REPORT

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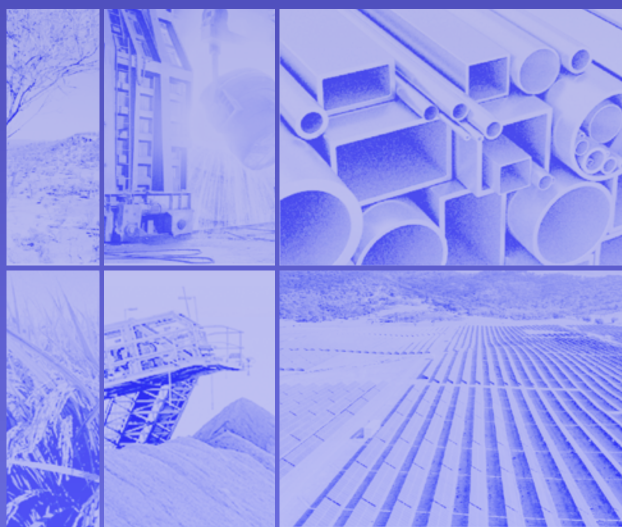
The *New* Energy Trade



Harnessing Australian renewables for global development

Reuben Finighan

The Superpower Institute

About The Superpower Institute

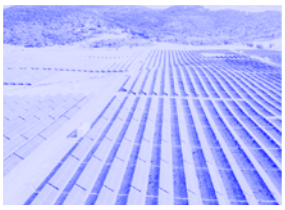
Founded in 2023 by economist Ross Garnaut and public policy expert Rod Sims, The Superpower Institute is a not-for-profit organisation dedicated to helping Australia seize the extraordinary economic opportunities of the post-carbon world.

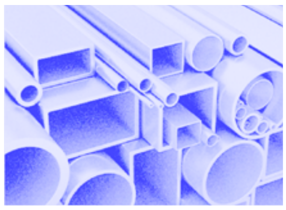
The Institute's focus is on developing the policy settings, market incentives and practical knowledge necessary for Australia to become a major exporter of renewable energy and green industrial products. By leveraging the nation's comparative advantage, the Institute aims to elevate Australia's economic and climate ambition and secure its place as a leader in a decarbonised global economy.

About Reuben Finighan

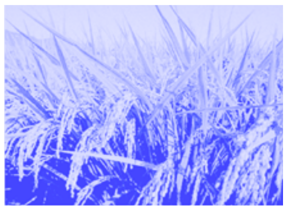
Reuben Finighan holds a PhD in Political Economy from the London School of Economics and a Masters of Public Policy from the Harvard Kennedy School, as a Fulbright, Frank Knox, John Monash, and Leverhulme scholar. He has co-authored papers with Harvard Professor Robert Putnam, Ross Garnaut AC, and Lord Nicholas Stern, and previously worked at the University of Melbourne in applied economics and as Chief Economist for the Universal Commons.

Reuben is currently Research Lead, Economic Pathways at The Superpower Institute.







The Superpower Institute
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This report was authored, edited, designed and printed on the Traditional Lands of the Wurundjeri People of the Kulin Nation. We pay our respects to their Elders past, present and emerging and acknowledge their enduring connection to the land, waters and community.

As Australia advances toward a new era of clean energy trade, we recognise the vital importance of ensuring that First Nations communities benefit equitably from these opportunities. Their stewardship and deep knowledge of this land remain invaluable as we work toward a sustainable, just and inclusive energy future.

Foreword

Australia has an opportunity to turn its exceptionally rich resources for producing renewable energy and sustainably harvested biomass into immense quantities of zero-carbon products that replace goods made with large carbon emissions. Utilising that opportunity makes it possible for the densely populated, highly industrialised countries of the world to achieve net zero emissions without suffering large reductions in their standards of living. And it makes it possible for Australia to return to full employment with rising living standards for most of its people after an unprecedented decade of stagnation.

These opportunities were sketched in *Superpower: Australia's Low-Carbon Opportunity* five years ago and *The Superpower Transformation: Building Australia's Zero-Carbon Economy* in 2022. This paper by Reuben Finighan at The Superpower Institute turns that sketch into a portrait.

International trade in fossil carbon has made modern economic development supporting high standards of living possible in Northeast Asia and Europe despite their own coal, oil, and gas resources being able to support only a small proportion of their requirements for energy and carbon industrial inputs. Reliable supply from Australia has played an important part in that trade, especially for Northeast Asia. Finighan's work shows that Australia's role will be even more important in the world of net zero carbon emissions that we must build quickly if we are to avoid human-induced climate change causing catastrophic disruption of living standards and political order all over the world.

Finighan examines in detail the quantities of renewable energy and biomass that will be required to achieve net zero emissions in Japan, Korea, China, Europe and India. Japan and Korea are the extreme cases of economies able to supply economically only a small proportion of their energy and carbon-related industrial inputs in a zero-emissions world. China and Europe now and India as its modern economic development proceeds will have proportionately smaller but absolutely immense requirements. Together these economies account for over half of global greenhouse gas emissions. Australia is one of several countries which can produce economically much more than their own requirements of goods with net zero emissions. It is distinguished as the country with by far the largest capacity to export to the densely populated, highly developed countries of the northern hemisphere.

Success for Australia requires continuing analysis of the Superpower opportunity, continuing development of policies to allow the emergence of large, new industries, and continuing structural change. That is only possible if governments, businesses and communities are well-informed. The Superpower Institute looks forward to contributing to continuing development of the knowledge building process that has been advanced by Finighan's important contribution.

Ross Garnaut
The Superpower Institute

Glossary of Terms

Biomass

Organic materials, most importantly from crop residues and dedicated energy crops, used as carbon feedstock for industry or combusted to produce energy.

Bioenergy

Renewable energy produced from organic materials (e.g. crop residues, dedicated energy crops).

Carbon Capture and Storage (CCS)

Technology for capturing carbon dioxide emissions, mainly from fossil fuels combusted in power plants or industrial processes, and storing them underground to prevent release into the atmosphere.

Carbon Feedstock

Carbon sourced from biomass, captured fossil fuel emissions, direct air capture, or other processes, used in industrial processes - such as making plastics, chemicals, or fuels - rather than for energy production.

Comparative Advantage

A country with comparative advantage can produce a good or service relatively more cheaply than others (most precisely, at lower opportunity cost), such that specialising in and exporting that product generates gains for all. Australia has a comparative advantage in renewable energy production.

Direct Air Capture

A technology for extracting carbon dioxide directly from the atmosphere for storage, to reduce atmospheric CO2 concentrations, or for utilisation as a carbon feedstock.

Electrification

The process of replacing fossil fuels with electricity in various sectors (e.g., transportation, heating) to reduce emissions, often in combination with clean energy sources.

Embedded Energy

The energy used in producing a product or service. Trading energy-intensive goods is an indirect trade in energy; importing embedded energy allows countries to reduce their domestic energy demand.

Energy-Intensive Goods

Products requiring large amounts of energy to produce, including steel, aluminum, and ammonia, and so with significant embedded energy. In the fossil economy they have large CO2 emissions and are important targets for clean production.

Market Failure

When markets fail to allocate resources efficiently, due to incomplete property rights, misaligned incentives, and/or asymmetries in information. The non-pricing of harmful CO2 emissions is a classic example.

Primary Energy

Energy in natural resources before conversion or transformation, including coal, oil, natural gas, biomass, wind, and solar energy sources.

Superpower Trade

The trade in clean energy embedded in energy-intensive goods, that relies on export countries' comparative advantage in clean energy production.

In most major economies, there will not be enough cheap clean energy available to meet demand by mid-century.

This is Australia's opportunity to contribute to global climate mitigation, and to benefit from large scale exports.

Contents

01.

The new energy trade

Fossil fuel resources—coal, oil, and gas deposits—are unevenly distributed across the globe. So is demand for fossil fuels. The consequence is a fossil fuel trade worth several trillion dollars each year. Without this trade, sustained growth in global living standards would have been impossible; most countries have only enough resources to burn brightly for a moment, before depletion would return them to poverty.[1]

At first glance, it appears that the new clean energy resources are available more or less everywhere. Yet in most of the world's energy-hungry economies, the scale of demand will exceed cheaply available energy supply. We will remain in a world of unevenly distributed resources, and so a world made richer by extensive trade.

This paper is about the new trade in green energy, and its significance for successful climate mitigation and economic development over the next several decades. It follows arguments first made by Ross Garnaut in 2015, then developed in the Superpower (2019) and The Superpower Transformation (2022). Garnaut emphasises Australia's comparative advantage in zero-carbon goods in the new global economy, and estimates that Australian exports of energy-intensive goods, including iron, aluminium, silicon, ammonia, and green fuels, could contribute around a 6 percent reduction in global emissions.

The paper tests and extends Garnaut's analysis, by going into much greater detail on future green energy demand and potential sources of supply. It concludes that

- the new energy trade will be dominantly a trade in embedded[2] green energy;
- demand for renewable energy will be larger than expected, given the high competitiveness of electrification as a mitigation strategy and the likelihood of modest contributions from nuclear power, bioenergy, and carbon capture;
- energy shortfalls therefore confront major economies with large appetites for energy and poor renewable resources; and
- the embedded energy trade can make very large contributions to closing the gap between electricity supply and demand.

It focuses on the trade in the most energy-intensive materials—iron/steel, aluminium, silicon and polysilicon, ammonia and urea, methanol, and green fuels for shipping, road freight, and aviation—between Australia and its likely partners: China, India, Germany/Europe, Japan, and Korea. Australia has among the world's richest clean energy resources, and they are in great excess to its own domestic needs. Its trade partners will be those countries that are home to vast

[1] Great Britain, the progenitor of capitalist economic development, reached peak coal production in 1913. In 1914, the UK purchased a majority stake in the Anglo-Persian Oil Company, which later became BP (Kuiken, 2014).
[2] Also known as "embodied" energy, embedded energy is the energy consumed in providing a good or service. Energy can be traded directly, e.g. via trade in fuels or electricity, or indirectly by trading products for which energy is a major input.

energy-intensive industries, but are densely populated and do not have enough quality sunlight and wind to cheaply satisfy demand.

It is worth first turning to the theoretical framework behind the analysis.

1.1 A framework: The benefits of trade

Open trade allows the global economy to access resources at lowest possible cost. The value of trade can be simply explained with reference to a global supply curve for a given energy resource. Figure 1.1 is an illustrative curve for a given energy resource, in a simple three-country world. Take Country A (blue) as accounting for 75 percent of demand, Country B (red) for 20 percent, and Country C (green) for 5 percent.

Country A has the cheapest resource and a rich overall endowment. Yet its demand for energy far exceeds its cheap domestic resources. Country B, meanwhile, has few cheap resources of any kind. Without trade, both Country A and B would need to draw on resources far beyond the righthand side of the graph. The consequent high marginal costs of energy would curtail productivity and reduce the standard of living.

Country C has a comparative advantage in energy production, at the given level of global demand. It is the energy-trading superpower. In today's world it may, for example, be the Middle East in oil, which has a low share of global demand but the majority of the cheapest oil. Or it may be Australia, as the world's top exporter of metallurgical coal, and top combined exporter of coal and LNG, most of which fuels the cities and industries of Japan, Korea, the People's Republic of China, and Taiwan.

The trade brings large benefits to all, providing a large export income for Country C while keeping the marginal costs of energy low for Countries A and B.

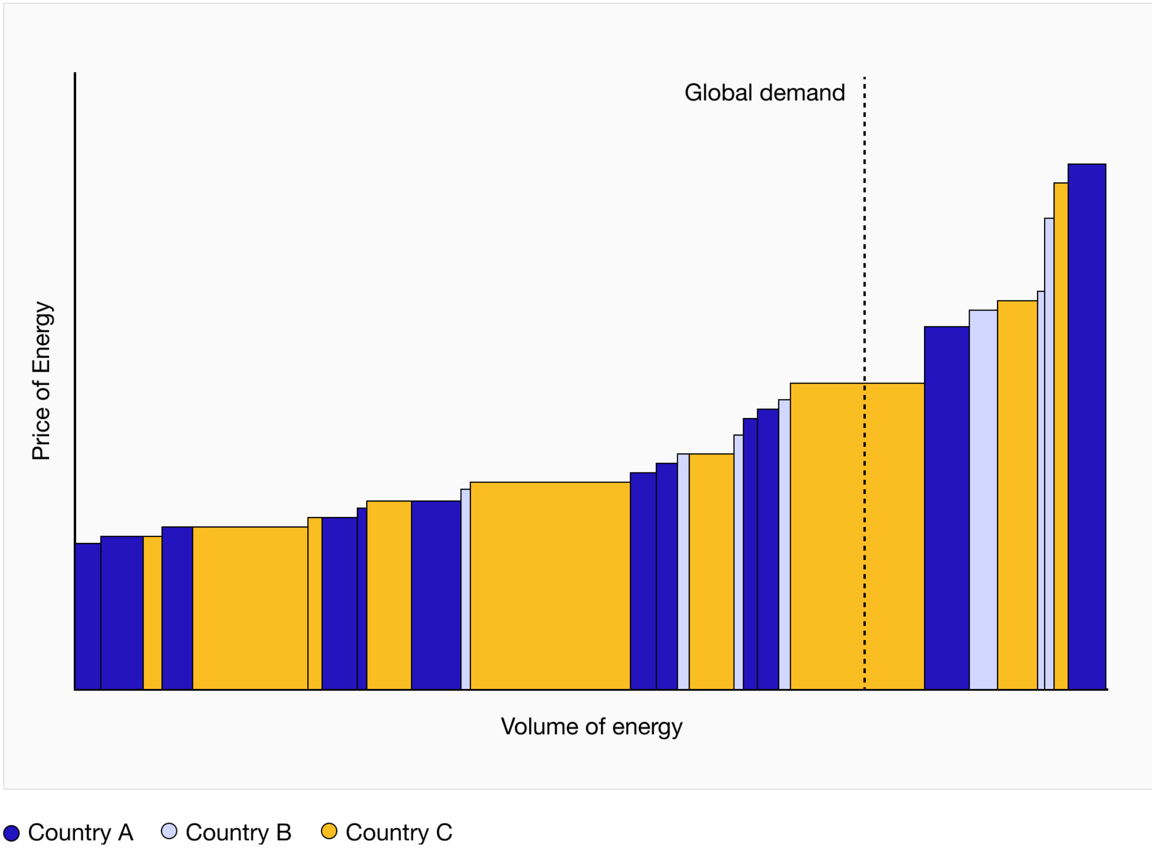

Figure 1.1. A hypothetical supply curve for energy in a three-country world.

This pattern may persist in the net-zero global economy, if demand for clean energy is large enough to exhaust cheap local resources. In the absence of trade, countries would need to turn to increasingly expensive local resources, including nuclear and new-build CCS, and the marginal price of energy would soar.

In the post-carbon world, the Country C pattern may be found in countries or regions including Australia, Chile, the Middle East, and northern and southern Africa. They have relatively flat supply curves (i.e. vast cheap renewable resources) and a small share of global energy demand. The competitiveness of renewable energy versus other mitigation technologies (Box 1.1) is examined in later parts of the paper.

The Country B pattern appears in economies such as Japan and Korea, and to a lesser extent Germany.

The Country A pattern is of special interest, because it suggests a break between present-day patterns and those of the future. The CSIRO, for example, predicts that India and China will have the cheapest renewable energy in 2050 (Graham, 2023). This simple analysis is based on the best available sites and labour costs—yet China, and especially India, will by mid-century be pushing far up their supply curves. It is not the cheapness of the best resources that matters, but the marginal cost of energy given the magnitude of energy demand.

These propositions are tested in what follows.

Box 1.1 The global mitigation supply curve

Clean energy would play an important role even in a world without climate change, but the main driver of its deployment at scale is climate mitigation. For this purpose, clean energy technologies are in competition with other mitigation technologies. This is important insofar as importing (embedded) renewable energy from Australia may, for example, compete with soil sequestration in Brazil.

The energy supply curve of Figure 1.1 can be subsumed within a broader global mitigation supply curve. This introduces price competition between a wider set of technologies: renewable energy, nuclear power, carbon capture and storage, sustainable biomass, land carbon sequestration, direct air capture, and so on.

Investment is driven mainly by carbon pricing or its substitutes. The effective carbon price rises over time until it reaches the social cost of carbon, which is the external cost of a marginal tonne of CO2 emissions. When the carbon price reaches the social cost of carbon, the externality has been fully internalised.

At equilibrium in an idealised global economy, the marginal cost of mitigation will be the same across all sectors, countries, and utilised technologies, and will be equal to the carbon price.[3] If mitigation via one technology/sector/country was cheaper than the rest, investment would flow there until the opportunity was fully exploited, and the marginal cost equalised.

[3] Marginal costs for a given technology (e.g. direct air capture) may be higher than all other options. In that case it will not be utilised until the carbon price rises sufficiently.

In practice there are many departures from this ideal.[4] Nonetheless, this model helps underline the large benefits of technological neutrality, and the large benefits of open trade and capital flows.

1.2 The high costs of trading green energy: Toward embedded energy

Trade is more extensive when the costs of transporting goods is low. If very high costs of transport were added to Figure 1.1, then trade would be stunted, and all countries would be worse off.

Transporting fossil fuels is cheap. This fact underpins some remarkable patterns in international development during the fossil age: not only can whole countries be cost-effectively powered with fuels extracted in distant lands—Japan and Korea, for example, import about 90 percent of their energy—but such countries can even compete in the most energy-intensive industries.

In the emerging zero-carbon economy, this will change. Transporting green energy over long distances is generally very costly. There will be some opportunities to trade power via cross-border transmission lines, when distances are short. Otherwise, it requires converting green electricity into intermediaries (such as liquid hydrogen, ammonia, or methanol), transporting them, and subsequently combusting them. This results in losses of typically 66-80%, of the original clean energy. Transported energy thus costs at minimum 3-4 times more than locally consumed energy.

Governments and firms have gradually become aware of the high costs of liquifying and compressing hydrogen for transport. This has fuelled interest in turning hydrogen into ammonia, which can be shipped and stored cheaply. Yet ammonia will also disappoint: there are substantial losses turning hydrogen into ammonia, and further losses in combusting ammonia to produce energy.

IRENA (2022) data suggests the cost of transporting renewable energy via ammonia today is around US$230-450/MWh, and it projects a decline to US$100-200/MWh by 2050.[5] This will be an order of magnitude too high to compete with the direct use of renewable electricity. The trade in electricity via green fuels will be important for grid stabilisation, but will nonetheless be modest even by mid-century. Ammonia imports will likely be necessary for countries with a strong comparative disadvantage in zero-carbon electricity generation, in order to satisfy their non-tradable electricity demand (Box 1.2).

The reality of costly energy imports has two main consequences.

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[4] Capital flows are not frictionless and information is imperfect. Effective carbon prices differ between countries and between sectors. Differences in national emissions targets, and rules for fulfilling them, may distort resource allocation. Most significantly in the present era, tariffs and other obstacles to exchange may interfere with trade and capital flows. Some of these “distortions” are technically unavoidable, and others may be necessary for reasons of political economy, but each of them raises the costs of mitigation.

[5] IRENA (2022) estimates US$720-1400 and US$310-610 per tonne of ammonia made from renewable energy today and in 2050 respectively. Each tonne contains 5.17 MWh of energy, and combustion efficiency is around 60%. Conversion/combustion are the costly steps, transport only adds US$10-20/MWh.

1. Countries with non-tradable energy demand (again see Box 1.2) that exceeds their cheap domestic resources will be stuck with high prices. They will therefore be uncompetitive in the energy-intensive trade.
2. Countries with poor renewable resources will import energy-intensive goods more than green fuels. That is, imports of embedded energy will be a substitute for imports of energy.

Anticipating and planning around the coming shift in trade patterns will be important to the global mitigation effort. It will also be important for the continued reaping of the benefits of trade, and growth in living standards.

Box 1.2. Tradable vs. non-tradable electricity demand

A crucial distinction can be made between tradable and non-tradable economic activities. Some goods and services, such as steel, ammonia, and data processing, are tradable. Countries compete to produce them at lowest cost, and countries without a comparative advantage may offshore such industries.

Other goods and services, such as the lighting of buildings, the charging of cars, healthcare, or construction, cannot be traded. They must be powered by domestic energy sources, whatever the cost.

For every country, non-tradable demand must be satisfied first. There is no available substitute. Satisfying non-tradable demand presses each country some distance along its supply curve. It is the marginal cost of clean energy after satisfying non-tradable demand that matters for competitiveness in the tradable industries, including the superpower industries of this paper.

If the marginal energy cost after satisfying non-tradables is high and uncompetitive, importing tradables helps to prevent prices rising higher. This benefits all economic activities that use energy.

1.3 Assessing the superpower thesis: Analytic strategy

We have noted the benefits of trade when countries' comparative advantages differ, and the dominance of embedded energy in the green energy trade. Establishing Garnaut's (2015, 2019, 2022) thesis requires several further steps.

Broadly, it is predicated on the idea that Australian renewable energy, like that in a few other superpower countries, is among the lowest cost and largest volume opportunities for global mitigation. Put in terms of global energy or mitigation supply curves, the rectangle is short and wide.

For trade to bring such advantages, future electricity demand in the other major economies discussed—China, Germany, India, Japan, and Korea—must exceed their locally available cheap supply. The expectation of high electricity demand in turn depends on the importance of electrification as a mitigation strategy, against alternatives to electrification such as carbon capture and storage or biofuels. The thesis further requires that renewables-poor countries will not be able to turn to cheap nuclear power and bioenergy to satisfy electricity demand, at least not at the scales required.

Demand, efficiency, and the electrification rate

A point of difference between this paper and most other studies is the magnitude of projected electricity demand. Projections of demand in the literature vary enormously, depending on assumptions about rates of economic growth, the fall in energy intensity, and electrification rates.

It is useful to take China as an example. Electricity demand growth to date has been around the very upper end of projections in the literature. China's electricity demand increased from 7500 TWh in 2020 to around 9,200 TWh in 2023 (Diting, 2024, via China's National Energy Administration). That is growth of around 630 TWh or 7 percent per year. At the time of writing, China's electricity demand has reached levels that some models had not expected to arrive until 2030 (IEA, 2021), 2040 (e.g. Kahrl et al., 2021), or even 2050 (Lu et al., 2022).[6]

The IEA's (2021) model of China's decarbonisation is an improvement, but its expected 16,500 TWh in 2060 is still implausibly low. It suggests demand growth of only a little over 1.5 percent per year, despite a tripling of China's economy to 2060, as well as deep electrification, which greatly raises the electricity-intensity[7] of economic activity. The IEA's (2021) underestimates apply to the supply side too: in 2023, China already exceeded the IEA's expected average rate of solar and wind additions from 2030 to 2060. The 2024 install rate is higher still.[8]

A handful of studies have produced electricity demand projections that are congruent with those in this paper, including China's Electric Power Planning and Engineering Institute (2021, see Abhyankar et al., 2022) and CEF and BoA (2024). These studies capture recent developments in demand, and they predict that demand in 2040 will have already reached the IEA's level for 2060 (average growth rate is 3.5 percent). Wang et al. (2023), the most influential of recent studies of Chinese decarbonisation, expects a similar level of demand to this paper—around 55 percent higher than in the IEA by 2060.[9]

What is driving this variation?

Among the most important drivers is the expectation of improvements in energy efficiency. Energy efficiency is something of a deus ex machina, sweeping into solve much of the green energy demand problem. The IEA's (2021) model anticipates energy intensity improvements of 3 percent per year, falling after 2040 to 2 percent. Over the 39 years from the IEA's model to 2060, this alone would cut energy demand by two thirds. Yet in China, energy intensity has fallen by only around 0.7 percent per year since 2017 (Enerdata, 2024). Getting this even modestly wrong has a large impact—if energy intensity falls not 66 percent but 50 percent, then demand for energy will be a third higher in 2060 than expected. If on current trends it falls by only 33 percent, demand will be twice as high.

Historically, IEA projections of declining energy intensity and slowed demand growth have been overly optimistic (Stern, 2017). They are very likely overly optimistic about the future. This is partly driven by the Jevons paradox, a phenomenon described by the economist William Jevons in 1865. He observed that improved efficiencies of coal use had caused an increase in English coal consumption. Improvements in the efficiency of resource use, he pointed out, tend to reduce the costs of processes that use that resource, and lower costs can cause a more-than-compensating

[6] The latter projects only 9,300 TWh of electricity demand in 2050, which China has already exceeded, or 10,900 TWh with accelerated electrification. Also see some of the models compared in Duan et al. (2021).
[7] Electricity-intensity is the amount of electricity used per unit of GDP. Countervailing forces, including efficiency improvements, are discussed shortly.
[8] The IEA (2021b) projects an average of 277 GW of wind and solar capacity installed annually from 2030 to 2060. The 2024 rate is expected to be between 260 and 339 GW (Howe, 2024; Xue, 2024).
[9] This is with a modest level of electrification of 58 percent, and deeper electrification could easily push demand over 30,000 TWh.

increase in demand. More recent scholarship has identified a few other mechanisms (e.g. Khazzoom, 1980 and Brookes, 1979).

The rebound in demand after energy efficiency improvements comes from two main dynamics:

- energy intensity declines less than expected, because lower energy costs make more energy-intensive activities viable; and
- even where energy intensity declines, it causes a more-than-compensating increase in total energy demand.

The evidence suggests that the rebounds in demand that follow improvements in energy efficiency are large (see Box 1.3).

Box 1.3. The Jevons Paradox: Evidence and qualifications

Typically, the literature finds that efficiency improvements are followed by a 50 percent or more rebound in demand (Brockway et al., 2021). Economy-wide rebounds of around 100 percent are supported by recent general equilibrium models (e.g. Rausch and Schwerin, 2018; Bruns et al., 2021) and econometric models across China, India, Sweden, the US, and various other countries (Jafari et al., 2022; Berner et al., 2022; Kong et al. 2023; Amjadi et al., 2022). Looking over a longer period of economic growth, Saunders (2013) found rebounds much greater than 100 percent after industrial efficiency gains in the US. Stern (2020) notes that this pattern is strongly suggested by economic history.

As Brockway et al. (2021) observe, the neglect of these findings may lead to the systematic underestimation of growth in energy demand.

There are some likely exceptions to Jevons' rebound. Ordinarily, economic actors pursue energy efficiency technologies that are internally profitable, and this boosts economic growth. When energy efficiency investments are costly compared to business-as-usual, e.g. investments that may only be induced by carbon pricing, then this will tend to reduce growth and produce lower rebound.

A second major driver is the projected rate of electrification. Assumed electrification rates have tended to increase over time, partly due to the falling costs of renewables and storage, the underperformance of alternatives such as carbon capture and storage and biofuels, and improved prospects for electrifying economic activity (e.g. more rapid uptake of electric vehicles than expected, and growing investments in the electrification of industry).

Finally, results are driven by analysts' presumed changes in economic composition, in both the degree of industrialisation and patterns of individual consumption. This is reasonable, but it has two downsides:

- First, it risks underestimation. Air travel, for example, may be more expensive in a zero-carbon future, but global incomes will be markedly higher. Spending on luxury goods increases with income, and demand for this particular luxury good may not abate.
- Second, compositional change may surprise. New energy-intensive technologies are always appearing. Data centres for cloud and AI services, for example, are expected to account for 9 percent of US electricity demand in 2030 (EPRI analysis, see Aljbour et al., 2024).

For this paper, there is one crucial point to make about compositional change: what will reliably drive an economy to switch away from energy-intensive activities is the scarcity of cheap domestic energy resources, especially in combination with trade with countries with abundant energy resources. Rather than presuming compositional change, a key aim of the analysis is to show what demand would look like without it—and hence show why such change is necessary.

Allowance is made, however, for anticipated reductions in Chinese steel consumption that typically accompany advanced development, and for Indian government plans to greatly increase steel and other heavy industry output.

Stepwise analysis

In the key countries, around 29 percent of fossil fuels are combusted to produce electricity. The analysis pays particular attention to the roughly 71 percent of fossil fuels that are consumed directly, so cannot yet be replaced by clean electricity such as renewables or nuclear. There are a few broad ways of decarbonising the latter activities, set out in more detail in Chapter 2. Simplistically for now, there are those that involve some electrification and increase electricity demand, and there are those that allow continued direct use of fossil fuels (carbon capture and storage and carbon sequestration) or direct use of biomass.

Focusing on the five key countries, the analysis moves through these possibilities sequentially, with a stepwise increase in complexity. Chapters 2 to 6 turn to the consequences of a nearly pure electrification approach, to provide an upper limit on potential clean electricity demand. They are concerned with the following questions:

- How much of economic activity is likely to be electrifiable in the future?
- How much electricity would be required to maximally electrify today's economies, given the expected efficiency of electrification?
- How much would be required in 2060, given economic growth and continued improvement in efficiency?
- What volume of sustainable carbon feedstocks would be required today and in 2060?
- What are the electricity and carbon feedstock requirements for the key tradable superpower industries?

This gives a first-pass picture of an electrified world without trade. Electrification is overall highly efficient and greatly reduces primary energy demand, but the resulting level of electricity demand is nonetheless extreme: from around a 2.7-fold increase for Japan up to a more than 10-fold increase for India. Sustainable carbon requirements of the superpower industries are also large, at a little over 1 billion tonnes. This excludes some carbon demand from non-superpower industries, not examined here.

In **Chapters 7 and 8**, other mitigation strategies and trade are introduced. They compete as alternatives to electrification in each of the key countries. Key questions include:

- How much does modelled electricity demand decrease when the main substitutes for electrification, i.e. CCS, bioenergy, and land carbon sequestration, are introduced?
- How much of the remaining electricity demand in the key countries can be supplied cheaply by domestic renewable energy resources, biomass resources, and nuclear power?

- If current rates of renewables and nuclear installation were sustained, how large would the countries' gaps between supply and demand be in 2060?
- How much can the superpower trade help to close the remaining supply-demand gap, and how much does this ease countries' mitigation task?

Based on various international sources, the contributions of the substitutes are expected to be modest—at least at any competitive price. There remain some uncertainties, but large surprises would be needed to greatly change the result. Electricity demand remains high. In satisfying electricity demand, the contribution of nuclear power is low unless its rollout can be accelerated by well over an order of magnitude. The contribution of bioenergy is limited by high demand for carbon feedstocks.

The superpower trade can make a very large contribution, closing from 35 to 75 percent of the countries' forecast gap between green electricity supply and demand.

Finally, **Chapter 9** focuses on the potential role of Australia in the superpower trade.

- What is the potential contribution of Australia to the superpower trade, and to global emissions reductions?
- What scale of renewable energy capacity and land use would be required to reach that potential?

The analysis confirms that if Australia processes its iron and aluminium ores before exporting, and satisfies 25 percent of demand for the other superpower tradables, it may cut emissions by from around 7 to 10 percent of 2021 global emissions from all sources. In terms of land area, the required renewables would directly occupy 0.6 percent of the Australian land mass, or around 1.1 percent including the space between turbines.

02.

Estimating future electricity needs: Decarbonising the 71 percent

Around 531 exajoules[10] of fossil fuels were consumed globally in 2021 (EIA, 2024). Only about 29 percent, or 153 exajoules, are used to generate electricity—around half of coal, one third of gas, and a few percent of oil. The average efficiency across the fleet of fossil fuel power stations is roughly 40 percent, with the remaining energy lost as waste heat. Globally these power stations deliver around 60 exajoules of electricity, or around 16,800 TWh.

The remaining 71 percent of fossil fuels, some 378 exajoules, are consumed directly. They are either

- combusted in cars, ships, aircraft, buildings, and industrial facilities, or
- used as a feedstock for industrial processes that require carbon.

It is a large task, but relatively straightforward, to replace the 29 percent of fossil fuels going to electricity. Each TWh of fossil electricity must be replaced with a TWh of renewable or nuclear electricity, or of fossil fuels with carbon capture and storage. The main technical challenge is the balancing of variable renewable energy sources.

How to decarbonise the remaining 71 percent? This task is more complex, with the strategy varying by sector and by industry. For hard-to-abate activities especially, success will depend on advances in a wide range of emerging technologies. Fortunately, these technologies are advancing rapidly. In each case, the choice of decarbonisation strategy will be shaped by technical feasibility and relative cost.

In most projections by major institutes and scholars, the dominant strategy for dealing with the 71 percent is electrification. Once electrified, these processes can be powered by solar, wind, or nuclear energy. The degree of electrification, and the consequences for electricity demand, are the principal focus of this report.

The main alternatives to electrification are bioenergy, carbon capture and storage (CCS), and sequestration of carbon in land or via direct air capture (DAC). Their significance depends on their costs relative to electrification.[11] Note, however, that DAC and CCS technologies are also electricity-intensive and will contribute to growth in electricity demand.

- CCS is discussed in Section 7.2. Progress in reducing the costs of CCS, and increasing capture efficiency, have been slower than hoped. CCS will play an important role, but, in IEA analyses and in this paper, a modest one.

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[10] An exajoule is one billion billion joules. The total electricity consumption of Australia in 2021 was around 1 exajoule, while total energy use was about 5.9 exajoules.
[11] Including savings on capital expenditure where they allow the continued use of old technologies.

- Bioenergy is discussed in Section 7.4. It is limited by the availability of suitable land, and—as we will see—by competing uses for biomass as a feedstock used for its carbon content.
- DAC is very expensive, but may play a small role in offsetting the emissions of hard-to-abate economic activities.

We begin with a pure electrification model, to identify the upper bounds of electricity demand at net zero. The model is applied to estimate the electricity required to decarbonise maximally-electrified economies today, using 2021 data derived mainly from the EIA (2024a) and the UN Statistics Division (2024). In Chapter 5, the electrification model is extended to 2060 by accounting for two factors: GDP growth, which increases electricity demand; and the falling energy intensity of economic activity (i.e. the amount of energy consumed per unit of GDP) due to efficiency improvements and some changes in economic composition. From there, I examine the potential contributions of CCS and biomass, and their consequences for electricity demand in 2060.

This electrification model is applied to the countries that are expected to be key partners in Australia's superpower trade: China, India, Japan, Korea, and Germany.

Having established potential future electricity demand in the key countries, the next question is about the feasible scale of clean electricity supply. Because clean energy itself cannot easily be traded, shortfalls in supply versus demand imply a large trade in energy-intensive goods. The effect of the superpower trade on these countries' decarbonisation pathways is examined, and the potential contribution of Australia specifically is defined.

2.1 Electrification: Direct and indirect

Our principal concern is not primary energy or final energy use, but electricity demand versus potential cheap electricity supply. The balance of electricity supply and demand shapes electricity prices, and those prices in turn shape international trade of energy and energy-intensive goods.

For this purpose, reported rates of electrification in major studies (e.g. IEA, 2021) are usually, on the surface, misleading because of technical conventions in the calculation of "final energy use".[12] Only the direct use of electricity is generally termed "electrification".[13] The consumption of zero-carbon hydrogen or ammonia, for example, is not considered electrification—but as discussed below, it should be. Not only do they contribute to electricity demand, but their contributions are disproportionately large.

We modify these conventions and distinguish between two modes of electrification, both of which add to electricity demand: direct electrification and indirect electrification.

Directly electrifiable economic activities are those where the end user can switch from direct combustion of fossil fuels to using electricity. Examples include replacing internal combustion engines with electric motors, gas heaters with electric heat pumps, or coal boilers with electric

[12] Final energy use refers to the energy that is consumed by end users. There are many opacities, and the interpretation of the measure requires a detailed decomposition of fuels and use efficiencies. For example, if an economy's final energy use switches from 1 PWh of green ammonia to 1 PWh of electricity, it will become much *less* electricity-intensive, and much richer in access to usable energy. This is because of losses in ammonia combustion, and because each MWh of ammonia has around 3-4 MWh of electricity behind it.
[13] The IEA's (2021) model of Chinese carbon neutrality claims an electrification rate of 50 percent, but a minor note observes that it is in fact 66 percent including indirect electrification via hydrogen. This value may be even higher including indirect electrification via green fuel production, but this is not covered.

boilers. This requires the development of economically competitive electric devices, such as the EVs that now make up 18 percent of car sales globally (IEA, 2024a).[14]

Indirectly electrifiable activities are those where the end user switches from fossil fuels to a green fuel or feedstock, where that fuel or feedstock is itself substantially the product of electricity. Foremost among these fuels is hydrogen, which is produced by channelling large amounts of electricity through water. Take two examples of significance in this report:

- Steelmaking today depends on using carbon, typically from coal, to chemically strip the oxygen from iron ore. The products are iron metal and CO_2. Green hydrogen[15] can replace carbon and do the same task, releasing water instead of CO_2, and that green hydrogen is principally the product of electricity.
- Long-range maritime shipping resists direct electrification because of the low energy density of batteries and long recharge times. Hydrogen, ammonia produced from hydrogen, and methanol produced from hydrogen and carbon are electricity-intensive alternatives (noting that the carbon component of methanol is not yet electrifiable).

Most economic activity can be directly electrified, and most of the remainder can be indirectly electrified, with hydrogen commonly playing a dominant role.[16] Indirect electrification is, however, typically much less efficient than direct electrification, because of losses in producing, transporting, and combusting green fuels such as hydrogen and ammonia. Thus, indirect electrification will contribute disproportionately to final electricity demand.

2.2 Non-electrification: Biomass and CCS as necessities and competitors

There are two main alternatives to electrification: biomass and carbon capture and storage (CCS). In some cases, one or more of these options is not available: CCS is not viable for road transport, and pure electrification is not viable for processes that need carbon. Biomass is versatile as both a fuel and feedstock, but its physical and chemical properties limit its use for applications such as blast furnace steelmaking.[17] In cases where more than one option is technically feasible, they compete on price. How this competition plays out depends on economic factors, but also political factors given the large influence of fossil fuel incumbents.

Two kinds of economic activity are not fully electrifiable today. The first are those activities that require carbon as a feedstock. Examples include the production of green methanol, green urea, and green plastics. In the future, it may become possible to use electricity to pull carbon out of thin air—that is more or less what is involved in DAC-derived CO_2. Unfortunately, DAC is far from being economically viable.

The second class of hard-to-electrify activities is that of high-temperature industrial processes. It is currently much easier to electrify low-temperature processes, although this is mainly a matter of technical challenges that can be overcome. I discuss this in more detail in Section 3.4.

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[14] Around 40 percent of sales in China, 21 percent in Europe, and 10 percent in the US.
[15] "Green" hydrogen is produced from renewable electricity. "Brown" hydrogen is made from fossil fuels and dominates today. "Pink" hydrogen is made from nuclear power, and is also zero-carbon.
[16] The IEA (2021b) finds that a majority of economic activity, at least 66 percent, can be directly electrified. These figures are accepted in scholarly studies such as Y. Wang et al. (2023).
[17] Historical steelmaking relied on charcoal for thousands of years. Blast furnace steelmaking, however, cannot use any coal/charcoal input, but requires quality metallurgical coal. There are efforts to produce bio-coke, but physical challenges include lower mechanical strength and lower density, and chemical challenges include lower and variable fixed carbon content, and higher and variable rates of impurity.

Today, carbon can be sourced either from biomass, waste, or carbon capture processes. For sourcing large volumes of sustainable carbon, biomass will be required. A less sustainable version is the capture of CO_2 released by fossil fuel combustion;[18] any resulting product would not add to emissions, but the overall system would remain emissions-intensive.[19]

2.3 *A taxonomy of greening*

The above processes may hybridise in various ways in complex industrial processes. One plant may exploit new direct uses of electricity, consume green fuels produced from electricity, harness biomass, and capture carbon emissions. For us, the main hybrids of interest involve combining electrification, whether direct or indirect, with a carbon source. Table 2.1 provides some examples of each of the simple and hybrid cases.

Table 2.1. Methods for decarbonising directly consumed fossil fuels.

	No carbon feedstock or DAC-carbon feedstock	**Plus green or brown carbon feedstocks**
Direct electrification	• Space heating/cooling • Electric vehicles • Industrial boilers • Green iron via electrowinning • e-methanol or e-diesel, made with DAC carbon	• Green urea made from biomass and electricity • Green ethanol via electric biomass fermentation • e-methanol or e-diesel, made with biomass carbon
Indirect electrification	• Green iron made using green or pink hydrogen • Road freight using green/pink hydrogen fuel cells • Maritime shipping fuelled by green ammonia made from hydrogen	• Maritime shipping using green/pink methanol made from hydrogen and biomass • Aviation using sustainable aviation fuel (SAF) made from green/pink hydrogen and biomass
Non-electrification	• Conventional kiln with CCS • Space heating with biomass as fuel	• Conventional steelmaking with biomass as both fuel and feedstock • Conventional steelmaking with CCS • Biomass with CCS for carbon-negative industrial heat

Note: e-fuels are produced primarily with electricity as the energy input, hence is direct electrification. The actual use of these fuels in vehicles would be a form of indirect electrification. Green and pink hydrogen are made from renewable and nuclear electricity respectively.

[18] Or other CO_2 releasing processes, such as cement manufacture with limestone.
[19] With the exception of processes where CO2 is captured again or sequestered permanently in the resulting product.

03.

The electrification model: Replacing fossil fuels with terawatt hours

A model of full electrification begins with building a detailed picture of how coal, gas, and oil are used across different sectors today, investigating the feasibility of electrification across economic activities, and identifying the efficiency of electrification. Here I present an overview, before going into greater detail on the energy-intensive superpower industries.

The efficiency of electrification is calculated as the electricity required to replace fossil fuels in a given application—for example, if 3.7 MWh of electricity is required to replace the 5.6 MWh (or 20 GJ) of coal needed per tonne of conventional steel, efficiency gains are around 35 percent.

Primary energy efficiency will be affected by electricity generation losses, but calculating primary energy is not our main concern. Lossless forms of generation, such as wind and solar, will keep primary energy close to final energy use—and future grids are expected to be dominated by wind and solar. Forms of generation with large losses, such as nuclear power, biomass, and fossil fuels with CCS, will significantly increase primary energy compared to final energy.[20] These differences are of little interest; what matters on the supply-side in practice is which technologies deliver electricity at lowest cost, regardless of primary energy losses.

Electricity transmission losses are material: the larger the losses, the more electricity must be generated. The EIA (2023) reports that grid losses average around 4.7 percent in the US, which is internationally low (World Bank, 2018) but this rate is assumed broadly achievable across the five countries of this paper in the future. For clarity, transmission losses are not added to demand calculations for specific sectors or industries; they instead affect the total amount that must be generated, in later chapters, to satisfy calculated demand.

The main data sources are the US Energy Information Administration's (2024) consumption dataset, BP's Statistical Review of World Energy (2022), and UN (2024) data on the use of fossil fuels. The year of analysis is 2021, to maximise data availability.

3.1 Coal

Figure 3.1 presents the uses of coal in China, India, Japan, Korea, and Germany.

Roughly 52 percent of all coal consumed across these countries is used in thermal power plants to produce electricity, varying from as little as 46 percent in China to as much as 81 percent in India.

[20] Efficiency is around 40 percent for nuclear power, on the order of 32 percent for a coal plant with CCS (given the "parasitic load" of CCS, which consumes 20-25 percent of plant energy), and around 32 percent for biomass power today (BP, 2022).

Around 43 percent of coal is consumed in industry. The biggest consumer is the iron and steel industry, accounting for about 20 percent of total coal use. Other major products using coal as a source of energy or a feedstock include cement, ammonia, and a variety of other chemicals. These activities are overwhelmingly concentrated in China, with India a distant second.

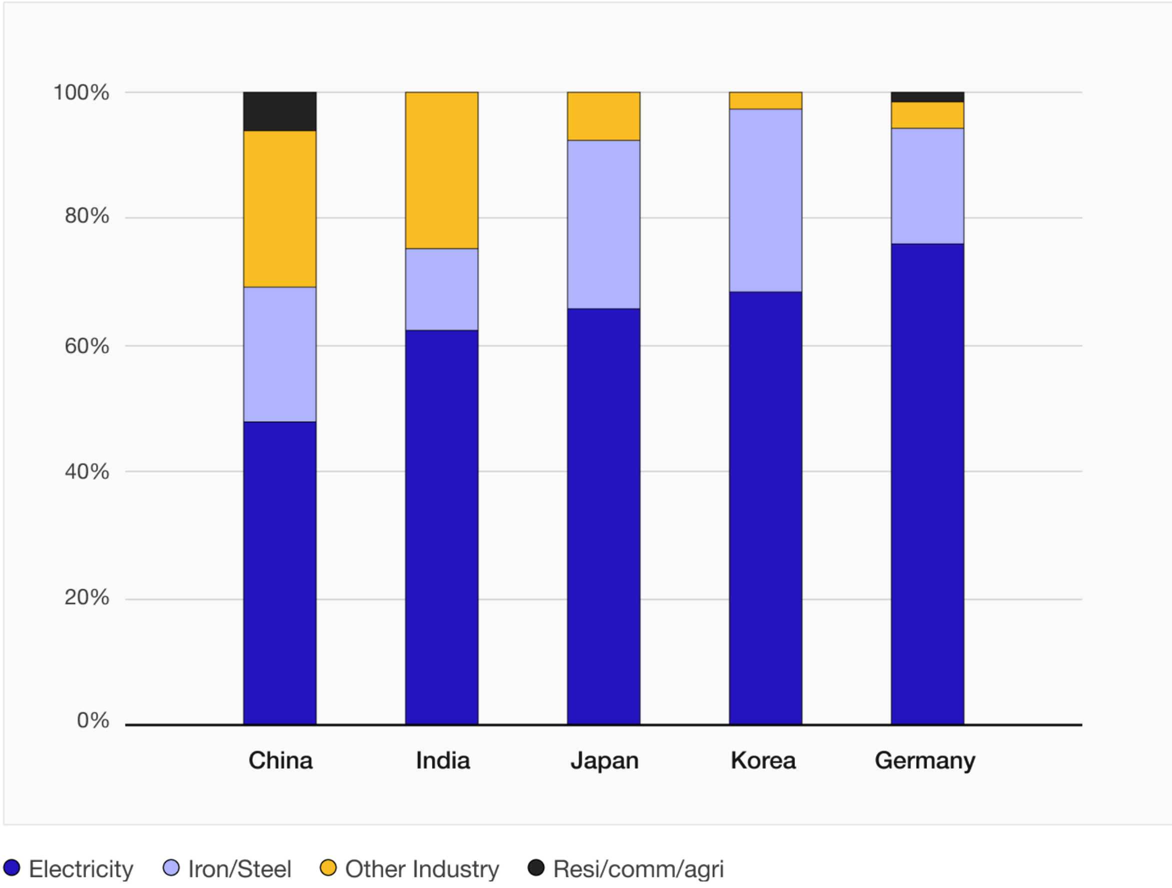

Figure 3.1. Uses of coal across the five key countries

The remainder, around 5 percent of coal, is consumed in agriculture, residential, and commercial settings, the overwhelmingly majority in China. Use in transport is negligible.

3.2 Gas

Figure 3.2 summarises the uses of gas across the five countries.

Around 38 percent of all gas consumed across these countries is used to generate electricity, with consumption much heavier in Japan and Korea (where 60-70 percent is used to generate electricity) and less in China, Germany, and India (close to 20 percent).

Around 42 percent is consumed by industry overall, although the share of consumption is much greater in China and India (around 60 percent). Across the countries, 36 percent of all gas goes to industrial energy uses and nearly 6 percent to non-energy uses. The most significant non-energy uses in industry are for ammonia (around half of which is then turned into urea), methanol, various feedstocks for plastics and other chemicals, and iron metal in gas-DRI plants. Energy uses are most important in the chemical and manufacturing industries, followed by minerals processing (mostly for materials other than iron).

Around 16 percent of gas is consumed in residential and commercial buildings, mostly for space and water heating with a smaller role for cooking and cogeneration.

Around 6 percent is used for transport in these countries. Cars running on natural gas are fairly common in China and India, where they have been adopted in part to reduce air pollution.

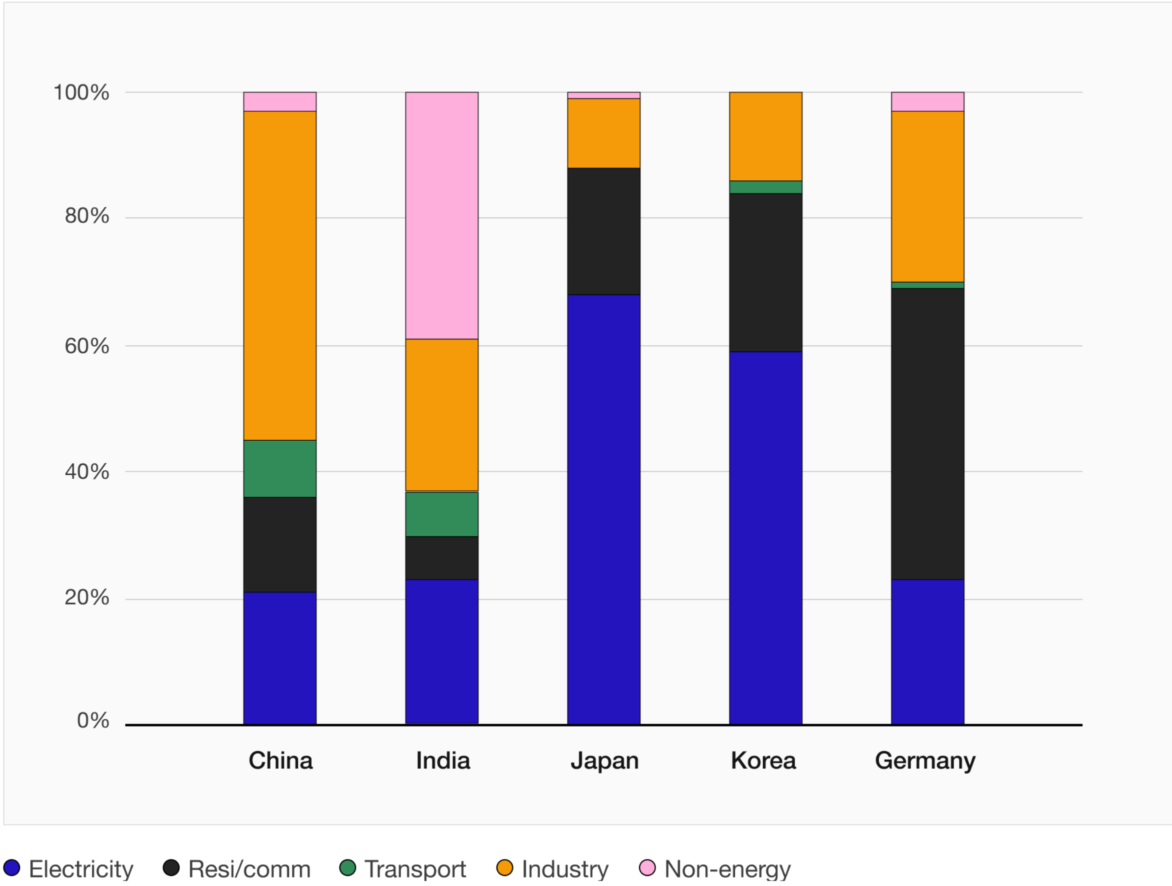

Figure 3.2. Uses of gas across the five key countries

3.3 Oil

Figure 3.3 summarises the use of oil across China, India, Japan, Korea, and Germany.

Around 54 percent of oil is consumed by the transport sector. Passenger vehicles and light trucks consume 63 percent of transport oil, and medium/heavy trucks another 19 percent. Around 7 percent goes to aviation, including military aviation, and around 5 percent to maritime shipping. The remainder goes to trains and other unspecified uses.

Around 38 percent of oil is consumed by industry. This includes around 14 percent for energy uses and another 24 percent for non-energy uses. Oil is the dominant feedstock for making plastics and various other petrochemicals.

Around 13 percent of oil is consumed in the residential, commercial, and agricultural sectors. Oil is used to fuel various kinds of agricultural machinery (tractors, combines, and irrigation systems) and backup generators, and heating oil is still commonly used to warm buildings especially in rural areas.

Only 1 percent of oil is used for electricity generation.

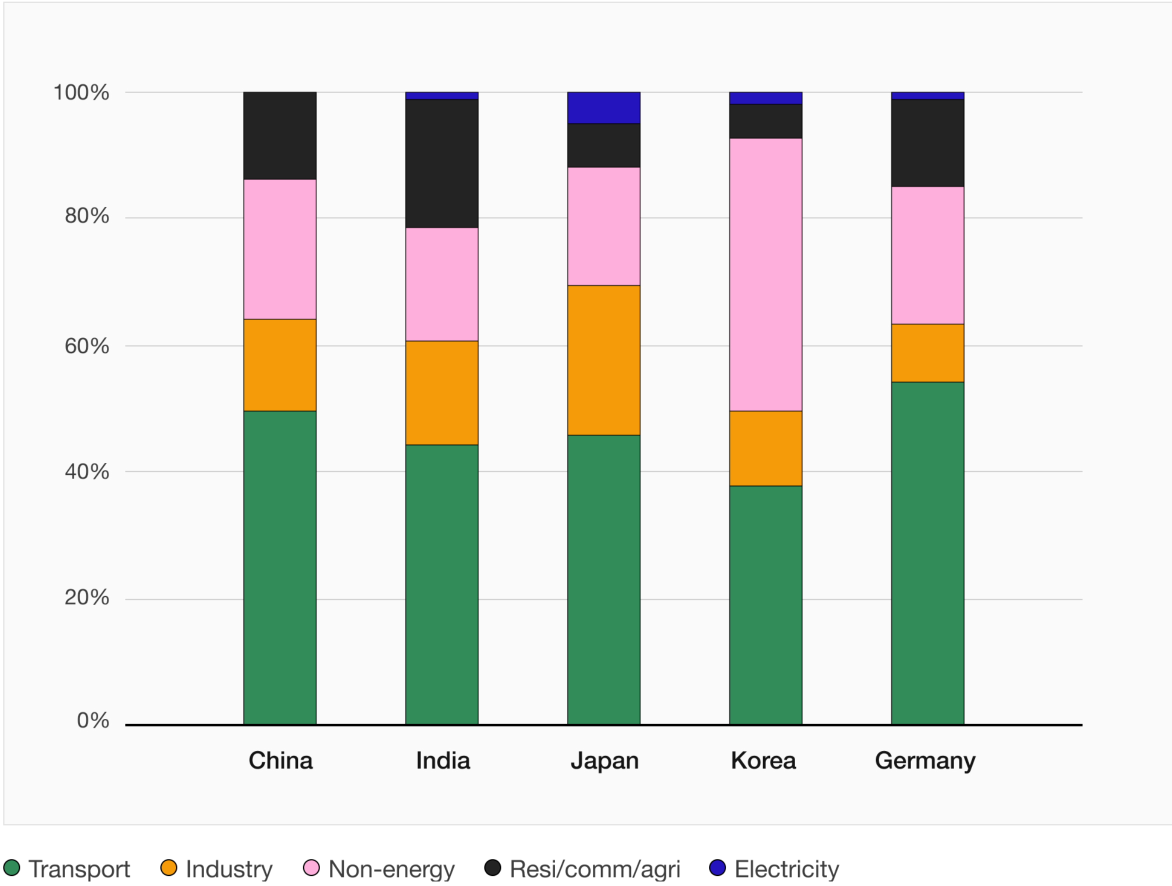

Figure 3.3. Uses of oil across the five key countries.

3.4 Electrification: High-level feasibility and efficiency

The next step is to answer two questions:

- Which uses of coal, gas, and oil can be electrified?
- What is the efficiency of electrification, i.e. how many units of generated electricity are needed to replace a unit of primary fossil fuel energy?

Volumes of (electrifiable) coal, gas, and oil consumption can then be multiplied by the relevant efficiency modifiers, to get an estimate of total electricity required for the maximally electrified economy.

A crude estimation can be conducted by considering the typical efficiency of conversion of fossil fuels into electricity, where losses are around 60 percent (BP, 2022, and author's analysis). Around 2.5 MWh of primary fossil energy is then required to produce 1 MWh of electricity. If all economic activity was electrifiable at this rate, then primary energy requirements would fall by 60 percent and electricity demand (on 2021 levels of consumption) would settle at around the levels in Figure 3.4.

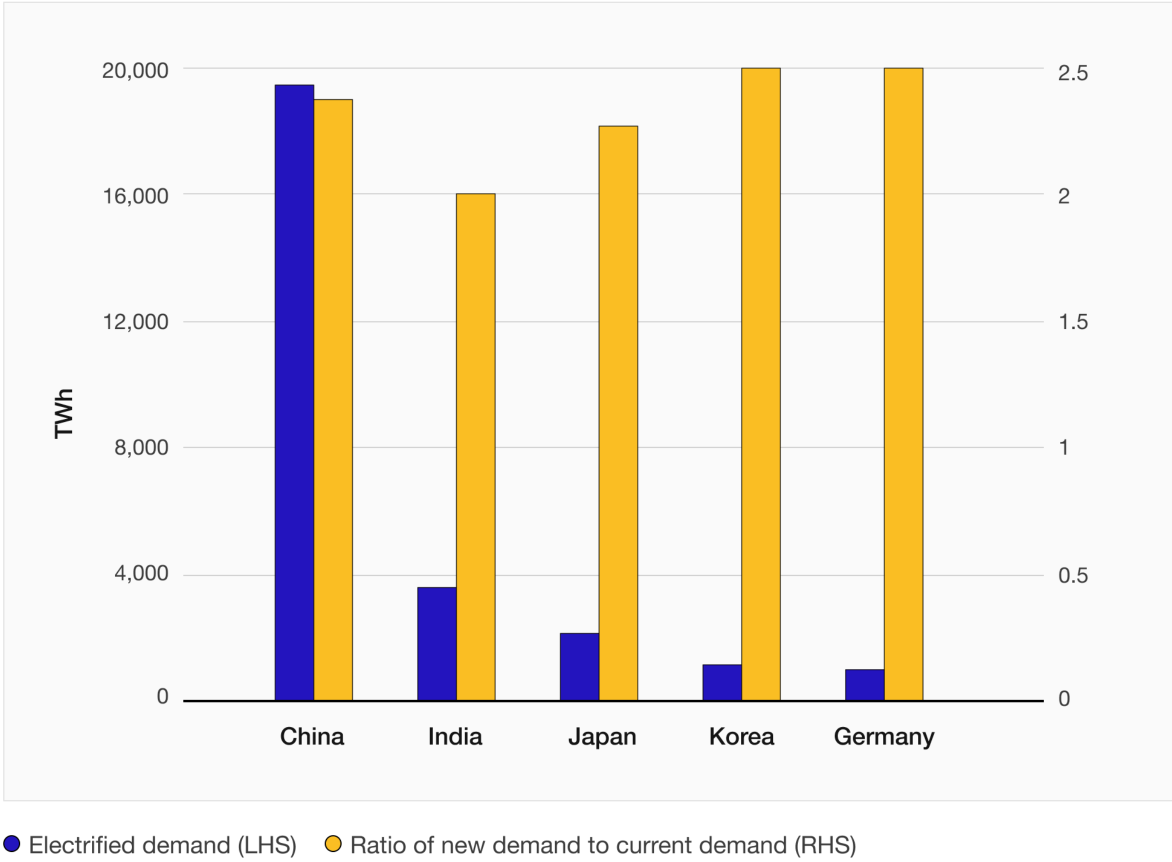

Figure 3.4. Crude TWh required for electrification of 2021 economies, assuming full electrification with a 60 percent decline in primary energy requirements.

Electricity requirements increase by 2 to 2.5-fold on these assumptions. However, a more detailed analysis is required. First, not all activities are electrifiable, although we will see here that the overwhelming majority are. Some activities, mainly the processing of fossil fuels, will largely disappear and will not need to be electrified. Second and more importantly, the efficiency of electrification differs greatly across activities, with primary energy requirements falling by more than a factor of 2.5 in some cases, and much less—with primary energy demand even sometimes increasing—in other cases.

We begin with a broad overview of electrification efficiency in major economic sectors, before turning to key energy-intensive industries.

Residential and commercial uses of coal, gas, and oil are fully directly electrifiable—that is, people can switch from combusting fossil fuels to directly using electricity. Demand is primarily for space and water heating/cooling, with lesser contributions from cooking and, especially in commercial buildings, heat and power cogeneration. Electric heat pumps are especially advantageous, requiring less than one third of the energy to produce the same output as fossil equivalents. Electrifying gas stoves and gas cogenerators offers smaller gains, on the order of 50 percent. Overall, energy requirements fall by 66 percent.

Agricultural uses are treated as fully electrifiable, around 90 percent directly and the remainder indirectly (recalling that indirectly electrified processes use fuels that are themselves produced mainly from electricity). Heavy vehicles are the most challenging to electrify, but around half of the heaviest tractors may already be electrifiable today.[21] Energy requirements again fall by around 66 percent overall.

[21] Around half of heavy-duty tractors are already electrifiable according to the NACFE (2022).

Road transport is electrifiable by a combination of direct and indirect means. Those methods of decarbonisation that rely on biomass as a feedstock also require significant electricity input, for reasons discussed in Chapter 4.

- Passenger vehicles, light trucks, and medium trucks are directly electrifiable, with EVs cutting delivered energy needs by 68-73 percent.
- Heavy trucks and other heavy vehicles are more difficult to directly electrify, although constraints on battery energy output and range are being overcome. The IEA (2021b) expects around 60 percent to be electrifiable with batteries, with the remainder covered by green fuels. The feasible battery-electrifiable share is growing and probably at least 80 percent. See Section 4.9 for the detailed analysis.

Among the above cases of electrification, average reductions in primary energy use are greater than the 60 percent used in the crude electrification estimate (with the exception of heavy trucking). For the uses that follow, efficiencies are much lower. These will be the main contributors to higher-than-expected electricity demand, and as such are the main substance of the superpower trade.

Non-road transport is electrifiable by a combination of direct and indirect means, with the addition of carbon in some methods.

- Shipping may be directly and indirectly electrified. Inland and short-sea shipping routes can be covered by batteries. Long-distance or “deep sea” shipping is indirectly electrifiable through the production of green fuels, although efficiency is low and significant carbon inputs are required for some fuel types. See Section 4.7 for the detailed analysis.
- Aviation can only be directly electrified over short distances. Indirect electrification of the remainder via green fuels is challenging and inefficient, with electricity requirements rising to extreme levels for some technologies. See Section 4.8 for the detailed analysis.

Industry is mostly electrifiable via direct and indirect means. Electrifying energy uses is most straightforward; Madeddu et al. (2020) find that around 78 percent of energy uses of fossil fuels can be directly electrified today, and this rises to 99 percent including technologies currently under development and likely to be available before 2050. Non-energy or feedstock uses of fossil fuels are mostly indirectly electrifiable, either fully (e.g. ammonia via hydrogen) or in combination with biomass or other carbon feedstocks (where electricity is required to increase carbon utilisation).

Among the non-superpower industries, some are non-electrifiable or difficult to electrify. Cement-making is the most important and is accounted for explicitly. Fossil fuel extraction and refining is also not electrified: demand for fossil fuels will sharply fall, with some remaining for CCS, feedstock uses, and other residual demand.

The most significant component that is treated as mainly non-electrified, and that continues to be made from fossil fuel feedstocks rather than biomass, is that of plastics. Plastics are discussed further in Section 4.10. In short, they are highly stable materials, with CO2 locked away in plastics on the scale of several centuries, and they are extremely demanding in terms of energy and carbon requirements. They are therefore treated as among the lowest of mitigation priorities. There will be some opportunity for chemically recycling the carbon in plastics through pyrolysis, gasification, or other processes (e.g. solvolysis), which can break down plastics to their simpler building blocks.

It is assumed that around 50 percent of oil industry activity, and 30 percent of residual gas and coal after accounting for the key tradable industries, will not be electrified in any scenario. In the maximally electrified model, from 30 to 50 percent of all industrial fossil use is non-electrified depending on the fossil fuel consumption profile of the different countries. Of course, the non-electrified percentage will increase as CCS and biomass are included in later chapters.

For the electrified industries, on average, efficiency gains from electrification are low. As McKinsey (2020) write in the case of industry, "[m]ost electrical equipment for industry is no more energy efficient than conventional equipment." Gains are low because industrial heat generation with fossil fuels is already highly efficient,[22] and electric heat pumps—which provide the greatest efficiency gains—are only useful for lower temperature processes (commonly <100°C but increasingly up to 200°C, with efficiency declining as temperature rises). The majority of industrial energy is consumed in high-temperature processes, above 200°C and into the thousands of degrees.

The superpower and non-superpower industries account for about half of all industrial energy demand each. For the non-superpower industries, I estimate modest average efficiency gains of 30, 10, and zero percent for replacement of coal, gas, and oil respectively. This is on the assumption that there is some improvement in electrification efficiency over time. Plastics are taken as a case study for oil in Section 4.10, to illustrate the inefficiencies of industrial electrification.

Now we turn to the superpower industries and green fuels in more detail.

[22] E.g. conventional gas boilers are around 70-80 percent efficient, and high-end condensing boilers may reach up to 98 percent efficiency.

04.

Electrifying the "superpower" industries

The superpower industries are those that are (A) tradable and that are (B) electricity-intensive. They are industries that, in an open global economy, would be predominantly located in countries with a comparative advantage in clean energy. The key industries examined here are iron and steel, aluminium, ammonia and urea, industrial methanol, green fuels for heavy freight, shipping, and aviation. Others of interest, for later work, include plastics and data centres.

Numerous data sources are employed, and data is mainly from 2021 to ensure consistency with the sectoral assessments of Chapter 3. For aviation, 2019 data is used instead to avoid distortion by the COVID disruptions. For polysilicon, 2023 data is used to capture the rapid ramp-up of the industry.

4.1 Iron and steel

Around 2 billion tonnes of steel are produced each year across the world, with more than half (1035 million tonnes) produced in China. Our main interest is the two thirds of global steel, around 1,334 million tonnes, that is primary steel—new steel made from iron ore. The balance is secondary steel, recycled from scrap. The processing of scrap is already electrified and is much less energy-intensive than the production of primary steel. China accounts for more than 60 percent of primary steel production, and Japan, Korea, India, and Germany together account for another 18 percent.

Table 4.1. Key country steel production, metallurgical coal consumption, and the Australian iron ore share in steel production

	Steel (Mt)	Primary steel (Mt)	Share global primary steel	Metallurg. coal consumed (Mt)	Australian ore share
World	1962	1334	100%	1110	~38%
China	1035	807	60.5%	720	52%
India	118	95	7.1%	75	0%
Japan	96	66	5.0%	44	53%
Korea	70	56	4.2%	37	62%
Germany	40	22	1.7%	15	0%

Note: "Mt" is million tonnes.

Globally, steelmaking consumed around 1.1 billion tonnes of metallurgical coal, producing nearly 3 billion tonnes of CO2 emissions. The IEA finds that indirect emissions, from electricity use and the combustion of off-gases, raise steel emissions by around 42 percent. The total would therefore be a little over 4.2 billion tonnes of CO2.[23] This amounts to around 12 percent of global fossil fuel emissions, or as much as 8.6 percent of global emissions from all sources.

China is responsible for around 65 percent of global steel emissions, a little more than its share of total steel production due to its higher-than-average carbon intensity. The focal countries—China, India, Japan, Korea, and Germany—together are responsible for around 80 percent of emissions generated by the steel manufacturing process.

Conventional primary steel is made in a two-step process. First, in a blast furnace (BF), metallurgical coal is used to provide heat and to supply the carbon needed to strip oxygen atoms from iron ore (usually hematite, Fe_2O_3) to produce molten iron metal. Second, in a basic oxygen furnace (BOF), oxygen is blown through the molten iron to oxidise and remove impurities, and to lower the carbon content of the melt to produce steel of the desired grade. Together this is termed the BF-BOF process.

The ironmaking step is fully electrifiable through numerous different processes. However, one minor chemically essential step in steelmaking is generally non-electrifiable: turning iron into steel requires the addition of a small amount of carbon.[24]

The most commercially developed process is "H2-DRI-EAF": Electrolysis of water produces hydrogen (H2), which is used to produce direct reduced iron (DRI) from iron ore. This iron is then mixed with carbon in an electric arc furnace (EAF) to produce steel.[25] A major disadvantage of the DRI process is that, lacking the purifying BOF process, it requires high grade iron ore of >67 percent. This usually means using magnetite, Fe_3O_4, because its magnetic qualities facilitate its concentration into high proportions of iron. Only around 3 percent of the seaborne iron ore trade is fit for DRI today (Gadd et al., 2023).

A modified version, "H2-DRI-SMELT-BOF", replaces the EAF with a smelting process that allows iron to be delivered to a conventional basic oxygen furnace (BOF). The advantage of this process is that the smelting can remove impurities from the lower grade ores that make up most of the seaborne trade. The disadvantage is the modest increase in energy consumption introduced by the smelting step. It also requires additional capital equipment, although this may in some cases be offset by allowing the continued use of existing BOFs. Other promising strategies that are compatible with lower-grade ores are discussed in Box 4.1.

How much power is required to electrify steelmaking? In the case of H2-DRI-EAF, estimates in the peer-reviewed and grey literatures range from 3.48 to 4.5 MWh per tonne of primary steel, with the lower end being near the theoretical ideal. The most detailed and cited recent study, Bhaskar et al. (2020), gives a figure of 3.72 MWh/tonne.[26] This value is used as the lower end of the range, and 4.5 MWh/tonne as the upper end. Electrification thus brings efficiency improvements, given conventional steelmaking requires around 20 GJ, or 5.6 MWh, of fossil fuels per tonne.

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[23] IEA (2019) figures are 2.6 billion tonnes of direct emissions and 1.1 billion tonnes of indirect, for a total of 3.7 billion tonnes. The difference may partly be due to the sharp rise in steel production to 2021, the data year for this study. IEA and EIA figures also differ; the EIA identifies higher emissions for China, especially for coal, where undercounting problems remain large (see for example Pearce, 2024).

[24] There are two exceptions: First, DAC effectively converts electricity into carbon, but is too expensive to consider here. Second, researchers have proposed the capture and electrolysis of CO2, allowing the reuse of carbon (Swinburne, 2021). This process is at a very early stage of development.

[25] Some carbon may also be added at the DRI step. Added carbon may come in the form of scrap.

[26] Higher because they account for required pre-heating of both iron and hydrogen inputs.

Box 4.1. Green iron/steel technologies compatible with low-grade ores

Some prospective technologies are less sensitive to the presence of impurities, and so can handle lower-grade ores. Given the world's limited reserves of high-grade iron ore, the advancement of these technologies is essential for long-term zero-carbon production of primary steel. All of these technologies are still under development, but, if successful, are expected to be ready for commercialisation at scale in the 2030s. The list below is not exhaustive, but covers the best-known strategies.

Direct electrification processes are variations on the theme of electrolysis. They include:

- low-temperature electrolysis in an alkaline/acid solution, plus an EAF (e.g. Australian firm Element Zero and US firm Electra);
- molten oxide electrolysis (MOE, see Boston Metals).

Indirect electrification processes, alongside H2-DRI-EAF and H2-DRI-SMELT-BOF, include fluidised bed reactors, a mode of hydrogen DRI that is suited to lower grade iron fines (e.g. Cicored, HYFOR, and Posco HyREX).

Lastly, there are partially electrified biomass-based approaches, such as Rio Tinto's BioIron project south of Perth which combines biomass with microwaves. Note the analysis suggest that biomass-based technology has limited potential at a larger scale due to carbon scarcity, and is therefore less relevant (see Chapter 7).

Direct electrification via electrowinning has slightly lower energy requirements in theory, partly because it avoids losses from hydrogen production. It is unclear if these will be realised in practice. Boston Metals, one of the leading firms born of MIT electrowinning research, has a target of 4 MWh/tonne. The CO2 electrolysis process will also have similar power requirements to H2 electrolysis.[27]

Whatever the technology, expected energy requirements are similar. Final energy demand of 5,370 to 6,500 TWh is required to produce green steel via hydrogen DRI globally. Based on current levels of primary steel production, around 3,250 to 3,930 TWh would be required in China alone, and another 960 to 1,160 TWh across Germany, India, Japan, and Korea. This is an extremely large amount of electricity: electrifying China's and Korea's steel industry would require electricity equivalent to around 60 to 70 percent of their total generation from fossil fuels today.[28] Finally, accounting for expected growth in demand for primary steel of around 10 percent to 2050 and holding this constant to 2060, the global range increases to 5,900 to 7,150 TWh.

Whatever the technology, the ironmaking step accounts for most of the energy required—in the case of hydrogen reduction, as much as 88 percent.[29] Both green iron and green steel may be produced economically in renewable-rich countries, but the gains are by far largest for green iron.

[27] The theoretical efficiency limit for H2 production is around 39 MWh/tonne. Converting CO2 to CO theoretically requires at least 3.2 MWh/tonne, but about 14 times more CO is required than H2 for the same reducing power. Thus 36 MWh of CO2 electrolysis is equivalent to 39 MWh of H2 electrolysis (Küngas, 2020). In practice, CO2 electrolysis is currently less efficient.

[28] Lower-end figures for India, Japan, and Germany are 29, 39, and 34 percent respectively.

[29] See Figure 9 in Bhaskar et al. (2020)

4.2 Aluminium

In 2021, the world produced around 67.5 million tonnes of primary aluminium and around 22.5 million tonnes of secondary, or recycled, aluminium. The latter is already fully electrified.

Primary aluminium is mainly produced from bauxite ore, which at the higher grades found in Australia and Guinea—the top exporters—typically contains around 50-60 percent aluminium oxide. Bauxite is refined via the Bayer process into alumina, in which the aluminium oxide purity reaches around 99 percent. From there, the Hall-Héroult electrolytic reduction process strips the oxygen from alumina and converts it into aluminium.

The Hall-Héroult process is the main source of emissions in primary aluminium production. It is already mostly electrified, so most aluminium emissions can be avoided simply by using clean electricity. In China, the world's main aluminium producer and the importer of nearly all of Australia's exported bauxite, more than 80 percent of aluminium smelter electricity comes from coal power plants (IEA, 2023). The process consumes around 13-15 MWh per tonne produced (Obaidat et al, 2018; Shen & Zhang, 2024), and a typical modern coal power station releases around 1 tonne of CO_2 per MWh, so coal-powered Hall-Héroult would release around 13-15 tonnes of CO_2 per tonne of aluminium.

One part of the Hall-Héroult process is non-electrified: like the iron-making process, aluminium smelting currently uses fossil carbon. After aluminium oxide (Al2O3) is dissolved in cryolite, the aluminium ions migrate to the cathode and settle as pure aluminium metal, while the oxygen ions migrate to the carbon anode and react to produce CO2. Around 450 kg of carbon is typically consumed per tonne of aluminium, releasing about 1.75 tonnes of CO_2 (Le Den et al., 2023).

Alumina refining via the Bayer process is the second most important emissions source in the aluminium production process, releasing around 1-3 tonnes of CO_2 per tonne of aluminium. This is mainly from fossil fuel thermal energy used to power the chemical reactions, with some contributions from electricity inputs and chemical process emissions (e.g. the use of lime and other carbonates). Some other steps, such as ingot casting, contribute a half tonne or so of CO_2 per tonne of aluminium.

Overall, coal-powered aluminium production releases around 18-22 tonnes of CO_2 per tonne of aluminium, but this may fall to around 4 tonnes for current best-practice producers using green electricity. In Europe, North America, and South America, aluminium smelting is mainly powered by hydroelectricity, and less than 7 tonnes of CO_2 per tonne of aluminium is typical (International Aluminium Institute, 2023; Maratou & Marcu, 2021).

Advances in electrifying alumina production (e.g. Alcoa's world-first pilot, see ARENA, 2022), and replacing carbon anodes with alternatives (e.g. with inert anodes that release oxygen instead of CO_2; see He et al. 2021), may push emissions close to zero. Both add to electricity demand. Electrifying alumina production may add up to 5 MWh per tonne of aluminium (Le Den et al., 2023). Use of inert anodes is likely to increase Hall-Héroult electricity requirements given the chemical energy in the carbon anode is no longer available. The analysis in Saevarsdottir et al. (2024) implies an increase in Hall-Héroult electricity demand of around 27 percent, to 16.5-19 MWh per tonne. Thus, more completely electrified aluminium production may require on the order of 22-24 MWh of electricity per tonne.

Finally, it is assumed that advances in process efficiency into mid-century can offset this increase and limit electricity demand to 18 MWh per tonne.

Global primary aluminium production in 2021 was 67.5 million tonnes, with total emissions of around 1.1 billion tonnes of CO_2—about 3 percent of global fossil fuel emissions (International

Aluminium Institute, 2023). Nearly 60 percent of primary aluminium is produced in China, which on a simple analysis would account for around 635 million tonnes of CO2. However, China's aluminium-making is primarily fuelled by coal: aluminium-making consumes about 422 TWh of coal in China, while the rest of the world uses only 58 TWh of coal and around 80 TWh of gas (ibid.). This suggests emissions of at least 700 million tonnes in China.[30]

More completely electrifying today's production, at 18 MWh per tonne, would lead to final electricity demand of around 1,220 TWh. The IAI forecasts that primary aluminium production will rise 33 percent to around 90 million tonnes by 2050 (International Aluminium Institute, 2023), which would raise global electricity requirements to around 1,620 TWh. It is assumed that demand is then flat to 2060.

4.3 Silicon and polysilicon

A total of around 9.2 million tonnes of silicon was produced in 2021, according to the US Geological Survey (US Geological Survey, 2023). Around 40 percent of this, or 3.7 million tonnes, was in the form of relatively pure metallurgical grade (MG) silicon. The remaining 60 percent, around 5.5 million tonnes, is alloyed to iron in ferrosilicon. Including the iron content, nearly 8 million tonnes of ferrosilicon were produced in 2021.[31]

Polysilicon is a highly purified, polycrystalline form of silicon composed of many small silicon crystals fused together. It is primarily used in the production of solar cells and semiconductor devices. Output is increasing exceptionally rapidly as demand for solar panels soars, so it is worth using more recent data from 2023 and placing additional emphasis on forecasts. At least 1.5 million tonnes were produced in China in 2023 according to Shanghai Metals Market (2024) analysis, with roughly another 150,000 tonnes across various other countries.

The IEA finds that a doubling of polysilicon production is required by the early 2030s, and Hallam et al. (2022) anticipate roughly a further doubling by 2050 to 6-7 million tonnes annually. Setting aside semiconductor demand, at current rates of production efficiency this would be enough to produce around 1.6 to 1.8 TW of solar PV capacity per year.[32] Assuming improvements in polysilicon production efficiency and some recycling, this level of production will be around enough to satisfy demand forecast in this paper.

The semiconductor industry accounts for a small share of polysilicon production, but reportedly consumed around 149 TWh of electricity in 2021 (Q. Wang et al., 2023). There are no known projections in the scientific literature, but market analysts generally forecast more than a doubling of output between 2020 and 2030 (e.g. McKinsey, see Burkacky et al., 2022). If the growth rate

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[30] There are discrepancies between Chinese and global analyses of aluminium industry emissions. Peng et al. (2022), for example, identify Chinese emissions of around 620 million tonnes in 2021 (16 tonnes of CO2 per tonne of aluminium, with ~39 million tonnes produced). However, Peng et al. also find that Chinese production is 1.5 – 3.5 times as emissions-intensive as other locations. If that is so, then global emissions would be well under the 1.1 Gt reported by the IAI (2023) and 1 Gt reported by the IEA (2023). The estimate in-text is consistent with increased Chinese production since 2013 (a 78 percent increase) with continued heavy use of coal. In 2013, emissions were 421 million tonnes; this would point to ~750 million tonnes today at the same intensity (Hao et al., 2016). It is also consistent with about 670 million tonnes of CO2 in 2020 reported by Yang (2021), with production increasing by about 5.4% to 2021.

[31] The most common ferrosilicon grade is 75% silicon, used mainly in steelmaking, although grades vary from 15% to 95%. Grades below 75% are more common than those above, so I assume an average grade of around 70%.

[32] Only around 1.8 tonnes of polysilicon is needed per MW. However, there are large losses in polysilicon production, with polysilicon utilisation rates of around 45-50 percent (Hallam et al., 2022). Thus around 3.8 tonnes are needed per MW in practice.

halves thereafter, semiconductor production will more than quadruple by 2050 and increase 6-fold by 2060.

Around 70 percent of silicon and 90 percent of polysilicon is produced in China (US Geological Survey, 2023). Brazil and Russia are also major silicon producers, while polysilicon is produced in smaller amounts in only a few countries, notably Germany. China's share in semiconductor chip production is surging; it reached 98 billion units in Q1 2024 (Mo & Goh, 2024), which implies a production share of around 25-30 percent.[33] Chinese production is concentrated in less advanced products.

Silicon production again involves chemical reduction. It begins with silicon dioxide, in the form of quartz or less commonly silica sand, and uses coke or coal to strip the oxygen from the silicon. It is not electrolytic like Hall-Héroult aluminium-making, and does not depend on direct use of fossil fuels like an iron blast furnace. Rather, it involves carbothermic reduction in an electric arc furnace.

What it shares with aluminium is that the majority of its emissions come from its electricity consumption. Around 8 MWh of electricity is required per tonne of ferrosilicon (FeSi), and around 12 MWh per tonne of metallic-grade (MG) silicon. The large majority of silicon is produced in China, mostly using coal power and so releasing roughly a tonne of CO_2 per MWh consumed.

To that we can add process emissions. Theoretically, reduction requires around 855 kg of carbon per tonne of MG silicon, which would release around 3.1 tonnes of CO_2. Reported process emissions are around 4.7 tonnes of CO_2, reflecting inefficiencies and other minor contributors to total emissions. Reported process emissions for FeSi are lower, at around 3.4 tonnes of CO_2 per tonne, because the added iron has already been reduced, and there is less silicon dioxide to reduce per unit of output.

Total emissions are therefore around 16.7 tonnes of CO_2 per tonne of MG-silicon and 11.4 tonnes of CO_2 per tonne of FeSi, if electricity is sourced from coal. Using clean electricity is the most important step in emissions reduction, cutting emissions by around 70 percent in both cases and leaving the remaining process emissions.

Globally, MG-silicon and FeSi are associated with around 150 million tonnes of CO_2 emissions. Polysilicon is associated with on the order of 190 million tonnes. If silicon production doubles, and polysilicon production increases fourfold, these rise to 300 and 760 million tonnes of CO2 respectively—together equal to around 2.8 percent of today's fossil emissions.

Alternative technologies for eliminating the emissions associated with carbon reduction are under development.

- **Biomass charcoal:** The most straightforward is the use of charcoal derived from biomass, which requires little change in current practices but—as we will see later—relies upon a biomass carbon resources that will be scarce.
- **Metallothermic reduction**: Using one metal (e.g. aluminium, magnesium, or zinc) to strip the oxygen from silicon.
- **Electrolytic reduction:** A process like Hall-Héroult aluminium-making, which could similarly use an inert anode to avoid carbon emissions.
- **Hydrogen reduction:** A process akin to H2-DRI but for silicon, where hydrogen gas is used to strip oxygen and produce water.

[33] Global production in 2021 was 1.15 trillion units, and China's 2024 output suggests around a 25-30 percent share. China had a 12.7 percent share in 2016, which some analysts expect to rise to nearly 40 percent by 2030 (IDC, 2024), concentrated in less advanced products.

Adding these processes could reduce silicon emissions to nearly zero. They would likely entail a significant increase in electricity requirements, given the loss of the chemical energy ordinarily provided by carbon. As for aluminium, the increase in energy requirements without carbon is assumed to be offset by efficiency improvements. Thus, as in 2021, MG-silicon still requires around 12 MWh per tonne, and FeSi around 8 MWh per tonne.

Finally, let us return to polysilicon. Production is usually via the Siemens process, where MG silicon is turned into a vapour by reaction with hydrogen chloride, and that vapour deposits high purity silicon in a high-temperature reactor. Carbon inputs are not required, and emissions are overwhelmingly from the electricity consumed in production—around 100 MWh per tonne of polysilicon refinement and ingot casting is typical for solar-grade silicon (Hallam et al., 2022; Bye & Ceccaroli, 2014), although electricity demand increases sharply for higher-purity semi-conductor applications that are presently growing rapidly. Efficiency improvements and growth in high-purity applications are assumed to offset one another.

Total clean electricity required to power present-day production is about 360 TWh (44 TWh for MG-Si, 63 TWh for FeSi, 105 TWh for PV polysilicon, and 150 TWh for semiconductors). If silicon production doubles, PV polysilicon production increases fourfold, and semiconductor production increases 6-fold, around 1,225 TWh of clean electricity would be required.

4.4 Ammonia

Around 188 million tonnes of ammonia was produced in 2021 (IEA, 2021). A little over half is consumed in the production of urea,[34] the world's most important nitrogenous fertiliser, while the remainder is used to make other fertilisers and a variety of chemical products.

Production forecasts vary greatly, depending on whether ammonia is used widely as a green fuel in vehicles, or for co-firing especially in coal power stations (e.g. IEA, 2021a). The importing and storage of ammonia may be especially important for firming the grid and supplying backup power for countries including China, Japan, and Korea. Fertiliser and chemical use alone will drive modest growth to 2050 on the order of 40 percent (IEA, 2021). Saygin et al. (2023) predict a three to fourfold increase in demand by 2050 on a 1.5-degree pathway.

Here it is assumed that demand will increase threefold by 2050 and fourfold by 2060, to 752 million tonnes. This may be a significant underestimate of global demand if ammonia enters into widespread use as a long-term energy store.[35] 752 million tonnes, combusted in 40 percent efficient power stations, produces around 1,500 TWh of electricity—a small fraction of future global electricity demand.

Korea, for example, targets around 25 million tonnes of ammonia by 2036 (ITA, 2023), and a 13.8 to 21.5 percent share in electricity generation by 2050 (Ammonia Energy Association, 2021). On the demand levels forecast in this paper, this would require as much as 210 million tonnes of ammonia. More conservatively, it is assumed that the planned growth rate from 2027 to 2036

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[34] Starting with IEA (2021a) numbers, stoichiometry implies that 53 percent of ammonia is used to make urea (177 million tonnes of urea produced, requires 100 million tonnes of ammonia, also 132 million tonnes of CO2 or about 35.5 million tonnes of carbon). About 88 million tonnes of ammonia would go to other purposes. This is similar to Boulamanti & Moya (2017), who found that 48 percent of ammonia is used to produce urea.

[35] Japan, Korea, and China's offshore wind farms will be vulnerable to typhoons that can disrupt power output for a week or longer. China's heavy dependence on its northern solar and wind resources will make it vulnerable to Gobi desert dust storms, which can last several days. Japan presently anticipates utilising around 30 million tonnes of ammonia by 2050 (Yoshida, 2024; Watanabe, 2022), and Korea around 18 million tonnes by 2036 (ITA, 2023), though these volumes must grow significantly if they are to provide significant backup power.

continues linearly, so that demand reaches 70 million tonnes by 2060. These figures are extended to Japan.[36]

Today China is the top producer, with around a 30 percent global share. Other important producers include India, Russia, the US, the Middle East, and Europe, which account for another 8-10 percent each. A majority of it is consumed on-site for production of fertilisers; global trade amounts to only about 10 percent of ammonia production.

Ammonia synthesis is by natural gas steam reformation or by coal gasification, followed by the Haber-Bosch process—the combining of purified (brown) hydrogen with nitrogen from the air. Natural gas-based production dominates globally, but coal gasification is the dominant mode in China. Thus, while China accounts for around 30 percent of ammonia production, the IEA reports that it accounts for around 45 percent of CO_2 emissions (IEA, 2021).[37] Global emissions attributed to ammonia production are around 450 million tonnes of CO_2, or about 1.2 percent of global fossil fuel emissions.

Ammonia is one of the simpler industrial processes to electrify, being fully electrifiable using technologies at a relatively high level of readiness. Brown hydrogen is replaced by green hydrogen, which is produced in water electrolysers that are powered by zero-carbon electricity. Green ammonia requires around 11.11 MWh per tonne produced (Kahn et al., 2023).

Globally, green ammonia production at today's levels would require around 2,100 TWh of clean electricity. If demand increases fourfold, it will require around 8,400 TWh in 2060, or around as much electricity as is fed into the entire Chinese national grid in one year. China, India, Japan, and Korea would account for more than half of this global demand.

4.5 Urea

Around 177 million tonnes of urea were produced in 2021, with an international distribution of production similar to that of ammonia. China is again the largest producer and consumer of urea, with around a 30 percent share. Urea, however, is more easily transported than ammonia, and so is more heavily traded—on the order of 30 percent is exported. The Middle East is the largest urea exporter: it has cheap gas for urea production, but less use for urea given scarce arable land and water. India and Brazil are the largest importers.

Urea synthesis occurs via the Bosch-Meiser process. The reaction requires carbon—urea is made by joining two ammonia molecules via a carbonyl group—and that carbon is readily available from the CO_2 released in ammonia production. Around one third of ammonia emissions, 125-150 million tonnes of CO_2, are captured and reused in urea production (IEA, 2020a; Smith et al., 2020), and this CO_2 is released again when the fertiliser is used.

Urea synthesis is exothermic, meaning that no energy input is required beyond the little needed to power pumps and compressors. Because ammonia and urea plants are highly integrated, urea-specific energy requirements are opaque. Reports generally range from 0.6 to 1.4 MWh per tonne (e.g. Batool & Wetzels, 2019), and Kahn et al. (2023) report 1.8 MWh per tonne for a slightly modified synthesis. To avoid overestimation, a value of 1 MWh per tonne is assumed. Given

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[36] Japan currently plans for 30 million tonnes of ammonia demand by 2050 (Yoshida, 2024; Watanabe, 2022), similar to what Korea plans by 2036. This will be grossly inadequate, so expected demand for Korea is replicated for Japan. Because Japan has markedly higher electricity demand, the role of ammonia in Japan stays proportionally smaller.

[37] This is consistent with a typical ratio of coal to ammonia of 1.6, and coal emissions of around 2.3 tonnes of CO_2 per tonne consumed (bituminous/sub-bituminous). China's emissions would be around 200 million tonnes, or 40 percent of the global 450 million tonnes recorded by the IEA (2021a).

CO2-intensities of electricity grids in the major urea producers, this implies emissions of around 0.3 tonnes of CO2 per tonne of urea.[38] Global emissions would be 53 million tonnes of CO2.

Greening urea production requires clean electricity and a sustainable carbon source. Around 1 MWh is needed per tonne of urea synthesised from biomass, the most likely route. This rises to 1.75 MWh per tonne where carbon is derived from DAC.[39] The range of potential global clean electricity demand is therefore 177 to 309 TWh at 2021 levels of production. With 50 percent growth in demand, this may increase to around 266 to 464 TWh by 2050. It is assumed that there is no further growth to 2060.

4.6 Methanol (industrial)

Approximately 110 million tonnes of methanol are produced each year (Deka et al., 2022), mainly as a feedstock for plastics and petrochemicals, with a smaller role as a fuel additive especially in China. Growth has been rapid, with production roughly tripling over the last twenty years (Alvarado, 2016; Deka et al., 2022). Under business-as-usual, given forecast plastic consumption growth at least 100 percent (see Section 5.4), we may expect another doubling to 2050. To be conservative, accounting for growth in recycling, this level of production is reached in 2060. Additional growth, driven by methanol use as a green fuel for shipping or road freight, will be considered in Sections 4.7 and 4.9.

China is the world's largest producer, accounting for nearly half of the total (AsiaChem, 2022). Other key producers are Iran, Saudi Arabia, Trinidad and Tobago, Latin America, Europe, and the US. Around a third or some 34 million tonnes is traded, with the Middle East, Trinidad and Tobago, and the US the top exporters (World Bank, 2024).

Roughly 40 percent of methanol is produced from coal, almost entirely in China, while the remainder is produced with natural gas. Methanol synthesis begins similarly to ammonia synthesis: brown hydrogen is generated via natural gas steam reforming or coal gasification. In this case, the carbon monoxide released from the gas or coal is retained and combined with hydrogen to produce methanol.

Production via natural gas releases around 2.2 tonnes of CO2 per tonne of methanol, while via coal it releases around 6 tonnes of CO2 per tonne.[40] Total emissions are therefore around 410 million tonnes of CO2 globally.

Green production can proceed via either the e-methanol or g-methanol routes. The e-methanol route combines a CO2 stream with hydrogen electrolysis, and is the most energy-intensive. Around 11 MWh is required per tonne produced, or 12 MWh with DAC carbon. The g-methanol route begins with a source of biomass or waste carbon, which is gasified and combined with some additional electrolyser hydrogen. Because the biomass/waste carbon input adds some energy and hydrogen to the process, less energy is needed—around 4.7 MWh is required per tonne (de Fournas & Wei, 2022, Supplementary data 1).

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[38] This is consistent with Khan et al.'s (2023) estimate of around 1.6 tCO2 per tonne of conventional urea: around 0.57 tonnes of ammonia are required per tonne of urea, which at IEA (2020a) emissions rates (2.4 tCO2 per tonne of ammonia) implies that ammonia production contributes around 1.3 tCO2 per tonne of urea, while urea synthesis adds the remaining 0.3 tCO2 per tonne. The total is thus 1.6 tCO2/t.

[39] DAC assumed to require 1 MWh/t in the future. About 0.75 tonnes of CO2 is required per tonne of urea.

[40] Based on 110g of CO2e/MJ for gas, 300g of CO2e/MJ for coal, and methanol energy content of around 19.9 MJ. See Methanol Institute (2022).

Electrification via the biomass-based g-methanol route brings around a 40 percent reduction in energy needs, while the DAC-based e-methanol route brings about a 55 percent increase in energy needs.

Total electricity required to green methanol therefore ranges from 525-1330 TWh, or around 1050-2660 TWh with anticipated growth to 2060. Again, this does not include expansion of methanol production as a green fuel, which is discussed in the next sub-section on shipping and Section 4.9 on medium-heavy trucks.

Carbon requirements are discussed in Section 5.4.

4.7 Shipping

Around 6 percent of global oil is consumed in the world's shipping industry, including deep sea or ocean shipping, short sea shipping, and coastal and inland waterway shipping. This amounts to around 2.1 billion barrels of oil per year, or around 11.6 exajoules of energy. Its combustion releases around 900 million tonnes of CO_2 (or around 2.4 percent of global fossil fuel emissions).

Deep sea shipping accounts for around 70 percent of fuel consumption and emissions in the shipping sector, short sea for around 25 percent, and inland for 5 percent. Some 40 percent of shipping carries fossil fuels, a segment that will all but disappear as the world decarbonises. The decline in the fossil fuel segment is assumed to be offset by a rise driven by other factors: continued population and economic growth, and the rise in the shipping of green fuels and goods embodying zero carbon energy. Shipping demand is therefore expected to be flat to mid-century.

All inland shipping will be directly electrifiable via batteries, and it is assumed this will be true for around half of short-sea shipping by 2060. The deep sea component is assumed non-electrifiable, so requires replacement with green fuel. All up, around 1.5 billion barrels of oil must be replaced for deep sea shipping, and another 260 million barrels for short sea shipping.

Green fuel options include hydrogen, ammonia, and methanol. Each has its advantages and disadvantages. The major advantage of hydrogen and ammonia is that they can be produced without a carbon input. However, hydrogen has very low volumetric energy density and is difficult to handle, requiring very high pressure and/or very low temperature storage. Leakage of hydrogen is difficult to control and introduces two risks: first, of explosion; and second, of methane generation via chemical reactions in the atmosphere, which would contribute to climate change. Ammonia has relatively low energy density, is highly combustible, and is exceptionally toxic both to humans and the marine environment.

For these reasons, methanol is viewed as the more favourable option. Its volumetric energy density is superior to hydrogen and ammonia, if still half or less than that of conventional marine fuels. It is non-explosive and non-toxic in marine environments, and requires the least adjustment to existing bunkering infrastructure and ship engines.

As discussed in the previous sub-section, from 4.7 to 12 MWh is required per tonne of methanol, for biomass-derived methanol and DAC-derived e-methanol respectively. To replace anticipated shipping fuel requirements would require around 482 million tonnes of methanol. This would require around 2,250 to 5,750 TWh for biomass and DAC routes respectively. Charging batteries for inland and short sea shipping would require around another 350 TWh, although this would not be a traded superpower industry but would occur as needed in most ports.[41]

[41] Taking conventional fossil fuel ship engines as around 50 percent efficient, while electricity transmission is 92 percent efficient, and electric engines and batteries are around 80 percent efficient.

The total efficiency gain in our base case, of batteries plus biomass-derived methanol, is 34 percent. With batteries plus DAC-based e-methanol, energy requirements instead increase over the fossil fuel baseline by around 50 percent.

Again, the carbon requirements of the methanol component are discussed in Section 5.4.

4.8 Aviation

Aviation in our base year of 2021 was dramatically curtailed by the COVID pandemic, so pre-COVID figures are used from 2019, which are expected to be a better estimate of demand as the recovery continues. On those figures, around 6.9 percent of global oil is used in aviation, equal to around 14.4 exajoules or 2.6 billion barrels of oil. Combustion releases roughly 1.1 billion tonnes of CO2, or nearly 3 percent of global fossil fuel emissions.

Growth projections generally fall in the range of 50-100 percent by 2050 (e.g. DITRDCA, 2024; EuroControl, 2022). Demand for air travel is heavily shaped by ticket prices, which in turn will be shaped by the costs of cutting aircraft emissions. If those costs are high, growth will be lower than anticipated. It is assumed that the upper end of this range, 100 percent growth, occurs by 2060.

Direct electrification of aviation, beyond shorter trips for the lightest aircraft, is improbable due to the low energy density of batteries: to provide energy equivalent to one tonne of aviation fuel requires about fifty tonnes of today's lithium-ion batteries. Aviation needs green fuels. There are two main options: First, sustainable aviation fuel, which mirrors the typical properties of jet fuel but is produced from a sustainable carbon feedstock. Second, hydrogen, which requires radically different infrastructure to conventional jet fuel and requires no carbon feedstock.

The disadvantage of sustainable aviation fuel (SAF) is its highly inefficient fuel production process. SAF can be produced more efficiently from vegetable oils (from the seeds or fruits of crops such as canola, soybeans, or the oil palm), but supply of that input is limited by its extreme land requirements (see Section 7.4). Arable land is required and productivity per hectare is low, because these plants only convert a fraction of solar energy into useful oils. Intensive use of conventional vegetable oils, such as soybeans and rapeseed, would strongly impact food prices and spur deforestation.

Waste oils are a helpful, but small-scale, alternative to vegetable oils.

Production of SAF at scale requires lignocellulosic energy crops, either herbaceous crops such as miscanthus (*Miscanthus x giganteus*) and switchgrass (*Panicum virtagum*), or woody plants such as Australia's mallees (e.g. *Eucalyptus polybractea*) and the various poplar species of Europe and the United States. They can be grown on marginal land, greatly reducing the impact on food prices. The whole above-ground plant can be used, rather than just seed or fruit oil, so that much more biomass—and energy—can be extracted per unit of land. Hundreds of millions, rather than billions, of hectares will be needed.

The conversion of whole-plant biomass into fuel, however, is complex and costly. This is particularly so for woody biomass due to its high lignin content. There are a few methods for getting from biomass to SAF: the Fischer-Tropsch (FT) synthesis; the methanol-to-jet (MtJ) pathway; and the alcohol-to-jet (AtJ) pathway. Key parameters of interest are the:

- carbon efficiency, or what percent of input biomass carbon is converted into the final fuel; and

- energy efficiency, or how much electricity and biomass energy is required to produce a unit of SAF.

We focus on the FT and MtJ pathways, given the especially low carbon and energy efficiency of the ethanol-based AtJ pathway (Voß, 2023).

Both FT and MtJ begin with gasifying biomass to produce syngas, a combination of carbon monoxide and hydrogen. In FT, the syngas is passed over a metal catalyst at high temperature, and this produces the desired hydrocarbons. In MtJ, methanol is first produced, then olefins, and finally the hydrocarbons. In both cases, the base process results in loss of a majority of the carbon input, and the future scarcity of sustainable carbon will make this unacceptable. The solution is to raise carbon recovery by adding hydrogen electrolysis to the system, although this will significantly raise electricity consumption (Hillestad et al., 2018).

Finally, both processes produce a variety of hydrocarbons, from light gases to heavy waxes. SAF requires hydrocarbons in the middle, of carbon chain length 8-16. Selectivity for SAF hydrocarbons can be improved, but further research is required. FT research suggests a SAF hydrocarbon selectivity limit of around 41 percent (Yang et al., 2020) and lower values are common (Eyberg et al., 2024), but selectivity as high as 72 percent has been reported using exotic catalysts (Li et al., 2018; Bube at al., 2024). MtJ selectivity exhibits a similar range. It is assumed that a future SAF selectivity of 50 percent may reasonably be achieved by mid-century.

Estimates of the energy efficiency of the FT process—i.e. how many units of fuel energy are produced per unit of energy input—vary enormously, from as little as 12.5 percent (CSIRO, 2023, low end)[42] up to around 70 percent (e.g. Hillestad et al., 2018; Bube et al. 2024; Atsonios et al., 2023). Van de Oever et al. (2022) survey the literature and find that various modelled strategies mostly cluster around 50 percent efficiency, so that around two MWh of input are required to get one MWh of fuel. Studies of MtJ generally find similar energy efficiencies to those of FT (Schmidt et al., 2018; Eyberg et al., 2024).

The energy input to the process includes both electricity and energy from biomass, and here it is the required electricity input that is of key interest. Low-electricity methods of production have unacceptable carbon efficiencies. In the US DoE's (2024) Billion Ton Report, carbon efficiencies of biomass conversion to fuel are around 32 percent. As discussed in Section 7.4, this raises sustainable carbon requirements to extreme levels.

It is possible to greatly improve carbon efficiency by adding hydrogen electrolysis. Dossow et al. (2021) is the most detailed recent study of combining FT with hydrogen electrolysis, and one experimentally validated in part by Todic et al. (2014). They find that adding hydrogen can raise final carbon efficiencies to 67-97 percent, and overall energy efficiency, including both biomass and electric energy inputs, is around 45-50 percent. To produce a barrel of liquid fuel containing energy equivalent to about 1 MWh would require biomass energy input of about 0.9 MWh and electricity input from 1.1 to 1.3 MWh.

At that conversion rate, total electricity requirements to produce around 14.4 exajoules of SAF (around 340 million tonnes) would be about 8,800 to 10,400 TWh. This is more than all the electricity consumed in China today. This high value is due to the inefficiency of indirect electrification plus the limited selectivity of the chemical processes for SAF (again, only a portion of FT and MtJ products will be SAF).

[42] The CSIRO's (2023, p. 105) low-end estimate is for a 5 percent by mass yield, so that one tonne of sugarcane bagasse yields 0.05 tonnes of jet fuel. At 17 GJ/tonne of bagasse, and 43 GJ/tonne of jet fuel, overall efficiency is 12.5 percent. The CSIRO's upper estimate is around 37 percent efficient. However, the studies cited are older and less technical.

A similar amount of lighter fuels and heavy waxes, i.e. around 14.4 exajoules in energy terms, will be produced as a byproduct. Most of this will have some market value. It is assumed that these byproducts are mainly recycled on-site back into the FT or MtJ process to produce more SAF. It is assumed that this raises SAF selectivity to 75 percent, and, optimistically, that the additional SAF produced from recycling requires 50 percent less electricity input. Total electricity requirements fall to 7,300 to 8,600 TWh.[43]

If direct air capture (DAC) of carbon becomes necessary due to limited biomass supply, then electricity demand increases sharply. This is due not only to the energy consumed by DAC, but more importantly due to the absence of biomass energy in the process. Assuming large advances in DAC efficiency, producing 1 MWh of liquid fuel would require around 2.4 MWh of electricity (Eyberg et al., 2024). With SAF selectivity of 50 percent, producing all jet fuel this way would require about 19,100 TWh. With recycling, energy requirements fall to 16,000 TWh.[44]

Finally, adding forecast growth in aviation of 50-100 percent, possible electricity consumption ranges from 11,100 TWh (with biomass and 50 percent growth) to 28,400 TWh (with DAC and 100 percent growth). These levels of electricity consumption are extremely high: 11,000 TWh is around 40 percent of, and 28,400 TWh more than 100 percent of, global electricity consumption in 2021. Without radical technical advances, DAC-based SAF is unlikely to be viable.

In the case of SAF, electrification efficiency is very poor: primary energy requirements per kilometre travelled increase by 85 to 255 percent, for the biomass and DAC routes respectively.

Hydrogen for aviation may appear unlikely given its low volumetric energy density, yet what matters most for aircraft is energy density by mass. Hydrogen has around three times the gravimetric energy density of jet fuel (120 MJ/kg vs 43 MJ/kg), so the weight of the fuel will actually decline by nearly two thirds. This will, however, be offset by requirements for a fuel tank that must hold four times as much volume, at high compression and low temperature. Advances in handing hydrogen, especially in the design of fuel tanks in planes, will be essential to the viability of this strategy.

There are two large advantages for using hydrogen rather than SAF to replace conventional aviation fuel:

1. no sustainable carbon input is required, only electricity and water; and
2. efficiency is a little higher than SAF produced using the technologies discussed above, mainly because it avoids the SAF selectivity issue—all produced hydrogen is useful as aviation fuel.

Hydrogen engines are assumed to be around as efficient as conventional jet engines (Oğur et al., 2024). Electrolyser and storage/transport efficiencies of 80 and 90 percent respectively imply a hydrogen delivery efficiency of 72 percent. The final energy required is around 5,500 TWh, markedly less than FT and MtJ processes—or 7,750 to 11,000 TWh if aviation growth forecasts are realised.

There is one large disadvantage: if hydrogen is to be a superpower industry, then it must be transported. The energy requirements of transport for most superpower goods are small and hence have been ignored in the analysis, but they are material for hydrogen. Future hydrogen liquefaction and shipping efficiencies are assumed to be 80 percent and 98 percent respectively, and this reduces the efficiency of hydrogen delivery to around 56 percent. Overall, the efficiency of

[43] 5,900 to 6,900 TWh for the first 9.6 exajoules of SAF, and 1,500 to 1,700 for the second 4.8 exajoules.
[44] 12,800 TWh for the first 9.6 exajoules of SAF, and 3,200 TWh for the second 4.8 exajoules

indirectly electrifying aviation via shipped hydrogen is quite poor, with energy requirements per kilometre travelled being around 80 percent higher than they are today.

The total energy required increases to around 7,100 TWh to replace aviation at 2019 levels. Including growth in aviation to 2060, electricity requirements are from 10,600 to 14,200 TWh. These figures are only a little below the lower end for SAF.

The assumed fuel mix

Following the IEA (2021b), the lower bound estimate for aviation electricity demand assumes a mix of 40 percent SAF and 60 percent hydrogen. The rationale is that hydrogen is most promising for short-range aircraft (<2,000 km), though reasonably forecastable technical advances may extend this to medium-range aircraft (<7,000 km). According to the EU Clean Hydrogen Joint Undertaking (2020), these account for around 27 percent and 43 percent of aviation energy use and emissions respectively. Long-range aircraft (>7,000 km) account for the remaining 30 percent, and here the viability of hydrogen is of low certainty. The most likely outcome is a mix of fuel types. The IEA's (2021) assumption is reasonable if SAF covers all of long-range aircraft and around a quarter of medium-range.

The upper bound estimate of aviation electricity demand assumes full SAF production with DAC-derived carbon.

4.9 Road freight

According to the IEA (2017), nearly one fifth of global oil is consumed by road freight. In 2021, this would be around 19.5 million barrels per day, or 33.6 exajoules per year globally. UN Statistics Division (2024) country breakdowns suggest that medium-heavy vehicles account for around half this figure.

An ITF (2023) study for the OECD estimates that road freight tonne-kilometres will increase by around 2.3 times from 2019 to 2050, with growth fastest in Asia and Africa. The average rate of growth is around 2.75 percent per annum, roughly in line with real global GDP growth. From 2050 to 2060, it is assumed this rate slows to 2 percent, so in total road freight increases 2.8 times to 2060.

The IEA's (2021b) China roadmap expected 60 percent of road freight to be decarbonised via batteries, but advances in technology suggest the battery share will be higher. Around 80 percent battery penetration is assumed. With future electric trucks reducing energy needs by as much as 70 percent, electrifying 80 percent of 2021 road freight would require around 8 exajoules or 2,240 TWh of electricity. With growth to 2060, demand would increase to around 6,270 TWh.

Potential green fuels for the remaining 20 percent include hydrogen, ammonia, methanol, and biofuels. Biofuels are excluded; as discussed in Section 7.4, the use of biofuels is limited by high arable land requirements. Ammonia is also excluded, as a fuel that is relatively dangerous to handle and that risks increasing NOX emissions in urban areas. Methanol has received significant attention in China especially—the world's main producer of methanol—as a road fuel (Yang, 2022). It is relatively safe to handle, and has higher combustion efficiency and markedly lower soot, NOX, and other pollutant emissions than diesel. Hydrogen is complex to handle, has low volumetric density, and it is difficult to transport, but has high gravimetric density and the advantage of not requiring a carbon feedstock.

The analysis mirrors that in the shipping and aviation sections. First, take the average diesel engine as around 35 percent efficient. At 2021 levels of road freight, green fuels must thus replace around 2.35 exajoules of useful energy.

With 19.9 gigajoules in a tonne of methanol, and taking methanol engines as 45 percent efficient by mid-century (see Shamun et al., 2017 and Brusstar et al., 2002), around 280 million tonnes of methanol would be required to supply this energy. As in Section 4.7, the production of methanol requires around 5 to 12 MWh depending on whether it is biomass-derived or DAC-derived. The range of energy requirements is thus 1,400 to 3,360 TWh to cover 2021 needs, or 3,920 to 9,410 TWh to meet 2060 needs.

Hydrogen's energy content is around 142 gigajoules per tonne,[45] and hydrogen fuel cells may be around 50 percent efficient. This entails consumption of around 33 million tonnes of hydrogen to meet 2021 needs. Electrolyser and transport/storage efficiencies are again taken as 80 and 90 percent respectively, for a total efficiency of around 36 percent. This implies electricity demand of 1,820 TWh to meet 2021 needs, or 5,080 TWh to meet 2060 needs.

If we account for liquefaction and shipping efficiencies, per Section 4.8, total efficiency declines to 28 percent. This implies electricity demand of 2,320 TWh to meet 2021 needs, or 6,480 TWh to meet 2060 needs.

Energy requirements fall by about 35 percent in the case of biomass-derived methanol, are unchanged in the case of domestic hydrogen production, increase by 25 percent with shipped hydrogen, and increase by 80 percent with DAC-derived methanol.

In the core scenario in this paper, a 50:50 mix of biomass-based methanol and hydrogen is assumed for the 20 percent of road freight covered by green fuels.

4.10 Plastics

Plastics are excluded from deep analysis in this report and left for future work. Nonetheless plastics are worth a brief analysis, especially because they are significant in Sections 5.4 and 7.4 on carbon feedstock demand.

Estimates vary, but on the order of 10 percent of oil is used as a feedstock to produce petrochemicals (Kapsalyamova & Paltsev, 2020), and the majority of this is directed to making plastics. Total plastic production is around 400-460 million tonnes per year globally. Taking a middle value, and taking oil as 85 percent carbon and plastics as on average 75 percent carbon, plastics embody the equivalent of around 380 million tonnes of oil or about 8 percent of global oil. The energy content of this feedstock oil is around 15.4 exajoules, though much more energy is required to transform these feedstocks into plastic.

A small share of plastics production occurs via natural gas, with estimates of the gas share ranging from 1 to 15 percent (Sharma et al., 2022; Statista, 2024a). Including gas would slightly reduce the oil consumption figures above.

Making plastics without fossil fuels is extremely electricity-intensive; rather than starting from oil, the starting point is CO_2, which is a simpler building block that requires more complex transformation. Take two of the most important base molecules for plastics:

[45] Taking its higher heating value as relevant for the fuel cell context.

- Propylene manufactured from an oil feedstock requires fossil fuel energy inputs of around 2.6 MWh per tonne (Karali et al., 2024).[46] Using electricity and biomass-derived CO2 lifts requirements to around 38 MWh per tonne (Palm et al., 2016).
- Ethylene cracked from ethane and naphtha requires energy equivalent to 4 to 6 MWh per tonne (Worrell et al., 2000). Starting from biomass-derived CO2 lifts energy requirements to around 20 MWh per tonne.

The EU produces only a modest share of global plastics, yet Palm et al. (2016) estimate that 1,600 TWh of electricity would be required to green its current level of plastic production. This is equal to more than 60 percent of all electricity demand in the EU today.

Electrification (plus biomass) efficiencies are extremely low, ranging from a 230 percent to nearly a 1400 percent increase. Costs increase accordingly: Posen et al. (2017) estimate that producing plastic from fossil fuel feedstocks and renewable energy increases costs by around US$85/tonne, while producing from biomass feedstocks raises costs by up to US$3000/tonne. These are on the order of a 9 percent and 200 percent increase in costs respectively. Biomass-based production, recycling, and incineration with CCS will compete to eliminate plastic degradation emissions.

Here it is assumed that most plastic decarbonisation will proceed by the use of renewable energy combined with fossil fuel feedstocks. As discussed in Section 5.4, the carbon embedded in many plastics is—unfortunately for the oceans—highly stable and will not be a major contributor to emissions this century.

However, a subset of plastics, dominated by LDPE, may degrade after only several years (Chamas et al., 2020). This increases the urgency of mitigation. LDPE accounts for around 17 percent of global plastics production, and it is assumed that this share plus another 8 percent, for a total of 25 percent, will be made by carbon-neutral means.

In the core scenario, half of this plastic—around 12.5 percent—is produced by biomass plus clean electricity, and the remainder by conventional recycling. Given LDPE is a polymer of ethylene, estimates of electrification efficiency are based on the analysis of ethylene cracking above. These estimates are used for calculating country electricity and carbon demand, but are not included in the superpower trade.

More complete treatment of plastic requires accounting for its other associated harms, including microplastics and chemicals such as BPA. Conventional plastic recycling, for example, is energy-saving but a major source of microplastic release into water; as much as 13 percent of plastic weight is converted into microplastics (Brown et al., 2023). Addressing these combined challenges, and assessing whether plastic manufacturing is a superpower industry, is reserved for future work.

4.11 Summary

Detailed analysis of the superpower industries is consistent with general expectations for industry and green fuels: electrification does not materially improve energy efficiency on average, and in most cases reduces efficiency. For those processes that require carbon feedstocks, using biomass greatly reduces electricity needs. Purer electrification, using carbon from DAC or CCU, is particularly electricity-intensive due to the lack of biomass energy.

[46] Excluding feedstock energy. The advantage of production from oil is that oil can be cracked into propylene, while beginning from CO2 requires much more energy.

Table 4.2. Global electricity requirements for electrified superpower industries, today and in 2060

	Electrification strategy	Efficiency: Change in primary energy per unit output[47]	Global electricity requirement with 2021 electrification	With growth to 2060
Iron	Indirect (hydrogen), some direct emerging. Small carbon input.	-33%	5,370 to 6,500 TWh	5,900 to 7,150 TWh
Aluminium	Direct. Carbon input may become optional.	Unchanged: efficiency losses offset gains	1,200 TWh	1,620 TWh
Silicon / polysilicon	Direct. Carbon input may become optional.	Unchanged: efficiency losses offset gains	311 TWh	1,270 TWh
Ammonia	Indirect (hydrogen).	Unchanged: efficiency losses offset gains	2,100 TWh	8,400 TWh
Urea	Direct. Significant carbon input.	Unchanged to +120% with DAC	170 TWh	350 TWh
Methanol (industrial)	Indirect (hydrogen). Significant carbon input.	-40% (biomass) to +55% (DAC)	525 to 1,330 TWh	1050 to 2,660 TWh
Shipping Inland and half of short-sea	Direct (batteries).	-43%	321 TWh	321 TWh
Shipping Deep-sea and half of short-sea	Indirect (methanol). Significant carbon input.	-15% (biomass) to +115% (DAC)	2,250 to 5750 TWh	2,250 to 5,750 TWh
Aviation	Indirect (SAF). Significant carbon input.	+85% (biomass) to +255% (DAC)	7,300 to 8,600 TWh (biomass) 16,000 TWh (DAC)	11,000 to 17,200 TWh (biomass), 24,000 to 32,000 TWh (DAC)
	Indirect (hydrogen).	+40%	5,500 TWh	7,750 to 11,000 TWh
Road freight Medium-duty and short-haul	Direct (batteries).	-70%	2,240 TWh	6,270 TWh
Road freight Heavy-duty and long-haul	Indirect (methanol). Significant carbon input.	-35% (biomass) to +80% (DAC)	1,400 TWh (biomass) 3,360 TWh (DAC)	3,920 TWh (biomass) 9,410 TWh (DAC)
	Indirect (hydrogen).	+25%	1,820 to 2,320 (shipping) TWh	5,080 to 6,480 (shipping) TWh

[47] Assuming lossless electricity generation, as is typical for renewables, and taking fossil fuel processing/transport losses as roughly equivalent with typical electricity transmission losses, and so excluding both from the analysis.

The estimates of 2060 demand include assumed continued progress in industry energy efficiency, beyond the effect of electrification. Historical efficiency progress has slowed decade by decade, as the low-hanging fruit have been plucked and further gains have been harder to win.

Note that in the countries analysed here, superpower and non-superpower industries would have around the same total electricity demand—on average, around 25 percent each, and so together around half of final electricity demand. China, for example, has a final industry share of around 54 percent in electricity demand, versus a 40 percent share in primary energy today.[48] Industry's share increases due to the relative inefficiency of electrification, although the increase is restrained by assumed non-electrified components as described in Chapter 3.

The results of the 2021 electrification model are presented in Table 4.3, with TWh rounded to the nearest fifty for clarity. The "low demand" results are a consequence of assuming that industry/sector electrification efficiencies are at the favourable end of the ranges given in Chapters 3 and 4. Opposite assumptions produce the "high demand" results.

Electricity demand in the 2021 model increases around 2.5 to 3-fold, while primary energy demand falls by roughly 50-55 percent. Compared to the crude model, where primary energy declined by 60 percent, the 2021 model leads to 10-20 percent higher electricity demand in the "low" case, and 40-120 percent in the "high" case. The difference between crude and detailed models is mainly driven by the small size of efficiency gains from industrial electrification, and the inefficiencies of green fuel production.

Table 4.3. The five countries' electricity demand in 2021, with maximal electrification: Low and high demand scenarios

	Electrification in 2021: "Low" demand (TWh)	Electrification in 2021: "High" demand (TWh)	Ratio of electrified TWh to present-day TWh	Total primary energy use versus 2021
China	20,600	27,550	2.5 to 3.4	-57% to -43%
India	4,050	5,450	2.4 to 3.2	-57% to -42%
Japan	2,550	3,750	2.7 to 3.9	-51% to -30%
Korea	1,700	3,300	2.9 to 5.6	-54% to -12%
Germany	1,700	2,500	3.0 to 4.5	-54% to -31%

The largest driver of increased demand in the high case is aviation, where DAC-dependent SAF is used instead of hydrogen. Other large effects come from assuming that biomass feedstocks are not available for industry (e.g. urea and methanol) or other green fuel production (e.g. for shipping and heavy freight). Korea is most affected, due to its intensive use of oil in industry. Smaller contributions come from assuming lower efficiencies for iron/steel production and electric vehicles.

These higher figures require the misfortune to simultaneously face larger than expected constraints on biomass, greater obstacles to hydrogen use in aviation, and generally low efficiency gains across industries and green fuels types. Any one of these additional barriers would induce additional, partly compensating adjustments in economic activity and international trade. Given

[48] Including shipping and aviation, to compare appropriately with electrified industries including green fuels.

the large role of aviation in driving these figures, the most important adjustment would be a sharp reduction in international travel.

We will focus on the “low” model. Note that it is not a projection, but just the first stepping-stone in the analysis.

05.

Bringing it together: Electricity demand in 2060

The preceding analysis tells us how much electricity would be needed to electrify the 2021 economies of China, Germany, India, Japan, and Korea. It provides an upper bound on required electricity in a case where countries reach net zero with:

- no presumed offshoring of industries, because an important purpose of the analysis is to assess the necessity of such changes;
- no other economic effects, such as substitution or reductions in demand due to prices;
- no CCS, to be added in Section 7.3;
- no bioenergy, to be added in Section 7.4; and
- growth in industry demand that follows international forecasts.

The next task is to extend this upper bound on electricity demand into the future, given our key interest is the degree of pressure on limited clean energy supplies at the point of full decarbonisation. Germany is committed to decarbonise by 2045, Japan and Korea by 2050, China by 2060, and India by 2070. Because China is the most significant emitter, and because superpower industries are forecast to 2060, the analysis projects China, Japan, Korea, and Germany forward to 2060. The India analysis is extended to 2070.

The projection must account for two factors:

- GDP growth; and
- the energy-intensity of GDP.

Holding energy intensity constant, a percentage increase in GDP drives a proportionate increase in energy demand (or electricity demand in the fully electrified economy). If energy intensity declines, then energy demand grows more slowly than the economy. If the decline in energy intensity exceeds the pace of economic growth, then total energy consumption falls as the economy expands. There are also upward pressures on energy intensity, including new AI data centres; these may appear unexpectedly. The task is to forecast the balance of these factors, and draw out the implications for electricity demand in electrified economies.

Energy intensity typically increases with early development and then falls again as economies mature. The initial rise is driven by low-efficiency industrialisation, and the later fall is driven by efficiency improvements and shifts in economic composition, especially from industry towards services (Metcalf, 2008).

Electrification is, of course, one of the drivers of efficiency improvements. The electrification model developed in the preceding chapters already captures this effect, so the analysis below aims to account for other factors that affect energy intensity. In the final model, these will compound with electrification to determine electricity demand.

Recent trends in energy intensity arise mainly from improvements in process efficiency and changes in economic composition, rather than electrification. Electrification has, so far, proceeded slowly. Moreover, in today's fossil-dominated electricity grids, electrification has minimal effects on primary energy intensity. This is because of the inefficiency of fossil fuel electricity generation. For example, the primary energy efficiency gains from electrifying passenger transport with EVs are large when electricity is derived from renewables (up to a 73 percent reduction), but approach zero when EVs are powered by coal.

5.1 The advanced economies: Germany, Japan, and Korea

Growth in total primary energy consumption has slowed in most advanced economies. This is a consequence of a variety of factors, the most significant of which are de-industrialisation and the switch to services, and the slowdown or reversal of population growth. On the short term, the echoes of the COVID disruption and the effect of the Russia-Ukraine war on energy prices are significant factors. Improving energy efficiency plays a role, although its impact is blunted by the Jevons Paradox (Box 1.3).

Looking to the key countries of this analysis, prior to the effects of COVID and the Russia-Ukraine war, energy consumption had flatlined in Germany, begun to decline in Japan, and continued to slowly rise in Korea despite falling population.[49] The pattern in Germany and Japan is partly driven by increased energy costs. Korea conversely heavily subsidises energy consumption.

Will these patterns persist? It may be reasonable to expect energy demand to decline in Japan and Korea, given a forecast 15 percent reduction in population by 2050. There are, however, countervailing forces. These include a push for re-industrialisation driven by geopolitical tensions, as well as growth in new energy-intensive industries. The Japanese government, for example, expects large growth in demand from semiconductor plants and data centres to 2050 (Reuters, 2024a). The reader may prefer to impose modest reductions in energy demand for these countries, but these will not change the stark results of Chapter 8.

Forecast economic growth rates for these countries, from 0.5 to 1.3 percent per annum, are similar to recent rates of decline in the energy-intensity of GDP. The baseline model presumes stable energy demand (prior to electrification). Thus, the electricity demand implied by the 2021 electrification model is assumed to remain unchanged into the future. In short, maximally-electrified demand flatlines.

This is altered slightly—notably in the case of Germany—by separately accounting for growth and efficiency changes in the superpower industries. Industry growth is slower than GDP growth in the steel, aluminium, and shipping industries. Expected efficiency improvements are lower in the superpower industries than the broader economy, reflecting proximity to technical limits.

Growth in ammonia demand would greatly increase Japanese and Korean electricity requirements, but the expectation is that these fuels will be imported. Korea, for example, plans to begin importing from a 1 million tonne per annum plant in the United Arab Emirates in 2027 (Yoshida, 2024). Ammonia is not taken to contribute to domestic demand, but it is part of the superpower trade.

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[49] This pattern also reflects differences in energy policy, with Korea heavily subsidising energy use and so encouraging continued growth in demand.

5.2 The rapidly developing large economies: China and India

In China and especially India, economic growth will outpace reductions in energy intensity. There are large uncertainties in projecting these factors. I rely on projections from other reports and papers, and long-run tendencies for at least partial convergence in per capita GDP and energy intensity.

In the case of China, the IEA (2021b) expects the economy to grow by more than 200 percent from 2020 to 2060, with an implied average growth rate of around 3 percent per annum. The OCED projects that China will grow around 185 percent (OECD, 2022). Some recent analyses are a little more pessimistic, given the emerging problems in the Chinese growth model and the shrinking and aging of its population (Al-Haschimi & Spital, 2024; Lowy Institute, 2022). I take the OECD value, and assume that China's economy increases by 185 percent. GDP is projected to rise from around US$28.8 trillion in 2021 (World Bank, 2024) to US$82 trillion in 2060 in constant 2021 international dollars.

China's primary energy intensity improvements since 2017 have averaged around 0.7 percent per annum (Enerdata, 2024), with electrification contributing little so far (given the coal-intensity of grid power). This is driven by stronger growth in services, slower growth in energy-intensive industries, and economy-wide efficiency measures. It is assumed that deeper investments in energy efficiency, and a faster shift to services, will lift this to an average 1.5 percent reduction in energy intensity, prior to electrification, over this period. Note that when electrification is returned to the analysis below, it contributes strongly to reductions in emissions intensity.

The total reduction in energy intensity to 2060, pre-electrification, is 45 percent. This is around the same as the reduction observed over the last 25 years, where much more low-hanging fruit was available for plucking (Enerdata, 2024).

With these trends combined—energy demand increasing due to economic growth and declining due to the fall in energy intensity—then prior to considering electrification, primary energy demand would increase by around 57 percent by 2060.

Thus, final electricity demand in a fully electrified China in 2060 is around 50 percent higher than for an electrified China in 2021—rising from around 20,500 TWh to around 31,500 TWh. Per capita electricity demand for electricity would be around 25 MWh, just above modelled figures for Germany and Japan (24 and 22 MWh per capita) but still well below those of Korea and the US (around 37-38 MWh per capita). Per capita electricity demand higher than Germany and Japan reflects the combined effects of China's economic maturation and its disproportionately high share of energy-intensive industries.[50]

In India, we can expect stronger economic growth and slower reductions in energy intensity. GDP growth pathways depend on the maintenance of open international trade, capacity to maintain institutions favourable for growth, and the degree of specialisation in energy-intensive industries. The OECD forecasts that India will approach Chinese GDP by 2060, with around 7-fold growth over the 39 years from 2021 to 2060 (OECD, 2022). I use this estimate.

Although high, this growth rate is well below the rate observed for China. China's output grew more than 6-fold in just 24 years from 2000 to 2024. The expected rate of growth changes with the stage of development. India's per capita income today is around the same as China's in 2009. Prior to reaching this income, Chinese growth averaged around 10 percent while India in recent

[50] Economic structure powerfully drives primary energy intensity. Consider that Russia, which has relatively low per capita GDP, has much higher GJ per capita than most advanced economies due to its fossil fuel and heavy industry intensity.

non-pandemic years has averaged around 7 percent. India's growth disadvantage is presumed to persist.

Indian GDP growth is extended to 2070, its date of decarbonisation. Growth is assumed to fall to 1.5 percent per annum after 2060, for a total 8.1-fold increase from 2021 to 2070.

India's energy intensity of GDP is already around 30 percent lower than that of China, despite generally lower uptake of energy efficiency measures. This is due to India's much lower prevalence of heavy industry, and higher prevalence of services. This difference is expected to fall. India plans rapid expansion of heavy industries such as steelmaking, with output planned nearly to triple from 2021 to 2030 to 300 million tonnes (Indian Ministry of Steel, 2017), and increase to 500 million tonnes by 2047 (Mishra, 2024).

It is assumed that by 2070, and in the absence of the superpower trade, India will have reached 500 million tonnes of primary steel production capacity.[51] In other major industries, India is projected to lift production to on average around 25 percent of Chinese output. Shipping and aviation reach around half the Chinese level. The avoidance of this growth in production, and so of growth in electricity demand, via the superpower trade is discussed in Chapter 8.

Changes in industrial composition will tend to halt and perhaps reverse reductions in energy intensity in some periods. The EIA (2019) foresees India's energy intensity falling by 11 to 33 percent to 2050, with the manufacturing industry share being the most important determinant.[52] The EIA's (2023a) most recent projection lies between these two, at around a 23 percent decline in energy intensity to 2050.

For this paper, the EIA's forecast is extended to 2070 to give a total energy intensity reduction of 35 percent. The fall may be lower; the EIA expects much slower growth in steelmaking, for example, than India currently plans. In any case, this modest rate of decline in energy intensity leads to some convergence with Chinese energy intensity, with India relatively more, and China relatively less, industrialised than today.

Given expected population growth of around 17 percent to 2050,[53] the model in this paper suggests India would require around 13 MWh per capita, well behind China's 25 MWh per capita in 2060. We turn to the full results in the next section.

The resulting change in primary energy demand—prior to electrification—for each country is given in Table 5.1.

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[51] Indian secondary steel, recycled from scrap, will be limited by its relatively low base of utilised steel per capita, and by high international demand for scrap.
[52] The EIA (2019) projects around a 3-4-fold increase in energy consumption from 2021 to 2050, and around a 4.5-fold increase in GDP.
[53] From 1.41 billion in 2021 to 1.67 billion in 2050.

Table 5.1. Before electrification: Key countries' projected growth, energy intensity, and change in primary energy demand to 2060 (2070 for India)

	Economic growth, 2021 to 2060	Fall in primary energy intensity, 2021 to 2060	Increase in primary energy, 2021 to 2060	2060 primary energy intensity (EJ/t$)
China	185%	45%	57%	3.0
India†	710%	35%	427%	1.9
Japan	55%	35%	0%	2.2v
Korea	55%	35%	0%	3.3
Germany	66%	40%	0%	1.5

† Figures for 2070 in India
Note: EJ/t$ is exajoules per trillion dollars (constant 2015 international US dollars).

5.3 Results of the 2060 electrification model: Core scenario

Table 5.2 presents the results of the electrification model at the point of country decarbonisation, compared with the "low" demand model of 2021. These results do not constitute a projection, but place an upper bound on required electricity in a world without trade, CCS, bioenergy, and so on.

Electricity demand increases fastest in India, driven by the combination of eightfold increase in economic output to 2070, industrialisation, and broad electrification. China's demand increases 3.9-fold to 2060, with economic growth more modest, efficiency gains larger, and some deindustrialisation. Japan, Korea, and Germany are clustered around a 3-fold increase, around the same as in the 2021 electrification model.[54]

Table 5.2. The five countries' electricity demand in 2021 and at the point of future decarbonisation, with maximal electrification: The core scenario

	Electrification in 2021: Total demand (TWh)	Electrification in 2060: Total demand (TWh)	Ratio of 2060 elec. demand to present day	Change in primary energy use versus 2021
China	20,600	31,550	3.9	-35%
India	4,050	21,600	12.7	+131%
Japan	2,550	2,550 (3,300*)	2.7	-52%
Korea	1,700	1,650 (2,450*)	2.8	-56%
Germany	1,700	1,800	3.2	-51%

* High figures exclude ammonia imports described in Section 4.4, omitted from the main figures used as discussed below.

[54] As noted in Section 5.1, GDP growth and declines in energy intensity offset one another, and the differences between 2021 and 2060 reflect different rates of growth of the Superpower industries discussed in Chapter 4.

Japan's and Korea's electricity demand would be greatly increased if including planned and potential ammonia consumption. However, in practice Japan and Korea intend to import the large majority of this ammonia, so that no analysts conceive of a future in which ammonia adds so intensively to domestic electricity demand. This ammonia is still counted as a superpower industry, and forms part of the superpower trade.

The electricity needs of the superpower industries in each of the five countries is presented in Table 5.3. Iron/steel and ammonia are the largest contributors to demand across the five countries. Total iron/steel demands are relatively unchanged from 2021. Whether ammonia demand grows so rapidly depends on its cost-competitiveness as a long-term energy store; it is particularly important for Japan and Korea, which have few alternatives. Green fuels for trucking, shipping, and aviation are together around as significant as steel, and the main driver of demand for Germany.

Table 5.3. Electricity demand of superpower industries in the selected countries, 2060

	Iron/ Steel (TWh)	Alumin. (TWh)	Silicon/ polysil. (TWh)	Ammonia (TWh)	Urea (TWh)	Indust. methanol (TWh)	Shipping (TWh)	Aviation (TWh)	Road freight (TWh)	Total (TWh)
China	2230	936	824	2666	106	525	456	1240	506	**9478**
India	1523	286	175	1086	66	165	211	748	444	**4699**
Japan	267	0	0	813*	1	0	48	113	62	**1304**
Korea	224	0	0	777*	0	0	66	77	40	**1183**
Germany	89	7	24	116	7	0	12	125	53	**431**

* These figures include 777 TWh of ammonia demand (see Section 4.4).

Figure 5.1 shows the stepwise mechanics of the analysis in the case of China. Primary energy consumption is here measured in TWh. It increases by 185 percent with growth to 2060, but is cut by 45 percent by (non-electrification-related) energy intensity improvements. Electrification cuts energy demand further, although raises electricity demand from around 8,200 TWh in 2021 (not shown) to around 31,500 TWh in 2060.[55] Finally, the superpower trade potentially cuts around 9,700 TWh of demand (discussed further in Chapter 8).

[55] Again, on the assumption that electricity generation is lossless, as with renewables. Demand is mostly met by renewables in any scenario, but nuclear, biomass, and fossil CCS will raise losses somewhat.

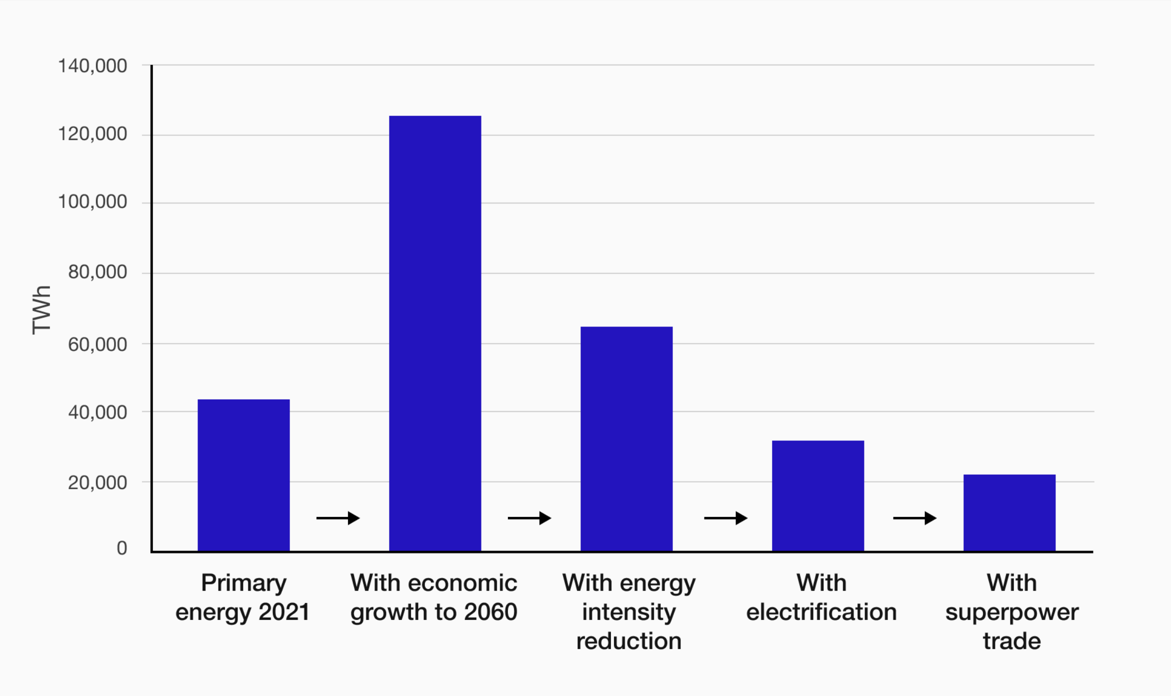

Figure 5.1. Detail on China: Separating the effects of economic growth, energy intensity reduction, electrification, and the superpower trade on energy demand

5.4 Feedstock carbon: Superpower industry demand

The first task is to estimate demand for carbon. Most of the superpower industries are carbon-hungry, and their requirements are summarised below. Other industrial processes beyond these industries also require carbon, and the most important, plastics, is included in the analysis.

- Steel is an alloy of iron and around 0.05 to 2 percent carbon. Because of losses in the production process, around 40 kg of carbon per tonne of steel is typically required (e.g. Rechberger, 2020).

- Aluminium currently requires 500 kg of carbon per tonne, but replacement with biomass is hampered by the presence of impurities that interfere with production (Senanu & Solheim, 2021). Inert anodes are the more likely decarbonisation strategy, hence aluminium is excluded from this analysis.

- Metallurgical grade silicon and ferrosilicon require around 1.3 and 0.9 tonnes of carbon per tonne respectively (Monsen et al., 1998). Unlike aluminium, biomass carbon is already used in silicon production today. Carbon-free alternatives, such as hydrogen reduction or electrolysis with inert anodes, have an uncertain development pathway.

- Ammonia requires no carbon input, only hydrogen and nitrogen. However, production of ammonia via biomass gasification would provide a ready supply of CO2, which is essential in urea production. Urea requires around 200 kg of carbon per tonne.

- Methanol for industry and for shipping requires around 375 kg of carbon per tonne, and carbon efficiency is assumed to be around 90 percent.

- Aviation fuel is about 85 percent carbon, and a SAF carbon efficiency of around 75 percent is assumed with recycling (see Section 4.8). A little over 1.1 tonnes of carbon are required per tonne of SAF. Alternatively, if hydrogen is used then no carbon is required.

Plastics are included in this analysis, as their production is the dominant industrial use of fossil feedstock carbon. Around 850 kg of carbon is required per tonne of plastic, and around 460 million tonnes of plastic are produced each year (OECD, 2022). Growth from 100 to 200 percent to 2050 is forecast, mostly due to growing consumption in developing economies; a middle value of 150 percent is taken for 2060. Growth in bioplastics is expected to be strong, from a low base. Some speculative analyses aim at a 100 percent market share by 2050 (e.g. in the EU, Frischenschlager & Reinberg, 2017).

With aviation growth of 50-100 percent projected to 2050, the core scenario of this paper assumes the middle value of 75 percent is reached by 2060.

The results are presented in Table 5.4. Steel and silicon carbon efficiencies are taken from the literature. For urea, methanol, green fuels, and plastics, the carbon needs listed above are modified by an assumed carbon efficiency of 90 percent.

Table 5.4. Global superpower industry demand for carbon, for a net zero economy in 2021 or in 2060

	Volume	Carbon requirement 2021	Growth to 2060	Carbon requirement 2060
Steel	1,334 Mt	53 MtC	+10%	59 MtC
Silicon	3.7 Mt MG-Si 7.8 Mt FeSi	24 MtC	+100%	48 MtC
Urea	177 Mt	40 MtC	+50%	60 MtC
Methanol (industrial)	111 Mt	46 MtC	+100%	92 MtC
Shipping	482 Mt (methanol)	201 MtC	0%	201 MtC
Aviation	340 Mt (SAF)	385 MtC	+75%	674 MtC
	120 Mt (hydrogen)	0 MtC		0 MtC
Road freight	280 Mt (methanol)	116 MtC	+180%	325 MtC
	33 Mt (hydrogen)	0 MtC	+180%	0 MtC
Plastics	430 Mt	433 MtC	+150%	1,075 MtC
Total		797 to 1,298 MtC		1,535 to 2,530 MtC

Note: “MtC” is million tonnes of carbon.

Note that with the US DoE’s (2024) much lower assumed carbon efficiencies for SAF production—around 32 percent, compared to 75 percent used here in Chapter 4—aviation would require around 900 million tonnes of carbon for 2021 aviation, and 1.6 billion tonnes by 2060. SAF at scale requires high carbon efficiencies.

Aviation, plastics, and road freight are the largest potential contributors to carbon demand, and the upper bounds on their combined feedstock needs is probably too high to be achieved. However, carbon demand is assumed to be restrained:

- As discussed in Section 4.8, I follow the IEA in having around 40 percent of aviation fuel derived from SAF. This cuts aviation carbon demand to 154 million tonnes in 2021, and 270 million tonnes in 2060.
- As discussed in Section 4.9, a 50:50 biomass-based methanol and hydrogen mix is assumed. This cuts freight demand to 58 and 163 million tonnes of carbon in 2021 and 2060 respectively.
- As discussed in Section 4.10, biomass carbon is presumed to be required for around 12.5 percent of plastics, mainly LDPE. This cuts demand to 54 and 134 million tonnes of carbon in 2021 and 2060 respectively.

The total carbon requirement is around 630 million tonnes to satisfy 2021 needs, and a little over 1 billion tonnes in 2060.

Box 5.1 The IEA on Chinese and global carbon demand

The IEA's (2021) carbon neutrality roadmap for China estimates that bioenergy will account for around 13 percent of Chinese primary energy consumption in 2060—around 16 exajoules in total. Around 40 percent of that bioenergy comes in the form of biofuels: 2.6 exajoules of liquid and 4 exajoules of gaseous biofuels.

The IEA does not analyse carbon demand, but at 90 percent carbon efficiency, the carbon content would be around 145 million tonnes. The remaining 9.4 exajoules, taken as directly consumed biomass, would likely contain around another 300 million tonnes of carbon. This implies acquisition of at least 445 million tonnes of carbon in China.

China's bioenergy use as a share of the global total is misreported as ~2.3 percent (IEA, 2021, Figure 4.18). It is presumably intended to be 23 percent, for a global figure of 70 exajoules.[56] If so, global demand for bioenergy carbon would be around 2 billion tonnes in 2060.

The IEA's (2024b) updated figure for the global net zero pathway—to be achieved in 2050, not 2060—is for a remarkable 99 exajoules of biomass energy. This would entail demand for biomass with carbon content of around 2.8 billion tonnes.

[56] The IEA reports Chinese consumption as ~2.3 percent of the global total. This would imply total bioenergy demand of 696 exajoules, more than all the energy consumed by the world today. 23 percent is reasonable considering Chinese biofuel consumption comprises around 14% of world production of liquid fuels and 37 percent of gaseous fuels. This implies a total of roughly 29 exajoules of biofuels globally, with global biofuels as a share of total bioenergy mirroring China's value of 40 percent.

06.

Sizing the potential superpower trade for the key countries

Chapters 3 and 4 developed a model of maximal electrification for the key countries, given the structure of their energy demand in 2021. Chapter 5 extended this model into the future by accounting for GDP growth and declines in energy intensity, to predict the countries' energy needs at the point of decarbonisation. This chapter identifies the share of countries' demand that can be attributed to the superpower industries. This brings us to one of the main purposes of the paper: determining the potential contribution of the superpower trade to reducing electricity demand in countries with supply constraints.

6.1 Key industry share in 2060 electricity demand

Chapter 4 identified the global electricity requirements of the superpower industries: iron/steel, aluminium, silicon and polysilicon, ammonia and urea, industrial methanol, and green fuels for shipping and aviation. Their share of countries' 2060 demand is presented in Table 6.1 below, for the core scenario of this paper.

Materials that make up the superpower trade comprise around 30 percent of electricity demand in China, 22 percent in India,[57] 21 percent in Japan, 25 percent in Korea, and 24 percent in Germany. Higher bracketed figures for Japan and Korea include forecast ammonia, if it were domestically produced for energy storage.

Table 6.1. Superpower industry share in demand, and effects of the trade on final electricity demand, for the five countries

	Superpower industry share in demand, 2060	Electrification in 2060: Total demand (TWh)	Demand after superpower trade (TWh)	Ratio of demand to present day
China	30%	31,550	22,000	2.7
India	22%	21,600	16,900	9.9
Japan	21% (39%*)	2,550 (3,300*)	2,000	2.1
Korea	25% (49%*)	1,650 (2,450*)	1,250	2.1
Germany	24%	1,800	1,350	2.4

[57] Without any rise in the rate of industrialisation, India's superpower trade share is only 12 percent.

* High figures for Japan and Korea include forecast ammonia, if domestically produced.

The superpower industry share in China is primarily driven by steel and ammonia production, followed by green fuels and aluminium. Shares in Japan, Korea, and India draw roughly equal contributions from green steel and green fuels. Germany's contribution from green fuels outweighs that from steel production.

As noted in the introduction, the trade in embedded clean energy may extend beyond the superpower industries discussed in this paper. The superpower industries represent, on average, close to half of all electrifiable industry demand. In China, for example, non-superpower industries amount to another 6,500 TWh of demand in the 2060 model. A sizeable share of this other half of industrial activity will be tradable, and will be sensitive to electricity prices (the two requirements for the embedded energy trade).

07.

Why the superpower trade? The future scarcity of cheap clean electricity and carbon

The promise of the superpower trade is to make cheap renewable electricity and carbon from countries which can produce them at comparatively low cost, such as Australia available to countries that are energy and carbon constrained in the zero-carbon world.

The economic basis of the superpower trade is that it substantially lowers energy costs, and so supports climate mitigation and economic development. This will only be present if the domestic substitutes for the superpower trade—domestic renewable energy, nuclear, CCS, and biomass—are relatively expensive at the required scales of deployment.

These substitutes for the superpower trade are now discussed in detail.

7.1 Solar and wind: Rags, riches, and reversals

Technically feasible solar and wind resources are more than sufficient to meet demand in every country. Cheng et al. (2022), for example, calculate the technical potential of solar in Japan to be around 4,300 TWh, which is enough to cover present-day electricity demand a few times over, and enough to cover a maximally electrified Japan. But this would entail covering all available water and land, including all agricultural land, in solar panels. It is not an economic analysis.

The availability of *economically competitive* solar and wind is akin to fossil fuels: unevenly distributed and, in many of the most energy-hungry countries, relatively scarce. For Japanese solar resources, the average capacity factor[58] is 13 percent, around half the best sites in Australia. Note that higher capacity factors lead to disproportionately higher profits, because costs remain flat.

The distribution of renewable resources relative to future demand is a story of "rags, riches, and reversals".

- China, India, and some countries in Europe enjoy apparent riches today but will experience a reversal of fortune. The scale of their energy needs is large enough to exhaust their cheap resources and their future renewables costs are expected to grow.
- Some countries, notably Japan and Korea, already confront a near total exhaustion of cheap renewable energy.

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[58] The capacity factor of a power generator is the ratio of the actual electrical energy produced compared to its full rated capacity. Because solar panel output varies with the diurnal cycle, capacity factors at best reach 25-30 percent, but are more typically under 15 percent in temperate climates.

- A few countries, including Australia, enjoy an effectively inexhaustible supply of cheap renewables, and so a nearly flat supply curve. Indeed the supply curve will slope downwards for a while, as higher quality resources of immense scale away from current transmission systems begin to be utilised.

These are the patterns of countries A, B, and C in Figure 1.1 of the introduction. They make the case for international trade.

The relative costs of renewables today

We begin with present-day prices. Figure 7.1 presents the average solar and wind prices, in US dollars, recorded by IRENA and the IEA for the main countries of interest. Prices are taken from 2020 and 2023 to minimise the effect of COVID disruptions to renewable energy supply chains.

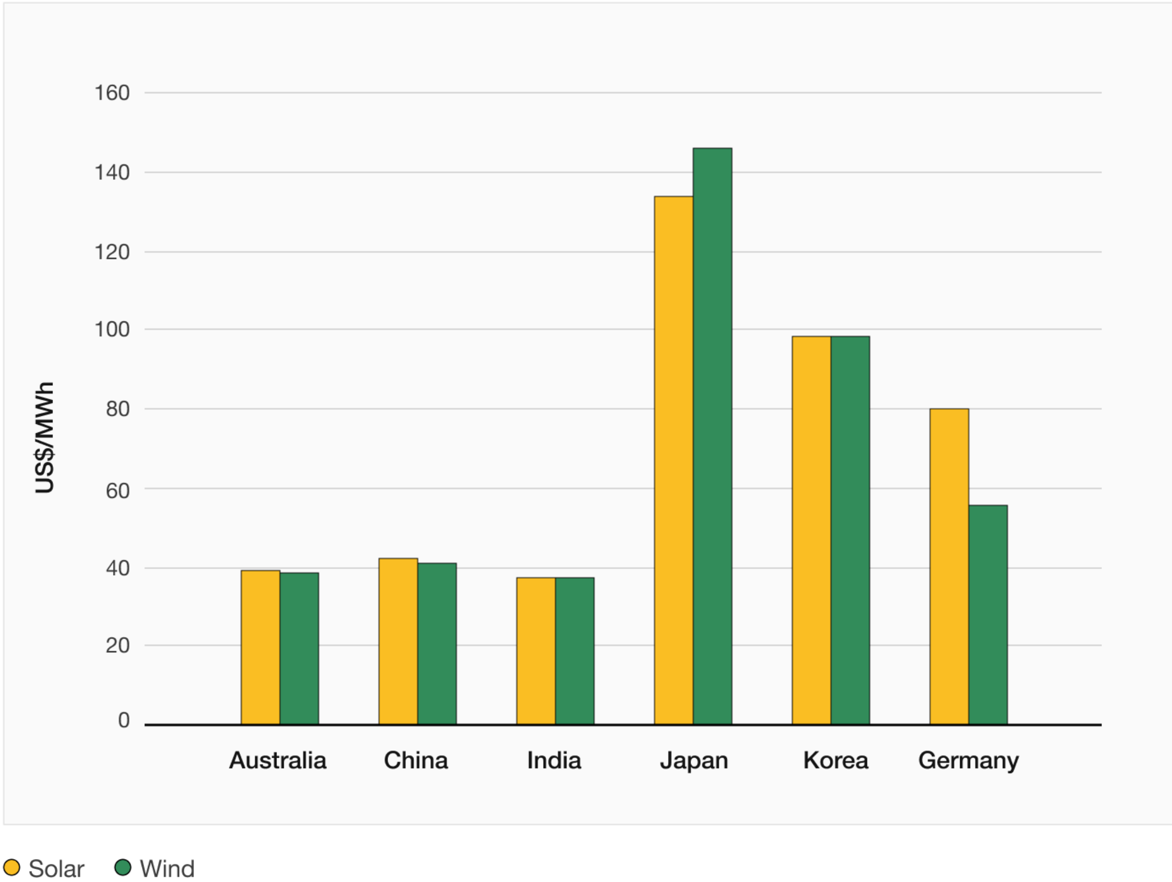

Figure 7.1. Levelised cost of solar and wind in Australia and the five selected countries (average of IEA, 2020b, and IRENA, 2023a, 2023b)

Japan and Korea, at the very start of their supply curve, already face high prices—and their prices, relative to other countries, will continue to rise as resources are utilised. Australia, China, and India start low, and Germany's wind prices at least are moderate. What is the shape of these countries' supply curves, up to the volumes required to meet future demand? The information presented shows that each of the selected countries will confront rising marginal costs. Australia will not.

Note that actual prices available to Australian superpower industries are lower than those reported here. Extant projects are of small scale and built in locations with suboptimal resources, proximate to power networks. Superpower projects can be located to take advantage of superior resources at vastly greater scales.[59]

Renewable electricity: Demand vs. supply

No detailed renewable energy supply curves are available for many countries. Some estimates are available for China, India, and Germany (and Europe), which are discussed below. High quality estimates of supply curves have not been identified for Japan and Korea. This is no barrier to analysis; the challenges in renewable energy supply facing Japan and Korea are already large and obvious today.

Geography has endowed Japan and Korea with poor solar resources, which at their peak are similar to the worst resources in southern Australia. In Korea, average capacity factors are under 14 percent and seasonality is high: the average summer peak is around 2.5 times the average winter nadir (Wiser et al., 2021). Onshore wind is poor due to the slowing effect of mountainous terrain. A large share of wind resources are located at the top of mountainous regions where construction is costly and ecosystems are protected. Finally, Japan and Korea are among the most densely populated countries in the world, and most land has high-value competing uses. This raises costs.

Obane et al. (2020) estimate Japan's onshore wind and solar potential on land with non-competing uses to be only 130 TWh. This estimate will probably increase as technology improves, but economically available supply potential will remain a small fraction of anticipated demand.

The main alternatives are nuclear and offshore wind. Nuclear is dealt with in Section 7.2, and has strict limits. Offshore wind costs are declining, though are expected to remain 50-100 percent higher than onshore costs in 2050 (Kim et al., 2021; IRENA, 2019). Offshore wind also presents reliability risks during the typhoon season. Storms may last more than a week, during which turbines must be shut down and access for turbine repair is blocked. This necessitates significant backup power, which may be secured by the import and storage of green fuels such as ammonia.

Today, Japan and Korea have among the most expensive wind and solar internationally. Costs are generally 2.5 to 3 times those of Australia. As supply chains deepen, costs may decline—but they will rise again as suitable land is exhausted and as higher penetrations increase the need for backup power.

The average solar endowment in **Germany** is poorer than that of Japan and Korea, although supply chain depth and land availability have kept its costs a little lower—around double those in Australia. Wind resources are of good quality in the northern half of the country and especially near its northern coasts. Nonetheless, lower capacity factors and limited land availability has kept costs 40 percent higher than in Australia. Ryberg et al. (2019) find that there is only around 8.5 GW of cheap wind (under €40/kWh), and another 136 GW of mid-price wind (under €60/kWh).

Moderately priced wind could supply around 440 TWh, which would cover 24 percent of demand in a fully electrified Germany.

[59] Superpower projects on their own (very large) "microgrid", separate from the main grid, may also avoid high Australian network costs. Network costs comprise around 40-50 percent of retail electricity prices, due to a highly dispersed population combined with regulatory failures (Wood, 2014; AER, 2022).

Land use constraints and subsidies increase the attractiveness of offshore wind, and around 30 small offshore farms have been constructed in German waters. IRENA (2023c) reports that offshore wind costs are still around 2.3 times that of onshore wind.

In the **European Union**, a highly integrated electricity grid allows renewable-poor countries to import electricity from the renewable-rich.

Quality solar is mainly located in the southern half of Spain.[60] However, land availability and social acceptance are significant constraints. Osorio-Aravena et al.'s (2022) multi-factor model identifies a ready potential of around 9 TWh of solar production in Jaén, one of the 18 or so provinces in the southern half of Spain. This would require covering around 1.5 percent of its land in panels. Were this repeated across the southern regions, more than two-thirds of Spain's present-day (but not future) electricity demand could be satisfied. Meeting 20 percent of the EU's solar demand would require increasing this effort more than 11-fold, covering on the order of 17 percent of Spanish land.[61] Increases much above 1.5 percent land coverage are probably infeasible.

Quality wind faces similar constraints. Ryberg et al. (2019) find that around 4,600 TWh of wind energy can be generated in the EU (plus Norway) at under €40/kWh. The large majority of this potential is in three countries: Ireland, Norway, and the United Kingdom. Most other countries, including Germany, have grossly insufficient cheap wind resources. High land prices mean that even in countries rich in wind, such as the United Kingdom, wind strike prices are no lower than those in Germany and still more than double those in Australia.

We have not closely analysed full electrification of the EU, but if it follows the Germany pattern—around a 3.3-fold increase—then 2050 electricity demand would exceed 9,000 TWh. To bring cheap power to the EU, enormous volumes of electricity must be transmitted from the EU's edges to its centre: wind power across the English Channel and North Sea, and solar from southern Europe. Transmission costs would substantially reduce the cost advantage of quality resources, such that widespread use of poorer local resources throughout Europe may be more likely.

China is a case of initial riches that, in the long-run, will be insufficient to meet demand. Chinese resources are of significantly lower quality than in Australia, but in combination with China's advantages in labour prices and cost of capital, prices have been roughly equal. This equality was explicit prior to 2020, but China has enjoyed large advantages in supply chain depth since the COVID disruptions. At the time of writing, COVID disruptions are beginning to resolve, although regulatory constraints continue to raise costs in Australia.

Relative price evaluations are rendered opaque by the variety of explicit and implicit subsidies that China provides to solar and wind firms: the zonal feed-in-tariff and other distributed solar subsidies, National Renewable Energy Development Fund subsidies, renewable price guarantees,[62] preferential loan terms, tax reductions, and land grants. Dong et al. (2021) found that PV deployment prior to the time of his study would have "virtually disappeared" without feed-in tariffs. However, grid parity is approaching, utility scale feed-in tariffs have been discarded, and other explicit subsidies have been lowered to around US$1 billion for 2024 (Reuters, 2024b).

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[60] Insolation is only 20 percent lower than the best regions of the Australian mainland, although, being around Tasmania's latitude, the resource is much more seasonal.
[61] Eleven times 9 TWh is 99 TWh, and if this could be secured in each of Spain's southern provinces it could supply 1,780 TWh. In a simple forward projection of EU demand in line with the German pattern, this could cover around 20 percent of future EU demand.
[62] Up until April 2024, renewable generators enjoyed a guarantee that renewable electricity would be purchased at a price tied to coal power. This prevented losses from producing electricity at times when it was not required, and its repeal may significantly reduce project profitability.

Looking forward, China faces large challenges in satisfying its vast electricity demand with renewables. Its renewable resources are distant from most demand centres, of moderate quality, and highly seasonal.

- Solar output is concentrated in the north of the country, under the clear skies of the Gobi desert and its surrounds. Although southeast China shares its latitude with the Middle East, the solar resource there is poorer than that of Germany due to persistent cloud. The Gobi resource is large in scale but of moderate quality: the Gobi is roughly the same distance from the equator as Tasmania, with average capacity factors of around 18 percent (Zhou et al., 2022, Supplementary Table 4) compared to as much as 30 percent in parts of Australia (Parkinson, 2023). It is also highly seasonal, with solar output about 2.5 times less in central northern winter versus the summer (Wu et al., 2023).
- Wind follows a similar pattern: resources are poor in the southeast, but rich in the north and northwest (Zhuo et al., 2022). Quality is excellent in some areas, but high quality resources would be exhausted long before decarbonisation had been completed. The average capacity factor is around 25 percent (ibid, Supplementary Table 4), compared to an average of 35 percent in parts of Australia. Output is again highly seasonal, falling as much as tenfold in some regions—but favourable inverse correlations in output will ease balancing (Li et al., 2022; Wu et al., 2023).

Solar and wind seasonality suggests that autumn is the most challenging season.

These facts mean that China faces large renewables integration costs. Most of China's VRE has been built in central, southern, and southeastern regions, which keeps transmission costs low. But supply curves in these regions are very steep, and these resources will soon be exhausted.

Intensive utilisation of northern wind resources will be necessary to meet China's renewable energy goals. The transmission and integration challenges involved are vast. Y. Wang et al. (2023), in a rich model of optimal energy system planning, aiming for 59 percent renewables by 2060, find that marginal prices of integrated renewable energy will rise from US$24/MWh for the first terawatt installed to US$78/MWh for the eighth terawatt.[63] The rise is driven mainly by increasing integration costs, but also by the increasing use of poorer-quality resources.

Y. Wang et al.'s "optimal" model makes extreme assumptions about the extent to which the diurnal pattern of electricity demand can be modified to match the pattern of solar generation in particular. This sharply reduces costs but is implausible. They report that their optimal system cost estimates are in the bottom quartile of the Chinese literature; if adjusted upward by around 46 percent to bring them in line with the cited median, power from the eighth terawatt installed costs US$114/MWh.

The core electrification model in this paper suggests that if China retains its energy-intensive industries, at today's capacity factors final renewable electricity capacity may reach 14-16 TW in 2060 (discussed in Chapter 8). Costs reach the inflection point of 4-5 TW by 2035, and 9-10 TW by 2045.

Can China competitively locate its energy-intensive industries in the north? This would resolve transmission challenges. There would be other challenges: the distance from the coast would add new logistical costs; the resource remains of only moderate quality; and the problem of seasonality would continue to limit plant capacity factors or require large investments in storage.

[63] Data available in Peer Review File of Wang et al. (2023). These values exclude additional cost savings Wang et al. modelled as possible if the demand curve can be adjusted to ideally match the renewables supply curve—e.g. using power while the sun is shining. This is deemed implausible.

For this to be attractive, China's other advantages—especially in interest rates, approvals, and policy certainty—must be large and persistent enough to offset Australia's advantages.

Estimates of solar and wind resources differ widely (e.g. Yin et al., 2024). The level of future electricity demand identified in this report is large enough to exhaust the cheap wind resources identified in Zhou et al.'s (2022) supply curve–at the upper end of the literature–especially if seasonality is added to the analysis.[64]

Resolving these uncertainties, and assessing the scale of Chinese advantages needed to offset Australian advantages, is a matter for future work.

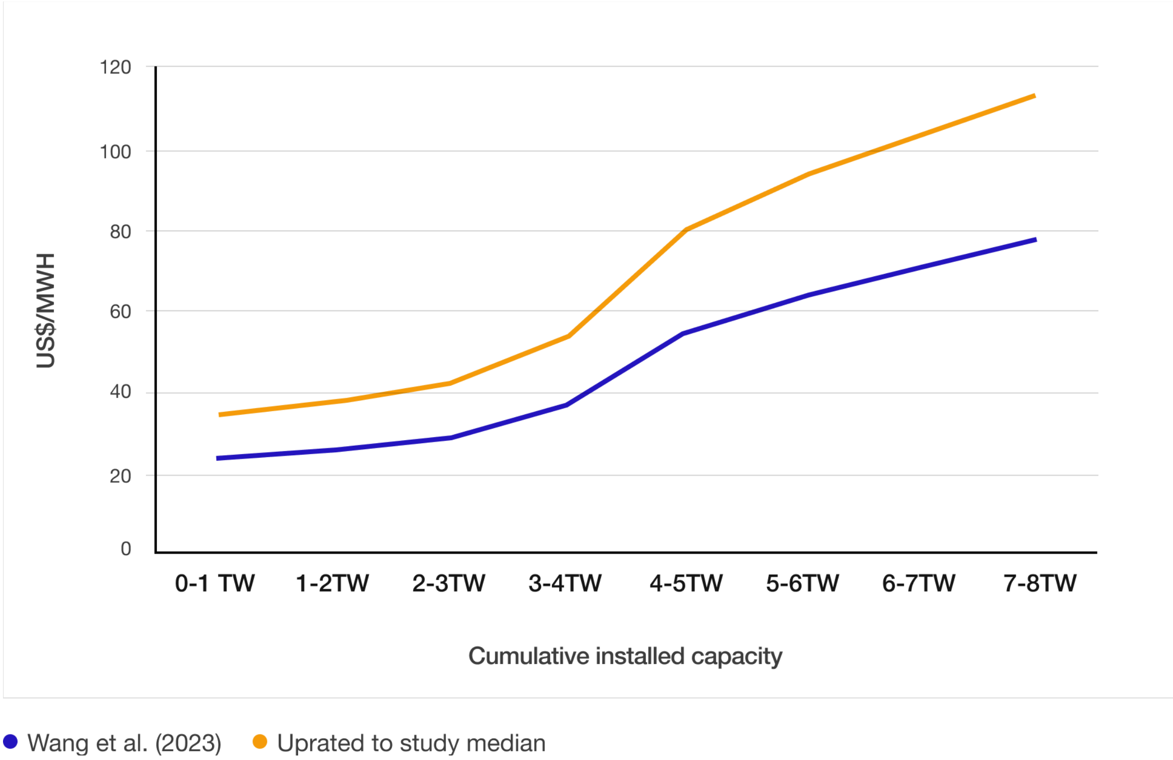

Figure 7.2. The supply curve for a firmed, 59 percent renewables Chinese electricity system, by cumulative installed renewables capacity (Y. Wang et al., 2023, Peer Review File)

India's renewable energy is today among the cheapest in the world. Even more than China, however, its solar and wind resources will be placed under pressure from soaring demand.

Solar resources around the equator and Tropic of Cancer may be excellent (Middle East) or middling (Southeast Asia) depending on cloud cover patterns. India's pattern is closer to that of Southeast Asia, with middling resources that are made variable by the monsoonal climate. Reported average capacity factors are around 18 percent, reaching up to 20 percent in the northwestern deserts. Solar output is especially low in the monsoon months of July and August, while excellent resources are available in the pre-monsoon April-May period (Hunt & Bloomfield, 2024; Jain et al., 2020).

Wind resources are India's weakness. Onshore wind is very poor in around 90 percent of the country, although there are a few areas with fair annual output (capacity factors mostly 20-25 percent). These resources are highly seasonal. Capacity factors peak at over 60 percent in parts of the south during the monsoon months of July to August, but then average less than 20 percent for

[64] Zhou et al. (2022) do not account for the seasonality of China's renewable energy resource, which significantly affects LCOEs. An annual resource that appears sufficient will, under high seasonality, greatly exceed needs for one part of the year and greatly underserve needs for the other.

most of the rest of the year. Because of the costs of long-term storage, high output in two months of the year is of little value; the power system must be designed around sub-20 percent capacity factors.

India may benefit by turning to offshore wind, which offers annual capacity factors closer to 40 percent around much of the coast. Seasonality is still challenging, especially in winter and the post-monsoon season, when offshore wind capacity factors fall to around 16 to 24 percent (Hunt & Bloomfield, 2024). Offshore wind costs around twice as much as onshore wind.

These fundamentals indicate that India's supply curve will be steeper than that of China. These conclusions are supported by the literature.

- India's NIWE (2019) identified around 680 GW with a capacity factor above 25 percent, only half of which is on unutilised land. Jain et al. (2020) identified only 951 GW of wind capacity with an LCOE below US$70/MWh (Figure 7.3). Only around 3 TW of wind is available with a capacity factor above 14 percent, and with low average capacity factors the total TWh produced is low.[65]
- Solar potential, at moderate qualities, is practically unlimited, with around 13 TW available below US$70/MWh. However, solar alone cannot keep costs down: low solar penetrations will saturate daytime demand and lead to heavy curtailment, such that the marginal value of additional solar approaches zero. India lacks the cheap, diverse, and consistent year-round wind sources necessary to complement solar.

[65] At an average capacity factor of 20 percent, 3 TW of wind produces only 5,250 TWh. Costs are therefore high.

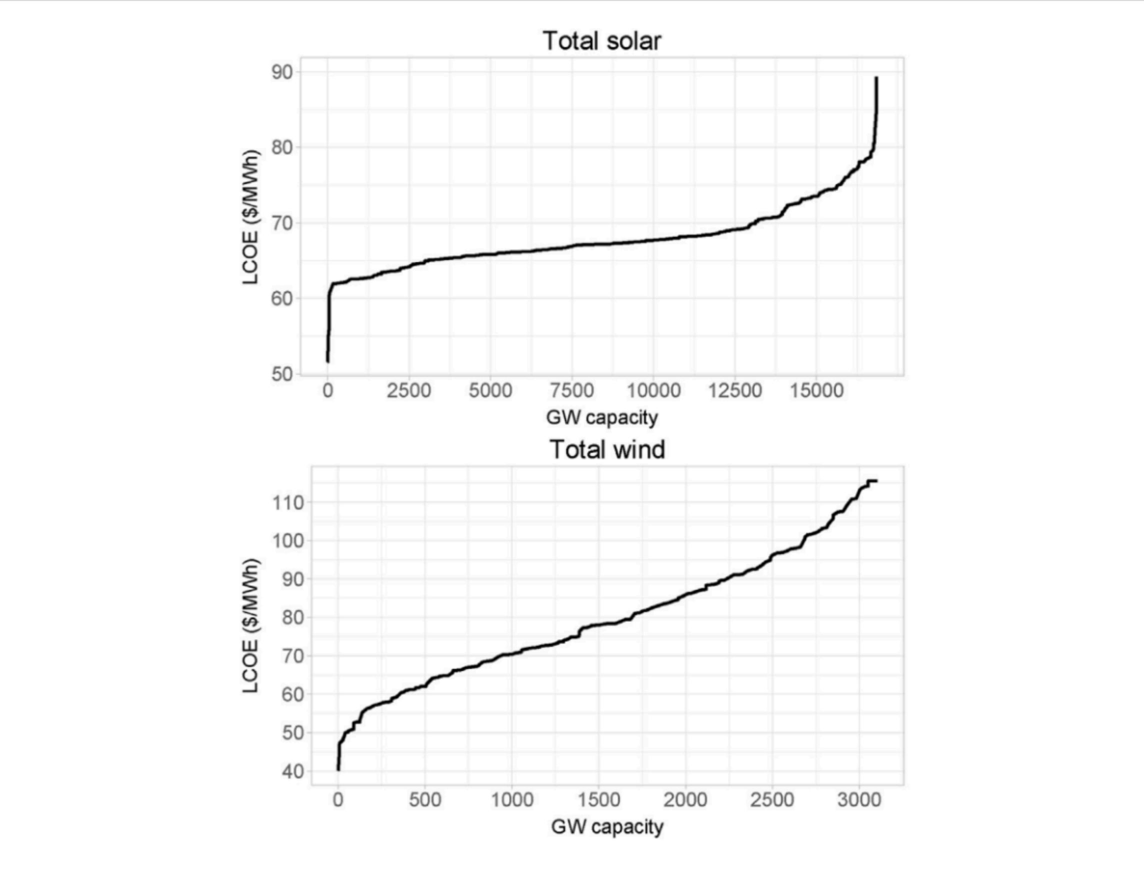

Figure 7.3. Supply curves for solar and wind in India in US$ (Jain et al., 2020).

To pursue high renewables penetrations, India will require costlier wind energy, and more short-term and long-term storage capacity than most countries. It may find it economically optimal to deploy significant quantities of CCS and nuclear power (with hard limits discussed in the next section) despite the costs.

Summarising

Table 7.1 summarises solar and wind resource quality at scale, accounting for the interaction between the level of demand and the capacity factor of the marginal resource. At relevant scales of demand, Australian solar has a capacity factor around 50 percent higher than in China and India, and around double that available in Japan, Korea, and Germany. The resource is highly seasonal in China's north, in India due to the monsoon, and in Germany due to its latitude and winter weather patterns. Japan and Korea have relatively low seasonality due to the abundance of summer cloud, at the cost of lower overall capacity factors. Australia's solar resource around the Tropic of Capricorn has remarkably low seasonality.

Wind is more sensitive to scale. At capacities of a hundred to a few hundred GW, Japan, Korea, and Germany exhaust their moderately-priced wind. At capacities of around a TW, India's wind resources degrade significantly. China has several TW available at an average capacity factor of 25 percent, but this resource is unlikely to be sufficient in a renewables-dominated Chinese grid. Both China and India have the additional challenge of highly seasonal resources, with output more than halving from the windy months to the doldrums. Resources in parts of Australia, including large areas of Queensland, exhibit very low seasonality.

Table 7.1. Marginal wind and solar capacity factors available at the estimated scale of electricity demand, and resource seasonality[66]

	Solar capacity factor	Seasonality	Wind capacity factor	Seasonality
Australia	**26%**	Low to moderate	**30-35%** onshore at multi-TW	Low to moderate
China	**17%**	Moderate to high	**<25%** in north at multi-TW, **<20%** elsewhere	High to very high
India	**18%**	High	**<14%** onshore at multi-TW	Very high to extreme
Japan	**13%**	Low	**<20%** onshore at multi-GW	Moderate to high
South Korea	**14%**	Low to moderate	**<20%** onshore at multi-GW	High to very high
Germany	**11%**	Very high	**<20%** onshore at multi-GW	Moderate to high

As VRE penetrations increase, the seasonality of the resource will become much more significant, requiring further overbuilding of VRE capacity. In turn, this will intensify the shortage of sites with favourable capacity factors.

7.2 Nuclear: Time and money

Nuclear power offers a means of generating zero-carbon electricity independently of weather conditions. Nuclear will be especially important for countries with limited wind and solar resources relative to demand. Its potential is limited by two main factors:

1. high costs, which cannot support competitive electricity-intensive industries but can meet non-tradable demand; and

2. the practical limits to scaling construction.

Money

In advanced economies, nuclear electricity typically costs between 3-6 times as much as renewable electricity. In the US and Australia, the cheapest solar and wind is around one sixth of

[66] See Zhuo et al. (2022), Supplementary note 5, for China's capacity factors available at scale, and Li et al. (2022) and Wu et al. (2023) on resource seasonality. See NIWE (2019), Jain et al. (2020), and Hunt & Bloomfield (2024) on India's supply curve and resource seasonality. See Shibata (2017) and Tsuchiya (2012) on Japan's solar and wind capacity factors, and Takada et al. (2023) and Kondoh (2023) on seasonality. See Kim et al. (2021), Oh et al. (2022), and Park et al. (2019) on Korea's CFs and seasonality. See Mockert et al. (2023) on Germany's CFs and seasonality. Note that reported solar capacity factors in Australia, as high as 32 percent (Edis, 2023), are the result of generators being oversized for their inverters (Lee, 2021). Adjusting for this suggests CFs of around 26-27 percent. Solar and wind resource seasonality is evaluated based on detailed wind/solar generator data from plants located in likely superpower industry regions (personal communication, Prof. Mike Sandiford, Director of the Melbourne Energy Institute at the University of Melbourne, 2024).

the cheapest predicted nuclear costs (see Table 7.2, all in US$). Renewables cost less than one seventh of observed nuclear costs, for example, those of the US Vogtle reactor at US$190/MWh (Lazard, 2024), or of Hinkley C with a heavily subsidised US$166/MWh strike price (Harvey, 2023), or an LCOE closer to US$300/MWh at market interest rates (e.g. Poljak, 2024).

Table 7.2. Relative costs of zero carbon generation technologies in 2023

	Solar	Solar with storage	Wind	Wind with storage	Nuclear	Offshore wind
Lazard (2023, US)	$24-96	$46-102	$24-75	$42-114	$141-221	$72-140
CSIRO (2023, Australia)	$24-36	$46-65	$30-47	$46-65	$130-230	$55-108

Note: All values in US dollars.

China and Korea are both outliers with apparently low costs. In both, nuclear invesment is tightly integrated with state planning decisions which absorb costs. Regulatory structures are weaker (e.g. King & Ramana, 2017; Andrews-Speed, 2020a, 2020b), and nuclear benefits from a mix of explicit and implicit subsidies.

In Korea, for example, electricity is overwhelmingly provided by the state-owned utility KEPCO, and electricity prices are fixed at a low level. Nuclear plants are mainly built by a KEPCO subsidiary, KEPCO E&C. KEPCO had losses of AU$47 billion from 2021 to 2023, but it retains a favourable credit rating because it is underwritten by the state. Low-interest state loans (e.g. KEEi, 2023) greatly lower costs for capital-intensive projects. These are funded by the taxpayer. With those supports, costs are estimated to be around US$66/MWh. However, the United Arab Emirates' Barakah nuclear power plant, built by Korea's KEPCO, appears to offer power at around US$110-120/MWh. This price too is substantially reduced by cheap state finance[67] supplied by the UAE and KEPCO.

There is little evidence for significant deviation from Lazard's and the CSIRO's results in Table 7.2, which assume a level playing field.

Over the last fifty years, we have observed a tendency for the costs of some technologies, but not all, to fall at a steady rate with each doubling in cumulative deployment. This pattern of decline in costs has been called "Wright's law". The rate of decline with each doubling of output has been called the "learning rate". (Wright, 1936; Roser, 2023). The future belongs to technologies that benefit most from Wright's law. Those technologies that do not decline with deployment, or that perversely become more expensive, will play only niche roles.

The cost of solar modules has declined by around 99.6 percent since 1976 (Figure 7.4). Solar exhibits a high learning rate, with a 20 percent reduction in price with each doubling in installed capacity (Roser, 2023). This rate increased to 24 percent from 2007 (Bolinger et al., 2022). Rapid reductions are expected to continue over the coming years and decades. In Nature, Nijsse et al. (2023) forecast that solar will by 2030 be the cheapest electricity source, if highly seasonal, even in Greenland.

[67] With capacity of 5380 MW, a cost of around US$32 billion or around $6000/kW, and a market rate of interest of 7-9 percent. See Power Technology (2024).

The learning rate for wind power has been around 15 percent, bringing a 93 percent decline in prices since 1982 (Bolinger et al., 2022). Battery storage has exhibited a learning rate similar to that of solar, at around 19 percent, and prices have declined around 97 percent in the last thirty years (Ritchie, 2021).

The per unit cost of nuclear power, by contrast, has tended to increase in Western economies (Figure 7.5). A recent MIT paper, Eash-Gates et al. (2020), found that in the period of most intensive nuclear construction the learning rate was negative 115 percent. Prices more than doubled with each doubling of installed capacity. Eash-Gates et al. find that increased safety requirements account for a modest minority of the cost increase; the majority is driven by the *sui generis* nature of each nuclear project, and failures in project and supply chain management.

Increasing costs of nuclear power are not limited to Western economies. India too has seen construction costs as much as triple since early deployment, and prices have quadrupled in Japan (Lang, 2017). Only China and Korea have bucked the trend, in part because of their distinct policy environments. Global mitigation would be easier if nuclear could achieve large and sustained declines in price over the next two decades, but there is no evidence yet that it is possible. In 2024 US dollars, the cheapest-ever nuclear plants were built in the US many decades ago, at close to US$750/kW. The cheapest modern plants cluster around US$3000/kW, and more typical prices are double that value (Lang, 2017; 2024 US dollars, adjusted from 2010 US dollars).

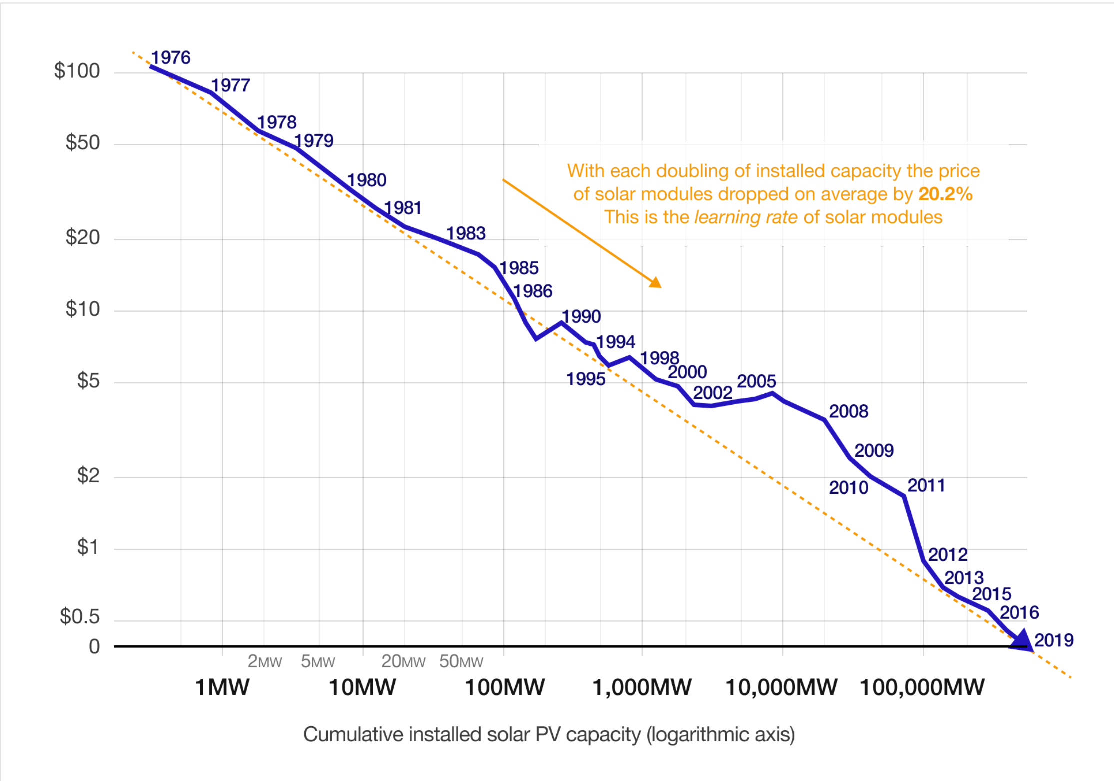

Figure 7.4. The falling costs of solar: A 99.6% reduction in the price per watt since 1976. Prices are adjusted for inflation and in 2019 US$ (Source: Roser, 2020).

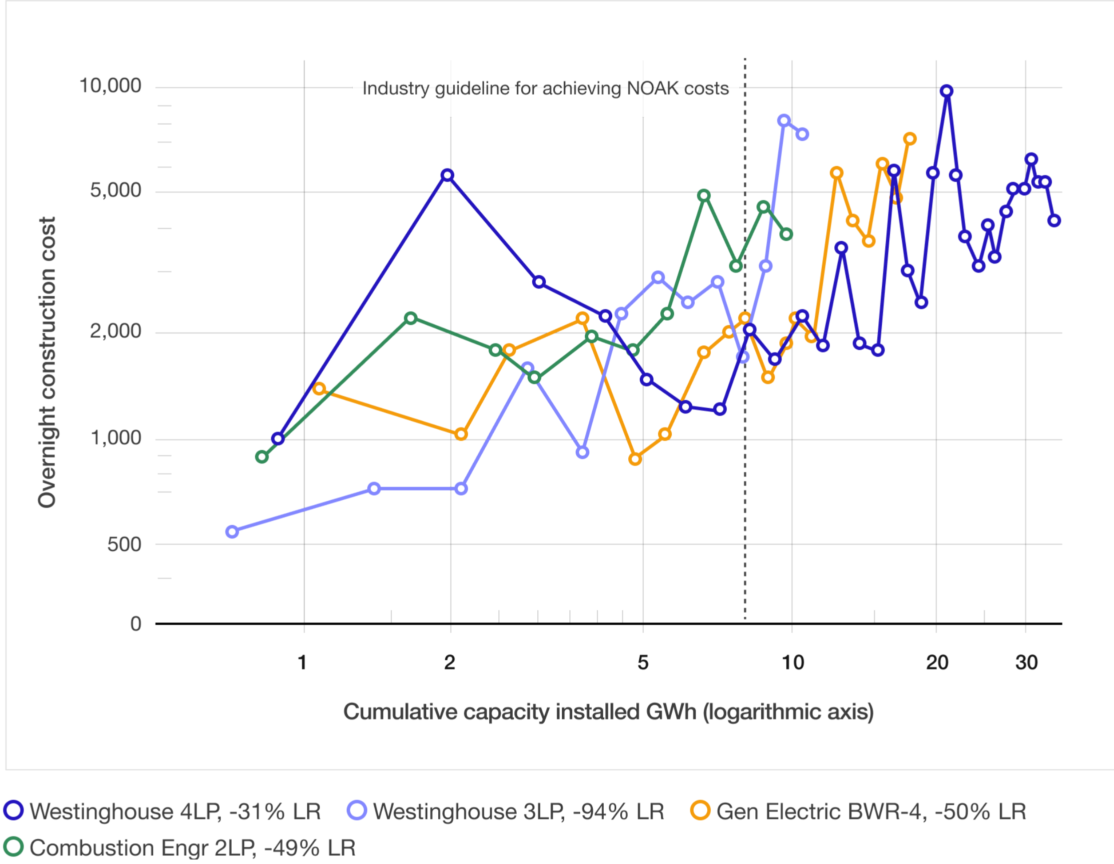

Figure 7.5. The rising costs of nuclear during the peak era for deployment, 1976 to 1987 (Source: Eash-Gates et al. 2020; see Lang, 2017, for similar recent trends).

Time

The second constraint is the slow pace of nuclear buildout, and the costs of expanding a complex supply chain while maintaining high safety standards. China is building around 2 GW of nuclear capacity per year, which is the most rapid pace of any country today. At this rate, nuclear is expected to contribute only 3.5 percent of China's power by 2060. Korea's current build rate would see nuclear decline from 28 percent of its power supply today to only 10 percent by 2050.

Greatly accelerating nuclear build-out rates would place pressure on the small nuclear supply chain and limited availability of specialists. It would likely greatly increase costs. Even a tenfold acceleration in the pace of nuclear rollout would leave the technology a minority contributor to total generation (32 percent in Korea and 18 percent in China).[68] Renewables would still dominate the grid.

Despite nuclear power at low costs by international standards, China is still prioritising investments in renewables. In 2023, China installed around 220 times more wind and solar than nuclear capacity, and around 50 times more wind and solar in terms of generated electricity output (see Kraev, 2024, on Chinese NEA-reported nuclear growth, and Enerdata, 2024b, on NEA-reported solar/wind growth).

[68] Reaching 50 percent nuclear would require a 20-fold acceleration of new nuclear buildout in China, a 30-fold acceleration in Japan, and a 14-fold acceleration in Korea.

Forecast: Acceleration with limited effect

In the country pathway model of Chapter 8, it will be assumed that from 2028, rates of nuclear deployment will increase three-fold in China, Japan, and Korea, and increase 13-fold in India, over those of the last decade. Germany is assumed to retain its zero-nuclear policy. The assumed capacity factor for nuclear plants is 90 percent. Note that Japan's deployment rate is increased through the 2020s, as it brings around 1 GW per year of nuclear plants back online, after they were mothballed in the wake of the Fukushima nuclear accident.

Table 7.3. Accelerated nuclear deployment and share at time of decarbonisation

	Nuclear gen. in 2021 (TWh)	Deployment rate from 2028 (GW/y)	Nuclear gen. at decarb. (TWh)	Nuclear share at decarb.
China	408	6	1890	6%
India	44	4	1360	6%
Japan	61	0.7 (1.7 in 2020s)	250	10%
Korea	151	1	310	18%
Germany	65	0	0	0%

Note: Decarbonisation dates are 2070 for India, 2060 for China, 2050 for Japan and Korea, and 2045 for Germany

7.3 CCS: An important, but modest, role

Carbon capture and storage (CCS) is an important alternative to electrification. It will have an especially important role to play in decarbonising non-electrifiable activities. CCS is well behind the development pathway that had been expected one and two decades ago. On current forecasts, it is not expected to be cost-competitive for most purposes. Its role will be meaningful but modest.

CCS costs depend heavily on the purity of the CO2 stream. Costs are lower where industrial processes release concentrated CO2. They are higher where the stream is dilute, as is usually the case where fossil fuels are combusted in air. Costs are also affected by the location in relation to quality storage, and by access to water resources (Box 7.1), and so may be highly differentiated across projects.

There is significant variation in estimates of CCS costs. The IEA's (2021c) middle costing for CCS applied to fossil fuel power plants is around US$92 per tonne of CO2, and around US$87 per tonne for steelmaking. More recent Bloomberg NEF market analysis estimates costs of around US$92-132 per tonne of CO2 for steelmaking (Casey, 2023).

Taking a middle value for capture, transport, and storage costs, CCS would add around US$110 per MWh to a typical coal power plant. If added to Lazard's (2024) middle costing for new-build coal plants, around US$120/MWh, the total cost of power from a new CCS coal generator would be around US$230/MWh. This is well above the average price of peaking gas power. Prices are not much lower in India, where Hiremath et al. (2021) estimate that by 2050, CCS coal power will cost around US$150/MWh, or nearly seven times the expected cost of solar power.

Commodity market analyst CRU's review of 300 CCS projects suggests that operating costs are generally understated and a minimum carbon price of US$200 per tonne of CO_2 is required to make CCS viable for coal power stations (Butterworth, 2023). The parasitic load is an important cost.[69] Giannaris et al. (2020) estimate that this load may be reduced to around 22 percent with additional efficiency investments on a retrofit plant. In the case of conventional steelmaking, CCS may increase energy requirements by around 15 percent (Witecka et al., 2024).

Typical rates of uncaptured CO_2 today are around 15 percent. While a high carbon price promotes CCS generators over unabated fossil fuel generators, it also imposes a penalty for CCS projects against zero emissions alternatives. Most of the last 15 percent can be captured, but currently only at higher marginal cost.

Assuming favourable project location and water access, there are three cases in which CCS is potentially viable:

- with enhanced oil/gas recovery, which is incompatible with net-zero;
- retrofitted to already-constructed coal power stations; and
- applied to certain industries, including potentially ammonia and steel.

Box 7.1. CCS and water scarcity

Thermal power plants are major water users, and major contributors to water stress in many regions of the world. Jin et al. (2022) find that nearly half of Chinese coal power stations are already under water stress, which reduces output by around one month across the whole fleet. Adding the presently commercial amine-based CCS process to thermal power plants is estimated to increase water consumption by around 100 to 150 percent (Yang et al., 2020; Rosa et al., 2021). If the water consumption increase of CCS is limited to 75 percent, Jin et al. (2022) find that around 15-20 percent of coal plants confront severe output reductions (>30 percent).

There are sometimes options for reducing this impact. Yang et al. (2020), for example, find that using captured CO_2 emissions to support water withdrawal from deep saline aquifers can reduce pressure on shallower freshwater aquifers, so that freshwater consumption increases by only 37 percent. However, such options are frequently not available and will also raise costs.

Newer CCS technologies may have lower water use, although technology readiness is lower, some are unsuited to retrofits, and their costs are unknown and usually expected to be higher (Haran et al., 2023; Rezaei et al., 2023; Sharma & Mahapatra, 2018). Using seawater is another option, but Jin et al. (2022) find that it has very little impact on CCS-induced water scarcity in China.

[69] The parasitic load of CCS is the portion of a power station or industrial facility's generated energy that is consumed by the capture and storage process, which is unavailable for other uses.

Enhanced oil/gas recovery

The large majority of CCS projects today, and especially large projects, involve utilising CO2 for enhanced oil recovery (EOR) or gas recovery.[70] It is the revenue from additional fossil fuel sales, usually combined with subsidies, that makes these projects viable.

Of course, EOR enables further emissions from oil combustion. If one sequestered tonne of CO2 enables one additional tonne of oil-related emissions, then the emissions of the overall system are cut in half—where there would have been two tonnes of CO2 emitted, at least one is sequestered. This is helpful, but it is incompatible with net zero targets. On average today, each sequestered tonne of CO2 leads to more than one tonne of additional oil emissions.

Coal power retrofits

Retrofitting CCS to amortised coal power stations may become cost-effective in the future, where plants have sufficient remaining life, distances to storage are sufficiently small, where baseload power generation from slow-moving coal plants remains sufficiently valuable, and with large improvements in CCS costs. These constraints are limiting.

In China, Singh et al. (2022) and Fan et al. (2020) estimate that the costs of energy from CCS-retrofitted coal power stations need to decline by around half to become competitive. Yang et al. (2021) examine the conditions under which retrofit CCS coal power stations can compete with conventional coal today (at an LCOE around AU$62/MWh). The result is not promising: the CO2 capture rate must be about 15 percent, and the capacity factor must be lifted from the fleet average of 46 percent up to 80 percent. That is, a near doubling in capacity factor is only enough to compensate for capturing a sixth of emissions. In the future, capture rates need to exceed 90 percent, and capacity factors of baseload coal power stations will likely remain suppressed by growth in VRE.

Fan et al. (2023) argue that coal plant CCS retrofits may have a role in reducing expenditure on the transmission lines and storage capacity required to stabilise VRE. Under favourable assumptions about CCS project costs and capacity factors, coal CCS may reduce total energy system costs by a 1 to 3 percent.

Should the costs of CCS retrofits be reduced, Lau's (2023) study of conditions required for retrofit viability identifies potential for around 700 TWh of CCS coal power in China and India each.

Industrial uses: Concentrated CO2 streams

CCS costs are lowest for industrial processes that produce highly concentrated streams of CO2—around US$40-78 per tonne according to Bloomberg NEF (Casey, 2023).

The IEA points to five industries with concentrated CO2 streams that may be amenable to low-cost CCS. Four of these are not particularly important:

- Two are forms of fossil fuel processing that will diminish into the future.
- A third is CCS for bioethanol production, where CO2 byproducts of fermentation can be captured for negative emissions. The scale of this process will not be significant globally.

[70] E.g. Only 19 percent of projects in China involve geological sequestration, all of which are small scale (P. Wang et al., 2023b).

- A fourth is production of ethylene oxide, a chemical used in production of antifreeze and polyester. CCS can only capture process emissions, and a large share of carbon is embedded in the ethylene oxide and its follow-on products, which is then released as CO2 upon use and degradation. Net zero requires biomass carbon.

The fifth and most significant is ammonia production. However, Mayer et al. (2023) find that CCS alone can reduce ammonia lifecycle emissions by only around 40 percent. Adding solar power and additional points of capture along the process,[71] at additional cost, can improve the CO2 reduction to around 75 percent. Finally, one of the strongest determinants of potential emissions reduction is the natural gas leakage rate. Mayer at al. assume a baseline natural gas leakage rate of 2 percent, but they find that at 9 percent leakage, CCS only cuts ammonia emissions by between 0 to 30 percent. Chen et al. (2023) find that the average leakage rate over 26,292 wells in New Mexico, US, was more than 9 percent.

Ammonia made from green hydrogen cuts emissions by around 90 percent or more. Mayer et al. (2023) find that the hydrogen process is around 40 percent more expensive than ammonia with CCS. Given green hydrogen achieves much deeper emissions cuts, it is made competitive by a carbon price of around US$130 per tonne of CO2—or as little as US$20-40 per tonne at higher observed natural gas leakage rates. Carbon prices sufficient to favour green hydrogen will need to be widespread in the 2030s if global climate goals are to be met.

Industrial uses: Dilute CO2 streams

Some processes with dilute CO2 streams, such as cement-making, may be decarbonised by CCS because there is no good alternative. CCS for cement-making is expensive; the IEA's (2021c) middle estimate is US$90 per tonne of CO2 captured, which may increase production costs by 70-100 percent.

Among the superpower industries, CCS for steelmaking is the most important contender. Cost estimates for CCS steelmaking vary greatly. Figures from the IEA (2021c) and Bloomberg NEF (Casey, 2023) suggest CCS would add around US$150 to US$224 per tonne of blast furnace steel. More recent Bloomberg NEF (2024) analysis has CCS adding around US$300 per tonne of steel, more than for hydrogen steelmaking.

Blast furnace CCS retrofits may be an economically attractive option over the coming two decades. Gu et al. (2023) find that with a 90 percent capture rate, the typical cost per tonne of CO2 abated is around US$50-100. The study includes a major role for enhanced oil recovery, and is not transparent about how this affects costs for projects along the CCS supply curve. A year later, Gu et al. (2024) appears less optimistic; only 14 steel plant retrofits are viable at an average carbon price of US$87 per tonne of CO2.

The retrofit opportunity is shaped by the size and remaining lifespan of the existing blast furnace fleet. According to the IEA (2021b), China's existing blast furnace assets will all have passed retirement age by 2040 (Figure 7.6). Their ages may be extended at some cost: Korea's POSCO, for example, recently invested US$382 million to reline and refurbish blast furnace No. 4 in Pohang, which was constructed in 1981 (Kolisnichenko, 2024). This is one of several reconstructions over its lifetime, and such costs reduce the advantage of CCS retrofits. However, as the IEA (2021b) observes, China has a history of much more rapid plant decommissioning and replacement than other countries.

[71] On average, around one third of the CO2 released from ammonia production is low purity, while the other two-thirds is a high-purity "process gas" that can be more cheaply collected.

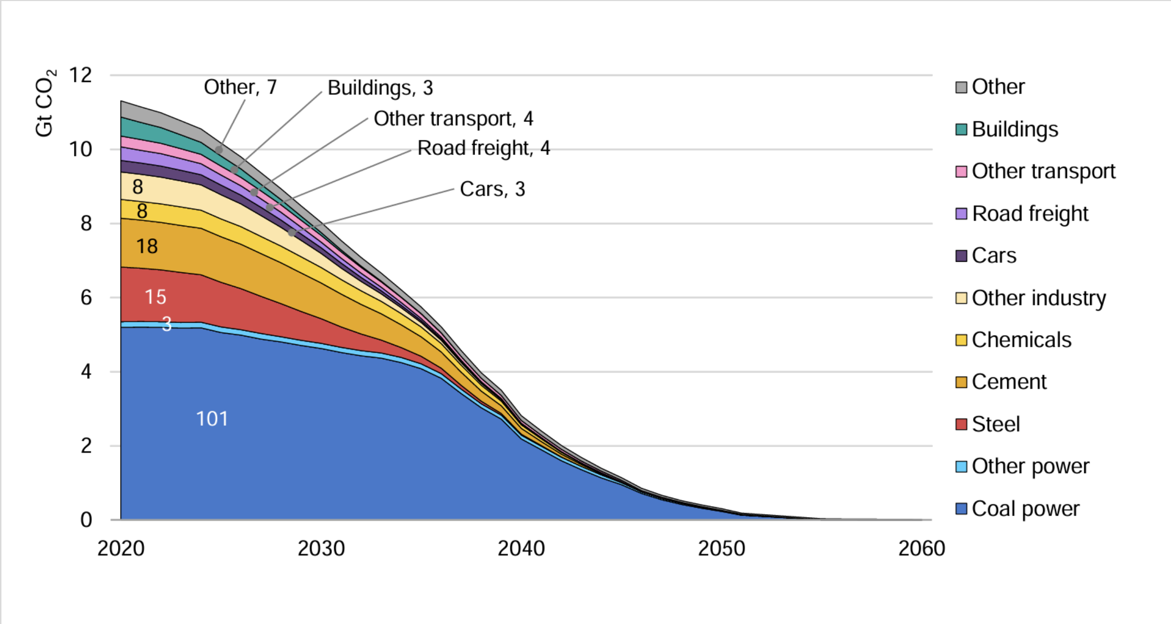

Figure 7.6. CO2 emissions from existing fossil fuel consuming assets in China, under typical lifespan assumptions. Note steel in red. Source: IEA (2021b).

In the long run, the relative competitiveness of CCS, hydrogen, and electrolysis will depend substantially on their respective learning rates. Various scholars have attempted to estimate learning rates for the first two technologies, and these tend to strongly favour hydrogen electrolysis:

- For CCS CO2 abatement costs, Kang et al. (2020) estimate a learning rate between 2 and 5 percent for applications to coal power, and 4 percent for carbon capture and utilisation in Faber et al. (2022).
- For hydrogen electrolysis, estimated learning rates include 18 percent in Vartiainen et al. (2021), Schmidt et al. (2017), and Schoots et al. (2008), 16 percent in Zeyen et al. (2023), 9 percent in Detz and Weeda (2022), and from 12 to 20 percent from the Hydrogen Council (2021). Böhm et al.'s (2019) detailed sub-component analysis suggests that the learning rate is likely to decline from 18-20 percent initially towards 13 percent with maturity.[72]

Another advantage for hydrogen and electrolysis steelmaking is that costs are significantly affected by the price of green electricity, where learning rates are known to be high.

Forecasts of steelmaking technology shares continue to evolve. In the IEA's 2021 Net Zero Roadmap, CCS accounted for more than 50 percent of steelmaking, and hydrogen for around a quarter, in 2050. A 2023 revision lifted hydrogen to 44 percent and lowered CCS to 37 percent (IEA, 2023b). More recently, Bloomberg NEF (2024) expects 64 percent of primary steelmaking to occur via hydrogen, and around 25 percent via CCS by 2050. These are also roughly the shares of these technologies in the investment pipeline to 2030.[73]

We presume CCS retrofits will play a transitional role in steelmaking, helping to cut the emissions of existing Chinese blast furnaces in the 2030s, and Indian (and Southeast Asian) blast furnaces in the 2030s and 2040s. Investment dries up thereafter due to a combination of high carbon prices

[72] This occurs because components with the highest learning rates, such as membranes, fall in price most quickly and become a smaller share of total costs over time. Conversely, components with lower learning rates become a larger share of costs over time.
[73] Of low-carbon primary steel projects planned by 2030, about 60 percent will use hydrogen and 26 percent CCUS (Bloomberg NEF, 2024).

and the maturity of hydrogen (and possibly iron electrolysis) technology, and by 2060 these CCS blast furnaces have been retired. If the learning rate for CCS surprises and matches or exceeds that of hydrogen-based or electrolytic steelmaking, this conclusion will be altered.

The scale of CCS deployment

The IEA's (2021b) 2060 model forecasts that CCS is likely to be deployed mainly in hard-to-abate industries in countries with net zero emissions pledges, as a strategy for removing the last several percent of emissions. It forecasts that 2.4 gigatonnes of carbon will be captured globally across major industries, including the power sector. China accounts for around two-thirds of all CCS, with a focus on the cement industry and fossil fuel backup power. Because cement-making is taken to be non-electrifiable in this paper, applying CCS does not reduce electricity demand.

In the nearer-term, BloombergNEF forecasts growth in CCS to 420 million tonnes of CO2 captured by 2035, based on current subsidy levels (Casey, 2023). The IEA's (2021b) aggressive expectations of 1.6 gigatonnes of CO2 being captured by 2030 have been lowered to around 1 gigatonne (IEA, 2024b).

The IEA's latest revision forecasts that, by 2050, around 800 million tonnes of CO2 will be captured from fossil fuel power stations, 750 million tonnes from natural gas-based hydrogen production, and around 2.1 gigatonnes from industry. A further 1.3 gigatonnes is captured via use of bioenergy for negative emissions—around 450 million tonnes from bio-power generators, 230 million tonnes from industry, and 600 million tonnes from biofuel production and transformation. Direct air capture contributes another 1 gigatonne. The global total comes to 6 gigatonnes.

This is a little below the global total estimated in this paper for 2060. In this analysis, CCS makes four main decarbonisation contributions:

1. **CCS for non-electrifiable industries.** These are industries where there are few good alternatives for eliminating emissions. I assume that around 3.6 gigatonnes of CO2 is captured in this category. Cement-making accounts for the majority. It releases 2.6 gigatonnes of CO2 globally today, and this figure is expected to be stable, with growth in demand from development in South and Southeast Asia as well as Africa enough to offset any efficiency improvements. It is assumed that CCS is applied to 80 percent of the total, or 2.1 gigatonnes of CO2. Further, the electrification model of this paper implies that around 65 exajoules of industrial activity is non-electrified globally.[74] Supposing that one fifth is covered by CCS, this adds another 1 gigatonne.
2. **CCS for electrifiable industries.** It is assumed that CCS may, even by 2060, be able to compete in some electrifiable industries. Of the electrifiable uses of coal and gas—around 42 percent of coal and 64 percent of gas globally—around 20 percent is decarbonised via CCS instead of via electrification. Oil is excluded, given the majority of oil goes to transport and non-energy purposes, which as non-stationary emitters are not amenable to CCS. Altogether, this implies capturing an additional 2.4 gigatonnes of CO2 globally.
3. **CCS for fossil fuel power generation.** Here the contribution is similar to that anticipated by the IEA (2024b), with 800 million tonnes of CO2 captured annually. Most of this will be in countries that lack lower-cost decarbonisation options, including Japan, Korea, and India. Japan has a target for 120 to 240 million tonnes captured CO2 annually by 2050. There it is assumed that in addition to CCS applied to industry, enough CCS is applied to power generation for Japan to hit the upper target by 2060. It is assumed that Korea's use

[74] Excluding emissions from fossil fuel processing, which are mostly eliminated.

of CCS is proportional to that of Japan, moderated by the overall scale of energy demand: it captures 150 million tonnes per annum.

4. **CCS for bioenergy.** CCS is applied to bioenergy at a similar rate to that in the IEA: around 1.4 gigatonnes of CO2 is captured from biomass power generators and biomass-fuelled industry globally. Negative emissions contribute to offsetting the remaining emissions from industries that are neither electrified nor subject to CCS, as well as some non-fossil emissions related to land use.[75]

In total, around 7.7 gigatonnes of CO2 would be captured and stored annually by 2060. This is equal to around 21 percent of global fossil fuel emissions, and nearly 16 percent of emissions from all sources, today.

In terms of the mass of CO2 that must be managed, it is equal to around 150 percent of all the oil consumed in the world each year (around 5 gigatonnes of oil). While much CO2 storage would be within-country rather than traded, those countries without appropriate geological formations—including Japan and Korea—would need to ship almost all captured CO2 overseas. BloombergNEF estimates that shipping liquid CO2 will increase transport costs as much as fourfold (Casey, 2023). Li et al. (2022), in a study with ExxonMobil staff, estimate transport and storage costs of CO2 shipped from Singapore to fall in the range of US$48-450 per tonne.

Figure 7.7 displays the contribution of CCS to satisfying or avoiding the electricity demand set out by the 2060 electrification model. The first category above has CCS applied to non-electrifiable uses, and this has no impact on demand. The second category allows avoiding industrial demand, by continuing to use fossil fuels directly. The third and fourth categories have CCS contribute to generating electricity.[76]

Power requirements fall by 15 percent in Japan and Korea, but only around 8 percent in China, and 6 percent in India and Germany.

[75] After the component accounted for by CCS for non-electrifiable industries, another 4 gigatonnes remains. Around 3 gigatonnes of this is stable plastics, for which carbon content is presumed to be recycled (whether conventionally or chemically) or left sequestered in plastic waste. The remaining gigatonne is covered by negative emissions. This leaves large residual non-fossil emissions from the agricultural sector and other land-use, which are presumed covered by land carbon sequestration. Detailed analysis is a matter for future work.

[76] As just noted, negative emissions from bioenergy with CCS cannot be used to avoid electrification by offsetting the continued direct use of fossil fuels. Negative emissions are used up in offsetting continued direct use of fossil fuels in non-electrified industries.

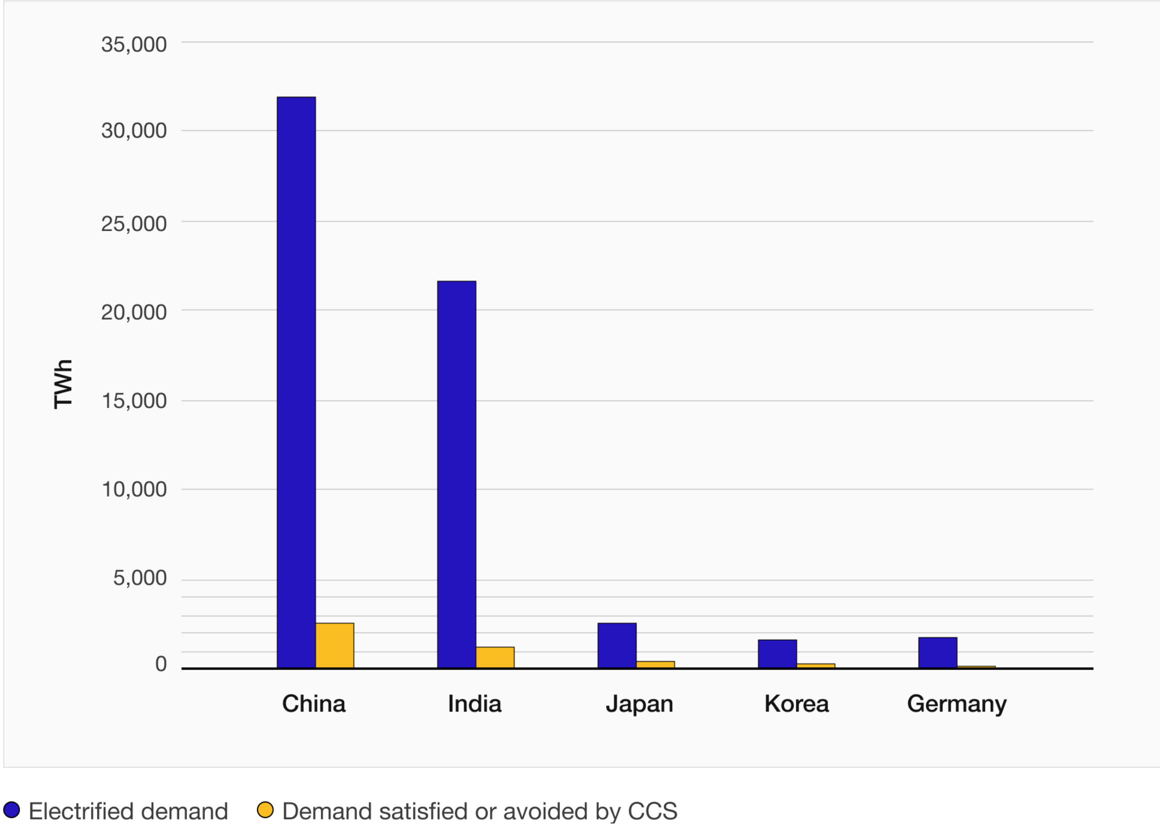

Figure 7.7. Electricity demand in 2060 compared to the contribution of CCS in satisfying, or otherwise avoiding, that demand.

There are many uncertainties in this analysis, but it demonstrates that even with highly optimistic assumptions about the scale of deployment, CCS can only make a modest contribution. It is instructive to consider an extreme scenario in which 50 percent of existing coal power stations in China have CCS applied, and are retained to 2060. This would supply China with around 2,500 TWh. This is only a little more than the electricity saved by the scenario already considered. It is not enough to resolve electricity shortfalls.

There is no likely scenario in which CCS offers a cheap alternative to renewable energy, or the renewable energy trade, at the required scale.

7.4 Biomass: High carbon demand means scarce bioenergy

Fossil fuels are both the dominant source of energy and the dominant source of carbon for industry. Bio-based materials, from bio-oils to whole-plant biomass, will serve both purposes—but for achieving deep carbon emissions reductions, the most valuable use will be as a carbon feedstock. Major analyses neglect that there are net-zero substitutes for bioenergy, but, in the absence of economically competitive DAC, there are no net-zero and large-scale substitutes for biomass as a carbon source.

The balance of demand versus supply for carbon feedstocks will have important consequences for the supply of zero-carbon electricity. Scarce carbon means:

- Reduced bioenergy availability. The bio-carbon that is available must be mainly used for feedstock purposes, hence there will be only a small contribution to electricity production.

- Higher electricity demand: The bio-carbon that is available must be used efficiently. Maximising carbon efficiency generally requires combining biomass with hydrogen electrolysis, which increases electricity demand.

Scarce carbon thus makes the electricity challenge more difficult: there is greater demand for electricity, and lower bioenergy supply to help satisfy it.

Biomass demand

The majority of carbon feedstocks must come from sustainable biomass. To be sustainable, biomass must be replaced with comparable stock after harvest, so that it is carbon neutral, and must not degrade land or significantly raise global food prices.

Carbon may also be sourced via carbon capture applied to fossil fuel combustion or other CO2-generating processes such as cement. However, while recycling of CO2 is preferable to the consumption of additional fossil fuels, it still results in release of CO2 into the atmosphere and is inconsistent with net zero.[77] Municipal waste may be carbon neutral, but plastic combustion results in greatly accelerated release of locked up carbon. It is, in any case, a minor carbon source. DAC may play an essential role in the distant future, but it is exceptionally expensive and at the beginning of a long development pathway.

The analysis in Chapter 5 found that from 860 million tonnes of carbon is needed to satisfy demand in 2050 and 1 billion tonnes in 2060. Dry biomass ranges from 40 to 50 percent carbon. If taking a middle value of 45 percent, typical of energy crops (see Bilandzija et al., 2022, on the important crop miscanthus), then:

- estimated dry biomass feedstock needs are on the order of 1.9 billion tonnes in 2050 and 2.2 billion tonnes in 2060; and
- to satisfy the IEA's (2021, 2023) requirements for 70-99 exajoules of biomass, around 4.3-6 billion tonnes of dry biomass will be required.

Biomass supply

Major biomass sources include energy crops, agricultural crop residues, and woody material that is sustainably harvested from forests. Energy crops are likely to be the dominant contributor.

On the surface, crop residues appear promising: they amount to around 5 billion tonnes globally (Shinde et al., 2022; Prasad et al., 2020), with a typical carbon content of around 40 percent (Stewart, 1993; Campbell, 2012). The total carbon resource is therefore 2 million tonnes per year. Crop residues are one of the two main sources of biomass in major studies including the IEA (2021b, 2024b) and US DoE (2024), the other being energy crops. The IEA (2024b) assumes the availability of around 40 exajoules of organic waste, mainly crop residues, and today the total volume of crop residues globally is on the order of 85 exajoules.

However, there are considerable uncertainties about how much of this 85 exajoules of crop residues can be sustainably withdrawn from the land:

1. not all residues are technically collectable, due to land conditions incompatible with heavy machinery;

[77] Cement-making is one of the better CCS options, given its process emissions—arising from the use of calcium carbonate—are not easily eliminated. If around half can be captured, this would supply around 270 million tonnes of carbon for use as a feedstock in other industries. However, net zero will require that these emissions are sequestered.

2. retention of residues contributes to long-term soil carbon stocks and agricultural fertility, so that not all residues are sustainably collectable; and
3. residues have competing uses besides retention, and are already heavily utilised in many countries. Not all sustainable crop residues can economically be used as carbon feedstocks or for energy production.

The discussion of these factors focuses on China, because it is one of the five countries of this paper, has the world's largest crop residue resource, and so has the largest potential contribution from bioenergy. The most commonly referenced estimate of its resource is around 800 million tonnes (e.g. Jia et al., 2018; Zhao et al., 2024), or 16 percent of the global total. Energy content is on the order of 10.5 exajoules.

In China, Zhao et al. (2024) estimate that around 75 percent of residues are technically collectable. Zhang et al.'s (2021) study, which accounts for the slope of arable land and suitability for machinery, puts the collectable share at around 56 percent.

With respect to sustainability, leaving crop residues on-field contributes significantly to nutrient cycling, soil structure, and erosion protection post-harvest. The long-term removal of crop residues is likely to result in long-term declines in soil productivity (Blanco-Canqui & Lal, 2009; Fu et al., 2021). A commonly cited figure is that around 30 percent of crop residues may be removed (W. Wang, 2023; Zhang et al., 2021; Andrews, 2006; Lindstrom, 1986; Allmaras, 1985). Zhang et al. (2021) argue for site-specific analyses of soil carbon, and in China—as discussed below—this leads to an average sustainable extraction rate of around 26 percent. Current extraction rates are excessive in a large share of Chinese farmland.

Loss of soil carbon has large significance for agricultural productivity, and is also directly relevant to the climate problem. Soils contain around three times as much carbon as the atmosphere. Among ten influences examined by Stella et al. (2019), the removal of crop residues is "the single most important factor" driving soil carbon loss. These soil carbon losses have been "exponential" in recent decades. In China, Chen et al. (2019) find that lifting the crop residue retention rate from 30 percent to 50 percent would sequester around 24 million tonnes of carbon per year, and prevent soil CO2 emissions of around 150 million tonnes per year. Zhang et al. (2021) account for measured soil organic carbon levels across Chinese farms, and so the need to retain residues to maintain productivity; this reduces the potential of crop residues by another 75 percent.

With respect to competing uses, Zhao et al. (2024) find that 90 percent of collectable crop residues are already utilised for high-value purposes, mainly as fertiliser and feed. Around 10 percent are already used to produce energy. Zhang et al. (2021) find that up to 20 percent of crop residues are technically available and not yet utilised as resources. However, only 25 percent of those residues can be sustainably withdrawn. Thus, on Zhang et al.'s figures, only 3 percent of the theoretical crop residue resource is available for immediate, sustainable withdrawal (Figure 7.8).

If China could use all its technical resources—as much as 600 million tonnes—then around 240 million tonnes of carbon would be available. Alternatively, if all 600 million tonnes were combusted in typical biomass plants, it would generate around 700 TWh. However, using Zhang et al.'s (2021) estimates of the technically available resource, these totals fall to around 45 million tonnes of carbon and 140 TWh. Estimates of the sustainable resource are smaller still, at 12 million tonnes of carbon and 36 TWh.[78]

[78] Generation estimates here are about 25 percent higher than in Zhang et al. (2021), because I assume that future biomass plants will be more efficient.

Limiting crop residue utilisation to sustainable rates makes it much more difficult to supply biomass at scale. The main alternative is the farming of energy crops, including “oil crops” grown for their oil content (e.g. soybeans, canola, oil palms, and jatropha) and “biomass crops” grown for the use of whole-plant biomass (e.g. miscanthus, giant reed, and switchgrass). The latter are likely to be much more significant.

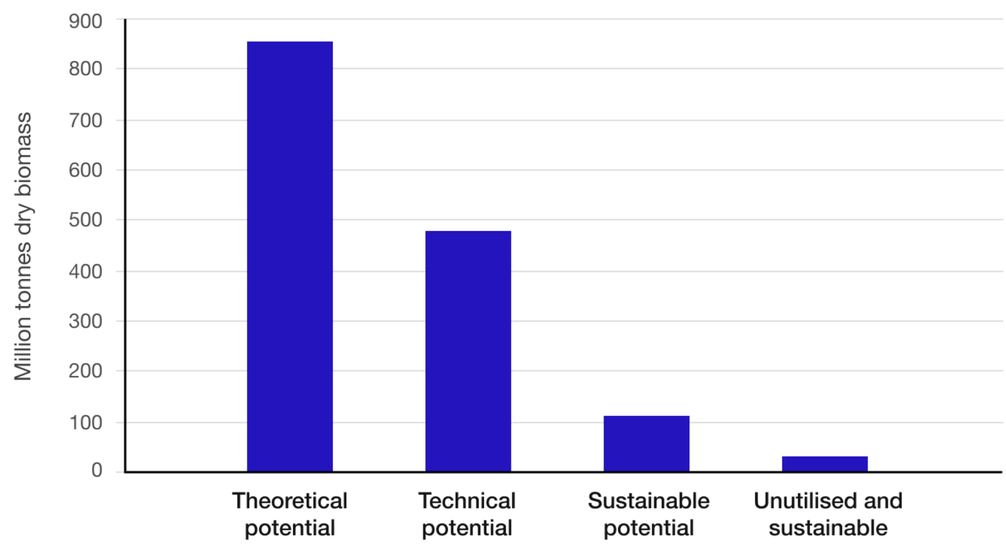

Figure 7.8. Agricultural residue withdrawal potential in China in Zhang et al. (2021).

Oil crops generally require fertile farmland and so compete with food production. Because only the oil content of seeds or fruit is utilised, they also yield much less than whole-plant energy crops.

A tonne of oil from oil crops has an energy content of around 38 gigajoules and carbon content of around 770 kg per tonne. Output for typical oil crops such as soybeans is about 0.5 tonnes per hectare. Oil palms average around 4 tonnes per hectare, but their need for a tropical climate has been a major driver of rainforest loss. Breeders claim that high-oil sugarcane varieties may produce somewhere between 1.3 and 5 tonnes per hectare (Kumar et al., 2017).

If the mean oil crop yields 1 tonne of oil per hectare per year, then:

- meeting 2060 carbon needs estimated in this paper would require around 1.3 billion hectares of land; and
- satisfying the IEA’s (2021b, 2024b) projected bioenergy needs of 70-99 exajoules would require around 1.85 to 2.6 billion hectares of land.

Global cropland is around 1.6 to 1.9 billion hectares, depending on definitions. Thus, supplying this paper’s calculated carbon requirements would require around 75 percent of all global cropland to be turned over to carbon production. On the IEA’s figures, around 100 to 160 percent of global cropland would be required. Clearly oil crops can only be minor contributors. This conclusion is consistent with other major analyses (e.g. the US DoE, 2024).

This leaves biomass crops as the most promising option for securing carbon and bioenergy at large scales. Using the whole plant increases energy and carbon yields per hectare, so that less land is required. Many biomass crops can also be grown on marginal land, removing the issue of competition with food crops for prime land.

Lignocellulosic energy crops include the herbaceous crops or woody plants touched on in Chapter 4. Miscanthus x giganteus is a representative biomass crop, suited to marginal land with reliable rainfall above 600 mm/year (Ouattara et al., 2022). Typical yields on marginal land are from 15 to 25 tonnes of dry plant matter per hectare,[79] with each tonne containing around 14-18 GJ and 450 kg of carbon. Taking simulated yield on marginal land of 17 tonnes per hectare (Xue et al., 2016) and a middle value of 16 GJ per tonne, total energy and carbon yields are 272 GJ and around 7.7 tonnes respectively.

Land requirements are reduced to as little as one tenth of those for a representative oil crop:

- to supply this paper's estimated volume of carbon required in 2060 would require around 130 million hectares of land; and
- satisfying the IEA's (2021, 2023) projected bioenergy needs of 70-99 GJ would require around 260 to 370 million hectares of land.

This is, of course, speculative output and depends on the availability of marginal land.

In China, Xue et al. (2016) report that while 171 million hectares of marginal land are available, the suitable area for miscanthus is limited to 7.7 million hectares. Simulations suggest a yield of around 135 million tonnes of dry biomass, offering around 60 million tonnes of carbon—or around 7.5 to 9 percent of global requirements.

The biomass supply curve

The marginal costs of biomass can be described by a supply curve like that in the introduction of this report. Few supply curves are available, although there is one for Jiangsu, a major agricultural province in China (W. Wang, 2023), and a more detailed supply curve available is from the US DoE (2024).

W. Wang (2023) adopts the 30 percent removal rate for crop residues and finds that around 0.7 to 12.5 million tonnes are viable in Jiangsu at a price of US$50-100. This is enough to provide 0.3 to 5 million tonnes of carbon. Uncertainty is high, with this estimate spanning more than an order of magnitude. Generation costs are also high, a matter discussed in the next subsection.

Much greater detail is available from the US DoE study, and though the US is not one of the focal countries of this paper, it is useful as a case study of sustainability issues and potential biomass scale. An estimated 1.1 billion dry tonnes is available at a price under US$1000/tonne (Figure 7.9). Note that in the following discussion, unlike the figure, short tons are converted to metric tons ("tonnes").

[79] Or 7 to 15.5 short tons of dry plant matter per acre in US DoE (2024).

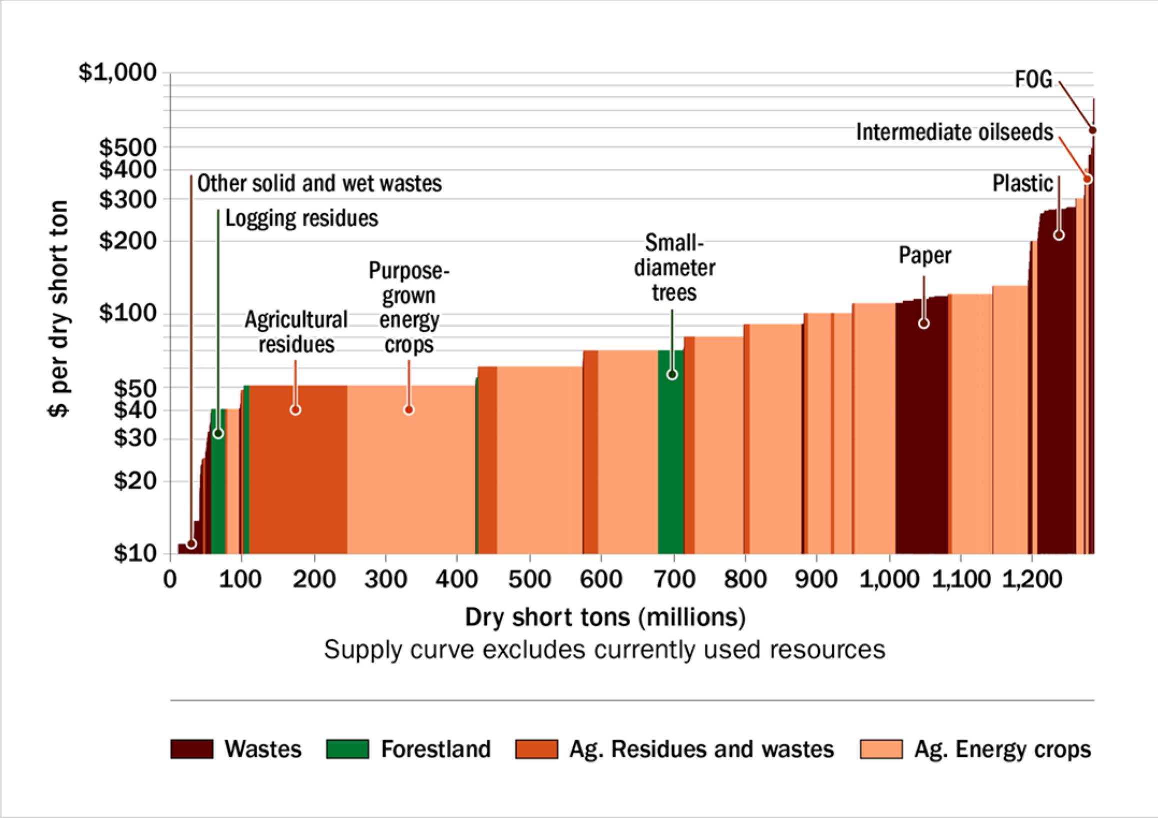

Figure 7.9. US DoE (2024) US biomass and waste supply curve, before transportation, in 2022 US dollars.

There are some important limitations to the DoE analysis. First, these are "roadside" prices, which is the price of biomass once it has been harvested and aggregated, so that it is ready for sale to the processing facilities. Transportation and processing costs are excluded, and these may double the actual prices of products at the lower end of the curve (e.g. agricultural residues).

The DoE analysis also contravenes the sustainable sourcing of biomass as defined here and elsewhere in the literature, including in much of the Chinese literature.

- Crop residues are harvested above rates considered acceptable in the literature, with residue extraction rates reaching 60 percent in participating farms.[80] Sustainable use generally requires halving this rate to 30 percent, and on arable land with low carbon content the constraint may be even tighter.
- The production of energy crops uses around 9 percent of existing agricultural land, displacing food production. This would impact food prices, with wheat prices, for example, rising by around 19 percent.[81] Such uses are excluded and replaced assumed production from marginal land (details below).
- Around 49 million tonnes of waste is derived from plastics. If plastic is combusted, the stored carbon is released immediately. Net zero emissions would require that plastics are derived from biomass or waste materials, or are otherwise offset by carbon sequestration.

[80] The average rate is around 30 percent, but 40 percent of farms do not participate, so the remainder have a 60 percent extraction rate.
[81] The DoE estimates low effects on final processed food prices, because commodity food prices are only a modest share of processed food prices. However, much of the world uses grains more directly, and US use of corn biofuels was previously connected to food riots in the 2008 food crisis. Similar events are expected to become more likely in a world with higher climate variability and higher world population.

> This would increase carbon demand, or demand for biomass carbon sequestration, enormously.[82]

Unfortunately, the DoE does not analyse production of energy crops on marginal land, the most promising option for sourcing sustainable biomass. If sustainable availability is assumed similar to that in Xue et al.'s (2016) study of China , then another 135 million tonnes of dry biomass, and 61 million tonnes of carbon, may be available.

Uncontroversially sustainable supply is therefore limited to 80, 148, 57, and 135 million tonnes of crop residues, waste, forest materials, and energy crops respectively. This comes to a total of 420 million tonnes.

Taking an average of 45 percent carbon content, total carbon is around 190 million tonnes. As a carbon feedstock, this could satisfy around 24-29 percent of global needs. Alternatively, it can provide a large amount of bioenergy: at 5 MWh of energy per dry tonne and presumed future plant efficiency rising from 30 percent today to 35 percent, around 735 TWh could be produced.

The majority has a roadside price between US$50 and US$120 per tonne. Transport and processing costs are not specified. In China, crop residue transportation costs are a large share of final costs (Xu et al., 2020). It is assumed they may increase US prices by another US$20-50 per tonne, for a price range between US$70 and US$170 per tonne.

After feedstocks: How much cheap bioenergy remains?

Our main question concerns the availability and cost of bioenergy after satisfying global demand for biomass as a carbon source. As already noted, there are substitutes for bioenergy, but no good substitutes for biomass carbon at scale. Thus, in the long-run, the relevant marginal bioenergy prices are those that apply after carbon feedstock demand has pushed us a significant distance up the biomass supply curve.

IRENA (2023c) assumes a biomass fuel cost of around US$1.50 per GJ. This would come to around US$24 per tonne of miscanthus, and a little less for agricultural residues, inclusive of transport and processing costs. IEA (2020b) figures are markedly higher, if for a limited set of plants across Denmark, Italy, and India, coming closer to around $65-110 per tonne. At IRENA's price point, no biomass crops, and only a small amount of waste, is available in the US. Adding transport and processing costs to US DoE (2024) figures will increase this gap and reduce available materials towards zero in the US. IRENA's figures may be accurate for existing plants, which draw on the cheapest (and sometimes zero-cost) biomass resources, but they are no indication of future costs.

Of course, as carbon prices rise towards the social cost of carbon, large amounts of biomass may become available especially to satisfy non-tradable demand (see Box 1.2). However, recall that this analysis is concerned with cheap bioenergy that can compete in satisfying tradable demand, and so is cheaper than world-best renewable energy resources embedded in the outputs of the superpower industries.

Chinese studies, such as Xu et al. (2020) and W. Wang (2023), point to prices of US$70-100 per tonne for agricultural residues. Revenues from carbon pricing of US$50-70 per tonne are needed to induce Chinese farmers to direct residues to electricity generation. Consequently, even in China, a key obstacle to biomass generation is the high LCOE (W. Wang, 2023). In Xu et al. (2020),

[82] Alternatively these emissions may also be offset by carbon sequestration elsewhere. In the electrification model of this paper, there will already be large demand for sequestration to cover fossil fuel uses that are non-electrifiable and not amenable to CCS; the limits of that potential is reserved for future work.

anticipated biomass at a price of US$70 per tonne implies a generation cost of around US$100/MWh, double that of coal power and significantly higher than the cost of firmed renewables. Yuan et al. (2021) find the same result.

Globally, this paper has found that around 1.45 to 1.8 billion tonnes of biomass will be needed for feedstocks alone. Consider the effects on China, which has the largest calculated biomass potential globally, and the US, which is the top biofuel and second biggest agricultural producer globally:

- If China covers 20 percent of global biomass carbon needs, it must supply from 300 to 360 million tonnes of biomass. This would require around 90 to 110 percent of the combined total of all sustainably available crop residues (Zhao et al., 2024) plus the total miscanthus potential on marginal land (Xue et al., 2016).[83] Of course, most crop residues are currently used for other purposes.
- If the US satisfies 15 percent of global demand for biomass feedstocks, it must supply around 220 to 270 million tonnes of biomass. This will consume 50 to 65 percent of its uncontroversially sustainable biomass with a "roadside" price under US$300 per tonne.

The marginal price of biomass available for bioenergy after feedstocks will be very high. This has large consequences for the competitiveness of bioenergy: if the marginal cost of biomass only doubles from US$70 to US$140 per tonne, the price per MWh increases by 50 percent. A tripling increases prices by 100 percent.

What, then, is the prospect for large-scale generation of internationally competitive electricity from biomass? At the lower end, with minimally intensifying the use of crop residues and with bioenergy crops limited to marginal land, global carbon production is likely to be less than one billion tonnes. The majority, and potentially the large majority, of sustainable carbon will be consumed by feedstock uses. Because this demand pushes us up the supply curve, the feasible contribution of cheap bioenergy is then **close to zero**.

Again, this is not to say that bioenergy will not make meaningful contributions to electricity grids, in the satisfaction of non-tradable demand. But those contributions will be associated with internationally uncompetitive prices, so that bioenergy cannot support competitive superpower industries.

We have noted reasons to be sceptical of the IEA's (2021, 2023) estimates of the potential from crop residues, with a focus on the Chinese evidence. Nonetheless, let us suppose that through bioenergy crops it is possible to achieve the IEA's (2021) implied supply of around 70 exajoules by 2060. Total dry biomass demand would be around 4.7 billion tonnes. After subtracting the portion that goes to feedstock uses in the core scenario of this paper, around 35 exajoules, or 2.35 billion tonnes, remains.[84] Combustion efficiencies for biomass power generation are typically only 30-35 percent today (IRENA, 2023b), but to test the limits of an optimistic scenario, it is assumed that biomass combustion may reach the efficiency of modern coal power plants, at around 40 percent.

Biomass-based electricity production would, in this case, rise to as much as **3,900 TWh globally**.[85] This is a large amount of electricity—over half of China's, and nearly a sixth of the

[83] Accounting for Zhao et al.'s (2024) estimate that 10 percent of crop residues are already used for energy.
[84] Take 15 GJ per tonne and 42.5 percent carbon as a intermediate values between crop residues and bioenergy crops. 70 exajoules is equal to around 4.7 billion tonnes of such biomass. To supply 1 billion tonnes of feedstock carbon, around 2.35 billion tonnes of biomass is needed. The remaining 2.35 billion tonnes contains 35 exajoules.
[85] Biomass can also be used directly, rather than via electrification, with a similar energy efficiency in most uses.

world's, electricity production in 2021—but it would not go far when spread across a global economy with greatly expanded electricity demand. Being nearly 5 billion tonnes of dry biomass up the global supply curve, it would be expensive at the margin.

The assumptions that underpin the latter scenario may be plausible at higher carbon prices. Given much higher carbon prices are expected, below and in Chapter 8 it is assumed that global bioenergy generation will reach 3,900 TWh. Bioenergy will not, however, be competitive with the superpower trade.

Country shares of bioenergy

Analysis of the biomass opportunities from crop residues, oil crops, and biomass crops suggests that China's bioenergy opportunity is low compared to its energy needs. Xue et al. (2016), for example, find that miscanthus grown on marginal land in China can contribute around 184 TWh of electricity generation. Under optimal mitigation without trade, however, all such sources of biomass would need to be allocated to feedstock uses. This would leave no excess for electricity generation. This is consistent with major concerns in China about the availability and sustainability of biomass, which have reportedly reduced policy support for the technology (W. Wang, 2023).

As an unlikely upper estimate, assume that China has a 23 percent[86] share in the 4,800 TWh left after feedstocks globally. That amounts to 900 TWh of biomass-based electricity, or around 3 percent of China's electricity demand in the 2060 model of this paper. This contribution to closing the electricity supply gap is less than half that of CCS in Section 7.3.

Biomass resources in India are smaller than those in China. The main source is crop residues, which are close to 700 million tonnes per year, but the same technical, sustainability, and economic limitations apply. For a relatively optimistic estimate, Negi et al. (2023) find that intensive use of crop residues may support 30 GW of biomass plants, which would provide on the order of 250 TWh.

Edrisi and Abhilash (2016) find that India has around 39 million hectares of wasteland, which is around 12 percent of the country. This is less than a quarter of that available in China. This relative scarcity is likely driven, in part, by India's threefold smaller land mass and threefold higher population density. It is unclear how much of this marginal land is suited to energy crops in practice; if Xue et al.'s (2016) findings in China are a guide, the suitable fraction will be low. A much smaller share of India appears to be viable for growing miscanthus, for example, than in China (Hao et al., 2022).

Nonetheless, Negi et al.'s (2023) estimate is tripled, allowing around 250 TWh each from residues, other organic wastes, and bioenergy crops. Total bioenergy potential reaches 750 TWh. However, if India's share in global carbon demand is around 15 percent, then there will be enough biomass leftover to generate around 450 TWh.

Resources in **Japan**, **Korea**, and **Germany** are minimal. Pambudi et al. (2017), for example, observe that meeting the Japanese government's target of around 33 TWh of biomass generation by 2030 may involve importing biomass. It is assumed that their resources will, in the best case, be sufficient only to meet carbon feedstock demand.

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[86] This is China's implied share of global biomass in the IEA's China model. Here, giving China such a share of *bioenergy after feedstocks* neglects that China has a disproportionately high level of industry feedstock demand, and hence will have proportionately less remaining for bioenergy uses.

Summary

Carbon will be scarcer in the net zero era than it has been throughout the whole of the fossil fuel era. This scarcity will interact with the energy system to increase the electricity supply-demand gap: scarcity necessitates the use of carbon efficient industrial processes, which often involve hydrogen electrolysis, so comes at the cost of much greater electricity demand. This means that carbon is expected to be largely dedicated to feedstock uses, with less available for energy purposes.

The analysis suggests that the contribution of bioenergy to satisfying future energy demand will be small.

In the long-run, carbon can be sourced at any desired volume via DAC, at least so long as the chemical processes involved in DAC do not run up against environmental boundaries. Reliance on DAC would, however, sharply increase electricity demand, and this returns us to the main question of this paper and the next section: Is potential clean electricity supply enough to satisfy demand?

Box 7.2 Australia's biomass potential

Detailed analysis of Australia's biomass potential is beyond the scope of this paper, and will be the subject of forthcoming Superpower Institute reports. However, it is worth a brief sketch of that potential.

The biomass crop potential lies in the mallee country of southern Australia, the savannas around and north of Capricorn, and the mulga country in the mid-latitudes of eastern Australia. These are marginal lands that are unsuited to crop production, hence would minimally impact Australia's agricultural output.

The productivity of mallee species such as Eucalyptus polybractea is estimated at around 5.4 tonnes per hectare per year on marginal land (Wu et al., 2008; Yu et al., 2009). Biomass crops such as miscanthus have similar attributes and requirements to sugarcane, which is grown at scale in Queensland. A large part of northern Australia appears suited to growing miscanthus (Hao et al., 2022). Another promising plant is Agave tequilana, which may produce up to 14.4 tonnes of carbon per hectare per year in semi-arid environments (Crawford et al., 2022).

Using around 5 percent of Australia's land to farm carbon-around 38.5 million hectares—at an average rate of 8 tonnes of carbon per hectare would allow production of around 308 million tonnes of carbon. This is around 30 percent of the carbon feedstock required globally in 2060 in this paper. Research on the extent and efficient use of this potential is of major importance for global decarbonisation as well as Australian rural and provincial development.

08.

Getting to net zero: Countries' mitigation gaps and the role of green imports

Most countries have set targets that are at least consistent with containing global warming to 2°C, though generally not 1.5°C. However, very few countries are on track to meet their 2°C-compatible commitments. This chapter assesses the five countries' current pathways to net zero. Its main purpose is to show how much the superpower trade may aid countries in reaching net zero, by closing the gap between their future electricity supply and demand.

The analysis brings together all the elements of the preceding chapters. The model of maximum electrification built over Chapters 2 to 5 provides the foundation. The alternatives to electrification discussed in Chapter 7 are added. Expected electricity demand is reduced by direct combustion of fossil fuels with CCS and direct use of biomass. The remaining electricity demand is met by some mix of renewables, fossil fuel generation with CCS, biomass generation, and nuclear power.

Superpower imports, examined across Chapters 4 and 6, greatly ease the task of reaching net zero targets. Through the trade, energy-constrained countries can access the world's cheapest renewable energy and avoid riding too high up their domestic clean energy supply curves.

Two graphs are presented for each country.

- The first shows the country's current pathway, based on rates of technology deployment observed over the last 3-10 years.[87] It shows how far that country will be from net zero by its scheduled date of decarbonisation (from 2045 for Germany to 2070 for India), if it maintains its current pace.
- The second graph adds planned or anticipated growth in technology deployment, based on government targets, agency or other third-party analysis, and the limits to deployment set out in Chapter 7.

In both graphs, the potential for the superpower trade to fill the remaining supply-demand gap is shown.

Treatment of solar and wind: Curtailment and overbuilding

The calculation of electricity supplied by variable renewable energy (VRE) sources, mainly solar and wind, requires modification due to curtailment at high penetrations.

[87] Three years is a more appropriate measure for technologies where deployment is rapidly accelerating, such as wind and solar power. A decade better captures technologies where deployment is discontinuous, with bursts of activity and lulls, such as nuclear power and hydroelectricity.

Take, for example, wind turbines operating at an average capacity factor of 25 percent, where 1 GW produces on average 2.2 TWh of electricity per year. This electricity is not dispatchable[88] and is not evenly distributed across the year. In India, it is concentrated in the monsoon months of July and August. In China, output peaks in spring and falls to as little as a third in the autumn lull. Nor is VRE evenly distributed across years, with some years subject to VRE "droughts" of varying intensity.

Any such pattern can be flattened if we assume sufficient long-term storage. Long-term storage, however, is costly—it requires inefficiently converting electricity into green fuels, the storage of those fuels, and their inefficient combustion.

An efficient response is to "overbuild" VRE plants to some degree (Perez et al., 2019; S. Wang et al., 2021). This increases curtailment in high output periods but allows more reliable satisfaction of demand during lulls. Average capacity factors for the VRE fleet fall, and average costs per MWh produced rise. But so long as marginal renewable energy costs remain below those of alternatives, overbuilding is cost-effective. The alternative, of more aggressively minimising curtailment, effectively involves the "overbuilding" of dispatchable supply (storage, peaking gas, etc.), which will reduce their capacity factors and increase costs. It is usually more efficient to overbuild the cheaper technologies.

Overbuilding VRE should proceed until the marginal cost, at lower capacity factors, is equal to the marginal cost of competing energy technologies. S. Wang et al. (2021) find that overbuilding from 33 to 75 percent, for curtailment rates of 25-43 percent, leads to lowest energy systems costs in California. Allowing zero curtailment triples total system costs.

For our purposes, it is important that curtailment, and lower effective capacity factors, entails increased nameplate capacity for a given volume of electricity generation. That is, it means moving further up the VRE supply curve, which means greater exhaustion of the best sites.

Above a certain penetration threshold, typically around 20-40 percent, curtailment begins to rise. That threshold depends on the seasonality, diurnal pattern, and inter-year variation in VRE resources. It also depends on complementarities between resources. Inland Queensland, west of the Great Dividing Range, for example, benefits from low-seasonality wind and solar, with a remarkable complementarity between daily solar and a nocturnal intensification of wind. Less overbuilding will be required, and higher average capacity factors can be maintained.

In the analysis below, minimum curtailment rates of 20 percent are assumed for high renewables penetration grids (i.e. overbuilding by 25 percent).

On CCS: Application to tradables versus non-tradables

CCS estimates are based on a combination of governmental plans, projections in the literature, and the analysis of Section 7.3, which presumed a rate of global CCS application that exceeds IEA forecasts. Application of this to the electricity supply-demand gap is complex, because CCS has three functions.

1. most importantly, it helps to decarbonise non-electrified activities, such as cement production;
2. it allows low-carbon supply of electricity, as a substitute for other green generation technologies;[89] and

[88] Dispatchable generation can be activated and adjusted as needed by grid operators.
[89] When applied to CO2 captured from the use of biocarbon, sometimes incompletely referred to as bioenergy with carbon capture and storage (or BECCS), it contributes negative emissions.

3. it can *displace* electricity demand, by allowing the direct use of fossil fuels in industry to continue.

For our purposes here, this leads to an analysis with two steps:

- First, we must set aside CCS applied to non-electrified activities, which is important for decarbonisation but does not contribute to closing the electricity supply-demand gap. This is calculated based on country-specific emissions from non-electrified industries.[90]
- Second, for the remainder, we need to convert CCS capture rates (i.e. gigatonnes of CO2 per year) into some volume of electricity demand that is either satisfied with fossil fuels (#2) or is avoided by use of CCS in industry (#3).

Following the analysis in Section 7.3, the exhaustion of the CCS retrofit opportunity, the decline in enhanced oil recovery, and differences in learning rates mean that CCS becomes uncompetitive compared to renewable energy and hydrogen sometime between 2030 and 2050. CCS cannot compete in the tradable industries, and is used either to allow fossil fuel power plant grid-stabilisation, or to decarbonise non-tradable industries.

Gigatonnes of CO2 captured is therefore converted into TWh on the assumption that CCS is applied to modern fossil fuel plants (the coal/gas composition depending on the country's present pattern of use). We must also account for the parasitic load. For an advanced coal plant with 800 kg of CO2 per MWh and reduced future parasitic loads of around 20 percent, 10 million tonnes of captured CO2 can cover around 10 TWh of electricity. For a gas peaker, the same volume of captured CO2 may cover around 20 TWh.

Countries may, of course, heavily subsidise CCS and other expensive generation options so that they can compete with the superpower trade. This would lower living standards and significantly slow mitigation. The fastest and cheapest pathway to decarbonisation is to focus scarce public resources to cover demand where there is no cheap substitute (i.e. non-tradables), rather than covering demand where there is a cheap substitute (i.e. the tradables).

8.1 China

If China's economy was maximally electrified under the core 2060 scenario, electricity demand would increase by a factor of around 3.9 to around 31,550 TWh by 2060.

Figure 8.1 shows the pathway that China has been on over the last few years.

China was four years late on reaching its 2020 nuclear target of 58 GW. Its recent deployment rate has been around 2 GW per year, enough to lift nuclear generation to around 936 TWh by 2060—around 3.4 percent of generation. This is a decline from its 5 percent share today. EIA analysis suggests the rate of around 2 GW per year is set to be maintained (EIA, 2024), though shortly we will assume that it increases.

China's rate of modern bioenergy deployment has been rapid over the last decade, beginning from a low base (Guo et al., 2022). Growth is mainly driven by the expansion of electricity generation, with direct uses of biomass (biogas and transport biofuels) relatively stable.[91] If its pace of around 25 TWh-equivalent across each of these categories per year is maintained, China will install

[90] Plastics are either covered by biomass, or assumed recycled or left as sequestered carbon.
[91] Biogas has stabilised at around 0.3 exajoules, and transport fuels reached around 0.1 exajoules (IEA, 2021d).

enough by 2060 to reach the maximum of 900 TWh identified in Section 7.4 (a total assessed as implausible and, if achieved, costly).

It is China's solar and wind installation rates that make it the world's leading deployer of clean energy. At the current rate—around 190 GW of solar and 70 GW of wind annually—China will reach around 8 TW of combined wind and solar capacity by 2060. At the capacity factors available at this scale of deployment, and with curtailment of 20 percent at the high level of VRE penetration, this 8 TW has a generation potential of around 10,300 TWh of electricity.

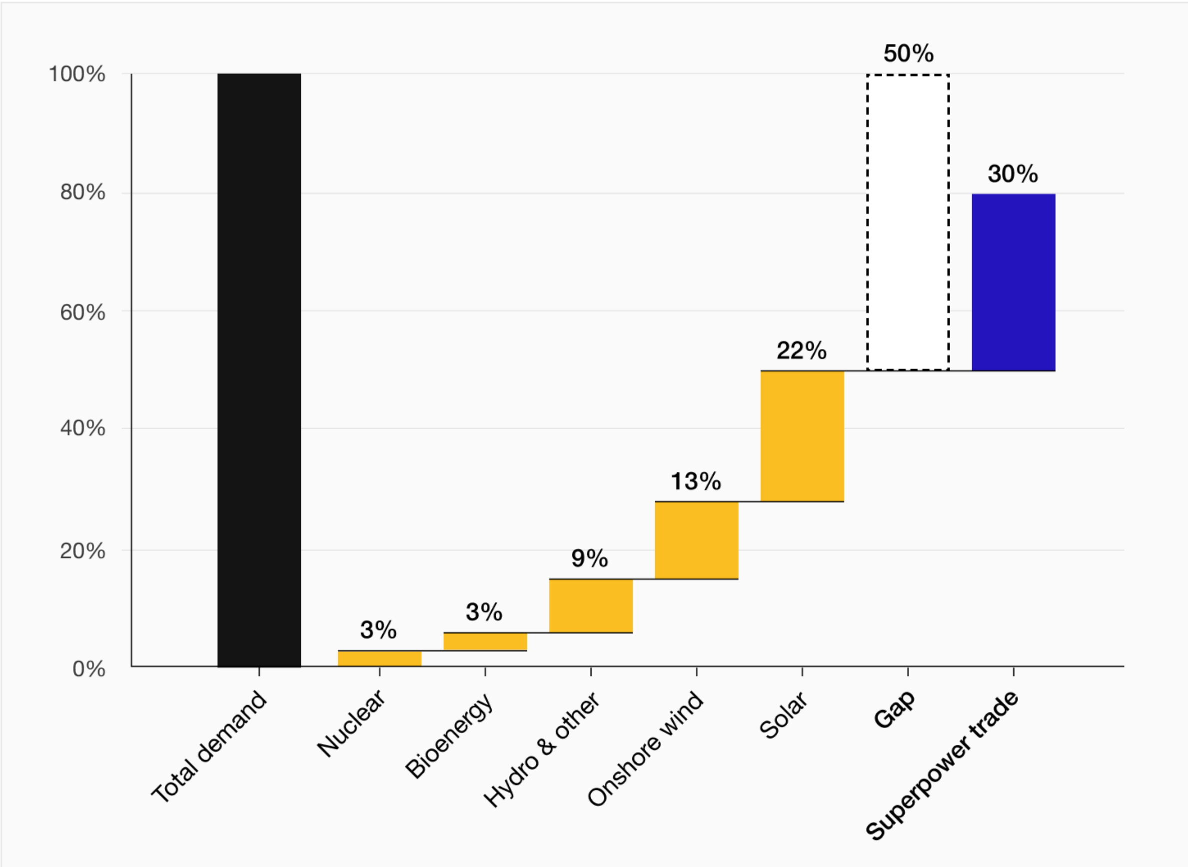

Figure 8.1. China's clean energy deployment based on recent trends as a share of electricity demand in 2060, the remaining supply-demand gap in 2060, and the potential contribution of the superpower trade.

However, here I assume that China can

- triple today's rate of nuclear install to 6 GW, i.e. around six standard reactors, per year, with generation reaching 1,900 TWh by 2060. This exceeds IEA (2021b) projections;
- cover 2.8 gigatonnes of CO2 per year, just above the upper end of all other projections reviewed.[92] Around 1 gigatonne is required for non-electrified industries. The remaining 1.8 gigatonnes is equal to the IEA's (2021) forecast of CCS that is, for us, electricity-relevant. Finally, it is assumed that 1.25 MWh is supplied/avoided per tonne of CO2 captured. Thus, CCS covers 2,250 TWh of demand; and
- generate 1,600 TWh of hydroelectricity, a 45 percent increase (following the IEA, 2021b).

[92] P. Wang et al. (2023) have 0.6 to 1.45 gigatonnes of CO2 captured by 2050, mainly covering power and chemical sectors. Sun et al. (2024) expect 1 to 1.8 gigatonnes annually. The IEA forecasts 2.6 gigatonnes of CO2 captured by 2060, although only 1.8 gigatonnes is relevant in that it reduces electricity demand (either avoids electrification or supplies clean electricity).

The remaining electricity gap to fill is around 12,700 TWh. The superpower trade would close most of the remaining gap. Importing the key tradables of Chapter 4 would be enough to:

- cut final electricity demand by around 9,500 TWh; and
- close around 75 percent of China's remaining electricity gap to 2060.

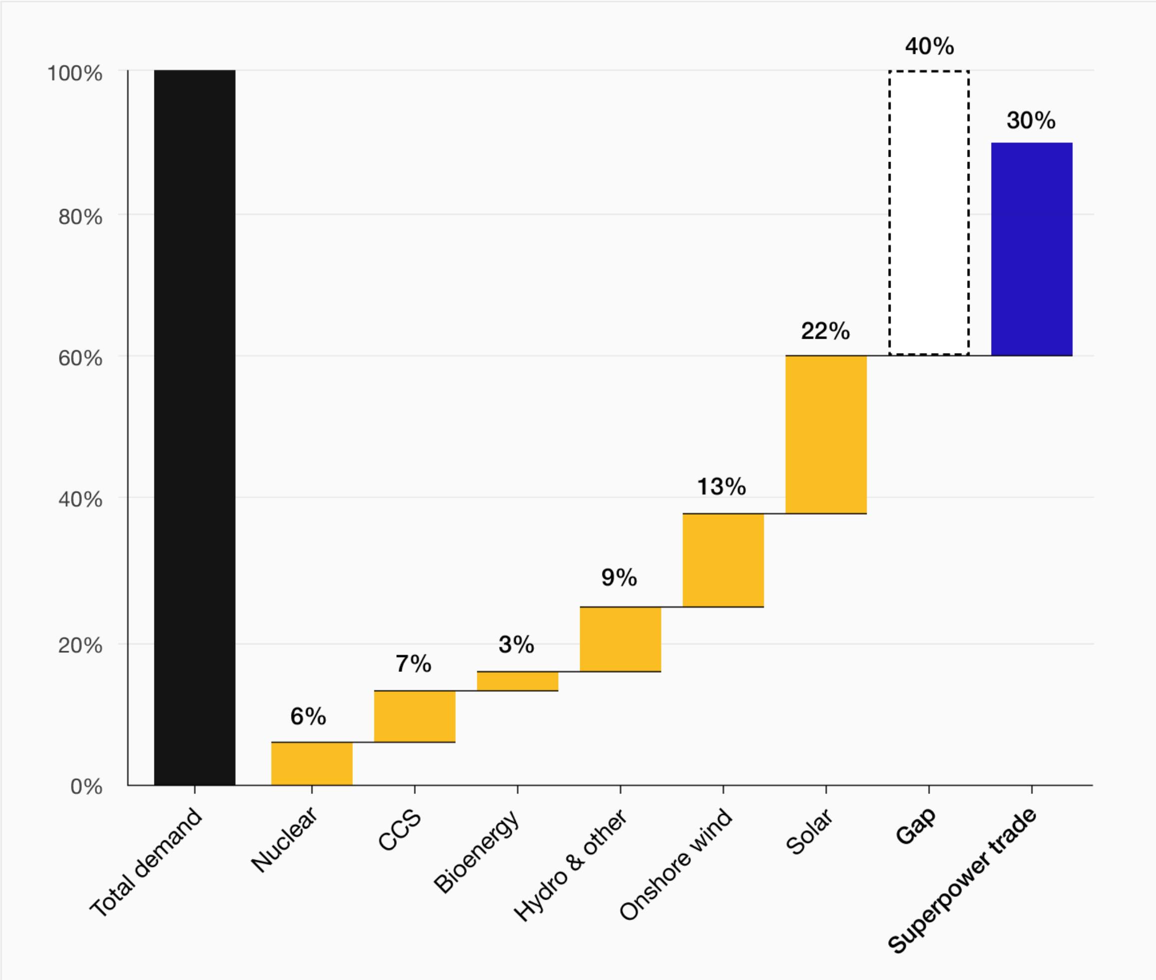

Figure 8.2. China's accelerated supply pathway versus demand, the remaining supply-demand gap in 2060, and the potential contribution of the superpower trade

China's options for finishing the job domestically will have rising marginal costs. China has already struggled to meet its nuclear targets, and the assumed threefold increase in the rate of nuclear deployment in Figure 8.2 may already test constraints on specialists and other elements of the supply chain. To significantly move the needle, much greater acceleration is required, very likely at high cost. CCS is most favourable for application to existing fossil-intensive assets, but these assets will mostly be defunct by mid-century. Without large advances, CCS will be an uncompetitive option for new-build operations.

China may also increase its generation of wind and solar by factor of around 2.4, assuming—at this high penetration—curtailment of around 25 percent. Such a curtailment rate may be a minimum, given 75 percent penetration and a seasonal resource. Assuming solar and wind capacity mixes clustered around 50:50, optimal in Liu et al. (2020), gives a total wind and solar capacity of at least 17 TW, or 8.5 TW each. This would press beyond the limits of China's wind supply curve as set out in Zhuo et al. (2022). The capacity factor for wind in particular will decline below 25 percent due to overbuilding and resource exhaustion (c.f. abundant 35 percent available in prospective superpower regions of Australia). With unlimited solar resources at a capacity factor of 18 percent, overbuilding solar plus deeper storage is an alternative, although effective capacity factors will fall well below 18 percent due to increased seasonality and curtailment (c.f. capacity factors of 27-30 percent in Australia).

China will pursue a mix of these strategies, but renewables will likely dominate: the IEA (2021b), for example, expects 70 percent penetration of wind and solar by 2060. China will have fully exhausted its competitive resources in most provinces at an early stage; there is on the order of only 600 GW of competitive wind across the most populous parts of the country (Zhuo et al., 2022). By the 2030s, China will face the mounting challenge of transmitting VRE power from the north and northwest.

The rise in China's VRE costs will materialise as economic growth and electrification advance over the coming decades, and become especially acute from the 2040s as VRE penetrations reach high levels. This analysis suggests it would be prudent for China to plan ahead, hedging against the risk of combining rising energy prices with a large base of energy-intensive industries. This would lead to a vast corpus of stranded assets—a late restructuring that should have come early.

The superpower trade is likely to be the cheapest option for a large share of the gap. Australian resources are much richer and less seasonal. It would allow China to avoid riding further up its renewable energy supply curve, giving greater assurance of maintaining moderate energy prices.

8.2 India

Electrifying India's economy as in the core 2070 scenario would see demand rise to around 21,600 TWh.

This demand results from assuming that India will successfully reach various government targets or other projections in the literature for industrialisation, and that India partly catches up to China in its rates of participation in superpower industries. As noted in Chapter 5, that the Indian government targets 300 million tonnes of steel production by 2030 (Indian Ministry of Steel, 2017), and reportedly 500 million tonnes by 2047 (Mishra, 2024). This is around a fourfold increase in capacity over 2021. In other major industries, India is assumed to lift production to on average around 25 percent of Chinese output. Shipping and aviation reach around half the Chinese level, in part driven by the economic growth assumptions of Chapter 5.

India's pace of nuclear, wind, and solar installation over the last few years (and last ten years for nuclear) is very low. The share of clean electricity in generation declines from 23 percent today down to 11 percent by 2070. To be on track to meet its net zero target by 2070, India needs to increase the rate of clean electricity rollout around 17-fold.

The pace of nuclear rollout over the past decade has been around 0.3 GW per year. The increase in modern bioenergy and CCS has been negligible (Rakos, 2024). India is on track for around 214 TWh of hydroelectricity (IEEFA, 2019).

India's peak annual rate of wind installation over the last few years has been around 2.4 GW. Its largest efforts have been in the rollout of solar, reaching around 21.5 GW in 2023. If this rate is maintained, solar will contribute around 1,300 TWh in 2070 (at an assumed capacity factor of 18 percent). This is about 7 percent of estimated 2070 demand.

The superpower trade would exceed India's mitigation effort from all these technologies combined.

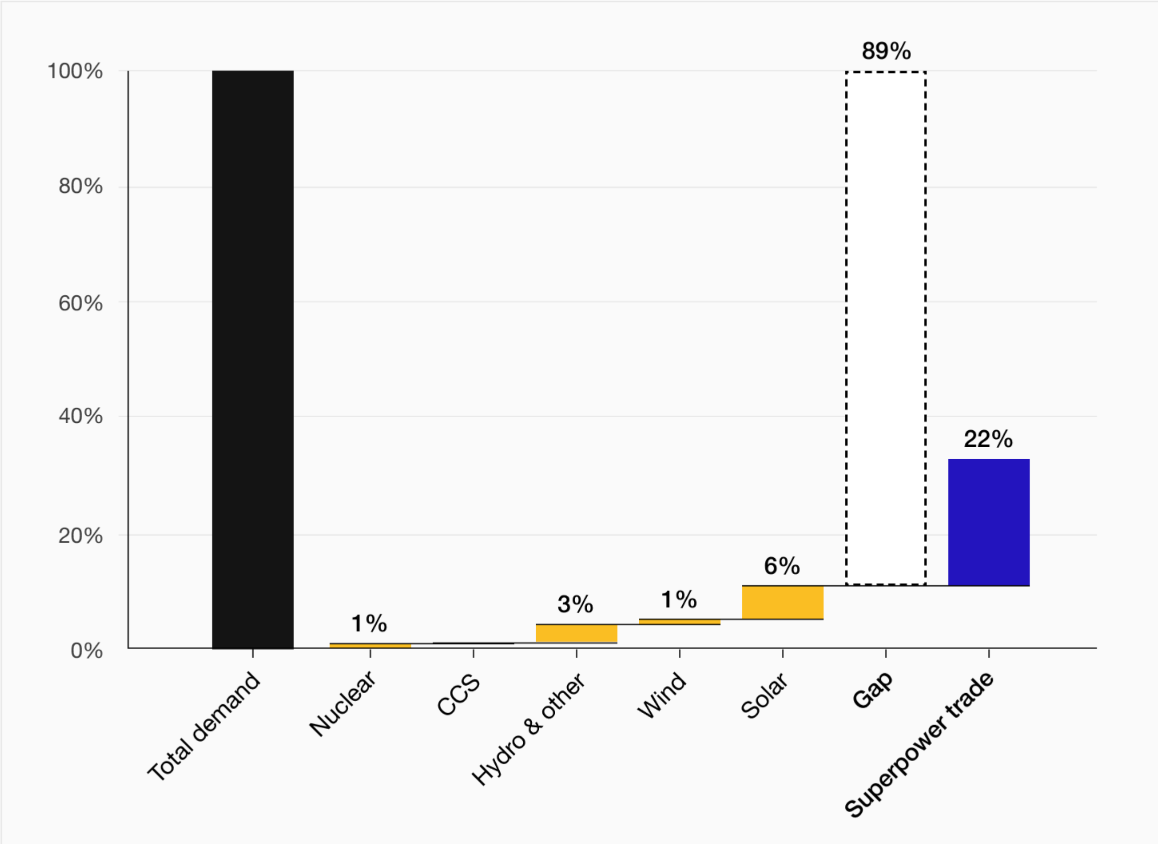

Figure 8.3. India's clean energy deployment as a share of demand in 2070 based on recent trends, the remaining supply-demand gap in 2070, and the potential contribution of the superpower trade.

India's target for nuclear power is 100 GW by 2047. Reaching this target would require increasing its nuclear installation rate to around 4 GW per year (starting today), a 13-fold increase over the rate of the past decade. If this rate were achieved and sustained, and capacity factors were 90 percent, in 2070 India would have around 172 GW of nuclear producing 1,360 TWh. This is a material but modest contribution, similar to that in the case of China, at around 7 percent of India's power needs in the main model here.

The contribution of CCS is assumed to be absolutely lower but proportionally higher than that in China due to India's relatively poorer alternatives. Around 2 gigatonnes of CO2 is captured by 2070; this is around 2.7 times the CCS contribution forecast for the Indian planning body NITI Aayog in 2050 (Mukherjee & Chatterjee, 2022). A third is used to cover non-electrified industry. The remaining two-thirds either covers coal power or displaces electrifiable industry; it covers around 1,800 TWh of demand.

Biomass is assumed to generate, or allow avoidance of, around 750 TWh of electricity.

The upper value of World Energy Council India (2023) projections for total hydroelectricity capacity is around 536 TWh, more than a tripling over today's levels and close to the estimated total national resource. This satisfies 3 percent of demand.

It is further assumed that India will reach its target of 500 GW of solar and wind by 2030, which requires increasing its rate of deployment to around 60 GW per year, starting today. If this rate is maintained, India will reach around 18 percent solar and wind by 2070.

The remaining gap is around 13,500 TWh, or 62 percent of 2070 demand. The rate of clean electricity deployment (or displacement via CCS applied to industry) of all kinds must increase a further threefold over this already accelerated pathway. Renewable energy could fill the gap with a further fourfold increase in the rate of solar and wind deployment to 250 GW per year.

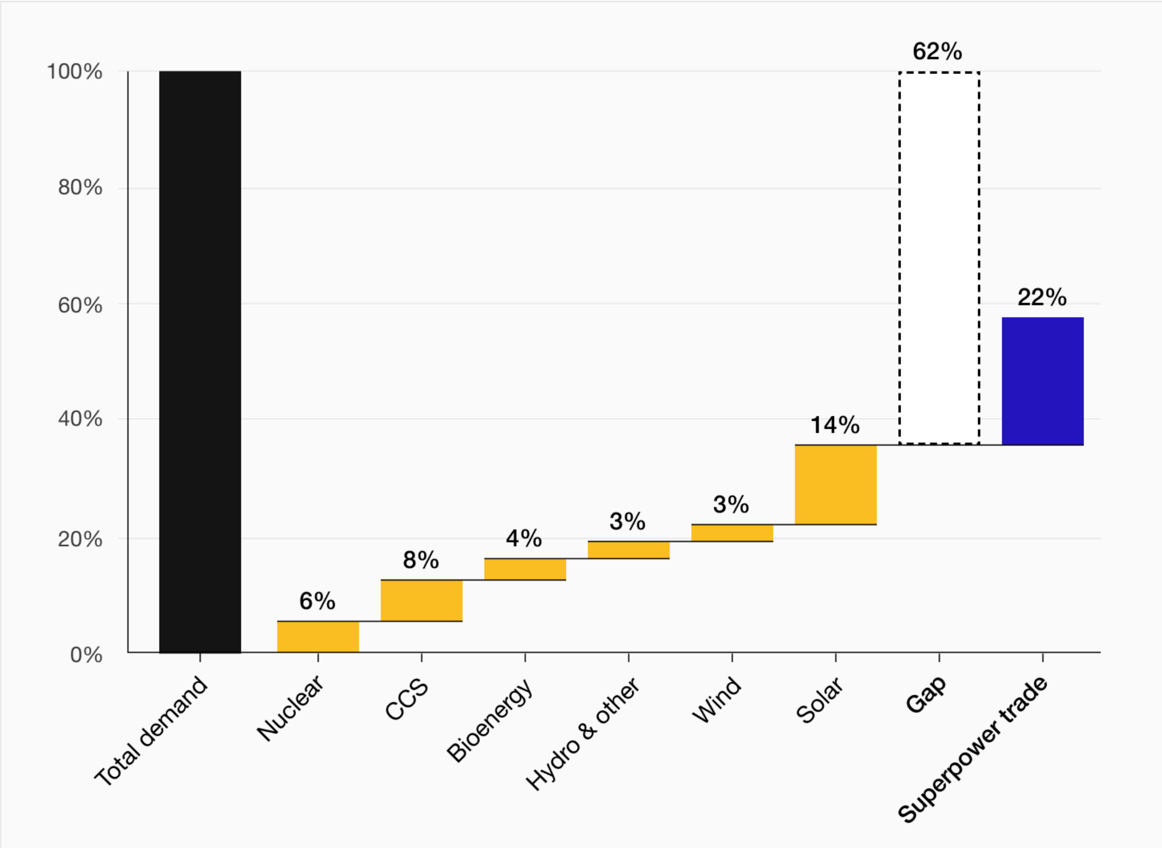

Figure 8.4. India's accelerated supply pathway versus demand, the remaining supply-demand gap in 2070, and the potential contribution of the superpower trade

However, all of India's options for closing this gap are relatively expensive and increasing at the margin. Solar power is the cheapest option, but without the extensive support of wind becomes expensive at even low penetrations because its diurnal pattern demands much more extensive use of energy storage. As discussed in Section 7.1, India's major constraint is its steep wind supply curve. It must depend more on nuclear, which is expensive in India and confronts deployment speed limits, and relatively expensive CCS.

While the short-term requirements are smaller in India than in China, the long-term case is even stronger: the superpower trade will be one of the cheapest options on India's energy supply curve. It could

- close 35 percent of the supply-demand gap by 2070; and
- cut India's final electricity demand by 22 percent.

These contributions will be larger if India industrialises as expected.

8.3 Japan

If maximally electrified as in the core model, Japanese power demand would increase to around 2,550 TWh, which is 2.7 times total demand today.

At Japan's current rate of nuclear and renewables rollout, the share of clean electricity in its grid would decline from 28 percent today to around 22 percent in 2050.[93] The rate of rollout must increase 12-fold to reach net zero by that date.

Japan is reopening nuclear plants that were mothballed after the Fukushima accident of 2011 at a rate of around 1 GW per year. Its rate of new nuclear plant deployment is, however, very low at around a quarter of a GW per year. If this rate is maintained, nuclear will produce only around 170 TWh in 2050. Deployment of bioenergy and CCS is, so far, negligible.

The rate of solar and wind deployment is internationally low, averaging around 6.5 GW and 0.3 GW respectively over the last few years. This is enough to supply only 220 TWh by 2050, around 10 percent of its electricity demand.

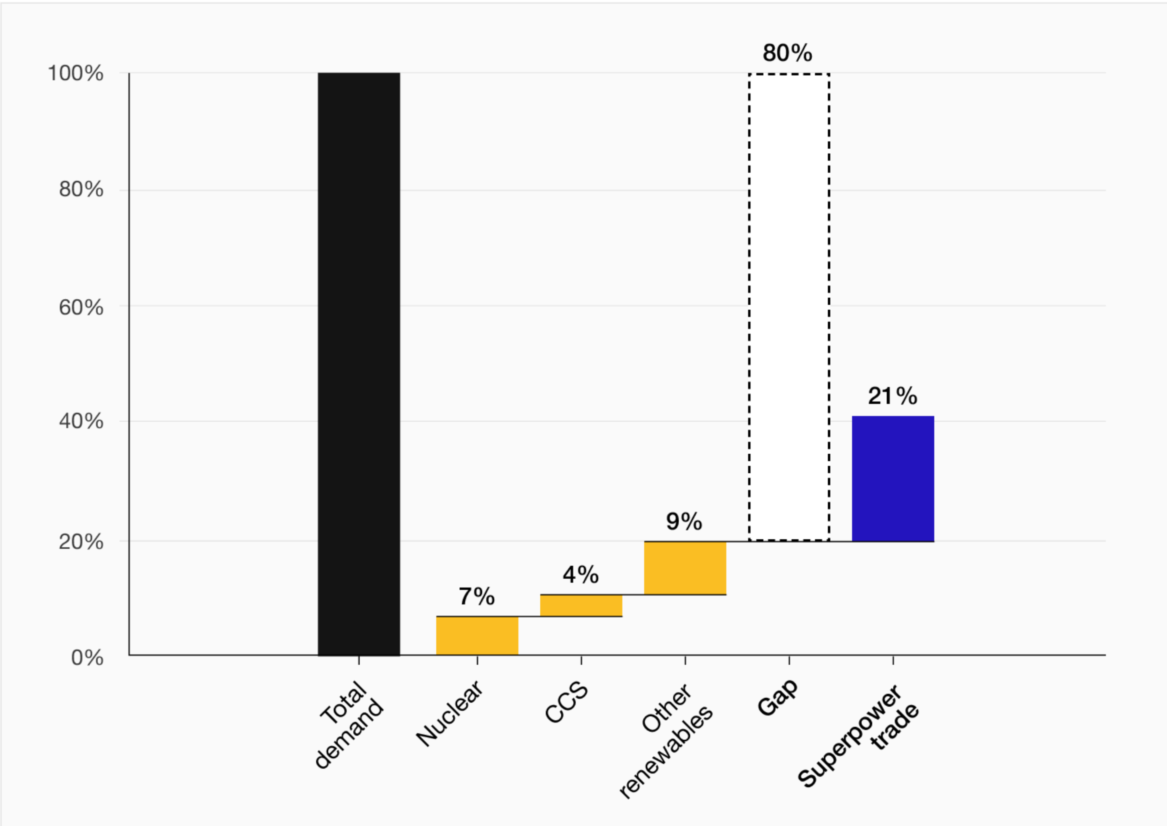

Figure 8.5. Japan's clean energy deployment as a share of demand in 2050 based on recent trends, the remaining supply-demand gap in 2050, and the potential contribution of the superpower trade.

We now turn to Japan's targets for energy deployment. Japan targets a nuclear power share of 21 percent. To achieve this, the pace of new nuclear reactor rollout must increase roughly 10-fold (from 0.23 GW to around 2.4 GW per annum), starting today. This is probably unrealistic and reflects Japan's underestimation of future electricity demand. Instead, as for China, the rate of nuclear rollout is assumed to triple, reaching an average of 0.7 GW per year. This lifts the contribution of nuclear to 250 TWh by 2050, meeting around 10 percent of demand.

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[93] This is inclusive of Japan's plan to restart around 1 GW of mothballed nuclear power per year to 2030.

Japan targets 120-240 million tonnes of CCS capacity by 2050. This is a very costly mode of climate mitigation, as Japan lacks geological formations for CO2 storage and must compress and ship CO2 for storage overseas. Nonetheless, it is assumed that a volume of 240 million tonnes will be achieved. Around 40 million tonnes is used by non-electrifiable industry. The remainder covers a mix of high-efficiency coal and LNG, with 1.8 TWh supplied for each tonne stored—hence 360 TWh satisfied.

Note that Japan plans to introduce ammonia co-firing into its coal power plants, and the Japanese government targets 30 million tonnes of ammonia by 2050 (Yoshida, 2024; Watanabe, 2022). At 40 percent power station efficiency, this ammonia will generate around 60 TWh. This is probably too low to meet needs for grid stabilisation; a higher contribution of 70 million tonnes producing 140 TWh by 2060, equal to that forecast for Korea (see next section), is assumed. This is a superpower trade, so this is added to the contribution of that trade.

Japan targets an increase in solar to 108 GW by 2030, which requires around 3.5 GW per year. This would be a slowdown from its recent efforts. It targets just 10 GW of wind by 2030, which would require lifting the install rate to around 0.7 GW per year.

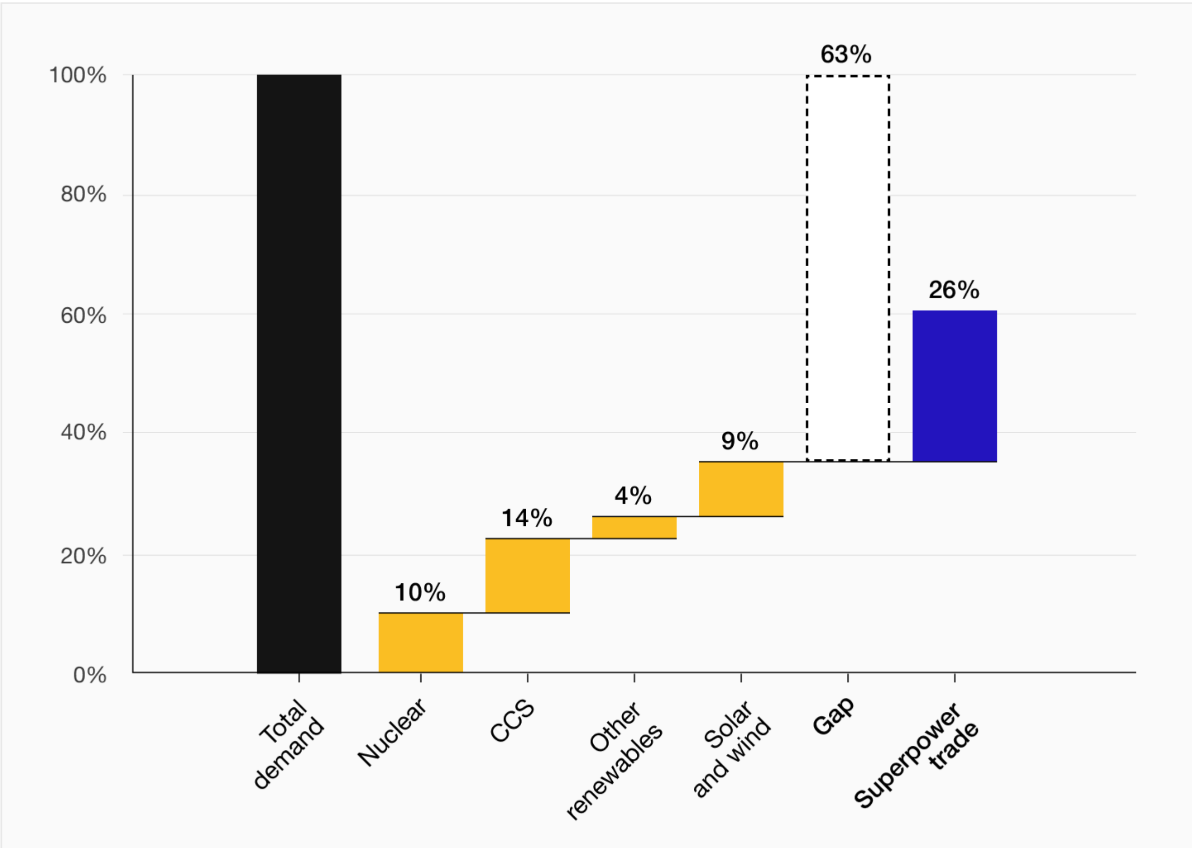

Figure 8.6. Japan's accelerated supply pathway versus demand, the remaining supply-demand gap in 2050, and the potential contribution of the superpower trade

This would leave Japan with around 63 percent of its demand unsatisfied. The superpower trade would make a large dent in this gap,

- closing 42 percent of the mitigation gap to 2050; and
- cutting final electricity demand by 21 percent (saving energy equivalent to 74 GW of nuclear reactors).

The economic case for the superpower trade is potent in the case of Japan, as every power generation option is costlier than the trade.

8.4 Korea

If Korea's economy were maximally electrified following the core scenario, electricity demand would increase by a factor of 2.8 to around 1,650 TWh in 2050.

At the current rate of growth in clean electricity, Korea's clean energy share would decline from 34 percent today to around 20 percent in 2050. The rate of rollout must increase around 12-fold to meet anticipated demand.

Korea has been building nuclear plants at an average rate similar to Japan for the last decade, at around 0.3 GW per year. Deployment of bioenergy and CCS is similarly negligible.

Korea's rate of solar and wind deployment is even slower than that of Japan, averaging around 3 GW and 0.1 GW respectively over the last few years. This is enough to supply only 105 TWh by 2050, around 5 percent of electricity demand.

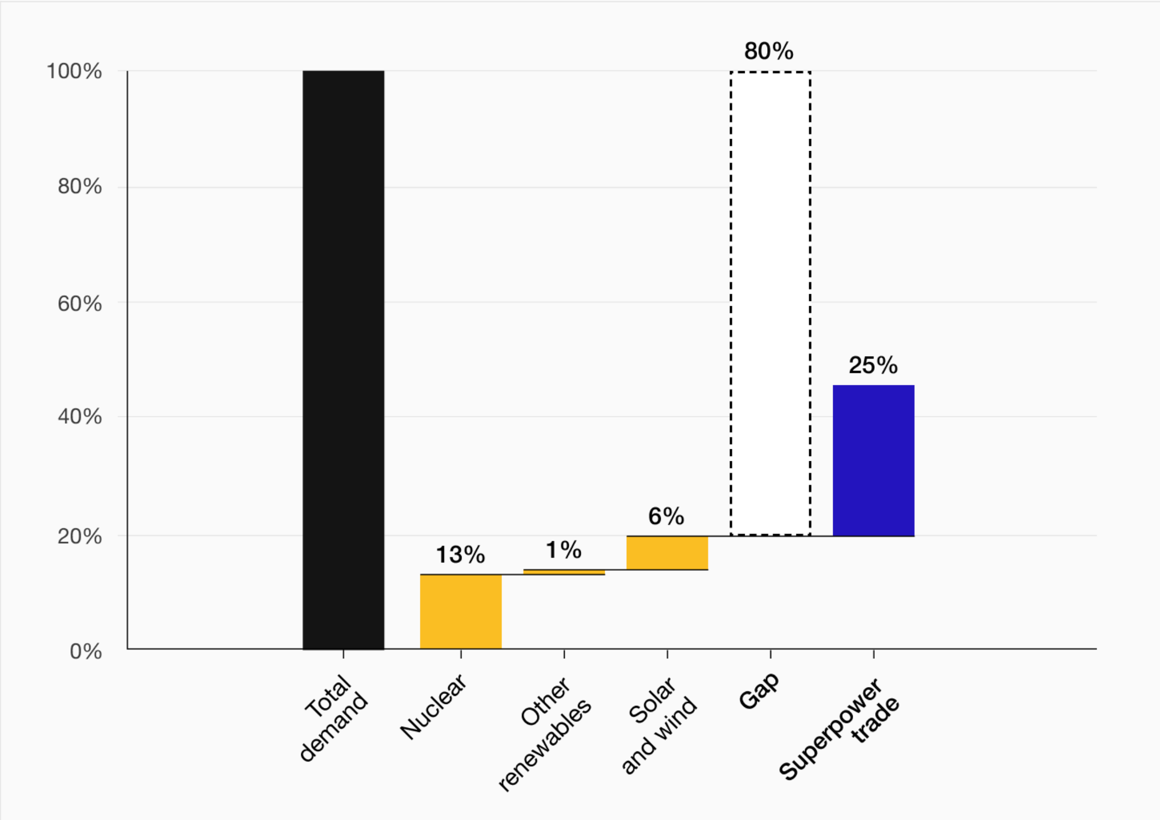

Figure 8.7. Korea's current clean energy deployment pathway as a share of demand in 2050, the remaining supply-demand gap in 2050, and the potential contribution of the superpower trade.

Korea has a target of around 230 TWh of nuclear by 2036 (ITA, 2023). To reach this target would require a tripling of the rate of installation, up to around 1 GW per year. If this is sustained to 2050, it brings nuclear to around a capacity of 39 GW of capacity, 310 TWh of generation, and a 15 percent share in demand by 2050.

Korea has a CCS target of 11 million tonnes by 2030, but no explicit longer-term target. Here it is assumed that Korea uses CCS in the same proportion as Japan, which means capturing 150 million tonnes of CO2. Around 40 million tonnes of CO2 is captured from non-electrifiable industry, and for the remainder I assume the same rate of 1.8 TWh of generation, or avoided electricity, per tonne of CO2. The CCS contribution is 200 TWh.

As noted in Section 4.4, Korea targets around 47 TWh of ammonia by 2036, increasing from 2027 at an average rate of around 4.3 TWh per year (ITA, 2023). Extending this growth linearly into the future, a total of 140 TWh of electricity would be generated from ammonia in 2060. This would satisfy around 8 percent of Korea's demand, which is below its planned ammonia contribution of 14 to 22 percent of electricity generation by 2050 (Ammonia Energy Association, 2021). This is a superpower industry and is added to that total.

Finally, Korea has retreated on its renewable energy target for 2030, reducing it from 30.2 percent to 21.6 percent. It targets roughly 72 GW of renewable energy by 2030, which would require increasing its current efforts by around a factor of 2.5. Were this pace maintained, solar and wind would supply 224 TWh, or 13 percent of Korea's energy needs by 2050.

To satisfy the remainder would require more than a fourfold further increase in the rate of installation.

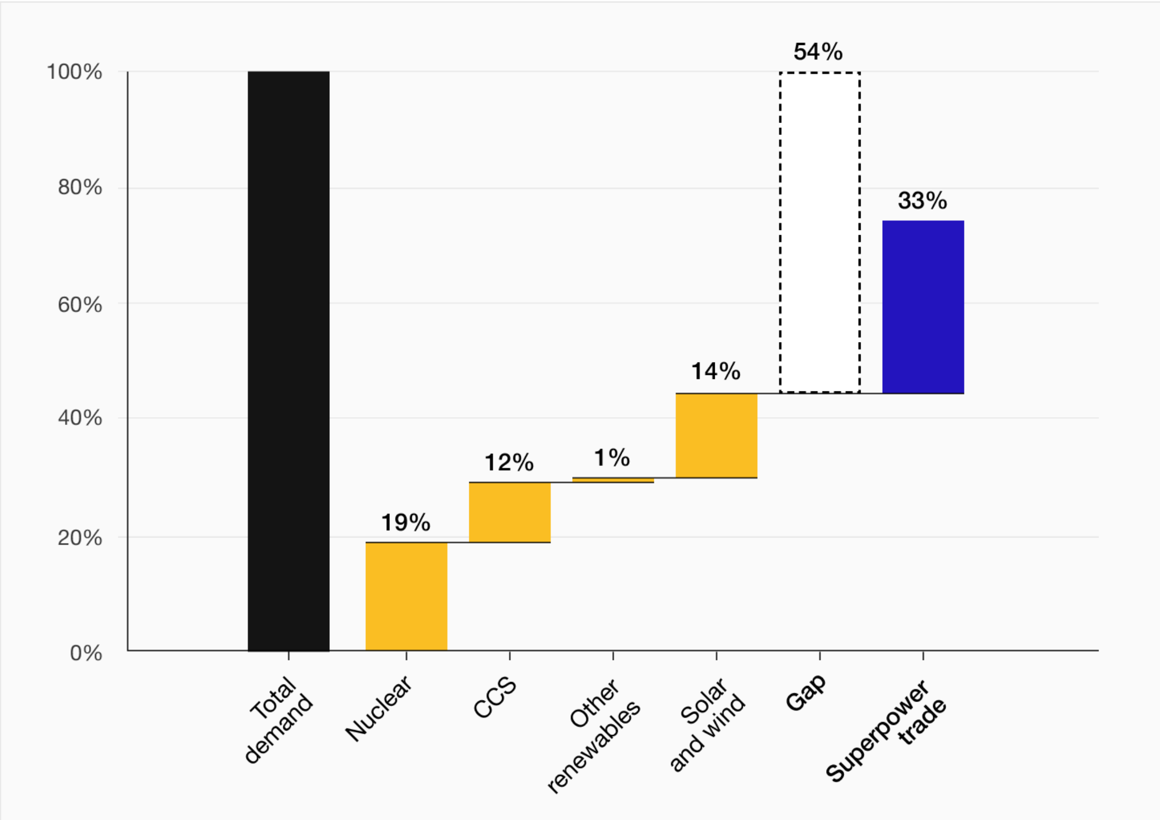

Figure 8.8. Korea's accelerated supply pathway versus demand, the remaining supply-demand gap in 2050, and the potential contribution of the superpower trade

The superpower trade, including ammonia, would:

- close 61 percent of the supply-demand gap; and
- cut Korea's final electricity demand by around 25 percent excluding ammonia, or cover 33 percent if including ammonia.

As for Japan, the superpower trade is significantly cheaper than all other generation options. The more that Korea engages with the trade, the less CO2 it must ship internationally, the less ammonia it must import, and the less it must ride up the supply curves of its poor renewable resources.

8.5 Germany

Germany currently targets net zero in 2045. Electrifying Germany's economy by then in the core scenario would lift electricity demand by a factor of 3 to around 1,650 TWh.

Germany's current rate of clean energy installation will, on these demand figures, see the share of clean energy decline from 54 percent today to 36 percent in 2045. Germany has banned nuclear power, and so far has seen a negligible increase in CCS and biomass.

Rates of solar and wind deployment are around 14 and 3 GW per annum respectively. The combined capacity will reach 445 GW by 2045, although at Germany's low capacity factors this will produce only 560 TWh. This is enough to satisfy 34 percent of demand.

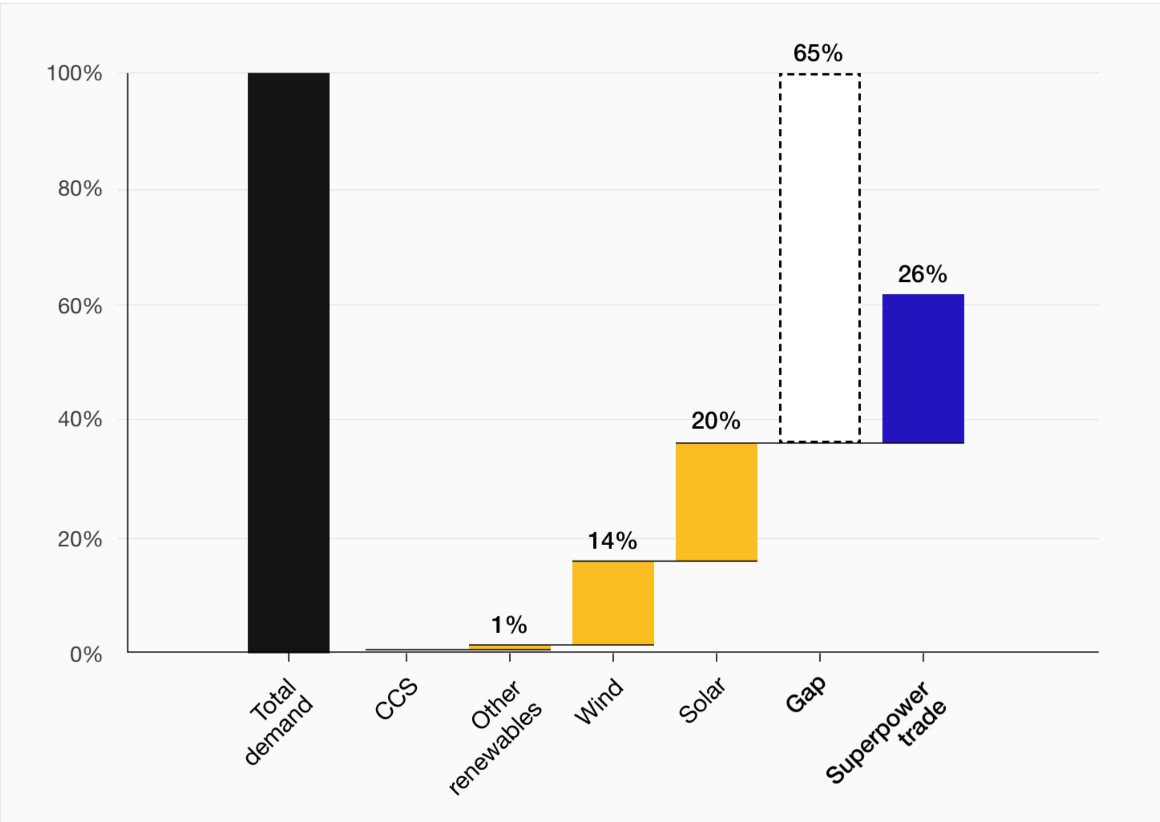

Figure 8.9. Germany's clean energy deployment as a share of demand in 2045 based on recent trends, the remaining supply-demand gap in 2045, and the potential contribution of the superpower trade.

The German government proposes CCS capturing around 73 million tonnes of CO2 per year by 2045 (Alkousaa, 2023). This is assumed to avoid or otherwise satisfy around 110 TWh of electricity demand.

Germany targets around 115 GW of wind and 215 GW of solar by 2030. This would require around a 3-fold increase in the pace of wind deployment and a 50 percent increase for solar. If this rate were maintained to 2045, wind and solar would together produce around 920 TWh and cover around 55 percent of demand in the main model of this paper.

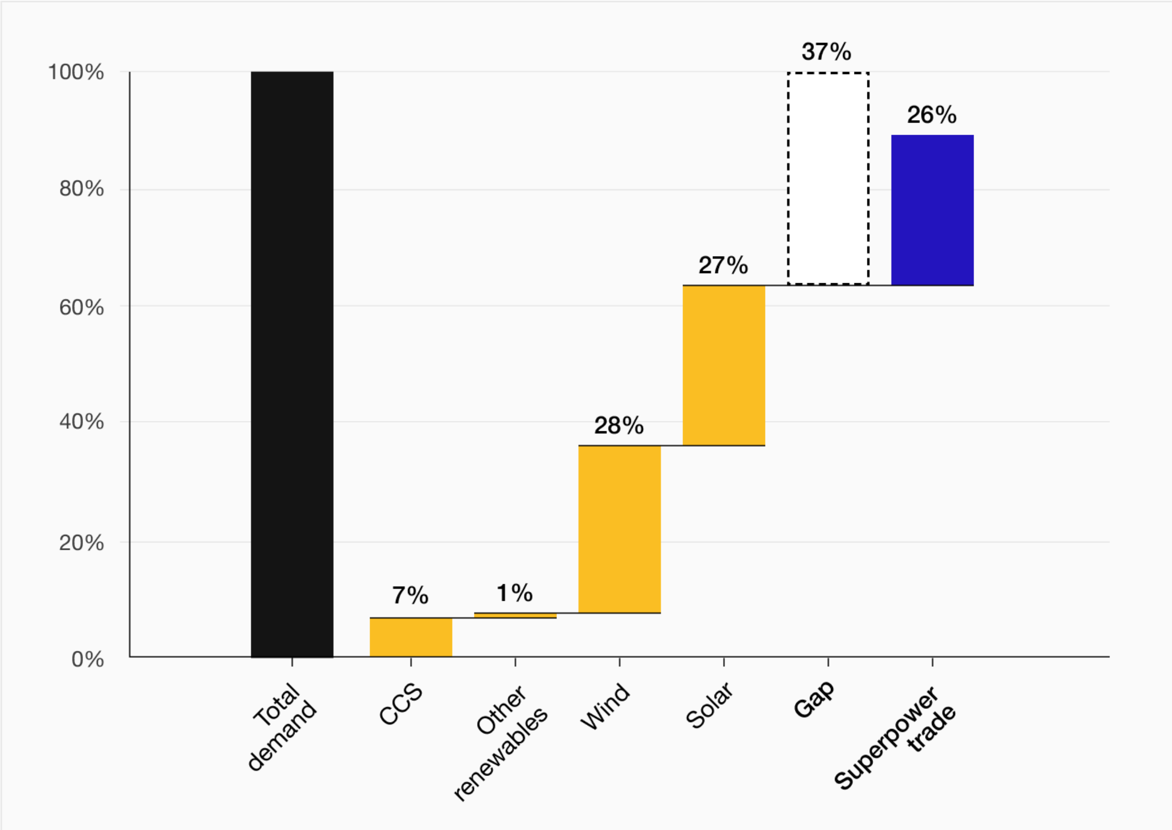

Figure 8.10. Germany's accelerated supply pathway versus demand, the remaining supply-demand gap in 2045, and the potential contribution of the superpower trade

A further 150 percent increase on top of these accelerated rates of wind and solar deployment would allow Germany to complete the task by 2045, assuming 20 percent curtailment. Illustrative solar and wind capacities would be on the order of 1,060 GW and 460 GW respectively.

Germany's renewables costs are, however, already relatively high. As noted in Section 7.1, solar is already very expensive in Germany, and Ryberg et al. (2019) find that there is only around 136 GW of mid-price wind (under €60/kWh). Cheap resources will be completely exhausted.

The superpower trade could:

- close 71 percent of the remaining gap to 2045; and
- cut final electricity demand by 24 percent.

It would come low and early on Germany's energy and mitigation supply curves.

8.6 Southeast Asia, Bangladesh, and Nepal

It is worth a brief comment on other Asian neighbours of Australia, including the countries of Southeast Asia, and Bangladesh and Nepal. They face a similar situation to that of India, but with an even more challenging renewables endowments. Their combined population is around two thirds that of India, with higher average population growth. They are developing rapidly, mostly from a similar or higher base than India. The growth in their production of energy-intensive materials such as steel is picking up pace.

Wind energy is exceptionally poor across these countries, even more so than in India. Solar energy is also considerably poorer and more seasonal than in India, because they lack India's western deserts and northern highlands. They have minimal experience in nuclear power, and immense rates of deployment would be required to meet future demand. Interest in CCS is therefore intensive in countries such as Indonesia, where its legacy of petroleum production helps to define suitable geological structures.

Energy will be expensive in these countries compared to others such as China, which have been more generously endowed with renewable energy. They will not be suited to energy-intensive industries, and will be important participants in the superpower trade.

09.

Australia's role: Superpower industry share, mitigation contribution, benefits, and required reforms

Australia has for practical purposes unlimited high-quality renewable resources on sparsely populated land, and hence faces a comparatively flat supply curve. Its domestic need for electricity outside the superpower industries will be small, at around 3 percent of that of China. It is therefore one of the natural homes for energy-intensive industries. Others include the Middle East and Sahara, the highlands of Chile and Peru, and to a lesser degree Brazil. Each of these will likely take some share; Australia has some advantage as by far the largest, and the most institutionally stable and mature large-scale superpower trade partner. Its status as a developed country with a large-scale established resources trade lowers the supply price of capital for investment in superpower industries.

The realisation of the superpower trade with the five selected countries would require that exporters, including Australia, embed around 17,100 TWh of electricity in the tradables. The full potential is larger still, extending to include other importer countries in Asia, Europe, and elsewhere. A back-of-the-envelope analysis, taking Southeast Asia as similar to India, and the remainder of Europe as having two-thirds the needs per unit GDP of Germany, implies an additional potential trade of around 4,000 TWh.

The potential expands if we include other energy-intensive tradables not covered here, and especially if green plastics become more widespread than presumed in this paper. These are matters for future work.

9.1 Australia's global mitigation contribution

It is estimated that setting Australia up as a renewable energy superpower, using cheap electricity to produce energy-intensive metals, and turning biomass into green feedstocks and fuels, could help to cut global emissions by 7-10%. At its full extent, this would make Australia the third most significant contributor to global climate mitigation, ahead of the EU and after China and the US.

Table 9.1 summarises each superpower industry's contribution to global CO2 emissions, Australia's potential share of the market for each industry, and so Australia's potential contribution to global climate mitigation. Australia's potential shares in the iron/steel and aluminium trades are defined by its current shares in global ore production (Box 9.1). At the limit, Australia could process all of these ores before export.

For the other materials, a flat 25 percent share is considered an upper limit. There are only a few competitors in the superpower trade, and Australia is well-positioned geographically, diplomatically, and institutionally to take a large share. Setting this to 15 or 20 percent makes only a modest difference, given the magnitude of the contribution from steel.

An exception is road freight, for which a potential of 15 percent is considered. Fuel for trucks is less intensively traded than that for ships and aircraft, in part because supply chains are much more dispersed and energy security concerns are more significant.

Table 9.1. Key tradable shares in global emissions, Australia's potential market share, and the resulting mitigation contribution

	Iron/ steel	Alumin.	Silicon & polysilicon	Ammonia & urea	Methanol (industrial)	Shipping	Aviation	Road freight	Total
Australia's potential market share	40%	30%	25%	25%	25%	25%	25%	15%	
Industry share of global emissions	8.6%	2.2%	0.7%	1.5%	0.8%	1.8%	2.2%	4.2%	**22%**
Australia's mitigation contribution	4.0%	0.7%	0.2%	0.5%	0.2%	0.4%*	0.6%	0.1%*	**6.7%**

* Excluding the share covered by batteries, including only that covered by green fuels.

Box 9.1. Australia's current role in global steel and aluminium production

China, Japan, and Korea together account for around 70 percent of global primary steel production. Each source a majority of their iron ore from Australia.

Around 62 percent of China's iron ore imports came from Australia, 21 percent from Brazil, and small amounts from another twenty or so countries. Including China's domestic ore production and weighting by iron content, Australia contributed around 55 percent of China's iron ore.[94] Japan and Korea have minimal domestic iron ore production, so Australia's import share—53 percent and 62 percent respectively—is around its share in total consumed ore. In 2021, around 883 million tonnes of exported iron ore was turned into around 550 million tonnes of steel.

In 2021, including a few other marginal importers, Australian ore was behind around 40 percent of global primary steelmaking. Australia's iron ore exports are therefore linked to about 4.4 percent of emissions from all sources. This underlines part of the superpower story: Australia can make an outsized global mitigation contribution by green processing of iron ore into iron metal, and perhaps also steel, before export.

[94] Average Chinese iron ore Fe content is around 34 percent, of which it mined about 400 million tonnes; compare to the average 60 percent grade exported from Australia (Chen et al., 2022).

Australia is also a major exporter of bauxite and alumina for aluminium production. Most bauxite exports go to China, while alumina is exported to a wide variety of smaller players. Altogether, Australia exports around 37 million tonnes of bauxite and 17 million tonnes of alumina, and is linked to around 30 percent of global primary aluminium production. Around half of that arises from exports to China.

These industries are continuing to grow, and this expands the potential contribution of the superpower trade to global mitigation beyond the figures in Table 9.1. The consequences of industry growth are examined in Table 9.2.

Note that while Table 9.1 estimates Australia's potential mitigation contribution as a share of global emissions in 2021, it is not possible to confidently project industry shares into the future for Table 9.2. Thus, Table 9.2 estimates the future global mitigation contribution taking 2021 emissions as a baseline. Table 9.2 does not indicate industries' expected shares at any point in the future.[95]

Table 9.2. Key industry growth to 2060: Effect on Australia's potential contribution to emission mitigation, expressed relative to 2021 global emissions

	Iron/ steel	Alumin.	Silicon & polysil.	Ammonia	Methanol (indust.)	Shipping	Aviation	Road freight	Total
Expected industry growth to 2050	10%	30.40%	100% (Si), 300% (PSi)	300%	30%	0	100%	180%	
Industry CO2 after growth, expressed as a percentage of 2021 emissions	9.5%	2.9%	2.1%	6.0%	1.0%	1.8%	4.4%	11.8%	39.5%
Aust. potential mitigation, relative to 2021 global emissions	4.4%	0.9%	0.5%	1.5%	0.3%	0.4%*	1.1%	0.4%*	9.6%

* Excluding the share covered by batteries, including only that covered by green fuels.

If all these industry shares are achievable, Australia's potential contribution lies between the lower and upper bounds of 6.7 and 9.6 percent. Today, 60 percent of the potential is in iron/steel. Given slow expected growth in primary steel compared to other superpower industries, the mitigation potential of the iron/steel trade will be about equal to that of all the other industries in the long term.

[95] This would require estimating a range of complex factors over time: the change in global emissions; relative rates of decarbonisation across all sectors, which will tend to increase the share of industrial emissions; and the share of growth in each key industry that will be met with fossil fuels. Road freight mainly falls into the easy-to-abate category, and will be more likely to shrink as a share of global emissions over time.

9.2 Export value for Australia

Australia's large fossil fuel exports will gradually decline into mid-century. Coal exports are typically worth on the order of $70 billion, and LNG on the order of $50 billion. Their peak value, during the global supply disruptions of the last few years, was around $220 billion in 2023. As these disruptions settle, their value is expected to revert back to a combined $110-130 billion.[96]

Superpower industry export revenues would replace fossil fuel export revenues many times over. The below briefly analyses global industry market sizes, and the potential export revenue for Australia given its potential shares in each industry. Deeper analysis is left for future work.

Where not otherwise indicated, figures below are in Australian dollars. Note that it is assumed that the green premium is zero—that is, by mid-century, green production methods and fuels reach price parity with fossil fuels. This is more likely for some industries, especially those without large carbon feedstock requirements, than for others. Adding green premia would increase these estimates.

Iron production most clearly benefits from Australia's comparative advantages, as the most energy-intensive and least labour-intensive step in the steelmaking process. A typical price for direct reduced iron is around US$450, or AU$690, per tonne. Australia's recent exports could be converted into around 560 million tonnes of direct reduced iron, for a total revenue of around $386 billion. Because iron ore would no longer be exported, the actual export revenue gain would be $75 to $100 billion lower. Taking a middle value, the increase in export revenue is around $304 billion.[97]

Aluminium would be produced from Australia's current bauxite and alumina exports, of around 36 and 21 million tonnes respectively (Australian DISR, 2022; International Trade Centre, 2024). The estimated aluminium price is $3500/tonne. Australia could produce around 19.25 million tonnes of aluminium, for a total revenue of $67 billion. After deducting the value of bauxite and alumina exports, together around $9 billion, Australian export revenues would increase by around $58 billion. With industry growth of 33 percent to 2060, and if Australia increases bauxite mining to maintain its market share, total export revenues would be around $89 billion.

The price of metallurgical grade **silicon** peaked at around AU$13,000 per tonne in 2022, but more typical prices are AU$3000 per tonne. Typical ferrosilicon prices are around AU$1,800 per tonne. With 3.7 million tonnes and 5.5 million tonnes produced respectively, the combined global market size at these prices would be around AU$21 billion. A doubling to 2060 would lift this to AU$42 billion.

Polysilicon prices vary considerably depending on the purity and structure of the material, and have been extremely volatile in recent years due to cycles of under- and over-supply. Assuming that current market saturation resolves, but that technology progress brings further price reductions, a price of AU$15,000 per tonne is estimated. With around 1.5 million tonnes produced per year today, this gives a global market value of around AU$22.5 billion, consistent with industry analysts (Mordor Intelligence, 2024a). This reaches around AU$100 billion following growth of solar and semiconductor industries to 2060.

With a 25 percent share in these markets, Australia would have export revenue on the order of AU$11 billion to AU$36 billion on today's and modelled 2060 production levels respectively.

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[96] The Australian DISR (2023) forecasts coal exports to return to around $69 billion in 2024-25. LNG is expected to decline to around $65 billion, before potentially falling to $45 billion by the end of the decade (Toscano, 2024).
[97] It is assumed that Australia's iron ore mining output does not increase with global growth in demand for primary steel, given the expected increase in production in several competitor countries.

Note that Australia is the world's second largest exporter of silica and quartz sands and exports around 44,000 tonnes of metallurgical grade silicon (CSIRO, 2024). The value of these exports is small and does not affect the above figures for net revenue gain from silicon and polysilicon.

Ammonia production reached around 188 million tonnes in 2021. The price of brown ammonia is sensitive to natural gas prices, so has sharply increased since the Russia-Ukraine war. A more typical price is around of around AU$400/tonne, which would give a market size of around AU$75 billion. It has been assumed that the market will quadruple to 2060, mainly for ammonia as a medium for long-term energy storage. This would lift the market value to AU$300 billion. A 25 percent share in the market of today and the future would be AU$19 billion and AU$75 billion respectively.

Urea prices similarly spiked since 2021, but will likely fall towards their previous level of around AU$450 per tonne (Bansal & Rawal, 2020). At those prices, and production levels of around 177 million tonnes, the market value would be around AU$80 billion. A 25 percent share would provide AU$20 billion of revenue at that level of production, or AU$30 billion with 50 percent industry growth by 2050.

Methanol spot prices have been around US$350, or AU$530, per tonne over the last few years in China, Europe, and the US (Statista, 2024b; MMSA, 2024). At the 2021 level of production, around 110 million tonnes, the market value comes to around $58 billion. This rises to AU$117 billion after a doubling of production to 2060. If Australia took 25 percent of the market, the value would be around $15 billion today or $29 billion by 2060.

Shipping uses several different types of fuels, with each priced differently and (except for LNG) affected by the underlying price of oil. At a crude oil price of US$80 per barrel, a breakdown of current fuel shares and their respective prices suggests that the shipping fuel market is worth about AU$250 to AU$300 billion per annum. This is the same range of estimates in market analyses (Mordor Intelligence, 2024b; Imarc, 2024). With zero forecast growth, this is the market value in the future too.

Alternatively, the value may be estimated from the methanol price. Around 390 million tonnes of methanol would be required, and at the current brown methanol price of $530 per tonne, total market value would be $207 billion. This lower value will be used here.

Because of the decline in the shipping of fossil fuels, no market growth is projected to 2060. Finally, some shipping will be electrified directly through batteries: inland shipping and half of short-sea shipping. If these are excluded, the value falls to around $172 million. If Australia took 25 percent of that market, total revenue would be around $43 billion.

Aviation consumed about 2.6 billion barrels of jet fuel, in 2019. At a price of around US$90 per barrel of jet fuel, a middle value over the last several years, total market size would be around AU$360 billion. The core scenario assumes growth of 75 percent, which would lift the market size to AU$630 billion.

Assuming price parity is reached, if Australia took 25 percent of the observed 2019 or forecast 2060 market, export revenues would reach $90 billion and $158 billion respectively.

Road freight consumes around 18 percent of global oil, or around 6.4 million barrels in 2021. At an average world price of US$1.2, or about AU$1.8, per litre, this has a value of around AU$1.8 trillion. Following ITF (2023) analysis to 2050, with assumed slowed growth to 2060, road freight volume increases by 180 percent. However, only 20 percent is modelled as decarbonised via hydrogen and methanol. If we assume that green fuels achieve parity with today's prices per tonne-kilometre, the green fuel market would be around AU$1 trillion.

Were Australia to capture 15 percent of the market, export revenues would be around AU$156 billion. A persistent green premium would lift revenue per unit exported, but would be more likely to increase the dominance of batteries and reduce market size.

Potential revenue estimates by industry are summarised in Table 9.3.[98] The most significant contributor is direct reduced iron, at more than half of the opportunity on contemporary levels of industrial output, and around 39 percent of that available in 2060.

The total potential is around 6 to 8 times larger than the size of typical Australian fossil fuel exports. Realising a fraction of the potential indicated here, e.g. with global market shares averaging around 4 percent, would be enough to replace Australia's fossil fuel export revenue.

Table 9.3. Australia's potential superpower industry revenue, excluding green premia

	Iron	Aluminium	Silicon & polysilicon	Ammonia & urea	Methanol (industrial)	Shipping	Aviation	Road freight	Total
Potential market share	40%	30%	25%	25%	25%	25%	25%	15%	
Export revenue, contemporary market size	$386 billion	$67 billion	$11 billion	$29 billion	$15 billion	$43 billion	$90 billion	$54 billion	**$693 billion**
Export revenue, 2060 market size	$386 billion	$89 billion	$36 billion	$90 billion	$29 billion	$43 billion	$158 billion	$156 billion	**$987 billion**

9.3 Electricity and carbon demand in the Australian superpower trade

Beginning with **iron**, at the limit Australia may turn its 2021 ore exports—883 million tonnes—into iron metal via the H2-DRI route before shipping it overseas EAF plants to be turned into steel. The DRI process would require around 2,220 TWh of clean electricity in Australia. The H2-DRI-SMELT route, which allows the use of conventional BOFs, would allow use of lower-grade ores but raise electricity requirements.

Carbon may be added during the DRI process or may be added into the EAF. Roughly 40 kg of carbon is required per tonne, although reportedly carbon requirements may double if added in the EAF step. It may therefore be appropriate to add this carbon in Australia. On the order of 23 million tonnes of carbon would be needed.

If Australia retains an **aluminium** market share of 30 percent and processes it into green aluminium prior to export, it implies electricity demand of around 360 TWh. This figure rises to 490 TWh into mid-century.

Taking 25 percent of the future global **silicon** and **polysilicon** markets would increase electricity demand by around 320 TWh. This includes around 30 TWh for ferrosilicon, 20 TWh for

[98] Totals on contemporary and forecast 2060 production levels are $496 billion and $753 billion respectively after deducting the value of current iron ore and bauxite/alumina exports, which are used to produce direct reduced iron and aluminium.

metallurgical grade silicon, and 270 TWh for polysilicon. The production of ferrosilicon and metallurgical grade silicon would require around 12 million tonnes of carbon.

A 25 percent share in **ammonia** production would entail around 525 TWh of electricity demand in Australia. If demand increases fourfold, this rises to 2,100 TWh.

Requirements for **urea** are more modest. A 25 percent share in the anticipated future market would require roughly 88 TWh. Around 15 million tonnes of carbon would be needed.

A 25 percent share in the industrial methanol market would require electricity equal to around 260 TWh if biomass carbon is available, or up to 665 TWh if DAC carbon is required. Production would need roughly 23 million tonnes of carbon.

In the case of **shipping**, first exclude the battery powered short-sea and inland component. If Australia takes a 25 percent share of the methanol-powered share of the short-sea and deep-sea shipping markets, it would require 560 TWh if biomass carbon is available, or 1,150 TWh with DAC-sourced carbon. Carbon needs would be around 50 million tonnes.

Taking a 25 percent share in global **aviation** markets, in the core scenario with 75 percent industry growth to 2060 and a mix of 40 percent SAF and 60 percent hydrogen, implies electricity demand of around 2,180 TWh.[99] Carbon demand would be around 68 million tonnes.

With a 15 percent share in the **road freight** green fuels market, with a 50:50 mix of hydrogen and methanol, electricity demand would amount to 780 TWh and carbon demand to 24 million tonnes.

The marginal cost of mitigation will be particularly high for aviation, and it may therefore be among the last of sectors to be decarbonised. Alternatively, if DAC prices fall sufficiently, aviation emissions may be offset by DAC with geological storage.

Total demand is presented in Table 9.4, assuming biomass availability and otherwise taking middle values. Electricity needs would be 9,000 TWh, and carbon requirements around 214 million tonnes.

Table 9.4. Electricity and carbon requirements for the Australian superpower trade

	Iron	Alumin.	Silicon & polysil.	Ammonia & urea	Methanol (indust.)	Shipping	Aviation	Road freight	Total
Electricity required (TWh)	2,220	490	320	2,190	260	560	2,180	780	**9,000**
Carbon required (Mt)	22	0	12	15	23	50	68	24	**214**

9.4 Australian resources: Capacity and land requirements

The average capacity factor for wind farms in Australia is around 30-35 percent. There is a large resource around the midpoint of this range. Typical quality solar resource capacity factors are around 26 percent; note that recorded values of 27 to 32 percent reflect (e.g. in Broken Hill, Moree, and Barcaldine, see Edis, 2023) reflect oversizing of generators compared to the inverter,

[99] This also assumes a 20 percent improvement in aircraft efficiency.

which exaggerates capacity factors. Let us assume a 50/50 mix of wind and solar, and take 30 percent as an average.

At this capacity factor, supplying 9,000 TWh would require around 3.4 TW of wind and solar.

How much land is required to meet this level of demand? The NREL (see Ong et al., 2013) analysed existing utility-scale solar plants in this US and found around 3.4 acres was required to produce a GWh in 2013 (including indirect land use). Average US capacity factors are around 24 percent, and the best Australian resources are around one third better. Adjusting for this difference, around 2.5 acres would be required per GWh for superpower projects. This may be an overestimate given recent, and anticipated, improvements in PV technology.

In the case of wind, actual turbine footprints are small and may be integrated into agricultural land, while total wind project sizes are significantly larger. Ritchie (2022) estimates that around 400 square meters is directly used per GWh, while total project area may be at minimum just over 2 acres per GWh. At the higher end, the Roscoe Wind Farm in Texas sparsely integrates turbines into agricultural land, and the project covers 45 acres per GWh. Superpower projects will not be based on agricultural land, so lower land use rates are more relevant.

Solar needs an estimated 4.5 million hectares. Wind requires just 170,000 hectares directly, but projects would extend over around 3.7 million hectares. Together, the required renewable energy would span about 1.1 percent of Australia, although only 0.6 percent would be used directly.

9.5 Grasping the opportunity: Australian policy reform

The case for establishing the superpower trade is exceptionally strong for Japan, Korea, and Germany from today into the early 2030s. The case for China is proportionately less compelling than Japan, Korea, and Germany, but will commence early and is absolutely very large. For India and Southeast Asia, the trade may begin in the 2030s and accelerate into the 2040s. Maximising the Australian superpower trade depends on maximising competitiveness against other superpower contenders.

The specifics of the policy frameworks required to grasp the opportunity are largely beyond the scope of this paper. They have been articulated in Garnaut (2022), Garnaut's and Sim's speeches to the Australian National Press Club that are published in Garnaut (2024), and Superpower Institute (2024) submissions to government inquiries. They are the focus of forthcoming work from the Institute.

It is worthwhile briefly emphasising six issues for further work.

The first is **addressing market failures**. There are three main market failures, requiring three distinct responses:

1. **The non-pricing of CO_2**. Carbon emissions are a negative externality imposing large costs on society. Currently most emitters can release carbon for free, creating a major market failure. Carbon pricing is essential to allow zero or low-carbon technologies to compete on a level playing field, and so attract investment.

2. **Innovation spillovers.** Early-movers pay large costs and take on large risks, generating knowledge that then benefits other late-moving players. In economic terms, early-movers generate positive externalities, and efficient market operation requires subsidies. The future social return from innovation determines the size of the innovation market failure,

and so the magnitude of efficient support. In the case of superpower industries in Australia, the magnitude is very large.

3. **Common infrastructure spillovers**. Early-movers must also pay large costs for establishing transport, transmission, pipeline, and other basic infrastructure in superpower regions. Private actors lack the incentive to provide such infrastructure at efficient scale. Government support, along with common user or consortia approaches, will be required to efficiently establish natural monopoly infrastructure.

The second is **reliance on market forces**, with zero-carbon projects competing on a level playing field. Having resolved market failures, the choice between technologies and projects should be left to the market. Approvals processes should be transparent and support made equally available to any credible firm that applies.

Australia is presently debating the centrally-planned rollout of a very expensive electricity generation technology, nuclear power. Unlike the US, EU, and UK, Australia has no established nuclear industry. Australian costs are highly likely to exceed the US Vogtle plant cost of AU$270/MWh. No evidence supports the idea that costs will decline from the first gigawatt to the tenth (see Figure 7.5 from Eash-Gates et al., 2020; also see Lang, 2017). Insofar as the costs are recouped in electricity markets, consumers and industry will pay much higher costs of electricity; this would undermine Australia's comparative advantage in the superpower trade. If these assets are publicly owned, these costs are borne by the taxpayer; available funds for investing in more efficient green projects, including the early superpower projects on which Australia's future trade opportunity depends, will be greatly diminished.

Australian support for nuclear power should be equivalent to support for other zero-emissions technologies. Nuclear would benefit from carbon pricing in the same way and to the same extent as renewable energy. It warrants support for innovation under similar rules to renewable energy and other decarbonisation technologies that are new to Australia. With these policies in place, we can rely on market exchange to sort the competitive from the unnecessarily costly technologies.

The third is **openness to international trade**. Australia cannot follow the US strategy of imposing tariffs on green technologies, and investing in domestic green industries in which it has little comparative advantage. This would raise the costs of Australian power generation and industrial inputs, so weakening or eliminating Australia's comparative advantage in electricity-intensive industries. It would make Australia an unreliable partner for other countries seeking to import zero-carbon goods.

The fourth is Australian **interest rates** and so the cost of finance. The superpower industries are capital-intensive, such that competitiveness is greatly determined by the cost of capital. Maintaining internationally favourable interest rates requires careful management of debt and inflation. Of particular importance is investing in superpower industries without reliance on increases in national debt, and this warns against the US IRA model.

Australia is in competition with countries that presently have lower financing costs. China, for example, not only has lower interest rates, but also provides green investments with favourable loan terms. Concessional loans have been especially important for reducing the cost of Chinese nuclear power, and important for bringing VRE and green industries to scale.

Access to foreign capital will be essential given the scale of investment required. Foreign investment also enables technology transfer. Where there are geopolitical concerns, there is little reason to obstruct minority ownership.

The fifth is **streamlining approvals**. Projects in Australia reportedly face larger hurdles and slower processes than in competing countries. The Superpower Institute is aware of major proposed green iron projects that may become unprofitable due to lengthy and costly approvals processes. If they fail here, their contributions will be replaced by investment in the Middle East. There is some progress on this front. South Australia, for example, has legislated processes that facilitate approval for renewable energy investments. Western Australia has introduced an approvals system reform that allows complex projects with multiple approvals processes to run in parallel rather than serially (Government of Western Australia, 2024).

Australian competitiveness will depend on deep study and reform of approvals processes, and improvements in stakeholder engagement and benefits dispersal.

The sixth is **policy certainty**, which depends significantly upon bipartisan support for major economic reforms. If Australia's political leadership cannot agree on basic facts about costs and opportunities, or on sets of incentives that apply independently of *a priori* judgements about the merits of different technologies, or if they agree in private but find disagreement useful publicly, then Australia cannot provide the reliable investment environment needed to realise the Australian superpower trade at scale. The opportunity will be captured by democracies with more favourable political cultures and configurations of interests, and by authoritarian states, particularly in the Middle East.

The more that Australia succeeds in resolving these issues, the greater the share of the superpower trade it will capture.

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