS can play a role in balancing the electricity grid (Elliott 2016; NEA 2019), and has importance for decarbonizing hard-to-abate sectors that are technologically constrained (IPCC 2023b). At the same time, prolonged operation of fossil fuel power plants[12] entails continuous upstream demand—that is, extracting and supplying new stocks of fossil fuels, while facing the environmental side effects associated with these activities (Boot-Handford et al. 2014; Corsten et al. 2013; Pires et al. 2011). Global decarbonization scenarios suggest that there is a role for CCS to capture residual emissions, although estimations differ significantly in the required capacity. These range from 0–≈11 gigatonnes of carbon dioxide ($GtCO_2$) captured per year through to 2050 in IPCC (2022), to 7 Gt per year in IRENA (2023c), and 6 $GtCO_2$ captured in 2050 in IEA (2023b), up from the current capacity of 0.04 $GtCO_2$ in 2021 (Global CCS Institute 2022a).

Technology maturity

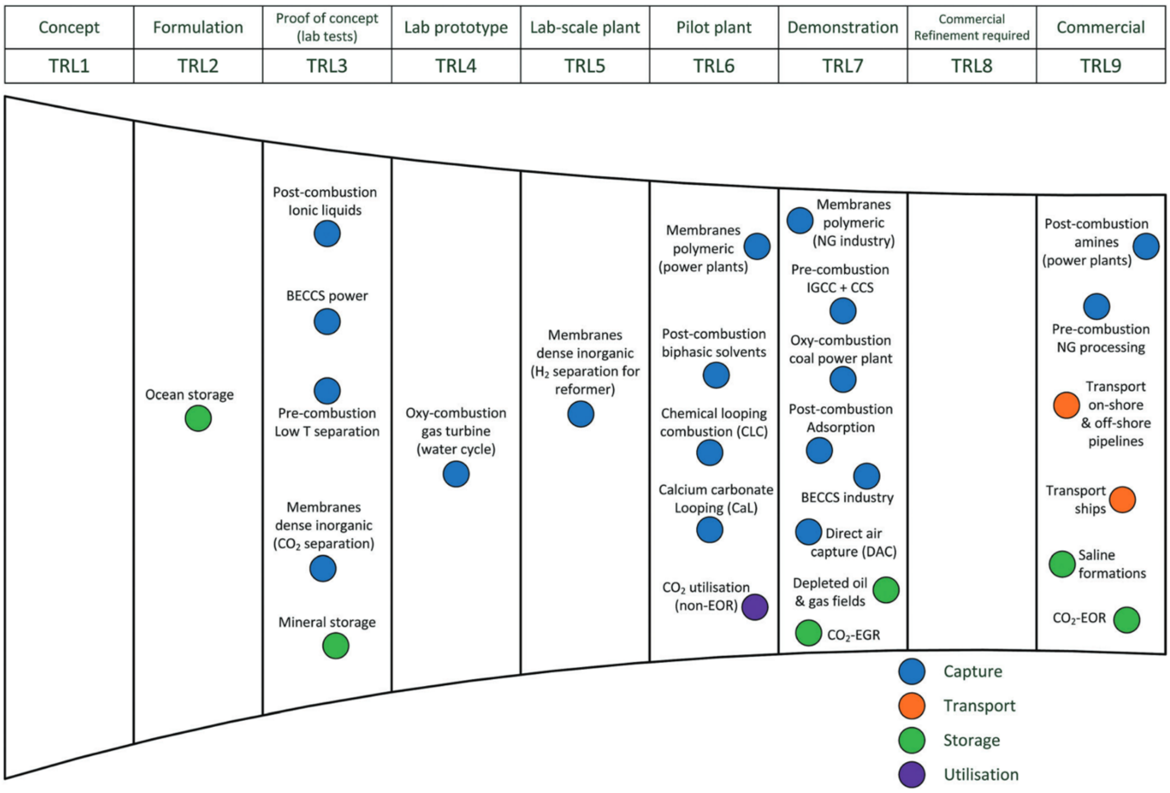
Despite some studies finding that CCS can be commercialized in the power sector, and some already stating it is (Bui et al. 2018; Global CCS Institute 2022b), these conclusions must be considered alongside the caveat that the volumes of capacity deployed have been insignificant.

From the point of view of the technology "valley of death" where energy technologies often struggle to commercialize (Hartley and Medlock 2017), most CCS technologies have been in experimentation and demonstration phases for more than three decades, and have not achieved significant cost reductions that would enable their commercial deployment (figure 3). Indeed,

[12] This section only covers electricity generation; it excludes CCS for industrial processes.

long-standing government-backed efforts have largely failed due to physical and commercial risks, and associated carbon transportation infrastructure requirements, which makes the private sector's interventions even more exposed to failure (Bui et al. 2018). As of 2021, nearly 30 CCS installations were operational, of which only 3 were in the power sector (Global CCS Institute 2022a). However, cumulative installations do not necessarily mean cost reductions, as previous attempts with CCS and nuclear power have demonstrated (van Alphen et al. 2010). Thus, large uncertainties about the prospects of technology learning and cost reduction potential remain.

Figure 3. Technology readiness levels (TRLs) across carbon capture and storage (CCS) and carbon direct removal (CDR) technologies



Source: Bui et al. 2018.
Note: CO_2 utilization (non-EOR) reflects a wide range of technologies, most of which have been demonstrated conceptually at the lab scale. The list of technologies is not intended to be exhaustive. BECCS = bioenergy with carbon capture and storage; CCS = carbon capture and storage; CO_2 = carbon dioxide; EGR = enhanced gas recovery; EOR = enhanced oil recovery; IGCC = integrated gasification combined cycle; NG = natural gas; T = temperature.

Cost-competitiveness with renewables

CCS commercialization in the power sector must also account for the competition from other low-carbon alternatives. Declining LCOE for newly commissioned renewables means that solar PV is already 44 percent cheaper and wind is 85 percent cheaper than coal power generation with CCS (Lyons, Durrant, and Kochhar 2021). Similarly, the "premium" of installed CCS makes new coal- and gas-fired power plants 70 percent to 140 percent more expensive than their conventional equivalents (Lyons, Durrant, and Kochhar 2021). From a purely market point of view, as opposed to regulatory standards, even to break even, CCS largely relies on carbon pricing (Fan, Wei, et al. 2019; Fan, Xu, et al. 2019). In practice, given current cost trends of CCS, that would require carbon price levels to rise significantly in the power sector (Elias, Wahab, and Fang 2018; Kumar et al. 2019), to heights that are likely not politically viable.

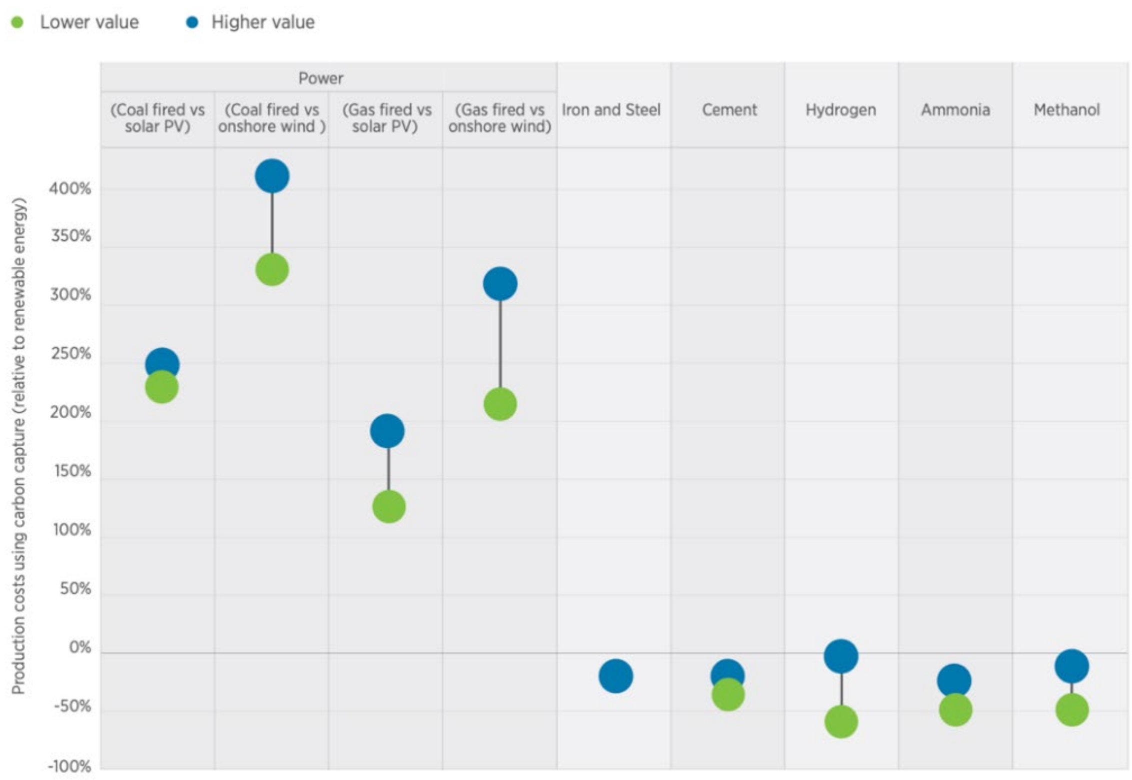
Power plants with CCS might be used for balancing variable renewables; however, this will require appropriate incentives. Once invested, capital costs must be returned with considerations for low capacity factors because operation is limited to peak demand hours (Heptonstall and Gross 2021). Moreover, long-term uncertainty about fossil fuel prices and the long-term possibility of carbon pricing must be taken into account. Similarly to trends in renewables, emerging electricity storage technologies demonstrate significant declining costs (Schmidt and Staffell 2023). Thus, they can potentially outcompete fossil fuel plants with CCS in capacity markets, even though further incentives must be developed to reflect the value to the electricity system. This possibility is further discussed in section 3.

Currently, the cost of carbon capture varies significantly, ranging from USD22 to USD225 per tCO_2, depending on the sector of application (Bui et al. 2018; Lyons, Durrant, and Kochhar 2021). Sectoral estimations for power vary from more than USD40 to less than USD120 per tCO_2, although there cost uncertainty is high due to the almost negligible scale of deployment (Bui et al. 2018; Lyons, Durrant, and Kochhar 2021). The relatively high cost of CCS compared to renewable alternatives in the power sector is displayed in figure 4, which also depicts the attractiveness of CCS in industry, due to far more expensive and, in some sectors technically limited, alternatives.

The future of CCS is contingent upon the technology choices and path-dependency for power plants: either to optimize existing technology and build new fossil fuel generation coupled with carbon capture, or to transform the power system and shift toward carbon-free variable renewables. Additionally, strategic decisions must be taken regarding the stock of already commissioned fossil fuel power plants—whether to retrofit them with CCS or write them off as stranded assets. Multiple attempts have failed to scale up CCS and bring its costs down. Thus, there is a high probability that from an economic perspective, rather than environmental and ethical ones, CCS in the power sector might never become economically competitive in the face of continuing falling costs of renewables and emerging electricity storage. Another caveat of continuing the operation of fossil fuel power plants is their exposure to volatile commodity prices—as the most recent energy crisis of 2022 demonstrated, with prices of coal tripling (figure 1) and gas quadrupling (IEA 2022b). It is therefore likely that no strong economic investment case exists for either new coal with CCS plants or gas with CCS plants (Lyons, Durrant, and Kochhar 2021).

In addition, the literature demonstrates how the cost reductions in renewables, particularly solar and wind, have been historically underestimated in energy modelling scenarios in previous decades—thus allocating higher shares of CCS in abating residual emissions (Carrington and Stephenson 2018; Creutzig et al. 2017; Xiao et al. 2021). This is an important consideration for policy making, as the value of CCS is reliant on competing cost reductions in renewables that not only demonstrate better economics but also help achieve more rapid electrification and foster decarbonization (Grant et al. 2021). However, there are stronger business cases for applications of CCS application in industry. This topic is discussed in Part B.

Figure 4. Production costs using carbon capture relative to renewable energy in the power sector and industry



Source: Lyons, Durrant, and Kochhar 2021, figure 17.
Note: The figure shows a range of production costs. PV = photovoltaics.

Further strategic considerations, beyond "the economics" of a particular technology, should incorporate moral hazards (ETC 2022; Lin 2013). Unrealistic hopes for CCS risk encouraging continued investment in both upstream (extraction) and downstream (generation) of fossil fuel assets (ETC 2022; Lin 2013). This can exacerbate carbon lock-in and the risk of stranded assets and resources (Bos and Gupta 2019). Most importantly, it can also jeopardize the net zero agenda (IEA 2023e). Supporting policies and public and private investments to bring down CCS costs can also compete with efforts to pursue other less mature carbon-free technologies, including emerging electricity storage, effectively crowding out funding for these technologies—another moral hazard.

Technology efficiency and sustainability

Even if CCS in the power sector can be considered as an abatement option, the currently available technical solutions capture about 60 percent to 80 percent of emitted carbon, while still requiring additional energy input, known as an "energy penalty" (Lyons, Durrant, and Kochhar 2021). Further down the supply chain, transportation of gas or oil is often associated with pipeline leakage. Thus, net efficiency of carbon capture can be as low as 47 percent, although it depends on the CCS technology and fossil fuel type (Corsten et al. 2013). Unless fed by renewables, the energy penalty might also produce more GHG emissions. Additionally, coal power plants already face water scarcity for cooling in some regions, mostly in China and India. Further installations of CCS can exacerbate this scarcity as they increase the demand for water—in some cases by 20 percent, putting plants at physical climate risk (Rosa et al. 2020). Also, CCS can be considered as an option for capturing emissions in bioenergy, known as BECCS (bioenergy with carbon capture and storage), which sometimes is framed as a carbon removal technology. Yet this comes with economic and sustainability challenges, which are further discussed in box 3.

Box 3. An Overview of BECCS, its Economics, Sustainability, and "Carbon Breakeven"

Bioenergy with carbon capture and storage (BECCS) is often presented as a negative emission technology (NET). The underpinning assumption is that biomass absorbs carbon dioxide (CO_2) from the atmosphere during its lifetime, and when combusted, BECCS captures the carbon, preventing it from being released back into the atmosphere (Fajardy et al. 2018).

The economics of energy production with BECCS are contingent on geographical and environmental constraints of the availability of biomass feedstock. Examples are land availability and productivity, competition with food security (Muri 2018), and, in some instances, deforestation that can be associated with illegal logging (Environmental Investigation Agency 2022).

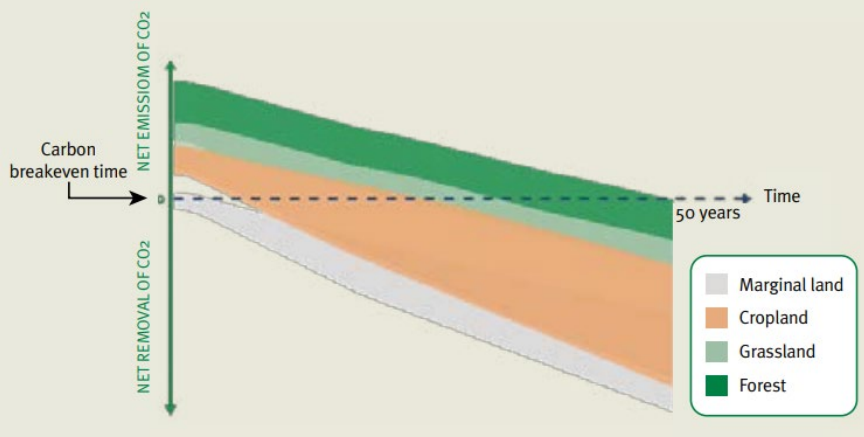
The economic challenges of BECCS are similar to those of fossil fuel carbon capture and storage (CCS). Installing CCS on bioenergy power/heat plants increases the costs of energy. Thus, the business case will require an increased level of carbon pricing and competitive price in cases where fossil fuels are subsidized. Similarly, with the use of variable renewable energies (VREs), it is likely that thermal power plants will operate with lower capacity factors (Robertson and Mousavian 2021), affecting the return on capital of BECSS.

More common bioenergy-specific challenges include the security of feedstock supply (Daioglou et al. 2019), including interseasonal variation, and its price uncertainty (Lindroos et al. 2019), driven by the agricultural sector. Another issue is biomass monitoring (Eakins, Sirr, and Power 2023) and sustainability (Bui et al. 2018). Grey markets providing cheaper feedstock have the potential to undermine forest regulation and environmental targets (Andreas, Burns, and Touza 2018), a problem that will be especially prevalent in less formal energy markets.

The future of BECSS should be scrutinized largely through geographic lenses. Unlike fossil fuel power plants, the share of transportation costs is significant (Fajardy and Mac Dowell 2017). The full carbon footprint of the activity should also be considered in life-cycle costs (Fajardy and Mac Dowell 2017). In some locations, bioenergy retrofits can deliver cheaper energy than VREs, when benefits of firm capacity are considered (Keller et al. 2018), becoming competitive when a cheap and abundant supply of biomass feedstock exists (Scarlat and Dallemand 2019), yet installing CCS increases the requirement on return on investment. BECSS can potentially play a role in energy security, mitigating the risk of geostrategic exposure of gas and coal (Zhao and Liu 2014). However, BECCS should not be seen as a technology that can "clean up greenhouse gas (GHG) emissions later," thereby incentivizing new bioenergy power plants despite added costs of energy production and questionable sustainability.

Another consideration is speed of action. The "carbon breakeven time"—the point when all life-cycle greenhouse gas (GHG) emissions of production, transportation, and energy generation equal zero—is extremely important for climate targets. In the case of a BECCS project, in some cases, it can take 50 years to reach project net zero emissions (figure B3.1). This implies that more GHG emissions will take place until 2050, before sequestration can be reached in another 20 years (Fajardy et al. 2018). Thus, while the idea of carbon sequestration through applying BECSS might sound compelling, this technology remains controversial. The perception that BECCS can clean up emissions later, and reliance on this technology, can be dangerous, given breakeven timescales.

Figure B3.1. Carbon breakeven time in BECCS for different types of land use change



Source: Fajardy et al. 2018.
Note: BECCS = bioenergy with carbon capture and storage; CO_2 = carbon dioxide.

Potential for CCS retrofits in middle-income countries

As discussed, fossil fuels have been a cornerstone of the recent rapid development in middle-income countries and their fleet of power generation is relatively young—up to 15 years (box 2). Between 2008 and 2018, more than 900 gigawatts (GW) of coal and almost 400 GW of natural gas and oil power plants were commissioned in countries that are not members of the Organisation for Economic Co-operation and Development (non-OECD countries), representing more than 55 percent and 40 percent of their entire fleet (including Türkiye, Costa Rica, and Chile). Also, 430 GW of coal and more than 500 GW of natural gas and oil power plants are in the pipeline for this group of countries in the coming decade, representing two-thirds of possible added global GHG emissions in the power sector (Tong et al. 2019). Given the global carbon budget of the Paris Agreement climate goals, no new fossil fuel generation can be commissioned in the power sector (IEA 2023c), but using CCS or planning for premature retirement may keep countries within the global carbon budget—assuming they can overcome the serious costs highlighted earlier (Tong et al. 2019).

Nearly 52 percent of global coal power plant installed capacity is in China, and 60 percent of that is less than 15 years old (box 2). This poses a significant risk of carbon lock-ins (Fan et al. 2018). At the same time, the homogeneity of regulatory and support policies within this one jurisdiction, which is also the world's second largest economy, presents the potential for successfully retrofitting this fleet of power plants. However, feasibility is still geographically specific. Densely installed coal power plants in some provinces can benefit from reduced transportation costs and availability of local hubs for storage. IEA (2016) estimates the potential application of CCS in China to be less than 20 percent of the current capacity of coal power plants, with another 45 percent remaining somewhat uncertain.

China's previous successes with government-backed deployment of electric vehicles (Lam, Mercure, and Sharpe 2023) demonstrates that the state can play a significant role in cushioning possible technology-related risks, and may do so to enable CCS commercialization. In the case of other middle-income countries that possess less dense and less significant stocks of fossil fuel power plants, installation of CCS and carbon transportation costs can be a major barrier, implying higher generation costs than renewables or non-CCS baseload generation. As discussed, the future of CCS requires a significant scale of public investments and carbon pricing, potentially driving up the electricity costs for both residential and industrial sectors. As the experience of other middle-income countries suggests, energy prices are an extremely socially sensitive issue and have trade competitiveness considerations (El-Katiri and Fattouh 2017). Therefore, governments often intervene with public spending to absorb possible negative impacts (Climate Action Tracker 2022)—hence, indirectly subsidizing fossil fuels.

3. The Future of Balancing and Flexibility in the Power Sector

3.1. Integration of renewables and associated costs

The rapid uptake of variable renewables over the last decade, combined with reciprocally decreasing costs of onshore wind and solar PV, demonstrates the extraordinary possibility of power sector decarbonization. Although such decarbonization has been historically dependent on support schemes, recent auctions in many countries demonstrate near or full competitiveness of the cost of electricity generation from renewables (IRENA 2022). However, with a rising share of renewables comes challenges, both technical and economic. Unlike the incumbent centralized electricity system that relies on baseload power and can be easily adjusted to demand, VRE generation depends on natural events—the levels of solar irradiation and wind velocity. Therefore, as the share of renewables increases in the power grid, so does the need to provide reliable balancing and capacity that meets peak demand.

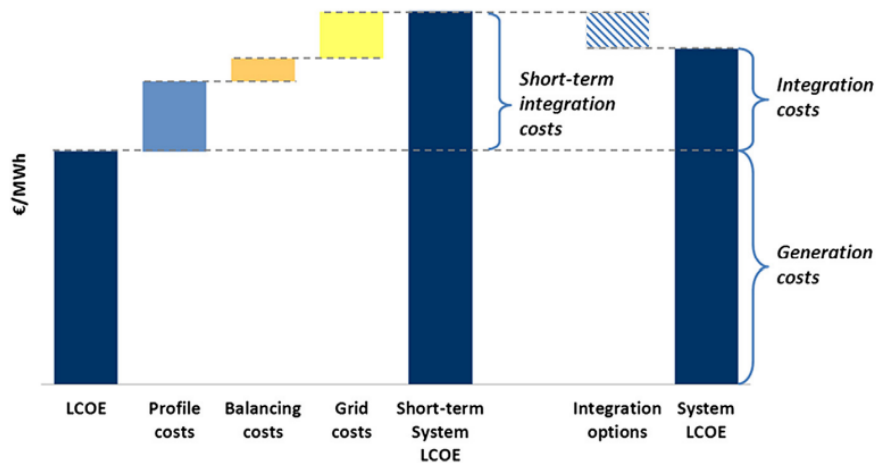
To demonstrate the cheapening of renewables projects with respect to fossil fuel power plants, LCOE has been most widely used as a reference point for comparison (IRENA 2022). Indeed, when applying LCOE, the evidence suggests that recent auctions for renewables (IEA 2019a) provide a better investment case than for new coal, gas, and nuclear power plants.

Although LCOE focuses on discounted generation output, capital costs, and operational costs, and is a convenient simplistic measure to illustrate electricity generation cost comparisons, it is calculated on the assumption of temporal homogeneity of electricity. This, therefore, does not account for the entire electricity system value (Heptonstall and Gross 2021; Ueckerdt et al. 2013), making LCOE a rather misleading metric for comparisons across technologies. A more appropriate way is to consider not only generation costs, but also the value that each energy technology provides to the entire power system (Joskow 2011). Hence, apart from electricity generation costs, a broader metric should also include other costs that enable reliable functioning of the entire power system—balancing, transmission and distribution, curtailing, and so on—and discussion of who bears those costs.

Integration costs

The costs of integration of renewables broadly comprise three main categories, although different literature proposes various typologies: *balancing costs* that are driven by uncontrolled variability and inaccurate forecasting of power generation; *profile costs* related to mismatch between generation and demand, affecting net load that is met by non-VRE generation or storage;[13] and *grid costs* that are related to location and the unit size of the VRE power plant (Heptonstall and Gross 2021). For simplicity, this discussion frames all nongeneration costs as *aggregated balancing costs* that address the issues of supply and demand, and *grid costs* that reflect transmission and distribution. These costs can be added onto LCOE to gain a more representative figure for the costs of integration (figure 5).

Figure 5. Illustration of LCOE and integration cost components



Source: Ueckerdt et al. 2013.
Note: LCOE = levelized cost of electricity; €/MWh = euros per megawatt hour.

With rising installations of renewables, two of the central questions appear to be what the plausible share of VRE is that the power grid can technically absorb, without significant increases in marginal costs, and whether integration costs will increase the electricity price to consumers with respect to fossil fuel generation. A systematic review of integrating VREs by Heptonstall and Gross (2021) concludes that there is a small body of literature that explicitly addresses cost impacts at higher penetration levels of VREs. More than 90 percent of studies are focused on Europe and only a few on Asia. Therefore, this background paper uses evidence from integration cost literature in developed economies as a proxy for similar implications in middle-income countries, while acknowledging that the difference in grid quality in the two groups of countries may play a significant role in the assumptions on integration costs analyzed.

The findings suggest that aggregated balancing costs do not increase significantly (below 10 percent) when up to 25 percent of demand is met by VREs, and median values still do not rise significantly at up to 45 percent penetration (Heptonstall and Gross 2021). Balancing costs have also stayed flat or even declined significantly after integrating renewables in the United

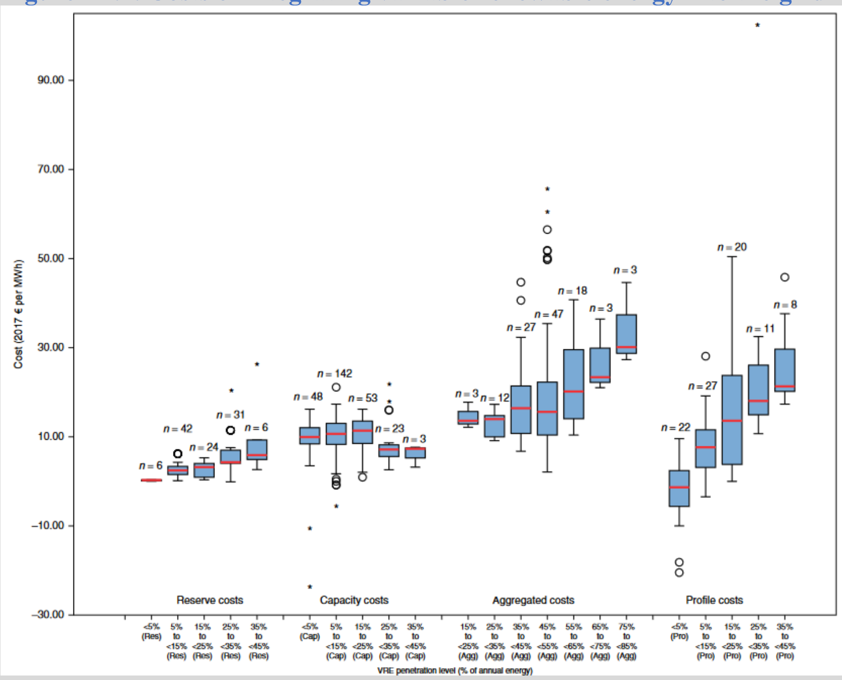
[13] Net load refers to the difference between total electricity demand and electricity generation from variable energy sources such as solar and wind to account for the required additional capacity when those sources cannot meet the peak demand due to their variability.

Kingdom and Germany. However, congestion management costs and system operation costs are found to increase significantly (Joos and Staffell 2018). Aggregated balancing costs in inflexible systems incur significantly larger integration costs, with most costs rising with VRE penetration (Heptonstall and Gross 2021; Pfeifer et al. 2021). Yet, this analysis further depends on the cost-effectiveness of available options to maintain flexibility, which are often country-specific. The results of Heptonstall and Gross (2021) are visualized and discussed further in box 4.

Box 4. Penetration of Variable Renewable Energy Sources into the Grid: Associated Costs and Curtailment of Power Supply

Figure B4.1 illustrates the cost of integrating renewable energy sources to the grid at increasing penetration levels of variable renewable energy (VRE) sources, split by category.

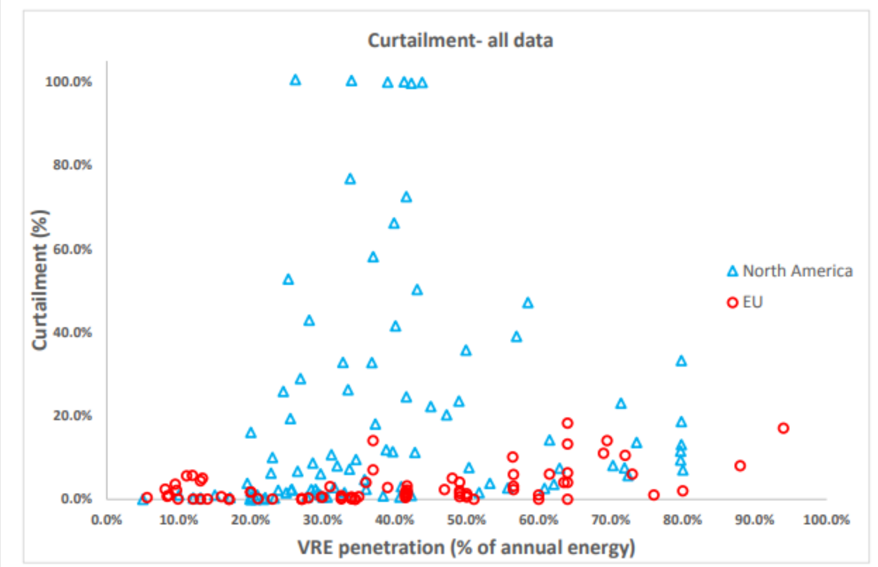
Figure B4.1. Costs of integrating variable renewable energy into the grid



Source: Heptonstall and Gross 2021.
Note: Operating reserve costs (Res), capacity adequacy costs (Cap), aggregated costs (Agg), and profile costs (Pro) are shown in relation to the variable renewable energy (VRE) penetration level. *n* refers to the number of the total number of data points. €/MWh = euros per megawatt hour.

The VRE penetration level has nearly negligible impacts on both reserve and capacity costs, with capacity costs likely to marginally decrease. However, both aggregated and profile costs are likely to rise with VRE penetration. For aggregated costs, the impact is relatively insignificant until a penetration level of about 55 percent is met. In some instances, despite rising with VRE penetration level, profile costs at low levels of renewable deployment start off in negative regions, accruing immediate benefits. Integrating renewables can also lead to curtailments of power supply when excess generation or low demand occurs, often leading to negative prices (Brijs et al. 2015). Figure B4.2, mostly focused on members of the Organisation of Economic Co-operation and Development (OECD countries), demonstrates that countries with developed grids in the European Union (EU) have capacity to mitigate curtailments, even at high shares of VRE (Heptonstall and Gross 2021). However, this is not the case for the United States, with its decentralized system of regulation.

Figure B4.2. Curtailment share as a function of variable energy penetration into the grid in the EU and North America



Source: Heptonstall and Gross 2021.
Note: Curtailment share in relation to VRE penetration level. EU = European Union.

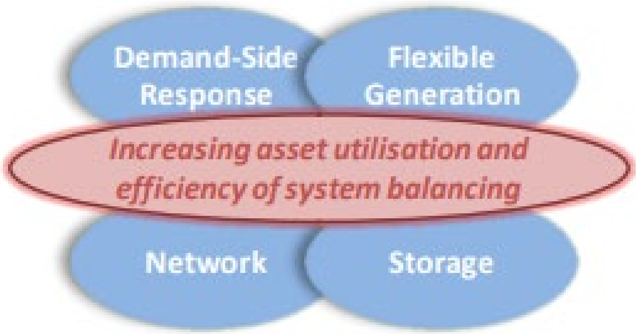
Research evidence about the extent to which increasing VRE generation drives grid costs is limited. Therefore, it is challenging to allocate investments in transmission and distribution specifically to VREs because those investments also bring a range of co-benefits of higher quality of power supply to end-consumers and other generators. Gorman, Mills and Wiser (2019) have attempted to disentangle those costs for the US grid, using renewables projects datasets (EIA 2017; MISO 2018). They arrive at an extremely wide range of possible impacts on LCOE of 3 percent to 33 percent. More broadly, the allocation of grid costs is predicated on assumptions about geographical density of non-VRE versus VRE power plants, availability of electricity storage, and its competitiveness, which can reduce the needs for long-distance transmission.

Overall, the research demonstrates that developed grids can absorb up to 40 percent of VREs with marginal impact on integration costs when addressing balancing. The grid costs, however, are much harder to robustly disentangle and attribute to VREs due to a range of co-benefits for other generators and consumers. More concrete estimates of marginal costs become very country-specific, and depend on available options, both technical and economic, to ensure grid flexibility. The incumbent highly centralized power system that relies on baseload will experience more curtailment as the share of VREs grows, which implies increased LCOE of VRE plants, and revenue losses, unless excessive generation can be stored or exported.

3.2. Electricity storage

As discussed, increasing the share of VREs in the power grid is plausible, yet their integration will require addressing broader challenges in the electricity system and associated costs. This section focuses further on the power grid balancing options for handling residual demand (which currently is mainly met by fossil fuel peaking plants and pumped hydro) and managing residual supply (which is mostly curtailed by the system operator). Further decarbonization of the power grid will require addressing those two key issues by phasing out existing fossil fuel backup capacities, while capturing temporarily excessive VRE generation. Broadly, there are four ways to address this issue, as represented in figure 6.

Figure 6. Options for power grid balancing



Source: Druce and Gammons 2012.

Demand-side response encompasses the energy efficiency of appliances and equipment, behavioral changes, and temporal patterns of energy consumption. These options are discussed for selected hard-to-abate sectors in Part B. On the supply side, the incumbent power system mostly relies on flexible generation, using gas, coal, or biomass that can be ramped up or down in seconds to minutes. Another widely used option is leveraging "network" effects, which uses the transmission (export or import) of electricity through interconnectors between countries or regions to cover the demand. Finally, electricity storage is based on conservation of energy, converted from one form to another and dispatched when needed.

Electricity storage, in contrast to flexible generation from power plants, can be a more sustainable low-carbon solution to address the balancing of supply and demand in the power grid. In fact, energy storage has been used by the incumbent system for a long time, most commonly through mechanical storage by pumped hydro (PHES). This method currently accounts for 96 percent of the entire global energy storage capacity (IRENA 2017). Yet, rising shares of VREs will require more advanced and more responsive dispatchable storage options. Generally, there are five main categories of ES: mechanical, electro-chemical, chemical, thermal, and electrical.

Value and lifetime costs of electricity storage

There are multiple granular needs in the power sector (table 1) that can be met by electricity storage, broadly linked to managing peak loads, flexibly providing energy, and ensuring power quality and reliability (Schmidt et al. 2019). Addressing the variety of needs in the power sector requires applying not only technically suitable low-carbon electricity storage technologies, but also consideration of economic feasibility. Unlike low-carbon technologies for power generation, novel ES remains less researched and highly uncertain, reflected in high capital costs and associated investment risks (Dodds and Garvey 2022; Schmidt et al. 2019). Further exploration of suitable ES technologies requires more detailed metrics for comparisons across technologies (Dodds and Garvey 2022).

Table 1. Electricity storage applications and technology suitability

Role	Application	Description	Pumped Hydro	Compressed Air	Flywheel	Lithium Ion	Sodium Sulfur	Lead Acid	Vanadium Redox Flow	Hydrogen	Supercapacitor
	1. Energy arbitrage	Purchase power in low-price and sell in high-price periods on wholesale or retail market	✓	✓		✓	✓	✓	✓	✓	
System Operation	2. Primary response	Correct continuous and sudden frequency and voltage changes across the network			✓	✓	✓	✓	✓	✓	✓
	3. Secondary response	Correct anticipated and unexpected imbalances between load and generation	✓	✓	✓	✓	✓	✓	✓	✓	✓
	4. Tertiary response	Replace primary and secondary response during prolonged system stress	✓	✓		✓	✓	✓	✓	✓	
	5. Peaker replacement	Ensure availability of sufficient generation capacity during peak demand periods	✓	✓		✓	✓	✓	✓	✓	
	6. Black start	Restore power plant operations after network outage without external power supply	✓	✓	✓	✓	✓	✓	✓	✓	✓
	7. Seasonal storage	Compensate long-term supply disruption or seasonal variability in supply and demand	✓	✓					✓	✓	
Network Operation	8. T&D investment deferral	Defer network infrastructure upgrades caused by peak power flow exceeding existing capacity	✓	✓		✓	✓	✓	✓	✓	
	9. Congestion management	Avoid re-dispatch and local price differences due to risk of overloading existing infrastructure	✓	✓		✓	✓	✓	✓	✓	
Consumption	10. Bill management	Optimise power purchase, minimize demand charges and maximise PV self-consumption				✓	✓	✓	✓	✓	
	11. Power quality	Protect on-site load against short-duration power loss or variations in voltage or frequency			✓	✓	✓	✓	✓	✓	✓
	12. Power reliability	Cover temporal lack of variable supply and provide power during blackouts				✓	✓	✓	✓	✓	

Source: Schmidt et al. 2019.
Note: PV = photovoltaic; T&D = transmission and distribution.

Beyond comparing technical indicators of ES, from an economic point of view, meeting electricity system needs requires further interrogation of the value of electricity storage and its costs. Addressing the value aspect of electricity storage is challenging due to the complexity of its technology costs, performance, and varying temporal power sector needs. Most studies to date have therefore focused primarily on investment costs (Dodds and Garvey 2022; Schmidt et al. 2019).

Currently, levelized cost of storage (LCOS) is used as a simplified metric to illustrate the costs of electricity storage across different technologies, similar to the way levelized costs of electricity (LCOE) is used in electricity generation cost analysis. LCOS reflects the discounted total lifetime cost of the investment in an electricity storage technology divided by its discounted cumulative delivered electricity.

Schmidt et al. (2019) propose the inclusion of investment, operation and maintenance (O&M), charging, and end-of-life costs divided by electricity discharged during the investment period in LCOS. Total investment costs comprise nominal *power* capacity costs (cost/kW) and *energy* capacity costs per discharge duration (cost/kWh). This has important implications for assessing the temporal cost-effectiveness of electricity storage for short-duration or long-duration needs across different technologies. O&M costs and annual cycles affect project life and total discharged electricity, while charging costs depend on round-trip efficiency and electricity prices (Dodds and Garvey 2022; Schmidt et al. 2019).[14] As the electricity storage value is time-specific, the electricity price should incorporate temporal dynamics. For most electricity storage technologies, LCOS is driven mainly by investment costs, annual cycle frequency, discharge duration, and the applied discount rate. The full methodology, as explicated by Schmidt et al. (2019), is shown in equation (1).

$$LCOS\left[\frac{\$}{MWh}\right]=\frac{\text{Investment cost}+\sum_{n}^{N}\frac{\text{O\&M cost}}{(1+r)^{n}}+\sum_{n}^{N}\frac{\text{Charging cost}}{(1+r)^{n}}+\frac{\text{End-of-life cost}}{(1+r)^{N+1}}}{\sum_{n}^{N}\frac{Elec_{Discharged}}{(1+r)^{n}}} \quad (1)$$

The equation assumes that all investment costs are incurred in first year, summing ongoing costs in each year (n) up to end of life (N), discounted by discount rate (r).

The application of LCOS is illustrated in box 5, which discusses the current lowest-cost electricity storage technologies and their future projections.

Box 5. Future Costs of Electricity Storage Technologies

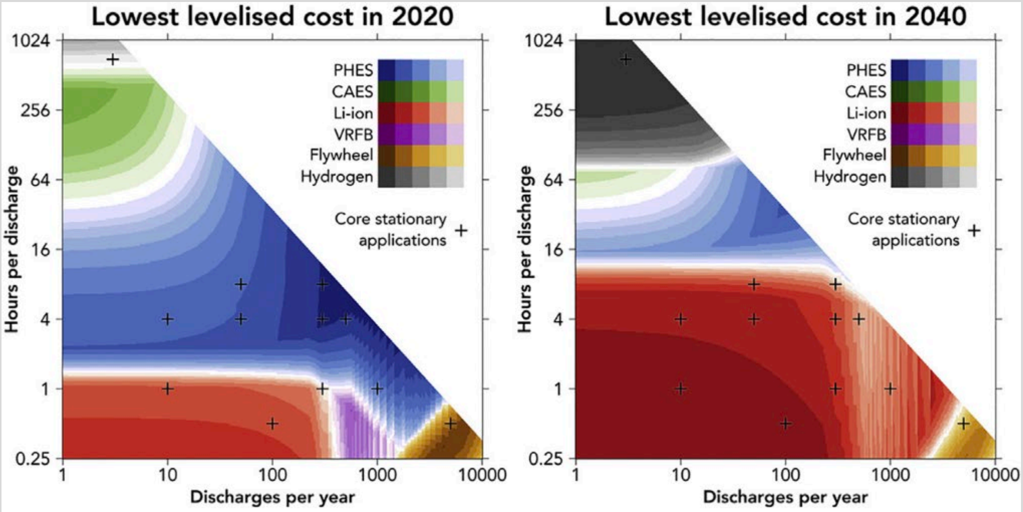
Figure B5. 1 visualizes the current lowest-cost technologies by levelized costs of (electricity) storage (LCOS), and future projections for 2040. The technologies are categorized by storage duration (hours per discharge) and frequency of use (discharges per year). Currently, pumped hydro, depicted by the blue areas, dominates many medium-duration and frequency applications as the lowest-cost option.

The results from an LCOS study by Schmidt et al. (2019) demonstrate that incumbent pumped hydro is likely to lose its dominance, as its cost stagnate while others fall, for applications in energy arbitrage, short- and medium duration storage, and addressing the overload of transmission and distribution networks. In most applications, lithium-ion batteries demonstrate dominant cost-effectiveness in 2040. Overall, primary response is dominated by flywheels, with a significant contribution from lithium-ion batteries. The second lowest LCOS in most cases is from flow batteries, represented by vanadium redox-flow, which start becoming a low-cost option in 2025, but are outcompeted by lithium-ion batteries in the longer term. In seasonal storage, compressed air initially provides the lowest LCOS, while hydrogen becomes dominant after 2025, and the role of other technologies remains marginal.

Through to 2040, lithium-ion batteries retain their cost dominance for many short- to medium-duration applications. A significant cost reduction is also forecast for hydrogen, which is potentially relevant for long-term storage applications. These projections should be treated with caution; modelling results regarding electricity storage costs are still limited by assumptions that are characterized by a high degree of uncertainty.

[14] Round-trip efficiency refers to the percentage of electricity put into storage that can be later retrieved.

Figure B5.1. Comparison of the lowest levelized costs in relation to the frequency and duration of discharges across different energy storage technologies in 2020 and modelled projections for 2040



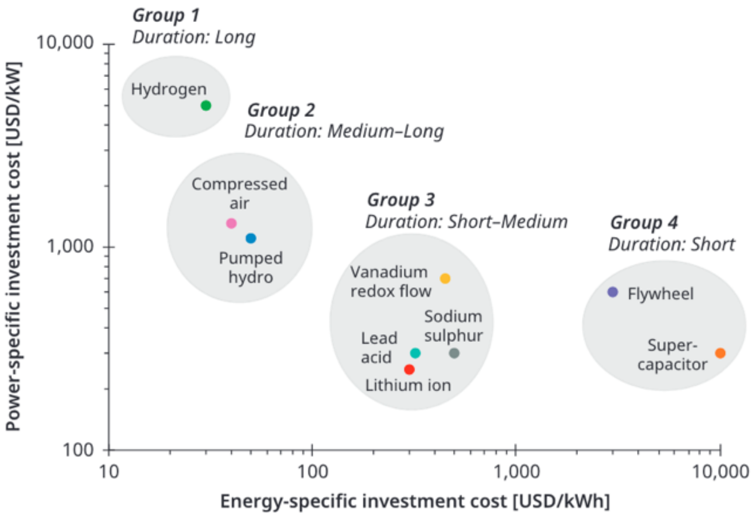
Source: Schmidt et al. 2019.
Note: CAES = compressed air energy storage; li-ion = lithium-ion; PHES = pumped hydro energy storage; VRFB = vanadium redox flow battery.

Costs of power capacity and energy storage capacity

While electricity storage is capable of meeting various electricity system needs, rising VREs and future projections demonstrate the need to consider temporal aspects. Given that investment costs comprise a significant share of LCOS, further reductions are critical to scale up electricity storage. As discussed in Grubb, Poncia, and Pasqualino (2024), the success of technology deployment is often depicted by experience curves that demonstrate reductions in technology costs as a function of cumulative installations. In the case of electricity storage, deployment is reflected in two dimensions: *power* capacity (gigawatts, GW); and *energy* capacity (gigawatts per hour, GWh)

The most cost-effective options depend on total investment costs and comprise *power* capacity costs (costs/kW) and *energy* capacity costs (costs/kWh), as depicted in figure 7 (Schmidt and Staffell 2023). As of 2020, flywheels and supercapacitors are capable of providing rapid discharge with moderate *power* capacity costs. However, these are on the high end of *energy* capacity costs—that is, costs per kWh fed into the electricity system during peak demand. Flow batteries along with lead acid and sodium sulphur are cost effective for short- to medium-duration electricity storage (MDES), with lithium-ion batteries the cheapest option in terms of both *power* capacity and *energy* capacity. MDES to LDES (long-duration electricity storage) is represented mainly by compressed air and pumped hydro, both characterized by higher power capacity costs and lower energy capacity costs. The same is true for hydrogen, which is the only viable seasonal storage option capable of providing cheap energy capacity; however, its power capacity costs are still enormous. While novel ES technologies demonstrate cost reductions through experience rates, incumbent carbon-free pumped hydro costs have plateaued, or are even rising, for new projects. One reason is that the technology is characterized by high *power* capacity costs due to limited availability of locations and suitable topology of landscapes (Ali, Stewart, and Sahin 2021). Also, similarly to fossil fuel power plants (section 2), pumped hydro will remain exposed to the impacts of climate change through water insecurity due to droughts.

Figure 7. Electricity storage costs and specifications, 2020



Source: Schmidt and Staffell 2023.
Note: Higher capital cost of longer duration storage technologies can be seen, as well relationship between discharge duration and storage capacity. USD/kWh = US dollars per kilowatt hour.

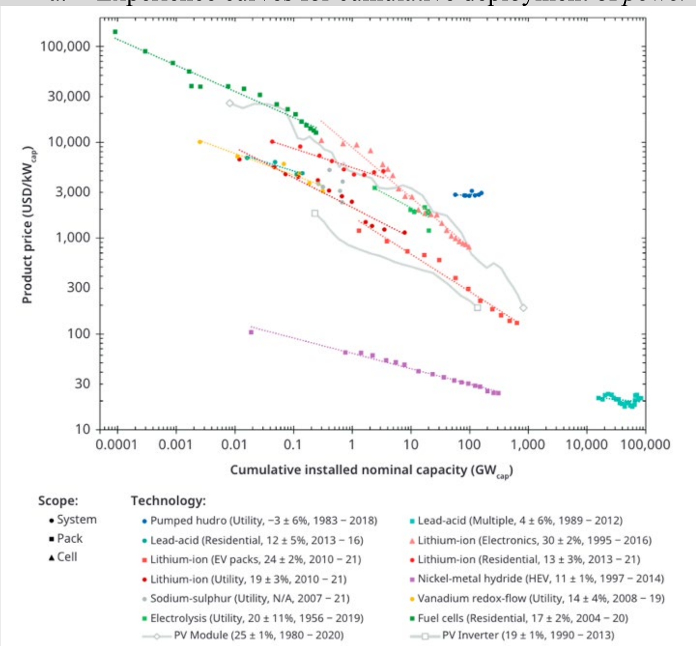
The empirical data demonstrate that lithium-ion batteries have achieved the most rapid price reductions per deployed capacity across other storage technologies, with annual learning rates of 25 percent to 30 percent (Schmidt and Staffell 2023). One of the biggest drivers was the subsidized deployment of electric vehicles (EVs) at scale, along with a growing demand from consumer electronics. As a result, costs of this technology have fallen from nearly 1,000 USD/kWh to less than 150 USD/kWh (Schmidt and Staffell 2023). Even though there are spillovers across different applications of lithium-ion batteries, this technology still requires further deployment as utility-scale battery storage to achieve investment costs lower than the current 300 USD/kWh. However, learning rates are based on historic empirical data. This implies that projected rates are rather exploratory because the longer the extrapolation, the higher the cost uncertainty. The learning rates and experience curves of electricity storage technologies are illustrated in box 6.

Box 6. Experience Curves for Electricity Storage Technologies

The experience curves for electricity storage technologies displayed in figure B6.1 illustrate the relationship between cumulative deployment of new storage capacity and price reductions of technologies. Novel electricity storage technology is projected to have significant cost reductions once deployment increases, influencing and reducing costs of the deployment of sources of variable renewable energy (VRE). Lithium-ion batteries are among those with the sharpest cost reductions.

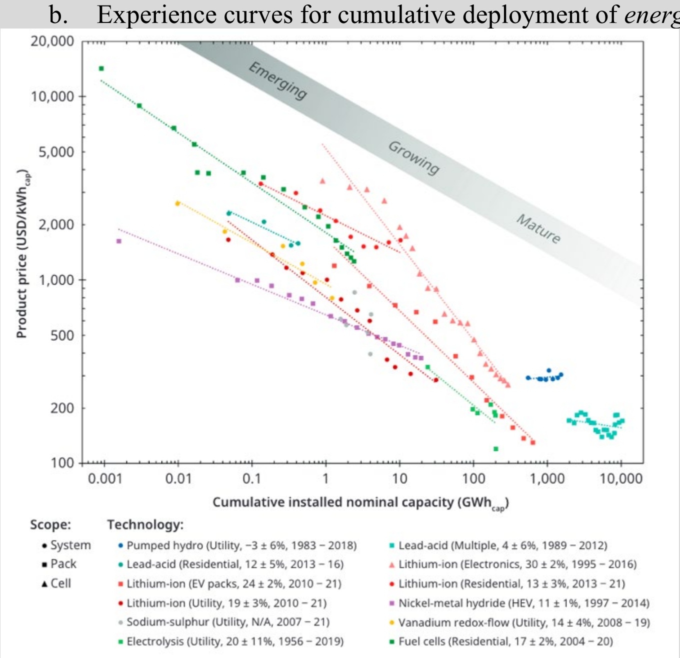
Figure B6.1. Experience curves of power capacity and energy capacity in storage

a. Experience curves for cumulative deployment of *power* capacity (GW)



Source: Schmidt and Staffell 2023.
Note: EV = electric vehicle; GW$_{cap}$ = gigawatt capacity; HEV = hybrid electric vehicle; N/A = not available; PV = photovoltaic; USD/kW$_{cap}$ =US dollars per kilowatt capacity.

b. Experience curves for cumulative deployment of *energy* capacity (GWh)



Source: Schmidt and Staffell 2023.
Note: EV = electric vehicles; GWh$_{cap}$ = gigawatt hour capacity; HEV = hybrid electric vehicle; N/A = not available; USD/kWh$_{cap}$ = US dollar per kilowatt hour capacity.

Cost-effectiveness of energy storage

As discussed earlier in this section, LCOE does not capture all energy system value components that enable the reliable provision of electricity; it fails to address various technical and temporal needs. An excluded dimension is the need for *power* and *energy* storage capacity to ensure reliable functioning of the electricity system. Most studies have focused on OECD countries. These studies find that a VRE share of up to 50 percent of energy demand requires, on average, 0.02 percent of *energy* storage capacity (kWh) relative to annual energy demand, and 20 percent of *power* capacity relative to peak power demand (Schmidt and Staffell 2023). At higher levels of VREs, storage needs increase exponentially, rising to 0.1 percent to 0.3 percent of energy capacity relative to annual demand and 50 percent to 75 percent of *power* capacity relative to peak demand. Overall, the rate of *energy* storage capacity increases faster than that of *power* capacity. This implies that the cost-effective marginal value of additional *energy* storage capacity (kWh) decreases with deployment of nameplate *power* capacity (kW).[15] This relationship further suggests that the LCOS of lithium-ion batteries will remain high—even though these batteries demonstrate significant capital cost reductions, and relying only on this technology is not cost-effective at high level of VREs in the power sector.

A cheaper alternative to more expensive lithium-ion batteries at high VRE share can be deployment of long-duration storage (LDES) (Sepulveda et al. 2021) or "overbuilding" of VRE capacity (Dowling et al. 2020). The system value of LDES largely depends on the *energy* storage capacity cost (kWh) and discharge efficiency. Due to its lower *energy* storage capacity costs, LDES is able to decrease system costs by 45 percent to 50 percent (Sepulveda et al. 2021). However, currently enormous *power* capacity investment costs (kW) remain a major barrier.

There are academic debates about use of other incumbent technologies, either to provide low-carbon baseload power or balancing, or both. In the case of nuclear power, research suggests that its combination with VREs increases needs for balancing rather than the opposite (OECD and NEA 2011). This is partly because nuclear and VREs can sometimes generate excessive amounts of electricity, potentially leading to curtailments that are not cost-optimal in comparison to storing residual output (OECD and NEA 2011).

Market design, barriers, and policy recommendations

Unlike for power plants, there is no unified business model for electricity storage, given the breadth of values that it can provide to the electricity system, which often vary over time (Schmidt et al. 2019). Investors in novel electricity storage technologies are dependent on long-term revenues to secure a reasonable return on investment, similar to VREs. This requires predictability of regulatory environment and government policies. For electricity storage, investment decisions will rely on data about projected costs of buying energy, the selling price in relation to the temporal aspects of storage dispatch, and the market competition, which

[15] Nameplate power capacity refers to the theoretical amount of power that can be produced by a power plant in ideal conditions, as rated by the manufacturer.

should not only recover the investment cost but also provide competitive returns (Royal Society 2023). The provided experience rates (box 6) suggest there is a potential for technology costs to fall further, yet this will require substantial investments to adjust electricity storage costs.

One of main barriers to deployment of electricity storage at scale is an incumbent market design that does not completely capture its value. Some countries, such as the United Kingdom, have tried to address this problem by establishing ancillary services and capacity markets (Castagneto Gissey et al. 2019; Dodds and Garvey 2022). The uncertainty about the full value of ES influences the projections for the optimal amount of storage with respect to other flexibility technologies: specifically, the grid architecture in terms of transmission, distribution, and interconnection. Also, due to a number of emerging electricity storage technologies, there is still a challenge of identifying the most appropriate way to "pick the winners" and associated needs for support (Dodds and Garvey 2022).

The so-called "revenue stack"—the ability to earn revenue simultaneously from multiple sources using the same capacity—can come from meeting various power system requirements. This revenue stack is needed to provide a business case for energy. Possible instruments include contracts for differences (CfD), capacity market, regulated asset base (RAB), power purchase agreements (PPAs), hourly energy attribute certificates, and cap and floor storage (Schmidt and Staffell 2023).

4. Financing Costs of Renewables in Middle-Income Countries

As discussed in section 2, the new generation of renewables have achieved extreme cost reductions over the last decade: notably, decreases of nearly 90 percent for solar PV, and 60 percent to 70 percent for wind (IRENA 2023a).

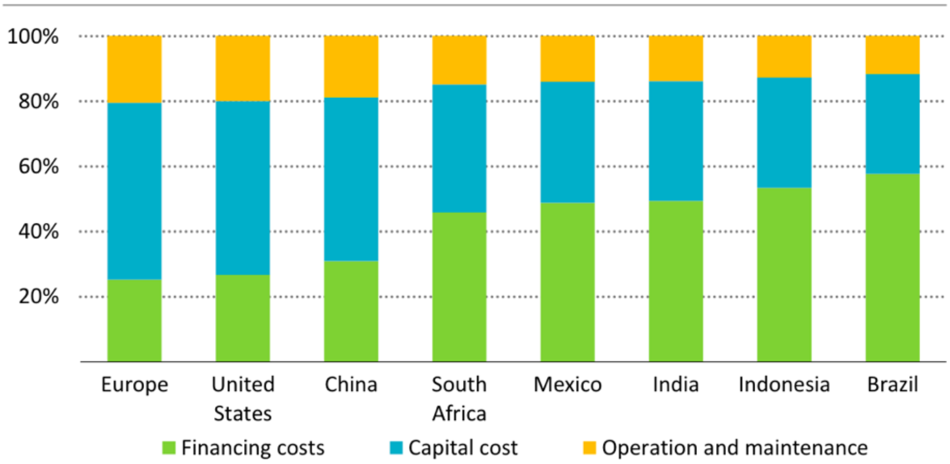
The observed falling costs of renewables have been reflected across capital expenditures (CAPEX), operating expenditures (OPEX), and financing costs. One reason for the fall in CAPEX was subsidized deployment and economies of scale (Elia et al. 2021; Kavlak, McNerney, and Trancik 2018), where costs fell as more manufacturing facilities were commissioned. This, in turn, had a reciprocal effect on technology learning—where increasing stock led to larger deployments and technology learning in wind turbines and solar PV (Elia et al. 2020; Elia et al. 2021). Technology learning also had a positive impact on OPEX as maintenance of facilities improved and optimized, and more qualified labor appeared on the market (Steffen et al. 2020). All these measures required policy certainty, a key driver in renewable deployment (Badouard et al. 2020; Shivakumar et al. 2019). Financiers and investors that initially assigned relatively high risks to renewables projects have revisited their perception and decreased IRRs (internal rates of return) and/or weighted average cost of capital (WACC) of new investments in renewables (IEA 2021b) in response to these developments (Egli, Steffen, and Schmidt 2019).

Even though the CAPEX of renewables achieved substantial reductions over the last decade, a major issue remains financing these costs, which largely depends on country risks, regulatory environments, access to the grid, market design, and stability of support policies (IRENA

2023b; Schwerhoff and Sy 2017). Another, although less significant, cost component is OPEX, which largely depends on the sufficient supply of (local) qualified labor.

Figure 8 illustrates this striking disparity of CAPEX, OPEX, and financing costs of a typical solar PV project between developed countries and middle-income countries. In some cases, financing costs accounts for more than 50 percent of the entire lifetime costs of the renewable energy project.

Figure 8. Composition of LCOE for solar PV at utility scale, selected developed and middle-income countries, 2021



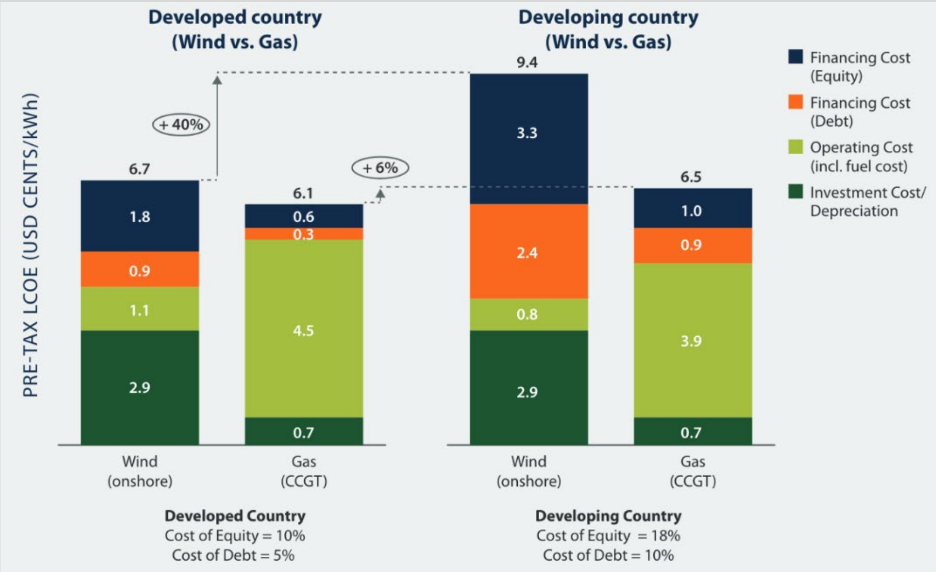
Source: IEA 2022b.
Note: LCOE = levelized cost of energy; PV = photovoltaics.

According to Net Zero Scenarios (EIA 2021), more than 80 percent of new electricity demand by 2040 will come from developing countries, where the cheapest and most affordable options will be sought, to fuel economic development, urbanization, and industrialization. First and foremost, this points to the question of which technologies will be deployed to meet this need cost-effectively. Second, given the lifetime cost distribution of the energy project, the decision will be between fossil fuels and renewables. Fossil fuel plants have smaller upfront costs, with most costs spread across the project lifetime, mainly dependent on fuel costs exposed to commodity price shocks (Partridge 2018) and the availability of public funds to absorb them. Renewables require much more significant upfront capital investments, coupled with a higher share of financing costs, as opposed to fuel-based power plants. Given the lower need for upfront capital in fossil fuel projects, even higher risk premiums in middle-income countries will still be negligible unless there is a significant risk of stranded assets (box 7).

Box 7. The Relative Cost of Renewables in Developing Countries

Developing countries attempting to decarbonize face the relative cost of additional renewable capacity compared to fossil fuels, and how this influences competitiveness. As displayed in figure B7.1, the lifetime cost of a combined cycle gas turbine (CCGT) gas plant in developing and developed economies is largely similar. However, there is a 40 percent premium on onshore wind power plants in a developing economy compared to that in a developed economy. This is due to the significantly higher financing costs driven by higher risks and scarce capital in developing economies—capital needed to meet the high upfront capital costs of renewable energy projects. This large increase makes renewables uncompetitive relative to fossil fuels. By contrast, in a developed country, wind is close to competitive.

Figure B7.1. Composition of LCOE for gas and wind power plants in developed and developing countries



Source: Waissbein et al. 2013.
Note: CCGT = combined cycle gas turbine; LCOE = levelized cost of electricity; USD cents/kWh = US cents per kilowatt hour.

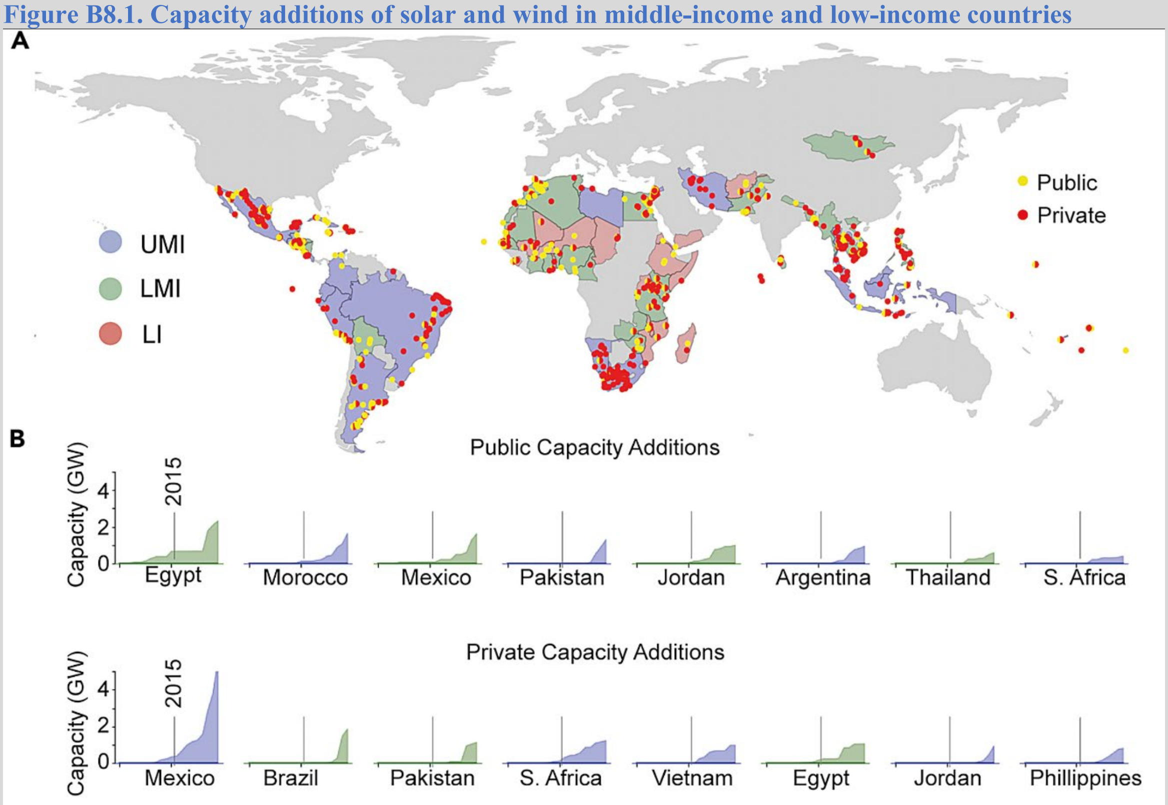
Even though many middle-income countries have the most abundant solar irradiation and wind endowments, renewable projects in these economies are often characterized by higher investment risks, attributed to immature of capital markets and a lack of capital stock. These factors pose a major barrier to abating carbon emissions globally (Ameli et al. 2021; Schwerhoff and Sy 2017). Higher risk premiums imply there is a need to provide a higher stock of capital per MW of renewable capacity. In the presence of higher risk premiums, capital is recycled with lower cost-effectiveness, delaying energy transitions in middle-income countries, and effectively reducing carbon emissions and local air pollution more slowly (Ameli et al. 2021). The weighted average cost of capital (WACC), which reflects energy project risks, is considered to be more significant in LCOE than the solar irradiation level, a proxy of the output potential (or capital productivity) (Ondraczek, Komendantova, and Patt 2015). This is reflected in a clear disparity between developing economies and developed economies. In most cases, developed countries are less endowed with solar irradiation, but account for the highest share of installed capacities of solar PV. Meanwhile, many struggling middle-income countries have abundant solar potential.

Not only is there a disparity between developing and developed economies, but there is a disproportionate distribution of public and private investments within middle-income countries. Similar to the case of technology learning, as more projects are deployed in a country, financing costs fall due to market maturation, as investors increase confidence and revise their risk perception downward. This financial learning in renewable energy projects improves their cost-competitiveness (Egli, Steffen, and Schmidt 2019). However, this also creates financial path-dependency and "investment lock-ins," with international public and private investments disproportionately flowing to more "financially suitable countries," leaving other developing countries behind (Rickman et al. 2023). Even though private capital remains the overall dominant source of funding, at nearly 65 percent of total investments in middle-income countries, almost two-thirds goes to upper-middle-income countries, while low-income countries receive only 2 percent, despite representing 21 percent of the countries by number of countries (Rickman et al. 2023). This disparity is analyzed further in box 8.

Box 8. The Global Disparity of Public and Private Investments in Renewable Energy

Figure B8.1 illustrates renewable energy capacity expansions following the Paris Agreement (2015) by public and private investments within upper-middle-income and lower-middle-income countries, as well as low-income countries. In many countries, the rate of capacity additions has increased significantly following the Paris Agreement, but they remain uneven. The Arab Republic of Egypt, Mexico, Jordan, Pakistan, and South Africa are top recipients of public and private finance, while the lack of both types of financing is significant in low-income countries. The majority of all investments is from private sources, with significant private capacity additions in upper-middle-income countries compared to lower-middle-income countries—especially Mexcio.

Figure B8.1. Capacity additions of solar and wind in middle-income and low-income countries



Sources: Rickman et al. 2023, based on BloombergNEF data.

Note: Panel A displays a color-coded map of middle-income and low-income group countries according to the locations of project investments made. It spans the period from 2010 to 2019. Panel B shows cumulative wind and solar capacity additions in the top eight recipients of public and private investment in 2010–19. GW = gigawatts; LI = low-income; LMI = lower-middle-income; UMI = upper-middle-income.

To address high financing costs in middle-income countries and associated financial path-dependency, a more holistic quantitative analysis and decomposition of components of risk premiums is needed. Revenue incentives, such as feed-in tariffs and contracts for differences, are often considered to be critical tools to mobilize the private capital for renewables projects. These instruments are designed to adequately compensate for the associated risks above the market price. Yet, providing premiums might be overgenerous unless those risks are holistically addressed. Hence, a more granular de-risking is required by developing tailored responses to licensing, policy stability, social acceptance, technical, and market and regulatory risks (Noothout et al. 2016; Waissbein et al. 2013), though the risk typology is not exhaustive and varies in the literature. Developing more tailored policies and de-risking specific components can increase investment certainty and, hence, cheapen renewable energy projects (UNDP 2014; UNDP 2017). More broadly, this can, in turn, reduce the amount of public finance, such as subsidies, needed to support those projects. If consumers bear some share of the renewable premiums embedded in the electricity price, then de-risking renewable energy projects can also make it more affordable.

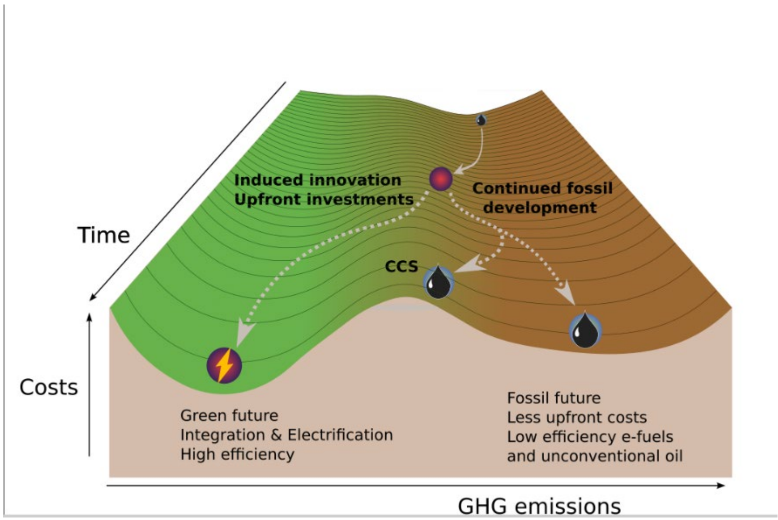
5. Part A, Conclusion: The Economic Structure of Electricity Systems Transition and Decarbonization

This extensive survey of low-carbon, electricity-related technologies and systems yields two main conclusions.

First, from a standpoint of technology and systems engineering, there is no reason to believe that low-carbon electricity systems are in general more expensive than high-carbon ones, even after accounting for the needs of storage and other balancing in the light of the variability of wind and solar power. Electrification is also increasingly attractive—notably, for much transport and some industry. The economics of getting all the way to zero-carbon electricity are at present more uncertain, and conditions will vary somewhat according to resource and other national differences. In general, however, it cannot be assumed that decarbonizing electricity is an economic burden, and it has obvious potential to bring benefits in terms of greater use of domestic renewable resources.

The general economic challenge is different. As suggested graphically in figure 9, it is about the contrast between two very different kinds of systems, and the associated pathways, indicated by "valleys" of comparable costs but very different characteristics.

Figure 9. The "double valley" of energy futures



Sources: EEIST: Grubb et al. 2024, building upon Grubb, Hourcade, and Neuhoff 2014.
Note: CCS = carbon capture and storage; GHG = greenhouse gas.

Most electricity systems have been developed on the basis of fossil fuels, along with centralized, one-way power grids and all the associated other networks and supply chains, and the established socioeconomic interests. Most countries have developed in the high-carbon valley and some are still digging themselves deeper, particularly concerning the continued coal-based developments in Asia and some parts of Africa.

The emerging electricity (and transport) systems will be very different in numerous ways. Moving from the high-carbon to the low-carbon valley does, however, require incurring the economic and political costs of "crossing the ridge" to the new systems. Given the technological breakthroughs of the past decade, this is entirely possible, but the longer this process is delayed—the longer that countries continue in the high-carbon trench—the more costly the transition will be.

The second important conclusion is that the capacity and cost of the transition for emerging economies is highly dependent on the terms of finance. The discussion has emphasized that the widely used metric of LCOE is increasingly redundant, not only because it ignores variability (which becomes increasingly important at higher penetrations), but because the practical costs of a low-carbon system—which are dependent upon capital investment, particularly in renewables, storage, and grids—depend critically upon interest rates for such investment.

That topic is beyond the scope of this paper. However, as Part A emphasizes, at least for the electricity-related dimensions of the global transition, the cost of finance is now just as important as the cost of the technologies themselves—and potentially, more so.

Part B. The Role of Carbon Capture and Storage and Hydrogen in Decarbonizing Hard-to-Abate Sectors: Steel and Cement

6. Overview of Industrial Processes: Iron and Steel, and Cement

Part A explored the options for decarbonization on the supply side—power generation. This part of the paper looks mostly into the decarbonization of end-use in hard-to-abate (HtA) sectors, focusing on the role of carbon capture and storage (CCS) and hydrogen in steel and cement.

End-use sectors of the global economy, such as industry, transport, and buildings, are responsible for more GHG emissions than the power sector and heat combined, with significant contributions from heavy energy-intensive industries (Fortes et al. 2019; IPCC 2023a). Decarbonizing end-use sectors is instrumental in achieving climate change mitigation targets. The role of electrification and the power sector was discussed in Part A. Industrial production accounts for about one-third of global energy-related and industry-related GHG emissions, and its decarbonization is essential to achieving net zero emissions. The discussion that follows takes a more detailed look at the role of electrification, alongside other available options, for the decarbonization of hard-to-abate sectors.

HtA sectors are often associated with significant energy consumption and intensive use and processing of materials. The decarbonization of such sectors depends not only on a shift to low-carbon energy sources, but also on abating emissions from processing materials, which are challenging to address (Paltsev et al. 2021). Solutions are therefore multifaceted, and often rely on the processing technology used and its energy requirements, sources of energy, and material processing efficiency. Another aspect of HtA sectors is that "energy" often refers to both electricity and the heat required to process materials.

As discussed in Part A, CCS and hydrogen are likely to have a more significant role in industry than in power generation or transport sectors, and each industrial sector is different and may require tailored solutions. To avoid overgeneralization, Part B examines two major cross-cutting options—CCS, and hydrogen—and focuses on the decarbonization of steel and cement, the biggest industrial emitting sectors, which account for about 15 percent of global emissions. This focus also serves to illustrate the range and complexity of options.

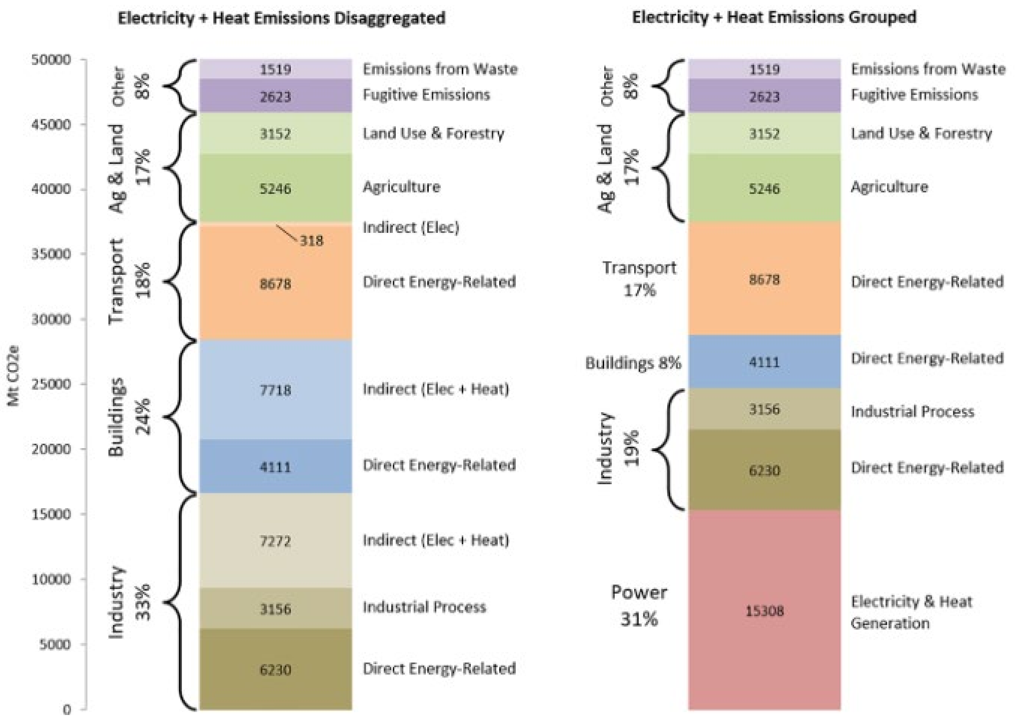
6.1. Industrial emission profiles

Industry is responsible for 34 percent of all global GHG emissions (Rissman et al. 2020).[16] Major sectors such as iron and steel and cement are key for decarbonization (Gerres et al. 2019), requiring a complex array of tools and technologies. The emission profile of the industrial sector, compared to other end- uses, is displayed in figure 10. Decarbonization tools include circular economy solutions, material efficiency and energy efficiency, fuel and

[16] This 34 percent tally includes both direct (Scope 1) and indirect (Scope 2) emissions.

feedstock switching, electrification of high-temperature processes, carbon-free electricity and heat, and carbon capture and storage to abate residual emissions (IPCC 2023b).

Figure 10. GHG emissions by sector, 2014



Source: Rissman et al. 2020.
Note: "Disaggregated" means that emissions from electricity and heat are separately accounted from direct fuel combustion (scope 1 emissions), and indirect emissions associated with purchased electricity and heat (scope 2 emissions). "Grouped" means that emissions from electricity and heat are aggregated, independently of their location in the value chain. MtCO2e = megatonnes of carbon dioxide equivalent.

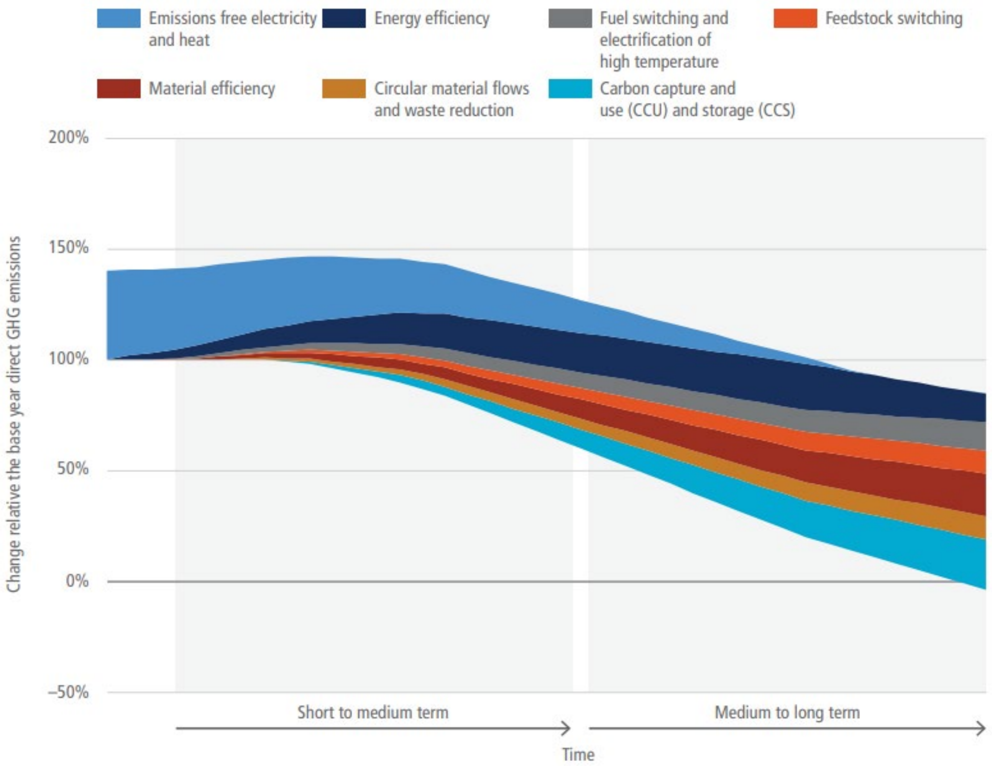
Much of the growth of key industrial sectors—for example, iron and steel—is expected in middle-income countries such as China, India, and later, African economies (Napp et al. 2014). Rapid industrial expansion in those countries will also imply new demand must be met from virgin ore, because the existing in-use stock of steel and iron is far beyond the projected needs (P. Wang et al. 2021). Hence, developing low-carbon industrial strategies and policies in such regions is crucial for global decarbonization.

Increasing carbon-free electricity and heat and energy efficiency, according to IPCC (2023a), are the most plausible paths in the short to medium term, offering the most significant potential to reduce GHG emissions. These paths align well with the industry emission profile, where power and heat generation account for 56 percent of GHG emissions, with industrial processes and direct energy input responsible for the remainder (Rissman et al. 2020).

Several technologies have the potential to reduce industrial GHG emissions, but, in most cases, require further support to reach commercialization in the near and longer term (Rissman et al. 2020). In the near term, decarbonizing high-temperature processes and energy efficiency are the most plausible options, along with further expansion of electric arc furnaces (EAFs). In principle, some CCS technologies (figure 3) are ready for deployment, but the scale and complexity is reflected in the very slow deployment to date (Lyons, Durrant, and Kochhar

2021); hence, they can be considered to be a longer-term solution. However, industrial sectors present different GHG emission profiles. For instance, iron and steel production results in more direct energy-related emissions, while cement production includes more process emissions (Rissman et al. 2020). Therefore, technologies and approaches to decarbonization will vary across sectors (figure 11), with little industry-wide consensus on one decarbonization pathway (Gerres et al. 2019).

Figure 11. Industry abatement in the short to medium term and long term



Source: IPCC 2023a.
Note: GHG = greenhouse gas emissions.

6.2. The iron and steel production process

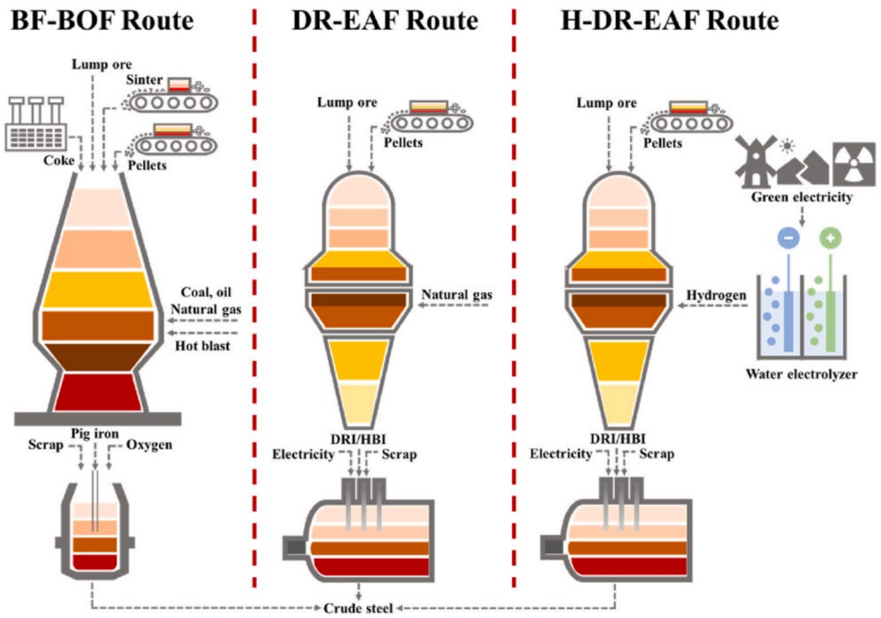
The production of steel primarily uses coking coal in blast furnaces (BF) to reduce iron ore. Molten iron is then refined into steel in a coal basic oxygen furnace (BOF), but sometimes in an electric arc furnace (EAF) (Fennell et al. 2022). The traditional steelmaking route (more than 80 percent of steel is produced this way) is from a blast furnace to a basic oxygen furnace (BF-BOF) (Bhaskar, Assadi, and Somehsaraei 2020). As discussed earlier, one near-term solution is likely to be the expansion of low-carbon power and heat generation with existing technologies, such as electricity. EAFs are predominantly used when dealing with scrap steel and allow a degree of fuel switching from coal to lower-carbon sources. However, EAFs cannot refine virgin ore, a process that requires a separate prior step to “reduce” the iron oxide (ore).

An alternative technology for processing iron ore is direct reduction (DR), which does not require coking coal, and typically uses hydrogen and carbon monoxide (CO) (derived from methane or coal). About 5 percent of global steel is currently made this way (Fennell et al.

2022). Using gas instead of coal direct reduced iron (DRI), with the iron then processed using an EAF, can reduce GHG emissions by 61 percent (Fan and Friedmann 2021; Fennell et al. 2022). However, even more emissions can be prevented by utilizing hydrogen direct reduction (H-DR), if coking coal is replaced fully by green hydrogen. GHG emission reduction estimations for this process range from 80 percent to 97 percent (Fan and Friedmann 2021; Fennell et al. 2022; R. Wang et al. 2021), again, when paired with EAFs. Figure 12 presents the traditional steel-processing route, along with the alternative routes discussed.

Historically, steel has followed a processing route where iron ore is mined and extracted, followed by BF-BOF production, with EAFs being utilized to process end-of-life steel (P. Wang et al. 2021). However, the decarbonization of steel from the highly carbon-intensive BF-BOF route requires new approaches and technologies, with the discussed approaches visualized in figure 12**.** The introduction of direct reduction technologies can process iron ore in a less carbon-intensive manner, while EAF utilization can facilitate a shift in processing routes, where scrap and recycling become a central feature.

Figure 12. Steel processing routes



Source: R. Wang et al. 2021.
Note: BF-BOF = blast furnace-basic oxygen furnace; DR-EAF = direct reduction-electric arc furnace; DRI/HBI = direct reduced iron/hot briquetted iron; H-DR-EAF = hydrogen direct reduction-electric arc furnace.

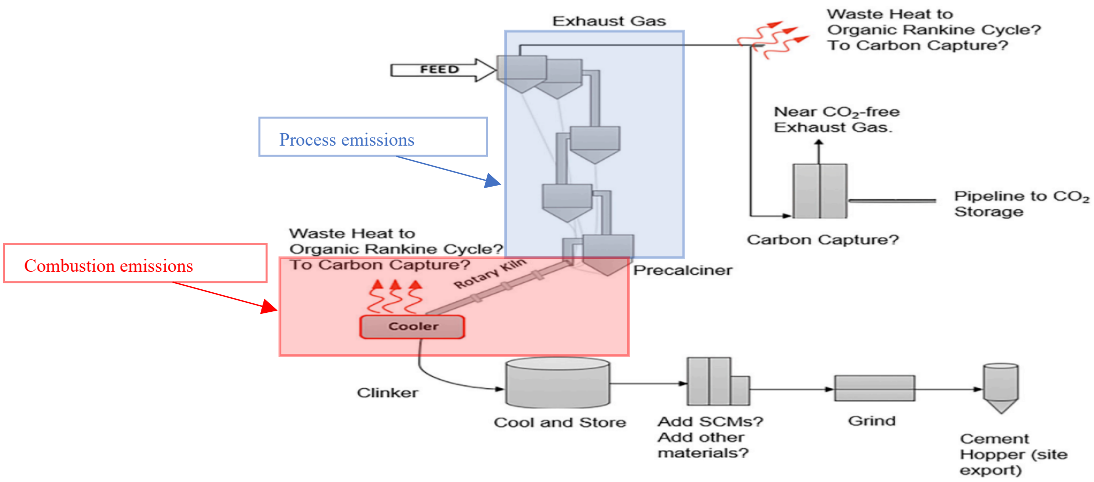
Rapidly developing emerging economies depend on a rapid supply of materials, including metals. The current in-use stock of steel and iron in such countries is relatively young—averaging between 8 years and 11 years in China and India, compared to more than 25 years in most OECD countries (P. Wang et al. 2021). Given the 70-year average lifetime of steel products (Pauliuk et al. 2013), meeting the near-term demand for steel means the reduction of ore requires a different processing technology, rather than depending on recycling with EAFs alone. Continued investment in fossil fuel BFs risks exacerbating carbon lock-ins (Fan and Friedmann 2021). In the long term, processing scrap metals offers the potential for low-carbon steel production through EAFs; the adoption of technologies, therefore, must be time- and geography-specific, depending on the steel profile age (P. Wang et al. 2021).

Demand-side response and material and energy efficiency can also contribute significantly to decarbonizing steel production, and are discussed further in section 7; however, their impact alone is insufficient for full decarbonization in the long term (P. Wang et al. 2021). Overall, decarbonizing iron and steel will require both supply- and demand-side responses to align with the 2050 climate targets (Rissman et al. 2020; P. Wang et al. 2021), similar to other industries (IPCC 2023b).

6.3. The cement production process

In emerging economies like China and India, cement is responsible for 48 percent of all non-combustion emissions (Lyons, Durrant, and Kochhar 2021). Almost 60 percent of global production capacity is located in such economies, whose production fleet is also the youngest (IEA 2020a). GHG emissions from cement, unlike those from steel, are primarily associated with process emissions, rather than combustion emissions (IPCC 2023b). Of the three main stages of cement production—extraction and preparation, clinker production, and cement grinding—nearly 60 percent of GHG emissions come from the HtA non-combustion processes in the pre-calciner for clinker production (Fennell, Davis, and Mohammed 2021; Lyons, Durrant, and Kochhar 2021) (figure 13). The remainder comes from fuel combustion for heating processes in the kiln (Hills et al. 2016) that are easier to reduce and can be addressed by low-carbon options.

Figure 13. Cement production process



Source: Adapted from Fennell, Davis, and Mohammed 2021.
Note: When depicted with by '?', the stage of production is not currently core to the process. CO_2 = carbon dioxide; SCMs = supplementary cementitious materials.

Potential mitigation options include energy efficiency across both process and combustion stages, the deployment of CCS, and alternative fuels in, or electrification of, kilns (Fennell, Davis, and Mohammed 2021). Once adopted, modern kilns are highly efficient, with limited scope to improve energy savings further (Habert et al. 2020). Instead, their inherent fuel source flexibility (Habert et al. 2020) can be utilized by supplying the heating process with low-carbon fuels, such as electricity (Rissman et al. 2020), or municipal waste or biomass (Fennell, Davis, and Mohammed 2021). Fuel switching by substituting out fossil fuels can cut GHG emissions by approximately 30 percent (Nurdiawati and Urban 2021).

Processing emissions are harder to abate given their technical specificity and lack of feasible options in cement production that can substitute clinker or limestone (Lyons, Durrant, and Kochhar 2021). GHG emissions from the kiln, and non-combustion emissions from calcination process, have high CO_2 concentration (14 percent to 33 percent), which makes cement plants more suitable for CCS technologies than power sector applications such as gas (~3 percent) or coal (~15 percent) (Bui et al. 2018). Post-combustion capture, oxyfuel combustion, and direct separation reactors (DSR), all CCS technologies, have various potential applications across cement plants. Post-combustion is more suited to retrofits, oxyfuel is theoretically appealing but less suited to retrofits, and DSR is a novel but new development (Bui et al. 2018). CCS in cement is explored further in section 10.

7. Energy Efficiency and Demand-Side Options

So far, the solutions discussed have been focused on technology, aimed at low-carbon fuels and the capturing of carbon. Aside from such options, in each industry, significant potential exists for energy efficiency savings and demand reduction (Habert et al. 2020; IPCC 2023b; Napp et al. 2014; Nurdiawati and Urban 2021). Ensuring production plants are of highest efficiency in iron and steel and cement industries can save significant energy. Insulation can reduce demand by 26 percent, upgraded boilers by 10 percent, and heat exchangers by 25 percent in refining processes (Fennell et al. 2022). Upgrading old, inefficient, cement plants has large potential GHG emission savings (Fennell et al. 2022), while upgrading kilns can yield large energy savings. European cement production could reduce GHG emissions by 80 percent compared to 1990 levels by 2050 without deploying CCS, but instead deploying efficiency measures and alternative materials and fuels, at a relatively low cost, Favier et al. (2018) suggest. Improvement of process controls and measurement devices in cement plants can also improve operational efficiency by 15 percent to 20 percent (Fennell, Davis, and Mohammed 2021). Such improvements have the added benefit of reducing the future electricity demand of the industrial sector (Lechtenböhmer et al. 2016).

Reductions in demand of 26 percent for cement and 24 percent in steel at end-use can be made, IEA (2019b) reports. In scenarios for India, Brazil, and South Africa, potential exists to reduce GHG emissions on the demand side by 13 percent to 26 percent for the cement and steel industries (Bataille, Stiebert, et al. 2023). Examples of demand-side approaches include material efficient design, reductions in material waste, alternative materials, and circular economy interventions (Rissman et al. 2020). However, the use of demand-side measures in developing economies undergoing significant urbanization and infrastructure development is challenging. Demand-side measures are likely to take decades of learning by policy makers, producers, and users, as well as regulatory development (Bataille, Stiebert, et al. 2023). A potential role exists for developed economies, with less pressing infrastructure expansion requirements, to develop the institutional education and building code reforms necessary to improve material design and recycling (Bataille et al. 2018).

The transition toward low-carbon industry extends the risk of stranded assets beyond the power sector. Early decommissioning should be analyzed as a decarbonization tool, as well as an investment risk for new capacity. Given the long operational lifespans of industrial facilities, which range from 20 to 50 years (Bataille 2020a; Gerres et al. 2019), the high carbon intensity of current plants poses a significant threat to 1.5-degree targets (P. Wang et al. 2021). For instance, it is estimated the steel industry cannot build more unabated BF-BOFs past 2025 without jeopardizing net zero ambitions (Bataille, Stiebert, and Li 2021).

It is likely that little to no new carbon intensive capacity can be commissioned, and that existing steel infrastructure may need to be decommissioned early, or retrofitted where feasible (Bataille 2020a; P. Wang et al. 2021; Tong et al. 2019). To meet IEA's Net Zero by 2050 Scenario, which envisions 53 percent of steelmaking to use EAFs by 2050, 347 megatonnes (Mt) per year of BF-BOF capacity will need to be retired or cancelled (Lempriere 2023). Investments into new carbon intensive facilities past 2030 therefore pose increased transition climate risk due to the probability of early decommissioning (Bataille, Stiebert, and Li 2021; E3G 2021). This dilemma is prevalent in China, where the average steel facility is 13 years old and stranded asset risk is significant (ETC 2021), and in India, where steelmaking capacity is expected to grow significantly (E3G 2021). Results from P. Wang et al. (2021) recommend an early decommissioning of primary steel facilities in China of 170Mt in the next 15 years and a further 500Mt by 2050, having retired 100Mt–150Mt between 2016 and 2020. Such a transition requires significant "sunset" support, where the decommissioning of GHG-intensive facilities is incentivized with policy and regulation to make way for new, low GHG capacity (Bataille 2020b). Highly discussed policies, such as carbon taxes, GHG emission reduction targets, market development incentives, and significant infrastructure development, should be paired with increased public climate awareness, the engagement of citizens, and firm-side innovation and investment to increase the certainty of sunset policy (Verrier and Strachan 2023).

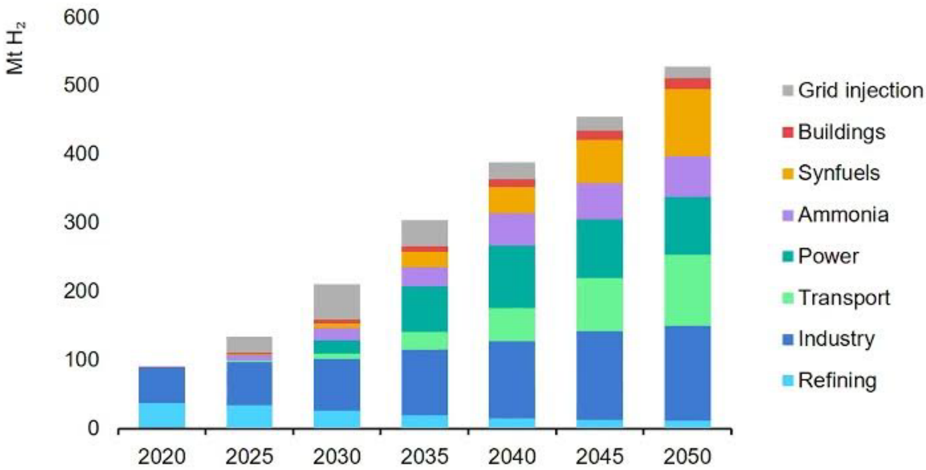
8. Opportunities and Barriers of Technology-Focused Approaches: Hydrogen and CCS

8.1. Hydrogen

Hydrogen can be used as an energy carrier, as a fuel, or for energy storage. It is already deployed in some industrial processes such as oil refining and ammonia production, and, to a lesser extent, in transport. Since 2000, hydrogen production has increased by nearly 50 percent. Its use is primarily dependent on production from hydrocarbons—76 percent through methane and 22 percent by coal gasification, mainly in China, while 1 percent is coupled with CCS, producing blue hydrogen (IEA 2021a). In 2021, out of 92 Mt of produced hydrogen, only 1 Mt was low-carbon hydrogen, a combination of its blue and green types (IEA 2021a). Currently, nearly one-third is produced for oil refining, about 25 percent is used in ammonia production (IRENA 2019), and less than 0.1 percent for fuel-cell electric vehicles (EVs) (IEA 2019c). As a decarbonization option, hydrogen can be used for fuel cells, reciprocating engines in transport, and gas burners and feedstock in industry (Schmidt and Staffell 2023).

There are two main considerations for the future scale-up and deployment of hydrogen. The first is whether the technology is commercialized and deployed at scale as a common "fuel" in industry, transport, and power sectors. The second is whether it can be produced with a zero-carbon "input," substituting carbon-based grey hydrogen, and, consequently, be utilized for decarbonization efforts in hard-to-abate sectors and for energy storage. Indeed, major Paris-aligned scenarios suggest the scaling up of hydrogen use. It is important to note, however, that estimates of hydrogen demand, which range from 240Mt to 1300Mt per year, vary significantly depending on modelling scenarios and related assumptions (Collett et al. 2022). Future demand for hydrogen requires consideration of carbon intensity and sound economics for a carbon-free type, rather than solely on the magnitude of its deployment and application (figure 14).

Figure 14. Global hydrogen demand by sector in IEA's Net Zero Scenario



Source: IEA 2021a.
Note: IEA = International Energy Agency; MtH_2 = megatonnes of hydrogen.

Low-carbon hydrogen

As the use of hydrogen as a fuel carrier has grown in prominence in decarbonization debates, so too has the issue of hydrogen typology. Consensus is often lacking between jurisdictions as to what constitutes low-carbon or clean hydrogen (Velazquez Abad and Dodds 2020). Overall, grey and blue hydrogen are produced from or powered by hydrocarbons, while green hydrogen is produced by water electrolysis powered by renewable energy or bioenergy (Collett et al. 2022; Robinius et al. 2022). Unlike grey hydrogen, blue hydrogen envisions installation of carbon capture to reduce GHG emissions; thus, it is often considered "low-carbon" hydrogen. Some studies also propose to include "clean" hydrogen that is produced by nuclear power (Naterer et al. 2008).

Currently, blue hydrogen accounts for only 1 percent of hydrogen production (Global CCS Institute 2021). The only commercialized technology of blue hydrogen is MDEA (methyldiethanolamine), with a carbon capture efficiency of 56 percent for 53 USD/tCO_2 avoided (Lyons, Durrant, and Kochhar 2021). A near-term potential alternative for blue hydrogen production can be MEA (monoethanolamine), which has a much higher carbon capture rate of 90 percent but higher abatement costs at 79 USD/tCO_2 avoided (Lyons, Durrant, and Kochhar 2021).

Currently, less than 0.5 percent of hydrogen is produced by water electrolysis powered by renewables (IEA 2021a). There is uncertainty about the costs, which range from 2.5 USD/kg to 10 USD/kg in different studies (Collett et al. 2022; IEA 2019c). Further scale-up of green hydrogen depends largely on developments in electrolyzers and conversion efficiency (Rissman et al. 2020). It is also contingent upon renewable electricity costs, which are considered to have a significant impact, ranging between 30 percent and 60 percent of the total cost (Collett et al. 2022).

Economics of hydrogen production

Hydrocarbon-based grey hydrogen, at least before the 2022 energy crisis, has been much cheaper than other options of producing hydrogen. The cost was 1.3 EUR/kg, compared with blue hydrogen at 1.7 EUR/kg and green hydrogen at 4.7 EUR/kg, Khatiwada, Vasudevan, and Santos (2022) report.

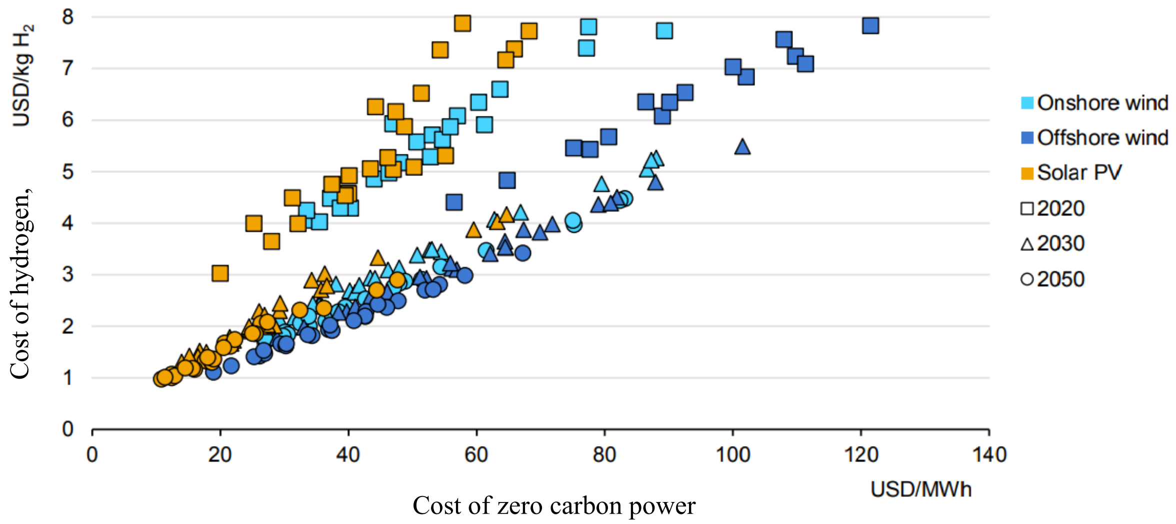
The comparative economics will, of course, depend on fossil fuel prices, dependence on the availability of industrial hubs for production, on-site consumption and transportation, and carbon pricing, while the add-on costs of CCS for "blue" hydrogen will depend on cost realization of CCS (Powell 2020; Schmidt and Staffell 2023). Other assessments observe that green hydrogen, despite being more expensive on average, has cost estimates at the low end similar to estimates of blue hydrogen at the high end (Collett et al. 2022).

One of the main barriers of the early deployment stage of electrolyzers are high capital costs. These costs are expected to decline with scale and technology maturity by 2030 (Schmidt and Staffell 2023). Water electrolysis will increase electricity demand that must be met by the deployment of renewables, even off-grid. It will also need sufficient fresh water supply, which should be a consideration in certain geographic regions (Rissman et al. 2020). Production of electrolyzers for large-scale deployment of green hydrogen, and their projected declining costs, can also spill over into the power sector, reducing power costs for storage (Schmidt and Staffell 2023).

Given the cost reductions in renewables and greater learning potential, notwithstanding current uncertainty (IEA 2019c), BloombergNEF (2020) project that costs for green hydrogen will be fully competitive with costs of blue hydrogen in 2030, and to outcompete blue hydrogen by 2050. The 2050 projection is consistent with costs projected by Collett et al. (2022), which range from 0.9 USD/kg to 1.6 USD/kg by 2050, compared to 1.4 USD/kg to 2.9 USD/kg for blue hydrogen with natural gas. In this case, blue hydrogen facilities could become stranded assets.

The cost and competitiveness of green hydrogen will depend on geography. Green hydrogen can be cheaper in areas with abundant wind and solar energy potential, and sufficient water for electrolysis, if financing costs can be well addressed in those middle-income countries. Future hydrogen costs are expected to be lowest (< 2 USD/kg) around North and South Africa, the Middle East, China and India, and southern South America, concentrated around Chile (IEA 2019c). This relationship between hydrogen costs and renewable costs is displayed in figure 15. By 2050, the cost of green hydrogen production is expected to fall to between 1 USD/kg and 3 USD/kg depending on the electricity price from renewables, with cost ranges decreasing through time. Such capacity can be off-grid, reducing system costs that otherwise occur when VREs are integrated into the power grid, but incurring costs for storage requirements (Janssen et al. 2022).

Figure 15. Hydrogen production cost as a function of renewable electricity costs for solar and wind, 2020, 2030, 2050



Source: IEA 2021a.
Note: Points represent production in different regions, taking local resources into account. Zero carbon power means that no carbon is being emitted from production of power. PV = photovoltaics; USD/kgH_2 = US dollars per kilogram of hydrogen; USD/MWh = US dollars per megawatt hour.

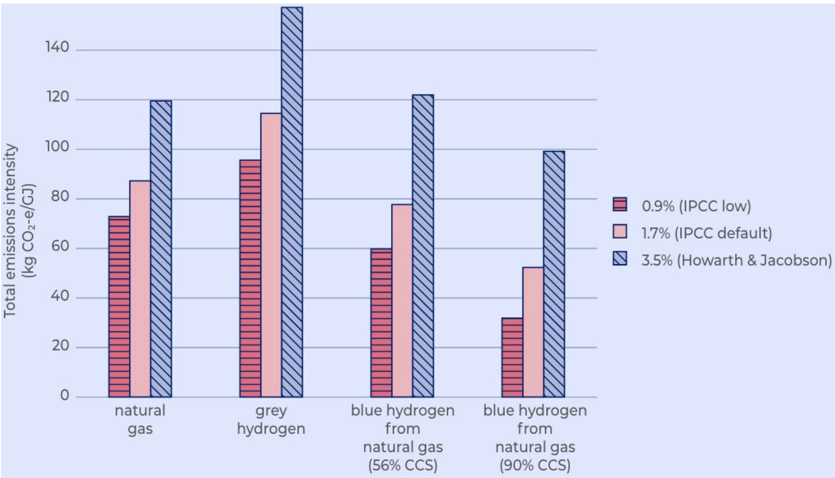
Other key sensitivities include transportation and storage uncertainties—most of current hydrogen is consumed on site, while only 15 percent is transported by trucks or pipelines (IEA 2019c). A "hydrogen economy" will require ambitious transformation and significant investment in logistics toward long-distance transportation at scale (Rissman et al. 2020), adding to the consumption costs. Debate continues about the scope for converting existing gas networks for hydrogen transportation (Ekhtiari, Flynn, and Syron 2020; Pellegrini, Guzzini, and Saccani 2020); others suggest that existing high-pressure infrastructure is unsuitable for the transportation of hydrogen (Dodds and Demoullin 2013; Rissman et al. 2020), with leakage and issues outlined further later in this section. Thus, further scale-up of hydrogen infrastructure will require technical improvements. Alternatively, such considerations may also make off-grid and on-site production and use of green hydrogen more attractive, as current consumption patterns demonstrate. Considerations between grid-connected or decentralized hydrogen production will need to be analyzed on a country-by-country basis. With regard to India's ambitious hydrogen production aspirations, evidence suggests that grid connectivity has benefits of lower energy costs, reduced curtailment of renewables, and lower energy demand for a new generation (Cesaro et al. 2023).

Sustainability of hydrogen

Pursuing Paris-aligned climate targets requires further interrogation of the environmental sustainability of hydrogen. While there are no questions about the emissions profile of grey hydrogen—the most emitting type, which is directly produced from hydrocarbons, blue and green hydrogen require further investigation. The previously discussed carbon capture rates do not account for life-cycle GHG emissions, especially in the upstream industry, thus reducing net capture of carbon (Howarth and Jacobson 2021).

The sustainability of blue hydrogen therefore remains questionable, for the same reasons as natural gas's role as a transition fuel—methane leakage. Estimates in the range of 0.9 percent to 1.7 percent leakage for hydrogen can double GHG emission profiles (Collett et al. 2022). This range is in line with estimates by Howarth and Jacobson (2021), who find that methane leakage of 3.5 percent leads to net GHG emission reductions of only 9 percent to 12 percent for blue hydrogen, a negligible advantage over grey hydrogen. They also find that the carbon footprint of blue hydrogen can be higher than that of natural gas burned for heat due to the energy penalty and associated GHG emissions—an important consideration for application in industrial processes. Blue hydrogen becoming a significant user of natural gas could stabilize global demand for liquified natural gas (LNG) (Al-Kuwari and Schönfisch 2022) and solidify a fossil fuel regime with high associated leakage and global warming potential. Defining sustainability criteria for low-carbon, carbon-free, and green hydrogen will be critical for sending strategic signals to investors. Figure 16 details the current emission intensity of each hydrogen type, drawing on the various estimates of methane leakage used by multiple sources.

Figure 16. Emissions intensity by hydrogen type



Source: Collett et al. 2022.
Note: The figure includes fugitive, process, and direct emissions of the 20-year global warming potential used for methane. Howarth & Jacobson refers to estimates in Howard and Jacobson (2021). CCS = carbon capture and storage; IPCC = Intergovernmental Panel on Climate Change; kgCO_2-e/GJ =kilogram of carbon dioxide equivalent per gigajoule.

8.2. CCS

The role of CCS has already been discussed in section 2, with a primary focus on the power sector. Here, the focus is more on CCS's role in industry.

As discussed earlier in this section, whatever progress is made with carbon-free electricity and low-carbon heat and electrification, decarbonizing so-called processing emissions (non-combustion emissions) remains challenging due to the technical specificity of processing certain materials (Paltsev et al. 2021). The most prominent option is CCS.

CCS for industry: Technology maturity and costs

Bui et al. (2018) review the technology readiness level (TRL) of carbon capture utilization and storage (CCUS) and conclude that most technologies are between proof of concept (TRL3) to demonstration (TRL7) stages (Figure 3). However, only a few have reached commercialization; these are natural gas-based CCS (TRL9) and charcoal BECCS (TRL10) (IEA 2020a). At the same time, Lyons, Durrant, and Kochhar (2021) suggest that some amine-based CCS technologies in ammonia and methanol, steel, and hydrogen have already reached TRL9. Such discrepancies in the assessment of CCS TRLs demonstrate both uncertainty about the actual stages of technology maturity and the pace of technology advancement, yet recent studies suggest that most CCS technologies might be commercialized after 2025 (Bui et al. 2018; Global CCS Institute 2022b; Lyons, Durrant, and Kochhar 2021). Currently, there are 24 commercially operated CC(U)S facilities globally, 11 of which are natural gas processing plants—that is, operating within the oil & gas industry, and 1 power plant. Another half are in industry—ethanol and blue hydrogen production, and steel production (Lyons, Durrant, and Kochhar 2021). This implies that although some CCS technologies have reached the high end of TRL, their deployment is still inadequate to assess their maturity and technology learning potential appropriately.

IEA (2020a) estimates that CCS increases production costs by 10 percent in steel, 60 percent to 95 percent in cement, and 20 percent to 40 percent in chemicals, and is cheaper than hydrogen-based options. In some cases, retrofitting with CCS can be a more economical option than replacing technologies with new low-carbon options. However, in others, CCS is not feasible due to the technical limitations of existing industrial facilities (Bui et al. 2018). In these instances, increasing energy efficiency and reducing energy consumption can be the most cost-effective approach in the short term (Bui et al. 2018). Overall, the costs of CCS in industry are very sector-specific and present a relatively wide range: 60 USD/tCO_2–160 USD/tCO_2 avoided for steel, and 40 USD/tCO_2–120 USD/tCO_2 avoided for cement (figure 17) (Lyons, Durrant, and Kochhar 2021).

As discussed in section 2, a review of several studies by Lyons, Durrant, and Kochhar (2021) concludes that CCS is not a plausible option in the power sector with respect to new renewable projects; however, its economics in industry seems much more plausible (figure 3), particularly for process emissions. For the latter, that means that, even though the costs of capture add to total production costs, they are often cheaper than avoided CO_2 emissions using carbon-free alternatives. This is also in line with the estimates of Fan and Friedmann (2021), who find CCS in steelmaking the cheapest BF-BOF retrofitting option, discussed further in this section. As shown in figure 17, despite the relative cheapness of CCS in industry, the avoidance cost per tonne of CO_2 is still large for industrial applications.

Figure 17. Avoidance costs of CCS for selected technologies

Source: Lyons, Durrant, and Kochhar 2021.
Note: BECCS = bioenergy with carbon capture and storage; CCS = carbon capture and storage; MDEA = methyldiethanolamin; MEA = monoethanolamine; NG = natural gas; NGCC = natural gas combined cycle; PCC = post-combustion capture; Pz/Amp = piperazine/amino-methyl-propanol; TGR-BF = top gas recycled blast furnace; USC = ultra-supercriticalv; $/t$CO_2$ = US dollars per tonne of carbon dioxide.

Sustainability aspects of carbon capture

The discussed cost ranges represent uncertainty related to CCS, which often depends on the specific site of the project and related CCS-technology costs, transportation costs, energy penalty and associated GHG emissions, and CO_2 volumes. The latter corresponds to different impacts on transportation costs depending on the industrial capacity size, potentially doubling them for small projects (Lyons, Durrant, and Kochhar 2021). Evidence suggests that feasibility studies often underestimate the high project costs, while uncertainty about potential learning rates is high due to low deployment levels (Lyons, Durrant, and Kochhar 2021). At the same time, the suggested cost range for industrial CCS can still provide cheaper alternatives to some emerging low-carbon technologies due to a lack of alternatives. Estimates of global warming potential (GWP) reductions range from 48 percent to 76 percent when industrial CCS is applied to a steel plant (Chisalita et al. 2019) and 39 percent to 78 percent when applied to cement facilities (Galusnyak, Petrescu, and Cormos 2022; Volkart, Bauer, and Boulet 2013).

Despite such improvements, concerns in other categories emerge from life-cycle assessment (LCA) studies regarding the cement industry, such as implications for toxicity potential, particulate matter, and land use potential (An, Middleton, and Li 2019; García-Gusano et al. 2015). Use in the steel industry also leads to energy-efficiency losses, which increases additional fuel demand and other related GHG emissions (Chisalita et al. 2019). The energy supply for CCS use is decisive for environmental impacts (Volkart, Bauer, and Boulet 2013)—a major limitation when supplied by fossil fuels as opposed to low-carbon electricity.

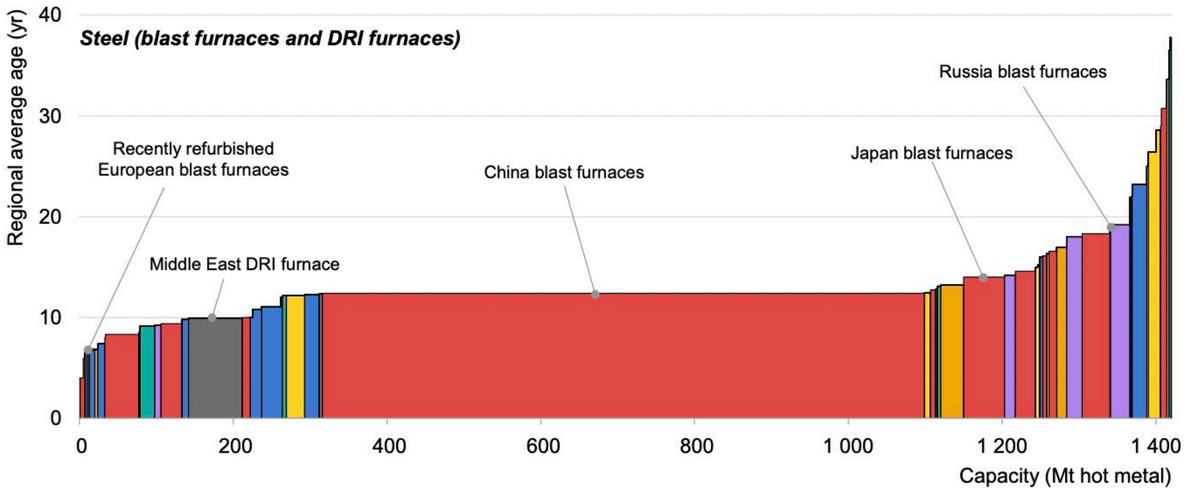
CCS's sustainability is also limited by current efficiency, which ranges from 80 percent to 95 percent, *before* accounting for upstream GHG emissions related to extracting and transporting fossil fuels, energy used for processing and transportation, and methane leakages, as well as potential leakages of captured CO_2 (Corsten et al. 2013; Lyons, Durrant, and Kochhar 2021). For CCS use to be aligned with Paris Agreement levels, stricter requirements are required. GHG emission capture level must be 90 percent to 95 percent, and fugitive emissions must be 0.5 percent of gas production emissions (Bataille, Khourdajie, et al. 2023). Despite such limitations, CCS will still likely play a role in sectors where, currently, there are less plausible options to abate GHG emissions, such as cement production. Paltsev et al. (2021) estimate that, due to this lack of alternatives, the global cost of reaching a 2-degree warming target may be higher by 12 percent by 2075 and 70 percent by 2100 when industrial CCS is not available. Political economy and inertia in some countries are likely to mean continuous use of fossil fuels, even if at a lower scale, or their slow phase-out (Lyons, Durrant, and Kochhar 2021).

Industrial processing emissions remain hard to abate due to limited technology options. Unlike CCS in the power sector, which directly competes with already cheaper new renewables projects, industrial CCS has no alternatives for reducing GHG emissions in some sectors, especially when for processing (non-combustion) emissions (Bui et al. 2018). The efficiency losses and increased demand for fossil fuels risk delaying low-carbon technology developments (Verrier and Strachan 2023) and further entrenching fossil fuel incumbency. Even more—the lack of commercial deployment of CCS still requires public subsidies to cushion investment risks, possibly crowding out investments into low-carbon fuel alternatives, as argued in section 2.

9. Application and Options for Decarbonizing Iron and Steel

This section explores the decarbonization options for iron and steel, discussing key technologies before assessing their economics and feasibility. Broadly, seven key groups, including more than 30 technologies, can foster the decarbonization of steel production: hydrogen-based options; electrolysis-based options; carbon capture utilization and storage (CCUS) with direct/smelting reduction; biomass-based options; BF improvement; carbon-free electric arc furnace; and low-carbon rolling technologies (P. Wang et al. 2021). An important issue to consider for these technologies is the age of existing fleets, a characteristic that plays into investment decisions surrounding whether to retrofit existing facilities, build new ones, or decommission old carbon-intensive ones. The current age of global steel facilities is visualized in figure 18. Facilities less than 15 years old dominate. The capacity of such young plants in emerging economies such as China is extensive.

Figure 18. Age of steel plant by region and capacity



Source: IEA 2020a.
Note: DRI = direct reduced iron; Mt = megatonne.

9.1. Economics of technology options in steel: Hydrogen, electricity, and CCS

Hydrogen can be used to supplement heating fuels that currently produce significant combustion emissions, by substituting coke and reducing the associated carbon monoxide. With minor retrofitting requirements, GHG emission reduction potential of 21 percent in BFs can be accessed (Fan and Friedmann 2021). However, the existing blast furnace fleet responsible for more than 70 percent of steel GHG emissions has limited technical capability of switching to hydrogen (Lyu et al. 2017). No more than 10 percent of blast furnaces can be feasibly altered, due to technical constraints (Fan and Friedmann 2021). In contrast, nearly 30 percent of gas DRI furnaces can be substituted with hydrogen without significant changes, and 100 percent replacement from gas to hydrogen is possible (Fan and Friedmann 2021).

Gas-based DRI and hydrogen-based DRI (H-DRI) depend on the cost of energy carrier—gas or hydrogen, respectively; and electricity for EAFs (Lyons, Durrant, and Kochhar 2021). Thus, H-DRI will have higher costs relative to gas-based DRI or BF without sufficient carbon pricing unless electricity prices are low enough to produce cheap hydrogen. The long-term competitiveness of hydrogen-based DRI-EAF will require access to cheap electricity, estimated at a level of 30 USD/MWh–50 USD/MWh (Lyons, Durrant, and Kochhar 2021; Rissman et al. 2020). Grey hydrogen-based DRI can become competitive even at higher electricity price levels at 50 USD/MWh. In the current market environment, however, it is still contingent upon carbon pricing, estimated in the range of 40 USD/t CO_2–75 USD/t CO_2 (Rissman et al. 2020). Electricity prices have the opportunity to hit this level, provided renewable electricity costs keep decreasing.

A more comprehensive study by Fan and Friedmann (2021) provides cost and emission data generated to estimate different steel technology options. For blast furnaces, they find that fuel switching to blue hydrogen at a production cost of 1.9 USD/kg increases steel production costs by 53 USD/t and requires a carbon price of 120 USD/tCO_2, and green hydrogen at cost of 5.5

USD/kg increases steel production costs by 153 USD/t, requiring a carbon price of 300 USD/tCO_2. In the DRI route, hydrogen competitiveness depends on the cost of electricity and natural gas. The marginal CO_2 abatement cost of 120 USD/tCO_2 of blue hydrogen is approaching a feasible level for a carbon price. With green hydrogen expected to reach parity with this level by 2030, before further cost reductions through to 2050 (Collett et al. 2022), the projected high cost increases to steel are likely to fall, with carbon pricing a potentially effective measure for incentivising.

A necessary consideration in the decarbonization of steel is electrification based on low-carbon power. Ren, Zhou, and Ou (2023) find that H-DRI can provide 62 percent GHG emission savings for the Chinese steel industry when life-cycle GHG emissions are considered, and is contingent upon the development of the entire hydrogen supply chain and decarbonized electricity. The already achieved level of electricity decarbonization in the EU can offer more than 35 percent GHG emission reduction in the steel industry by coupling H-DRI with EAFs (Bhaskar, Assadi, and Somehsaraei 2020), if green hydrogen can be deployed at scale. Such GHG emission reduction, compared to the high estimates of 80 percent to 97 percent reported by Bailera et al. (2021), Fennell et al. (2022), and R. Wang et al. (2021), show the influence of grid carbon intensity on industrial decarbonization. Renewable energy is therefore instrumental, both to power EAFs and to create green hydrogen. Policy supporting low-cost, low-carbon electricity is key to industrial decarbonization (Wei, McMillan, and de la Rue de Can 2019). Investment in overcapacity for steel production units and energy storage systems for hydrogen and hot briquetted iron (HBI) is also recommended if coupled with variable renewables, so production can follow intermittent electricity supply (Toktarova et al. 2022).

In the case of CCS, Bui et al. (2018) find that amine-based post-combustion capture (PCC) in steel BF can cost between 65 USD/tCO_2–119 USD/tCO_2 with a capture efficacy of 50 percent to 55 percent, while oxy-fuel top gas recycled (TGR) BF can capture 65 percent in the range of 54 USD/tCO_2–88 USD/tCO_2. Lyons, Durrant, and Kochhar (2021) conclude that amine-based PPC for retrofitted plants could cost 80 USD/t–160 USD/t of avoided CO_2 with an TGR BF at 57 USD/t of avoided CO_2, with a capture rate of 90 percent. Applying either CCS option depends on the facility. Amine-based PCC is more suitable for retrofitting existing steel plants, while TGR is better for new plants due to its lower costs and capture efficiency (Bui et al. 2018). Currently, fewer CCS projects are in the pipeline for iron and steel than for cement. Only 3 projects, none of which are commercial, are in development to add to the current 5 operating plants (Lyons, Durrant, and Kochhar 2021).

9.2. Comparison of technology options in steel

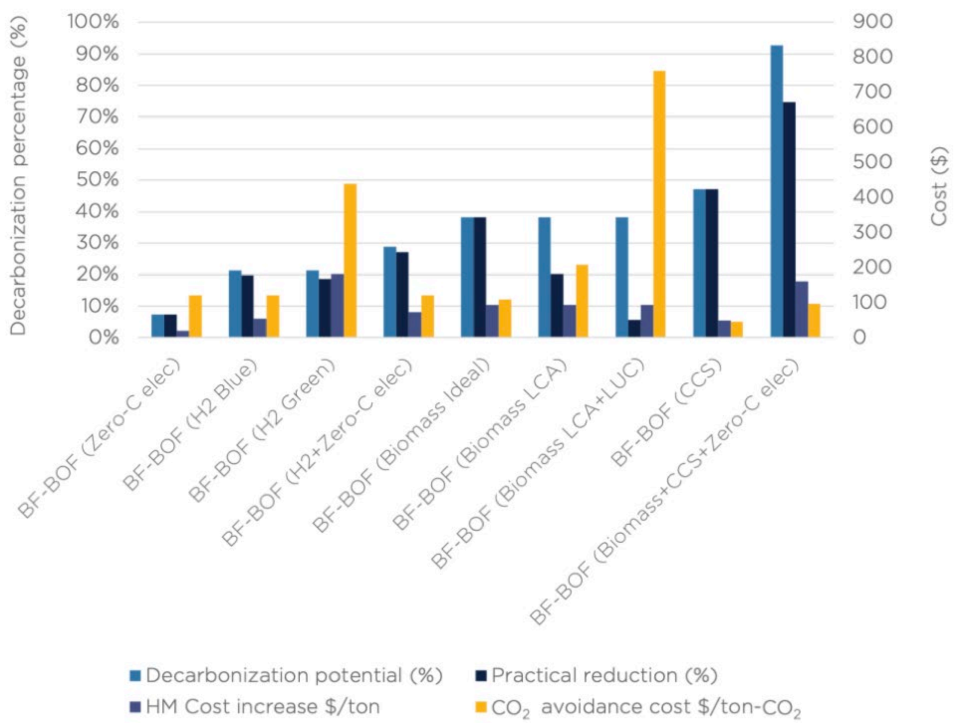
Fan and Friedmann (2021), when comparing different decarbonization options (apart from biomass-based) for existing BF-BOF technologies, conclude that the lowest-cost option, with respect to CO_2 avoidance cost, is the retrofitting of current plants with CCS (figure 19). Carbon-free electrification has more than double the avoided CO_2 emission cost, with a low impact on decarbonizing BF. The cost range is similar for retrofitting BF with blue and grey hydrogen, in combination with carbon-free electricity, with the latter option offering higher decarbonization rates. The green hydrogen option in BF triples abatement costs to nearly 500 USD/tCO_2

avoided while having a similar decarbonization efficiency to blue hydrogen. Apart from when BF-BOFs are combined with biomass, CCS, and electrification, the decarbonization potential of BF-BOF options remain lower than 50 percent, though biomass contribution is marginal when LCA and land use change are taken into account.

Specifically, as seen in figure 19, the contribution of biomass to the theoretical 40 percent of emission reduction decreases to the practical level of 10 percent when a life-cycle assessment (LCA) approach is used, and again when land use change (LUC) is considered. This reduction is due to multifaceted challenges of bioenergy, including sufficiency of supply, sustainability of sourcing and transportation, and competition with food production, as discussed in section 2. However, some studies suggest that using biomass in industry is a more plausible option than in the power sector because it can offer many alternative carbon-free technologies (Fan and Friedmann 2021).

Due to the limited scope for GHG emission reductions in BF-BOF technologies, the goal of deep decarbonization in iron and steel will require alternative production technologies. However, these estimates are particularly relevant to the context of middle-income countries, where young fleets of BF-BOFs have recently been commissioned. Here, pragmatic decisions regarding retrofitting or early decommissioning must occur, and future investment decisions into BF-BOFs must be carefully considered.

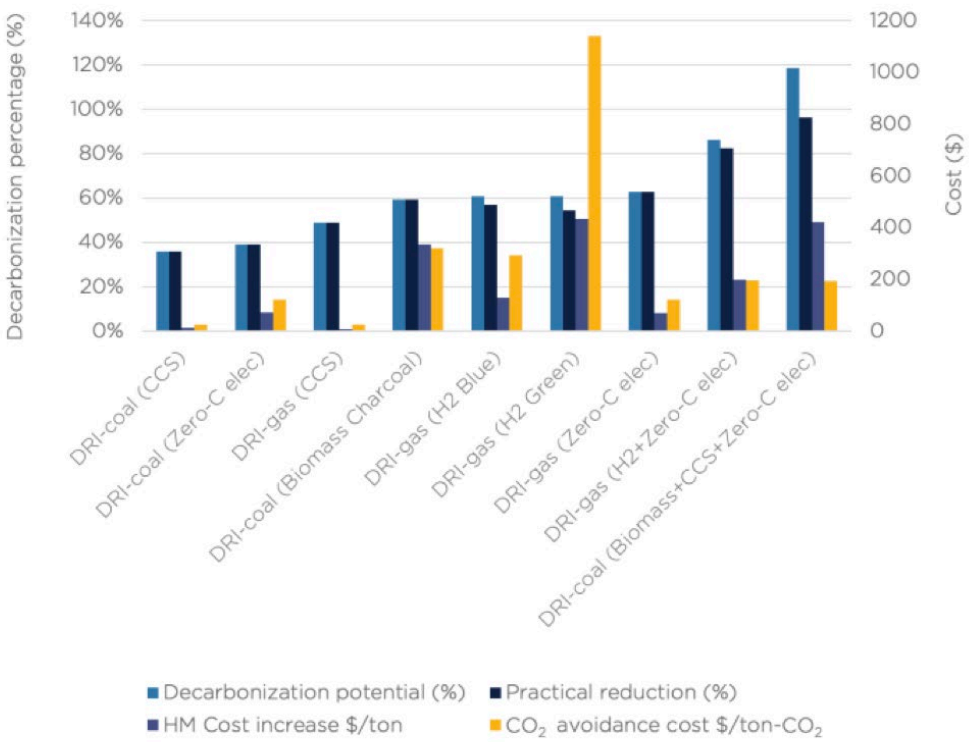
Figure 19. BF-BOF decarbonisation technology options costs



Source: Fan and Friedmann 2021.
Note: The figure provides four meaningful statistics when analyzing decarbonization technologies for iron and steel. The purple(ish) bar shows the increase in cost of hot metal (HM) produced once the technology is adopted. The yellow bar shows how expensive each ton of carbon dioxide (CO_2) avoided is because of the investment. The first two blue bars convey the difference between theoretical emission reductions (light blue) and realistic emission reductions (dark blue). BF-BOF = blast furnace-basic oxygen furnace; CSS = carbon capture and storage; H2 = hydrogen; LCA = life-cycle assessment; LUC = land use change: Zero-C = zero carbon.

In the case of DRI decarbonization options, more significant decarbonization potential is possible. CCS when applied to coal-fueled DRI is the cheapest option with respect to cost of tCO_2 avoided in this instance. Carbon-free electrification is estimated to be much more expensive—almost quadrupling to near 180 USD/tCO_2 avoided (figure 20). When using gas-based DRI, the blue hydrogen pathway cost without electrification reaches almost 380 USD/tCO_2; however, this decarbonization rate is very similar to that of the pathway of gas paired with carbon-free electricity, which is almost twice as cheap. The best decarbonization efficiency in DRI includes a combination of hydrogen and zero-carbon electricity. Due to current high costs, green hydrogen is the most expensive, at more than 1100 USD/tCO_2. The conclusions about CCS cost-effectiveness are in line with those of Lyons, Durrant, and Kochhar (2021), while Bataille (2020a) emphasizes that higher volumes and quality of steel recycling, alongside CCS for existing BF-BOFs, will be critical for retrofitting the existing stock. However, boundaries on decarbonization at about 50 percent when installed individually persist.

Figure 20. DRI decarbonisation technology options costs



Source: Fan and Friedmann 2021.
Note: CSS = carbon capture and storage; DRI = direct reduced iron; H2 = hydrogen; Zero-C = zero carbon.

The reviewed studies suggest that in terms of technology, hydrogen has a role to play in decarbonizing iron and steel production, with a carbon reduction rate between 60 percent and 80+ percent depending on the boundaries applied to life-cycle assessments. However, the current policy landscape makes it less financially viable than alternatives such as low-carbon electricity or CCS. In the DRI route, the highest abatement potential lies in the technology mix of hydrogen and carbon-free electricity, the most mature low-carbon option, which can capture up to 80 percent of CO_2 (Fan and Friedmann 2021). When analyzing options for the large fleet of young BFs, there is a more limited role for hydrogen, with a decarbonization rate of up to 20 percent, compared to CCS at nearly 50 percent. The difficulty of achieving deep decarbonization in the BF-BOF fleet implies that such a pathway has significant carbon lock-in. Even with the aggressive use of technologies (figure 19)—each of which possesses its own barriers, options are limited (Fan and Friedmann 2021). BF-BOF capacity constructed now will be a potential emitter for 40+ years in a world that must be approaching net zero, highlighting the urgent need for policy attention (Fan and Friedmann 2021), and the serious risk inherent in any further investments into BF-BOF plants.

There is no single route to decarbonization. A combination of solutions should be adopted: CCS, hydrogen, and carbon-free electricity in different combinations depending on processing routes, plant specific locations, and economics (Lei et al. 2023). At the same time, unlike in the power sector, all steel decarbonization options are likely to lead to cost increases. To begin, these will be in the form of large capital investments. For example, the CAPEX of a H-DRI plant is estimated to be 574EUR/tonne—30 percent higher than for an integrated BF-BOF plant, with electrolyzers and EAFs contributing significantly to such costs (Vogl, Åhman, and Nilsson 2018). Therefore, policy intervention is needed to create a level playing field and incentivize investments in low-carbon steel that otherwise will likely remain an uncompetitive industry in the coming decade or two(Fan and Friedmann 2021). The choice of options also depends on investment scales. Given the capital intensity of steelmaking, a likely near-term pathway is incremental retrofits. Such retrofits, however, are associated with inertia and long lead times, unless salient policy intervention is in place, such as a carbon border adjustment mechanism (CBAM), support schemes, or regulatory standards (Fan and Friedmann 2021). Domestically, support policies may include grants, feed-in tariffs, tax credits, and green procurement and public investments in research and development.

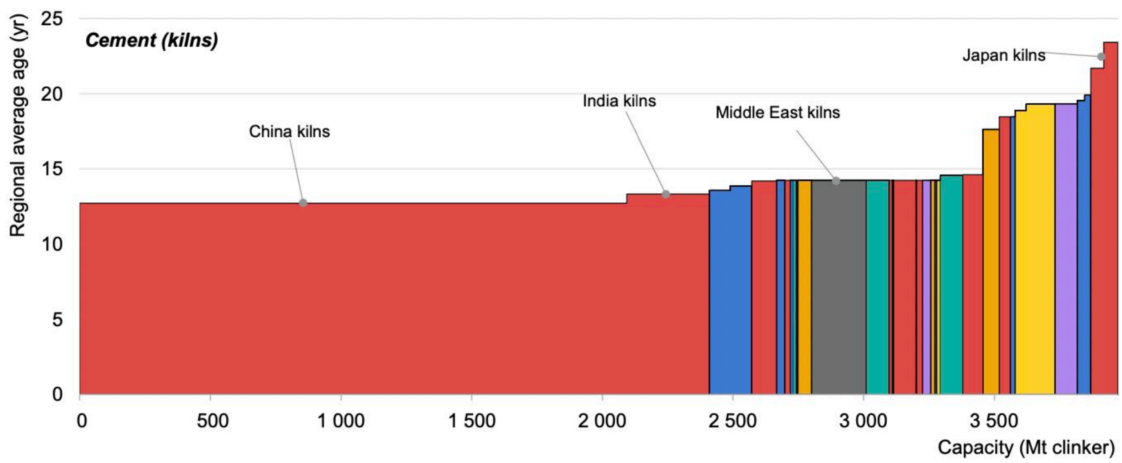
After investing in hydrogen-based direct iron ore reduction (H-DRI), the cost of producing hydrogen is crucial for the cost of low-carbon steel. The electrolyzer uses 70 percent of the total energy consumed in the hydrogen-based direct iron ore reduction with the electric arc furnace (H-DRI-EAF) process (Bhaskar, Assadi, and Somehsaraei 2020), with the price of renewable electricity estimated to determine 30 percent to 60 percent of the cost of green hydrogen (Collett et al. 2022), potentially rising to 80 percent with recent electricity prices (UKERC 2022). Bhaskar et al. (2022) find that electricity cost has the single largest influence on the cost of H-DRI-EAF produced steel in Norway. Vogl, Åhman, and Nilsson (2018) conclude that an electricity price of 40 EUR/MWh and a carbon price in the range of 34 EUR/tonne CO_2–68 EUR/tonne CO_2 are required to make H-DRI cost competitive with an integrated steel plant; at this level, electricity represents 32 percent of production costs. Bailera et al. (2021) similarly conclude that 40 EUR/MWh electricity price and a carbon allowance of 60 EUR/tCO_2 are needed. While highly influential, both the costs of electrolyzers and renewable electricity are expected to fall significantly, as discussed in section 8, and policy support to facilitate this must continue.

The priority of near-term decarbonization will require reducing GHG emissions from the coal-fueled BF-BOF processing routes that represent 70 percent of steel production. Short-term options require retrofits, either by CCS (Lyons, Durrant, and Kochhar 2021), altering process routes (Lei et al. 2023), or early decommissioning of the most inefficient plants, especially in China (P. Wang et al. 2021). When assessing options for existing BF-BOFs, without changing processing routes, CCS emerges as a low-cost technology (Fan and Friedmann 2021), but concerns around the realistic scale-up and commercialization of CCUS persist. Lei et al. (2023) map and model global steel plant retrofits by altering process routes. The prescribed retrofit depends on the current technology employed by the plant, its retrofit history, and its age. Options include replacing a BF-BOF route to natural gas-based DRI or a short-processing scrap-based EAF plant, as well as the use of CCUS technologies. Key to this process is wide array of retrofit options, dependent on inherent and local characteristics of plants. In the near term, the improvement of scrap recycling and collection systems is recommended. In the medium to long term, the adoption of deep decarbonization technologies is required (Bataille 2020a), such as H-DRI and EAF (Lyons, Durrant, and Kochhar 2021), CCUS (Fan and Friedmann 2021; Lei et al. 2023), and electrolysis of iron ore (Rissman et al. 2020). Another key finding is that if capacity is retrofitted 5 years earlier than planned, almost double the CO_2 emissions of 2021 can be avoided between 2020 and 2050 (Lei et al. 2023). Currently, 57 percent of global plants lie in the retrofitting window (8–24 operational years). Crucially, each unit will need to be assessed individually, with optimal response varying between plants.

10. Technologies for Decarbonizing Cement

Due to the prominence of process emissions in cement production, the number of technologies available to facilitate decarbonization is more limited than in steel. This section further discusses options such as CCS for process emissions and fuel switching for combustion emissions. The stock of existing plants is important to consider in the global decarbonization of cement. The relatively young age of facilities (less than 15 years old) and dominance of emerging economies such as China and India can be seen in figure 21.

Figure 21. Age of cement plant by region and capacity



Source: IEA 2020a.
Note: Mt = megatonne.

10.1. CCS

CCS is likely to play a more significant role in cement than in steel, due to the greater variety of options in the latter (Lyons, Durrant, and Kochhar 2021). Pre-combustion carbon capture in cement production is the least effective, with a rate of 33 percent; however, it can be a feasible option for new kilns. At the same time, PCC and oxycombustion are more suitable for retrofitting existing stock of cement plants, which generally operate between 30 and 50 years. These two technologies can play a significant role in middle-income countries, where the youngest fleet of production facilities is located (IEA 2020a). Different CCS options in cement production present various challenges related to production quality, shutdown periods, space requirements, and energy penalties (Lyons, Durrant, and Kochhar 2021), and most of those options are still in the pilot or demonstration stages. Therefore, considerable uncertainty remains concerning these challenges and the relative feasibility of options. Currently, 3 cement CCS projects operating, 2 of which are commercial, and 9 projects are in various stages of development (Lyons, Durrant, and Kochhar 2021).

A review of literature by Lyons, Durrant, and Kochhar (2021) summarizes capture rates, energy penalties, and costs for crucial CCS technologies in cement production based on numerous studies (De Lena et al. 2019; Hills et al. 2016; Hills, Sceats, and Fennell 2019). Post- and oxy-combustion capture technologies have 90 percent efficacy of CO_2 capture. The cheapest option is oxy-combustion, with costs of 44 USD/tCO_2–46 USD/tCO_2 avoided; however, the retrofitting process is more complex, and the energy penalty is high. Yet, significant uncertainty remains as the technology is still at TRL4 and is likely to become commercial after 2040. Amine-based PCC is the most mature (TRL6-8), with prospects of commercialization after 2025. It has the lowest requirements for retrofitting, but the highest capture costs at 63 USD/tCO_2–94 USD/tCO_2 avoided, and the energy penalty is also high. Calcium looping PCC is a technology in the early development stage (TRL 3-6), although its prospect for commercialization after 2025, with costs at 68 USD/tCO_2–84 USD/tCO_2 avoided, is about 10 percent cheaper than amine-based PCC. Leeson et al. (2017) model an 80 percent deployment rate across the cement industry through to 2050. They find that 6.9Mt of GHG emissions can be mitigated by 2050 for a total cost of $191.3 billion and an average cost over the modelling period of 27 USD/tCO_2 avoided. These results reflect an expected cost decrease in the technology as deployment ramps up. A novel technology for new plants can be direct separation; it has an efficacy of 95 percent for capturing processing GHG emissions, but does not abate combustion emissions (Lyons, Durrant, and Kochhar 2021). Overall, there is a broad consensus in the literature suggesting that abating industrial GHG emissions in cement production will likely depend on CCS. The availability of CCS across all industrial sectors is crucial. A scenario without CCS increases costs by 70 percent for a 2-degree target by 2100 (Paltsev et al. 2022).

10.2. Other options

Although CCS seems to have the most significant decarbonization effect on non-combustion emissions in cement production, significant barriers to commercial deployment remain (Budinis et al. 2018; Kazemifar 2022). Elements of carbon capture technologies have low

TRLs, and only one commercial storage facility has been completed (Kearns, Liu, and Consoli 2021). Accelerated deployment of projects and demonstrations, research, and increased assessment of life-cycle GHG emissions, are required before commercialization can be achieved. This may take another 5 to 10 years (Bui et al. 2018; Lyons, Durrant, and Kochhar 2021). The discussion that follows therefore explores additional options for the cement industry for the near term.

Fossil fuel combustion accounts for nearly 40 percent of cement GHG emissions that come from heating. There are fewer estimates of decarbonization in the literature for this source of emissions, combustion emissions can be a more viable target in the near term with adequate support policies. Several options exist, including waste-derived fuels, electrification, biomass and hydrogen (Mineral Products Association 2019). IEA (2023a) suggests that decarbonization of thermal energy in the sector can reach 20 percent by 2030 in the Net Zero Emissions (NZE) Scenario, primarily using bioenergy and biowaste, with only 2 percent allocated to hydrogen. Therefore, the current research evidence suggests that hydrogen is likely to play a very marginal role in decarbonizing cement production.

A variety of alternative decarbonization options also utilize electrification, such as indirect electrification through oxy-combustion, using oxygen as a byproduct of green hydrogen production, and combining direct electrification with alternative fuels (Quevedo Parra and Romano 2023). With an electricity price of 50 EUR/MWh, these partial electrification strategies have a cost of 101 EUR/tCO_2 avoided (Quevedo Parra and Romano 2023). The competitiveness of alternative fuel routes will depend on fuel prices and capital costs. Concerns exist around the high cost and complexity of hydrogen-driven kilns (Fennell, Davis, and Mohammed 2021). The downstream GHG emission of fuel carriers must also be considered; the production of electricity, and hydrogen, is again crucial for the sustainability of industrial strategies. Two main options can reduce reliance on expensive investment into CCS technologies; the increased use of low-CO_2 substitutes as partial replacement for Portland clinker, and the more efficient use of cement clinker in mortars and concrete (UN Environment et al. 2018). Improvements in the efficiency of the cement content in concrete and the clinker content in cement can be significant if the whole industry is required to adopt such measures. Technological advancements in alternative cements and CCS are likely essential for long-term sustainability (Habert et al. 2020).

11. Part B Conclusion: Implications for Middle-Income Countries and Financing

The future adoption of low-carbon technologies, such as H-DRI furnaces or CCS, could dramatically change the cost profile of industrial products compared to traditional processing routes (IEA 2020a). For steel, green hydrogen and electricity costs significantly contribute to production costs, which, globally, will vary given the availability of cheap renewable energy resources (Collett et al. 2022). Due to such disparities, as well as the costs incurred when transporting hydrogen, the global order of steel trade has the potential to shift. Future H-DRI-EAF production facilities are faced with decisions regarding full domestic production, the import of hydrogen, the import of low-carbon hot briquetted iron (HBI) for domestic EAF production, or simply the import of low-carbon crude steel (Lopez et al. 2023).

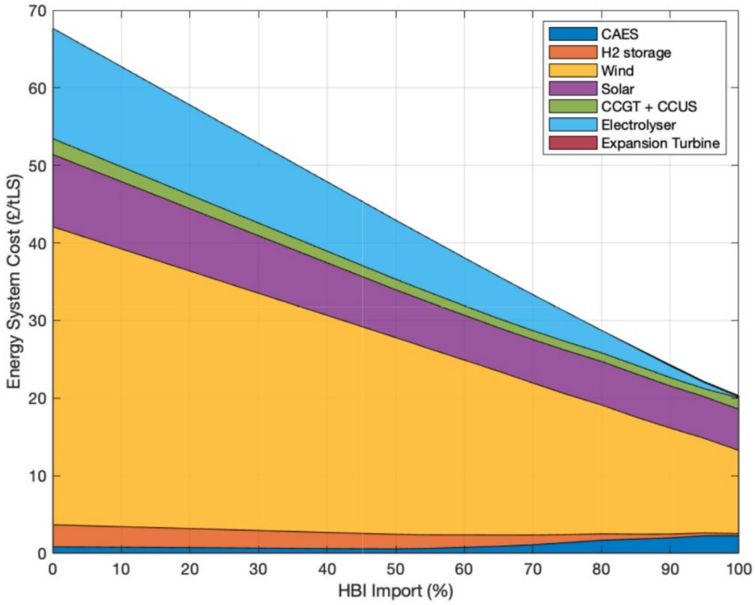
Such a production line may be faced with a trade-off similar to that depicted by figure 22, showing the estimated system capital cost of zero-carbon steelmaking in the United Kingdom, where the optimal response will depend on import costs of HBI compared to more intensive use of domestic renewable resources. Currently, iron ore export is led by countries such as Australia, Brazil, and South Africa, with Ukraine and India also possessing significant reserves. Imports are mostly dominated by China (Holmes, Lu, and Lu 2022). A potential for a shift toward trade in HBI, rather than ore (and finished steel) exists, and may persist if domestic extraction in such countries can be paired with cheap renewables to produce low-carbon iron exports.

Domestic policy that incorporates industrial decarbonization is thus also likely to influence global trade and the distribution of emissions globally. The near-term costs associated with decarbonizing industry influence global competitiveness, and may cause emissions to be offset to countries without carbon controls—a process known as carbon leakage (Babiker 2005). Metals and cement are known as emission-intensive trade-exposed (EITE) products in which leakage is a significant risk, and domestic policy may therefore also require consideration about international competitiveness (Grubb et al. 2022). Accordingly, EITE sectors have historically been left out of schemes using strong incentives such as carbon pricing (Grubb et al. 2022), and there is currently a lack of incentives for industry to invest due to concerns about global competitiveness (Warren 2020).

To achieve deep decarbonization in industry, policy attempts must address carbon leakage. In industrialized countries, one trend is toward low-carbon subsidies at scale. The US Inflation Reduction Act aims to decarbonize industry, including CCS and hydrogen development, with a huge subsidy program. The EU has also in part been moving in this direction, albeit in a smaller and more targeted way. For example, "carbon contracts for difference" are being developed to support low-carbon industrial investments by directly paying the difference between the cost of low- and high-carbon production, in terms of the carbon saved.

Internationally, economic policy debate has largely focused on cross-border charging mechanisms, which aim to charge a carbon price on imported products whose production-related emissions have not been taxed at the same level as the domestic territory (Bellora and Fontagné 2023). The most prominent example is the EU's plans to enact a carbon border adjustment mechanism (CBAM) on carbon-intensive products, such as steel, cement, hydrogen and some electricity, imported to the European Union across the entire region. The enactment of such policies has also raised equity and distribution concerns. Many developing economies have more than 2 percent of their exports exposed to impacts from the EU CBAM (Magacho, Espagne, and Godin 2024). Without adequate support for adverse impacts, such as using revenues for technology transfer or climate finance, or making specific exemptions (Lowe 2021), the jobs, tax revenues, and export revenues associated with carbon-intensive exports would be lost (Lowe 2021), rather than being transferred into low-carbon options.

Figure 22. Capital cost breakdown of optimal energy system to power H-DRI-EAF steelmaking in the United Kingdom



Source: Pimm, Cockerill, and Gale 2021.
Note: The figure examines zero-carbon steelmaking with hydrogen-based direct iron ore reduction with the electric arc furnace (H-DRI-EAF) in the United Kingdom. It assumes a 50 percent scrap charge, based on UK renewable resources, and hot feed of non-imported direct reduced iron (DRI) to electric arc furnaces (EAFs). CAES = compressed air energy storage; CCGT = combined cycle gas turbine; CCUS = carbon capture utilization and storage; HBI = hot briquetted iron. £/tLS = British pounds sterling per tonne of liquid steel.

The end of Part A presented the economics of low-carbon electricity and many electrification-related processes in terms of the diverging valleys of different technological systems. It is increasingly clear that low-carbon systems are not necessarily any more expensive than high-carbon systems. At best, this is less clear for industrial processes and associated utilization of hydrogen and CCS. In these areas, the uncertainties (and potential added costs) are still much higher and there are much greater complications arising from trade. Yet time is short and the risk and cost of stranded assets is growing with each new carbon-intensive plant constructed—while it is clear that alternative pathways, at minimum, require far more upfront investment, and at present, technological risk.

The inevitable investment requirements of near-term industrial decarbonization in middle-income countries are estimated at $10 billion per year on average between now and 2050 globally for both steel and cement (ETC 2023). That leads to discussion around how this investment will be financed or incentivized, and by who. In the international climate finance arena, donors are often risk averse. They tend to focus more on proven sectors such as renewables (Warren 2020) because the requirements for first-of-a-kind technologies, business models, and high capital intensity make it difficult to secure investment (ETC 2023). Current non-fossil fuel targets in many middle-income countries, such as India, depend on receiving such low-cost international climate finance and technology transfers (Paltsev et al. 2022).

However, very little overlap currently exists between climate finance and hard-to-abate sectors in developing countries, with a need to increase transfers for the deep decarbonization of heavy industries (Warren, Frazer, and Greenwood 2023). Grant support for R&D and demonstration projects, support for pilot projects, and technical assistance activities are all important for incentivizing climate finance flows to industry (Warren 2020). Another important mechanism is advanced market commitments, where a government or donor provides procurement guarantees or subsidies to reduce the risk of investment into capital-intensive products and attract private investors (Warren, Frazer, and Greenwood 2023). Importantly, this mechanism assumes sufficient international climate finance, but pledges have fallen short of agreed levels (Timperley 2021).

The literature indicates that decarbonizing energy-intensive industry is certainly possible, and it will involve whole new areas of economic activity, new areas of comparative advantage, and shifting trade patterns. Achieving decarbonization globally, however, will require a mix of accelerated domestic efforts in industrialized countries, along with much smarter and equitable integration of international finance and trade policies to support a rapid transition in the major emerging economies.

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